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British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Mr. Patrick Wruck,
Commission Secretary and Manager, Regulatory Support

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. 2016 Rate Design Application

In accordance with the Regulatory Timetable set for this proceeding by Order G-109-17, and the extension granted by Commission letter dated September 28, 2017, we enclose for filing the electronic version of the book of authorities, with the cases and textbook authority cited in FEI's Reply Argument.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by Christopher Bystrom]

Christopher Bystrom

Encl.

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE UTILITIES COMMISSION ACT, R.S.B.C. 1996, CHAPTER 473

and

FORTISBC ENERGY INC.

2016 RATE DESIGN APPLICATION

COSA RESULTS AND RANGE OF REASONABLENESS

FORTISBC ENERGY INC.

BOOK OF AUTHORITIES FOR REPLY SUBMISSION

INDEX

CASE LAW

1. Alberta Energy and Utilities Board, Decision 2004-079, *ATCO Pipelines 2004 General Rate Application Phase II*, dated September 24, 2004

2. Alberta Energy and Utilities Board, Decision 2007-086, *ATCO Electric Ltd. 2008 Distribution Tariff Phase II*, dated November 8, 2007

3. Alberta Energy and Utilities Board, Decision U99034, *Alberta Power Limited 1996 General Rate Application – Phase II*, dated August 10, 1999

4. British Columbia Utilities Commission, *Decision In the Matter of British Columbia Hydro and Power Authority Application For Approval Of Rates Between BC Hydro And FortisBC Inc. With Regards To Rate Schedule 3808, Tariff Supplement No. 3 – Power Purchase And Associated Agreements, And Tariff Supplement No. 2 To Rate Schedule 3817*, dated May 6, 2014 (Order G-60-14)

5. British Columbia Utilities Commission, *Decision In the Matter of FortisBC Inc. Application for Approval of Stepped and Stand-By Rates for Transmission Voltage Customers*, dated May 26, 2014 (Order G-67-14)

6. *Canso Electric Light Utility (Re)*, 2015 NSUARB 195

7. *Domtar Inc. v. Quebec (Commission d'appel en matière de lesions professionelles)*, [1993] 2 S.C.R. 756, 1993 CanLII 106

8. *I.W.A. v. Consolidated Bathurst Packaging Ltd.,* [1990] 1 S.C.R. 282

9. New Brunswick Energy and Utilities Board, *Decision In the Matter of an Application by New Brunswick Power Corporation pursuant to the Electricity Act, S.N.B. 2013, c.7, for the Approval of a Class Cost Allocation Study Methodology,* dated May 13, 2016 (Matter No. 271)

10. Newfoundland & Labrador Board of Commissioners of Public Utilities, Order No. P.U. 13(2013), *Decision and Order of the Board In the Matter of a General Rate Application Filed by Newfoundland Power Inc.,* dated April 17, 2013

11. *Nova Scotia Power Incorporated (Re)*, 2014 NSUARB 53

12. Ontario Energy Board, Decision EB-2013-0416/EB-2014-0247, *In the Matter of an Application by Hydro One Networks Inc. for Approval of Distribution Rates for 2015-2019*, dated March 12, 2015

CASE LAW

13. Ontario Energy Board, Decision and Rate Order EB-2011-0210, *In the Matter of an Application by Union Gas Limited for an Order or Orders Approving or Fixing Just and Reasonable Rates and Other Charges for the Sale, Distribution, Transmission and Storage of Gas Commencing January 1, 2013*, dated January 17, 2013

14. Prince Edward Island Regulatory and Appeals Commission, Order UE16-04R*, In the Matter of an Application by Maritime Electric Company, Limited to Approve the Rates, Tolls and Charges for Electric Service for the Period Beginning March 1, 2016 and for Certain Approvals Incidental Thereto*, dated July 11, 2015 (Docket UE20942)

15. Yukon Utilities Board, Board Order 2005-1, *In the Matter of an Application by Yukon Energy Corporation for Approval of 2005 Revenue Requirements*, dated January 27, 2005

SECONDARY MATERIALS

16. Macaulay & Sprague, *Practice and Procedure before Administrative Tribunals,* s. 6.5A (extract)

Decision **2004-079**

ATCO Pipelines

2004 General Rate Application
Phase II

September 24, 2004

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2004-079: ATCO Pipelines
2004 General Rate Application – Phase II
Application No. 1315997

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Contents

List of Tables

ATCO PIPELINES	**Decision 2004-079**
2004 GENERAL RATE APPLICATION	**Application No. 1315997**
PHASE II	**File No. 4100-3**

1 INTRODUCTION

On October 1, 2003, ATCO Pipelines (AP), a division of ATCO Gas and Pipelines Ltd., submitted a Phase II application (the Application) to the Alberta Energy and Utilities Board (the Board or EUB), seeking approval of 2004 rates for North and South zones.

A Notice of Hearing was distributed by e-mail on October 29, 2003 to the parties on the AP 2003-2004 General Rate Application (GRA) Phase I distribution list. Notice was also published in the major Alberta newspapers on November 4, 2003. A list of parties who appeared at the hearing is included in Appendix 1.

The final process schedule for the Application was outlined in a December 15, 2003 letter from the Board, with the public hearing set to commence on May 3, 2004.

The Board panel assigned to this application was comprised of Ms. C. Dahl Rees, LL.B., (Chair), Mr. B. T. McManus, Q.C., Member and Mr. M. W. Edwards, Acting Member.

The Board considered the Application at a public hearing held in Calgary from May 3, 2004 to May 7, 2004 and from May 17, 2004 to May 20, 2004. Written Argument and Reply were submitted on June 10, 2004 and June 28, 2004 respectively. Accordingly, for purposes of this Decision, the Board considers that the record closed on June 28, 2004.

In this Decision, the Board will make a determination as to 2004 cost allocations and rate design directions for AP, with final rates to be fixed following the submission of a Compliance Filing.

Having heard the evidence and reviewed the arguments of the interested parties, the Board hereafter sets out its Decision with reasons respecting the Application.

2 BACKGROUND AND OVERVIEW

2.1 Background

On December 18, 2002, AP requested approval to allow continuation of approved 2002 rates and Rate Schedules for AP North (APN or the North) and AP South (APS or the South) customers on an interim basis effective January 1, 2003. In Order U2002-1034, dated December 20, 2002, the Board approved the application.[1]

[1] The Order stated: AP's rates, tolls, and charges, approved in Decision 2001-53 and set out in Schedule "A" of Decision 2000-84 are hereby approved, on an interim basis, as a continuation of 2002 rates and Rate Schedules effective January 1, 2003.

On February 14, 2003, AP filed its 2003/2004 Phase I North, South and Total GRA.

By letter of April 11, 2003, AP requested approval to commence negotiations regarding all aspects of the 2003/2004 Phase I and II GRA for the North and the South.

In Decision 2003-035, dated April 30, 2003, the Board approved the application to negotiate with respect to Phase I and II matters for 2003, but did not approve negotiations for 2004 matters. AP was directed to continue to advance its GRA of February 14, 2003 with respect to 2004 matters.

The Board noted that it was necessary to have a more extensive examination of the 2004 issues than would be possible in the review of a negotiated settlement in light of the length of time since the last APN GRA and in light of the competitive issues arising between AP and NOVA Gas Transmission Ltd. (NGTL).

By letter dated May 30, 2003, AP requested that the Board vary Decision 2003-035 to allow AP and its customers to negotiate 2003 and 2004 depreciation matters, on the grounds that this was an independent and specialized portion of the GRA. In a letter issued on June 2, 2003, the Board varied Decision 2003-035 to allow negotiations regarding 2004 depreciation issues. With respect to cost of capital matters, the Board directed that 2004 cost of capital matters be addressed in the generic proceeding which had been convened by the Board.

In a letter dated June 10, 2003, the Board set aside consideration of the Muskeg River pipeline and related issues, as a separate module, to a later date following the compliance filing of AP related to Decision 2003-040, Affiliate Transactions and Code of Conduct, Part B.

On June 13, 2003, AP filed a settlement application with respect to 2003 and 2004 depreciation matters.

On October 1, 2003, in response to Board Decision 2003-003 and Board letters of August 1, 2003 and September 11, 2003, AP applied for the approval of a revised set of postage stamp rates for each of APN and APS. In support of its request for revised rates, AP filed a cost of service study for 2004 for each of the North and South zones. AP also requested the approval of deferral accounts for other pipeline receipts and other pipeline delivery costs along with a request for approval for amendments to rate structures and to transportation service regulations.

On December 2, 2003, the Board issued Decision 2003-100 approving Phase I revenue requirements, subject to compliance filings, for AP on behalf of APN and APS, for the test years 2003 and 2004. With respect to certain matters[2] in that proceeding, AP was directed to include "placeholder" amounts, pending final determination of those amounts in separate Board proceedings or by applicable authorities.

On December 31, 2003, AP submitted a letter to the Board requesting consideration of several items in Decision 2003-100 that AP felt required correction. The letter also sought clarification

[2] ATCO I-Tek service fees to be benchmarked, ATCO executive compensation amounts, the Muskeg River pipeline module, 2004 Cost of Capital, actual income tax rates and actual NGTL charges.

and requested guidance from the Board regarding other matters, prior to submitting its revised filing of Phase I matters on January 26, 2004.

On January 15, 2004, the Board issued Decision 2004-003, an Errata to Decision 2003-100. In this Decision, the Board provided AP with further clarification and guidance regarding certain Phase I matters, along with the correction of errors or omissions that resulted from its own review of Decision 2003-100.

On January 26, 2004, AP submitted to the Board its 2003/2004 GRA Phase I refiling (the Compliance Refiling) which incorporated Board adjustments pursuant to Decision 2003-100, Decision 2004-003, and the Board's clarification letter dated January 15, 2004.

On February 9, 2004, AP filed an application for interim rates to be effective from March 1, 2004 to October 31, 2004 on the assumption that final rates from the Phase II process would be in effect by November 1, 2004. In January 2004, in the North zone, AP was operating under interim rates authorized by Order U2002-1034, which permitted the continuance of rates approved in Decision 2001-53, and in the South zone, AP was operating under interim rates authorized by Decision 2001-97 and amended by Decision 2002-111. AP proposed a 20.51% decrease in all North demand and commodity rates, except for Firm Service Receipt (FSR), Over-run (OR) and Interruptible (IT) rates for which a 13.21% decrease was proposed. The percentage decrease for these latter services was less due to the allocation of the North Exchange Deferred Account (EDA) deficit for 2001 and 2002, which was only partially offset by the estimated North EDA surplus for 2003. AP proposed an 18.79% increase in South rates for all demand and commodity rates.

In Decision 2004-023, dated March 9, 2004, the Board directed AP, effective March 1, 2004, on an interim basis, to place Gas Alberta in the North on the same proposed interim rate as AGN, until the final determination of fair and reasonable rates was concluded in Phase II. The Board also found that the appropriate interim billing demand for Gas Alberta in the North should be the 2004 forecast demand[3] used by AP in the Phase I application.

With respect to Gas Alberta in the South, in Decision 2004-023, the Board considered that AP's proposal for interim rates[4] for the period March through October 2004 would be reasonable until the final determination of appropriate rates in the Phase II proceeding.

In Decision 2004-038, dated April 30, 2004, the Board approved other rates, tolls and charges for the North and South service zones on an interim basis for the period March 1, 2004 to October 31, 2004. The interim rates were established on the basis of the revenue requirements filed in the January 26, 2004 Compliance Refiling.

In Decision 2004-038, relating to the Compliance Refiling, the Board noted that it did not expect that the directions in Decision 2004-038 would have a significant effect on revenue requirement or forecast revenues and considered that any revisions required as a result of Decision 2004-038 could be dealt with in a second compliance filing to Phase I (the Second Refiling) to be submitted by AP.

[3] 48 TJ/day

[4] The Memorandum of Understanding between Gas Alberta Inc. and AP specified a demand charge of \$1.95/GJ/month for the period January 1, 2001 to December 31, 2002. The contract demand quantity under the MOU was 16.782 TJ/day for 2002. (see schedule A and MOU in Decision 2001-97)

The Board also noted in Decision 2004-038, that the findings in that decision would change certain amounts from the January 26, 2004 Compliance Refiling. The Board considered that the total of all changed amounts from the January 26, 2004 Compliance Refiling would be insufficient to warrant a change to the interim rates and therefore, interim rates would remain effective without an amendment to reflect Decision 2004-038.

The Board notes that AP identified amounts of $8.063 million (2003) and $30.529 million (2004) that were included in the revenue requirement as placeholders. The Board recognized that the 2003/2004 revenue requirements would be impacted by the outcome of various ongoing proceedings and benchmarking processes.

The Board directed that, within 30 days of issue of a Board decision affecting the revenue requirements for any placeholder amount not already adjusted in the Second Refiling, AP should file its calculation of the difference between the final amount approved in any future decision and the placeholder amount established in Decision 2004-038, and place the difference in a deferral account for subsequent disposition at an appropriate time in the future.

In Decision 2004-038, the Board directed AP to identify the amount of change between the revenue requirements shown in the January 26, 2004 Compliance Refiling and the amounts as changed by Decision 2004-038, and to place the difference into a deferral account for subsequent disposition. The Board considered that the amounts accumulated in this deferral account could be combined with the deferral account amounts resulting from the changes in placeholder amounts, for purposes of final settlement in the future.

By letter of April 13, 2004, the Board permitted AP and interested parties to commence negotiations with the objective of reaching a settlement with respect to the provisions for customer account balancing set out in Article 6 of AP's Transportation Service Regulations (TSR) and in regard to the settlement of daily imbalance quantities set out in Item 4 of the Rate Schedules.

On April 26, 2004, the Board granted AP's request based on an agreement reached with certain parties to withdraw the previously proposed daily balancing requirements in Article 6 of the Transportation Service Regulations and Item 4 of the Rate Schedules. The Board granted approval for the parties to resume negotiation in September 2004 with the objective of reaching a settlement of these issues by January 2005. Therefore, these two issues were not canvassed in the 2004 GRA Phase II hearing, and are not addressed in this Decision.

On May 28, 2004, AP filed its Second Refiling, which reflected the directions in Decision 2004-038. In Decision 2004-059, dated July 13, 2004, the Board approved the Phase I rate base, revenue requirement, and forecast revenues for the 2003/2004 test years and also approved the deferral of the 2003/2004 net revenue shortfall of $6.240 million in the South and the deferral of a net revenue surplus of $4.634 million in the North.

The Board indicated in a letter of September 11, 2003, that it would hold a competitive pipeline proceeding (Competitive Proceeding) in relation to the years 2005 and beyond for competitive tariff issues involving AP and NGTL. The Board stated at the commencement of the hearing of the Application that it understood that broad competitive issues might arise in the course of the hearing, and cautioned parties to ensure their discussion of competitive issues was relevant to this proceeding. A number of competitive issues were raised by parties and were considered by the Board in relation to the Application, and several remain to be more properly addressed in the Competitive Proceeding.

2.2 Decision Overview

Traditionally, a GRA Phase II decision will consider and determine how to apply the appropriate rate design criteria for the determination of just and reasonable rates to collect the utility's approved revenue requirement, determine the rates for the proposed services and establish the appropriate terms and conditions for these services. Certain of those rate design criteria address the accuracy of the cost allocation methodologies used to support the collection of a share of revenue requirement from each class through rates. The primary tool utilized in determining an appropriate cost allocation is a cost of service study (COSS). A COSS will ordinarily analyze the costs incurred in providing regulated services, categorize or functionalize these costs and then determine an appropriate set of methodologies for the allocation of these costs. An appropriate allocation may be done in one of any number of ways, including on a fully allocated cost basis for all costs or a mixed allocation of costs with costs that can not be attributed to a single customer class (general system costs) being allocated on a fully allocated basis and costs that can be attributed to a single customer class being direct assigned to that class.

In the present Application, AP has filed a COSS with a proposed allocation of costs and the resulting rates flowing therefrom. It has also proposed terms and conditions for its regulated services.

Given, the importance of a COSS in the process leading to an appropriate rate design, Section 3 of this Decision will review AP's COSS and if necessary direct adjustments to the methodologies employed to achieve the appropriate allocation of costs among rate classes.

Section 4 will consider the rate design criteria that are not primarily focused on the allocation of costs and consider whether an appropriate balancing of these criteria would result in any adjustments to the rates that would otherwise result from the determinations made in Section 3.

Section 5 will consider the appropriateness of each of the proposed rate schedules.

Section 6 deals with several miscellaneous matters considered during the proceeding and provides direction on these matters.

3 COST OF SERVICE STUDIES

3.1 Introduction

The traditional principles and methods of rate design have been canvassed on numerous occasions by the Board, and are referred to more extensively in Section 4.1. Two such principles relate to the "fairness" in the apportionment of costs and the "avoidance of undue discrimination" in the rates charged by a utility to the various classes of customers in light of the costs allocated by the utility to each of the rate classes for the services provided. A COSS has been the traditional tool utilized by utilities to address these fairness criteria.

Gas Utilities Rate Design Inquiry Report No. E80100, dated July 31, 1980 (the GURDI Report), confirmed that a fully distributed COSS was the appropriate method of determining the costs to be allocated to the various customer classes as a guide to establishing reasonable rates.[5] In Decision 2001-097,[6] the Board determined that the business environment had changed substantially since the issuance of the directives in the GURDI Report in 1980, and that the application of the principles emanating from the GURDI Report since that time may need modification to adapt to the new circumstances being experienced by Alberta's utilities.[7] The Board went on to state at page 140 of Decision 2001-097 that it considered the direct assignment methodology adopted by ATCO in that proceeding to be more appropriate than rolled-in, fully distributed costing for the purposes of that proceeding.

In this Application, AP characterized its COSS as a fully allocated cost of service study (AP's COSS) and described the procedures and assumptions used in the process. The AP's COSS suggests that an additional modification to the COSS methodology suggested by the GURDI Report is appropriate in the circumstances of this Application. The AP's COSS in this Application provides for the reallocation of certain costs from two newly defined rate classes to the previously existing rate classes.

The Board is prepared in the context of this specific Application, to generally accept the underlying allocation principles employed in the AP's COSS. However, the Board considers that certain procedures and allocation factors used by AP for the direct assignment, cost allocations, income credits and cost reallocations in this Application require some adjustment to ensure they reasonably address the fairness criteria noted above. The Board's findings are delineated in the following sections.

3.2 Classes of Service

In its COSS for each of the North and South[8], AP included the three service classes, Distributing Company Deliveries, Industrial Deliveries and Producer Receipts (Primary Service Classes) that were included in the APS 2001/2002 GRA COSS plus two other service classes; Other Pipeline Deliveries (OPD) and Other Pipeline Receipts (OPR). In its COSS, AP proposed to initially allocate all system costs to all points on its system that either receive or deliver gas.

AP defined Distributing Companies as those parties whose function was to receive gas from AP and to redistribute that gas to their residential and commercial customers. Distributing Companies include AG, Gas Alberta, AltaGas Utilities, Rate 5 customers and the Town of Wainwright in the North, and AG, Gas Alberta and AltaGas Utilities in the South.

AP defined an Industrial customer as a party whose predominant requirement for gas was for processing or manufacturing use, or whose primary requirement for gas was for space or water heating, but where the operation was one of manufacturing or processing.

AP defined a Producer as a party receipting gas from a gas well, battery or gas plant into the AP system, excluding gas first receipted to another pipeline.

[5] Gas Utilities Rate Design Inquiry Report No. E80100, dated July 31, 1980, P 134
[6] Decision 2001-097, *ATCO Pipelines South 2001/2002 General Rate Application Phases I and II*, dated December 12, 2001
[7] Decision 2001-097, page 140
[8] North and South COSS dated February 2, 2004.

AP defined Other Pipelines as rate regulated pipeline (transmission) facilities not owned or operated by AP, which were used to deliver or receive merchantable quantities of gas to or from a facility owned or operated by AP. AP noted that Other Pipelines included Alliance, Many Islands Pipeline/TransGas (MIPL/TransGas) and NGTL.

Views of the Applicant

AP submitted that its proposal resulted in the allocation of all system costs to all "ons" and "offs", which formed the basis of its fully allocated COSS.

AP submitted that a number of factors prompted the inclusion of all “ons” and “offs”, as follows:

- The current inequitable exchange fee was essentially an "off" that was based on the variable costs of flowing volumes onto the NGTL system;
- The "off" to NGTL did not currently include any AP system costs; and,
- Gas received into AP’s system at gas plants close to interconnection points with NGTL paid an FSR rate, while gas received directly from the NGTL system has not historically paid a charge and facilities were required for both receipts.

AP submitted that interveners either agreed to or were not opposed to the inclusion of all customer groups as identified by AP in the COSS, and argued that most of the issues were related to AP's proposal to reallocate these costs and the resulting rate design.

With respect to Calgary’s comment that OPD and OPR were not customers as suggested by AP, AP submitted that OPD and OPR reflected a type of service provided to customers, just as the terms “Distributing Companies”, “Industrials” and “Producers” reflected types of service provided. AP indicated that the costs allocated to the Distributing Companies resulted in an FSU service rate and the costs allocated to the Industrial and Producer service classes resulted in an Firm Service Delivery (FSD) service rate and an FSR service rate, respectively. AP submitted that OPR and OPD customers consisted of such entities that use these services.

AP disagreed with the Rate 13 Group (Rate 13)’s comments on the necessity of OPR service and its weighted average OPR/OPD solution, and FGA’s statement that only incremental and direct costs should be allocated to OPR and OPD. AP submitted that in a fully allocated COSS, it was important to identify and allocate costs to all services and argued that OPR and OPD were unique services with unique characteristics.

AP submitted that its proposed service classes were reasonable and requested that the Board approve them as filed.

Views of the Interveners

CALGARY

Calgary[9] submitted that OPD and OPR were not really customers at all since they were neither 'flesh and bones’ nor corporate entities. Calgary submitted that AP introduced two new classes of service (OPD and OPR) in its COSS analysis which were utilized to a greater or lesser degree by the traditional customer groups, Distributing Companies, Industrials and Producers. Calgary

[9] The City of Calgary

submitted that AP elected to recognize OPD and OPR as two new classes for purposes of identifying cost responsibility.

Calgary submitted that OPD and OPR should be treated on a stand alone basis, and that AP had provided all of the justification required to treat OPD and OPR as such, including the magnitude of the cost responsibility, the distinct nature of each service, their part of the totality of the intra-Alberta delivery market and their distinct nature as service offerings.

Calgary submitted that the Board should recognize the need to institute stand alone rates and terms and conditions for OPD and OPR services, and should direct AP to bring forth the required rates and terms and conditions of service.

In the alternative, Calgary urged the Board to consider that, before any treatment of OPD and OPR services were embraced, other than on a stand alone rate basis, there should be a process engaged in whereby all the options were vetted and the best one clearly established.

CCA

CCA[10] did not consider that AP's criteria for an industrial customer should include any customers whose primary requirement was for space or water heating. CCA submitted that these customers should be considered commercial customers, whether or not their operations involved manufacturing or processing. CCA submitted that industrial rates were not appropriately designed for space heating loads and should not be used as such.

CG

CG did not object in principle to the allocation of costs to all receipt and delivery points as proposed by AP, but it was concerned with how costs allocated to receipt points from other pipelines were reallocated to other rates.

Although CG did not recommend the establishment of stand alone rates for OPR and OPD services based on fully allocated costs, it did consider it appropriate to identify the costs associated with these services in order to provide an indication of the quantum of costs that may be involved in the TBO arrangement recommended in CG's evidence.

FGA

FGA indicated that it had no objection to Rate 5 customers and Gas Alberta being included as part of the Distributing Company Deliveries class, as these customers incur costs on the AP system in a similar, but not identical manner to AG. FGA submitted, however, that there were sufficient operating differences among AG, Rate 5 and Gas Alberta to warrant distinct rate classes within the Distributing Company Deliveries class.

With respect to the Industrial Deliveries and Producer Receipt classes, FGA considered that there was sufficient homogeneity in these classes that these classifications could be considered valid.

FGA considered that the OPR and OPD classes were not valid customer classes. FGA submitted that both services could only be used by existing customer classes and argued that the OPR class

[10] The Consumers' Coalition of Alberta (CCA) is comprised of the Alberta Council on Aging and the Consumers' Association of Canada (Alberta).

was inhomogeneous as the OPR rate could be used by both Industrial customers and Distributing Companies and the OPD class could be used by either Producer customers or marketers.

RATE 13

Rate 13 indicated that there seemed to be no benefit and no efficiency gained through an OPR rate. The OPR rate was significantly different from the Other Pipeline Delivery Commodity (OPDC) rate in terms of its potential impact on economic efficiency. The OPDC rate would have a significant impact on receipt customer decisions and consequently a direct impact on system costs. Rate 13 argued that the impact of the OPDC rate would start with the long-run decisions to connect to either AP or NGTL and continue to the short term decisions to sell on-system, store, or export gas to NGTL.

However, Rate 13 argued that the same could not be said for the OPR rate because, if the physical supply on-system (including storage) could not serve the on-system market, gas would have to be nominated from NGTL. Therefore, the OPR rate should be zero. Rate 13 submitted that the cost allocation study should be run without an OPR service or alternatively, the costs allocated to OPR should be reallocated to the Industrial Deliveries and Distributing Company Deliveries customers on the same basis as the proposed reallocations except for the exclusion of the Producer Receipt class.

Views of the Board

The Board has reviewed this matter and, with some reservations, has concluded that the factors identified by AP for establishing the five classes of service are acceptable for this Application. The Board understands AP's rationale for layering its physical reality of necessary operational interconnection with other pipelines with two new service classes (OPR and OPD), resulting in the five service classes it has proposed.

However, the Board is not completely persuaded that OPR and OPD could not be treated as general system costs to be allocated in the COSS as such. The Board notes that most interveners were not opposed to the inclusion of the five service classes in the COSS. Despite the Board's reservations, the Board accepts AP's proposed service classes for the purpose of assigning and allocating costs and income credits in this case. Therefore, for present purposes, the Board considers that the five classes identified by AP should be characterized as service classes. The Board also understands Calgary's position that OPR and OPD could be regarded as stand alone services with rates structured as separate services. However, such treatment was not proposed in the Application; rather AP proposed a reallocation methodology. The Board has addressed this issue further in Section 3.7.

The Board agrees with CCA that the FSD rate was not designed for space heating loads. In order to confirm that AP's industrial rates are appropriate for all customers within the Industrial customer class, the Board directs AP to file evidence in its next GRA to identify the number of industrial customers and associated load where the predominant requirement for gas is for processing or manufacturing use, and the number of industrial customers and associated load where the primary requirement for gas is for space or water heating, but where the operation is for manufacturing, processing or another industrial use.

3.3 Directly Assigned Costs

AP described directly assigned costs as directly allocated costs that include Dedicated Assets and Other Directly Allocated Assets.

Views of the Applicant

AP submitted that Dedicated Assets were assigned directly to Producers or Industrials, as they were customer specific assets. AP submitted that Other Directly Allocated Assets were not considered to be dedicated as other customers or customer groups could use those assets if circumstances change.

AP argued that its cost allocation methodology was consistent with the Gas Utilities Rate Design Inquiry (GURDI)[11] and with good utility practice. AP submitted that direct assignment (direct allocation) only occurred where the facility was solely and entirely used by a particular customer group. AP indicated that within that customer group, however, there was no further direct assignment to individual customers or subset of customers.

Where there were General Pipeline facilities downstream of the assets directly assigned to Distributing Companies, the downstream assets by definition were only being used by Distributing Companies. Further, those downstream assets were not included in Other Directly Allocated Assets, as the projects included in the Other Directly Allocated Assets were only for projects of $100,000 book value or greater. AP indicated that it provided details on how it allocated operating costs to direct projects by gross plant.

AP noted that Calgary proposed to reduce the Distributing Companies' peak demand factor used to allocate General Pipeline costs by 206 TJ/day. AP indicated that both the Other Directly Allocated Assets and General Pipeline Assets were being used to serve these peak demand markets. AP argued that the Distributing Companies should be assigned these Other Directly Allocated Assets and allocated a share of the General Pipeline Assets.

In response to Calgary's claim that a direct assignment of costs followed by an allocation of a full share of mainline asset and operating costs, imposed duplicate costs to the Distributing Companies class, AP submitted that it was not duplicating any costs. AP argued that Other Directly Allocated costs were deducted from total pipeline costs, to arrive at General Pipeline Costs.

Views of the Interveners

CALGARY

Calgary indicated that it supported the direct assignment of costs as long as there was full and complete recognition of all of the obligations that come along with direct assignment.

Calgary submitted that when AP first introduced direct assignment of transmission costs to the Distributing Companies, dedicated transmission facilities were identified on a system map that did not connect to the AP mainline, but rather exclusively to the NGTL system. Calgary argued that these dedicated systems do not receive service from the APS mainline and should not be allocated costs related to the mainline. Calgary submitted that to do both a direct assignment of

[11] Report E80100, dated July 31, 1980.

asset and operating costs and then to allocate a full share of mainline asset and operating costs imposed duplicate costs to the Distributing Companies. Calgary indicated that it adjusted its COSS analysis by reducing the peak day demands by 206 TJ/day with respect to the allocation of General Pipeline asset and Operating and Maintenance (O&M) related expenses.

CCA

CCA supported the CG position on this issue. CCA disagreed with the AP definition of dedicated facilities. CCA argued that dedicated facilities should reflect usage and the customer who actually uses the facilities was a more reasonable indicator of whether the assets were dedicated.

CG

CG supported Calgary's evidence and recommendations on the matter of directly assigned costs to the Utilities class of customers. CG submitted that Calgary's evidence demonstrated that, while the concept of direct assignment of capital and operating costs may be appropriate, the application of this concept to the Utilities class of customers was fraught with practical difficulties. CG submitted that the Board should reject the AP proposal because it was not workable and would lead to further complications in future Phase I and II proceedings.

FGA

FGA argued that fairness and common sense should always overrule the rigidity that AP apparently wanted to build into COSS procedures. FGA submitted that there was evidence in this proceeding that challenged AP's direct allocations of pipeline assets and that FGA provided Information Requests on the matter. Further, the AP panel was questioned on the matter of its dedicated assets. Thus interveners did address this issue in evidence, contrary to AP's suggestion that they did not.

Views of the Board

The Board accepts AP's method of identifying isolated systems and dedicated customer specific assets solely used by a customer class. The Board also considers that directly assigning the costs of these systems to the customer classes is a reasonable method. Furthermore, the Board accepts AP's $100,000 threshold for assignment of Other Directly Allocated Assets as reasonable.

With respect to the reduction of 206 TJ from the peak demand of Distributing Companies, as proposed by Calgary, to correct the "double counting" of isolated system costs and general costs, the Board agrees conceptually with Calgary that the methods of allocating peak demands for isolated systems and overall costs to customer groups should not result in attracting more general system costs to the customer group to which the isolated systems belong. However, the Board considers that the peak demand amount of 206 TJ/day includes a combination of the demand for isolated systems not connected to the AP mainline plus the demand for facilities dedicated to the utility class that are connected to the mainline. The Board considers that any adjustment to the total utility peak demand as advocated by Calgary to avoid double-counting of mainline costs, should have included only the peak amounts for isolated systems not connected to the mainline. Therefore, the Board does not accept Calgary's recommended adjustment amount of 206 TJ/day as being representative of the peak demand for isolated systems.

No evidence was presented to indicate a specific amount of peak demand that would be attributable to the isolated systems; however, the Board considers that the peak demand for isolated systems would be insignificant due to the small number of customers being served from the isolated segments. However, for greater clarity in the future, the Board directs AP in its next GRA to remove the peak demand amount for all customer/service classes on "isolated systems" from the peak demand allocator used to allocate general system costs.

3.4 Allocation of Costs to Functions

AP directly assigned or allocated asset related expenses and operating and maintenance (O&M) related expenses to six functions[12] and subsequently redistributed the administration expenses to the remaining five functions.

Views of the Applicant

AP submitted that there was no evidence provided by interveners that opposed its method of assignment of asset-related costs and O&M costs to the various functions. AP argued that its assignment was reasonable and it requested that the Board approve its cost assignment as filed.

Views of Interveners

No interveners provided comments.

Views of the Board

The Board considers AP's assignment and allocation of asset related expenses and O&M related expenses to the six functions to be reasonable. The Board also considers the subsequent redistribution of administration expenses to be reasonable.

3.5 Distribution of Function Costs to Service Classes

AP directly assigned or allocated various expenses from five functions to the five service classes[13] discussed in Section 3.2. The methodologies proposed by AP for the various expenses within each function are discussed in the following subsections.

3.5.1 Marketing

AP indicated that the marketing function was responsible for providing analysis of growth areas around the existing pipeline system in order to identify, evaluate and implement system expansion projects that provide an overall benefit to new and existing customers.

AP proposed to allocate Marketing costs to customer groups based on the sum of all other costs excluding Natural Gas Supply, NGTL Firm Transportation – Alberta Delivery Service (FT-A) and Minimum Annual Volume (MAV) costs, and Oversupply Delivery Costs (ODC).

Views of the Applicant

AP stated that marketing costs included 70% of the Planning Group's system design and engineering efforts. Thus peak demands, including those of the Distributing Companies, drove AP's marketing effort to some degree.

12 Administration, marketing, customer support, pipelines, compression and measurement and regulation.
13 Distributing Company Deliveries, Industrial Deliveries, Producer Receipts, Other Pipeline Deliveries and Other Pipeline Receipts.

AP submitted that its allocation method treated all customer groups fairly since it recognized both the effort being spent on all groups and the benefit, in the form of reduced rates, that all customer groups get from increased peak demand volumes on the pipeline system.

AP submitted that the percentage used to allocate marketing costs to customer groups was very close to the four-hour peak allocation percentages used by AP to allocate the majority of costs, and was consistent with the methodology previously approved by the Board for predecessor companies of AP.

With respect to the allocation of marketing costs, AP submitted that the amount of marketing effort spent on individual customers and customer groups can vary significantly from year to year and from customer to customer, making it difficult to forecast a direct or time estimate allocation of costs that also recognized the benefit that all customers derive from increased volumes, regardless of which customer group experiences the growth.

AP submitted that FGA's proposed allocation of marketing costs would allow it to receive all the benefits of marketing through a higher share of the benefit of the growing peak demands[14] while only paying for a smaller share of marketing costs through an allocation based on throughput.[15]

AP disagreed with FGA's argument that AP did not improve the study of marketing expenses from the 2001/02 GRA. AP argued that it provided an allocation method that considered both where the marketing effort was being spent and who benefited from that effort, which was responsive to the Board's direction in Decision 2001-097 to improve the study of marketing costs.

AP submitted that its allocation method was simple and straightforward but, if the Board considered that a simplification of the allocation of marketing costs was required, the allocation should be done based on peak demand and not on throughput since increasing demand on the pipeline system was one of the primary goals of the marketing effort. The higher the demand, the higher the revenue and the greater the total peak demand volumes that could be used to allocate general system costs. However if throughput increased without increasing demand, there was a much smaller impact on revenues and on customers than if demand also increased.

AP submitted that CG presented ill-defined and untested evidence on the allocation of marketing costs to customer groups based on the costs of business development and planning full-time equivalents (FTEs). AP argued that it was possible to allocate the Planning Group time to customer groups but it was very difficult to allocate marketing costs to customer groups. Further, CG's allocation did not consider that an increase in peak demand volumes decreased all rates, not just the rates of the respective customer group.

Views of the Interveners

CALGARY

Calgary submitted that the amount of marketing costs allocated to the Distributing Companies did not look reasonable given that it is AP's affiliate, ATCO Gas South (AGS), that makes up 98.5%[16] of the Distributing Companies class on the APS system. Calgary argued that it was

[14] 33.0% in the North and 48.8% in the South
[15] 14.1% in the North and 27.0% in the South
[16] Based upon billing demand

difficult to conceive how two affiliates, who used to be a single entity, require the expenditure of more than $500,000 for APS to market to AGS, given that the service to AGS was provided under an exclusive contract which prohibits AGS from receiving service from a competitor. Calgary submitted that the argument that all customers benefit from the marketing efforts of AP did not answer the question of proportion and did not justify the amount of marketing costs APS allocated to AGS.

CCA

CCA supported the CG position on this issue.

CCA further considered that demand had no relationship to marketing expense for a pipeline company and argued that marketing expense should be allocated to the customer group where the marketing effort was placed. CCA submitted that little to no marketing effort was placed towards core customers and therefore no marketing costs should be allocated to them.

CG

CG argued that all customers do not benefit from marketing efforts in the same way. CG submitted that AP could and should have directly assigned marketing costs to the customer groups that use the service.

CG submitted that all of the business development FTEs which were part of the marketing function should be allocated to the Producer, Industrial and Rate 13 customers on an all costs basis. In addition, AP did not demonstrate why any of the planning FTEs should be allocated to AG or other Distributing Companies, particularly since daily transportation planning for these customers was done by the control centre which was not part of the marketing function.

With respect to the longer term system planning function, CG argued that, given there was little or no growth forecast for the distributing utilities, an allocation of 2 of the 7 FTEs of the Planning group, one to North and one to South, was appropriate. The remainder of the 5 planning FTEs could be allocated to the remaining customer groups on an all costs basis.

FGA

FGA submitted that marketing costs should be allocated by throughput and argued that a COSS, in the absence of direct assignment of costs, should allocate costs approximately in the manner in which they were incurred.

FGA outlined a number of reasons for allocating marketing costs by throughput, including the following:

- The marketing staff's activities appeared to be directed towards the Industrial and Producer class;
- There was not a lot of marketing done to the Distributing Companies; and
- Allocating costs by throughput was a more stable method than allocation by the sum of all other costs.[17]

[17] FGA indicated that the marketing expense allocated to the distributing companies decreased from $518,000 in AP's COSS to $494,000 in Calgary's COSS because of a single change in allocation made between the two studies which had nothing to do with the marketing function.

FGA noted that AP did not directly assign any business development staff specifically to marketing to the Distributing Companies and did not exhibit a viable transportation transition plan for sales to other Distributing Companies provided under Rate 5.

FGA submitted that AP did not improve its study of marketing expenses as directed in Decision 2001-097 and argued that the method proposed by AP was a retrograde step from the estimation method by throughput, which was used in the APS 2001/2002 GRA Decision. FGA submitted that the Board should redirect AP to perform a study of marketing activities that would allow these costs to be directly allocated on the basis of the effort actually expended.

Views of the Board

In Decision 2001-097, with respect to the APS 2001/2002 GRA, the Board approved marketing costs allocated as estimated by APS, with a further sub-allocation to the Distributing Companies. The Board noted in that Decision that APS had little history available for use in projecting marketing expenses, and directed APS to improve its study of marketing expenses and file the results at its next GRA, when it would have a longer history of data with respect to these expenses.

In theory the Board would support AP's concept of using an allocation method that considers both the effort being spent on all customer groups and the benefit, in the form of reduced rates, that all customer groups receive from increased peak demand volumes on the pipeline system. Further, this concept could support an allocation being done based on peak demand, since AP indicated that increasing demand on the pipeline system was one of the primary goals of the marketing effort.

However, the Board does not consider that AP has responded adequately to the Board's direction in Decision 2001-097 to improve its study of marketing expenses based on actual past data. AP has not provided evidence to demonstrate that its marketing effort has resulted in increased producer or industrial peak demand and hence the claimed benefits.

The Board agrees with AP that it would be very difficult to forecast a direct allocation or time estimate allocation of costs that also recognized the benefit that all customers derive from increased volumes, regardless of which customer group experiences the growth.

Until such time as AP demonstrates that its marketing effort has resulted in the implementation of system expansion projects with increased demand (not just throughput), the Board believes it is appropriate to allocate marketing costs based on throughput. The Board considers that all customer groups should share some degree of marketing costs, particularly since system design efforts are included in these costs.

The Board agrees with some of the reasons advanced by FGA for allocating marketing expenses based on throughput, and considers that a reasonable amount of costs are allocated to the various customer groups using throughput as an allocation factor.

Therefore the Board directs AP to reallocate its marketing expenses in its Compliance Filing based on actual throughput for 2002.[18]

[18] Excluding throughput associated with non-standard contracts. See Section 7.7

3.5.2 Customer Support

AP indicated that the Customer Support function was responsible for gas coordination between receipt and delivery customers, transportation measurement, contracts and billing, and communicating with customers regarding transportation services.

AP proposed to allocate Customer Support expenses to the five service classes based on 2002 actual throughput.

Views of the Applicant

AP submitted that its allocation method was reasonable since gas flows were an indication of transactions and time devoted to each customer by the Customer Support group.

AP noted that, except for the issue of using 2002 actual data, no intervener provided evidence with respect to the allocation of Customer Support costs to the customer groups based on throughput.

Views of the Interveners

Interveners expressed concern with the appropriateness of using 2002 actual throughput data. This issue is discussed in Section 7.7.

Views of the Board

The Board considers that AP's throughput allocation factor appears reasonable for the Customer Support function. In addition, as discussed in Section 7.7, the Board has also determined that it is appropriate for AP to use 2002 actual throughput in this situation. Therefore the Board directs AP to allocate Customer Support expenses in its Compliance Filing based on actual throughput for 2002.

3.5.3 Pipeline

AP proposed to directly assign or allocate pipeline function related asset and O&M expenses to the service classes as shown in Tables 1 and 2 for the North and South systems respectively.

Table 1. AP Proposed Pipeline Expenses to Service Classes - North

	$000's						
Income Credit	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**	**Method**
Dedicated Assets		301		2,008		2,309	Direct
Other Directly Allocated Assets	1,604		76	97		1,777	Direct
Salt Cavern	4,857	2,434	330			7,621	Delivery Demand
Non-Standard	379	190	25	259	295	1,148	Demand
General System	13,188	6,609	898	9,015	10,243	39,953	Demand
Industrial Facility		707				707	Direct
TBO	1,032		600	118		1,750	Direct
Totals	21,060	10,241	1,929	11,497	10,538	55,265	

Source: AP COSS, February 2, 2004, Table 2.6.1, lines 11-26

Table 2. AP Proposed Pipeline Expenses to Service Classes - South

	$000's						
Income Credit	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**	**Method**
Dedicated Assets		32		136		168	Direct
Other Directly Allocated Assets	2,897					2,897	Direct
Non-Standard	7	1		2	5	15	Demand
General System	7,314	695		1,941	5,044	14,994	Demand
Totals	10,218	728		2,079	5,049	18,074	

Source: AP COSS, February 2, 2004, Table 2.7.1, lines 11-19

See Section 3.5.3.1 for a discussion on Salt Cavern expenses.

Views of the Applicant

AP indicated that Other Directly Allocated Assets were assigned to the service class currently using those assets. AP noted that no intervener addressed this issue in argument and AP made no further comments.

Views of the Interveners

No customers commented specifically on the methods used by AP to directly assign or allocate pipeline related expenses to the five service classes.

Views of the Board

The Board notes that the views of all parties with respect to Salt Cavern expenses and non-standard expenses are included in Sections 3.5.3.1 and 7.2 respectively.

With respect to the other pipeline function related expenses, the Board considers AP's assignment and allocation methodology to the five service classes to be reasonable. Given the Board's direction to revise some of the peak demands for the service classes in the North and South, the Board notes that the final amount allocated to the five service classes in AP's Compliance Filing should be slightly different than the amount proposed by AP in Tables 1 and 2.

3.5.3.1 Salt Cavern Expenses

AP indicated that Salt Cavern expenses were allocated to North Distributing Companies, Industrials and Other Pipeline Deliveries based on peak demand.

Views of the Applicant

AP indicated that the purpose of the Salt Cavern peaking facility was to provide increased peaking delivery capability in the North and that it was typically required to flow during periods of cold weather when AG demand increases and, on occasion, when industrial power plants come on suddenly. AP indicated that it had contractual obligations to deliver to the Distributing Companies, Industrials and Other Pipelines.

AP also indicated that the Salt Cavern peaking facility creates a demand on the North pipeline system during the gas injection phase that occurs between April and June each year.

AP submitted that the peak demands of the customer groups best represent the cost causation of providing Salt Cavern deliverability.

With respect to IGCAA's proposed allocation of Salt Cavern costs, based on the one-hour peak demand of Distributing Companies, AP submitted that IGCAA's proposal should be rejected because AP designs its system, including Salt Caverns, to meet the four-hour and not the one-hour peak for all customer groups. AP submitted that the difference between the four hour and one hour peak was primarily met by line pack.

With respect to IGCAA's proposal to allocate a portion of Salt Cavern costs to the Producer class, AP argued that IGCAA's estimated volumes injected during the April to June period were overstated and the dollar impact of its allocation to producers was immaterial. AP submitted that IGCAA's allocation to producers, using an average injection rate of 40 TJ/day for the three-month period, was $50,000. AP submitted that there was no evidence in this proceeding that the Salt Cavern costs provided any further benefit to producers.

In response to IGCAA's statement that the Straddle Plant peak demand should not be included when allocating Salt Cavern costs to the Industrial class as these costs were not included in the Straddle Plant rate, AP submitted that, if AP excluded the Straddle Plant peak demand from the Industrial four hour peak demand, the Straddle Plant revenue would have been allocated to all customer groups based on four hour peak demand. AP argued that all customers would then share revenues and costs of Straddle Plant service and the net result would be an Industrial rate of $1.947/GJ/Month that would remain unchanged. AP submitted that IGCAA acknowledged that it was economically indifferent whether these costs were included in the Industrial peak demand.

Views of the Interveners

CG

CG supported the allocation of Salt Cavern costs as proposed by AP.

IGCAA

IGCAA submitted that Salt Cavern peaking costs should be allocated to receipt and delivery services in accordance with the purpose and use of the Salt Caverns. IGCAA argued that allocations to delivery services should be based on the one-hour peak demand for Distributing Companies and should exclude the 53 TJ of Straddle Plant demand deemed for the Industrial class.

IGCAA submitted that, since AP allocated Salt Cavern costs based on peak demand, AP over allocated $136,000[19] to the Industrial class because Straddle Plant demand[20] was included within the industrial demand. IGCAA argued that Salt Cavern peaking benefits do not exist for Straddle Plants since AP indicated that Salt Cavern expenses were excluded from extraction, given that it could control Straddle Plants and by-pass them if operationally necessary during peak demand periods.

[19] IGCAA submitted that excluding straddle plant demand from industrial peaks on lines 12 and 19 of Table 2.6-1 in AP's COSS results in an allocation of $1,802,000 instead of $1,909,000 and $496,000 instead of $525,000 respectively.

[20] 53 TJ.

IGCAA submitted that, since AP admitted that Salt Cavern storage reduced ODC, which would otherwise be incurred on its system, producers on the system would also benefit. IGCAA argued, however, that the benefit the producers received would not be reflected in a cost allocation based on peak demand where producer injections reach a high of 40 TJs per day.

IGCAA submitted that if the Board accepts the logic of allocating costs based on benefits, all Salt Cavern costs would have to be allocated as general system costs.

Views of the Board

The Board accepts AP's submission that the Salt Cavern peaking facility is required to meet its contractual obligations to deliver to Distributing Companies, Industrial customers and Other Pipelines. The Board considers that the use of peak demand associated with the delivery service classes to be a reasonable basis on which to allocate the Salt Cavern expenses.

However, in the Compliance Filing, the Board expects AP to remove the 53 TJ/day of Straddle Plant demand from the demand established for the Industrial class as directed in Section 7.1, Peak Demand for Cost Allocation and Rate Design.

In addition, in its next GRA, the Board directs AP to address the reasonableness of revising the peak demand numbers of the delivery service classes for the purposes of allocating Salt Cavern expenses. The Board considers that the peak demands associated with Distributing Companies and Industrial customers on isolated pipeline systems may not directly cause the requirements of the Salt Cavern peaking facility.

With respect to IGCAA's proposal to allocate Salt Cavern expenses based on the one-hour peak demand of Distributing Companies, the Board agrees with AP that this proposal should be rejected given AP's claim that it designs its system to meet the four-hour peak for all customer groups.

3.5.4 Compression

With respect to compression function expenses, AP directly assigned or allocated[21] the expenses to the five service classes.

Views of the Applicant

AP indicated that it allocated compression costs to the service classes based on the same allocation that it used to allocate pipeline costs, except that there were no Salt Cavern costs, industrial facility or TBO costs.

Views of the Interveners

No interveners provided comments.

Views of the Board

The Board considers AP's assignment and allocation of compression function expenses to the five service classes to be reasonable. Given the Board's direction to revise some of the peak demands for the service classes in the North and South, the Board notes that the final amount

21 AP used four-hour peak demand to allocate some compression function expenses.

allocated to the five service classes in AP's Compliance Filing should be slightly different than the amount proposed by AP in the Application.

3.5.5 Measurement and Regulation

AP proposed to directly assign or allocate measurement and regulating (M&R) function related asset and O&M expenses to the service classes as shown in Table 3 and Table 4 for the North and South systems respectively.

Table 3. AP Proposed Measurement and Regulating Expenses To Service Classes - North

	$000's						
	Distribution	Industrial	OPD	Producer	OPR	Total	Method
Dedicated Assets		514		4,825		5,339	Direct
Custody Transfer Meter – 50%	1,100					1,100	Direct
Custody Transfer Meter – 50%	155	312	83	448	103	1,100	Throughput
Other Directly Allocated Assets			465			465	Direct
Non-Standard	428	214	29	292	333	1,296	Demand
General System	3,041	1,525	208	2,079	2,363	9,215	Demand
Totals	4,725	2,565	784	7,644	2,797	18,515	

Table 4. AP Proposed Measurement and Regulating Expenses To Service Classes - South

	$000's						
	Distribution	Industrial	OPD	Producer	OPR	Total	Method
Dedicated Assets		205		1,515		1,720	Direct
Custody Transfer Meter – 50%	1,174					1,174	Direct
Custody Transfer Meter – 50%	317	129	139	505	84	1,174	Throughput
Other Directly Allocated Assets			253			253	Direct
Non-Standard	116	11		31	80	239	Demand
General System	2,783	265		739	1,919	5,705	Demand
Totals	4,390	610	393	2,790	2,083	10,266	

The discussion on the allocation of general system (GS) expenses and Unaccounted for Gas (UFG) custody transfer meter (CTM) expenses are included in sections 3.5.5.1 and 3.5.5.2 respectively.

Views of the Applicant

AP indicated that its allocation of M&R costs to all customer groups was based on the same allocation that it used to allocate pipeline costs except that there were no Salt Cavern costs, industrial facility or TBO Costs.

Views of the Interveners

No customers commented specifically on the methods used by AP to directly assign or allocate the other M&R related expenses to the five service classes.

Views of the Board

With respect to the other M&R function related expenses, the Board considers that AP's method employed to assign and allocate these costs to the five service classes is reasonable. In Section 7.1 following, the Board has determined that revisions to the four-hour peak demand for the Distributing Company class in the North and South are required. Therefore, the Board notes that in AP's Compliance Filing, the final amount allocated to the five service classes should be different from the amounts proposed by AP in Tables 3 and 4 above.

3.5.5.1 Allocation of General System M&R to Utilities

AP proposed to allocate GS M&R related expenses[22] to the service classes in the North and South based on four-hour peak demand.

Views of the Applicant

AP submitted that GS M&R expenses were calculated by taking the total M&R expenses and deducting dedicated M&R expenses, other directly allocated M&R expenses, UFG CTM expenses and non-standard M&R expenses. AP indicated that CTM expenses formed only a small part of GS M&R expenses. AP submitted that GS M&R expenses included expenses related to general system facilities upstream of the CTMs that were necessary to operate the pipeline system. AP argued that all customer groups benefited from these facilities.

With respect to the Distributing Companies' share of M&R expenses related to non-standard contracts, AP submitted that FGA's analysis was inconsistent in that it eliminated the Distributing Companies' share of non-standard M&R expenses but did not make any adjustment to the Distributing Companies' share of revenues associated with non-standard contracts.

With respect to FGA's calculation of the asset-related costs for the CTMs that were proposed to be sold to Gas Alberta, AP submitted that, while FGA was correct in its calculation of return on these assets, it excluded the costs of depreciation and income taxes related to these assets. In addition, AP submitted that FGA did not provide a calculation of O&M expenses. AP submitted that the total cost should have been $150,000 and argued that these costs were not directly allocated to Gas Alberta in its rate. AP submitted that these costs were included in GS M&R expenses[23] that were allocated to all customers based on peak demand. The costs of the CTMs that were allocated to Gas Alberta based on Gas Alberta's share of peak demand was only $2,000[24] and other customers were allocated the other $148,000.

AP submitted that contrary to what FGA stated, CTMs were only a small part of the GS M&R expenses. AP argued that the cost of service of FGA's CTMs was only $150,000 while the total 2004 year end cost of service of GS M&R expenses was $9.215 million.[25]

In response to FGA's submission that the value of the CTMs proposed to be sold to Gas Alberta should be removed from rate base, AP submitted that the sale has not yet occurred and there was nothing on the record to support that this sale would in fact take place in 2004. AP argued that the setting of rate base was a Phase I matter that was decided upon in Decision 2003-100, and it

22 General asset-related expenses and general operating and maintenance expenses.
23 Exhibit 002-01(p) - Revision to Refiling – 2004 COSS, North, Table 2.6-1, lines 41 and 49.
24 $148,000 * 48/4,002.
25 Exhibit 002-01(p) - Revision to Refiling – 2004 COSS, North, Table 2.6-1, lines 41 and 49.

was not appropriate to open up previously decided rate base calculations to selectively include a revised capital expenditure forecast.

AP submitted that industrials and producers did not object to paying for a share of GS M&R expenses even though their CTM expenses were directly assigned to them as part of dedicated assets.

AP submitted that FGA's M&R proposals should be rejected by the Board since they were not fair to other customer groups. AP argued that it was not appropriate for the FGA to evade responsibility for M&R expenses simply because its participants own or plan to own the CTMs.

Views of the Interveners

FGA

Gas Alberta submitted that it should not be allocated any GS M&R expenses on the basis that it owns or will own and operate all the CTMs at the custody transfer points with AP.

FGA did not agree with AP's assertion that Gas Alberta should pay GS M&R expenses because they were GS M&R expenses. FGA submitted that the annual capital cost of the $500,000 estimated book value of the meters that Gas Alberta intended to purchase almost equals the GS M&R expenses allocated to Gas Alberta in the AP COSS and argued that any difference between the return on $500,000 and the allocated M&R expenses was likely due to depreciation on the meters. FGA submitted that the GS M&R expenses were insignificant relative to the CTMs that Gas Alberta would be removing from rate base.

FGA submitted that, in the hearing, AP was unable to show how its COSS differentiated between these "system-wide" costs and the CTMs that Gas Alberta was purchasing and argued that it appeared that the most costly items were owned by Gas Alberta's members and not in AP's rate base.

FGA submitted that Gas Alberta would pay an appropriate share of GS M&R expenses, if they were identified, quantified and appropriately allocated to Gas Alberta's operations. However, FGA argued that such expenses did not appear to be either real or of sufficient significance to warrant functionalization in the COSS.

FGA submitted that, instead of evading costs, Gas Alberta has already incurred costs and would be incurring its own costs through its ownership of the master meters and the data acquisition systems. FGA indicated that Gas Alberta would be assuming the cost of maintenance and replacement. FGA submitted that there was a program of data acquisition for the needs of Gas Alberta's own members and the benefits of this program would accrue to AP and its customers at no cost.

With respect to AP's submission that FGA wanted all the benefits of non-standard revenues but none of the non-standard M&R expenses, FGA indicated that it would gladly forgo the benefits of a non-standard contract, such as the Calpine contract, if the corresponding costs were not allocated to rates paid by Gas Alberta and Rate 5.

In response to AP's assertion that FGA's calculation, with respect to asset-related costs for the CTMs to be sold to Gas Alberta, was incomplete and misleading, FGA agreed that the calculation was incomplete but not in the direction represented by AP. FGA argued that the purpose of its simplified calculation was to illustrate that the return portion of the net CTM costs was almost equal to the cost allocated to Gas Alberta, based on a level of demand that AP had already accepted in the hearing.

FGA provided a revised calculation and submitted that, if the missing capital costs were included and only correctly calculated asset-related costs were compared to the asset-related costs[26], it would put the existence of GS M&R expenses in doubt. FGA submitted that, by including depreciation and income taxes, it appeared that Gas Alberta had been contributing to far more costs[27] than it should have been allocated[28], to the benefit of all other customers on the system.

Views of the Board

The Board notes that GS M&R expenses allocated to all classes were determined from the total M&R expenses less dedicated and other directly allocated M&R costs, UFG CTM and non-standard M&R expenses. The Board accepts that the remaining costs are GS facilities upstream of the CTMs and are necessary for the pipeline system operation. Therefore, the Board agrees with AP that the remaining costs in the GS M&R account should be allocated to all customer groups based on four-hour peak demand.

In Section 7.8.1, the Board addresses FGA's request for a separate reduced rate within the Distributing Companies service class to compensate Gas Alberta for owning and operating costs of the metering and other equipment.

3.5.5.2 UFG Custody Transfer Meters

AP proposed to allocate 50% of the UFG CTM asset-related expenses and O&M related expenses to the five service classes based on throughput and to assign the remaining 50% of these expenses to the Distributing Company Deliveries class.

Views of the Applicant

AP submitted that the 50% allocation of UFG CTM costs to all service classes, based on throughput, was reflected in the Board's rulings in Decisions 2001-097 and 2003-100, whereby the Board indicated that, since all customers benefit from the installation of these meters, this cost should be allocated to all customers.

AP argued that its 50% direct allocation to Distributing Companies also recognized that these meters provided the same physical function and served the same purpose as dedicated CTMs that were directly assigned to Industrials and Producers.

With respect to CAPP's submission that the UFG CTM costs should be allocated 100% to the Distributing Companies Deliveries class, AP argued that its 50/50 allocation proposal provided a balancing of interests.

In response to FGA's assertion that there were no direct benefits of reduced UFG/Fuel to delivery customers with AP's proposed reallocation of UFG/Fuel, AP submitted that shifting

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26 AP Application Table 2.6-1, line 41
27 $66,528
28 $48,251

UFG/Fuel to receipt volumes would result in UFG/Fuel being allocated to all customer groups. AP indicated that, in Decision 2001-097, the Board approved the allocation of UFG CTM costs to both receipts and deliveries when the UFG/Fuel cost was being charged solely on deliveries. AP requested that the Board approve its proposed allocation method as filed.

Views of the Interveners

CALGARY

Calgary submitted that the Board should continue to enforce Decision 2001-97 and direct AP to allocate the cost of the UFG CTMs using the ratio of volume throughput to each customer class. Calgary submitted that AP's proposal was effectively an implicit review and variance request of the Board's decision. Calgary submitted that AP provided no evidence or business case for overturning the Board's decision and argued that the underlying foundation for the Board's decision remains the same today. Calgary argued that if the parties did not like what the Board said in 2001-097, it was always open to those parties to seek a review and variance application.

CAPP

CAPP submitted that the costs related to UFG CTM should be charged 100% to Distributing Companies since the meters serve the same function as CTMs used by and charged directly to the producer and industrial customer groups respectively. CAPP also noted that AP agreed that the meters for all three customer groups were necessary for accurate calculation of UFG.

In response to AP's assertion that its proposal provided a balancing of interests, CAPP submitted that AP did not define what these interests were. CAPP argued that undefined interests should not negate the fundamental ratemaking principle of cost allocation according to cost causation.

With respect to the CG's contention that CAPP's argument was faulty because it was not possible to segregate exactly which assets were direct assigned versus allocated to these customer classes, CAPP submitted that this assertion was irrelevant because there should not be different treatment for assets that perform the same function.

CCA

CCA supported the CG position on this issue.

CG

CG supported AP's proposed methodology for allocating UFG CTM costs and noted that it agreed with AP's rationale that all customers benefit from the installation of the meters and that the proposal provided a balancing of interests.

CG submitted that it was not possible to segregate exactly which assets were directly assigned versus allocated to these customer classes and therefore, CAPP's argument that utilities' customers should pay for all of the costs associated with UFG CTM was faulty.

FGA

FGA noted that for the UFG CTMs that were first installed on the APS system, the Board determined that the capital and O&M costs should be allocated 100% by throughput to all users.

FGA submitted that the basic rationale for the allocation was related to the purpose of the meters, which was for the determination of gas sold to AG and a more precise determination of UFG.

FGA submitted that AP consistently agreed that the meters were required by AG to determine the correct allocation of UFG between the AG distribution network and the AP transmission system and to provide AP and AG with the ability to accurately identify and be accountable for their own UFG. FGA submitted that the evidence was abundantly clear that these CTMs were needed only because of the reorganization of the former Northwestern Utilities Limited (NUL) and CWNG utility corporations into AG and AP. FGA argued that the purpose of the UFG CTMs was to measure gas delivered to the customers of AG, not to measure gas delivered to any other customer.

FGA indicated that Gas Alberta and Rate 5 delivery points have always had CTMs and have been accurately measured and, similarly, Industrial and Producer customers have also always been accurately metered. FGA submitted that since AG was the only AP customer requiring the UFG CTMs, the project should be charged solely to that customer.

IGCAA

With respect to UFG CTM costs, IGCAA supported the CAPP position, which IGCAA submitted was based on the principle of cost allocation based on cost causation. IGCAA argued that the cost of UFG CTMs was caused by the provision of service to distribution utilities at delivery points.

IGCAA submitted that the Board should not consider its Decision 2001-97 to be a precedent regarding the issue of proper allocation of UFG CTM costs to distribution utilities because the decision related to UFG CTM costs in 2001 and was made in the context of reviewing the COSS that had been filed for the limited purpose of determining whether costs allocated to AG were generally fair. IGCAA also indicated that the industrials, producers and the FGA reached settlements with AP and although IGCAA had intervened in the proceeding, it was for the limited purpose of establishing an interim UFG allocation methodology pending the installation of meters.

Views of the Board

The Board considers that the use of the UFG CTMs in the test years is for the purpose of determining UFG for distribution and transmission using measurement data rather than the allocation procedure, thereby providing a more accurate determination of the transmission and distribution UFG.

The Board considers that throughput associated with the various receipts and deliveries remains a reasonable proxy for allocating the UFG CTM costs. Therefore, the Board directs AP, in its Compliance Filing, to allocate 100% of the UFG CTM asset related and O&M related expenses to the five service classes based on actual 2002 throughput[29].

However, it appears that in future test periods, the UFG CTMs might be used to support load balancing and the monitoring function for any proposed FSU penalty provisions. Therefore, the Board considers that it would be appropriate to reevaluate the purpose of the CTMs and review the cost allocation methodology at the next GRA.

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[29] Excluding throughput associated with non-standard contracts.

With respect to the arguments raised by FGA, please refer to Section 7.8.1.

3.5.6 Other Costs

The subsections included in this section discuss the expenses that were not directly assigned or allocated to the five main functions.

3.5.6.1 Natural Gas Supply

AP allocated natural gas supply expenses to the Distributing Companies service class and the Industrial service class in the North. AP also allocated the corresponding gas cost revenues to the same service classes. There were no natural gas supply expenses or revenues for South customers.

Views of the Applicant

AP indicated that natural gas supply expenses were allocated directly to the service classes that benefit from AP's natural gas supply service. AP submitted that the net result of the expense and recovery allocations was a flow-through item that was not included in the net revenue requirement used to develop Phase II rates.

AP submitted that there was no evidence provided by the interveners with respect to the allocation of natural gas supply expense and revenue. AP argued that its allocation was reasonable and requested that the Board approve it as filed.

Views of Interveners

CCA

CCA supported the CG position on this issue.

CG

CG recommended that existing sales customers should be provided with a choice of continuing on sales rates and indicated that, if this recommendation was accepted, some modification to this expense category might be required by AP in its Compliance Filing.

Views of the Board

The Board considers AP's proposed allocation methodology for natural gas supply expenses and revenues to be reasonable and approves it as filed. The Board notes that the issue of continued sale services is discussed in Section 7.4.

3.5.6.2 Taxes Other than Income – Rider A & B

AP allocated tax other than income tax (property tax), to the Distributing Companies service class and Industrial service class in the North and South. AP also allocated the corresponding Rider A[30] and B[31] revenues to the same service classes.

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[30] Municipal Franchise Fee
[31] Municipal Property Tax and Specific Costs

Views of the Applicant

AP indicated that the net result of the allocation of expenses and revenues associated with Property Tax was a flow-through item that was not included in the net revenue requirements used to develop Phase II rates.

AP submitted that there was no evidence provided by the interveners with respect to the allocation of these expenses and revenues. AP argued that its allocation was reasonable and requested that the Board approve it as filed.

Views of Interveners

No interveners commented on AP's proposed allocation methodology.

Views of the Board

The Board agrees with AP that its allocation methodology with respect to Property Tax results in no impact upon the net revenue requirements used to develop Phase II rates. Therefore, the Board considers that AP's proposed allocation methodology for Property Tax expense and revenue is appropriate.

3.5.6.3 NGTL Charges – FT-A and Facility Connection Service (FCS) MAV

AP proposed to directly allocate NGTL FT-A and FCS MAV charges to the OPR service class and the 2004 forecast with respect to these charges is shown in Table 5. AP also proposed to include the NGTL FT-A and FCS MAV expenses in the OPR deferral account as discussed in Section 7.3.

Table 5. 2004 Forecast NGTL FT-A and MAV Charges

Item	APN ($000s)	APS ($000s)
FT-A	2,360[32]	1,494[33]
MAV	1,020	680
Total	3,380	2,174

Source: IR BR-AP-11 (c)

Views of the Applicant

AP submitted that NGTL FT-A and MAV costs were part of the cost of delivering gas onto the AP system from the NGTL system and were directly allocated to the OPR service class. AP argued that its allocation was reasonable and requested that the Board approve it as filed.

Views of Interveners

No interveners objected to the initial allocation of these costs to the OPR service class.

32 157.3 PJ x 1.5 cents/GJ.
33 99.6 PJ x 1.5 cents/GJ.

Views of the Board

The Board has accepted OPR as a class of service for this GRA. Since these costs are associated with receiving gas from NGTL onto the AP system, the Board considers that AP's proposed allocation of the NGTL FT-A and FCS MAV costs to this service class is appropriate.

3.5.6.4 Oversupply Delivery Costs

AP noted that ODC were the costs of physically delivering gas to another pipeline system when the supply exceeded the demand (market) on the AP system. AP proposed to allocate these costs to all customer groups based on four-hour demand.

Views of the Applicant

AP submitted that, currently, there was a mismatch between customer groups who receive the benefit of additional on-system producer receipts and customer groups who pay the costs related to these excess receipts. Therefore, AP proposed to allocate ODC to all customer groups because AP submitted that they benefit from the additional receipts.

AP noted that by choosing to contract higher receipt volumes than required to meet the base summer load, gas had to flow to NGTL and this resulted in ODC. AP submitted that these extra receipt volumes, above the summer baseload, provided revenue that exceeded incremental costs.

AP submitted that the costs of system bottlenecks, such as at Monarch, need to be allocated appropriately and argued that the requirement to flow gas to NGTL arises from a combination of these system bottlenecks and excess supply over market requirements. AP submitted that the costs of flowing excess supply to NGTL at Monarch was a more cost effective solution than building a pipeline to the Calgary market which AP argued would be a general system cost.

With respect to IGCAA's proposal to add ODC to the OPD customer group, AP submitted that it effectively ignored the matching of ODC with revenues/benefits. AP noted IGCAA's claim that it was hard to understand where those benefits were, but AP submitted that it made these benefits clear. AP argued that the increase in the receipt volumes resulted in a reallocation of costs from the delivery customer groups to the producer customer group because of the larger receipt demand base, so all customer groups benefit through a decreased unit cost (lower toll per GJ).

AP submitted that the fundamental issue was whether AP's proposal resulted in an appropriate matching of costs and benefits of ODC. AP argued that, under its proposal for ODC, the benefits of producer volumes over the minimum summer load were matched with the ODC associated with these volumes while, under the interveners' proposals, all customer groups get the benefit of these producer receipt volumes over the minimum summer load, while producers or OPDC shippers were solely responsible for the ODC. AP submitted that this was not fair to producers or OPDC shippers and did not provide the proper price signal to producers.

AP submitted that its proposed ODC allocation (where all parties sharing the benefits share the associated costs) provided a more appropriate matching of costs to benefits than the existing Exchange Fee Mechanism. AP requested that the Board approve its proposed allocation of ODC as filed.

Views of the Interveners

CALGARY

Calgary submitted that ODC was part of providing OPD services and should be part and parcel of the OPD cost center. Calgary also submitted that ODC should be included in developing appropriate rates for this service.

Calgary subscribed to the proposition that rates for service provided by regulated utilities should be cost based, not value based. Calgary further supported the proposition that, where service was a cost based service, it provided appropriate price signals to the market place that would enable the market to manage costs.

With respect to shipper benefits from ODC, Calgary submitted that industrial and utility customers' tolls have not gone down, notwithstanding the doubling of receipts. Calgary argued that receipts equal volumes, which do not reduce tolls. Only increased contract demand provides revenue.

CAPP

CAPP agreed with AP's proposal to charge ODC to all customer groups because ODC was incurred in the course of bringing additional receipts onto the AP system and these additional receipts benefit all shippers. In addition, CAPP submitted that the costs were caused, not by a service provided to one particular customer group, but by the mismatch between overall on-system supply and on-system markets. CAPP argued that it was neither the markets nor the supply that was causing ODC but rather the net difference between the two.

CAPP disagreed with Calgary's characterization that ODC was part of providing OPD services. CAPP argued that OPD service could be offered without incurring any ODC and, on the APS system, some ODC was incurred due to system bottlenecks where no OPD service was provided. CAPP submitted that ODC was cost incurred in order to bring the benefits of incremental receipts to all shippers on the AP system.

CAPP disagreed with IGCAA's submission that ODC was caused by the shippers who put gas onto the AP system in excess of market demand. CAPP argued that ODC was caused because AP encouraged additional receipts onto its system in order to bring the benefits of lower tolls than they otherwise would be. CAPP also disagreed with IGCAA's assertion that it should not be responsible for any portion of the ODC because industrial customers have relatively flat load factors. CAPP argued that industrial load factors were relatively flat but could and do drop during the summer months.

With respect to IGCAA's assertion that there was no reliable evidence on the record quantifying the extent of the benefits, CAPP directed the Board to Exhibit 035-27 and argued that, combined with other aspects of the proposed AP rate design, ODC allocated only to producers would result in receipt volumes declining to the bottom of the summer demand trough.

With respect to Rate 13's claim that receipt customers have a choice between connecting to AP or NGTL and to sell on-system, store or export gas to NGTL, CAPP argued that on-system buyers have precisely the same menu of choices. CAPP submitted that both groups face the fact that, on the AP system at certain times of the year, the NGTL system needs to be used for "swing". CAPP submitted that it was self-serving and disingenuous of Rate 13 to simultaneously argue for a zero OPR rate and for an increased OPD Commodity (OPDC) rate.

CCA

CCA did not consider that core customers were responsible for providing other customer groups markets for their products. CCA submitted that core customers pay a premium for the purchase of natural gas in the winter because of their low load factor and argued that core customers should not be required to subsidize producers because they have no market to sell their gas in the summer. CCA submitted that economics demand that the net effect price should drop when supply exceeds demand and rate design should not be used to offset proper economic functioning of markets. CCA argued that the costs of moving natural gas to market must be borne by the party who caused the costs and receives the benefits and costs of ownership and, in the case of ODC, this should be the producer.

CG

CG submitted that ODC was made up of NGTL receipt and fuel charges caused by producer customers when no exchange service was available.

CG indicated that its preferred approach for addressing the issue of ODC was to have these costs effectively absorbed by NGTL through NGTL offering a summer TBO on AP or expanded to a two way TBO. CG also noted, however, that it recognized that implementation of this TBO solution could not be achieved as part of the present proceeding.

With respect to ODC, CG submitted these costs should be recovered from the producer class given the variable nature of these costs. CG argued that the benefit argument for reallocating to all other classes was less defensible for variable costs that must be attributed and recovered from the class that was causing the cost.

IGCAA

IGCAA noted that currently the EDA was the mechanism for managing NGTL costs and the AP UFG/Fuel costs associated with delivering gas off the AP system. IGCAA submitted that AP was proposing to resolve the EDA problem by renaming the EDA as ODC and spreading these costs out amongst all shippers on its system.

IGCAA submitted that AP's proposal departed from the principle that cost allocation should be driven by cost causation in order to achieve both fairness and efficiency. IGCAA argued that the most important reason for allocating costs based on causation was that it provided the appropriate price signals to the marketplace and promoted efficiency.

In order to provide a proper price signal, IGCAA submitted that these shippers must be directly accountable for the costs associated with putting gas onto the NGTL system, including NGTL receipt charges and fuel. By failing to provide proper price signals in the OPDC rate, IGCAA submitted that shippers on the AP system would make inefficient service choices, create a significant risk of construction of unnecessary facilities and distort gas pricing on the AP system.

IGCAA submitted that ODC was caused by the shippers who put gas onto the AP system in excess of market demand and argued that it made no sense to blame the seasonality of demand on the system as the cause of ODC. IGCAA submitted that it was receipt shippers who choose to put gas on the system, notwithstanding the lack of system market, that directly trigger ODC.

IGCAA also submitted that, even if CAPP's position regarding the core market causing ODC had merit, it would not provide a basis for allocating ODC to high load factor industrial customers who have little, if any, seasonality associated with their demand.

IGCAA submitted that the only way that it could be said that all shippers on the AP system benefited from incurring ODC was if the ODC, for which they were made responsible, resulted in incremental receipt revenue that would not otherwise be received by the system. However, IGCAA argued that there was no evidence on the record that tied ODC to incremental receipts and to the contrary, all of the evidence on the record suggested that receipt revenue would not change.

With respect to the ODC matter, IGCAA submitted that AP was proposing to make all producer receipts on its system the same as the non-standard PanCanadian/EnCana volumes in the south. IGCAA argued, however, that there was no evidence that AP stands to lose any receipt volumes unless it makes all producer receipts on its system non-standard by putting exchange costs into the system and, in fact the evidence was to the contrary.

IGCAA submitted that AP stands to lose no forecast receipt revenue in the south and, as a result, there was no benefit to system shippers by incurring this $4.7 million in ODC. IGCAA submitted that instead, AP's proposal reduced the amount of revenue it recovers from receipt shippers that was attributable to the provision of service to those shippers. IGCAA argued that receipt shipper revenue was in effect decreased by the amount of the ODC incurred.

IGCAA was concerned with assigning ODC to general system costs because of the uncertainty associated with managing these costs. IGCAA submitted that CAPP admitted that quantifying benefits of additional receipt revenue was almost impossible because it had no idea how shippers would react to AP's new rate design.

IGCAA noted that AP indicated that certain ODC was incurred on its system because of bottlenecks and that incurring this ODC was less expensive than building pipeline transmission facilities required to transport on-system supply to on-system markets. IGCAA indicated that, in principle, it had no difficulty making ODC general system costs to the extent that AP could establish that these costs were incurred to avoid adding pipeline facilities. IGCAA stated, however, that, since AP did not take this limited approach to make ODC general system costs, it was difficult to quantify what portion of ODC in the south could properly be made general system costs. IGCAA submitted that AP should be directed by the Board to take this approach in its next GRA.

Rate 13

With respect to AP's assertion that ODC was the result of having higher receipt volumes on its system, Rate 13 disagreed with AP's characterization of the cause of oversupply costs. Rate 13 submitted that ODC occurred only as a result of having higher receipt volumes relative to delivery volumes and argued that higher volumes were needed such that supply exceeded demand.

Rate 13 submitted, that in this context, ODC was NGTL receipt costs charged to AP for the transfer of gas from the AP system to NGTL and argued that it was obvious that those customers who ship their gas to NGTL via AP using the OPDC service impose these costs.

With respect to AP's argument that all customers should pay for those costs because all customers benefit from the higher receipt revenues, Rate 13 submitted that AP's logic appeared flawed because this argument completely ignored cost causation and the fact that gas leaving the system causes those costs. In addition, Rate 13 submitted that AP was attempting to make some value judgment that other customers should pay higher rates because of the overall system benefit from higher receipts. Rate 13 noted that the Application indicated that there were significant shortfalls in the past (and proposed) collection of ODC from the exchange fees/OPDC rate. Rate 13 submitted that increases to average customer rates were proposed to cover these shortfalls.

In addition, Rate 13 submitted that AP did not demonstrate that a subsidy was required such that all customers should share oversupply costs. Rate 13 submitted that only under special and relatively unique circumstances should a customer receive a subsidized rate and argued that AP did not demonstrate any type of special circumstance applies in this instance. Rate 13 submitted that if it was not economic for receipt customers to pay the full cost of their service, then they should seek other economic transactions.

Rate 13 submitted that AP should be directed to allocate ODC 100% to the OPD customer class.

Views of the Board

The Board notes that AP submitted that NGTL FT-A and MAV costs were part of the cost of delivering gas onto the AP system from the NGTL system and were directly allocated to the OPR service class. On a similar basis the Board considers it reasonable to allocate the ODC to the OPD service class since the ODC is part of the cost of delivering gas to the NGTL system from the AP system. The Board considers that the OPD service class most directly causes the costs and should be responsible for them.

With respect to AP's argument that certain ODC was incurred on its system because of bottlenecks, the Board notes that AP indicated that the main occurrence of pipeline capacity restriction was on the East Mainline Pipeline system and that pipeline capacity restrictions on the remainder of the integrated pipeline system were short term, unplanned and infrequent events resulting in little or no impact to ODC. The Board notes that AP also provided estimated costs incurred for flowing East Mainline producer receipts to NGTL due to pipeline capacity.[34]
The Board agrees with IGCAA that, to the extent that AP could establish that certain ODC would be incurred to avoid adding pipeline facilities, the Board would consider making those ODC general system costs. Therefore, the Board directs AP, in its next GRA, to provide further evidence with respect to pipeline facility costs that were avoided through ODC as the least cost alternative (LCA) and to provide a forecast of the associated ODC for the appropriate test years.

[34] Response to CAPP-AP-4. AP estimated costs for 2001, 2002 and a portion of 2003.

3.6 Income Credits

AP proposed to directly assign or allocate income credits to the five service classes in the North and South as shown in Tables 6 and 7 respectively. For the income credits that were allocated, AP proposed to use four-hour peak demand as the basis for allocation.

Table 6. AP Proposed Income Credits to Service Classes - North

	$000's						
Income Credit	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**	**Method**
Fixed Revenue		694				694	Direct
Non-Standard Revenue	1,046	524	71	715	813	3,170	Demand
IT & OR Revenue	835	418	57	571	648	2,529	Demand
Commodity/Other Revenue	75	1,633				1,708	Direct
Lease and Other Revenue	460	231	31	315	357	1,394	Demand
Totals	2,416	3,500	159	1,601	1,818	9,495	

Source: AP COSS, February 2, 2004, Table 2.6.1, lines 61-65

Table 7. AP Proposed Income Credits to Service Classes - South

	$000's						
Income Credit	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**	**Method**
Fixed Charge		167				167	Direct
Agrium Carseland FSD Rebate				(523)		(523)	Direct
Non-Standard Revenue	1,161	110		308	801	2,381	Demand
IT & OR Revenue	361	34		96	249	740	Demand
Totals	1,522	311		(119)	1,050	2,765	

Source: AP COSS, February 2, 2004, Table 2.7.1, lines 51-54

Tables 8 and 9 show the forecast billing determinants and associated forecast revenue for various services that have commodity charges in the North and South respectively.

Table 8. AP Forecast Billing Determinants and Revenue for Commodity Charges - North

Revenue Item	Service Class Credited	Forecast Quantity (TJ's)	Forecast Revenue ($000's)
Wainwright (Jan to June)	Distribution	340	75
Producers IT/OR (Oct – May)	Producer	32,862	1,906
Producers IT/OR (Jun – Sep)	Producer	8,540	623
Straddle Plant Service	Industrial	19,392	834
Industrial Overrun	Industrial	1,288	90
Rate 6 Power Plants	Industrial	20	1
Industrial Facility	Industrial		708
OPDC	OPD	44,734	2,371
OPR Commodity	OPR	157,300	2,360
Non-standard Industrial Commodity	All	106,299	2,360
FBA Cost of Service	All	2,742	773
Total		373,517	12,101

Source: Information Response Attachment IGCAA-AP02-1 (a)

Table 9. AP Forecast Billing Determinants and Revenue for Commodity Charges - South

Revenue Item	Service Class Credited	Forecast Quantity (TJ's)	Forecast Revenue ($000's_
Producers IT/OR (Oct – May)	Producer	10,453	606
Producers IT/OR (Jun – Sep)	Producer	1,830	134
Industrial Overrun	Industrial	461	23
OPDC	OPD	53,397	2,243
OPR Commodity	OPR	99,600	1,494
Non-standard Industrial Commodity	All	650	22
Agrium Carseland Rebate	Producer	21,780	(523)
Total		188,171	3,999

Source: Information Response Attachment IGCAA-AP02-1 (a)

Views of the Applicant

AP submitted that there was no evidence provided by the interveners with respect to the direct assignment or allocation of the income credits.

AP argued that its methodologies were reasonable and AP requested that the Board approve the direct assignment and allocations of income credits as filed.

Views of the Interveners

No interveners provided comments on the income credits.

Views of the Board

The Board considers that the proposed direct assignment and allocation methods for the various income credits appear reasonable except for the proposed allocation of IT revenue, OR revenue and the direct assignment of straddle plant revenue to the Industrial service class in the North, which is included in the Fixed Revenue and Commodity/Other Revenue categories.

Given that the revenue associated with the fixed charges, for FSD service, and commodity charges, for industrial OR service, was directly credited to the Industrial service class, the Board considers it appropriate to directly credit the IT and OR revenues associated with on-system receipt service to the Producer service class.

As noted in Section 7.1, Peak Demand for Cost Allocation and Rate Design, the Board has directed AP to remove the straddle plant demand from the Industrial class demand. Therefore, the Board considers it appropriate to treat the revenue associated with the SPD service in a similar fashion to non-standard revenue and allocate the revenue as an income credit to all service classes (before reallocation of OPR and OPD revenues and expenses) based on four-hour peak demand. The Board directs AP to allocate the revenue resulting from SPD service to all service classes based on a four-hour peak demand.

The Board expects that the final amounts for each service, for items allocated based on peak demand, will change in the Compliance Filing since some of the peak demand numbers to be used for cost allocation purposes have been changed by the Board. This matter is discussed in Section 7.1, Peak Demand for Cost Allocation and Rate Design.

Allocation methods with respect to OPD and OPR commodity revenues are discussed in Section 3.7 below. The Board recognizes that forecasts of income credits requires the use of forecast billing determinants such as throughput. With respect to the North and South billing determinants used to derive OPR commodity and OPDC revenue forecasts, please refer to Section 7.7, 2002 Versus 2004 Data.

With respect to the other North and South billing determinants used to derive revenue forecasts for income credit items, the Board considers that the forecast billing determinants outlined in Tables 8 and 9 appear reasonable. Therefore, the Board approves the numbers as filed.

The Board directs AP to file in its next Phase II application a North and South schedule similar in concept to the response to IGCAA-AP02-1 (a).

3.7 Reallocation of OPR and OPD Expenses and Revenues

AP allocated OPDC revenue to the five service classes based on four-hour peak demands. AP then reallocated revenues and expenses, which were initially allocated to the OPD service class, to the four remaining service classes[35] based on four-hour peak demands.

AP then allocated OPR revenue to the service classes based on 2002 exchange receipt nominations. AP subsequently reallocated revenues and expenses allocated to the OPR service class, including the reallocation from the OPD service class, to the three remaining service classes[36] based on 2002 exchange receipt nominations.

Views of the Applicant

AP submitted that the OPD costs and the majority of the OPR costs were system costs. AP agreed with Calgary that ideally the OPR and OPD system costs should be developed into stand alone demand rates, but AP argued that rate design must consider other factors in addition to cost causality in determining fair and reasonable rates.

AP submitted that stand alone OPR and OPD demand rates, where the rates include all costs allocated to the OPR and OPD customer groups, were inappropriate due to fundamental gas market liquidity concerns. AP argued that liquidity was largely dependent on customers' options to move to or from the NGTL Inventory Transfer (NIT) market. AP submitted that demand rates for transactions between AP and NGTL would require delivery customers to commit to the sources of gas, and would require receipt customers to commit to either on-system or off-system markets a year in advance. AP argued that this would significantly impair the liquidity of gas on its system.

AP submitted that a stand alone commodity rate to collect system or demand type costs would send inappropriate price signals because load factors could result in very high commodity rates. AP also submitted that a stand alone commodity rate could also result in competitive responses, including bypass. If OPR system costs were collected through a full or even partial commodity rate, the on-system gas price, driven by the NGTL NIT price and the variable rates on AP to and from NGTL NIT, would become unreasonable and result in uncompetitive delivered costs to the customers who have bypass options. AP submitted that a North OPR commodity rate would be about 19¢/GJ and a South rate would be about 30¢/GJ.

35 Distribution Company Deliveries, Industrial Deliveries, Producer Receipts and Other Pipeline Receipts.
36 Distribution Company Deliveries, Industrial Deliveries, Producer Receipts.

In addition, AP submitted that the use of a commodity rate to collect both OPR system and variable costs would result in a large portion[37] of total revenue requirement being collected on a base (nominations) that was not stable from year to year. AP argued that, although the percentage allocations of nominations were fairly consistent, the absolute values could vary significantly from year to year to reflect changes in commercial transactions. AP requested that the Board not approve blended rates, which would combine demand and commodity rates, to collect OPR and OPD system costs.

AP submitted that since a demand rate for OPR and OPD was not practical for its system, the second best alternative was the reallocation of these system costs to the other customer groups as proposed.

With respect to OPD system costs, AP submitted that peak demand was a more appropriate reallocation factor since this was consistent with the allocation of ODC, which result from increased on-system receipts that benefit all customers. AP submitted that its proposal to reallocate OPD system costs and OPDC revenues based on four-hour demands provided a fair and reasonable allocation.

With respect to OPR system costs, AP submitted that since nominations reflect the usage of OPR facilities by the customer groups, the use of nominations to reallocate the OPR facilities into the demand rates for Distributing Companies, Industrials and Producers was appropriate. AP argued that the use of nominations reflected the fact that OPR facilities were used primarily to receipt gas from NGTL to meet the gas requirements of the Distributing Companies' core customers, particularly in the winter months.

AP did not support IGCAA's proposal to include ODC with the OPD system costs that AP allocated to this customer group, and to reallocate the total to the other customer groups based on nominations. AP submitted IGCAA's proposal was inconsistent with the matching of costs and revenues/benefits of increased producer volumes and of non-standard contracts.

AP submitted that Rate 13's OPR and OPD unit cost calculation was flawed because it started with a revenue requirement, which was comprised of costs that were either directly assigned or allocated based on four-hour peak demand, and divided it by throughput volumes. AP argued that different load factors would yield different results just as they would for Distributing Companies and Industrials. AP also submitted that Rate 13 was correct when it noted that there was no peak demand for NGTL deliveries because there were currently no firm customer commitments for deliveries to NGTL, whereas there were to Alliance and MIPL/TransGas.

AP noted the CG's proposal to reallocate OPR plant related costs and associated O&M on the basis of peak demand. AP also noted the CG's position that producers should pay a portion of the general system costs associated with providing OPR service because they get the benefit of exchange service as a result of the incremental volumes coming onto the system. AP argued that OPR volumes provide little benefit to exchange capacity in the summer, when it was needed the most.

[37] $18 million in the North and $11 million in the South.

With respect to IGCAA's comments on TBO, AP indicated that the TBO costs that were assigned to the OPD customer group were part of the $1.166 million of Other Directly Allocated Costs incorporated into the calculation of the OPDC rate. AP submitted that if it had not entered into the TBO, but instead built facilities, AP would have directly assigned these assets to OPD.

Views of the Interveners

CALGARY

Calgary submitted that, historically, the costs associated with OPD and OPR services have not been specifically identified and, to the extent that these costs existed in the past, they have been treated as general system costs and, as such, allocated to all classes of service recognized in the COSS.

Calgary argued that the Board must determine whether OPD and OPR should stand alone as defined services or whether the costs attributed to these services should be re-allocated to the three primary customer classes.

Calgary submitted that once a class of service has been identified, it should stand on its own merits and service should be provided under defined rate schedules and defined terms and conditions of service.

Calgary argued that AP selected OPD and OPR as stand alone service offerings for cost allocation purposes and they should either be priced on a stand alone basis or treated as system costs and dealt with using the 2002 Board approved COSS methodology.

Calgary argued that the subsequent reallocation of revenue requirements to other classes, after identification of a class and its related share of the revenue requirement, defeats the entire COSS process and the regulatory processes. Calgary emphasized that this was especially true when the classes of service were of the size and complexity of OPD and OPR. Calgary submitted that the OPD and OPR classes represent about 33 to 40 percent of the total AP revenue requirement, and this alone mandated that they stand on their own merits. Calgary argued these services were unique and constitute an AP identified cost centre.

Calgary submitted that AP provides numerous services and maintains discrete rates for each service and, while not identified for costing purposes as classes of service, Interruptible, Over Run and Non-standard contracts all have stand alone individual rates for service.

Calgary submitted that, absent a full and complete market analysis, there was no foundation for the Board to accept AP's liquidity position. Calgary argued that no buyers or sellers of gas on the AP system came forward to support AP's position. With respect to AP's comment that demand rates would require customers to commit to either on-system or off-system markets a year in advance, Calgary submitted that such a condition was self-imposed by AP and self-imposed impediments were not candidates for meaningful evaluation, but rather tended toward a pre-disposed view.

Calgary noted that, while AP acknowledged that a commodity rate would solve the liquidity problem, AP also argued that it would make the services uncompetitive. Calgary submitted that, if the commodity rate turns out to be uncompetitive, it was not appropriate to shift the costs and bury them in some other rate or rates. Calgary argued that such a rate was demonstrative of the lack of competitiveness on the part of AP in providing that service and cost control was appropriate, not cost shifting.

Calgary submitted that CG's arguments on by-pass and liquidity were speculative and that stand alone rates for OPR service would neither cause by-pass nor reduce the liquidity on the AP system. Calgary argued that where by-pass might have a real potential, which could be demonstrated, it could then be addressed. Calgary submitted that APS currently serves AGS under an exclusive Transportation Service Agreement (TSA), which does not expire until December 31, 2008 and therefore, the concept of by-passing the APS system was more than four years in the future. With respect to the potential of by-pass of industrial customers, who were not dually connected, Calgary submitted that this would require the building of pipe to these customers that would have to come before the Board for ultimate disposition.

In response to the CG assertion that the lack of liquidity of stand alone OPR tolls could also hinder exchange volumes, Calgary submitted that the toll was the price for the service. Calgary submitted that the toll does not have liquidity nor does the service. Calgary argued that liquidity was a function of the supply and demand for the commodity in conjunction with the related cost of moving the commodity. Calgary argued that natural gas was a commodity that was traded recognizing all market conditions including transportation tolls.

Calgary submitted that the reallocation of OPR and OPD costs to Distributing Companies resulted in a level of cost shifting that was unconscionable, did not result in just and reasonable rates and was contrary to long established costing and rate design principles. Calgary submitted that the Board should recognize the AP proposal to reallocate OPD and OPR costs as an attempt to burden the end use ratepayer with costs that were formally regarded as system costs.

Calgary argued that the reallocation moved 95.6% of the costs associated with OPR service to the Distributing Companies. In addition, AP proposed to reallocate the majority of the OPD costs to the Distributing Companies class. Calgary argued that the reallocation was simply an attempt to saddle the Distributing Companies class with an excessive rate increase through the manipulation of traditional costing techniques.

Calgary noted that AP used nominations as the basis to reallocate OPR costs. Calgary submitted that, if it was appropriate to reallocate on nominations, it was equally appropriate to use nominations for the development of appropriate stand alone rates for OPR service.

Calgary submitted that, absent the Board's acceptance of OPD and OPR as stand alone service offerings, the Board's costing and rate design guidelines established in Decision 2001-097 form a solid foundation for costing and related rate designs for the APS system.

Calgary disagreed with CG's recommendation that the reallocation of OPR system costs to Utilities, Industrials and Producers be based upon the use of peak demand. Calgary argued that there was no developed framework that supported the reallocation of the costs to serve one class of service to other classes. Calgary indicated that this same argument applied for both OPR and OPD.

In response to CG's comment that Calgary's proposed treatment of OPR and OPD may not be practical, Calgary submitted that there was no evidence supporting CG's assumption that users of OPD and OPR services were directly proportional to its proposed reallocation of OPD and OPR costs on peak demand. Calgary argued that both AP and the CG proposed to allocate costs, not in proportion to actual use, as the Calgary proposal would accomplish, but to pre-assume a level of use through their respectively proposed reallocation schemes. Calgary submitted that the cost of providing OPD and OPR services should be borne by the users of the service and, from a practical standpoint, the Calgary proposal would place the cost of using the OPD and OPR services out in the open for the benefit of the marketplace using cost based and transparent prices.

Calgary submitted that if stand alone pricing for OPD and OPR services was to have negative impacts on AP, then the issue could be clearly examined to determine if solutions were available, or if the negative impact was truly due to the AP cost structure being outside the marketplace; and, what the market would pay for the services. Calgary argued that, conversely, melding the costs of OPD and OPR into other costs would never allow the marketplace to evaluate competitive alternatives for these services.

Calgary indicated that it appeared that FGA was proposing that no system costs would be allocated to OPD and OPR, thus reverting back to the 2002 methodology, except for the inclusion of the incremental cost of providing OPD and OPR, which would be included in the OPD and OPR stand alone rates. Calgary submitted that such a proposition was a compromise position between AP and Calgary and should only be accepted by the Board as an inferior result to Calgary's recommendation.

In response to Rate 13's claim that a reasonable fix to the cost allocation problem for AP's system costs would be to combine the system costs allocated to both OPR and OPD, and to allocate the combined amount to each service based on forecast volume,[38] Calgary indicated that this analysis was a new costing and rate design theory, which no one had the opportunity to test and evaluate. Calgary indicated that, while there might be some merit to the Rate 13 argument, in reality AP proposed to cost OPD service on an incremental concept; i.e. no pipeline costs. Calgary argued that the concept of adding the two cost centres together and dividing by two to establish rates failed to meet either the concept of cost causation or cost based transparent rate design.

CAPP

In response to the CG recommendation that, absent a TBO arrangement, the fixed system costs of OPD service should be allocated back to all customer classes and the variable costs should be allocated to producers as a group, CAPP submitted that CG neglected to describe on what basis the fixed costs should be allocated to all customer classes and therefore, this proposal lacked sufficient detail to be adopted. CAPP also indicated that CG's other proposal was based on the false premise that ODC (variable costs) should be allocated to producers. CAPP argued that ODC was cost incurred on behalf of all shippers to bring the benefits of increased receipt volumes.

CCA

CCA supported the CG position on this issue.

[38] The Rate 13 evidence showed unit costs of $0.084/GJ for OPD and OPR in APS and $0.112/GJ for OPD and OPR in APN where the revised revenue requirement was equal to the aggregate cost per GJ multiplied by the forecast volume for each service.

CG

With respect to Calgary's proposal that OPR and OPD should be stand alone services, CG indicated that this might not be practical because of the physical realities of the AP system. CG submitted that, even if someone saw the price signal and tried to respond by buying less gas on NGTL, it simply meant that someone else would have to buy gas from NGTL.

CG submitted that under a strict cost causation approach, stand alone OPR and OPD rates might appear to make sense. However, under the cost causation standard, CG argued that the OPR and OPD system related costs must be recovered by way of demand rates, not by way of nominations. CG believed demand related rates would not be practical and would curtail liquidity on the system. CG was also concerned that the Calgary proposal may lead to bypass opportunities.

With respect to a blended rate in which the direct users of OPD and OPR services would pay some of the system costs included under the OPD and OPR classes, in addition to variable costs attributed to these classes with the remainder of the system costs reallocated to various customer classes, CG confirmed such an approach would be feasible subject to the constraint that it did not result in bypass opportunities. Also, the Board must weigh the Calgary proposal against the particular circumstances of AP and the dual tolling issue with NGTL. CG submitted that, currently, the dual tolling between AP and NGTL was largely mitigated by the existence of significant exchange volumes at NIT and argued that increasing OPD or OPR rates by the inclusion of some or all system-related costs could potentially negatively impact the volume of gas exchanged on the NIT system. Therefore, CG submitted that the OPR rates should reflect only the variable cost component, namely the pass through of FT-A charges from NGTL.

CG argued that, given the impracticality of demand related stand alone rates, system related OPR and OPD costs should be reallocated based on peak demand. In both instances, CG recommended that the allocation of fixed system costs made to OPR and OPD in the AP COSS should be allocated back to all customer classes and variable costs should be allocated to the customers who cause them.

CG believed the allocation of costs related to NGTL FT-A and MAV charges on the basis of nominations would be consistent with cost causation. However, CG submitted that the allocation of AP's plant related costs and associated O&M on the basis of nominations was not consistent with cost causation.

CG submitted it was appropriate to reallocate system related OPR costs to all classes on the basis of coincident peak demand to reflect cost causation[39] and to reflect the benefit received by producers through exchange service.[40] CG recommended that the Board direct AP to refile its COSS using this approach.[41]

[39] CG submitted that the system was planned to meet the demand requirements of primarily the distribution companies and the industrial customers.

[40] CG submitted that a producer customer would pay the FSR plus the other pipelines' delivery costs plus fuel and UFG in order to access another pipeline, and even after paying those tariffs, the producer's costs would be lower than those of accessing NGTL directly. CG argued that there was a certain benefit, and as a result of its allocation of some of the system costs to the producer group, there was still that benefit, although somewhat reduced by approximately a cent.

[41] CG noted that the results of its proposed allocation of system related OPR costs were set out in response to CAL CG 3.

CG indicated that AP was proposing that ODC, which was primarily incurred in summer months, be reallocated to all customer classes based on peak demand. CG argued that there was no cost causation link between incurrence of ODC in the summer months and the peak demands used to allocate costs to distribution and industrial classes. CG noted that AP's rationale for these reallocations was that OPD and ODC provided system benefits.

CG submitted that, if it was considered appropriate to reallocate system related OPD costs to all classes based on peak demands to reflect the system benefits generated by OPD services, the same principle should apply to reallocation of system related OPR costs. CG argued that the existence of exchange benefited all customer classes and that OPD and OPR services were required for the efficient functioning of exchange service. CG submitted that, while it was recognized that exchange service provided benefits to all classes through the avoidance of dual tolls, it was not possible to trace these benefits to one class or another. CG also submitted that it was also not possible to measure the benefit of OPR service based on nominations, as implied by AP's suggestion, since exchange service, made possible by OPR, benefits all customers through its impact on the volumes entering the AP system, the netbacks to producers and on-system gas prices on the AP system. CG noted that it was this exchange benefit that justified non-standard rates to industrial and producer customers. CG submitted that these customers would bear their fair share of system costs if there were no benefits from the additional on-system volumes attributable to these customers. Therefore, CG argued that it was fair and reasonable to reallocate system related OPD and OPR costs to other classes in the same way they were initially allocated to these classes, namely peak demand.

With respect to IGCAA's statement that CG could not identify the benefits producers received from other pipeline receipts, CG submitted that exchange service provided a benefit to all customer classes as reflected in the on system gas prices. CG submitted that on-system gas prices were a reflection of the sharing of benefits resulting from avoidance of dual tolls among producers, industrials and distribution companies.

CG submitted that, consistent with its recommendation concerning reallocation of system related OPR costs, the system related OPD costs should be reallocated to other customer classes on the basis of coincident peak demand, as proposed by AP.

In the case of OPD, CG submitted that the variable costs that should be allocated back to the customers causing them should be the variable ODC. CG did not believe individual producer customers could be identified and recommended that these variable costs should be allocated to producers as a group.

FGA

FGA supported the position of CG and Calgary with respect to reallocation of OPR and OPD costs. FGA submitted that the customer who incurs the cost was the one who must bear the cost and the reallocation of OPR and OPD costs was needlessly complicated and distorted the cost of providing service to all customer classes.

FGA suggested that, should the Board agree with the creation of these classes of service, the COSS should be reconstructed so that the OPR and OPD rates bear only their incremental costs. With respect to the OPR rate, the FGA submitted that the incremental charges would consist of the NGTL delivery and MAV charges, for gas received from NGTL, and the direct costs of metering the flows on to the AP system. With respect to the OPD rate, FGA submitted that the incremental charges would consist of any NGTL receipt charges, the costs of metering the flows off the AP system and any direct compression costs. FGA submitted that, if AP could identify any other direct costs of providing OPR and OPD service, these should be included in the rate.

FGA submitted that costing these services incrementally would likely result in a rate that was economic to provide without reallocating a portion of the cost arbitrarily to other customers. FGA argued that the need for these rates might disappear if the joint pipeline module resulted in a TBO solution that allows the seamless transfer of gas between the AP and NGTL systems.

IGCAA

IGCAA indicated that it found the stand alone allocation of costs as advocated by Calgary to be principled. IGCAA also indicated that, although it did not necessarily agree that the stand alone allocation of OPR costs would have liquidity problems, IGCAA appreciated that stand alone OPR tolls could give rise to by-pass threats. Therefore, IGCAA indicated that it could accept the blended approach to OPR reallocation applied for by AP where OPR costs were put back to customer classes based on nominations.

With respect to AP’s submission that a stand alone commodity rate to collect system or demand type costs sends inappropriate price signals because load factors could result in very high commodity rates, IGCAA agreed that this may be true for an OPR commodity rate. However, IGCAA submitted that no evidence was given that demonstrated that including ODC in the OPDC commodity rate would result in high commodity rates giving inappropriate price signals. Therefore, IGCAA submitted that all ODC should be recovered in the OPDC commodity rate. If there was such evidence, IGCAA indicated that it would support allocating ODC among customer groups based on the nominations of those groups.

IGCAA submitted that all costs associated with deliveries to other pipelines should be recovered in a stand alone OPDC charge. However, IGCAA indicated that if there were liquidity or competitiveness concerns, it could accept a reallocation of OPD costs based on customer group nominations. Therefore, IGCAA noted that this would treat both OPR costs and OPD costs in the same manner.

IGCAA did not support reallocation of OPR and OPD costs among all customer classes as proposed by CG because the allocation of OPR costs across all customer classes was the same as allocating ODC as general systems costs. IGCAA submitted that the reallocation methodology did not accord with the principle of cost causation and was fraught with the peril of attempting to match benefits or values with costs incurred. As with ODC, IGCAA submitted that the witnesses for CG could not quantify the benefits producers received from other pipeline receipts. In addition, IGCAA submitted that witnesses for CG could not indicate how they would adjust the allocation of OPR charges in the event that exchange capability was somehow reduced through the facilitation of FT-P service.

In the North, IGCAA submitted that AP inappropriately reallocated TBO costs to industrials through OPD reallocations and argued that TBO costs should not be directly allocated to industrials because industrials do not cause any of these costs. IGCAA submitted that the appropriate treatment for allocating TBO costs would be to directly allocate all of them to producers and distributing companies.

NGTL

NGTL noted that AP's OPD service was not restricted to deliveries to the Alberta System through its NIT account and would also apply to export deliveries from AP's system to Alliance and MIPL. NGTL indicated that AP proposed to provide export delivery service to Alliance and MIPL at a zero rate for shippers using OPDM service.

NGTL submitted that it appeared that AP's competitive position relative to NGTL was a significant factor in AP's determination to reallocate costs associated with the provision of its OPR and OPD services to other customer groups.

NGTL was concerned about AP's consideration and use of competition as a factor in determining its tolls for situations other than customer-specific circumstances. NGTL indicated that, in the past, the Board considered the impacts of competition as a factor in establishing specific non-standard contracts and load retention services for itself and AP. However, NGTL suggested the Board has not commonly accepted and considered the competitive position of a regulated utility relative to another regulated utility, where both were under its jurisdiction, as a significant factor in determining the rates for a general class of utility service.

NGTL requested that the Board, in its decision on AP's proposed OPR and OPD service rates, clearly establish whether competition with another regulated utility under its jurisdiction was a legitimate basis on which a regulated utility may reallocate actual costs for a class of service, and how it specifically considered and applied this factor in determining the just and reasonable rates for OPR and OPD services, if ultimately approved.

NGTL also indicated that, if the Board accepts that competition between regulated utilities was a legitimate basis for the reallocation of costs and determination of rates, it would like the Board to provide guidance on whether this factor equally applied to the determination of rates for other regulated utilities under the Boards' jurisdiction, and, namely, NGTL.

NGTL submitted that, if the Board decided to allow AP to continue to exchange dual connected volumes to the Alberta System under OPD service, the Board should at least require the parties using the OPD service to pay the full costs associated with it. NGTL argued that AP should be prohibited in these instances from reallocating any of the costs it incurs in providing OPD service to other customer groups, as proposed in the Application. NGTL submitted that this requirement would ensure that parties at dual connected stations receive proper price signals for the service, and it would prevent inappropriate cross-subsidization from other AP customers. NGTL argued that it would also assist in leveling the "playing field" for any continued competition between NGTL and AP in these circumstances. NGTL suggested that this was an appropriate requirement to specifically impose on parties whose volumes are dually connected, because these parties have options not available to single connected parties.

Rate 13

Rate 13 submitted that the OPDC rate must not be subsidized for proper and orderly economic development of the AP system to occur. Rate 13 argued that a highly subsidized OPDC rate would disturb proper economic signals and would act to increase costs to system users.

Rate 13 indicated that it prepared the analysis in Exhibit 035-13 to demonstrate that AP's revenue forecast from the OPDC rate was significantly lower than the actual costs to provide the service. Rate 13 changed the Applicant's data, first, to allocate ODC to OPD and, second, to remove the revenue and cost reallocations. Table 10 compares the OPD service costs and OPDC revenues as determined by Rate 13.

Table 10. OPD Service Costs versus OPDC Revenues

Item	APN ($/GJ)	APS ($/GJ)	Data Source
AP Proposal	0.053	0.042	Table 2.6-1 & 2.7-1
Actual Cost	0.090	0.122	Ex. 035-13 (a & b)

Rate 13 submitted that the fully allocated cost to provide the OPD service was nearly double the proposed OPDC rate in the North and nearly triple the proposed rate in the South. Rate 13 argued that the firm receipt and delivery rates would significantly and materially cross subsidize such transactions, with the result being unjust and unduly discriminatory rates for firm receipt and delivery customers.

Rate 13 submitted that a significantly subsidized OPDC rate might result in uneconomic transfers to NGTL where other alternatives, such as storage, could be accessed at a lower total cost. Rate 13 submitted that injecting into storage in the summer may become much more attractive if the alternative was to pay a cost-based OPDC rate, rather than a significantly subsidized rate.

Rate 13 also submitted that the Board should give strong consideration to the impact of a low OPDC price on system prices because it was very concerned that the discounts would disappear or reduce significantly. Rate 13 argued that this would not be in the public interest because there should be strong incentives for on-system production to be sold to on-system markets. Rate 13 submitted that, if there was little or no incentive for suppliers and customers to find each other, then it was likely that less economically efficient shipments to NGTL would result, with potentially higher overall costs for customers.

Instead of AP's proposal, Rate 13 submitted that a much better mechanism would be to charge proper costs to the firm receipt rate and also to charge a full cost OPDC rate. In this way, Rate 13 argued that customers could make up their own mind as to whether it was economic for them to connect to AP or instead to NGTL or elsewhere.

Rate 13 submitted that the OPD rate should be structured as a variable rate with deferral accounts. Rate 13 argued that the OPDC service was basically a service used on an as-needed basis and was not a service where long-term commitments (generally underpinning investment in local facilities) were warranted.

Rate 13 indicated that Calgary's approach to the OPD proposal was philosophically consistent with Rate 13's approach. However, Rate 13 submitted that a firm demand rate for OPD as proposed by Calgary would not be in the public interest given that the Board does not have evidence on the impact of demand charges for OPD and OPR on the on-system price of gas. In addition, Rate 13 had additional concerns about demand charges for OPD and OPR with respect to rules around capacity utilization that it argued have not been fully defined in the Calgary proposal.

Rate 13 questioned the necessity for the OPR service. In addition, Rate 13 submitted that it appeared that there was a significant discrepancy between the unit cost of OPR and OPD in regard to the system costs allocated between OPR and OPD. Rate 13 submitted that its evidence showed that the unit cost of OPR was significantly higher than OPD[42] and argued that there was no logical reason why AP system costs should vary so dramatically simply by the change in direction of flow.

Rate 13 submitted that inclusion of the peak demand created by the volumes shipped to NGTL in the allocation of system costs would be more correct than AP's proposal to ignore demands from volumes shipped to NGTL.

Rate 13 submitted that more study on this issue was required in future rate hearings to address the shortfalls identified. Rate 13 argued that, for this proceeding, a reasonable fix to the cost allocation problem for AP's system costs would be to combine the system costs allocated to both OPR and OPD, to calculate a total average cost, and to allocate the combined amount to each service based on forecast volume.[43] Rate 13 submitted that, in this way, the system unit cost for OPR would equal the system unit cost for OPD and would reflect the fact that AP's system costs do not materially change when the direction of flow between NGTL has changed.

Views of the Board

As discussed in Section 3.2, the Board determined, with some reservation, that it was appropriate to use five service classes to assign and allocate expenses in the COSS. In this section, the Board believes the first question it should address is whether two of the service classes, OPR and OPD, should be fully cost based services with stand alone rates or whether the two services should be designed to recover only a portion of the allocated and assigned costs with the balance being reallocated.

The Board is sympathetic towards Calgary's view in principle that, if OPR and OPD are separate service classes, then they should stand alone as proper services with defined rate schedules and terms and conditions of service. In theory either demand rates or commodity rates would be established.

However, the Board notes that AP and others have argued against the approach of creating stand alone rates for OPR and OPD, and have raised concerns with respect to basing such rates on either a demand or commodity basis.

With respect to structuring stand alone OPR or OPD rates on a demand basis, AP submitted that stand alone OPR and OPD rates, where the rates include all costs allocated and assigned to the OPR and OPD service classes, would be inappropriate due to liquidity concerns. However, the Board does not consider AP's argument to be completely convincing.

42 The Rate 13 evidence showed that unit costs of OPD and OPR were \$0.039/GJ and \$0.108/GJ respectively in APS and \$0.074/GJ and \$0.123/GJ respectively in APN.

43 The Rate 13 evidence showed unit costs of \$0.084/GJ for OPD and OPR in APS and \$0.112/GJ for OPD and OPR in APN where the revised revenue requirement was equal to the aggregate cost per GJ multiplied by the forecast volume for each service.

The Board agrees with Calgary's view that liquidity is related to the trading, buying and selling of gas on the AP system and that liquidity is a function of supply and demand for gas in conjunction with related costs such as transportation. The Board considers that, in the context of the natural gas business, liquidity is related to the degree to which natural gas can be bought or sold in the market without affecting the price. Generally a high level of trading activity accompanies liquidity.

The Board considers that buyers and sellers of gas on the AP system would be in the best position to comment on the issue of liquidity on the AP system and potential threats or impacts to it. The Board notes that two key entities involved with performing the gas Default Supply Provider (DSP) function, namely AG as a previous provider and Direct Energy Regulated Services (DERS) as a current provider, did not participate in the proceeding. In addition, CAPP was silent on the issue and IGCAA did not necessarily agree that the stand alone allocation of OPR costs would cause liquidity problems. Therefore the Board considers that threats to liquidity were not well substantiated in this proceeding.

With respect to AP's comment that demand rates would require customers to commit to either on-system or off-system markets a year in advance and that this would significantly impair the liquidity of gas on its system, the Board agrees with Calgary that such a condition is self-imposed by AP in its own customer contract provisions. In addition, the Board also notes that AP acknowledged that the day market on its system was fairly small and that most gas was acquired on annual terms.[44]

The Board notes that the DSP acquires gas on a variety of terms. The Board considers that it might be possible for AP to structure short-term demand type OPR services with various terms (seasonal, monthly), similar in concept to its short-term receipt services, that could accommodate the needs of its customers. Further, it might be possible for AP to structure short-term demand type OPD services in a similar fashion. The Board also considers that it might be appropriate for AP to consider a two-part rate (demand and commodity) for the costs assigned and allocated to the OPR and OPD service classes.

The Board agrees with the CG that the physical realities of the AP system require physical gas supplies from the NGTL system during certain times of the year. The Board notes that AP indicated that industrial customers acquire most AP on-system gas supply. The Board considers that, if AP were to design a stand alone rate for OPR, consultation with DERS and other parties that acquire gas for distributing company customers on the AP system could provide a reasonable estimate of NGTL gas supply requirements throughout a given year and therefore, OPR service requirements for this market segment.

With respect to structuring stand alone OPR or OPD rates on a commodity basis, the Board generally agrees with AP's submission that stand alone commodity rates to collect system or demand type costs would probably send inappropriate price signals because load factors could result in very high commodity rates. The Board also agrees that a commodity rate would not be an appropriate billing method to recover fixed costs such as those allocated to the OPR service class.

[44] Transcript, page 447, lines 15-24

With respect to AP's submission that a stand alone commodity rate could also result in competitive responses, including bypass by industrial customers, the Board agrees that this is hypothetically possible. However no evidence was submitted indicating the likelihood of bypass in this instance. The Board agrees with Calgary that a specific bypass proposal would require an application for Board consideration.

Overall, the Board considers that there may be merit in stand alone services, but the present record is unclear as to whether the potential benefits of stand alone OPR and OPD services, assuming such services could be suitably structured, would be worth the effort required to develop them.

Given the timing of this Decision and the follow-up Compliance Filing, the Board does not believe that AP would have enough time to discuss potential OPR and OPD services with its customers in order to establish stand alone OPR and OPD services for 2004. The Board is prepared to accept AP's position that OPR and OPD services should not be stand alone services at this time. The Board directs AP to confer with its customers to determine whether stand alone OPR and OPD services are practical and cost effective and to address this matter in its next GRA.

In addition, if stand alone OPR and OPD services do not appear to be appropriate or achievable on reasonable terms, the Board believes that the fundamental question of whether OPR and OPD should be treated as service classes or simply as system costs, should be addressed in a the next GRA.

Given that fully cost based OPR and OPD services with stand alone rates will not be established for this proceeding, the next question is to determine what costs should be recovered by OPR and OPD services.

With respect to the OPR service class, the Board notes that AP proposed to charge a commodity toll to recover only NGTL's FT-A expense. The Board notes that other parties have proposed that, in addition to the NGTL FT-A expense, other expenses could be recovered through an OPR commodity rate. At this time, the Board is prepared to accept AP's proposal to continue to only recover NGTL's FT-A expense through the OPR rate.

With respect to the OPD service class, the Board notes that AP proposed the OPDM service and a commodity rate service (OPDC). As discussed in Section 5.5.2, OPDC, the Board is currently prepared to accept AP's proposed methodology for establishing the OPDC rate.

Given that the Board has accepted AP's proposals with respect to the OPR and OPD commodity rate methodologies, the Board must now examine AP's proposed reallocation methodologies for the income credits and expenses assigned and allocated to the OPR and OPD service classes. The Board notes that a reallocation methodology is neither a traditional approach nor a preferred approach for dealing with expenses assigned or allocated to a service class.

With respect to reallocations for the OPR service class, AP proposed to use 2002 exchange receipt nominations as the basis for reallocating the income credits and expenses, on the grounds that nominations reflect the usage of OPR facilities by the customer groups. Further, AP argued that the use of exchange receipt nominations reflected the fact that the OPR facilities were used primarily to receipt gas from NGTL to meet the service requirements of the Distributing Companies' core customers, particularly in the winter months.

CG submitted that the allocation of costs related to NGTL FT-A and MAV expenses on the basis of nominations would be consistent with cost causation, but that the allocation of AP's plant related costs and associated O&M on the basis of nominations would not be consistent with cost causation. CG also argued that, since AP allocated plant related costs on the basis of peak demand in its initial allocation, it should use the same method to reallocate OPR costs, excluding those related to NGTL FT-A and MAV charges, to the Primary Service Classes.

The Board has considered the arguments put forth by parties on this matter and agrees with AP that exchange receipt nominations are appropriate for the reallocation of all expenses and income credits allocated and assigned to the OPR service class. In addition, at this time, the Board also considers it appropriate to allocate the OPR commodity revenue to the Primary Service Classes based on exchange receipt nominations.

The Board considers at this time that usage is an appropriate factor for reallocating income credits and expenses determined for the OPR service class.

In this case, the Board considers that it is reasonable to base the reallocation on actual historical usage. Therefore, the Board directs AP in the Compliance Filing to use 2002 actual exchange receipt nominations[45] made by the Primary Service Classes to reallocate the income credits and expenses determined for the OPR service class.

With respect to the reallocation of OPD income credits and expenses, AP submitted that peak demand was an appropriate reallocation factor for OPD system costs because this factor was consistent with its proposed allocation factor for ODC. The CG supported the AP proposal on the basis of consistency with the CG reallocation proposal. However, with respect to OPD variable costs, the CG submitted that the ODC should be allocated back to the customers causing them, specifically, to the producers as a group.

The Board notes IGCAA's submission that all costs associated with deliveries to other pipelines should be recovered in a stand alone OPDC charge. However, if there were liquidity or competitiveness concerns, IGCAA could accept a reallocation of OPD costs based on customer group nominations. This would treat both OPR costs and OPD costs in the same manner.

AP did not support IGCAA's proposal to include ODC with the OPD system costs and to reallocate the total to the other customer groups based on nominations, on the basis that IGCAA's proposal was inconsistent with the matching of costs and benefits of increased producer volumes and of non-standard contracts. The Board notes that in Section 3.5.6.4, AP was directed to assign the ODC costs to the OPD service class in the Compliance Filing.

The Board has considered the arguments put forth by various parties with respect to the reallocation of OPD income credits and expenses and agrees with IGCAA that other pipeline delivery nominations are appropriate for the reallocation of all expenses and income credits allocated and assigned to the OPD service class including ODC. In addition, the Board also

[45] Excluding nominations related to non-standard contracts. See Section 7.7 2002 Versus 2004 Data and CAL-AP02-16(a).

considers it appropriate to allocate the OPD commodity revenue to the Primary Service Classes based on other pipeline delivery nominations. As noted above, with respect to OPR reallocations, the Board considers that usage would be an appropriate factor for reallocating income credits and expenses of the OPD service class.

In this case, the Board considers that it is reasonable to base the reallocation on actual historical usage. Therefore, the Board directs AP in the Compliance Filing to use 2002 actual other pipeline delivery nominations made by the Primary Service Classes to reallocate the income credits and expenses determined for the OPD service class. Section 7.7, 2002 Versus 2004 Data provides Board directions with respect to the 2002 actual other pipeline delivery data.

With respect to the TBO reallocation issue identified by IGCAA, the Board considers that its OPD reallocation determination should mitigate this concern.

The Board directs AP to describe in the Compliance Filing its process for assigning a particular nomination (other pipeline receipt and other pipeline delivery) made by a given customer to one of the Primary Service Classes.

With respect to AP's forecast of OPR and OPD commodity revenue, the Board discusses this issue further in Section 7.7, 2002 Versus 2004 Data.

3.8 Adjustments to COSS Components

The Board has made a number of adjustments to components of the COSS in each of the North and South. Appendices 4 and 5 show the Board's adjustments. Included are changes to the OPR commodity rates and the straddle plant (SPD) rate in the North. Appendix 6 shows the services and respective charges that the Board expects will be changed in the Compliance Filing due to the Board's determinations outlined in Appendix 4 and 5.

4 RATE DESIGN

4.1 Rate Design Criteria

As discussed in Section 2.2 a Phase II decision will consider and determine how to apply the appropriate rate design criteria for the determination of just and reasonable rates to collect the utility's approved revenue requirement, determine the rates for the proposed services and establish the appropriate terms and conditions for these services. Section 3.1 considered the cost related rate design principles in reviewing the AP's COSS. Section 4 will first consider and balance other applicable rate design criteria in reaching conclusions on just and reasonable rates and then determine if any adjustments are appropriate in light of these principles.

The Board refers to Professor Bonbright's criteria or rate structure attributes [46] which were summarized and commented on by the Board in Decision U96055[47] in the following words:

> The Board agrees with parties that the basic attributes of an appropriate rate design include simplicity, understandability and public acceptability; freedom from controversy; effectiveness in achieving revenue sufficiency and in providing revenue and rate stability; fairness in the apportionment of total costs and avoidance of undue discrimination; and the encouragement of efficiency. The weight to be given to each of these characteristics will depend largely on the desired balance between various goals, objectives and

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46 *Principles of Public Utility Rates* (2ed), James C. Bonbright, Albert L. Danielsen and David R. Kamerschen Public Utilities Reports, Inc., 1988 at P 383-384

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.
2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.
3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to rate-payers and with a sense of historical continuity. (Compare "The best tax is an old tax.")

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company;
   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).
6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) *horizontal* (i.e., equals treated equally); (2)*vertical* (i.e., unequals treated unequally); and (3) *anonymous* (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).
7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).
8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes:

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.
10. Freedom from controversies as to proper interpretation.

See also *Gas Utilities Rate Design Inquiry Report* No. E80100 dated July 31, 1980, P 53

47 Decision U96055 NOVA Gas Transmission Ltd. 1995 General Rate Application - Phase II dated June 12, 1996 at P 24

> interests. The Board does not believe that there exists a rate design which will accommodate all interests and satisfy each and every individual shipper.

Professor Bonbright acknowledged, however, that his list of criteria is ambiguous, overlapping and fails to offer any rules of priority in the event of conflict. [48] There is a need to strike a balance in order to meet the interests of all stakeholders. The Board also recognizes that the circumstances for each application are different from other applications and therefore, the weighting and prioritization for the criteria may vary for each application.

With respect to this Application, the Board believes that two of the non-cost rate design criteria are of particular importance:

(i) stability and predictability of rates which has as its main objective the avoidance of rate shock and,
(ii) the practical attributes of simplicity, certainty, convenience, understandability and public acceptability.

The Board believes that consideration of these two criteria in particular will assist in achieving an outcome which balances cost causation as reflected in the AP's COSS (as adjusted by the Board's directions provided in Section 3), and rate impacts to the respective classes.

The next section of this Decision will apply the above two rate design criteria in considering the impact to the respective rate classes of the rates that would otherwise result from the adjusted AP's COSS.

4.2 Rate Impact

The Board has traditionally reflected cost causation as a primary rate design principle by endeavoring to approve rates which result in revenue/cost ratios within a 95 – 105% range. [49] However, in Section 4.1 above the Board identified two non-cost rate design criteria of particular importance in the circumstances of the present Application, namely stability of rates and the practical considerations of simplicity, understandability and public acceptability. These two rate design criteria to a large extent relate to the impact of change to existing rates which may work to temper the Board's targeted revenue/cost 95 – 105% range for rates.

It has been recognized in various Board decisions[50] that extenuating circumstances may be taken into account, particularly if adjusting rates to achieve the desired 95 – 105% range leads to possible rate shock. In such situations, the Board may limit or cap a rate adjustment to some acceptable level, even if the result falls short of achieving the target revenue/cost range.

In this case, the Board notes that in the North, adjusting the Distributing Companies demand rate (FSU) to achieve at least a 95% revenue/cost ratio, would result in a significant rate increase. This situation is in part a by-product of not having a litigated rate case based upon a full COSS since 1993[51]. It would appear from the AP's COSS, as adjusted by the Board earlier in this

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[48] *Principles of Public Utility Rates* (2ed), James C. Bonbright, Albert L. Danielsen and David R. Kamerschen Public Utilities Reports, Inc., 1988, P 384

[49] See for example Decision 2003-019, *Aquila Networks Canada (Alberta) Ltd. 2002/2003 Distribution Tariff*, dated February 28, 2003 at P 117.

[50] EUB Decisions U99034, 2003-019, 2001-097

[51] Decision E93098

Decision, that Producers in the South would also receive a significant rate increase, attributable in part, to the fact that there has only been one litigated GRA with a partial COSS since 1993.

The Board notes that AP indicated in AUMA/EDM/PICA-AP 11(b) that it considered that in the present Application there was no reason to introduce "gradualism", or a phase-in of rate shifts, for its applied-for rates. The Board does not agree with this position. Given:

(a) the length of time between litigated rate cases, and the reallocation of costs among rate classes,

(b) the Board's findings in Section 3 on the AP's COSS, and

(c) a review of the rate impact considerations discussed in Section 4.1 above,

the Board considers that some degree of gradualism is appropriate. The Board considers that limiting the rate increase to 25% above the rates existing in January 2003, the latest rates set by the Board for AP South and those determined through the negotiation process for the North, would strike a reasonable balance between moving rates to fall within the target range and limiting rate shock. The Board expects that AP's next GRA will provide an opportunity to further graduate the affected classes to within the 95 – 105% revenue /cost range.

The Board notes that percentage impact calculations by themselves are most meaningful when considered in the context of the actual monetary impact of such adjustments. It would appear that a large percentage impact to rates with respect to AP customers may have less impact on a per unit basis on a customer bill than a similar percentage rate increase for some other utilities. Accordingly, in determining an appropriate cap on rate increases, it is difficult to make a meaningful comparison between utilities based on potential percentage increases alone. In absolute terms, a 25% rate increase is more than the Board would ideally prefer. The Board notes for example the 10% cap utilized in Decision U99034 for ATCO Electric. However, the Board notes that the increase in the transmission rate will likely result in a only a moderate increase in the context of the total delivery charges for customers of the Distributing Companies. This consideration of the combined impact of transmission and distribution demand charges on ratepayers is consistent with the Board's approach in the recent Aquila distribution tariff Decision 2003-019.

Accordingly, the Board directs AP to ensure in the Compliance Filing, that the rates are increased by no more than 25% for any customer class in both the North and the South above the rates that were in place as of January 1, 2003.[52]

The Compliance Filing should recalculate rates on the basis of:

(a) a 100% revenue/cost ratio and the resultant increase/decrease in rates from the January 1, 2003 rates; and

52

2003 Rates Prior to Interim Adjustment	North $/GJ Demand	South $/GJ Demand
FSU	1.806	1.605
FSD	1.610	1.500
FSR	3.497	2.250

(b) the implementation of a 25% cap on the results obtained in (a) above. The residual revenue requirement not collected from a capped rate shall be redistributed proportionally between the two remaining customer classes based on billing demand, such that, upon redistribution, the rate increase for any class shall not exceed 25%.

Given that the Board approved the rate relationships proposed by AP with respect to the FSR demand and OR rates and FSR demand and interruptible receipt transportation (ITR) rates, the Board recognizes that as AP's shifts Net Revenue Requirements to/from the Producer Receipt service class, the FSR OR revenue and IRT revenue will be impacted. The Board directs AP to take this revenue impact into account when establishing the Net Revenue Requirements for the Producer Receipt service class.

4.3 North/South Rate Integration

Parties provided views on the possibility of using a weighted average rate for both the North and South systems given the restructuring of the systems under common ownership and the increasing separation of transmission and distribution.

Views of the Applicant

AP described differences between the transmission systems in the North and South. AP indicated that the distances required to deliver gas to on-system markets were different as were the flows within, onto and off of the systems as noted.[53] AP submitted that the distance to deliver gas to the core customers was greater in the North than in the South and AP argued that these system differences resulted in cost differences. Further, AP indicated that the allocation of total costs of each system was also different due to many factors, including the respective composition of customers.[54]

AP submitted that the Board approved separate North and South Revenue Requirements in Decision 2003-100 under the expectation that separate rates would be retained for the North and South in Phase II.[55] However, AP indicated that if the North and South rates for individual customer groups were within 5% of each other at the time of preparing the Compliance Filing, it intended to use the same weighted average rate for both the North and South.[56]

Views of the Interveners

CG

The CG disagreed with AP's proposal to use the same weighted average rate for both the North and South if the North and South rates for individual customer groups were within 5% of each other at the time of preparing the Compliance Filing.

The CG submitted that separate cost of service studies were filed and that separate rates were proposed. The CG argued that it was inappropriate to change this direction in the compliance filing. Moreover, the CG submitted that AP should still be required to report separate North and South rates for each customer class, irrespective of their differences.

[53] AP 2003/2004 Phase I Application, Exhibit 002-02(a)-Response to AUMA/EDM-AP-2, System Map.
[54] Exhibit 002-02(d-1) – AP Response to BR-AP-19(a).
[55] Exhibit 035-07 – Response to Undertaking regarding the allocation of marketing expenses, given by Mr. Rochon to Mr. Bryan at T1 page 139.
[56] Exhibit 002-01(e) – Application, Section 3, Rate Schedules, page 1, lines 11-15.

Views of the Board

At this time, the Board is of the view that the rate differential due to system differences between the North and the South is of a magnitude that would not permit the use of a province wide weighted average rate. Therefore the Board directs AP to submit separate North and South rates for each customer class in its Compliance Filing.

5 SERVICES AND RATE SCHEDULES

With respect to the Rate Schedules, the Board directs AP to file an updated version of all schedules in the Compliance Filing based on Board determinations in this Decision.

5.1 On-System Receipt Transportation Service

AP proposed that receipt transportation service would be available to customers who physically receipt gas onto the AP pipeline system at an on-system point of receipt.

AP proposed that a customer could select firm or interruptible receipt transportation service. AP also proposed that overrun OR service be considered interruptible service.

AP proposed that it would not be obligated to design its pipeline system or to receive, at the point of receipt in any one hour, a quantity of gas in excess of 1/24 of the contract demand.

5.1.1 FSR

AP proposed to maintain the existing structure of the demand portion of the FSR rate, while revising the structure of the OR portion of the rate. AP's current receipt OR rate has a single commodity charge (higher than the commodity equivalent rate of the firm receipt demand rate) and AP proposed to offer OR service with different rates for two periods[57] in a year.

AP submitted that the FSR demand rate was designed to collect the costs allocated in the COSS to the Producer service class. AP proposed that the FSR rate would have a demand charge applied to the customer's contract demand and an OR charge by which a commodity rate would be applied to the monthly flows in excess of the contract demand.

Views of the Applicant

For the months of June through September, AP proposed that OR charges would be priced at a commodity rate equivalent to the FSR demand rate, plus the estimated NGTL receipt and fuel charges to be incurred by AP[58].

For the months of October through May, AP proposed to price the OR charge at a commodity rate equivalent to the FSR demand rate, less the avoided NGTL FT-A delivery toll.[59] AP also proposed that the October to May OR charge would remain at a 1.5¢/GJ discount even if NGTL's FT-A rate was increased.

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[57] October to May and June to September.

[58] AP estimated the NGTL receipt and fuel charges to be 14.7¢/GJ and 17.0¢/GJ in the South and North respectively.

[59] AP noted that the FT-A toll equivalent was 1.5 ¢/GJ

AP submitted that increasing on-system OR receipt volumes for the months of October through May would directly reduce FT-A charges.

AP considered the Producer receipt service offering provided in the FSR Rate Schedule to be just and reasonable.

Views of the Board

The Board notes that no interveners objected to AP's proposed FSR rate structure. The Board has reviewed AP's proposed FSR rate schedule and the proposed demand and OR components and considers them to be reasonable. The actual level of the FSR demand rate and associated OR rate will have to be revised based on directions in this Decision.

At this time, the Board is prepared to approve AP's proposed October to May OR charge at a commodity rate equivalent to the FSR demand rate, less the avoided NGTL FT-A delivery toll of 1.5¢/GJ. The Board accepts that the amount of this discount will remain static and will not fluctuate with changes in the approved NGTL FT-A toll from time to time, unless and until this rate and the associated discount are revised in a GRA decision or in a negotiated rate settlement.

With respect to the June through September OR charge, please refer to Section 5.1.5 of this Decision for further discussion.

5.1.2 FSRS

Relative to the current firm short-term receipt transportation service (FSRS), AP proposed to revise the structure of the demand and OR services in the short-term firm receipt transportation service (FSRS) rate. AP currently offers short-term service with different demand rates for two periods in a year and a receipt OR service with a single commodity rate (higher than the commodity equivalent rate of the winter firm receipt demand rate) for the entire year.

AP proposed to offer an FSRS rate from November 1 through March 31 with a demand charge less than the demand charge associated with FSR. AP also proposed to offer a short term OR service with a commodity rate for the same period. AP proposed that the demand charge would be applied to the customer's contract demand and an OR charge based on a commodity rate would be applied to the monthly flows in excess of the contract demand.

Views of the Applicant

AP submitted that the FSRS rate components were designed to encourage incremental receipt volumes during the winter period. In addition, AP indicated that the FSRS rates were 1.5¢/GJ lower than commodity rate equivalent to the FSR demand rate in order to reflect the fact that for the colder months, during which FSRS would be offered, short term on-system receipts would offset receipts otherwise required from the NGTL system. AP also indicated that the FSRS rates would remain at a 1.5¢/GJ discount even if NGTL's FT-A rate was increased.

Like the October to May OR charge associated with FSR, AP proposed to price the FSRS OR charge at a commodity rate equivalent to the FSR demand rate, less the avoided NGTL FT-A delivery toll.

Views of the Interveners

CG

The CG supported the rate as filed.

Views of the Board

The Board agrees with AP that offering a discounted FSRS rate as proposed from November 1 through March 31 should encourage incremental receipt volumes, which would result in reduced FT-A toll charges. The Board has reviewed AP's proposed FSRS demand and OR rate components and the relationship between these rates and the FSR rates and considers them to be reasonable and consistent with the purpose of offering this service. The Board notes that the FSRS demand charge on an annual equivalent commodity rate basis is equal to the OR charge under the FSRS rate and also equal to the October to May FSR OR charge. The Board approves the FSRS rate in principle, and notes that it will have to be revised based on directions in this Decision.

As with the FSR OR rate, the Board accepts that the amount of the FSRS demand and OR discount will remain static and will not fluctuate with changes in the approved NGTL FT-A toll from time to time, unless and until this rate and the associated discount are revised in a GRA decision or in a negotiated rate settlement.

5.1.3 ITR

AP proposed to replace the current receipt interruptible service (Rate TIS), which offered a single commodity rate throughout the year, with interruptible receipt transportation ITR service.

AP proposed that ITR service would have commodity rates for the October to May and June to September periods. AP also proposed to maintain a minimum annual charge.

Views of the Applicant

For the months of June through September, AP proposed that ITR charges would be priced at a commodity rate equivalent to the FSR demand rate, plus the estimated NGTL receipt and fuel charges to be incurred by AP.

For the months of October through May, AP proposed to price the ITR charge at a commodity rate equivalent to the FSR demand rate, less the avoided NGTL FT-A delivery toll[60]. AP submitted that increasing on-system IT receipt volumes for the months of October through May would directly reduce FT-A charges. AP indicated that the October to May ITR charge would remain at a 1.5¢/GJ discount even if NGTL's FT-A rate was increased.

Views of the Interveners

IGCAA

IGCAA submitted that AP's proposed winter rebate, which IGCAA stated to be 1.8 cents, was inconsistent with AP's stated objective of encouraging interruptible transportation to convert to firm transportation. Further, the amount of this rebate was inconsistent with AP's proposed treatment of ODC. IGCAA submitted that with respect to ODC, AP was proposing to match

[60] AP noted that the FT-A toll equivalent was 1.5¢/GJ

costs and benefits but with respect to the winter rebate, AP indicated that if the NGTL FT-A rate went up to 8 cents, it would not increase the rebate to the full amount of the FT-A rate and instead, would hold the rebate at 1.8 cents.

Views of the Board

The Board notes that AP's current interruptible receipt services in the North and South have commodity rates that are constant throughout the year while in the Application, AP proposed to establish different rates for two periods.

While the Board acknowledges that AP's proposed ITR winter rebate would appear to be inconsistent with AP's objective of encouraging interruptible transportation to convert to firm transportation, the Board considers that, in theory, increasing on-system IT receipt volumes for the months of October through May should reduce FT-A charges. Even though the precise reaction by producers to this proposed service is unknown at present, given the supply and demand dynamics of the AP system, the Board considers it acceptable for AP at this time to structure services and associated rates in order to optimize use of its system.

The Board has reviewed AP's proposed October to May ITR rate and its relationship with the FSR demand rate and considers them to be reasonable at this time. Therefore, the Board is prepared to approve AP's proposed October to May ITR charge at a commodity rate equivalent to the FSR demand rate, less the avoided NGTL FT-A delivery toll of 1.5¢/GJ. As with the FSR OR rate and FSRS rates, the Board accepts that the amount of this discount will remain static and will not fluctuate with changes in the approved NGTL FT-A toll from time to time, unless and until this rate and the associated discount are revised in a GRA decision or in a negotiated rate settlement.

Given the rate relationships between the October to May ITR rate and the FSR rates, the Board notes that the October to May ITR rate will need to be revised based on directions in this Decision.

With respect to the June through September ITR charge, please refer to Section 5.1.5 of this Decision for further discussion.

5.1.4 AGRIUM CARSELAND REBATE

The Agrium Carseland Rebate was negotiated as part of a non-standard contract intended to protect from bypass certain volumes supplied by Encana Corporation (EnCana) to the Agrium Carseland industrial complex. AP proposed to adjust the Agrium Carseland Rebate from 5¢/GJ to 2.4¢/GJ for producers who declared to AP that their South zone, on-system receipts were designated for transfer to the Agrium Carseland customer account. AP proposed that the rebate would apply to South zone on-system receipts only and was limited to a maximum of the actual consumption at the Agrium Carseland complex.

Views of the Applicant

AP stated that it could not support maintaining the current rebate of 5¢/GJ and submitted that the proposed 2.4¢/GJ rebate provided a reasonable balance between retaining the rebate of 5¢/GJ and eliminating it altogether. AP argued that eliminating the rebate would encourage Agrium Carseland to continuously pursue competitive alternatives. AP submitted that the return to the pre 2001 rebate level of 2.4¢/GJ to on-system producers (receipt shippers) provided Agrium Carseland with an effective toll equivalent to both pre 1999 and pre 2001 tolling levels.

AP indicated that prior to February 1, 1999, Agrium Carseland was served under a point-to-point agreement with a rate of 10¢/GJ plus UFG. This rate was considered effective in addressing the risk of by-pass. AP submitted that the Industrial and Producer (I/P) Settlement, effective February 1, 1999, effectively maintained that rate through a standard receipt rate (FSR) at 7.4¢/GJ, plus a standard delivery rate (FSD) at 5.0¢/GJ, less a 2.4¢/GJ rebate to on-system producers who sold to Agrium Carseland.

AP submitted that the I/P Reopener Settlement, effective January 1, 2001, increased the rebate to 5.0¢/GJ. AP submitted that the UFG/Fuel rate, applied to the significantly higher gas prices at that time, resulted in an effective charge that was in the order of 16¢/GJ, or three times the FSD rate. AP indicated that in this Settlement, AP also agreed to pursue UFG/Fuel differentiation between AP and AG. AP noted that since that date, AP received Board approval[61] for an allocation of UFG/Fuel between AP and AG.

AP noted that IGCAA took issue with the linkage between the reduction in the Agrium Carseland Rebate and the UFG reduction included in the I/P Settlement. AP submitted that a settlement by its very nature was a compromise and issues were not normally linked. However, AP argued that both issues go to the competitiveness of AP's industrial rates and Agrium Carseland was the largest South industrial.

Views of the Interveners

IGCAA

IGCAA requested that the Board deny AP's proposal to reduce the Agrium Carseland Rebate for the following reasons:

- It would be unfair and discriminatory because the basis for the reduction was a by-pass option that led to EnCana obtaining a non-standard contract;
- It would be unfair and discriminatory to allow EnCana to continue to benefit if it continues to supply Agrium Carseland, while taking away the increased rebate that had been given to Agrium Carseland on account of the same by-pass option;
- It would not necessarily result in a benefit to any party other than EnCana;
- It would unnecessarily increase renewed threats of by-pass.

IGCAA indicated that the Agrium Carseland Rebate started out at 2.4¢ in February of 1999 and in early 2000, PanCanadian Petroleum (now EnCana) approached AP threatening to build a by-pass pipeline directly to Agrium Carseland. IGCAA indicated that AP then negotiated a non-standard contract with PanCanadian for a 10 year term which was justified on the basis that, but for the non-standard contract, AP was at risk of losing the EnCana and Agrium Carseland volumes.

IGCAA noted that in addition to obtaining approval for the increased Agrium Carseland Rebate, in Decision 2001-097, AP was successful in its application to reallocate UFG in the South. In

61 EUB Decision 2001-097.

addition, IGCAA argued that the reduction in the large industrial rebate by 2.6 cents was disproportionate to shifting one cent in UFG charges to receipt point shippers where that cost would likely be shared as part of the gas price.

IGCAA argued that while AP submitted that all of its customers would benefit as a result of the reduction in the Agrium Carseland Rebate, AP failed to consider that its non-standard contract with EnCana still provided EnCana with a 5 cent rebate if it supplied Agrium Carseland. IGCAA submitted that in proposing the rebate reduction, AP gave no consideration to the competitive advantage it might give to EnCana and whether this competitive advantage would negate any possible benefits to other customers on its system. IGCAA submitted that, not only was it unfair and discriminatory to continue to provide EnCana with the rebate, this further competitive advantage for EnCana brought with it the risk that there would be no benefit to others as a result of reducing the Agrium Carseland Rebate.

IGCAA argued that while AP conceded that the reduction of the rebate increased the risk of by-pass threats from Agrium Carseland, AP believed it could deal with the risk of increasing by-pass threats because it hoped that in the face of such by-pass threats, the Board would follow its Fort Saskatchewan decision and not allow the construction of duplicate facilities. IGCAA submitted that the Board should not allow AP to encourage by-pass threats on this basis.

Views of the Board

The Board notes that Agrium Carseland was served prior to February 1, 1999 with a rate intended to compete with direct by-pass options. This rate of 10¢/GJ plus UFG was essentially maintained following the I/P Settlement by incorporating a 2.4¢/GJ rebate to the FSD charge.

The increase in the rebate to 5¢/GJ came about at a time when increased gas commodity prices, in concert with a blended UFG rate, produced an effective charge substantially higher than the 10¢/GJ rate. Following separation of the blended UFG rate between AP and AG in Decision 2001-097, the specific UFG rate for transmission was reduced from 1.39% to 0.59% including compressor fuel. The Board considers that the benefit to industrials as a result of the change in UFG rate justifies examining the need to maintain the full 5¢/GJ rebate. The Board has often considered that a by-pass type rate should be no more attractive than required to address the by-pass threat. The Board accepts AP's submission that the 2.4¢ GJ rebate is a reasonable balance to retain the original approximation of the competitive by-pass option.

5.1.5 Summer IR/OR Receipt Surcharge

Currently, customers using AP's receipt transportation interruptible service or overrun receipt service pay a commodity rate that does not vary during the year. AP proposed to include a summer surcharge to its commodity rate for interruptible receipt transportation service and overrun service, related to its firm receipt service.

Views of the Applicant

The proposed components of AP's summer commodity rate design is shown in Table 11.

Table 11. Summer Interruptible/Overrun Receipt Tolls

June 1 to September 30
Commodity rate equivalent to FSR
plus
Estimated NGTL receipt and fuel charges incurred by AP

Source: Application, Section 2, p. 6 of 32

AP proposed that the revenue generated by the surcharge component (estimated NGTL receipt and fuel charges) of the summer Interruptible/Overrun receipt rate (IT/OR) tolls would be credited to the proposed North and South OPD deferral accounts.

AP submitted that during October 1 through May 31, increasing on-system IT/OR volumes directly reduced NGTL FT-A charges. During the warm months when firm receipts exceed markets (June 1 through September 30), AP submitted that incremental IT/OR receipts cause incremental ODC.

AP stated that dual connected shippers would have the option of paying the IT/OR rate or shipping volumes off to another pipeline in the summer.

AP indicated that it proposed to increase the summer IT/OR to prevent cross-subsidization of IT/OR by other customers. AP argued that IT/OR should be priced such that the incremental IT/OR revenue exceeded the incremental (marginal) IT/OR costs, that IT/OR pricing should not discourage firm service, and that IT/OR pricing should promote additional supply onto AP in colder months.

AP submitted that the current receipt IT/OR pricing, 110% of the fully utilized firm rate, has provided an insufficient signal to producers to contract for firm service. AP indicated that nine of the top ten IT/OR customers average 55% of their flow as IT/OR. AP argued that these shippers did not provide the same commitment to the system as firm receipt customers and they were not covering the incremental cost of flowing volumes to NGTL.

AP submitted that CAPP's proposal to price receipt IT/OR year-round at 100% of firm was insufficient to provide the appropriate price signals or to recover the incremental costs in the warmer months. AP argued that CAPP had previously agreed that IT/OR should be priced to recover incremental variable costs, and had stated that IT service, as the marginal service, was appropriately priced through a bid process using a floor based on the marginal cost of providing IT.

With respect to CAPP's comment that AP decided to avoid expanding its system, AP argued that it agreed with its customers' desire to pursue this alternative. AP submitted that while this supported AP's argument that ODC should be considered to be system costs, it did not detract from the need for IT/OR to at least cover its incremental cost and also to pay a share of general system costs.

In response to CAPP's assertion that AP risks driving supply down to the bottom of the demand trough, AP indicated that, while this was always a risk, this contradicted CAPP's evidence that interruptible volumes have made a commitment to the system.

With respect to CAPP's comment that IT/OR shippers have made a commitment by connecting to the AP system, AP noted that Producers still have a choice about whether to use firm or interruptible service to ship their gas, and the interruptible shipper has not provided the same level of commitment to AP's system, especially at dual connected plants. AP submitted that with 12 months notice, customers with service at dual connected plants could decontract and leave the AP system.

With respect to CG's statement that increased volumes of receipt gas were beneficial in reducing costs paid by all rate classes, AP submitted that this was not true for volumes over a threshold receipt level.

In response to IGCAA's statement that the market would respond to the price signals and choose the optimal level of receipts if the ODC were included in the OPDC rate, AP stated that such an increase to OPDC rates would significantly benefit delivery customers through lower on-system gas prices, leading to the type of rate instability that has been a significant problem in recent years with exchange fees.

Views of the Interveners

CAPP

CAPP argued that AP's proposal to charge a surcharge on interruptible receipts in the summer was unfair and unjustified. CAPP did not agree with AP's assertion that the surcharge was needed to control oversupply of gas in the summer.

CAPP submitted that it was unfair to penalize the supply that made the commitment of attaching to the AP system in response to AP's goal of ensuring supply availability on an annual basis. CAPP argued that AP risked driving supply to the bottom of the demand trough.

CAPP submitted that AP's proposal sent a contradictory signal to interruptible shippers by discounting winter interruptible rates below the equivalent firm rate, because sound resource conservation practices dictated that winter production not be shut in during the summer.

CAPP submitted that AP's proposal for a summer IT/OR receipt surcharge should be rejected and argued that if any change to the calculation of the IT/OR rates was needed, it should be 100% of the firm service rate year round.

With respect to AP's submission that IT/OR should at least cover its incremental cost, CAPP did not agree with the characterization of ODC as a marginal or incremental cost of the IT/OR service. CAPP submitted that ODC were properly viewed as supply/demand imbalance costs wholly unrelated to whether the supply of gas comes on to the AP system under a firm transportation agreement or IT/OR transportation. CAPP argued that AP itself implicitly supported the concept of ODC being a supply/demand imbalance cost when it proposed that ODC costs be allocated to all customer groups.

With respect to AP's suggestion that the incentive to firm up volumes was insufficient because nine of the top ten IT/OR customers average 55% of their flow as IT/OR, CAPP argued that this would be inconclusive if those nine customers were in areas where the risk of interruption was minimal.

CAPP disagreed with AP's assertion that differential IT/OR rates would encourage additional supply onto its system during colder months. CAPP noted that AP agreed in argument that IT/OR receipt volumes were essentially flat throughout the year. CAPP argued that this flat profile was a result of production practices; it was not and would not be, to any significant degree, driven by transportation prices.

CAPP noted IGCAA's argument that ODC costs would "skyrocket" just as the EDA did if ODC costs were general system costs and there was no summer IT/OR surcharge. CAPP submitted that this hyperbole ignored the commitment by AP to manage the supply on their system to ensure that the benefits of additional receipts onto their system exceeded the costs of bringing those receipts on.

CAPP noted that Rate 13 preconditioned their objections to the summer IT/OR surcharge on ODC being included in the OPDC rate. CAPP submitted that Rate 13's argument was based on the erroneous assumption that ODC were caused by receipts. CAPP argued that ODC were more accurately described as being caused by the overall supply/demand balance.

CCA

The CCA agreed that the surcharge was appropriate if TBO was not implemented, but argued that TBO was a better solution than the surcharge.

CG

The CG supported the principle that increasing the volumes of receipt gas brought onto the AP system was beneficial, in the sense that the additional revenues act to reduce the costs paid by all rate classes. The CG argued that the surcharge proposed by AP would send the wrong signal to producers and would unnecessarily discourage receipt supply. The CG supported the recommendations of CAPP for IT/OR tolls which would be consistent on a year round basis at the equivalent of a 100% load factor firm toll.

The CG indicated that its preferred solution would be to have NGTL provide a summer TBO service to receive the excess summer supply from AP.

IGCAA

IGCAA submitted that the IT/OR summer receipt surcharge would likely be unnecessary if ODC were included within the OPDC commodity charge. IGCAA argued that if the market was given the appropriate price signal, producers themselves would respond to these price signals and choose the optimum level of receipts to put onto the AP system. In addition, if ODC were paid based on nominations, rather than on whether the producer held firm or interruptible service, IGCAA submitted that CAPP's concerns over market allocation between firm and interruptible shippers would be addressed.

IGCAA submitted that it would be unacceptable to go soft on the issue of the IT/OR rate, and at the same time make ODC general system costs. IGCAA submitted that ODC costs would sky rocket just as the EDA account did in the past and all AP's shippers would be left paying the bill and at the same time paying an artificially high gas price on the AP system. IGCAA argued that this result would be neither fair nor efficient and cannot be accepted by the Board.

Rate 13

Rate 13 submitted that not all summer production incurred costs attributable to the OPDC service because a producer could choose to sell its gas to an on-system market, store the gas, or transfer the gas to NGTL. Rate 13 argued that a high summer IT rate did not reflect that a producer has these options and AP's proposal deemed all summer IT receipted gas to be the gas transferred to NGTL, when this was not the commercial reality.

Rate 13 submitted that, if the OPDC rate was properly cost based, the receipt volumes actually sent to NGTL would properly pay the OPDC costs. Rate 13 submitted that, if the Board approved a full cost OPDC rate, the Board should not approve AP's summer IT rate and the IT rate should be structured as it has been historically.

Views of the Board

The Board notes that AP has proposed a surcharge for summer IT/OR receipts to apply when the summer supply exceeds the summer on-system demand, whereas the current rate structure for IT/OR transportation service is a commodity rate that does not vary during the year.

The Board is concerned that an insufficient summer IT/OR rate may result in an under-collection of ODC in the OPD deferral account and result in substantial swings in transportation rates.

The Board considers that IT/OR transportation service can be used by a shipper as a short term or seasonal offering, wherein the shipper would provide no commitment to AP's longer term supply requirements. In such a case AP could not rely on IT/OR volumes as a firm revenue source for forecasting purposes. The Board notes that AP, appropriately, does not design facilities to provide firm capacity on a year-round basis for IT/OR volumes. Neither can these volumes be relied upon to determine the supply/demand balance points referred to in Section 7.5.

The Board considers that IT/OR volumes are beneficial to the system during times when the demand exceeds the on-system supply. However, when supply exceeds demand, IT/OR volumes may result in an ODC in excess of the revenue provided through FSR. Therefore, the Board considers that a summer IT/OR surcharge is appropriate to discourage excess ODC costs and to collect summer NGTL charges from IT/OR shippers who have not committed to the system through firm contracts, which could offset these summer charges with firm revenue throughout the year. The level of the surcharge should be set from time to time to equal the summer ODC costs, which should include the estimated NGTL receipt charges plus fuel charges. The surcharge would be applicable to IT/OR volumes delivered in the period June 1 to September 30, in each year.

The Board approves AP's proposal that the revenue generated from the summer IT/OR surcharge shall be credited to the proposed OPD deferral accounts. The Board has addressed the requirement for AP to provide information with respect to deferral accounts in Section 7.3 of this Decision.

5.2 OPR

AP proposed an OPR commodity rate that was modeled after the OPR commodity rate approved by the Board in Order U2003-401, dated November 7, 2003.

In Order U2003-401, the Board accepted AP's proposal to include the revenue associated with the OPR rate in North and South deferral accounts with NGTL FT-A and FCS MAV expenses. At the same time, the Board also accepted AP's proposal to revise the OPR rate if circumstances changed on AP's system such that deferral account balances carried forward from prior years or changes in the relationship between nominated and physical flows were forecast to result in a surplus or deficit of over $1 million in either the North or South deferral accounts by year end. Further, the Board accepted AP's proposal that it might also present an application for adjustment to the OPR rate when NGTL changed its FT-A rate.

Views of the Applicant

AP proposed to charge a commodity toll that would recover only the NGTL FT-A expenses assigned to the OPR service class, instead of establishing stand alone services to recover all the expenses allocated and assigned to this class. The initial OPR commodity rate was established in October 2003 and prior to establishing this toll, gas receipted onto AP from the NGTL system was not tolled. The current rate for this service in the North and South was 1.4¢/GJ and AP proposed to increase the rate to 1.5¢/GJ.

AP proposed that after approving a customer's nomination request for OPR service, the customer's gas would be allocated through AP's NIT account to the customer's account on the AP system.

AP noted that while NGTL would bill AP based on physical deliveries to the AP system, AP's business practices were designed to reflect exchange (paper) receipts from NGTL to AP through its exchange service. AP proposed to charge its commodity rate on volumes nominated from NGTL to AP through AP's NIT account.

AP submitted that the proposed OPR commodity rate was fair and reasonable since it was designed to collect the variable FT-A costs. AP noted that the IGCAA and the CG supported the proposed OPR commodity rate.

In response to Calgary's statement that either the OPR rate should reflect AP's proposed 8¢/Mcf rate or the proposed reallocation should be eliminated, AP indicated that it would apply to the Board to increase the OPR rate to reflect any approved increased in the NGTL FT-A rate.

Views of Interveners

Calgary

Calgary submitted that from a consistency standpoint, AP should either advocate the inclusion of an 8¢/Mcf rate, which AP proposed in the NGTL 2004 Phase II proceeding, in the NGTL receipt charge or eliminate its proposed reallocation proposal for identified system costs for OPD and OPR services.

CG

The CG agreed that the OPR rate should pass through the NGTL FT-A expenses but recommended that only Rider D charges of 50% of UFG/Fuel should be added to the OPR rate.

NGTL

NGTL submitted that AP was effectively the gatekeeper of all volumes that entered and left its system at interconnections with the NGTL Alberta System. NGTL argued that AP achieved this status by taking commercial control of all gas volumes coming on and going off its system, and by refusing to allow others to make any physical nominations on or off its system at interconnections with the NGTL Alberta System.

NGTL submitted that AP's gatekeeper status was presently functionally embodied in section 13 of its Business Policy and Practices (BP&P) and argued that under this provision, parties that wanted to move gas to AP's system from the NGTL Alberta System must use AP's NIT account.

NGTL noted that AP advised that it was not seeking Board approval in this proceeding of its BP&P generally, or section 13.3 specifically. NGTL argued, however, that AP requested Board approval of a provision that it proposed in each of its OPR and OPD service rate schedules that would, if approved, achieve the same practical result.

NGTL requested that the Board specifically deny AP's proposed provisions in section A of its OPR rate schedule which mandate that its customers use AP's NIT account to access AP's systems. NGTL submitted that these provisions should not be allowed to stand, as they were competitive barriers that indirectly prevented customers from using an approved NGTL service.

Views of the Board

As noted in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues, the Board determined that a fully cost based OPR service with stand alone rates would not be established for this proceeding. At this time, the Board is prepared to accept its previous findings in Order U2003-401 that support AP's proposal to recover NGTL's FT-A expenses through the OPR commodity rate.

The Board notes that the current OPR rate in the North and South is 1.4¢/GJ as approved in Order U2003-401. The Board also notes that AP's commitment to revise the OPR rate in order to reflect any increase in the NGTL FT-A rate, appeared to be stronger in this proceeding than previously indicated in the application related to Order U2003-401.

With respect to AP's proposed increase in the OPR rate, the Board does not consider that AP has provided sufficient evidence to justify the proposed increase given the criteria established in Order U2003-401 with respect to OPR rate adjustments. Therefore, the Board considers that the existing OPR rate in the North and South should remain in place. However, the Board is prepared to vary its position, if AP files evidence in the Compliance Filing that establishes that on a forecast basis, the balance in the North and South OPR deferral accounts is projected to be greater than $1 million on December 31, 2004.

With respect to NGTL's request to deny AP's proposed provision in its OPR rate schedule which mandates that customers use AP's NIT account to access AP's system, the Board is prepared to accept this provision at this time. However, the Board considers that this matter could be explored in the Competitive Proceeding if parties requested it to be considered as an issue.

5.3 FSD

AP proposed that delivery transportation service would be available to industrial customers who physically take gas off of the AP system at an on-system point of delivery (Rate FSD). AP also proposed that term-differentiated rates would be available for customers selecting a longer minimum term date.

Relative to the current firm delivery transportation service, AP proposed to maintain similarly structured demand and OR service rates. AP's current firm delivery transportation service has different demand rates for three possible ranges of contract terms and an associated OR service rate, which is priced at 110% of the commodity rate equivalent to the 3 or 4 year FSD demand rate.

Views of the Applicant

AP proposed that the charge for an average daily flow in a month that fell between 90% and 110% of the nominated demand (billing demand), would be the FSD demand charge applied to the average daily flow in that month plus the fixed charge. Further, if the average daily flow in a month exceeded 110% of the nominated demand, an OR charge would be applied to the difference between the total flow in the month and 110% of the nominated demand (billing demand) times the number of days in the month. AP also proposed that if the average daily flow in a month was less than 90% of the nominated demand, the charge would be the demand charge applied to 90% of the nominated demand (billing demand) plus the fixed charge.

AP proposed that it would not be obligated to design its pipeline system or to deliver in any one hour at the point of delivery, a quantity of gas in excess of 1/24 of the nominated demand.

In response to IGCAA's statement that AP should be willing to reduce the FSD OR charge below the firm service rate in the summer if it was going to offer a rebate to encourage IT/OR volumes during the winter, AP submitted that IGCAA did not present any evidence that Industrials would respond to such a price signal, especially as it was somewhat inconsistent with the current 90%/110% feature.[62]

Views of Interveners

CG

The CG agreed with this rate as proposed subject to the addition of Rider D, which would include charges for 50% of UFG/Fuel.

IGCAA

IGCAA submitted that if AP was going to provide a rebate to encourage receipt volumes to come onto its system in the winter months, it was equally logical to reduce FSD OR charges below the firm service rate in the summer because increased summer demand on the AP system would reduce ODC.

[62] AP noted that FSD customers' minimum billing demand is 90% of nominated demand and overrun charges do not start until actual volumes are greater than 110% of billing demand.

Views of the Board

The Board notes that AP proposed that the FSD OR service rate would be set at 110% of the commodity rate equivalent of the 3 or 4 year FSD demand rate, similar to AP's current rate offering. The Board has considered the positions of the parties with respect to the proposed FSD demand and OR rates and agrees with AP that the rates appear to be reasonable. The Board also believes that the derivation of the billing units for this rate by AP appears appropriate.[63]

The Board notes that the FSD demand rate itself and the associated OR rate will have to be revised by AP based on directions in this Decision.

The Board will therefore approve the FSD demand rate and associated OR rate in principle, subject to the necessary revisions to be made in the Compliance Filing.

With respect to IGCAA's claim that FSD summer OR charges should be lowered to encourage summer demand in order to reduce ODC, the Board considers that this argument appears to have merit. However the Board agrees with AP that evidence has not been introduced as to the details and impacts of this proposal, and considers that parties have not had an opportunity to consider it properly. Therefore, at this time, the Board is not prepared to approve such a rate reduction to OR charges for the summer months.

5.4 FSU

AP proposed to provide delivery transportation service to Distributing Companies who physically deliver gas off of the AP system (Rate FSU). AP proposed that gas would be allocated to the Distributing Companies' delivery account on AP's system and would be available to transfer to other customer accounts.

AP also noted that as selected by the customer and approved by AP, the delivery transportation service for Distributing Companies was firm service.

With respect to billing, AP proposed to apply a demand rate to the customer one hour peak demand nomination.

5.4.1 FSU versus Separate Services for Distributing Companies

AP proposed to offer one firm delivery transportation service (FSU) to all Distributing Companies with a common FSU demand rate.

Views of the Applicant

AP submitted that the expenses allocated to the Distributing Companies group should not be further segregated to individual customers because this protects smaller Distributing Companies from unwarranted and unjustifiable variations in rates.

AP submitted that the FGA agreed with the position of having a common rate for all utilities in the 2001/02 GRA.[64] Further, AP noted that the 2001 Memorandum of Understanding (MOU) between AP and the FGA stated that FGA would buy the CTM in the South, even with a

63 AP Response to IGCAA-AP-15(d).
64 Transcript, Vol. 4, page 368, lines 14-25; Decision 2001-097, page 130.

common rate for all utilities.[65] AP indicated that the Board also agreed with the evidence of AP and FGA in Decision 2001-097.[66]

With respect to FGA's evidence that it should not pay any M&R costs, AP submitted that FGA's proposed adjustment was not valid and should not be used when reviewing the reasonableness of the FSU rate for Gas Alberta.

In response to FGA's contention that the FSU rate schedule does not describe the services received by Gas Alberta or Rate 5 customers, AP submitted that this contention was without merit. AP argued that the FSU rate schedule was a new rate schedule and the FSU rate, when approved, would apply to all Distributing Companies, including Gas Alberta and those customers currently administered under the Rate 5 rate schedule. AP submitted that the FGA did not present any evidence with respect to what services do not apply.

AP submitted that there were three specific examples that the Board should consider when it reviews the reasonableness of the FSU rate for Gas Alberta and Rate 5 customers. AP submitted that these examples reflected situations where an allocation directly to Gas Alberta or Rate 5 customers, rather than to all Distributing Companies, would result in a substantial variation in rates for Gas Alberta and Rate 5 customers:

- No allocation of UFG CTM to Gas Alberta[67];
- Direct allocation of Gas Alberta CTM costs to Gas Alberta;[68]
- Direct allocation of Smoky River Crossing Project to Rate 5.[69]

In response to FGA's submission that providing separate rates for Gas Alberta and Rate 5 customers would not be administratively burdensome, AP submitted that this was not the issue but instead, the issues were whether the services provided were significantly distinct, whether separate rates could be justified through the COSS, and whether there would be a distortion in cost assignments which would result in unwarranted and unjustifiable variations in the rates.

AP stated: "FGA's position for Gas Alberta and Rate 5 falls under the saying "Be careful what you wish for, it might come true" in that not all consequences have been considered. ATCO's proposal to charge one rolled in rate for all Distributing Companies protects smaller Distributing Companies from unwarranted and unjustifiable variations in rates."[70]

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65 Decision 2001-097, p. 143.

66 Page 141

67 AP submitted that 50% of the UFG CTM were directly allocated to distributing companies and the impact of not charging these costs to Gas Alberta in the North would be a rate reduction of $0.068/GJ/Month (2.7% of the North FSU rate of $2.494/GJ/Month) and in the South $0.086/GJ/Month. (or 4.3% of the South FSU rate of $1.992/GJ/Month).

68 AP indicated that the Gas Alberta CTM were currently included in the North general or system-wide measurement and regulating costs and they were allocated based on peak demand. AP submitted that if they were directly allocated to Gas Alberta, it would have increased the Gas Alberta rate by $0.26/GJ/Month (or 10.4% of the North FSU rate of $2.494/GJ/Month).

69 AP indicated that this project was allocated to all distributing companies and if the project was directly allocated to Rate 5, since it was identified as serving Rate 5 only, it would have increased their rate by $0.58/GJ/Month ($77,000 divided by 11 TJ/day divided by 12 months) (or 23.2% of the North FSU rate of $2.495/GJ/Month).[69]

70 AP Argument, p. 59

AP requested that the Board approve its proposal as filed.

Views of the Interveners

CALGARY

For the South, where only two utility customers exist, Calgary submitted that the use of separate rates, which existed for 2001 and 2002, did not appear necessary. However, Calgary indicated that it would leave this issue for the FGA to pursue.

CCA

The CCA supported the CG position on this issue.

In addition, the CCA did not support separate FSU rates. The CCA submitted that no distinction between the service provided by AP to AG or other distribution utilities could be found. The CCA argued that the FGA did not meet the onus to justify further paring down of AP's existing or proposed customer classifications.

CG

The CG submitted that a single FSU service in terms of its structure and terms and conditions of service was appropriate for all Distributing Companies. However, the CG argued that a rate charged for FSU service to AGN and AGS should continue to be individually established as proposed by AP.

FGA

The FGA submitted that it would be difficult to reflect the operational differences among Gas Alberta, Rate 5 customers and AG if the Board approved a rate that was suited to the operations of only AG, with credits or surcharges for certain optional services. If the Board approved different rates for the three rate classes within the Distributing Company customer class, the FGA submitted that this would facilitate the offering of services unique to each rate class.

The FGA submitted that returning the meters to AP would resolve the financial inequities of maintaining one rate for Distributing Companies, but it would not reap the full operational benefits for Gas Alberta's customers. The FGA submitted that, with respect to Gas Alberta, the Board should look beyond the financial aspects of a rate and recognize that not all utilities were created the same and that Gas Alberta's members provided clear evidence that they wish to operate differently from AG.

With respect to Rate 5 customers, the FGA submitted that the ownership and operation of the delivery stations was a mixed bag[71] and that logically, this meant that Rate 5 customers required a different rate from AG. The FGA argued that Rate 5 customers should also have a different rate from the rate offered to Gas Alberta, where both the stations and meters were owned and operated by the shareholder member.

The FGA suggested that a Rate 5, or any successor rate , should provide the various options to reflect the customer's choice of operation including but not be limited to, owning and operating

[71] FGA-AP02-25 (c)

the delivery station, owning the metering and data acquisition devices and the option of taking gas at the delivery station, for at least an appropriate transition period.

The FGA submitted that since AP provided a greater number of rates for its Industrial and Producer customer classes through its non-standard contracts and was not burdened by this number, there was no logical basis for one single rate, FSU or otherwise, for the different types of distributing companies served by AP.

The FGA suggested that the Board should approve a rate for AG and separate rates for Gas Alberta and the Rate 5 customers.

In response to AP's submission that there were three specific examples that the Board should consider when it reviews the reasonableness of the FSU rate for Gas Alberta and Rate 5, the FGA indicated that the second example[72] was exactly what the FGA proposed in its evidence.[73]

With respect to AP's third example[74], the FGA submitted that the AP proposal appeared to constitute new evidence that should not have been put forward in argument and argued that the Board should ignore this discussion.

Views of the Board

The Board notes that AP proposed one firm delivery transportation service to all Distributing Companies with a common FSU demand rate.

The Board also notes the FGA argument that Gas Alberta and Rate 5 customers required rates different from AG due to Gas Alberta owning certain metering equipment and Rate 5 customers owning and operating delivery stations.

The Board considers that dividing the Distributing Companies Deliveries service class into discrete service classes may result in distortion in cost assignment and result in unwarranted and unjustifiable variations in rates and/or revenue to cost ratios. At this time, the Board believes that being part of a larger service class results in an averaging of costs such as general system and administrative expenses across the class, thereby potentially conferring a benefit to small Distributing Companies when compared to rates that could result if these costs were allocated separately to these customers on a cost causation basis. The Board believes that a postage stamp approach results in reasonable rates for all customers in the service class, particularly for those in more remote areas. Therefore, the Board is not persuaded at this time that separate rates are appropriate for Gas Alberta and other Distributing Companies. The Board considers that the FSU demand rate is just and reasonable for all utilities in the class. The Board tends to agree with AP's comments that creation of separate rates for the smaller Distributing Companies would likely result in rate increases for those customers.

Accordingly, for the above reasons and the reasons provided in Section 7.8.1, the Board declines to approve a reduced rate for Gas Alberta at this time.

[72] Direct allocation of Gas Alberta CTM costs to Gas Alberta.
[73] Exhibit 011-04, page 6, line 7 – page 7, line 8
[74] Direct allocation of Smoky River Crossing Project to Rate 5

5.4.2 Peak Demand Notice and Curtailment

For Delivery Transportation Service to Distributing Companies (Rate FSU), AP proposed that the Billing Commencement Date[75] would be January 1 of each year.

AP proposed that twelve months in advance of the Billing Commencement Date, a Distributing Company must advise AP of its peak demand at each point of delivery for AP's approval. If the Distributing Company does not provide the required advance notice, AP proposed that the peak demand for the current year would be carried forward.

AP proposed that should the actual flow at any point of delivery in any one hour period exceed the peak demand at that point of delivery, the Distributing Company would be invoiced an additional charge equaling the difference between the actual one hour flow and the peak demand at that point of delivery multiplied by 24 months. In addition, the peak demand for the remainder of the year would be increased by that amount and would form the minimum peak demand for the next five year period at that delivery point.

Views of the Applicant

AP submitted that the incremental charges for actual flow exceeding peak demand and the increase to the customer's peak demand were intended to prevent Distributing Companies from under forecasting their peak demand requirements. AP argued that Distributing Companies would be motivated to understate their peak demand requirements until such time as they had exceeded their nominated one hour peak demand. AP was concerned that since Distributing Companies may not encounter a peak day each year (due to temperature dependence), they could be motivated to understate their peak demand requirements.[76]

AP indicated that should a customer exceed its peak demand at one delivery point but stay within its overall peak demand in the immediate area, AP would review certain factors including whether the difference would have impacted the facility design and whether other customers were curtailed.

AP submitted that the five year forward peak demand increase provision was fair because Distributing Company growth rates would limit the impact of the penalty to the customer to the first few years.

AP indicated that although CG, CCA and FGA argued that the proposed incremental assessments were onerous compared to the FSD rate, FSU service was provided the highest service priority available on the AP system. FSD customers can be curtailed to 1/24th of their nominated demand on an hourly basis and are subject to further curtailment due to a lack of system capacity, which included FSU customers' actual flows exceeding their peak demand.

AP noted that Calgary was asking for the benefits of the 90-110% FSD billing demand treatment without accepting the lower service priority granted to FSD. AP indicated that an FSD customer nominated its peak demand requirement with the understanding that AP was not obligated to design its system to deliver volumes of gas in excess of 1/24th of the nominated contract demand.

[75] Billing Commencement Date means the commencement date for invoicing the tariffs and charges set forth in Article 10 of the Transportation Service Regulations.

[76] Response to BR-AP-12 (e).

AP submitted that the alternate penalty proposals provided by CG and Calgary were not sufficient incentives for Distributing Companies to accurately forecast their peak demands. AP argued that peak demand nominations provided on the basis of Distributing Company system design should be based on the same parameters as the Distributing Companies use to design their own systems, taking into account projected impacts of weather.

In regard to Calgary's argument that there was no historical experience to provide the basis for a need for penalty charges, AP provided a historical context by noting the difficulty in reaching agreement with the FGA on peak demand and the fact that actual measurement was not previously available.

With respect to Calgary's submission that the five year forward ratchet was also out of line with the reality of the TSA, AP submitted that the evidence on the record of this proceeding does not support Calgary's claim. AP indicated that Article 9.1 of the TSA stated that "ATCO Gas shall pay...the tariffs and charges as determined by ATCO Pipelines and approved by the Board". AP also indicated that this article incorporated the potential for greater detail and amendments into the Agreement as approved by the Board. AP argued that this concept was consistent with AP's intentions for the treatment of this Agreement, as described in the 2001/2002 GRA. AP indicated that it would integrate the service provided to AG into the Rate Schedules and Transmission Service Regulations proposed in the Application upon approval by the Board.

With respect to the requirement for Distributing Companies to nominate their annual one hour peak demands by individual delivery point one year in advance of flow, AP submitted that this was required so that AP can ensure that any incremental facility requirements can be designed, built and commissioned prior to the commencement of each contract year.

While AP indicated that Distributing Companies should have a higher level of service priority than other delivery rates and that deliveries to Distributing Companies should not be curtailed, AP argued that its capability to deliver gas to Distributing Companies was limited to its system design. Therefore, in its proposed FSU rate schedule, AP indicated that it was not obligated to design the pipeline system or deliver, in any one hour at any point of delivery, a quantity of gas exceeding the peak demand established for each point of delivery.

AP argued that it was critical to have Distributing Companies' facilities operational for the coldest/peak demand part of the contract year whereas Industrial customers' delivery timelines were not dependent on temperature but on commercial arrangements.

AP disagreed with FGA's assertion that Distributing Companies were unlikely to be responsible for delivery curtailment since 70% of APN throughput was attributable to the Industrial and Producer groups and any increase in demand would most likely come from these groups. AP stated that pipeline systems were designed to meet the peak demand requirements of its customers, not throughput requirements. AP indicated that the APN Distributing Companies were accountable for 1,321 TJ of the 2,073 TJ total delivery peak demand, or 64%.

AP indicated that it could not find any evidence on the record of this proceeding to support Calgary's statement that on the AP system, ATCO Gas has the right to a maximum of 300,000 GJ/day of withdrawal capacity and in an emergency the full 600,000 GJ/day of Carbon capacity.

Views of the Interveners

CALGARY

Calgary submitted that the ratchet provision to adjust the billing demand retroactively represented a penalty for an event that never occurred in the prior billing period. Further, the concern expressed by AP was only hypothetical since there have been no historical problems associated with AGS' forecasts. In addition, with the obligation to provide an annual forecast in advance of the billing year, the five year forward ratchet was out of line with the reality of the TSA.

Calgary submitted that a 12 to 24 month forward ratchet by delivery point with a minimum 2% tolerance would provide a more reasonable ratchet provision and argued that such a constraint would impose the discipline that AP requires, would provide a baseline for the AP reasonableness check and would not unduly penalize the Distributing Companies class.

Calgary indicated that if the Board accepted that all class demands for billing and cost allocation should be developed on the same basis, the one hour ratchet would not be applicable if the Board adopts the twenty-four hour standard for all classes. Calgary submitted that under the twenty-four hour standard, the tolerance levels expressed in the FSD rate would also be appropriate for the FSU rate.

Calgary indicated that the CG's ratchet proposal was not far from Calgary's proposal, although the CG's position that the ratchet end with the next forecast period made sense. Calgary submitted, however, that there should be no retroactive imposition and ratchets should be forward looking.

Calgary submitted that the curtailment issue appeared to be more of a red herring than a practical reality. Calgary submitted that curtailment would only occur due to a shortage of gas supply or the lack of pipeline capacity. With respect to a shortage of gas supply, Calgary submitted that AGS has indicated that the Carbon Storage facility was no longer needed for operational purposes because AGS can buy all the gas it needs at any time. Given this position, Calgary submitted that there would not be an opportunity to curtail other loads in order to serve the Distributing Companies.

With respect to a lack of pipeline capacity, Calgary submitted that provincial policy requires the Alberta load to be served before gas was exported from the province. Calgary submitted that absent a classic *force majeure* related to pipeline capacity or loss of supply, there appeared to be very little opportunity for curtailment ever to occur on the APS system.

CCA

The CCA did not support incremental charges for actual flow exceeding peak demand for FSU rates and argued that the demand allocations already over allocate costs to customers of the Local Distribution Company (LDC) utilities. The CCA argued that if the charges for exceeding peak demand were borne by customers, AP would have excess earnings and if the charge remains with the distribution utility, it would encourage the distribution utility to over forecast expected demand to minimize the risk of incremental non-recoverable charges. The CCA considered that utilities should be responsible for forecast risk.

The CCA submitted that AP has the capability to challenge billing determinants provided by AG or other distribution utilities in order to determine reasonableness. The CCA argued that it was inappropriate for AP to charge penalties that might simply be based on an extreme weather condition that exists for a short period of time. The CCA submitted that the weather driven load of the LDC was clearly outside of their control and should not result in a potential for additional costs to consumers.

CG

The CG submitted that the proposed charge was very onerous compared to the overrun charges under the FSD rates. The CG indicated that it accepted the evidence of AP that service to utilities could not be practicably curtailed and that, accordingly, firm service to utilities had a greater degree of reliability than firm service to other classes of customers.

Therefore, the CG indicated that FSU overrun charges should directionally be somewhat more rigorous than FSD overrun charges but not to the degree proposed by AP. The CG submitted that an immediate 12 month charge for the overrun amount[77] would be ample.

The CG submitted that the twelve month penalty charge would protect AP from any loss in the current period from any utility having low balled its estimate at a particular delivery point, and argued that the continuation of the higher peak demand and charge on a forward basis, until the time of the next estimate to be provided by the utility for that point, would also protect AP.

The CG submitted that it was not reasonable to automatically lock in the customer utility to the higher demand rate for a further five years. The CG argued that if AP was exercising due diligence in reviewing the forecasts it receives, the utility in question would have to provide strong rationale to AP if it forecast a lower demand again at a delivery point that had overrun in the past twelve months.

With respect to AP's comment that the growth over time at FSU delivery points would limit the impact of the penalty to the first few years, the CG accepted that the aggregate of deliveries under the FSU rate would likely grow slowly, but they also argued that there was no guarantee that each and every FSU delivery point would experience growth and in some cases, smaller towns or villages in rural areas might decline.

FGA

The FGA agreed that a distributing company was in the best position to provide AP with its needs for service, however, the FGA submitted that the planning horizon set out by AP was excessively long and unresponsive to reasonable changes that may be realized within a distributing company on a year to year or month to month basis. The FGA submitted that in effect, a distributing company would be applying for growth in service two years in advance of the actual need.

The FGA submitted that AP had not considered an adjustment mechanism within the FSU rate to reflect the loss of load that a distributor may face. The FGA argued that the notice requirements and punitive overrun provisions did not properly serve a distributing company's planning cycle,

[77] The penalty charge, plus a continuation of the newly established one hour peak demand for forward months until the time of receipt of the next peak day estimate of the particular utility.

nor did they fit with the construction season for new facilities. The FGA noted that there was no such advance notice required of industrial customers.

The FGA submitted that it would be more appropriate for the distributing companies to provide their requirements at a reasonable interval before the beginning of the gas year or other milestone. The FGA requested that the Board direct AP to develop planning procedures with the distributing companies that would satisfy the needs of both the distributing companies and those of the transmission company.

The FGA submitted that in its experience, AP had chosen to exaggerate or highball peak day demand as determined by the FGA, with an obvious benefit accruing to AP for over billing throughout 2003 and 2004 year-to-date.

The FGA submitted that the proposed FSU rate was designed to over-recover rather than recover costs and argued that the proposed two year retroactive penalty was so onerous that customers may be compelled to continuously nominate excess demand and therefore pay too much in demand charges rather than risk an onerous penalty. The FGA submitted that provisions must be allowed for periodic adjustments, both upwards and downwards, to ensure that both AP and its customers are each assured of equitable treatment.

The FGA submitted that curtailment might be necessary when a transportation system cannot meet the coincident demand placed on that system by all of its customers. With respect to the impact on system operations, the FGA submitted that based on existing usage and apparent focus of the AP marketing efforts, the greatest potential for additional demand and therefore, cause for curtailment, would be the Industrial and Producer markets rather than the core served by Distributing Companies.

The FGA indicated that security of supply was actually an issue for the Distributing Company. The FGA submitted that Distributing Companies ensure their security of supply through a number of means and the best assurance of a secure supply of gas would be for a distributing company to arrange for default supply itself and to deal only with reputable retailers. The FGA argued that if there was an issue with AP's inability to transport sufficient gas supply arranged by the distributing company, then this reflected on the transporter's ability to plan for both its industrial and distributing company's transportation requirements.

Views of the Board

Peak Demand Notice and Billing Commencement Date
The Board considers that AP requires a reasonable time period for notice of changes in peak demand requirements (Peak Demand Notice) at each location where it delivers gas to its Distributing Company customers, in order to provide for adequate time to plan and reconfigure its transmission system to accommodate the changes.

The Board notes that AP proposed that the Billing Commencement Date should be January 1 of each year and that the Distributing Companies did not comment on this proposal. At this time, the Board is prepared to accept AP's proposal for the Billing Commencement Date.

With respect to timing of the Peak Demand Notice, AP requested notice 12 months prior to the Billing Commencement Date, while FGA argued that it would be more appropriate for the Distributing Companies to provide their requirements at a reasonable interval before the beginning of the gas year or other milestone. At this time, given no specific alternatives, the Board considers that a 12-month period for Peak Demand Notice, prior to the Billing Commencement Date, is reasonable.

With respect to FGA's submission that provisions should be allowed for periodic adjustments to the peak demand quantity, the Board notes that no evidence was presented with respect to the number and magnitude of such possible adjustments. While the Board would expect that these adjustments would be infrequent, it would appear reasonable that such provisions should exist.

The Board agrees with FGA that AP should develop planning procedures with the Distributing Companies that would satisfy the needs of both the distributing companies and AP. Therefore the Board directs AP to discuss this matter further with the Distributing Companies and to file a proposal in its next GRA. It appears to the Board that the details on such a proposal could be included in AP's BP&P.

Peak Demand, System Design and Curtailment

As stated in Section 3.0 of AP's BP&P, AP may restrict or curtail service in excess of a customer's contract demand or nominated demand if such excess cannot be accommodated due to pipeline operating conditions. In addition, AP will not curtail firm service except in certain instances, which includes the necessity to ensure gas service to temperature sensitive customers. The Board considers that on the peak day, AP's curtailment procedures would provide an appropriate framework to deal with the priority of service to its customers.

The Board notes that while AP indicated that Distributing Companies should have a higher level of service priority than other delivery services and that deliveries to Distributing Companies should not be curtailed, AP also indicated that its capability to deliver gas to Distributing Companies was limited to its system design. For Distributing Companies, the FSU rate schedule provides that AP is not obligated to design the pipeline system or deliver, in any one hour at any point of delivery, a quantity of gas exceeding the peak demand established for each point of delivery.

The Board accepts that AP operates to provide a higher level of service to Distributing Companies in that it would endeavour not to curtail them, but as its obligations are currently structured, it is reliant on the proper peak demand values for design and delivery purposes to these customers. The Board therefore considers that the Distributing Companies must provide accurate peak demand requirements at each delivery point.

Incremental Penalty Charges for Exceeding the Nominated Demand

With respect to AP's proposal that Distributing Companies should pay incremental charges for actual flow exceeding peak demand nominations, AP stated that since Distributing Companies may not encounter a peak day each year (due to temperature dependence), they could be motivated to understate their peak demand requirements.

The Board considers that AP has not fully justified its proposal for a 24 month charge equaling the difference between the actual one hour flow and the nominated peak demand at the affected point of delivery, plus a five year forward minimum peak demand value at the new actual peak level.

Interveners were generally not in favour of the level of the proposed penalty. The Board notes that two of AP's Distributing Company customers[78] did not provide comment on this matter, which could have been useful, particularly with respect to the mechanics of how the level of nominated demand would be chosen, whether or how retailers would be involved in the demand forecasts, and how the proposed penalty would be passed onto customers for payment.

The Board considers that the record is not completely clear on when a Distributing Company would be motivated to intentionally understate its delivery requirements from the AP system, particularly where the Distributing Company might require incremental distribution facilities to meet its own load forecast.

The Board tends to agree in principle with the CG's submission that if a Distributing Company did "low ball" its estimate at a particular delivery point, an immediate 12 month penalty charge would motivate Distributing Companies to provide adequate demand forecasts, and that the continuation of the higher peak demand and charge on a forward basis, until the time of the next estimate to be provided by the Distributing Company for that point, would also be appropriate.

The Board would be sympathetic to AP's need for a penalty clause with reasonable parameters to ensure sound forecasting practices by Distributing Companies. However, as indicated above, the Board is not clear on the probable degree of underforecasting by Distributing Companies at this time. The Board has further concerns with respect to the administration and practical implementation of AP's proposal, including how the penalty provision would be determined and how AP would decide whether to trigger such a charge when the peak demand at one delivery point was exceeded but the overall peak demand in the immediate area was not exceeded.

Therefore the Board will not approve AP's proposed penalty charges associated with the FSU rate at this time.

5.5 OPDM and OPDC

In response to its North and South system settlements, implemented in 1998 and 1999 respectively (North Settlement and South Settlement), AP implemented an exchange service, under which it used its NIT account to provide gas exchanges between its system and the NGTL Alberta System. AP proposed in the Application to replace the exchange service with an OPD service.

Views of the Applicant

AP proposed to replace the current exchange fee mechanism, which was priced at the difference between AP and NGTL tolls, with delivery transportation service to customers who deliver gas to other pipelines from the AP system. AP proposed two rate options (OPDM, being an OPD Must Flow rate and OPDC, being an OPD commodity rate) for deliveries to all other pipelines including NGTL, Alliance and MIPL/TransGas.

With respect to CCA's claim that AP was expropriating the core customers' and other customers' exchange revenues and using these to subsidize producers' costs, AP submitted that exchange revenues were not being expropriated because the core customers and other customers did not own them. AP indicated that it proposed to allocate OPDC revenues to customers based

78 ATCO Gas and AltaGas.

on peak demand. AP also submitted that the benefit of exchange service that CCA referred to was a reduction to ODC, which AP proposed to allocate to customer groups based on peak demand. AP argued that it was treating all customers fairly.

Views of the Interveners

CCA

With AP's proposal to eliminate the EDA and replace it with an OPD rate, the CCA argued that core customers should still be entitled to revenue credits as originally contemplated in the North Settlement.

The CCA submitted that exchange capacity was created by nominating shippers[79] and should be available to be used by nominating shippers as they saw fit. The CCA considered that exchange revenues should benefit the party doing the exchange and core customers should benefit and not subsidize AP sourced producers. The CCA submitted that the subsidy was becoming so significant that it was affecting natural gas pricing on the AP system.

Views of the Board

With respect to the CCA's claim that exchange capacity was created by nominating shippers and that it should be available to be used by nominating shippers as they saw fit, the Board considers that many factors including the core demand profile, the industrial demand profile and the producer supply preferences have all influenced AP's current situation with respect to exchange capacity. With respect to the CCA's submission that exchange revenues should benefit the party doing the exchange and core customers should benefit and not subsidize AP sourced producers, the Board considers its determinations in this Decision, with respect to the allocation of expenses and income credits to the OPD service class and subsequent reallocation, to be reasonable and fair to all customers.

5.5.1 OPDM

AP proposed that a "must flow" (OPDM) rate would be available to deliver gas to NGTL, Alliance and MIPL/TransGas. AP proposed that the rate would incorporate 100% load factor deliveries to the other pipelines. Under this rate, AP proposed that the customer must pay all tolls and fuel to access the other pipelines. AP indicated that the OPDM rate was designed on the model provided by the current FSDA rate for Transportation Firm Service to Alliance Pipeline.

Views of the Applicant

AP indicated that it might direct a customer to reimburse AP for other pipeline charges[80] incurred by AP when the AP system was available to effect delivery of the nominated demand and such nominated demand was not fully utilized by a customer. AP indicated that the customer would incur these charges if the customer failed to deliver the must flow volumes during a period that ODC to NGTL were incurred. AP proposed that the revenue from any such charges would be credited against the ODC in the OPD deferral account.

[79] Including LDC core customers since gas is purchased on their behalf.
[80] AP proposed that these charges would be based on the current month's average ODC multiplied by a quantity of gas equal to the nominated demand less the amount the customer actually delivered to the other pipeline on the given day.

AP proposed that customers holding OPDM service would have first priority to the customer's pro-rated share of incremental delivery capacity in excess of the nominated demand as it became available on the other pipeline. AP also proposed that if the excess capacity was still not fully utilized, the remaining capacity would be available to those customers holding OPDC service on a "first come, first served" basis.

AP proposed that an agreement would be required by shippers contracting for OPDM and the nominated demand would be established at the time the agreement was executed and would generally be for a one year minimum term.[81] AP also indicated that the OPDM service was firm.[82] AP also proposed that at its sole discretion, monthly OPDM terms might be approved. AP also proposed that either a customer or AP could terminate must-flow agreements by providing 12 months written notice to the other party.

AP also proposed to provide North and South overrun charges for OPDM service at a commodity rates equal to the OPDC rates in the North and South respectively.

AP submitted that the no charge demand rate reflected the fact that the "must flow" resulted in a market for on-system receipt volumes for a full year and resulted in a reduction in volumes required to flow to NGTL in the warmer months.[83]

AP indicated that if it was past a level of supply/demand balance on its system that it could economically deal with, customers would be required to enter into other arrangements such as OPDM service.[84]

AP indicated that under OPDM service to NGTL, as long as there was exchange capability, the customer would not incur penalty costs in no flow conditions.[85] AP indicated that if a customer that elected OPDM service failed to flow off to the other pipeline on a given day and AP determined that there was a physical oversupply problem that the customer had compounded on that day, and incremental flow was required to NGTL, the customer would incur a charge. On a practical basis, AP submitted that if a customer failed to delivery in January, they would not likely incur the charge while if the customer failed to deliver in July, they would probably incur a charge.[86] AP also indicated that while the OPDM service was available for delivery to NGTL, Alliance and TransGas, it did not expect shippers to elect the service to NGTL in the short term because of more attractive netback options.[87] AP also indicated that it expected that all producers would be using the OPDC service to access NGTL.[88]

CG

The CG supported the rate as filed.

81 IR AIPA-8 (d)
82 Transcript, page 592, lines 3 – 4.
83 Transcript, Vol. 6, page 583, lines 19-23.
84 Transcript, page 268, line 13 to page 269, line 3.
85 Transcript, page 732, lines 2 – 10.
86 Transcript, page 733, lines 4 – 14.
87 Transcript, page 737, lines 7 – 17.
88 Transcript, page 737, lines 18 – 25.

Views of the Board

In reviewing the evidence on the OPDM service, the Board agrees with the concept of the service in principle, but is concerned that certain aspects of the service have not been clearly defined. At this time, the Board is prepared to accept the concept of a zero demand charge with penalty provisions for no flow conditions, and is also prepared to accept that the North and South OPDM overrun charges would be equal to the respective North and South OPDC rates. However, at this time, the Board is not prepared to approve other aspects of the OPDM service until AP provides updated rate schedules that clearly describe the OPDM and OPDC services and how these services relate specifically to the three other pipelines (NGTL, Alliance and MIPL/TransGas).

The Board is concerned that AP's proposed rate schedule is written somewhat generically for "other pipelines" while also including specific references to system specific items such as the use of AP's NIT account.

With respect to the OPDM service, it appears to the Board that the customer would commit to a nominated demand upon execution of a minimum one-year agreement, but AP's obligations with respect to this nominated demand are not clear and it appears that they depend upon whether the nominated demand is for NGTL, Alliance or MIPL/TransGas. The Board also notes that AP proposed that at its sole discretion, monthly OPDM terms might be approved, but it is not clear whether AP would accept the nominated demand for each day in the period upon execution of the agreement or whether this acceptance would be decided daily. In addition, it would appear that under certain circumstances (such as the amount of NGTL exchange capacity) and depending upon the selected delivery pipeline, a customer would still incur incremental charges even if they were prepared to meet their nominated demand.

Therefore, the Board directs AP to refile the rate schedule for Delivery Transportation Service to Other Pipelines (Rates OPDM and OPDC) as part of its Compliance Filing in such a way that the OPDM and OPDC services are clearly defined and that the service provisions and service requirements with respect to the other pipelines (NGTL, Alliance and MIPL/TransGas) are clearly distinguished for both OPDM and OPDC. The Board requests that unique aspects of the OPDM and OPDC services with respect to each connecting pipeline be clearly defined.[89] The rate schedules should also clearly indicate the responsibility of the customer with respect to charges from the other connecting pipelines.

5.5.2 OPDC

AP proposed that a commodity rate (OPDC) would be available to deliver gas to NGTL, Alliance and MIPL/TransGas and that the commodity rates would be applied to nominated volumes.

[89] For example, how the OPDM penalty provisions would work for each respective interconnecting pipeline.

Views of the Applicant

AP established the OPDC rate by taking certain expenses and revenues that were assigned or allocated to the three delivery service classes and dividing by the demand for the three services, and then dividing by 365 to establish a daily equivalent rate.[90]

In the case of NGTL, AP proposed that this rate would result in access to the NGTL system at the NIT point in much the same manner as payment of the current exchange fee. AP proposed to continue to utilize the exchange mechanism provided by two-way flows to enable access to NIT.

AP proposed that for Alliance and MIPL/TransGas, the shipper would pay the toll and fuel to access either system because the exchange mechanism would not work (no two way flow).

AP proposed that separate agreements for OPDC were not required and nominations could be made daily as required by the customer.[91]

AP submitted that the average delivery general system cost rate was determined as a fair and reasonable commodity rate because there were no direct variable costs on which to base a commodity rate. AP also submitted that the OPDC rate was a 100% load factor rate based on a full allocation of general system delivery costs that would provide a proper price signal.

AP indicated that on a given day when a customer wanted to move gas to NGTL, the customer would pay the OPDC rate (whether exchange capacity was available or not) and any ODC incurred would go into the OPD deferral account[92].

AP indicated that the OPDC rate was not intended to underpin customer specific facilities.

Views of the Interveners

CG

The CG supported the rate as filed.

IGCAA

IGCAA submitted that ODC should form part of the OPDC charge. IGCAA argued that a blended approach could be used where there was a discrete OPDC charge, and any remaining costs could be allocated back to customer groups based on delivery nominations. IGCAA also submitted that there was no evidence placed on the record regarding market problems associated with including AP system charges and ODC in the OPDC commodity charge.

Views of the Board

As noted in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues, the Board has determined that a fully cost based OPD service with stand alone rates would not be required at

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90 North: General Asset Related Expense, General O&M Expenses, Custody Transfer Meters, Salt Cavern Expenses, Other Directly Allocated Expense, Oversupply Delivery Costs and Lease/Other and IT/Overrun Revenue.
South: General Asset Related Expense, General O&M Expenses, Custody Transfer Meters, Other Directly Allocated Expenses, Oversupply Delivery Costs and IT and Overrun Revenue.

91 IR AIPA-8 (d)

92 Transcript, page 737, line 23 to page 738, line 12.

this time. At present, the Board is prepared to accept AP's proposed methodology for establishing the OPDC rate. However the Board considers that the rate will have to be updated by taking into account the revisions to AP's cost allocations as reflected in this Decision. Therefore the Board directs AP to recalculate the OPDC rate for the North and South as part of the Compliance Filing. The new OPDC rate should be established by using the same expense and revenue categories[93] that AP used in its proposed methodology, but the values assigned or allocated to the three delivery service classes for these expense and revenue categories will have to be updated based on the Board's revised allocation and assignment methodologies described in this Decision.

With respect to the Delivery Transportation Service to Other Pipelines rate schedule, the Board has provided its views and directions in Section 5.5.1.

5.6 SPD

AP proposed that delivery transportation service for straddle plants (Rate SPD) would be available to customers who physically take gas off of the AP pipeline system at a point of delivery to a straddle facility (liquids extraction plant) in the North. The rate was not required in the South. AP proposed that the commodity rate associated with this service would be applied to the total energy removed in the straddle plant. AP also proposed a monthly fixed charge for this service.

Views of the Applicant

AP indicated that the straddle plant rate was equal to OPDC rate less the impact of removing Salt Cavern Costs and Other Directly Allocated Expenses.[94]

In response to the CCA statement that the SPD rate should be higher to take into account a percentage of the volumes that move through the plant, AP submitted that the CCA's proposal was unsupported and incomplete. The CCA did not state what percentage of volumes should be used. AP argued that the Board should reject CCA's proposal because it would effectively result in gas volumes moving through the plant being charged twice for delivery service, once through the SPD rate and again through the ultimate delivery rate (FSU, FSD or OPD).

Views of the Interveners

CCA

The CCA considered that the SPD rate was too low because straddle plants receive a higher level of service than simply an amount of energy removed from the gas stream. The CCA argued that straddle plants remove valuable components from the gas stream and therefore, greater costs should be allocated than the energy removed. The CCA submitted that energy removed plus some percentage of volumes moved through the plant would be more appropriate.

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[93] North: General Asset Related Expense, General O&M Expenses, Custody Transfer Meters, Salt Cavern Expenses, Other Directly Allocated Expense, Oversupply Delivery Costs and Lease/Other and IT/Overrun Revenue.
South: General Asset Related Expense, General O&M Expenses, Custody Transfer Meters, Other Directly Allocated Expenses, Oversupply Delivery Costs and IT and Overrun Revenue.

[94] Exhibit 002-02(c) – ATCO Response to AIPA-AP-18(d).

CG

The CG supported the rate as filed.

Views of the Board

The Board considers that straddle plant service generally has little impact on the transmission service of AP, and that AP has the option of bypassing the straddle plants if operationally necessary. Furthermore, straddle plant service creates no demand upon the AP system to move contracted quantities into the plant gate, as would other industrial customers. The straddle plants merely take gas volumes available, extract various products out of the gas stream, recompress the residual gas and redeliver it to the AP system without loss of pressure and only a slight reduction in heating value. Therefore, the Board considers that the straddle plant operation is relatively benign to the operation of the pipeline transmission system.

The Board notes AP's recommended straddle plant rate as the OPDC rate less the impact of removing Salt Cavern and Other Directly Allocated Expenses. The Board accepts AP's submission that straddle plant service has the attributes of delivery service to other pipelines. Therefore the Board accepts that the OPDC rate would be an appropriate rate for straddle plant service. However the Board does not believe that AP has provided adequate reasons to remove from the SPD rate the costs associated with Salt Caverns and the Other Directly Allocated Expenses.

Therefore, the Board directs AP, in the Compliance Filing, to revise the SPD rate to the OPDC rate without deductions and to effect the required changes in the income credit allocation section of the rate design.

5.7 MAS

AP proposed that a Market Account Service (MAS) would be available to customers who wish to make account transfers on the AP system. AP also proposed that a customer's market account must be balanced to zero at all times and that the account would not allow physical receipt and delivery transactions. AP proposed a fixed monthly fee of $1,000 for this service.

Views of the Applicant

AP indicated that the MAS would be available to customers that do not require the ability to receive or deliver physical quantities of gas on the AP systems but require the ability to purchase and sell gas to other account holders through account transfers. AP submitted that the MAS provided a forum for pure buyers and sellers to trade gas and therefore, increase gas market liquidity. AP indicated that the COSS did not include an assignment of costs to the MAS since there were no separate identifiable costs to provide the service.

In response to CCA's suggestion that the MAS rate should be eliminated in order to improve AP's system market liquidity, AP argued that no party presented evidence indicating that the existence of the MAS rate was a concern in this regard. AP indicated that market liquidity was an important consideration for its systems and after further analysis, AP might apply in future to the Board for a variance in this rate. At this time, however, AP considered the rate to be fair and reasonable.

Views of the Interveners

CCA

The CCA considered that the MAS rate should be eliminated because the rate acts as a barrier to small retailers or small commercial or industrial customers who wish to operate an account on the AP system. The CCA argued that anything that discouraged parties from operating accounts on the AP system should be eliminated.

CG

The CG supported the rate as filed.

Views of the Board

The Board notes that the current North and South rate for MAS is a fixed charge of $300 per month and that AP proposed to increase the rate to $1000 per month.

In respect of the CCA concern, until some evidence is provided that demonstrates to what extent the monthly fee may present with the MAS rate, a barrier to smaller customers use of the account, the Board does not consider the rate to be unreasonable. Therefore, the Board approves the MAS rate schedule as proposed by AP. However, the Board directs AP to file a market barrier analysis on the MAS rate when it applies for any future variance in the rate, which may be on a stand alone basis or as part of its next Phase II GRA.

5.8 Rate Riders

AP provided a general description of eight rate riders applicable to its rate schedules and included rate schedules for three of the riders, Rider D (UFG/Fuel), Rider J (2001/2002 South EDA Deficit Recovery) and Rider K (2003/2004 South EDA Deficit Recovery).[95] Rider D is discussed separately in the section below.

Views of the Applicant

AP indicated that rate riders would be applied for, separate and apart from this proceeding, as required.

Views of the Interveners

No interveners commented on the rate riders.

Views of the Board

The Board notes that subsequent to AP's filing of the South Rider K schedule in this proceeding, the Board approved Rider K in the North,[96] for the 2004 exchange deferred account, which will remain in effect until October 31, 2004.

The Board considers it appropriate for AP to apply for rate riders as required, separate and apart from this proceeding. However, for completeness, the Board directs AP to include the current rate rider schedules for both the North and South in the Compliance Filing.

95 IR Attachment IGCAA-AP02-1 (b), pp. 35-38
96 Board letter April 29, 2004

5.8.1 Unaccounted-for-Gas/Fuel Shift to Receipt Services

AP proposed to recover unaccounted for gas and transmission system compressor fuel (UFG/Fuel) through transportation receipt services including FSR, FSRS, ITR and OPR.

Currently, AP recovers UFG/Fuel through transportation delivery services, excluding gas delivered to the NGTL system via exchange service.

Prior to 1998 in the North and 1999 in the South, UFG was included in the "Old World" point-to-point tolls and was effectively charged to both receipt and delivery customers. In the North Settlement, UFG/Fuel was allocated to delivery customers. A similar approach was adopted in the South.

AP proposed to continue to recover UFG/Fuel "in-kind" from each customer account.

Views of the Applicant

AP submitted that UFG/Fuel was a system cost and therefore should be a shared cost. AP submitted that placing the UFG/Fuel on receipts would result in the UFG/Fuel impact being negotiated into the on-system trading price by receipt and delivery customers.

AP indicated that the trading price on the APN and APS systems was determined in the marketplace. AP submitted that buyers and sellers look at the "bookends" and then negotiate from those positions. AP indicated that prior to October 1, 2003, the higher bookend was NIT[97] with the lower bookend being NIT less a full exchange fee.[98]

AP submitted that, under its proposal, the high bookend would shift to NIT plus the OPR rate plus the full UFG/Fuel charge while the lower bookend would become NIT less the OPDC rate. AP indicated that placement of UFG/Fuel on the receipt side would have the side effect of increasing the AP on-system trading price by roughly half of the value of the UFG/Fuel charge.

AP submitted that by moving the UFG/Fuel to the receipt side, it would be consistent with its interconnecting pipelines (Alliance, MIPL/TransGas and NGTL) and would make it easier to understand and eliminate the UFG/Fuel competitive mismatch with other pipelines due to varying gas prices.

In response to CAPP's statement that AP's continued primary focus was on deliveries to core and industrial markets, AP submitted that while its primary focus was on the core and industrial markets when it was an integrated gas utility, it has evolved into a gas transmission pipeline serving both receipt and delivery markets.

With respect to the CG's proposal to share the UFG/Fuel between receipts and deliveries, AP submitted that placing the UFG/Fuel on deliveries has not resulted in UFG/Fuel being shared between receipt and delivery customers, and if 50% of the UFG/Fuel was allocated to deliveries it was unlikely to enter the price negotiation. AP argued that the net result of the CG proposal would be that 50% of the UFG/Fuel might end up being shared equally between receipt and delivery shippers, which could effectively result in a sharing of UFG/Fuel of 25% to receipt

[97] Gas delivered to AP from NGTL incurred no AP charges and NGTL did not charge for Intra-Alberta deliveries.
[98] Reflecting the seller's option to pay an exchange fee to transfer gas onto NGTL at the NIT point.

shippers[99] and 75% to delivery shippers.[100] AP argued that it was better to allow the market place to negotiate the full UFG/Fuel rather than try to directly assign costs in the manner proposed by CG.

Views of the Interveners

CALGARY

Calgary supported AP's UFG/Fuel proposal given its claim that the North American pipeline industry has had a long standing policy that each shipper was responsible for its share of UFG/Fuel. Calgary argued that by imposing UFG/Fuel at the receipt point each shipper would be responsible for its proportional share.

CAPP

CAPP submitted that it was appropriate to recover UFG/Fuel on the delivery side because AP had not provided a cost or benefit based justification for shifting UFG/Fuel to the receipt point.

CAPP did not agree with AP that UFG/Fuel should be shifted to receipt services in order to be consistent with interconnecting pipelines such as NGTL because AP was not like NGTL. CAPP argued that AP was developed as a system for deliveries to core and industrial markets and this primary focus had not changed.

CAPP submitted that Calgary, IGCAA and Rate 13 supported AP's proposal while also agreeing that UFG/Fuel was properly a system cost which should be shared by all shippers. CAPP argued that these parties were all looking for a shift in costs from the delivery customers to the receipt customers for their own benefit. CAPP submitted that there was no support for Rate 13's statement that the competitive mechanism would better allocate costs among end-use customers than would regulation.

CCA

The CCA supported the movement of UFG/Fuel to receipt services.

CG

The CG submitted that UFG and compressor fuel costs were created by both delivery service and receipt service, and that the point of recovery of UFG/Fuel was a matter that clearly has competitive impact.

The CG argued that measurement error was a major contributor to UFG, therefore both receipt and delivery meters would be points of cost causation for UFG. Similarly, leakage or fugitive emissions, another source of UFG, occurred at points throughout the physical facilities of AP.

With respect to compressor fuel, the CG noted that AP allocated compression costs to both receipt and delivery service in its COSS. The CG argued that the provision of fuel to run those compressors should also be allocated to both services.

99 One-half of 50%.
100 50% plus one-half of 50%.

The CG agreed with AP that negotiations on the UFG/Fuel costs would occur in some instances. The CG submitted that while these negotiations might occur on longer-term gas purchase arrangements, more typically for high load factor customers, the CG questioned the practicability of these negotiations occurring for the short-term purchases that were more representative of core market purchases. In any event, given that UFG/Fuel costs resulted from both receipt and delivery services, the CG argued that UFG/Fuel recovery should be directly allocated equally to receipt and delivery services rather than depend on the uncertain results of sharing that might occur through the negotiation process.

FGA

The FGA indicated that it was indifferent to AP's UFG/Fuel proposal. The FGA submitted that delivery customers, whether on-system or off-system, ultimately pay for all costs of the system and argued that they either pay directly through their delivery charges or through the cost of gas purchased on the system. The FGA submitted that UFG/Fuel would be recovered by producers through their sales to the ultimate customers.

IGCAA

Based on cost causation, IGCAA submitted that it did not make sense for delivery customers to bear 100% of UFG/Fuel costs. Rather than attempting to allocate UFG/Fuel charges between receipt and delivery points based on what would likely be an arbitrary cost allocation methodology, IGCAA supported moving UFG/Fuel to receipt points where producers can recover an appropriate share of these costs as part of the gas price on the AP system.

Rate 13

Rate 13 supported AP's proposal to charge UFG/Fuel on receipts and agreed with its rationale. Rate 13 supported the desirability of negotiating the UFG/Fuel component of the producer's cost, rather than having these costs directly allocated. Rate 13 submitted that this competitive mechanism would better allocate costs among end-use customers than would regulation.

With respect to CAPP's comments, Rate 13 argued that AP was much more than a pipeline delivering to on-system markets, and therefore the UFG/Fuel cost allocation should reflect the commercial realities that several other transactions acted to reduce pressures on the system, notably transfers to interconnecting pipelines.

Views of the Board

The Board notes that there are various ATCO UFG related issues currently before the Board or expected to come to the Board in the near term.

In this proceeding, the Board must determine how AP should recover transmission UFG and compressor fuel from its customers. The Board notes that a number of parties support AP in its proposal to shift recovery to receipt services. CAPP prefers the status quo (recovery through delivery services), the FGA is indifferent and the CG suggests recovering UFG/Fuel equally between receipt and delivery services.

The Board agrees with AP that UFG/Fuel is a system cost. Further, the Board considers there is some appeal in principle to the CG's UFG/Fuel recovery concept. However it does not appear that this concept and its potential ramifications on negotiated gas prices has been fully considered by all parties. While the CG proposal may have merit for future consideration in greater depth, for the present time the Board considers that consistency between interconnecting pipelines is a positive objective. Therefore, the Board will accept AP's proposal to move UFG/Fuel recovery to its receipt services.

With respect to the shift of UFG/Fuel recovery to receipt services, the Board agrees with the CG that there is uncertainty with respect to how sharing of the UFG/Fuel charge between gas buyers and sellers would occur. The Board directs AP to file an application by November 1, 2004 outlining its proposal for recovering UFG/Fuel (Rider D) from transmission transportation customers for implementation on January 1, 2005.

The Board agrees with CG that the point of UFG/Fuel recovery has a competitive impact, and believes the issue could usefully be discussed in the Competitive Proceeding, where both regulated pipeline companies and interveners could debate the appropriate recovery mechanism and whether consistency between pipelines is a key factor.

Other UFG issues are outstanding and before the Board, a brief background on which follows.

The Board notes that in November 2003, AG[101] submitted Rider D rates applicable to transmission transportation service customers in the North and South and retailer delivery service customers in the North and South. These Rider D rates were to be implemented January 1, 2004. AG subsequently withdrew its application pending further review of the quantity of imbalances that are used in the UFG calculation. On May 31, 2004, AG refiled Rider D rates and Application 1347869 is currently before the Board. The current Rider D rates for transmission transportation customers and retailer delivery service customers have been in place since January 1, 2003 in the South and July 1, 2003 in the North.

The issue of UFG allocation to the AG distribution system and AP transmission system was dealt with in Decision 2001-97 for the South and Decision 2003-042 in the North. In Decision 2003-042, the Board indicated that the method for allocating UFG between distribution and transmission for the North system would apply in all future Rider D applications for APN until such time as metering hardware was installed between APN and AGN and the resulting metered data yielded separate and adequate UFG data for APN and AGN. The timing for the conversion from the allocation methodology to the separate UFG obtained from measurement between APN and AGN would be determined in future Rider D applications.

In the hearing, AP indicated that it would expect to make a decision in summer 2004 on whether the data received from the UFG meters in the South would be reliable enough to move to a physical basis for UFG or whether one more year would be required using the allocation method. AP indicated that results in the North would be two years behind the South results because the UFG meters were installed later. With respect to the South, the Board directs AP to file its plans for determining UFG on a physical basis as part of the November 1, 2004 application required by the Board above.

The Board notes that there does not appear to be any information on the record outlining AG's position with respect to recovering the distribution portion of UFG from its distribution transportation customers. In addition, AP has not outlined its plans, if any, with respect to

[101] On behalf of AG and AP.

removing the requirement for the DERS DSP customers to take the residual impact of Rider D inaccuracies. Therefore, the Board directs AP to work with AG so that the November 1, 2004 application noted above also outlines AG's proposed mechanism for recovering distribution UFG and the impact to the DERS DSP customers.

5.9 Non-Compliance/ Unauthorized Service

AP included a consequence for Non-compliance/Unauthorized Service in its General Conditions which apply to rate schedules. AP noted that the Non-compliance / Unauthorized Service charge was to be used in situations where a customer failed to comply with either a service curtailment notification or an account tolerance restriction notification.

AP indicated that after it advised a customer to reduce transportation service to a specific nomination and a subsequent non-compliance notice was issued, the charge on the Non-Compliance Quantity[102] would be five (5) times the NGX/AECO Intra-Alberta previous gas day trading instrument daily high, or if this price was not available, the charge would be based upon the industry recognized daily reference price for the previous day.

Views of the Applicant

AP submitted that the Non-compliance/Unauthorized Service provision was the last step available in a process of enforcing a service curtailment action. AP submitted that customers who failed to meet the requirements of a service curtailment could seriously jeopardize the operation of AP's pipeline system as well as the ability of AP to meet the peak demand requirements of Distributing Companies. AP submitted that this charge was just and reasonable and indicated that this condition of service was previously approved by the Board in the form of Rate 7 B (ii) and Rate 8 B (ii).

Views of the Interveners

No interveners provided comments.

Views of the Board

The Board notes that no Interveners commented on the proposed Non-compliance/Unauthorized Service provision.

AP referred to the current Rate 7 B (ii), Emergency Service, Unauthorized Sales in the South and current Rate 8 B (ii), Emergency Service, Unauthorized Sales in the North, in connection with the proposed Non-Compliance/Unauthorized Service charge. The Board notes that the current Rates 7 B (ii) (South) and 8 B (ii) (North), provide for a daily fixed charge for these services and an energy charge of five (5) times Rider F (GCRR), with a minimum price of the highest cost of gas purchased on the day.

Although the Board considers that the purpose and circumstances surrounding the current unauthorized emergency sales services to be different than the enforcement mechanism of AP's proposed Non-compliance / Unauthorized Service charge, the Board considers that AP's proposed enforcement mechanism is reasonable in consideration of its obligation to operate a

[102] Non-compliance quantity means the quantity of gas, in each day, by which a customer exceeds the quantity of gas contained in an instruction given, upon notice, by AP.

safe and reliable gas pipeline system. Therefore, the Board approves AP's proposed Non-compliance / Unauthorized Service provision as filed.

5.10 Closed Rates

AP proposed that a number of rates would expire upon approval by the Board in this Decision.

Views of the Applicant

Sales rates were classified as closed rates because AP proposed to only offer sales service until October 31, 2004. In Abcom/CCG-AP-1, AP submitted that they were proposing to cease all sales rates because providing a sales service (buying and reselling the gas commodity) was not a service typically provided by gas transmission entities. AP also argued they only had a small number of sales customers in 2004. AP noted that they had no sales customers in the South and that the ones left in the North were progressively moving to transportation only.

The following are the rates that AP proposed to close, as they were set out in the Application[103].

(a) Rates Currently in Use

(i) North
Rate 4 - Large Use Sales Service (expired October 31, 2004)
Rate 5 - Sales to Other Distribution Companies (expired October 31, 2004)
Rate 6 - Sales to Power Plants (expired October 31, 2004)
Rate 7 – Sales to Gas Alberta (expired October 31, 2003)
University of Alberta (expired October 31, 2003)
Rate 10 - Transportation Service (expired October 31, 2004)
Town of Wainwright (expired June 30, 2004)

(ii) South
Rate No. TFS - Transportation Firm Service Large Industrial

(b) Rates Not Currently in Use

(i) North
Rate No. TFS - Transportation Firm Service Agrium/Dow
Rate 8 – Standby, Peaking, and Emergency Sales (expired October 31, 2004)
Rate 50 – Balancing Service
Rate 30 – Firm Transportation Receipt Service
Rate 31 – Firm Transportation Receipt Service (1-year)
Rate 33 – Firm Transportation Receipt Service (3-year)
Rate 34 – Interruptible Transportation Receipt Service

(ii) South
Rate 4 – Optional Sales Special Transmission (expired October 31, 2004)
Rate 6 – Sales to Gas Alberta
Rate 7 – Standby, Peaking, and Emergency Sales (expired October 31, 2004)

[103] From Section 3 – Rate Schedules - Index

Rate 9 – Transportation Rate for Natural Gas (expired October 31, 2004)
Rate 20 – Firm Delivery Transportation Service
Rate 21 – Firm Delivery Transportation Service (1-year)
Rate 22 – Firm Delivery Transportation Service (2-year)
Rate 23 – Firm Delivery Transportation Service (3-year)
Rate 24 – Interruptible Delivery Transportation Service
Rate 30 – Firm Receipt Transportation Service
Rate 31 – Firm Receipt Transportation Service (1-year)
Rate 32 – Firm Receipt Transportation Service (2-year)
Rate 33 – Firm Receipt Transportation Service (3-year)
Rate 34 – Interruptible Receipt Transportation Service

Views of the Interveners

No interveners commented on or objected to the proposed rate closures with respect to the rates that were not currently in use. With respect to the positions of parties regarding the proposed closure of Rate 5, please refer to Section 7.4 of this Decision. Other than with respect to Rate 5, no interveners commented on the closure of any current rates as proposed by AP.

Views of the Board

With regard to the rates that are not currently in use, the Board notes that no party took issue with these rates being permanently closed. The Board agrees with AP that it appears appropriate to close these rates at this time.

With respect to the proposed closure of current rates, the Board notes that with the exception of Rate 5, which is specifically dealt with in Section 7.4 of this Decision, no parties objected to the closure of these rates. The current rates to be closed are generally sales rates. The Board agrees with AP that a transmission service provider would not typically provide sales rates. Therefore, the Board agrees with the closure of these current rates. The Board is of the view that these current rates should expire and be replaced with new transportation rates as determined in this Decision and as a result of the Compliance Filing.

5.11 Daily Customer Account Balancing

The Board varied its Decision 2003-035 in order to permit a negotiation of Daily Customer Account Balancing conditions starting in September 2004.

Views of the Applicant

AP indicated that the Application included the currently approved General Conditions Applying to Rate Schedules – Section 4 Settlement of Monthly Imbalance Quantity. AP also indicated that a modification to the General Conditions to incorporate a new Settlement of Imbalance Quantities would be made in 2005 upon Board approval of the submission resulting from the customer negotiations on this matter.

Views of the Board

In its letter of April 24, 2004, the Board approved the amendment to the Application to withdraw the proposed changes to Item 4 of the Rate Schedules and Article 6 of the Transportation Service Regulations, related to Settlement of Monthly Imbalance Quantity and Balancing of Customer

Account, respectively. In that letter, the Board permitted the initiation of negotiations of the issues related to these matters.

The Board expects that AP will file a settlement agreement for Board consideration or, by January 31, 2005, AP will file a separate application to address these matters.

6 TRANSPORATION SERVICE REGULATIONS

6.1 Revisions

AP proposed the following revisions to the currently approved Transportation Service Regulations.

- Quality of Gas (Article 3.1)
  - A change in the Gas specifications from 36.5 megajoules per cubic meter to 36.0 megajoules per cubic metre.
- Quantity of Gas (Article 5.5)
  - Customers requesting heated Gas will have to provide the line heater fuel in kind. In the past, the fuel was part of UFG/Fuel.
- Balancing of Customer Account (Article 6.5)
  - Customers required to balance daily with provision to settle daily through buys and sells at prices included in the Rate Schedules. In the past, the requirement to settle was monthly.

Subsequent to filing of the Application, the customer account balancing provision was eliminated from the scope of the Application as discussed in Section 5.11.

Views of Applicant

AP noted that in Decision 2001-097, the Board directed AP to discuss the compatibility of gas specifications used by AP and NGTL. AP submitted that differences in gas quality specifications between the two companies might create confusion and uncertainty for customers since AP receives gas from and delivers gas to NGTL.

AP submitted that its heat value specification could be changed from 36.5 megajoules per cubic metre to 36.0 megajoules per cubic metre to match NGTL's specification while its sulphur and H_2S specifications could not be changed to match NGTL specifications due to AP's delivery obligations to Distributing Companies. AP argued that the reduction in heat value specification would reduce confusion for customers with gas receipts at dual connected plants without negatively impacting delivery customers.

AP considered its proposed heat value reduction to be just and reasonable and requested that the Board approve the heat value of 36.0 megajoules per cubic metre as filed.

With respect to line heater fuel, AP submitted that the current practice was to recover this fuel for customer specific facilities through Rider D (UFG and Fuel). AP submitted that this fuel should be recovered from the customers causing the costs and not through Rider D.

Views of the Interveners

FGA

FGA submitted that gas quality was a concern to customers and argued that the cost implications of this issue had not been fully vetted in these proceedings due to other initiatives of AP that had drawn more attention. With respect to AP's submission that differences in gas quality specifications between AP and NGTL may create confusion and uncertainty for customers, the FGA submitted that the supposed customer confusion was undocumented. The FGA argued, that since this appeared to be a problem only at the AP/NGTL interfaces, the change in heat value was a matter that should be deferred for discussion at the Competitive Proceeding.

Views of the Board

The Board agrees with AP that the proposed heat value reduction from 36.5 megajoules per cubic metre to 36.0 megajoules per cubic metre to match NGTL's specification is appropriate in order to maintain uniform base heating values with NGTL and to reduce confusion for customers. Thus, the Board approves the heat value of 36.0 megajoules per cubic metre as filed.

With respect to AP's request to directly charge line heater fuel to customers who desire their delivered gas to be heated, the Board notes that no interveners provided comment on this issue. The current practice is to recover this fuel for customer specific facilities through Rider D. The Board notes that, in addition to customers that incur Rider D charges, DSP customers would also pay for such line heater fuel. While the Board supports the concept that customers should pay for costs they cause, in this situation, the Board does not consider that AP has provided sufficient information with regard to the scope of this proposal and the cost to measure the line heater fuel. Therefore, the Board is not prepared to grant approval at this time and directs AP to file evidence including a detailed cost/benefit analysis with respect to this matter in its next GRA.

6.2 Integration of Business Policy and Practices into Board Approved Documents

AP noted that its BP&P were filed with the Application for acknowledgment.

AP requested specific approval of the following portions of the BP&P and movement of these provisions into the proposed TSR and/or Rate Schedules (RS):

1. Section 2.0, Investment Policy should be moved to the proposed TSR and RS.
2. Section 2.1 General; Section 2.2 Investment for Customer Specific Facilities; Section 2.4 Demand and Term Stacking; and Section 2.5 Customer Specific Facility Charges should be moved to the TSR.
3. Section 2.3 Contract Term should be moved to the RS, specifically the General Conditions Applying to RS, with corrections to the availability of Short Term Summer Service.[104]
4. The definition of customer specific facilities should be included in the TSR by substituting the words 'Customer Specific' in place of 'lateral' and 'General System' in place of 'mainline'.

[104] AP proposed that FSRS would only be available in the winter.

AP indicated that, with the exception of credit policies, the remainder of the BP&P generally related to the administration of the TSR and/or RS. AP did not propose to move these administrative and procedural issues to the TSR and RS.

Views of the Applicant

AP submitted that given the level playing field issues that have emerged with NGTL's entry into the delivery pipeline business, Board approval of the fundamentals of investment policy and accountability are required for both AP and NGTL.

AP submitted that the NGTL Products and Pricing Decision 2000-6 altered NGTL's investment policy with respect to laterals and NGTL's Fort McMurray and Fort Saskatchewan applications caused AP to express concerns with respect to NGTL's approach to cost allocation, cost accountability, and the LCA. AP argued that while NGTL's cost accountability did not have to be identical to AP's cost accountability, it should be based on the same principles.

AP indicated that customers should be required to make a contractual commitment for a service, such that the term and rates for that service equal the cost of the customer specific facilities. AP submitted that strong cost accountability policies prevent other customers from subsidizing poor capital investment decisions.

AP indicated that the following key elements were part of its cost accountability policy:

- AP would invest in facilities to meet customer needs;
- Whether facilities are customer specific or general system determines whether customer accountability was required;
- General system facilities were installed to meet the aggregate needs of customers as per the function definition;
- Customer specific facilities require that the customer sign for a primary term, which, under a demand based rate, ensures that the customer was directly committed to pay sufficient revenue to equal the customer specific facility cost, on a present value basis;
- The investment and cost accountability described above was for producer and industrial assets. The investment and cost accountability for Distributing Company assets were specific to the agreement between the customer and AP, primarily the TSA with AG; and,
- For accounting purposes, industrial and producer customer specific facilities were classed as 'dedicated'. These facilities were depreciated at two times contract life, which ensured the revenue requirement associated with dedicated facilities was recovered during the normal service life of industrial or producer customers. The revenue requirement associated with dedicated assets was directly assigned to either the industrial or producer customer group for cost of service and rate making purposes.

AP submitted that its investment and cost accountability policies have been discussed in four proceedings since 2001 and have received little criticism.

AP indicated that no intervener presented evidence in this proceeding on these issues and submitted that, while the Competitive Proceeding could certainly engage these issues, it was important that the Board provide focus to NGTL, AP and the industry through policy decisions in the NGTL and AP GRAs. In particular, AP stated that it would like the Board to make some policy decisions through the Phase II proceedings in each application.

AP proposed that the Board deal with the following issues:

- What facilities require accountability (customer specific);
- The definition of customer specific facilities;
- That accountability must derive directly from the rates paid for the applicable service;
- The level of accountability required; and,
- Board approval of investment policy, cost accountability and customer specific facilities definitions.

AP indicated that it could not support CCA's recommendation that the BP&P be included in the Terms and Conditions of Service. AP submitted that with the movement of the investment policy to the TSR and the removal of the exchange fee mechanism, the remainder of the BP&P was operational in nature, essentially providing the detailed operating procedures for the policy, which translate the TSR into day to day operations. AP noted that changes to AP's BP&P were subject to customer consultation, and were filed with the Board for acknowledgement. AP argued that requiring Board approval for all changes in its BP&P, such as nomination practices, would unnecessarily constrain AP's ability to operate its pipeline system and to respond to changes in the natural gas industry or requirements of the Gas Industry Standards Board. AP submitted that to adopt the CCA recommendation "holus bolus" without a sound rationale and without an examination of the individual items to be moved to the BP&P or an assessment of the impact that such an approach would have on the pipeline company and its customers, was arbitrary.

Views of the Interveners

CALGARY

Calgary submitted that these issues would be better examined in a Competitive Proceeding, where a complete analysis of these issues in tandem with NGTL (and any other pipelines) could be made, so that the Board could render an informed decision.

CCA

CCA considered that the investment policy and cost guidelines must be included in the terms and conditions of service. CCA submitted that it was inappropriate that AP or any utility have flexibility to adjust investment policies and practices and, therefore, placement into the terms and conditions of service was critical. CCA argued that neither AP nor NGTL should be able to adjust investment policies and cost guidelines without explicit Board approval.

CCA submitted that all BP&P should be included in the terms and conditions of service.

CG

CG recommended that the investment policy and LCAs be determined in the respective Phase II decisions of NGTL and AP.

CG agreed that AP should move its investment policy to the TSR and indicated that the Board should approve the investment policy.

Views of the Board

The Board notes that AP's current Investment Policy and Contract Term Section 2.0 in AP's BP&P includes procedures to deal with issues related to investment for customer specific facilities, contract term, demand and term tracking, and customer specific facility charges.

The Board views that the item related to contract term will be an integral requirement of the revised schedule of rates approved in this Decision. Therefore, the Board directs AP, in its Compliance Filing, to include the issue of contract term, currently Section 2.3 of the BP&P, into the appropriate sections of its RS.

Regarding the remaining items in Section 2.0 of the current version of the BP&P, the Board considers that these items would best be examined in the Competitive Proceeding.

The Board also directs AP to file updated TSR in the Compliance Filing based on Board determinations in this Decision.

7 OTHER MATTERS

7.1 Peak Demand for Cost Allocation and Rate Design

AP indicated that it used two types of peak demands for the purpose of the Application, namely the four-hour peak demand and the one-hour peak demand. AP noted that the four-hour peak demand was used for system design and cost allocation purposes and the one-hour peak demand was used only for the purpose of calculating rates (billing units) for Distributing Companies.

Table 12 for Distributing Companies shows:

- the existing demand based methodology for system design, cost allocation and rate design/billing
- AP's proposed demand based methodology for system design, cost allocation and rate design/billing
- Interveners' proposed demand based methodology for system design, cost allocation and rate design/billing

Table 12. Application of Peak Demand for Distributing Companies

	System Design TJ/day	Cost Allocation TJ/day	Rate Design and Billing TJ/day
Existing Methodology (Decision 2001-097)	4-hour peak	4-hour peak	24-hour peak
ATCO Proposed	4-hour peak	4-hour peak	1-hour peak
Calgary Proposed	4-hour peak	24-hour peak	24-hour peak
CG Proposed	4-hour peak	24-hour peak	24-hour peak
CCA Proposed		50% Non-coincident peak demand and 50% energy	

Table 13 shows AP's forecast of 24-hour, four-hour and one-hour demands for 2004.

Table 13. Delivery Peak Demand

ATCO Pipelines	24-Hour Demand TJ/day	4-Hour Peak Demand TJ/day	1-Hour Peak Demand TJ/day
Total Distributing Companies South	1041	1115	1137
Total Distributing Companies North	1216	1321	1343
Total Distributing Companies North and South	2257	2436	2480
Total Industrials	768	768	768
Total Other Pipeline Deliveries	90	90	90
Total System Demand North and South	3115	3294	3338

Views of the Applicant

AP submitted that four-hour demand was its primary allocation factor because, as the basis of system design to virtually all facilities, except in a few cases for the facilities directly upstream of Distributing Company facilities, it was the best measure of cost causation.

AP submitted that four-hour demand was used to allocate costs to all five customer groups: Distributing Companies; Industrials; Other Pipeline Deliveries; Producers and Other Pipeline Receipts.

AP submitted that the four-hour period for pipeline system design reflected customer demand profiles and significant operating experience. AP indicated that Distributing Company or FSU customers typically have a four-hour peak beginning by 7:00 a.m., Industrial customers typically have steady within day flow rates and Producer customers have a relatively flat profile. Therefore, AP submitted that the allocation of general system facilities to customer groups utilized a four-hour basis.

AP also submitted that the one-hour peak demand was used for rate calculation purposes for Distributing Companies because it was the design service requirement in the current TSA between AP and AG and was the basis of Rate FSU.

With approval of the Application as filed, AP indicated that the twenty-four hour billing demand would no longer be required.

AP submitted that whether a four-hour peak demand or a one-hour peak demand basis was used for the FSU billing determinant, the result would only be a change to the FSU rate, as the revenue collected from Distributing Companies would not change.

With respect to FGA's submission that a four-hour peak demand was not a design criterion but instead an operational concern, AP submitted that this comment was inconsistent with statements made by FGA on the record of this proceeding where FGA acknowledged that the "point by point" demand data was essential for system design, and that the one-hour and four-hour peak demand data could be accepted if it was applied universally to all customers and rate classes. AP also submitted that FGA further acknowledged during the hearing that a pipeline company should design its system to meet the peak hour demand of all its customers, including

Distributing Companies. Finally, AP submitted that FGA acknowledged that cost causation was an appropriate basis to allocate costs.

With respect to FGA's submission that a four-hour peak demand was not a design criterion since, at worst, it was merely the product of the one-hour peak multiplied by four, AP submitted that FGA was incorrect. AP argued that it had demonstrated what the differences were between the four-hour and the one-hour peak demands for Distributing Companies. AP indicated that its general facilities were designed to a four-hour peak demand and that larger pipe could utilize line pack to deliver the larger one-hour peak demand. AP also indicated that the formula to calculate four-hour versus one-hour peak demand was provided in Exhibit 002-07(c) – AP response to Supplemental BR-AP-27.

AP submitted that FGA attempted to link the proposed balancing of accounts on a daily basis with the four-hour and one-hour peak demand. AP argued that these issues were not related and that account balancing can be on a monthly, daily or hourly basis regardless of the pipeline design criteria.

In response to FGA's submission that there was an inconsistency between the peak demands filed in the Phase I Application and those in Phase II, AP submitted that billing units were properly a Phase II matter. AP argued that the billing units in the Phase I Application properly utilized the rates and bases previously approved by the Board in Decision 2001-097 and subsequent compliance filings. AP indicated that it included the AG one-hour peak demands as information in its Phase I Application.[105] AP also indicated that it filed the TSA between AG and AP, which dealt with the change to one-hour peak demand. AP also noted that in Decision 2003-100, the Board confirmed that it would address the change to a one-hour peak day design (for billing purposes) as part of the Application.[106]

In regard to FGA's statement that the OPR peak demand was an inconsistent blend of daily Industrial and one-hour Distributing Companies peak demand, AP submitted that it demonstrated that the four-hour peak demand was consistently used for all customer groups for cost allocation purposes. AP argued, that since the calculation of OPR was based on the four-hour peak demands of Distributing Companies, Industrials and Producers, OPR peak demand was also a four-hour peak demand forecast, and not an inconsistent blend of peak demands as suggested by FGA.

With respect to FGA's claim that the one-hour peak demand supplied by AG was a theoretical number based on an arbitrary gross up of daily demand by 10%, AP submitted that this was not arbitrary and argued that the Distributing Company peak demand evidence demonstrated an actual one-hour peak demand that was 10% greater than daily demand.

With respect to FGA's suggestion that Distributing Companies line pack would reduce their peak demand requirements from one-hour peak demand, AP submitted that FGA failed to present any quantification of the impact of line pack. AP argued that the Distributing Companies understand their system design and it was incumbent on them to incorporate their line pack adjustments into their one-hour peak demand requirements provided to AP.

[105] Phase I Application, Section 5.1.
[106] EUB Decision 2003-100 (December 2, 2003), page 160.

In response to FGA's claim that the load profile of rural delivery stations was unlikely to match that of an urban, primarily residential, delivery station, AP submitted that FGA declined to provide its within-day diversity[107] and provided no evidence in this proceeding to support a within day diversity for Distributing Companies serving rural customers that was different from those serving urban deliveries. AP argued that the only evidence on the record on the within day diversity for Distributing Companies was that provided by AG.

In response to CCA's submission that it was appropriate to design a transportation system on the basis of forecast non-coincident peak, AP submitted that CCA presented no evidence to support its recommendations and did not file information requests or cross-examine the AP panel on these issues. AP argued that it was obligated to honor the peak demands of all customers by designing and operating its pipeline systems to meet their coincident peak design requirements.

With respect to CCA's recommendation that costs be allocated based on a maximum of 50% weighting of non-coincident peak demand and at least 50% energy, AP submitted that the coincident four-hour peak demand design of the pipeline system and cost causation were an appropriate basis for the allocation of costs to customer groups in the COSS. In addition, AP argued that CCA's illustrations[108] regarding transmission assets were not relevant to this issue of cost causation.

With respect to CCA's comment that the use of –40 degrees was excessive, AP submitted that this comment was misdirected toward AP. AP argued that it does not design its systems to a specified temperature and that individual Distributing Companies typically use temperature for system design. AP indicated that it only required one-hour peak demand nominations from its Distributing Companies customers.

In response to CCA's submission that AP has complicated Distributing Companies peak demand when describing the 27% load factor as a rule of thumb that was used to calculate demand, AP indicated that the CAL-AP-2(a) Addendum showed that the 27% load factor was used to estimate throughput from known peak demand values for directly assigned Distributing Company assets and not the reverse, as described by CCA.

In regard to CCA's assertion that it was inappropriate to calculate demand on a point specific basis, AP submitted that the nomination of peak demand by individual delivery point was a fundamental requirement for pipeline design and a requirement that transcends all customers and all customer groups. AP argued that CCA's request to have Distributing Companies provide peak demand on a pooled basis was contrary to efficient pipeline design and good utility practice. AP submitted that the total peak demand should also equal the sum of its parts, otherwise it was meaningless and impossible to verify.

AP submitted that the four-hour peak demand should be used to allocate costs to all customer groups. AP requested that the Board approve this allocation methodology as filed, for cost allocation purposes. AP also requested approval of a one-hour peak demand as the billing unit for Distributing Companies.

[107] Exhibit 011-02 – FGA response to AP-FGA-8(a); T10 page 1079, line 20 to page 1081, line 9.
[108] CCA Argument, p. 6, commencing at line 3.

AG Peak Demand

With respect to the AG peak demand, AP indicated that AG provides only a one-hour peak demand to AP.

AP submitted that the Distributing Company demand typically has two peaks in its within day demand; one occurs in the morning period around 7 a.m. and the other occurs in the early evening around 6 p.m. AP submitted that the morning demand was generally the largest demand seen throughout the day and in its peak hour was approximately 10% higher than the average daily demand.

AP noted that AG provided the base data and calculation methodology used to determine the 2004 peak demand values at one North and South high pressure tap. AP also noted that further examples showing the peak days of Edmonton and Calgary for the past three winters were provided and one example showed a one-hour demand that exceeded the 24-hour demand by greater than 10%.

Industrial and Producer Demand

With respect to industrial and producer demand, AP submitted that these customers contract for their daily demand requirements. AP argued that the four-hour peak demands for Industrials and Producers was proportional to their 24-hour peak demand.

In response to Calgary’s comments on AP’s use of 130 TJ/day of Carbon storage deliverability, AP argued that the 130 TJ/day Carbon to Calgary flow was relevant to the OPR calculation because it represented the peak volumes that have been received on AP’s system from Carbon storage or NGTL through the Carbon to Calgary pipeline, to satisfy the peak demand of South delivery customer groups, as indicated in actual peak day flows for each month over the last four winters. AP submitted that there was no basis for Calgary’s requested adjustment to the peak demand.

AP disagreed with Calgary’s claims that it was inconsistent in its approach for allocating costs amongst the customer groups. AP also disagreed with Calgary’s claim that costs should be allocated to the Distributing Companies customer group based on the Distributing Companies 24-hour peak demand.

AP noted that Calgary derived industrial and producer annual load factors but AP did not agree with its conclusion that annual load factors equate to within day demand diversity for these customer groups. AP submitted that it provided evidence that indicates industrials' and producers' services flow at relatively steady rates.

AP disagreed with Calgary's claim that AP did not provide data that would allow a calculation of one-hour and four-hour peak demands for other customer groups beyond the Distributing Company and submitted that the four and one-hour demand for Industrial and Producer customer groups were 4/24 and 1/24 of their 24-hour demand.

AP indicated that Industrials and Producers were subject to curtailment and therefore bear the risks of any under-estimating for hourly requirements.

AP argued that the Board should disregard Calgary's attempt to shift costs to other customer groups by requesting a reduction to the peak demand for distributing companies. AP submitted that Calgary's proposal was not fair to other customer groups. AP requested that the Board approve the four-hour demand basis for cost allocation for all customer groups.

FGA Peak Demand

AP submitted that the use of 24-hour demand for FGA would go against the same rate design principles that FGA agreed to during the hearing and should be denied by the Board, as it was not fair to other customers.

AP argued that it was not appropriate for FGA to evade their responsibility for a fair share of cost by using a 24-hour peak demand for cost allocation purposes while all other customers use a four-hour peak demand.

AP requested that the Board approve 2004 one-hour peak demands of 44 TJ/day in the North and 15.4 TJ/day in the South for Gas Alberta as provided by FGA, using AP's factors. AP indicated that this one-hour peak demand was calculated based on 24-hour peak demands agreed to by AP and FGA. AP submitted that, while FGA does not agree with the one-hour peak demand number, it did not provide any other four-hour or one-hour peak demand information. AP argued that this estimate of the one-hour peak demand was more accurate and fairer to other customers than the 24-hour peak demand that FGA proposed. AP indicated that the four-hour peak demands for Gas Alberta that would be used for cost allocation purposes were 43.2 TJ/day for the North and 15.1 TJ/day in the South based on the formula provided in Exhibit 002-07(c) – AP response to Supplemental BR-AP-27.

AP noted that it agreed that the 24-hour peak demands proposed by Gas Alberta (North and South) were reasonable as a base to calculate the four-hour and one-hour peak demands and, upon approval by the Board, AP indicated that this would be reflected in the AP Phase II Compliance Filing.

Straddle Plant Peak Demand

AP indicated that peak demand for Industrials included 53 TJ/day for straddle plants based on average daily volumes. AP submitted that IGCAA was the only intervener that disagreed in principle with including the 53 TJ/day in the Industrial peak demand but it provided no reasons for the disagreement in principle. AP argued that IGCAA acknowledged that it was economically indifferent whether these volumes were included in the Industrial peak demand.

AP submitted that revenue from SPD was directly allocated to Industrial customers and therefore, there was no impact on the Industrial demand rate. AP submitted that the inclusion of the 53 TJ/day of straddle plant demand with the industrial peak demand was reasonable and AP requested approval by the Board.

Views of the Interveners

CALGARY

Calgary noted that AP professes to design its system on a four-hour basis; yet it continues to use 24-hour integrated demands for cost allocation and billing for Industrial and Producer classes as compared to four-hour demands for a portion of the Distributing Companies class for cost allocation and one-hour demands expanded to 24 hours for the AGS billing demand. Calgary argued that if the AP system is driven by four-hour demands, then four-hour demands should be used for all classes for all purposes. If AP desires to retain the currently used 24-hour billing demands, Calgary submitted that it should recognize the intra-day diversity for all classes of service in determining the billing demand and use the 24-hour demand for billing and cost allocation purposes. Calgary submitted that the importance of this discrepancy was manifested in a cost shift of $4.734 million for the Distributing Companies class.

Calgary submitted that the calculated utility billing demand was overstated when compared to demonstrated performance and the use of the diversified daily demands of the Industrial and Producer classes.

Calgary submitted that the Distributing Companies class should be treated the same as the Industrial and Producer classes with the same demand being used for both cost allocation and rate design because both fairness and equity demand that all classes be treated equally.

Calgary submitted that AP's determination of the OPR demand was inaccurate because AP only accounted for 130 TJ of Carbon deliverability instead of the amount approved in Decision 2004-022.[109]

CCA

CCA submitted that the use of peak demand was an inappropriate method to allocate all costs of a transmission system. CCA indicated that it was appropriate to design a transportation system on the basis of forecast non-coincident peak since it was unlikely that all customers or customer groups would peak at the same time. CCA submitted that the use of energy reflected usage of the transmission system. CCA submitted that a weighting of energy and non-coincident peak demand was a more appropriate method of allocating joint system costs and therefore, costs should be allocated based on a maximum of 50% weighting of non-coincident peak demand and at least 50% energy.

CCA submitted that it was not appropriate for AP to use a "rule of thumb" to determine a load factor to calculate demand and was concerned that AP and/or AG over-forecast the distribution peak demand. CCA submitted that AP used this to attempt recovery of additional costs associated with the low load factor or high peak.

CCA considered that the use of -40 degrees was excessive to determine demand to allocate costs and noted that it was not appropriate particularly for the Southern system where temperatures were generally milder than the Northern system.

CCA submitted that it was inappropriate to calculate demand on a point specific basis and argued that demand, if utilized, should be calculated on a total basis for the utility based on a non-coincident peak because any other method would simply result in an excessive amount of costs being allocated to distribution customers.

CCA supported the position of the CG on its proposals to adjust the load factor for industrial and producers.

[109] In Decision 2004-022, the Board approved a maximum monthly withdrawal of 265 TJ per day for each day of January from the Carbon Storage facility for AGS.

CCA submitted that AP should be directed to analyze the degree to which local distribution company line pack was available to assist in any concerns around the low load factor of the LDC utilities.

CG

The CG noted Calgary's statement that the demand measure AP used to allocate system costs to distribution companies was different from that used to allocate system costs to other rate classes. In response to Calgary's identification of annual load factors for industrials (79%) and producers (88%), CG indicated that in its assessment, less than a 100% load factor means a 24-hour demand for industrial and producer companies would likely be lower than a four-hour demand.

CG submitted that the four-hour peak demand should be used for allocation of system related costs to all customer classes because this demand was the basis for system design purposes. Given that four-hour peak demand information for all customer classes may not be available for this proceeding, CG supported Calgary's recommendation that the allocation of system costs should be consistent for all classes which means use of the 24-hour peak demand for all classes for the purposes of this proceeding.

CG indicated that transmission system planning should reflect the coincident peak demand and submitted that the Compliance Filing should ensure that the data for all classes are on a coincident peak basis.

CG noted that AP uses the one-hour peak demand as the billing determinant for the FSU rate class which reflected the basis on which nominations are made by the distribution companies. CG submitted that this use of nominations does not recognize diversity between distribution company customers in relation to system coincident peak.

With respect to the billing determinant, CG considered that the use of nominations versus the use of a coincident peak demand was an intra class issue. CG indicated that given the temperature sensitive nature of distribution company loads, it assumed there would be little intra class diversity between different distribution company customers within this class, with the exception of seasonal customers such as irrigation service. Therefore, the CG did not object to the AP proposal as long as the coincident peak demand used as the distribution company billing determinant reflected the contribution to this coincident peak by each utility customer class. CG submitted, however, that AP should be directed to address the appropriateness of using nominations as the billing determinant for this class, in light of peak demand diversity within the class, at the time of its next GRA.

FGA

FGA submitted that the four-hour and one-hour peak demands were inconsistent measures to perform a COSS and then to bill customers according to the COSS. FGA argued that this inconsistency would generate an error in recovering revenue requirement in favour of AP.

FGA submitted that a four-hour peak demand was not a design criterion since, at worst, it was merely the product of the one-hour peak multiplied by four. FGA submitted that the four-hour peak was an operational concern, intended to balance receipts and deliveries of physical volumes on NGTL or other pipeline systems flowing through the AP system. FGA submitted that performing a COSS using one measure of demand (four-hour peak) and then billing by an even more stringent demand (one-hour demand) would result in over-recovery of allocated revenue requirement from the Distributing Companies class.

FGA submitted that the four-hour and one-hour peak demands were also inconsistent with the manner in which customer classes other than the Distributing Companies class were currently billed, and how their costs were allocated within AP's COSS. FGA argued that, if the Board allows this inconsistency in peak demand to creep into AP's COSS, this would have the effect of shifting costs to the Distributing Companies class without any increase in the responsibility of these customers for these costs, in terms of cost causation.

Although the matter of load balancing has been deferred to negotiations, FGA submitted that the Board should not approve a billing demand that was different from and more stringent than the operating procedures being proposed by AP for balancing these same accounts.

FGA submitted that there was further inconsistency in that the peak demands filed in the AP Phase I proceedings were daily peak demands and revenues were based on those demands. FGA submitted that, if Phase I was premised on daily demand figures, Phase II should proceed on that basis as well.

FGA noted that AP stated that the reason for using the one-hour peak was because its system was designed to deliver gas at the hourly peak demand. FGA also noted that AP stated it allocated costs to the OPR class of service based on the sum of four-hour demands at NGTL receipt points. FGA also noted that Industrial customers and Distributing Company customers could also nominate gas from the NGTL system. Therefore, FGA submitted that the OPR demand must be an inconsistent blend of daily Industrial demands and one-hour Distributing Company demands. FGA submitted that, since the NGTL receipt facilities were, presumably, designed on the same basis as the rest of the system in order to physically transport gas to customers on the AP system, AP was inconsistent in applying its design criteria only to the Distributing Company class.

FGA submitted that contradictions abound in the use of daily, four-hour and one-hour peaks in the ATCO system. FGA submitted that ATCO Gas actually provided daily demands grossed up by an arbitrary 10% factor and asserts that these are one-hour peaks. FGA indicated that Gas Alberta also measures only daily peaks, although Gas Alberta may be able to measure hourly peaks.

Whatever the rationale for the one-hour peak, FGA submitted that AP measures only daily peaks, not hourly peaks and argued that the one-hour peak was currently a theoretical number, not an actual measurement at any delivery point. FGA submitted that AP has used a rule-of-thumb conversion factor of 110% (or 1.1) to convert the 24-hour peak to a one-hour peak based on support from SCADA readings taken at its Calgary Gate station.

FGA indicated that it did not consider that the 1.1 factor was an appropriate estimation of one-hour demand for the distributing companies it serves because the measurement at Calgary's gate stations, whatever the accuracy of these measurements may be, was not applicable outside Calgary. FGA also submitted that the load profile of rural delivery stations was unlikely to match that of an urban, primarily residential, load delivery station due to the presence of livestock and poultry production. FGA indicated that these agricultural operations were a temperature sensitive load but were not set back at night like residential load, resulting in a more stable daily load profile for the rural distribution system.

FGA also submitted that the peak hour demand on FGA systems was also affected by the available line pack within LDC transmission and distribution systems located downstream of the AP delivery facility.

IGCAA

IGCAA indicated that, from a principle point of view, it did not believe it was appropriate to include the deemed demand[110] for straddle plant service with the peak demand for the Industrial service class. IGCAA indicated that, while in the current case it might be economically indifferent between AP's proposal and AP's suggestion that straddle plant revenue should be allocated to all service classes if straddle plant demand is excluded from the Industrial class demand, it was not clear that this would always be the case.[111]

Views of the Board

Peak demand for various customer groups is used for system design, cost allocation, rate design and billing purposes. The Board notes that AP used a four-hour peak demand for system design and cost allocation purposes and a one-hour peak demand for calculating rates and billing units for Distributing Companies. In Decision 2003-100, the Board indicated that it would address the change to a one-hour peak day for billing purpose as part of the Phase II proceeding

The Board recognizes that customer groups use different starting points to determine their individual peak demands. In the utility group, AG has nominated peak demand for each tap using a one-hour maximum throughput forecast, whereas FGA has forecast the peak demand for each tap based upon an extrapolation of daily readings during a cold period of time. The peak demand forecast for the Industrial class was based upon the nominated demand (twenty-four hour daily demand).

System Design and Cost Allocation Demand

The Board notes that general system facilities are designed to deliver the average four-hour peak demand and that the line pack available in the larger diameter pipe can usually supply a larger one-hour peak for distribution customers. The Board accepts the evidence of AP that its pipeline system must be designed and built to deliver the average four-hour peak demand to meet the service reliability requirements of all of its customers. Therefore, the Board considers that, generally, the four-hour peak demand is the appropriate basis to design the integrated system pipelines. Accordingly, it would also be the appropriate cost driver for allocating general system costs, non-standard expenses and revenues, Salt Cavern expenses, and some of the income credits.

Rate Design and Billing Demand for Distribution Companies

For Distributing Companies, the Board notes that AP proposed to use a one-hour peak demand for rate design and billing purposes. The Board is of the view that use of the one-hour peak demand for rate design and billing purposes is not necessary and creates added complexity and confusion among parties when analyzing rates and costs. Therefore, for purposes of simplifying

110 53 TJ/day
111 IGCAA Opening Statement.

the approach and providing clarity, the Board considers that the four-hour peak demand as determined for the system design and cost allocation purposes, should also serve in future as the rate design and billing determinant for the Distribution Deliveries service class.

The Board recognizes that, in the TSA between AG and AP, the parties agreed that the one-hour peak demand would be used for billing purposes. AP indicated in its evidence[112] that the TSA was clearly dependent on tariffs and changes approved by the Board, and was a high level document not intended to be outside Board approved terms and conditions. Therefore the Board considers that the TSA should be revised to reflect the change to the use of a four-hour peak for billing purposes.

The Board also accepts AP's evidence, as discussed below, that the average four-hour peak is in the range of eight percent higher than the average 24-hour demand on a peak day. Therefore, the Board directs AP, in its Compliance filing, to revise the billing peak to equal the system design peak as adjusted for use of a four-hour demand period, for all members of the Distribution Companies Deliveries service class, and to further reflect other changes determined by the Board for Gas Alberta and the OPR revised peak as set forth below.

Determination of Four-hour Demand for Service Classes

Utilities

AG

AP proposed that the four-hour and one-hour peak demand for AG in the North and South zones should be based upon the one-hour nominated demands provided by AG as shown in BR-18 Addendum, the derivation of which was detailed in Supplemental BR-26 Addendum.

In addition, AP presented evidence in Exhibit 35-18, listing the throughput for a single day in January for each of the years 2002, 2003 and 2004 for each of the North and South zones. On the basis of Exhibit 35-18, the Board accepts AP's recommendation that the average four-hour peak is in the range of eight percent higher than the average demand on a twenty-four hour peak day. The Board notes that the data supplied in Exhibit 35-18 is based upon single point observations for one day in each of three years for each of the North and South zones. Despite the limited nature of this data, for the purposes of this Decision, the Board will accept the results of the data and considers that, for utility type consumption patterns, the average four-hour peak demand appears to be eight percent above the 24-hour average peak demand.

However, the Board is not satisfied that a comprehensive study and adequate data was provided to fully support the peak demand relationships provided in this Application. Therefore, the Board directs AP, in its next GRA, to file a comprehensive study with adequate data to support the peak demand relationships for all customer classes.

With respect to AG peak demand data, the Board expects that AP will request such data and back up study to justify the peak demand nominations provided to it and file that data in its next GRA to provide the justification for the peak demands used for cost allocation and rate design purposes.

[112] AP Rebuttal P 16

Gas Alberta

The Board notes that the evidence of Gas Alberta indicates that its load factors are somewhat different from the AG load factors.[113] Despite the differences in load factor, the Board considers that Gas Alberta customers are generally heating load customers served through a distribution network and, therefore, Gas Alberta should be included in the Distributing Companies service class. The Board considers that AP will use updated daily load consumption data in its comprehensive study to be filed in the next GRA that will include Gas Alberta consumption patterns, and that the resulting update will properly reflect the weighted average consumption patterns for the Distributing Companies service class as a whole. For the purposes of this Decision, the Board accepts the peak demand amount supplied by Gas Alberta in Exhibit 011-05 and agreed to by AP[114] for the twenty-four hour demand. However, for the purposes of system design and billing demand, the twenty-four-hour demand shall be increased by eight percent to an equivalent four-hour peak demand. For the purposes of establishing a peak demand for the test years 2003/2004, the Board has determined that the four-hour peak demand for system design, rate design and cost allocation purposes shall be as shown in Table 14 as follows:

Table 14. Gas Alberta Peak Demand 2003/2004

	Gas Alberta North	Gas Albert South
Twenty-four hour peak demand supplied by Gas Alberta[115] (TJ/day)	40.0	14.0
Factor to convert twenty-four hour to four-hour	1.08	1.08
Gas Alberta Demand for system design, cost allocation and rate purposes (TJ/day)	43.2	15.1

Industrial Peak Demand

AP proposed that the peak demand for Industrial customers served under FSD should be the sum of the nominated demand. AP provided an intra-day demand profile for APS FSD customers[116]. AP noted that the BP&P permit AP to curtail the demand of industrial customers to their nominated demand.

The Board accepts AP's 24-hour peak demand for FSD customers (excluding non-standard contracts) as the sum of the nominated demands. The Board also accepts AP's position that the Industrial customers generally exhibit stable flow rates. Due to the curtailment provisions, which limit the demand to the nominated demand, the Board agrees that the average 24-hour demand and average four-hour demand stated on a 24-hour basis should be the same amount. Therefore, no increase is required in calculating a four-hour demand amount for the industrial demand to account for intra-day peak variations. For these reasons, the Board considers that the use of the 24-hour demand for billing purposes for the Industrial class will not cause a shift in cost responsibility nor generate errors in recovery of revenue requirement. Therefore, the Board considers that the continued application by AP of 24-hour billing demand for the Industrial class remains appropriate, including the billing methodology described in the proposed FSD rate schedules.[117]

113 Exhibit 011-04 P18 & 19
114 Exhibit 002-010 P27
115 Exhibit 011-05
116 CAL-AP02-23
117 GRA Application Section 3.0 Rate FSD

Producer Peak Demand

As with the Industrial class, the Board accepts AP's position that the Producers generally exhibit stable flow rates, and that their four-hour demand for design and cost allocation purposes will be the same number as their 24-hour contract demand. For this reason, the Board considers that the continued use by AP of the 24-hour contract demand for billing purposes for the Producer class should not cause a shift in cost responsibility nor generate errors in recovery of revenue requirement. Therefore, the Board considers that the continued application by AP of 24-hour contract demand for the Producer class remains appropriate as requested in this Application.

OPR

The Board accepts, for the purposes of this Decision, AP's peak demand deliverability amount of 130 TJ/day[118] as the amount that is available through the Carbon to Calgary pipeline and the amount of 530 TJ/day as the amount available from Salt Cavern storage. Therefore, the amount delivered from NGTL though other pipeline receipts would provide the residual requirements to balance deliveries and supplies.

OPD Demand

For the North system, the Board accepts the amount of 90 TJ/day for OPD as being the contract demand for Alliance and MIPL.

Straddle Plant Peak Demand

With respect to the inclusion of the deemed demand for straddle plant service with the peak demand for the North Industrial service class, the Board agrees with IGCAA that in principle, it was not appropriate. Even though AP proposed to allocate the SPD revenue to the Industrial service class, the Board does not consider it appropriate to increase the expenses allocated to the Industrial service class by including a deemed demand for straddle plant service if the straddle plants would not pay the resulting FSD demand rate. The Board notes that AP proposed to set the SPD rate equal to the OPDC rate less the impact of removing Salt Cavern expenses and Other Directly Allocated expenses. Therefore, the Board directs AP to reduce the Industrial four-hour peak demand by 53 TJ/day. Given this determination, the Board does not consider it appropriate to allocate the SPD revenue to the Industrial class directly. Therefore, the Board also directs AP to allocate the revenue resulting from SPD service to all service classes based on four-hour peak demand. The Board's determination with respect to the SPD rate is discussed in Section 5.6.

Peak Demand Summary

Table 15 shows the Board's peak demand determination for the various customer groups to be used for purposes of design, cost allocation, and billing purposes.

[118] CAL-AP02-15

Table 15. Peak Demand

Distributing Companies 4-Hour Peak	North Demand TJ/day	South Demand TJ/day
ATCO Gas	1233.8	1097.3
Gas Alberta	43.2	15.1
AltaGas Utilities[119]	22.0	
Rate 5	11.0	
Wainwright	6.0	
Total Distributing Companies 4-hour peak	1316.0	1112.4
Industrials (Standard) FSD 24 hour peak[Note 1]	609	106.0
Other Pipeline Deliveries OPD 24 hour peak	90.0	0
Subtotal Delivery	2,015	1218.4
Non-standard contracts 24 hour peak[120]	386.0	57.0
Total Delivery Demand	2,401	1275.4
Other Pipeline Receipt OPR	968	766.4
Producers FSR	903.0	296.0
Non-standard Receipt		83.0
Delivery from Storage	530.0	130.0
Total Receipt	2,401	1275.4

Note 1 – The billing demand for the Industrial class will be determined as described in the Rate Schedules (Rate FSD Pages 9 – 11 of 38). The billing demand for 1, 3 and 5 year contracts amounts to 599 TJ/day.

7.2 Non-Standard Contracts

In Decision 2003-100, the Board approved seven[121] new non-standard contracts filed by AP, in addition to the four[122] existing non-standard contracts. In this proceeding, AP proposed that all customers would share the net benefit of non-standard contracts.

Views of the Applicant

In the Application, AP proposed to allocate expenses and revenues associated with the non-standard contracts to the five service classes based on four-hour peak demand.

AP submitted that its justification for non-standards, including the rates, was approved in the Phase I Application. AP argued that as long as the incremental revenues exceeded incremental costs, there was a benefit to all customers.

AP provided two examples where there was currently a mismatch between the customer groups that receive the revenues/benefits and the customer groups that pay the costs of the non-standard contracts. AP submitted that with the EnCana non-standard contract, the ODC went to the EDA and the benefit of reduced rates went to other customers, while with the Calpine non-standard

[119] FGA-AP02-21

[120] Table 2.6-1 and 2.7-1 Pages 6.1

[121] North - Agrium Fort Saskatchewan and Redwater, ATCO Power Valleyview, Dow Chemical Fort Saskatchewan, Shell Fort Saskatchewan, Sherritt Fort Saskatchewan and TransGas FSD (replaced with OPDM). South - Calpine Calgary Energy Centre.

[122] North - Devon Grizzly Bear Creek. South - Dow Chemical Chain Lakes (Prentiss), EnCana Agrium Carseland and NOVA Chemicals Joffre (expires October 31, 2003).

contract, benefits of an increased on-system market went to the EDA through reduced ODC and the asset related and O&M costs were allocated to other customer groups.

AP submitted that the benefits of non-standard contracts should be appropriately shared by all customers, and that the appropriate sharing of the benefits cannot occur if the costs of non-standard contracts were only allocated to the Industrial and Producer service classes as proposed by CG, or included in a separate service classes as proposed by the FGA. In addition, if costs were allocated to a separate service class, AP submitted that the net shortfall would still have to be allocated to all service classes, so that revenue generated from rates would equal the approved revenue requirement. AP argued that the net result would be the same as AP's proposed method. AP submitted that the sharing of the benefits of non-standard contracts by all customers should be the same for all non-standard contracts.

In response to FGA's comment that non-standard costs should not be charged to Distributing Companies, AP submitted that it was not clear whether this removal also applied to the income credit for non-standard revenues. AP argued that FGA was seeking all the benefits of non-standard revenues but none of the non-standard costs.

In response to FGA's statement that AP has not provided any evidence that the benefits are related to allocated costs, AP submitted that this was incorrect and contrary to the evidence provided on the EnCana and Calpine non-standard contracts.

AP submitted that there was no basis for the FGA's request to re-evaluate the Calpine contract, in that the exchange service mechanism was not being phased out (being the rationale for re-evaluation in Decision 2003-100). AP indicated that the OPDC rate would be charged on nominations that were transferred to NGTL through AP's NIT account in the same manner as the exchange fee.

With respect to IGCAA's suggestion that all firm Producer receipts would be converted to non-standard contracts if ODC were allocated as general system costs, AP submitted that this suggestion was illogical since on-system receipts were related to a receipt service while ODC were related to a delivery service to other pipelines. AP indicated that non-standard contracts were contracts at rates that were not included in AP's standard schedule of rates and which require specific Board approval. AP argued that the FSR rate was a standard rate and therefore, should not be considered as a non-standard rate.

AP submitted that its proposed methodology matched the benefits and costs of the non-standard contracts and all customer groups would share the net benefit.

Views of the Interveners

CALGARY

Calgary indicated that it continued to support the Board's findings on non-standard contracts as set forth in Decision 2003-100. Calgary also indicated that, for the purposes of the AP Phase II proceeding, it has accepted the revenue credit concept to the COSS as proposed by AP for the non-standard contracts.

However, Calgary urged the Board to direct AP to provide, in a Compliance Filing or in its next GRA, a COSS that included the non-standard contract as a stand alone class of service or as part of the Industrial/Producer classes. Calgary submitted that, by including the non-standard contracts in the COSS process, a fair and transparent evaluation of the costs and benefits of non-standard contracts can be undertaken, and only through this process can the real validity be established for the use of the revenue credit concept as compared to a full COSS process for non-standard contracting.

CCA

CCA supported the CG position on this issue.

CG

CG submitted that if the FSR or FSD rates, excluding the non-standard contracts, do not recover allocated and direct assigned costs, then AP was, by default, proposing rates that were less than unity. CG argued that, given AP's proposal to recover costs through the rates at 100%, any shortfall in FSR or FSD costs caused by non-standard contracts, should be "absorbed" by the respective customer classes, not all other customer classes.

CG submitted that, while AP argues that the "net benefit" would be shared by all customer classes, the contra was that any "net costs" would also be shared. CG argued that AP's example of the Calpine contract demonstrated AP's convoluted approach to this issue.

CG supported the Calgary recommendation that the Board should direct AP in its Compliance Filing to have a separate rate class for non-standard contracts or include the non-standard contracts in the respective Producer/Industrial rate classes.

FGA

FGA submitted that AP did not provide any evidence that benefits of non-standard contracts were directly related to allocated costs, and argued that there were several problems associated with AP's allocation of non-standard costs:

- The COSS was unnecessarily complicated and masked the true cost of service for any customer;
- There was a disconnect between costs in the COSS and the benefits of a particular service;
- FGA's view was that the Board did not direct the sharing of all non-standard costs among all customers but rather the benefits for a limited number of non-standard contracts;
- Since the distributing companies have no non-standard contracts[123], AP's COSS with its plethora of reallocations, has the effect of moving costs out of the Industrial and Producer classes of service to the distributing companies.

With respect to the Calpine contract, FGA submitted that exchange service was being phased out and the rationale for the Board acceptance of this contract had disappeared.

FGA submitted that the only way to resolve all the identified problems was to remove the redistribution of the non-standard contract costs from the COSS and determine the actual costs of providing service to each customer class.

[123] FGA-AP-18

IGCAA

IGCAA agreed that non-standard contracts provided a net benefit to all shippers on the AP system and therefore the costs and the revenue attributable to non-standard contracts should be allocated to all shippers.[124]

However, IGCAA indicated that the same logic used to allocate the benefits and costs of non-standard contracts should not be used to allocate oversupply delivery costs as general system costs, as there was no evidence that the receipt revenue associated with incurring ODC would not otherwise be received by AP. IGCAA submitted that if AP allocated ODC as general system costs, it would be converting all firm producer receipts on its system to non-standard contracts.

Views of the Board

The Board notes that in Decision 2003-100 it approved certain non-standard contracts for the reasons stated therein, including that they provided a net benefit to the AP system. The Board continues to rely on the original submissions related to each non-standard contract wherein the data and results indicated that an overall net benefit would accrue to all shippers on AP's system from having the non-standard contract volumes on the system. The Board notes Calgary's continued support of the non-standard contracts and IGCAA's position that the non-standard contracts provide a net benefit to all shippers on the AP system and therefore the costs and the revenues attributable to non-standard contracts should be allocated to all shippers. The Board agrees and is prepared to approve the allocation of costs of the non-standard contracts to all service classes as proposed by AP in its COSS. The Board also approves the allocation of revenues associated with the non-standard contracts to all service classes, as proposed by AP in its COSS.[125]

The Board considers that the benefits of non-standard contracts can alter over time, and agrees with Calgary and the CG that a COSS which includes the non-standard contracts as a stand alone class of service is the only way to observe the specific impacts of these contracts on the system and on all customer groups. Therefore, the Board directs AP in its next GRA, to provide a COSS which isolates the impact of non-standard contracts by including them as a separate class of service. Further the Board directs that AP address the impact and differences in results in the COSS if the non-standard contracts were specifically included within the Industrial and Producer classes.

7.3 OPR and OPD Deferral Accounts

AP proposed to use deferral accounts for OPR and OPD in both the North and South. Within the OPR deferral accounts, AP proposed to include actual less forecast (variance) numbers for the components shown in Table 16. Within the OPD deferral accounts, AP proposed to include actual less forecast (variance) numbers for some of the components and actual numbers for other components as shown in Table 17.

[124] Transcript Vol. 11, page 1277.

[125] AP proposed to allocate non-standard expenses and revenues to the service classes based on 4 hour peak demand.

Table 16. Other Pipelines Receipts Deferral Account

Item	Category
OPR Commodity	Revenue (actual less forecast)
NGTL FT-A	Cost (actual less forecast)
NGTL MAV	Cost (actual less forecast)

Source: Application, Section 2, p. 31 of 32

Table 17. Other Pipelines Deliveries Deferral Account

Item	Category
Summer[126] IT/OR Receipt Toll in Excess of 100% FSR Toll	Revenue (actual)
OPDC Toll	Revenue (actual less forecast)
NGTL Receipt Toll and Fuel Charges Collected from OPDM	Revenue (actual)
Oversupply Delivery Costs[127]	Cost (actual less forecast)

Source: Application, Section 2, p. 32 of 32

With respect to the OPR deferral accounts, AP proposed to include the same components approved in Order U2003-401. In Order 2003-401, the Board also approved the following process to be followed for administration of the OPR deferral accounts:

> Forecast FT-A and FCS MAV charges approved by the Board for 2003 and 2004 with respect to the 2003/04 General Rate Application (GRA) Phase I compliance filing will be credited to the deferral account. Forecast OPR revenue for 2003 and 2004 approved by the Board in the GRA Phase II compliance filing will be debited to the deferral account.
>
> Actual FT-A and FCS MAV charges will be debited to the deferral account and actual OPR revenue will be credited to the deferral account. The difference between the approved costs and revenues and the actual costs and revenues will result in a surplus or deficit at the end of 2004. This balance would be carried forward, resulting in an adjustment to subsequent rates.
>
> ATCO will provide a draft report to interested parties by April 30th of the following year which would include the forecast and actual amounts for each of the FT-A charges, FCS MAV charges and OPR revenue. A final report will be provided to the Board by June 30th of that following year. If there are any unresolved issues, these will be presented with the report to the Board for resolution.
>
> Since the 2003 period is only three months and finalization of this rate in a Phase 2 Decision is unlikely until mid 2004, ATCO proposes that 2003 be included with the 2004 report.[128]

In the Application, AP proposed that the balance in the OPR deferral accounts at year-end would be brought forward to a future test year and allocated to customer classes based on OPR nominations.

126 June to September
127 Oversupply Delivery Costs are the costs of physically delivering gas to another pipeline system when the supply exceeds the demand (market) on the AP system.
128 Letter from ATCO Pipelines, dated October 20, 2003

AP proposed that the balance in the OPD deferral accounts at year-end would be brought forward to a future test year and allocated to customer classes based on four-hour peak demand.

In the Application, AP proposed to discontinue the current exchange fee mechanism in the North and South as of October 31, 2004 and through other proceedings[129], the Board has approved rate riders[130] to supplement current exchange fees[131] in order to target zero balances in the associated EDAs on October 31, 2004. The components in the North and South EDA are shown in Tables 18 and 19 respectively.

Table 18. North 2004 Exchange Deferral Account

Item	Category
Rate Rider K	Revenue
Exchange Revenue - Standard	Revenue
NGTL IT Toll	Cost
NGTL Fuel	Cost
ATCO UFG	Cost
Contingency	Cost

Source: Application 1343401, dated April 23, 2004

Table 19. South 2004 Exchange Deferral Account

Item	Category
Rate Rider K	Revenue
Exchange Revenue - Standard	Revenue
NGTL Firm Toll (Monarch)	Cost
NGTL IT Toll	Cost
Reverse 2003 Carbon Storage Credits	Cost
Credit for Carbon to Calgary Flows	Cost
NGTL Fuel	Cost
ATCO UFG	Cost
Contingency	Cost

Source: Application 1343401, dated April 23, 2004

In Application 1333099, AP proposed that any EDA balances outstanding at October 31, 2004, would be carried forward to be collected/refunded in a future period. In Decision 2004-023, the Board noted that parties did not comment on the proposal for the treatment of significant outstanding balances in the EDA after November 1, 2004, and the Board approved AP's proposal, commencing on November 1, 2004, to charge /credit the EDA balances when the total balances were in excess of $500,000 at a financing charge rate using the most-recently Board approved weighted average cost of capital for either the North or South as applicable.

[129] Application 1333099, Decision 2004-023 dated March 9, 2004 and Application 1343401, Board letters dated April 29, 2004 and June 30, 2004.
[130] North Rider K, 0.9 cents/GJ and South Rider K, 3.6 cents/GJ.
[131] North 6.0 cents/GJ and South 13.0 cents/GJ.

Views of the Applicant

AP submitted that the OPR and OPD deferral accounts were being proposed due to the difficulty in forecasting the items that it argued should be included within the respective accounts.

With respect to the annual allocation of the balance of the OPD deferral account to customer groups, AP submitted that this allocation was consistent with its proposed allocation of costs to be charged to this account.

AP disagreed with Calgary's assertion that deferral accounts for OPD and OPR service would not be necessary if demand based rates were determined to be appropriate and argued that there was a significant risk that actual OPD or OPR revenues would be materially different from any revenue forecast, due to circumstances beyond the control of AP.

In response to IGCAA's suggestion that AP should be made responsible for any ODC in excess of its forecast, AP submitted that there were many factors (other than incremental receipts) outside of AP's control that influence actual ODC, including industrials shutting down for market reasons, abnormal weather, the AP UFG/Fuel rate, the NGTL Fuel rate, the price of gas and NGTL receipt tolls.

Views of the Interveners

CALGARY

Calgary recognized that the OPR and OPD rates proposed by AP would require deferral accounts due to the estimated volumes being subject to large variances.

Calgary indicated that to the extent the Board adopted Calgary's position that OPD and OPR services should be offered as fully cost based services with stand alone rates, Calgary would support the use of deferral accounts. Calgary indicated that under its OPD proposal, as being a fully cost based service provided under stand alone rates and collected on a demand, energy or combination basis, a deferral account should be in place at least until the next GRA when further evaluations could be conducted.

Calgary submitted that, recognizing that ultimate rates for 2004 would not be determined until late 2004, the use of deferral accounts to reconcile costs and revenue for OPD and OPR services represented a relatively painless process to true up the revenue requirement to revenue collection.

CCA

The CCA supported the CG position on this issue.

CG

The CG submitted that this was another issue that would simply disappear if the receipt and delivery of inter-system gas between NGTL and AP were resolved through the use of TBO. If that situation did not come about, then in principle, the CG would support the use of deferral accounts for these costs since they clearly were difficult to predict.

IGCAA

IGCAA submitted that OPR costs attributable to NGTL FT-A charges and MAV charges were approved by the Board in AP's Phase I decision, and that proceeding did not approve any amount of ODC. IGCAA submitted that AP was asking the Board to recover over $5 million in ODC that were not even considered during its Phase I proceeding. In addition, IGCAA argued that AP was asking for the establishment of a deferral account just in case it experiences the same problem that it previously had with the EDA.

In the event that the Board accepted IGCAA's request that responsibility of ODC be assigned to nominating shippers or at least allocated to customer groups based on delivery nominations, IGCAA indicated that it would take no position on the deferral account. However, if ODC were made general system costs, IGCAA argued that it would be essential that AP be responsible for any ODC in excess of forecast, given that AP benefits from additional receipts on its system.

IGCAA submitted that AP was inconsistent in its desire not to have a deferral account on the revenue side, but to insist on a deferral account on the cost side where ODC were related to whether AP met or exceeded its revenue requirement. IGCAA argued that if AP wanted the benefit of excess revenue, it should also accept the risk of additional costs incurred in obtaining that revenue.

Views of the Board

OPR Deferral Accounts

The Board notes that AP proposed to maintain the same components in the OPR deferral accounts as approved in Order U2003-401. The Board also notes that AP continued to propose that the OPR rate only recover NGTL FT-A charges, that actual less forecast NGTL MAV expenses would go in the OPR deferral account, and that forecast NGTL MAV expenses would be recovered as part of the demand charges for FSU, FSD and FSR. The Board also notes that AP proposed to credit the revenue from the OPR rate in the COSS in order to lower the resulting demand charges. It also appears that AP has proposed to continue with the administration process it outlined in the application that resulted in Order U2003-401. Therefore, at this time, the Board is prepared accept the OPR deferral account and related administration process as filed, and as previously approved in Order U2003-401.

The Board agrees with AP that the balance in the OPR deferral accounts at the end of 2004 should be allocated to service classes based on OPR nominations. The Board expects that AP will discuss the approach for recovering or crediting the balance with its customers after AP files its draft report with customers, but prior to the submission of the final report to the Board, which should occur by June 30, 2005.

In order to maintain transparency with respect to the OPR deferral account, the Board directs AP to include the most current actual monthly balances and end-of-year forecast balances for the North and South on its website and to update the information on a monthly basis.

The Board considers that it may be more appropriate to establish a stand alone process for dealing with the OPR deferral components and to establish an OPR commodity rate that recovers all cost components in the deferral account. Therefore, the Board directs AP to file, as part of its next GRA, such a stand alone proposal so that parties can express their views. The Board is also interested in receiving parties' submissions with respect to alternative mechanisms to adjust the OPR rate that would balance rate stability with larger deferral account balances.[132] The Board notes that this concern may not be an issue if AP files evidence in its next GRA indicating that stand alone OPR services are practical and cost effective as discussed in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues.

OPD Deferral Accounts

With respect to the summer IT/OR receipt revenue in excess of the 100% equivalent FSR toll, the Board notes that this revenue is only included in the OPD deferral account and has no impact on the demand charges derived in the COSS. AP proposed that this revenue would go to the OPD deferral account in order to offset NGTL charges (NGTL receipt toll and fuel charges) if there was a requirement to flow gas onto the NGTL system because of incremental IT/OR volumes in the summer.[133]

Further, AP proposed to credit the revenue from the OPDC rate in the COSS in order to lower resulting demand charges. The Board has not accepted AP's proposed allocation method with respect to OPDC revenues,[134] but its determination with respect to this matter has resulted in lower demand charges to parties who nominated for delivery to other pipelines in 2002.

AP proposed that the forecast ODC would be recovered as part of the demand charges established in the COSS. The Board has approved this process, but the allocation of the ODC and subsequent reallocation process of the OPD service class have been revised by the Board as outlined in Section 3.7.

The Board notes that the forecast ODC were not approved as part of the revenue requirements in Phase I. AP proposed to manage the supply versus demand balance on the North and South systems through decisions to accept incremental firm receipts, in order to have greater control of ODC.

AP proposed that the revenue related to the NGTL receipt toll and fuel charges collected from OPDM customers would go to the OPD deferral account in order to offset the NGTL charges if there was a requirement to flow gas onto the NGTL system.[135]

The Board would prefer not to see the same experiences with the OPD deferral account as were encountered with the EDA. Given the above measures (summer IT/OR, OPDM with FSR and supply/demand balance management program) that AP has proposed and that the Board has approved, the Board is prepared to accept AP's proposed OPD deferral account.

With respect to AP's proposal to bring the year-end balance in the OPD deferral accounts forward to a future test year and to allocate the balance to customer classes based on four hour peak demand, the Board directs AP to allocate the balance based on delivery nominations to other pipelines consistent with the Board's findings in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues.

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132 For example, an OPR commodity rate could be established and revised monthly or quarterly using a forward 12-month rolling forecast period.

133 BR-19 (c)

134 As discussed in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues

135 IR AIPA-8 (f)

Although the administration process related to the OPD deferral account was not discussed to any great extent in this proceeding, for the time being, the Board directs AP to follow a process similar to the process approved for the OPR deferral account. In particular, the Board expects that AP will discuss the approach for recovering or crediting the end-of-year balance with its customers on an annual basis. Given that the OPD deferral account is only expected to be in place for two months in 2004 (November and December), the Board directs AP to include the 2004 balance in the 2005 OPD deferral account and to begin formal reporting to its customers by April 30, 2006 with subsequent reporting to the Board by June 30, 2006.

The Board also directs AP to file, as part of the Compliance Filing, its plans with respect to booking forecast and actual ODC expenses in the EDA and OPD deferral accounts for 2004. In addition, the Board directs AP to provide, as part of the Compliance Filing, its forecast of OPDC revenues for the period November 1, 2004 to December 31, 2004.

In addition, the Board directs AP to discuss with its customers an approach for modifying the OPD deferral account components (OPDC rate adjustment, Summer IT/OR rate adjustment or other measures) if the forecast balance as of December 31, 2005 is greater than $1 million.

In order to maintain transparency with respect to the OPD deferral accounts, the Board directs AP to include the most current actual monthly balances and end-of-year forecast balances for the North and South on its website and to update the information on a monthly basis.

As with the OPR deferral account, the Board considers that it may be more appropriate to establish a stand alone process for dealing with the OPD deferral components and to establish a stand alone OPDC rate that is adjusted as such, in order to target a zero forecast balance in the account. Therefore, the Board directs AP to file, as part of its next GRA, such a stand alone proposal so that parties can express their views. The Board is also interested in receiving parties' submissions with respect to alternative mechanisms to adjust the OPDC rate that would balance rate stability with larger deferral account balances.[136] The Board notes that the above matter may not be an issue if AP files evidence in its next GRA indicating that stand alone OPD services are practical and cost effective as discussed in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues.

With respect to the EDA, the Board still expects that any EDA balances outstanding at October 31, 2004, would be carried forward to be collected/refunded in a future period. The Board expects AP to discuss an approach with its customers and to file an application with the Board by May 1, 2005 with respect to disposition of the balances.

7.4 Possible Elimination of Existing Sales Service

AP currently provides sales service to nine sales customers in the North[137], while in the South, sales service is not currently provided to any customers. AP proposed to discontinue its provision of sales service effective October 31, 2004.

[136] For example, a OPDC rate could be established and revised monthly or quarterly using a forward 12-month rolling forecast period.
[137] Montana Band, 3 power plants, AltaGas Utilities, Wainwright, Samson Band, Redwater, ARC Resources

7.4.1 Elimination or Continuation

Views of the Applicant

AP submitted that its primary function was that of a gas transmission company and argued that sales[138] was not a service typically provided by a gas transmission entity. Provision of sales service was not viable for a gas transmission company like AP and was not consistent with the Alberta government's legislated deregulation.

AP also submitted that there was no legislative requirement for a transmission company to provide a sales service.

AP submitted that parties, including DERS, provide such services and there was no reason for AP to be the middleman. If an AP customer desires such a service, whether it be purchasing, billing, or regulatory submissions, the customer should approach DERS or another service provider itself. AP submitted that it should provide only a delivery transportation service to Distributing Companies (FSU service).

AP submitted that Section 51 of the *Gas Utilities Act,* R.S.A. 2000, c. G-5 (GUA) prevented a person from discontinuing the provision of gas "by reason of or pursuant to any other contractual obligations in respect of the furnishing or supplying of gas". AP indicated that the Abcom/CCG[139] was not suggesting that AP was proposing to discontinue sales service by reason of or pursuant to any other contractual obligation with respect of the furnishing or supplying of gas.[140]

AP submitted that the inquiry into Section 51 only occurs, and the Board's jurisdiction to prevent AP's proposed discontinuance of sales service is only invoked, if the proposed discontinuance of gas supply is being proposed "*by reason of or pursuant to*" other contractual obligations. AP argued that there was no evidence that it was proposing to discontinue providing sales service because of a contractual obligation and therefore, there was no basis in fact or law for the Montana Band's purported reliance on Section 51 of the GUA.

For these reasons, AP did not agree with the Band's suggestion that the proposed "Terms and Conditions" and rates constitute an "other contractual obligation" upon which the Board could invoke Section 51 of the GUA. Furthermore, AP submitted that such an interpretation would always invoke Section 51 and render meaningless the stipulation that discontinuance be by reason of another contractual obligation.

AP submitted that in the circumstances, the Board does have the jurisdiction to allow AP to discontinue sales service, and that there was no impediment to the discontinuance of sales service.

AP submitted that in order to continue to provide sales service to the Montana Band and other similar customers in the North it would require incremental resources and systems to provide procurement, risk management, credit analysis, accounting, alternate supply plans upon failure of supply, balancing and regulatory filings related to establishing and reconciling the sales rate. AP estimated its incremental internal cost for continued sales service to be $75,000 and submitted

138 AP noted that sales service includes the buying and reselling of the gas commodity.
139 Montana Band (Aboriginal Communities) and Care Centre Group (Abcom/CCG)
140 Transcript, page 1181, lines 19-23.

that this was five times the current estimated FSU for the Montana Band. In addition to the estimated $75,000 internal cost, AP indicated that the charge for sales service would include the actual gas commodity costs and the FSU rate. AP submitted that the costs for the provision of sales service should be paid by those customers who utilize the service.

AP submitted that it was not in the public interest to incur the significant costs that would be required for the continued provision of a sales service, particularly where there was only one customer requesting continued service and that one customer had not even decided whether it would use the sales service if it was offered, particularly given its likely cost.

In the hearing, AP indicated that in the transition of the DSP function from AG to DERS, DERS was willing to continue to provide sales service to AP until October 31, 2004. AP also indicated that the only cost from DERS to AP would be the cost charged through the deferred gas account (DGA). AP also indicated that it had not gone forward to ask DERS for a proposal for an ongoing sales service.[141]

Views of the Interveners

Abcom/CCG

Abcom/CCG submitted that the proposed Terms and Conditions of Service and the rates resulting from the Application together would constitute new or "other contractual obligations" within the meaning of Section 51 of the GUA. Therefore, Abcom/CCG argued that the Board did not have the jurisdiction to allow AP to terminate sales service. Section 51 of the GUA provides as follows:

> Notwithstanding the terms of any contract, a person or company furnishing or supplying gas by retail or wholesale either directly or indirectly to or for the public or any member of the public shall not discontinue the furnishing or supplying of the gas by reason of or pursuant to any other contractual obligations in respect of the furnishing or supplying of gas.

Abcom/CCG submitted that in recent years the provincial government has promoted customer choice as being beneficial to customers, and any attempt to diminish the choices available to a customer was contrary to this policy. Abcom/CCG also questioned whether any legislation in Alberta gives rise to an implication that gas service can be discontinued or substituted to accomplish the government's legislation on deregulation. It was their understanding that deregulation was to encourage additional options and competition, not to create an avenue for suppliers to avoid contractual responsibilities.

Abcom/CCG submitted that AP indicated that it cannot unilaterally discontinue gas supply without the order or concurrence of the Board and whether that position was supportable by the legislation without more, may be debatable. Abcom/CCG argued that such service could not be unilaterally adjusted by way of notice, no matter how much notice was given.

Abcom/CCG noted that it was not proposing that Rate 5 be preserved in its current form and that a demand rate would be appropriate for the transportation component of the service.

[141] Transcript, page 782, lines 1-15.

Abcom/CCG acknowledged that the Band would be prepared to pay for the sales rate based on the reasonable cost of service but the Band did not require or expect all of the services outlined by AP. Abcom/CCG argued that if the Band could procure gas for $13,000 per year, AP should be able do so at a lower cost.

Abcom/CCG submitted that AP could easily make arrangements with its affiliates for procurement of the small amount of gas that the remaining sales customers require at the daily wholesale market price (the AECO C price) adjusted as necessary for transportation. Alternatively, Abcom/CCG submitted that AP could continue the existing arrangements with DERS to provide the gas at the regulated default price or the Gas Cost Recovery Rate (GCRR).

CCA

The CCA did not support the elimination of sales service to those customers who request it and indicated that the costs for these services should be prudent and paid by those customers who utilize the service.

CG

The CG submitted that in a generic sense, all existing sales customers on the AP system, who were indirect customers of AG for purposes of their gas supply, should all have the same opportunities (or not) to remain customers purchasing gas from regulated supply, now administered by DERS, as if those AP customers were customers of AG. The CG argued that this seemed reasonable given that these customers originally commenced their sales service contracts with AP when AP was part of a single predecessor company (NUL or CWNG) that functioned as an integrated transmission/distribution utility. The CG indicated that if the Board agreed with this principle, it should direct AP to negotiate the necessary arrangements with DERS and bring forward those negotiated arrangements with DERS for approval as part of the Compliance Filing in this proceeding.

FGA

The FGA submitted that sales service should not be discontinued as of October 31, 2004, since there was no apparent burden on AP to provide the service.

In addition, the FGA submitted that AP's role in providing sales service was merely as a billing agent, passing through the AG GCRR. With the sale of retail to DERS, the FGA argued that nothing changed and instead of AG, DERS, would be responsible for the procurement, risk management, credit functions, accounting, contingent supply plans, balancing and regulatory filings. The FGA submitted that the AP sales customers were still eligible for the Default Supply Tariff since, presumably, they were transferred along with other retail customers. The FGA argued that AP only needed to pass through DERS's charges and treat DERS as any retailer transporting gas on its system.

The FGA also submitted that improper notice and inadequate transition should prevent AP from discontinuing sales service.

Views of the Board

The Board notes that the deregulation process conducted by the Government of Alberta in both electricity and gas markets and the restructuring of the ATCO group of utilities has been under way for quite some time. The segmentation of previously vertically integrated utilities into separate regulated service providers and the evolution of a competitive retail market has been a number of years in the making.

Within the restructured markets the Board considers that, without compelling reasons to the contrary, it is not generally appropriate for transmission service providers to offer sales service, which is otherwise provided by gas suppliers through both the DSP function and on an unregulated basis.

In the present case, the Board accepts AP's evidence that sales service is not a viable option for it without taking on additional costs associated with procurement, risk management, credit analysis, accounting, contingency supply plans, balancing, regulatory filings and rate reconciliations. The Board considers that AP's estimate of $75,000 per year to perform this type and amount of work is likely in the right range. The Board notes that Abcom/CCG indicated that it did not believe it needed all these service components and that AP should be able to provide sales service to the Band for a much lower price. The Board considers that the record is not satisfactory as to which components associated with sales service could be stripped from the service or the rate. Nevertheless, in any event the Board agrees with FGA that DERS is now the party responsible for these same activities in association with the regulated gas supply. In addition, other retailers and gas suppliers besides DERS are active in the market.

Given the changes in the market and the existence and functions of DERS and other suppliers, the Board believes that it is not cost effective for AP to undertake the type of work associated with sales service. If AP did undertake this work, the Board considers that it should be paid for by the customers that would cause this work to be undertaken.

The Board agrees with AP that Section 51 of the GUA prevents a person from discontinuing the provision of gas "by reason of or pursuant to any other contractual obligations in respect of the furnishing or supplying of gas". The Board does not believe the existence of another contractual obligation causing the discontinuance of gas provision has been made out. The Board does not agree with Abcom/CCG that the rates and terms and conditions of service of a utility constitute such "other contractual obligations" in the context of the legislation. Such an interpretation would not be in keeping with the general powers of the Board to fix just and reasonable rates which involve the consideration of tariff modifications, and rate closures, over time.

Having concluded that Section 51 of the GUA does not prevent the discontinuation of the sales service, that the provision of such a service would not be within the customary activities of AP, and that the provision of such a service would create additional costs going forward, the Board agrees with AP that it should cease to provide the sales service to Rate 5 customers. The Board considers that the Rate 5 customers should receive FSU service on a demand rate basis as proposed by AP. Where a demand figure has not been settled between a Rate 5 customer and AP, or otherwise determined, the Board considers that AP's forecast of customer demand should be used for the test years, since no evidence was submitted to the contrary on this point. However, as discussed in Section 7.8.1, for refund purposes to Samson Band and Redwater, the Board has directed AP to use the maximum daily quantity shown for these Rate 5 customers in the FGA Argument. AP's forecast demand number should be adjusted as necessary to reflect the Board's direction in Section 7.1 that the four-hour peak demand be used for billing purposes.

What remains to be considered is the question of notice, and related questions as to the appropriate time for the gas sales service to terminate and an appropriate amount of compensation, if any.

7.4.2 Notice and Compensation

Views of the Applicant

AP submitted that its proposed October 31, 2004 date for discontinuance of the sales rate service was appropriate and provided sufficient notice for its customers.

AP indicated that it provided customers with notice that it would be proposing to discontinue provision of the Rate 5 sales service in its Phase I 2003/04 GRA Application that was filed on February 14, 2003. AP noted that the Band filed an intervention in that Phase I proceeding by letter dated March 25, 2003. AP also indicated that the issue of discontinuance of Rate 5 was raised in the oral portion of that Phase I proceeding by the FGA.[142]

Given the advance notice already provided pursuant to the Phase I and Phase II AP filings and proceedings, AP suggested a decision allowing 30 days notice of discontinuance of sales service should be sufficient.

AP submitted that the Band had not presented any evidence to suggest that it would be unable to obtain an alternative gas supply by October 31, 2004, rather that the Band had provided evidence that an alternate gas supply could be arranged in short order.[143] AP submitted that the Band did not see the situation as urgent and had not considered contingency plans or contacted other suppliers or marketers.[144] AP submitted that the Band's inaction should not serve to delay AP's proposed discontinuance of sales service.

AP agreed with the CG that the issue of compensation should be determined on the facts and based on the merits of the particular situation, rather than trying to land on some overall compensatory principle.[145] In the circumstances, AP submitted that no compensation should be paid to the Band for transition costs for the discontinuance of the sales service given that there was no evidence to support the Band's request for compensation, nor was there any basis for the generous quantum which the Band had suggested. AP argued that the Band's own inaction in seeking out a gas supply should not invoke compensation for the Band, or otherwise impact other Rate 5 customers who have taken appropriate measures to investigate their options for gas supply.

With respect to FGA's request for financial assistance to Rate 5 customers through a rate adjustment, AP submitted that it provided adequate notice to its Rate 5 customers and that no compensation should be payable in the circumstances. In addition, FGA presented no evidence regarding the amount of requested financial assistance.

If the Board determined that compensation was payable, AP submitted that the costs of compensation should be payable by AP's customers, as these costs would be no different than any other costs recoverable through rates.

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142 See Transcripts, Phase I, page 342, lines 1-11 and lines 20-22.
143 Transcript Vol. 11, page 1197, lines 23-24.
144 Transcript Vol. 11, page 1198, lines 16-25.
145 Transcript Vol. 12 page 1339, lines 4-6.

Views of the Interveners

Abcom/CCG

Abcom/CCG submitted that adequate notice was a fundamental principle of the judicial process, and that adequate notice was not provided and could not be provided until the Board made its determination on this issue. Abcom/CCG argued that a reasonable notice period was one year following any decision by the Board allowing AP to discontinue sales service.

Abcom/CCG submitted that for 27 years the utility had provided a full service. Since the Band was now required to obtain or develop equivalent service Abcom/CCG argued that the utility should pay for the estimated cost of transition.

Abcom/CCG submitted that the Application presented a parallel to the Board's previous decision regarding the elimination of farm tap services. Abcom/CCG stated that Decision E90024 dated March 2, 1990, indicated that there must be appropriate legislative authority to discontinue service, and that transition costs would be paid by the pipeline company.

Abcom/CCG indicated that the Band had expressed its desire to continue having the choice of taking sales service or transportation service and submitted that if sales service was discontinued, AP should provide compensation to the Band for the expenses it would incur in procuring an appropriate gas supply. Abcom/CCG requested an amount of compensation of $20,000 initially plus $13,000 per year for four years, which would cover administration costs, which should assist the Band to develop the capability to manage its own gas supply. Abcom/CCG considered that the shareholders of AP should pay the compensation because it was AP and not its customers who wanted to terminate sales service.

CCA

The CCA considered that appropriate notice should be given, and any compensation provided should be at the expense of AP's shareholders.

CG

The CG submitted that if sales service continued to be available as a choice for current AP sales customers, then the issue of compensation would not arise.

The CG noted that, with the exception of the concerns expressed by the Band, it accepted the evidence of AP that it initially endeavored to provide notice of termination of sales service on a verbal basis in the spring of 2003 to all sales customers. The CG indicated that, since this notice was 18 months in advance of the proposed actual termination date, an adequate period of time had been provided to sales customers to make alternate arrangements and compensation to those customers would not be appropriate.

The CG submitted that in the particular circumstances of the Band, the record indicates that there was no indication of this initial contact nor whether there was sufficient follow-up by AP to ensure that the necessary communication got through to the appropriate Band officials so that necessary decisions could be taken in a timely fashion.

If the Board decided that sales service should be terminated, the CG indicated that the record would support compensation for the Band. The CG also indicated that it would defer to the evidence and argument of Abcom/CCG as a basis for establishing the level of that compensation.

FGA

The FGA submitted that AP made no effort to negotiate a transportation contract with the Samson Cree Nation and has made no effort to contact the Rate 5 distributing companies to determine their requirements and to negotiate a peak demand as part of a planned transition to transportation service.

The FGA submitted that the Board should enjoin AP from applying any punitive rates for providing gas supply after October 31, 2004. The FGA argued that AP should not be threatening customers with hefty penalties for a situation that the customer did not request, and may not be aware of or understand.

The FGA submitted that Abcom/CCG have proposed a transition plan that incorporates proper notice and financial assistance to make the transition[146]. The FGA agreed that at least a year of joint planning between AP and the Rate 5 customers was required to effect a proper transition to transportation.

Concerning the financial assistance to Rate 5 customers, the FGA indicated that its preference was that Rate 5 customers instead receive an adjustment of their rate to the actual cost of service. The FGA considered that this would better match the transition costs to the size of the customer. In addition, the FGA argued that a rate adjustment was more in keeping with regulatory precedent.

The FGA submitted that should the Board decide to direct AP to discontinue sales service, this should only be done after suitable transition arrangements and an appropriate level of demand has been negotiated with the current sales customers.

Views of the Board

As indicated in Section 7.4.1, the Board considers that the deregulation process conducted by the Government of Alberta in both electricity and gas markets, including changes in legislation over the past several years, has been evolving for some time. The Board also concluded that it was appropriate for AP to discontinue sales service subject to the appropriate form of notice and/or compensation.

With respect to a notice period for termination of sales service, the Board believes a significant amount of time has passed since the original filing of the Phase I 2003/04 GRA Application in February, 2003. The Board notes AP's attempts in the spring of 2003 to provide verbal notice to sales customers of the termination of sales service. A complicating factor relates to the circumstances and effectiveness of the attempts to provide verbal notice to the sales customers.

However, during the Phase II GRA process, the Montana Band entered submissions through Abcom/CCG on December 10, 2003, being the date of the filing of their information requests in the AP Phase II application. Therefore the Montana Band obviously had actual notice of AP's

[146] Transcript, page 1136, line 16 – 1164, line 10

intent to discontinue sales service since at least December 2003. Since December 2003, there has been ample opportunity for the parties to discuss termination and transition plans. Following the retail sale by AG to DERS, it now appears that DERS is providing the regulated retail service. In effect it appears that not only has actual notice been received but there has been some transition to a retail service provider.

In these circumstances and for the reasons set out above, the Board is not willing to entertain compensating any of the Rate 5 customers, including the Band, for transition to a retail service or to DERS as the DSP.

The Board notes that the arrangements undertaken between AP and DERS reference a continuation of the regulated supply service for sales customers until October 31, 2004. Although the Board is satisfied that Rate 5 customers have been aware of the potential need to make arrangements with a new retail service provider for a significant period of time, certainty with respect to this matter would not have been achieved until the release of this Decision.

Accordingly, the Board believes it appropriate that the Rate 5 customers who have not notified AP that they have put in place alternative arrangements should continue to receive sales service for a period of six months from November 1, 2004, being the commencement of the 2004/2005 gas year and the projected date for implementation of new rates pursuant to this Decision. The Board therefore directs AP to provide, or put in place necessary arrangements with DERS or another service provider to continue to provide, sales service until April 30, 2005, to those Rate 5 customers that have not otherwise notified AP that other service arrangements have been secured.

The Board will allow the recovery in revenue requirement of the costs associated with the provision of these sales services upon application by AP.

7.5 Management of Supply/Demand Balance

AP proposed to manage the supply versus demand balance on the North and South pipeline systems through accepting incremental firm receipts on each system to a maximum firm receipt threshold that would be revised from time to time when market demands and/or oversupply costs change. AP proposed to assess the revenue versus cost impacts of incremental firm receipt volumes and to offer unrestricted firm receipt service as an option, provided the forecast benefit exceeded the forecast cost. AP also indicated that it would provide other receipt service offerings including short term firm service (November 1 to March 31), IT/OR service and firm receipt service linked to an OPDM service.

Views of the Applicant

AP noted that deliveries of gas to other pipelines were required if receipts exceeded on-system deliveries and that generally, these deliveries occur in the warmer months when the temperature sensitive volumes for Distributing Companies' markets are lower. AP submitted that these seasonal flows of gas are an integral part of how it operates its system, when it uses the physical capacity of its system to accept receipts that exceed the minimum market demands, thereby optimizing the system as long as the receipt revenues exceed the ODC.

AP indicated that customers want proactive management of the ODC and in order to do this, AP submitted that it must manage the supply versus demand balance on each system (North and

South) through decisions to accept incremental firm receipts. AP indicated that it does not generally have termination rights under its FSR or FSD Contracts and service continuance was a customer choice. While AP can manage receipts onto its system, once on the system ODC were difficult to effectively manage due to factors beyond its control such as unplanned industrial turndowns and shutdowns and NGTL toll changes.

AP indicated that it would manage supply and demand by establishing a maximum quantity that can contract for FSR transportation on each pipeline system. AP also indicated that this maximum FSR quantity (firm receipt threshold) would be determined for each of the North and the South by assessing the market demands that exist on each pipeline system, the revenue generated by incremental receipts, average customer specific facility costs of 4.3¢/GJ to tie-in new receipt points, and the costs to deliver the oversupply. AP submitted that the forecasted point at which an incremental GJ of FSR revenue ceases to exceed the cost to tie-in and deliver the resultant oversupply would identify the firm receipt threshold. AP indicated that this was the level where additional FSR quantity would no longer create a net benefit for all customers on the system.

AP indicated that the current firm receipt thresholds were 1,067 TJ/day in the North and 433 TJ/day in the South. AP also indicated that the firm receipt threshold was close to being reached in the south but additional firm receipt capacity was available in the north. AP submitted that there would be ongoing communications with industry on the firm receipt threshold.

AP indicated that a queue for firm service, based upon this firm receipt threshold, would be maintained.

In response to the CG's statement that there was no basis to expect that AP would be sufficiently accurate in its forecast of supply and demand to implement such a policy, AP submitted that while no forecast could be completely accurate, the calculation would be based on the best information available. AP noted that for deliveries, it would use the last two April 1 to October 31 periods adjusted for known changes. For ODC, AP noted that it would use the current interruptible rates for deliveries of oversupplies to NGTL, the average fuel rate for the prior two April 1 to October 31 periods and the forward gas price for the next April 1 to October 31 period. For facility costs, AP noted that would utilize a historical average of 4.3¢/GJ.

In response to CAPP's recommendation that AP work with industry to develop additional mechanisms to ensure that AP remains open and accountable for decisions to limit access to FSR service for economic reasons, AP indicated that, if the Board approves AP's proposal for management of supply, it would work with its customers to include the threshold calculation in AP's BP&P and establish regular reviews on both the calculation and AP's current level of receipts.

With respect to the CG's summer TBO proposal, AP submitted that it could be a refinement of the management of supply/demand principles that AP was proposing, and if presented and approved, could modify AP's proposal.

Views of the Interveners

CAPP

CAPP submitted that AP proposed to implement a process that would limit access to full FSR for economic reasons unrelated to physical pipeline capacity and argued that such a process would be a significant departure from the normal pipeline practice of contracting firm service up to physical capacity. CAPP noted that customers have not had the opportunity to review the threshold limits nor the impacts of those limits.

CAPP submitted that should the Board approve AP's proposed process, AP should be directed to work with the industry to develop additional mechanisms that will ensure AP remains open and accountable for decisions to limit access to FSR service for economic reasons.

CG

The CG did not support AP's proposal to try to manage incremental firm receipts in order to balance the cost/benefit of receipts on to the system.

The CG submitted that there was no basis to expect that AP would be sufficiently accurate in its forecasts of supply and demand to implement such a policy. The CG argued that a summer TBO was a much more supply friendly approach to resolving the problem and would also be consistent with the principle of additional flow on the AP system being beneficial to all customers.

IGCAA

IGCAA submitted that there was no evidence before the Board to suggest that any incremental receipts will be attracted over and above those currently on AP's system, especially in the South where receipt volumes have left the system and AP would still be close to the maximum amount of firm receipts it would propose to take on.

IGCAA indicated that these artificial mechanisms to control receipts on the AP system would not be necessary if receipt shippers on the AP system had to pay the full cost of taking gas off the AP system. IGCAA argued that FSR volume caps were an imperfect substitute for allowing market signals to control the supply demand balance.

IGCAA was concerned with the uncertainty around AP's FSR rate cap methodology and submitted that AP only disclosed the methodology by way of an undertaking response at the end of the hearing and then admitted that its methodology would have to be discussed with its shippers. IGCAA submitted that areas of possible disagreement with its shippers include the 4.3¢ capital charge. IGCAA submitted that the Board cannot rely on AP's methodology to control ODC.

Rate 13

Rate 13 was concerned that AP's proposal to do a cost benefit analysis to manage incremental producer receipts was flawed and that the total costs would not be considered.

Rate 13 submitted that AP would be provided with the Board-approved ability to discriminate between customers, and there may be instances where one customer was allowed and another was not due to AP's interpretation of benefits and costs, in spite of similar circumstances between both customers. Rate 13 argued that allowing this to occur would not be in the public interest.

Views of the Board

The Board notes that parties were not generally accepting of AP's proposal to cap incremental firm receipts at a calculated balancing point. Some parties were concerned about AP's ability to accurately forecast and control FSR volumes. CG recommended a summer TBO as an alternative.

At this time, the Board will not entertain the establishment of a summer TBO, which the Board considers will be an issue for the Competitive Proceeding.

The Board considers that management by AP of the FSR threshold is one key to the minimization of balances in the OPD deferral account. The Board accepts the concept that the threshold point is the incremental volume that creates a revenue stream equal to the costs to deliver the over-supply volumes and the cost to tie-in the new facility, if applicable, for the warmer months.

The Board considers that producer receipts above the demand trough to the threshold point would generally provide a benefit to all customers. All customers would benefit from increased producer firm contract demand up to the threshold volumes since the revenue from firm receipt volumes for the full year would exceed the costs of summer over-supply. This would result in lower rates for all customer groups. The Board does not agree with CAPP that a normal practice for AP should be to contract FSR up to the physical capacity since this would entail receipt volumes above the threshold thereby, causing ODC costs in excess of receipt revenues.

The Board considers that the concept of the maximum receipt threshold for each of the North and South zones, as proposed by AP, is reasonable and herein approves the concept as filed. The Board expects that AP will manage the threshold receipt amount to minimize the balance in the OPD deferral account. The Board agrees that AP should work with industry to develop mechanisms that will ensure an open and transparent process for setting and administering the threshold limits for each zone as described in Exhibit 35-021.

Following consultation with stakeholders, the Board directs AP to file with the Board, for information, the mechanism and application guidelines it proposes to utilize to implement the firm receipt threshold in determining available FSR service, including support for the forecasted threshold levels and proposed implementation dates. The mechanism and forecasting methodology may be further reviewed by the Board at the next GRA or upon application by an interested party.

7.6 NGTL FT-P Available from AP

In Decision 2003-051, the Board approved the terms and conditions for NGTL's firm transportation points-to-point service (FT-P). NGTL offered this service to provide intra-Alberta customers with the ability to transport gas from multiple receipt points on the NGTL system to one intra-Alberta delivery point, including AP/NGTL interconnections. However, NGTL customers have not been able to use this service if they want to deliver to AP/NGTL interconnections because AP has not accepted nominations at interconnections.

The FT-P was a replacement service for NGTL's firm transportation point-to-point service (P2P). FT-P has no access to NIT.

Views of the Applicant

AP noted that Decision 2003-051, wherein the Board approved NGTL's FT-P, resulted from an opposed negotiated tariff settlement. AP submitted that it was not rational or fair to require that AP effectively amend its applied-for rate design and rates on the basis of an NGTL service that had not been approved by the Board for 2004.

AP submitted that if the Board ordered it to allow customers to nominate gas onto its system at specified interconnections, its rate design would be undermined and its operational flexibility would be greatly impacted.

AP noted that it contracts for standard receipt and delivery services with NGTL to receive and deliver physical volumes of gas between the pipelines as well as to transfer gas between its NGTL account and other NGTL shipper accounts. AP indicated that it requires that all customer receipt and deliveries with NGTL move through its NGTL account to facilitate the efficiencies associated with exchange and to allow AP greater operational flexibility of its pipeline system. This practice became an integral part of the North Settlement and South Settlement. AP and its customers agreed to change from a rate design based on physical point-to-point service to a system where buyers and sellers could transact. AP submitted that this change resulted in gas market liquidity being created on the AP system. The current practice of netting customers' receipt and delivery nominations with NGTL, through its NIT account, continued to be a fundamental requirement for AP's rate design.

AP indicated that it would not accept nominations at interconnects with NGTL due to its physical system being constrained.

AP submitted that it was not appropriate for AP or its customers to adjust the business fundamentals, rate designs and applied for rates to accommodate NGTL's FT-P service.

AP submitted that use of its NIT account to net customer delivery and receipt nominations with NGTL created efficiencies that were realized in reduced rates for all customers. AP argued that allowing customers to nominate FT-P service at AP interconnections, to the potential amount identified by IGCAA, would diminish exchange capacity and dramatically increase the ODC costs, especially in the summer. All customers would be negatively impacted since these costs were allocated to all customer groups. AP submitted that IGCAA's proposal would result in the FT-P shipper getting all of the benefits of direct access to the AP system and all other shippers would pay the incremental costs. AP submitted that the negative impacts to all customers, including those not using the service, outweigh the value of the service.

AP submitted that in order to complement FT-P service, the AP rate design would have to include a point to point service offering and this point to point service from a connecting pipeline might require facilities to accommodate the service. AP submitted that provision of a point-to-point rate would entail increased tolls to customers and curtailment risks if the supply was not available at the designated point. AP submitted that NGTL provided no evidence substantiating its assertion that a matching point-to-point service on AP was not required to facilitate FT-P service.

AP argued that it requires operational flexibility to meet the demand requirements of its markets and this flexibility includes the ability to choose NGTL receipt points and volumes to meet changing operating parameters and hydraulic restrictions. AP indicated that the operating flexibility extended to the priority AP places on serving temperature sensitive markets as described in AP's BP& P Article 3.1. As a result, AP submitted that FT-P nominations could not be confirmed at many AP interconnections with certainty throughout the year without incremental facilities.

AP noted that NGTL designed the FT-P service as a point-to-point service but denied FT-P service holders the benefits of access to NIT. AP argued that IGCAA was essentially requesting that FT-P service enjoy the benefits of the AP market pool while FT-P service cannot enjoy the same benefits on the NGTL system. AP submitted that if NGTL had structured its FT-P service to allow NIT access, AP's operational concerns regarding access to the service could have been avoided.

With respect to NGTL's request that the Board deny some of AP's proposed provisions with respect to the use of AP's NIT account, AP submitted that NGTL's request presumed that this issue would be further considered in a timely way in the Competitive Proceeding. This presumption was inappropriate at this stage.

AP requested that the Board approve the continued use of the AP NIT account for the movement of all gas receipts and deliveries between the AP and NGTL system, and thereby deny IGCAA's FT-P proposal.

Views of the Interveners

CALGARY

Calgary submitted that based on its review of the evidence, there appear to be some operating or structural barriers to having the FT-P rate available, including the AP insistence that all transactions involving gas moving from NGTL to AP must go through the AP NIT account.

However, Calgary submitted that transactions may be able to occur on a case by case basis or that operating parameters may be developed to accommodate FT-P service from NGTL to AP. To the extent that the AP position hinders the development of a more competitive market, Calgary submitted that it was incumbent on AP to modify its process to accommodate market services.

CAPP

CAPP was concerned that making FT-P service available on a customer-by-customer basis, , would result in the erosion of AP's operational flexibility.

In addition, CAPP submitted that it would negatively impact AP's ability to provide the OPD service under the OPDC rate because the provision of OPD service depends upon AP being able to execute a "paper" transaction to move gas simultaneously off and on to the NGTL system, commonly referred to as an exchange, through the NGTL NIT service. To the extent that the volumes moving through AP's NIT account were diminished, AP's ability to execute cost-free paper transactions would be diminished and in the short term, higher ODC would result, and in the long term reduced exchange capacity may result. CAPP submitted that reduced exchange capacity would ultimately lead AP to restrict firm receipts on its system at even lower levels than currently contemplated, and thereby reduce benefits to all shippers.

CG

The CG submitted that AP was being unnecessarily rigid in rejecting any possibility of accepting FT-P deliveries from NGTL, and argued that discussion of this issue belongs in the Competitive Proceeding. In principle, a reasonable goal was the removal of limitations to access to all intra-Alberta rates available from NGTL.

The CG noted that, if customers on AP did have the ability to access the NGTL FT-P service, this would reduce the volume of gas moving through the AP NIT account on the NGTL system and in turn reduce the volumes available for use as exchange and could therefore potentially increase costs of moving excess gas supply from AP to NGTL.

Notwithstanding this potential negative impact, the CG believed that all AP customers would be better served in the long run if access to alternate services available on NGTL were made available to those AP customers who could benefit from access to that rate. Gas prices on the AP system generally reacted to the prices of gas sourced on the NGTL system. The CG submitted that this was a matter of record in terms of pricing mechanisms in several of the AP non-standard contracts. These pricing mechanisms ensured that the delivered price of gas sourced from the AP system remained competitive with gas sourced from the NGTL system.

The CG believed that the consumers it represented would indirectly benefit from the impact on the price of gas in the AP market, which the CG expected would follow from access to the FT-P rate.

In addition, the CG submitted that, if the full TBO proposed by CAPP were to come to pass, this would eliminate the problem since the AP physical system would become a *de facto* part of the NGTL system.

IGCAA

IGCAA submitted that to some extent, the introduction of FT-P service addressed AP's accountability criticisms of NGTL's intra-Alberta rate design. IGCAA argued, however, that AP was only willing to accept changes to NGTL accountability if it believed itself to get a competitive advantage from them. Where there was no competitive advantage, or AP might experience a disadvantage through the loss of exchange capacity, AP resisted implementing rate design changes.

IGCAA submitted that even if reduced exchange capacity were to occur, it was the nominating shippers who created exchange capability and who should be entitled to choose whether to trade through AP's NIT account or to use FT-P service. IGCAA submitted that exchange capacity was not the property of AP or its shippers generally.

IGCAA submitted that the physical constraint issues raised by AP were hypothetical. IGCAA argued that prior to the North Settlement and South Settlement AP accepted point-to-point receipts onto its system from NGTL without any evidence of undue burden. In the present circumstances, IGCAA submitted that AP did not provide any evidence of actual physical constraints and under cross-examination admitted that on the basis of impacts to its exchange capability alone it would resist allowing FT-P receipts onto its system.

IGCAA submitted that the requirement to exchange gas through AP's NIT account expired with AP's North Settlement and South Settlement and AP was now trying to introduce this requirement from its informal BP&P into its rate schedules, for Rates OPR, OPDM and OPDC, which it was asking the Board to formally approve. IGCAA submitted that this request should be denied.

IGCAA submitted that there was no evidence introduced to support AP's assertion that it would have to provide a point-to-point service in order to facilitate deliveries under the FT-P service.

With respect to AP's comment that FT-P gas should not be afforded access to AP's market pool since NGTL does not allow FT-P service to access the NIT market, IGCAA did not understand why NGTL's FT-P service requirements should affect the service AP's customers should be entitled to under its tariff.

IGCAA submitted that to the extent that AP was physically able to accommodate FT-P deliveries, the Board should require it to do so.

NGTL

NGTL submitted that none of AP's reasons for refusing to allow direct nominations at interconnects were sufficient to justify AP's position.

NGTL argued that the North Settlement and South Settlement (the Settlements) had ended, as had any agreements to the exchange practices established under them. NGTL submitted that AP did not provide any evidence of any further agreements with its customers to continue its exchange practices and the "gatekeeper" status that it established under the Settlements.

In response to AP's suggestion that a point-to-point 100% load factor service from a connecting pipeline would logically require a corresponding point to point service response from AP, NGTL submitted that upstream and downstream pipeline services do not have to match or otherwise have the same attributes, and the service on the downstream pipeline needed to only accommodate the physical nominations.

NGTL submitted that AP provided no analysis or evidence to support its claim that capacity constraints at interconnects further justified its refusal to allow direct nominations. In any event AP had conceded that it would refuse to accept deliveries at interconnects using FT-P service even if it had sufficient physical capacity on its system to accept them.

NGTL requested that the Board direct AP to accept direct nominations at interconnects from NGTL customers that seek to use NGTL's FT-P service. NGTL indicated that if AP determined that acceptance of a nomination in a particular case was not feasible due to physical capacity constraints on its system, then it should be required to define and communicate the nature and extent of the constraints to both the requesting customer and NGTL. This information would allow the customer, AP and NGTL to discuss how such constraints could be eliminated or at least acceptably managed.

NGTL also requested that the Board specifically deny AP's proposed provisions in section A of its OPR rate schedule and reject section 13.3 of its BP&P, which mandate that its customers use AP's NIT account to access AP's systems. NGTL submitted that these provisions should not be allowed to stand as competitive barriers that prevent customers from using an approved NGTL service.

Views of the Board

The Board accepts AP's position that its rate design would be undermined and its operational flexibility could be negatively impacted if it were required to allow customers to nominate gas onto its system at NGTL/AP interconnections specified by the customer at any given time. The Board considers that AP's physical system would likely be unable to accommodate uncontrolled point-to-point service due to its physical size and operating constraints.

At this time, the Board considers that all AP customer receipts and deliveries with NGTL should continue to be facilitated through the AP NIT account with NGTL, in order to continue to facilitate the exchange volumes and to provide enhanced operational flexibility of the pipeline. The Board is of the view that this method of operation reduces costs for all customers on the AP system. At present, the Board believes that any value received by certain customers from a point-to-point service could be offset by increased ODC. Furthermore, it is possible that additional facilities would be required to accommodate point-to-point service between the AP system and NGTL interconnects.

Therefore, the Board will not require AP to provide point-to-point service and accommodate FT-P receipts from NGTL at this time. The Board approves the continued use of the AP NIT account for the movement of all gas receipts and deliveries between the AP and NGTL systems.

The Board notes that a number of parties indicated that a more detailed examination was warranted with respect to possible service offerings on AP with point-to-point accommodation to NGTL/AP interconnects. The Board considers that there would likely be some difficulties for point-to-point service on AP due to seasonal variations in flow and changes in receipt volumes at receipt point locations. However, the Board will be determining the scope of the Competitive Proceeding with the input of interested parties in the next few months. There may be merit in examining in that proceeding the possibility of selective locations or conditions for point-to-point service on the AP system with accommodation for NGTL FT-P deliveries.

7.7 2002 Versus 2004 Data

In its COSS, AP proposed to use 2002 actual throughput as the basis for allocating certain expenses and 2002 actual OPR nominations as the basis for reallocating OPR related expenses and revenues. The percentage of throughput for each service class (based on 2002 actual data) is shown in Tables 20 and 21 for the North and South respectively. The percentage of other pipeline receipt nominations (based on 2002 actual data) for each service class is shown in Tables 22 and 23 for the North and South respectively.

Subsequent to its February 2, 2004 COSS, AP noted that its 2002 actual throughput and 2002 actual other pipeline receipt nominations included throughput and nominations associated with non-standard contracts.[147] AP provided revised throughput and receipt nominations in its Rebuttal

[147] IR CAL-AP02-16

Evidence by excluding throughput and nominations associated with the non-standard contracts. AP also provided more recent throughput and other pipeline receipt nominations for the 12-month period ending February 29, 2004. The adjusted and more recent numbers are also shown in the Tables 20 through 23.

Table 20. Throughput Percentages - North

	% By Service Class					
Methods	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**
2002 Actuals	14.1	28.3	7.5	40.7	9.3	100
2002 Actuals Adjusted	14.7	24.8	7.9	42.8	9.8	100
2003/2004	15.9	20.9	6.9	44.5	11.8	100

Source: AP Rebuttal Evidence, p. 36

Table 21. Throughput Percentages - South

	% By Service Class					
Methods	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**
2002 Actuals	27.0	11.0	11.9	43.0	7.1	100
2002 Actuals Adjusted	29.8	11.1	13.1	38.1	7.9	100
2003/2004	32.5	8.9	11.2	34.7	12.7	100

Source: AP Rebuttal Evidence, p. 36

Table 22. OPR Nomination Percentages - North

	% By Service Class					
Methods	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**
2002 Actuals	80.0	10.3		9.7		100
2002 Actuals Adjusted	81.6	8.5		9.9		100
2003/2004	84.3	5.9		9.8		100

Source: AP Rebuttal Evidence, p. 37

Table 23. OPR Nomination Percentages - South

	% By Service Class					
Methods	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**
2002 Actuals	95.6	0.1		4.3		100
2002 Actuals Adjusted	95.6	0.1		4.3		100
2003/2004	93.8	0.0		6.2		100

Source: AP Rebuttal Evidence, p. 37

Table 24 shows 2002 other pipeline delivery nominations using 2002 actual exchange deliveries (nominations to NGTL) and 2002 adjusted numbers to account for gas flow under OPDC to Alliance Pipelines. Table 25 shows the corresponding percentages for each service class.

Table 24. OPD Nominations - North

	TJ By Service Class					
Methods	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**
2002 Actuals (1)	1,802	383		39,889		42,074
2002 Actuals Adjusted (2)	1,802	383		42,549		44,734

Source: (1) IR Attachment NGTL-AP-3 (d), p. 1 of 2
(2) IR Attachment NGTL-AP-3 (d), p. 1 of 2, BR-AP-4 (a)

Table 25. OPD Nomination Percentages - North

	% By Service Class					
Methods	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**
2002 Actuals	4.3	0.9		94.8		100
2002 Actuals Adjusted	4.0	0.9		95.1		100

Source: IR Attachment NGTL-AP-3 (d), p. 1 of 2, BR-AP-4 (a)

Table 26 shows 2002 other pipeline delivery nominations for the South using 2002 actual exchange deliveries (nominations to NGTL) and 2002 adjusted numbers to account for nominations associated with non-standard contracts. Table 27 shows the corresponding percentages for each service class.

Table 26. OPD Nominations - South

	TJ By Service Class					
Methods	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**
2002 Actuals (1)	3,413	165		80,465		84,042
2002 Actuals Adjusted (2)	3,413	165		49,820		53,398

Source: (1) IR Attachment NGTL-AP-3 (d), p. 1 of 2
(2) IR Attachment NGTL-AP-3 (d), p. 1 of 2, BR-AP-4 (a)

Table 27. OPD Nomination Percentages - South

	% By Service Class					
Methods	**Distribution**	**Industrial**	**OPD**	**Producer**	**OPR**	**Total**
2002 Actuals	4.1	0.2		95.7		100
2002 Actuals Adjusted	6.4	0.3		93.3		100

Source: IR Attachment NGTL-AP-3 (d), p. 1 of 2, BR-AP-4 (a)

Views of the Applicant

AP submitted that its cost allocation proposal assigned costs directly to each customer group as appropriate and allocated costs (joint costs), which could not be directly assigned, using the allocation factors described in the COSS.

AP indicated that it used 2004 forecast allocation factors where available and only used historical factors when forecasts were not available. AP indicated that it used 2002 actual results as its 2004 forecast allocation factors for throughput and OPR nominations and argued that this was consistent with the method it used in its 2001/2002 GRA. AP submitted that these percentages were updated to exclude nonstandard volumes. AP indicated that it also used 2002 actuals as its forecast of OPR and OPD billing units.

AP submitted that it used 2002 actuals as its best 2004 forecast given the uncertainty involved in providing a separate a 2004 forecast of throughput and OPR nominations. AP indicated that there were many factors associated with providing a throughput forecast including temperature, utilization of firm demand, industrial plant turnarounds and use of storage. AP submitted that these factors not only directly affected throughput to the three main customer classes but also indirectly impacted the throughput of OPR and OPD. AP also submitted that the forecast of OPR nominations was not only affected by the above noted factors but also by confidential commercial arrangements of customers. AP argued that the reasonableness of its forecast was confirmed by a review of the actual results for the 12-month period ended February 29, 2004.

Views of the Interveners

CALGARY

In its evidence, Calgary submitted that in the AP COSS, AP used a mix of 2002 and 2004 data in assigning cost responsibility to the customer classes. Calgary indicated that AP included 2002 data in the COSS when it used 2002 Distributing Company throughput for UFG CTM expense allocation and 2002 volumes to allocate Customer Support expenses. Calgary indicated that the 2004 revenue requirement was based on 2004 forecast data approved in Decision 2003-100. Calgary suggested that the Board compel AP in the Compliance Filing to conduct its analysis using either 2002 or 2004 data but not a combination of the two years.

In its reply, Calgary submitted that, with respect to the use of data for cost allocation purposes, it seemed inherently sensible and logical to use data for the same year and consequently, Calgary urged the Board to require AP to provide consistent data in its Compliance Filing, which in this case ought to be 2004 data.

CG

The CG agreed with Calgary that either 2002 actual data or 2004 forecast data should be used for cost allocation purposes and not a combination of the two. The CG recommended that AP be directed to reflect this change in its Compliance Filing.

IGCAA

With respect to the allocation of OPR commodity revenue and OPR expense and revenue reallocation, IGCAA submitted that using nomination data for the last 12 months[148] rather than 2002 data would reduce the OPR allocation to industrials in the north by $700,000. IGCAA also submitted that there would be an additional $400,000 reduction for industrials related to using up to date throughput.

IGCAA submitted that the Board should require a Compliance Filing based on the prior 12 months to obtain the fairest cost allocation because of these considerable discrepancies and argued that 2002 data does not reflect the current situation closely enough for a fair cost allocation.

Views of the Board

The Board notes that some parties wanted AP to use either 2002 actual data or 2004 forecast data for cost allocation purposes in its COSS, while other parties wanted AP to use more recent data for allocation and reallocation of specific items in the COSS. For throughput and OPR nomination data, AP indicated that it preferred to use 2002 actual data as the basis for its 2004 forecast given the uncertainty involved in providing a separate 2004 forecast. The Board notes that these alternatives would lead to different outcomes for each customer class.

The Board considers it important to distinguish between data used to allocate costs within the COSS and data used for other purposes in this proceeding and the Phase I proceeding. In its COSS, AP proposed to use many factors[149] to allocate costs to the functions and a few factors[150]

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[148] For the period ended February 29, 2004.
[149] Operations direct costs, number of employees, head office number of employees, labour expense, etc.

to allocate the functionalized costs to the service classes. With respect to its 2004 forecast revenue requirements, the Board notes that AP used various data to derive or support its forecast. In addition, AP was required to forecast billing determinants used to establish revenue forecasts for various services[151] that were credited to the service classes in the COSS.

With respect to data used for cost allocation purposes and the throughput example identified by Calgary, the Board notes that in the APS 2001/2002 GRA Phase II, it accepted actual 2000 throughput for the purposes of allocating Customer Support expenses and UFG CTM expenses in 2002. Although the Board is sympathetic to IGCAA's claim that more recent data would lead to a cost reduction to the industrial class, the Board considers that consistency in approach from one Phase II proceeding to another is an important factor to consider when using data for allocating expenses or income credits.

The Board notes, that for cost and revenue allocation purposes, it is the relative share of each allocator that drives the allocation of the expense or revenue to the respective service classes and not the total amount of the particular allocator such as throughput. The Board considers that even if AP had provided a 2004 throughput forecast and split for each service class, most parties would have compared these forecasts to recent historical data in order to determine whether the forecasts were reasonable.

In general, for items that are difficult to forecast in total and by service class, such as throughput and other pipeline receipt and delivery nominations, the Board considers that the use of historical actual data is a better method for allocating costs and revenues. In addition, as noted above, the Board considers that consistency between GRAs is important. Therefore the Board considers it appropriate in this case for AP to use 2002 actual data for throughput, other pipeline receipt nominations and other pipeline delivery nominations for purposes of cost allocation and income credit allocation for 2004.

With respect to the billing determinants used to derive revenue forecasts for income credit items, the Board considers it appropriate to establish forecasts for these items, even if it is determined that the most appropriate forecast would be based on the numbers from a prior historical period.

Although OPR nomination data was not considered in the APS 2001/2002 GRA Phase II, the Board notes that this data is required to forecast and allocate OPR commodity revenue and also for reallocating the expenses and income credits determined for the OPR service class.

In addition, the Board notes that OPD nomination data is also required in this proceeding in order to forecast and allocate OPDC revenue and to reallocate the expenses and income credits determined for the OPD service class.

AP indicated that it used 2002 actuals as its forecast for OPR and OPD billing units. However, it appears that AP used 2002 actual other pipeline deliveries[152] for determining 2004 OPDC revenue while it used forecast other pipeline receipts[153] (not 2002 actual other pipeline receipts[154])

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150 Peak demand, throughput, other pipeline receipt nominations, etc.
151 OPDC revenue, OPR revenue, receipt overrun service, receipt interruptible service, etc.
152 North example: 44,734 TJ, Line 114, Table 2.6.1, North COSS and response to NGTL-AP-3 (d)
153 North example: 157,300 TJ, Line 114, Table 2.6.1, North COSS and response to BR-AP-32, 2003/2004 AP GRA Phase I.
154 North example: 83,357 TJ, Line 109, Table 2.6.1, North COSS.

for determining 2004 OPR commodity revenue. As a separate issue, it appears that AP used the 2004 forecast of physical flows from NGTL as a substitute for 2004 forecast exchange receipt nominations.[155] While the Board recognizes that it has accepted that OPDC revenue and OPR commodity revenue should be included in deferral accounts, the Board believes AP should still strive for accuracy in its forecasts. In this respect, the Board is concerned with the lack of consistency and presentation of data provided by AP in this proceeding.

With respect to throughput data for the purposes of cost allocation, the Board considers it appropriate for AP to use the 2002 actual adjusted percentage data shown in Tables 20 and 21. This data excludes throughput associated with non-standard contracts. However, the Board is concerned that the throughput numbers[156] that support derivation of the throughput percentages may not relate to other material filed in this proceeding and the Phase I proceeding. Therefore, AP is directed to reconcile the North throughput numbers for each service class to the receipts and deliveries shown on Attachment IGCAA-AP-17 (c) and to the throughput shown on Attachment AUMA-EDM-AP-7 (b)[157] from the Phase I proceeding. AP is also directed to reconcile the South throughput numbers for each service class to the receipts and deliveries shown on Attachment IGCAA-AP-17 (c). The Board requests a full explanation of how the numbers relate to each other. The Board also directs AP to explain whether the actual 2002 throughput numbers it identified for the OPR[158] and OPD[159] service classes were physical flows or nominations (paper flows).

With respect to OPR nomination data for the purposes of cost and income credit allocation and OPR service reallocation, the Board directs AP to use the 2002 actual adjusted data shown in Tables 22 and 23. This data excludes nominations associated with non-standard contracts.

The Board notes that in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues, the Board directed AP to use other pipeline delivery nominations for allocating OPDC revenue (income credit) and for reallocating expenses and revenues assigned or allocated to the OPD service class. Therefore, the Board directs AP to confirm in the Compliance Filing that the 2002 actual adjusted data shown in Table 24 does not include any delivery nominations associated with non-standard contracts and that the nominations for each service class are appropriate. If AP confirms this matter, the Board expects AP to use the data in Table 25 as directed in Section 3.7. If the data does include non-standard delivery nominations, the Board directs AP to adjust the data by excluding such nominations. With respect to the South, the Board also directs AP to ensure that the 2002 actual adjusted delivery nominations shown in Table 26 are appropriate for the service classes in order to respond to the directions of the Board in Section 3.7 with respect to this matter.

With respect to forecast 2004 OPR commodity revenue and 2004 OPDC revenue, the Board considers it appropriate to use forecast billing determinants (receipt nominations and delivery nominations respectively). However, as noted above, it appears that AP used 2002 actual delivery nominations for purposes of deriving the OPDC revenue. The Board notes that AP has

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155 North example: 157,300 TJ, Line 114, Table 2.6.1, North COSS and response to BR-AP-32, 2003/2004 AP GRA Phase I.
156 Application, Table 2-9, Section 2, p. 19 of 32.
157 p. 6 of 9
158 North 79.3 PJ, South 30 PJ.
159 North 63.9 PJ, South 50 PJ.

filed ODC forecasts that would have been based on physical flows to NGTL.[160] Therefore, in the Compliance Filing, the Board directs AP to either adjust[161] this forecast physical flow data as required to establish a delivery nomination forecast for 2004 or to use 2002 actual other pipeline delivery nominations as a substitute for 2004 forecast numbers. The Board requests that AP provide an explanation supporting its position on this matter.

7.8 Interim versus Interim Refundable Rates

AP proposed to adjust rates on a prospective basis and not to adjust the rates on a retroactive basis.

Views of the Applicant

AP considered that the interim rates approved in Decision 2004-023 were interim rates and not interim refundable.[162] AP submitted that its customers, particularly industrials, producers and marketers, were not in favour of retroactive rate adjustments.

AP stated that rates currently in place would recover the appropriate revenue requirement to October 31, 2004 so that all that would be left, at least on a forecast basis, subject to any adjustments to recover in the last two months, would be two months worth of charges. AP also indicated that any net shortfall or surplus at October 31, 2004 would be allocated to all customers.

AP submitted that its proposal for adjustment to rates on a prospective basis was in the public interest, consistent with prospective rate making and in accordance with its customers' preferences. AP requested that the Board approve its proposal.

AP noted that, as cited by the FGA, the Board's authority with respect to rates is provided in Section 40(d)((i) and (ii) of the GUA and Section 91(1)(e) of the PUB Act. AP submitted that these provisions specifically empower the Board to determine the method by which and the period during which excess revenues received or revenue deficiencies incurred are to be dealt with.

AP did not disagree with the proposition that interim rates can be made refundable. AP submitted, however, that just because rates were interim does not make them refundable.

AP indicated that in Decision 2003-105[163], the Board specifically emphasized that the 2004 Interim Tolls were being approved on an interim and refundable basis.[164] AP noted that the rates being set pursuant to Decision 2003-105 were being set prior to a determination of the NGTL Revenue Requirement, distinguishing the facts from the Application. AP submitted that in the noted decision, NGTL, the Board and all parties expected interim and refundable rates where

160 Response to CAL-AP02-20 (b)
161 Including nominations to other pipelines in addition to NGTL.
162 T1 page 80, lines 7-16; Alberta Energy and Utilities Board Decision 2004-023 (March 9, 2004) page 26. The one noted exception is rates with respect to AltaGas where there is a predetermined agreement in place with respect to retroactive rates: T4 page 355, lines 12-19.
163 2004 Interim Rates for NGTL
164 Alberta Energy and Utilities Board Decision 2003-105, page 3, bottom paragraph.

revenue requirement had not yet been established. AP also noted the Board's comments on the level of scrutiny with respect to the materiality and refundability.[165]

AP requested that its proposal with respect to implementing its rates and rate design on a go-forward basis be approved by the Board. AP submitted that this was also consistent with how NGTL implemented its 2003 final rates where rate design changes approved in Decision 2003-051, such as amendments to FT-P service and MAV charges, were introduced prospectively. AP also made submissions with respect to the issue whether FGA should have been on a transportation rate during 2003 and 2004, and what type of adjustment should be made to interim rates accordingly. These matters are addressed in Section 7.8.1 of this Decision.

Views of the Interveners

CALGARY

Calgary submitted that rates for a test period should recover the revenue requirement allowed by the Board for that test year and argued that the fundamental end state of a Phase II proceeding was to develop rates which, when applied to billing determinants for the test year, collect no more and no less than the test year revenue requirement.

As a result of the Board's approval of interim rates, Calgary submitted that revenue collection for 2004 would have to be adjusted to reflect final rates. Calgary submitted that AP should be allowed to collect the Board approved revenue requirement in 2004. To the extent that this process would require billing adjustments over the last month or months of 2004, Calgary argued that the adjustments must be made to assure that the revenue requirement was collected and the approved rates collect only the allowed revenue requirement. From a simplicity standpoint, Calgary submitted that end of year adjustments would meet this goal. However, if inter-generational inequities were to be recognized, Calgary submitted that re-billing on approved rates from the beginning of the test period would be the only method that would recognize and reconcile inter-generational inequities.

CAPP

CAPP's concern with respect to interim rates was related to the disposition of the recovery of the North EDA deficit for the years 2001/2002. CAPP submitted that recovery of these costs was clearly a responsibility of the producer and that it expected that the recovery of these costs would be included in the costs to be recovered from receipt revenues when the impact of the approved rate design was calculated. CAPP indicated that it expected that the calculation of over or under collection of costs would be done on a customer group basis such that, if producer revenues for 2003 and 2004 exceeded the allocated costs, including the EDA deficit recovery costs for those years, any over collection would result in an adjustment to 2004 final producer rates or be carried over to 2005 producer rates.

CCA

The CCA considered that any rate change should only be on a go forward basis. The CCA was concerned that the applied for rate increases for transportation service to northern residential customers was significant and considered that an increase of as much as 62.4%[166] constituted rate

[165] Decision 2003-105, p. 4
[166] AUMA/EDM/PICA-AP-7

shock. The CCA argued that to include retroactive portions would only magnify such a rate increase and should not be permitted.

CG

The CG supported the concept of interim rates and indicated that AP would collect its revenue requirement for the 2003 and 2004 test years and therefore remain whole.

The CG submitted that AP's rates in this proceeding were being designed on the basis of rates going forward into 2005 based on the 2004 revenue requirement. The CG submitted that the Board has generally not required the utility to retroactively go back to each rate class or individual customer and re-calculate the customers' bills for the test period. The CG argued that this exercise would be onerous and would not yield a significant benefit to customers, especially those who have made consumption decisions on the basis of the rates that were then in place. The CG submitted that the Board should determine appropriate rates to be put in place commencing January 1, 2005 and that no retroactive adjustment should be made to AP's rates, subject to any further adjustments required.

FGA

The FGA submitted that interim rates were refundable. The FGA noted that Mr. Vander Veen indicated that interim rates were interim and the outcome of the AP Phase II proceeding would be a revenue requirement, a cost allocation and rates for 2004 and to the extent that a true up was required, it should be done. The FGA submitted that Mr. Vander Veen's comments were consistent with the nature of interim rates as understood by regulators and the courts in the realm of utility regulation.

Furthermore, the FGA submitted that in section 40 of the *Gas Utilities Act* and section 91 of the *Public Utilities Board Act*, the Board in Alberta was given express powers to issue final orders that have the effect of adjusting for discrepancies between interim and final rates in order to achieve a just and reasonable end result. The FGA also submitted that the Board continued to routinely exercise these powers through recent decisions.

The FGA submitted that neither the CG nor the CCA nor AP provided any legal authorities for "interim but not adjustable" rates while the FGA provided numerous legal authorities and precedents for its position. The FGA also submitted that these three parties have not provided any precedents or practices of this Board to support interim rates that were not subject to adjustment or "true-up".

The FGA made other submissions specific to its position as to whether FGA should have been charged a transportation rate by AP throughout 2003 and 2004 and how the interim rates for that period should be adjusted accordingly. These issues are dealt with in Section 7.8.1 of this Decision.

IGCAA

IGCAA submitted that the Board should not retroactively adjust interim rates by making them refundable.

Views of the Board

The terms "interim rates" and "interim refundable rates" are used from time to time in various applications. The Board considers that interim rates are used in a situation where the revenue requirements are either not known or the billing determinants are not final, and therefore the proper forecast revenue cannot be determined. In the case of interim rates, the Board process typically involves measurement of the difference in revenue collected under interim rates and the final revenue requirement, when determined, and that difference is collected by the application of rate riders going forward. The Board does not typically require recalculations of what the final rates should have been for a past period, resulting in retroactive refunds or charges to customers.

Only in exceptional circumstances would the Board consider it appropriate that the difference in revenue collected pursuant to interim rates and what would have been collected in respect of the finally approved revenue requirement under final rates had they been in place instead, should either be refunded or collected from customer groups through a determination based upon a retroactive billing calculation.

The Board agrees with the AP and most interveners that the preferred approach is to make rate adjustments on a go-forward basis and not to use refundable rates requiring recalculations for past periods. The Board agrees that this exercise is onerous and in most cases would not yield significant benefits to customers, particularly where they have made consumption decisions on the basis of the rates that were then in place.

With respect to the FGA's position on an appropriate transportation rate that should have been applicable to it for the test years, and whether adjustments to the FGA rate should be retroactive, the Board has addressed this specific issue in Section 7.8.1 of this Decision.

7.8.1 FGA 2003-2004 Rate Adjustment

The FGA submitted that Gas Alberta North should have been billed on demand based transportation rates during the test years, not on commodity rates. The FGA argued that its rates should be considered interim and refundable and argued that the Board resolved this issue in Decision 2004-023[167] when it stated: "Nonetheless the rates remained interim and, therefore, adjustable."

The Board has addressed the general issue of interim rates and interim refundable rates in Section 7.8 above. In this section, the Board will address whether there are special circumstances in respect to Gas Alberta, the Samson Cree Nation (Samson Band) and the Town of Redwater (Redwater)[168] that would suggest a different treatment in respect of adjustments or refunds related to interim rates. The Board will also address the specific issue of the appropriate billing determinants (peak demand) and rates applicable to Gas Alberta for the test period and any necessary adjustments to the interim rates. This section also addresses similar issues related to the Samson Band and Redwater.

[167] Decision 2004-023, March 9, 2004, 2003, 2004 Interim Rates
[168] Rate 5 sales customers.

Views of the Applicant

With respect to FGA's suggestion that AP's proposal to proceed with rate adjustments on a prospective basis was inconsistent with utility regulation, Alberta legislation and prior Board decisions, AP disagreed.

AP also disagreed with FGA's position that Gas Alberta North should be placed on transportation demand rates retroactively to January 1, 2003. AP indicated that it administered Gas Alberta North as a stripped Sales Rate 7 customer in 2003 and early 2004 and submitted that a package deal to address recovery of the unbundled services was considered an essential part of the conversion to a demand based transportation service. AP argued that FGA supported this position for Gas Alberta South when it sought approval for its MOU with AP in AP's 2001/2002 GRA. In addition, AP argued that FGA requested that AP establish a mode of operation for Gas Alberta North similar to that for Gas Alberta South.

With respect to FGA's request for demand rate retroactivity for Sales Rate 5 customers, including the Samson Band and Redwater, back to the beginning of 2003, AP submitted that these customers had not requested AP to convert their service to a demand rate, nor had any peak demand been established for these customers. Furthermore, AP argued that Rate 5 was a Board approved rate and, therefore, could not be considered obsolete as suggested by FGA.[169]

In response to FGA's statement that Gas Alberta's daily demand should be adjusted to 40 TJ in the North and 14 TJ in the South, AP agreed to those peak demands as reasonable 24-hour demand values for Gas Alberta's current system but indicated that the one-hour peak demand remained in dispute. AP did not agree that the current 24-hour peak demand values represented the requirement of Gas Alberta's system in 2003. AP indicated that in both the North and South, a portion of Gas Alberta's peak demand was transferred to AltaGas Utilities in 2003 and any potential peak demand adjustments for demand rate retroactivity would have to reflect the higher peak demand required by Gas Alberta in 2003. AP stated that it did not have properly prepared Gas Alberta and Rate 5 forecasts for purposes of a reasonableness check. With respect to FGA's assertion that its forecasts were provided on a consolidated basis derived from point by point data suitable for use in a COSS, AP submitted that the evidence on this record indicated that Gas Alberta did not provide any delivery point specific demand forecasts prior to February 2004.

In regard to FGA's conclusion that the original and final results for Gas Alberta's North system peak demand were similar, AP submitted that although the absolute value of demand was similar, the basis for the demand was much different. AP argued that the original 39.484 TJ/day demand that FGA pointed to was the high end of a range of demand presented by Gas Alberta and the low end of that demand range of 35.356 TJ/day was substantially lower. In addition, AP indicated that the original Gas Alberta demand was based on a larger customer base as Gas Alberta lost delivery points to AltaGas in mid 2003. AP submitted that a greater number of Gas Alberta delivery points in 2003 than 2004 would suggest that a higher peak demand was reasonable for 2003 than 2004. AP also submitted that FGA failed to draw similar conclusions about its South system peak demand forecasts. AP argued that the Gas Alberta South evidence was indicative of the unreliable forecasts presented to AP by Gas Alberta. AP submitted that Gas Alberta South lost 750 GJ of demand to AltaGas in July 2003, and despite this loss of demand in

[169] FGA Argument, page 44.

2003, Gas Alberta's first forecast of 11.563 TJ/day in its October 9, 2002 letter[170] was substantially lower than its 2004 forecast that AP accepted.

AP noted that it had been concerned with Gas Alberta's forecasts until a reasonable and verifiable point specific peak demand forecast was provided by Gas Alberta for its North system for January 27, 2004. AP argued that the evidence presented in reply argument and in AP's Rebuttal Evidence were indicative of the veracity of Gas Alberta's forecasts and AP's inability to agree on a reasonable forecast with Gas Alberta. AP noted that it would not be fair to other customers to refile the COSS using Gas Alberta's daily peak demand. AP submitted that the cost allocations in the COSS must be based on four-hour peak demand.

AP submitted that, absent a reasonable and verifiable peak demand forecast from Gas Alberta, AP forecasted an appropriate level of demand for Gas Alberta in AP's 2003/2004 Phase I and 2004 Phase II Applications. In response to FGA's statement that AP should have incorporated Gas Alberta's forecast demand in its Phase I forecast, AP submitted that Gas Alberta did not provide a reasonable and verifiable point specific demand forecast for its North system until February 12, 2004 and until March 8, 2004 for its South system.

In response to FGA's claim that AP should have provided an appropriate demand rate in the North as of January 1, 2003, AP disagreed and indicated that the administration of Gas Alberta in the North was a stripped Rate 7 sales customer that was appropriate for the level of service provided by AP in 2003 and the first 2 months of 2004. AP submitted that Gas Alberta received a similar service level from AP in this 14 month period to that received in 2002.

In response to FGA's submission that "cash" refunds to Gas Alberta and Rate 5 customers for demand rate retroactivity to the beginning of 2003 would not impact other customers, AP disagreed and indicated that the revenue requirement for AP was established in the Phase I proceeding and subsequent compliance filing and any demand rate retroactivity would require an adjustment to the November 1, 2004 rate calculation that would ultimately result in rate adjustments to other customers.

AP submitted that FGA agreed with the AP position that there were a number of issues[171] outstanding before Gas Alberta North could be transferred to a transportation demand rate. AP argued that any transportation demand rate retroactivity for Gas Alberta North or any other sales customer would have to be considered with respect to the costs incurred in 2003 and 2004 for meter and regulating station operation, odorant, and meter value.

AP requested that the Board deny retroactive rate administration for Gas Alberta North and other sales customers.

AP submitted that if the Board agreed with FGA that it should be a transportation customer in 2003 for the purpose of setting a demand rate, FGA should also be considered to be a transportation customer for the purpose of eligibility for the Fort Saskatchewan/Beaverhill production asset proceeds.

[170] Exhibit 011-04 (b) – FGA Evidence, Attachment 9.

[171] AP submitted that the outstanding issues in 2003 included the recovery of meter and regulating equipment operation expenses, odorant expenses, meter purchase value and peak demand.

With respect to FGA's suggestion that the eligibility for proceeds of the sale of Fort Saskatchewan/Beaverhill production assets was pre-determined in Board Decision 2002-018, AP disagreed. AP submitted that the more relevant eligibility criterion for the disbursement of proceeds from Fort Saskatchewan/Beaverhill assets was the recognition of foregone future benefits of company-owned production.

AP submitted that, in addition, the only AP customers to receive these proceeds were sales customers of record on February 21, 2003. AP argued that this matter should be revisited in this proceeding since FGA was requesting demand rate retroactivity to January 1, 2003 for Gas Alberta North and Rate 5.

Views of the Interveners

FGA

For 2003 in the North, Gas Alberta requested an adjustment of its rate between the stripped fixed charge plus commodity charge to the \$2.10/GJ/month demand rate that was filed in the Phase I proceeding. Gas Alberta also requested a further adjustment of its demand rate to the rate set for AG for 2003 since this would recognize that AP owned the meters at Gas Alberta's delivery stations in 2003. Finally, Gas Alberta requested an adjustment of its billing determinants from the 48TJ/month to the 40TJ calculated in its evidence. The FGA noted that the North refund was subject to a settlement with AP for odorant and station operations and submitted by using the 2003 placeholder for ATCO Gas of \$1.806/GJ/month rate as an illustration, the North refund, when all these adjustments were made, would be \$560,880. The FGA submitted that the over-billing of Gas Alberta on the stripped sales rate would fund the major portion of this refund. Given that this over-billing was over and above the 2003 surplus, the FGA argued that the major portion of Gas Alberta's refund would not affect other customers.

For 2003 in the South, Gas Alberta requested an adjustment of its rate between the MOU demand rate of \$1.95/GJ/month to \$1.283/GJ/month. The FGA submitted that the rate proposed for Gas Alberta consisted of \$1.605/GJ/month charged to AG in 2003 less the \$0.322/GJ for master meters and UFG meters, and indicated that this recognized that Gas Alberta owned the master meters during 2003 and that the UFG CTM project was substantially completed that year. Gas Alberta requested a further adjustment of its billing determinants from the 16.5 TJ shown in AP's Phase I filing to the 14 TJ calculated in its evidence. The FGA noted that an adjustment was made for the AltaGas tap[172]. Gas Alberta also requested a refund of \$156,008 for 2003.

The FGA indicated that for the first two months of 2004, AP continued to charge Gas Alberta the Rate 7 commodity rate in the North but in Decision 2004-023, the Board denied the interim rate proposal with respect to Gas Alberta and directed AP to place Gas Alberta on the same interim demand rate as AG.

With respect to 2004 in the South, the FGA submitted that the Board continued the MOU rates and demands as placeholders for Gas Alberta.

Gas Alberta proposed that its final rate be adjusted to the demands filed in its evidence and accepted by AP. Furthermore, the FGA submitted that Gas Alberta's final rate should be

[172] Exhibit 35-06

$0.293/GJ less than the AG rate to reflect the purchase of meters and that UFG CTM were not required to provide service to Gas Alberta

For both the 2003 and 2004 adjustment, Gas Alberta requested a cash refund in order to ensure that Gas Alberta received exactly the amounts due and noted that it would forego any interest on these adjustments, if the adjustments were received in a timely manner through a cash refund.

The FGA submitted that Rate 5 customers were also eligible for an adjustment to the actual cost of providing service from the beginning of the test period to the time of implementation of final rates. The FGA indicated that Rate 5 customers received an obsolete rate, which was the product of the five-year negotiated settlement with NUL, during 2003 and the first two months of 2004. The FGA submitted that this rate was not based on costs, as the settlement made it uncertain what the considerations were in setting this rate.

The FGA further submitted that this non-cost-based rate should be ignored in setting a fair rate for service to Rate 5 during 2003 and 2004. The FGA indicated that a fair rate would be based on the rate for AG, less a $0.078/GJ adjustment for the UFG meters. The FGA indicated that AP owns the meters that serve both ATCO Gas and Rate 5 so the only difference between the two rates was that the Rate 5 customers have not incurred the cost for the UFG CTM.

For 2003, the FGA prepared an illustration of the necessary refunds for Redwater[173] and the Samson Cree Nation[174] using the $1.806/GJ AG placeholder rate less the $0.078/GJ adjustment for the UFG meters. The FGA submitted that the refund should be adjusted for any difference between the $1.806 placeholder and the rate that is ultimately approved for AG for 2003.

The FGA also requested that the Board direct AP to make a cash refund to Rate 5 customers for the same reasons as Gas Alberta requested a cash refund.

The FGA indicated that it could not understand why AP's 2003 interim rate application did not include a rate that recognized that Gas Alberta had already converted to transportation service November 1, 2002. The FGA argued that AP was informed that Gas Alberta required "an appropriate interim refundable demand rate" 6 months before the interim rate application. The FGA wondered why the strip rate was not recognized in Phase I revenues if the strip rate was so important as an incentive to make Gas Alberta come to terms on a package deal.

In addition, the FGA submitted that the package deal was not communicated to Gas Alberta and in fact, the opposite was the case. The FGA argued that Gas Alberta's evidence was that AP's understanding was that it could not negotiate a "package deal" such as the 2001/2002 South MOU.

The FGA submitted that any linkage between the proceeds of the sale of the Fort Saskatchewan/Beaverhill production assets should be dismissed out of hand given that the Board, in Decision 2003-018, determined that Gas Alberta, along with other transportation customers, was eligible for proceeds from this sale of assets. The FGA submitted that the Board used the sale of the Viking assets in Decision 2002-018 as the model for the Beaverhill/Fort

[173] The 2003 illustrated refund for the Town of Redwater was $22,374.
[174] The 2003 illustrated refund for the Samson Band was $31,024.

Saskatchewan sale, that the matter was concluded and that AP was incorrect to revisit the matter in the AP Phase II proceeding.

Views of the Board
Adjustment for Gas Alberta North and South Interim Demand

The Board notes FGA's argument that the interim demand for revenue forecast purposes for the test years was stated in the Application as 48 TJ/month in the North, and 16.5 TJ/month for the period January through June 2003 and 15.75 TJ/month for the period July 2003 through December 2004 in the South. FGA argued that the agreed demand was 40 TJ/month in the North for the test years and 14.75 TJ/month for the period January through June 2003 and 14 TJ/month for the period July 2003 through December 2004 for the South, which would be the appropriate demands for Gas Alberta.

In Section 7.1, the Board determined the appropriate four-hour peak demand for system design, cost allocation and rate design purposes for Gas Alberta. The Board considers that these new four-hour peak demand amounts[175] for Gas Alberta are applicable to rates on a go-forward basis, and would apply commencing on the implementation date of the final rates to be approved subsequent to the Compliance Filing to this Decision. In addition, the Board also expects AP to use these new four-hour demand amounts when it updates its COSS with revised peak demand numbers for the Distributing Companies Deliveries service class in the North and South and derives FSU demand rates as part of the Compliance Filing.

However, for the purposes of establishing a refund amount in the North (discussed below), the Board considers that for the period April 1, 2003 to the implementation date of the final rates, the interim demand amount of 48 TJ/day in the North is reasonable. The Board observes that the new 24-hour demands for Gas Alberta were determined from data acquired early in 2004. These new forecasts were agreed to by AP in April 2004. The Board does not consider that the new demand amounts should be applicable for billing purposes on a retroactive basis. In the normal course of nominating demand, the Board understands that the process would require a customer to nominate well in advance of the next contract year.

Credit for Owning Meters

As discussed in Section 5.4.1, it appears beneficial to smaller Distributing Companies to be a part of a larger service class. As part of a larger service class, smaller Distributing Companies may be insulated to a degree from potentially higher cost of service charges (and associated rates) reflecting the physical realities of providing service in geographically large areas with lower population densities. Although the Board appreciates FGA's argument that ownership of certain metering facilities should directionally lower their overall costs, the Board considers that this is one element of many that the Board must consider when making its determination of whether or not the overall rates charged to FGA continue to be fair and reasonable. Accordingly, the Board has determined that Gas Alberta should not be billed on a rate separate and distinct from the rates for the Distributing Companies, and that there should not be a reduction in the rate related to Gas Alberta's ownership of certain metering equipment. The Board declines to provide for a credit for meter ownership in the calculation of the refund owed to Gas Alberta by AP.

[175] North 43.2 TJ/day, South 15.1 TJ/day.

Adjustments to Gas Alberta North Service

In Decision 2004-023, the Board considered that Gas Alberta was clear in its intention to switch to a transportation service and therefore required an appropriate demand based rate commencing on January 1, 2003.[176] However, in that decision, the Board also noted that AP and Gas Alberta had not agreed upon a billing demand. In fact the record indicates that AP and Gas Alberta have been unable to agree on proper demand figures to be used for Gas Alberta for almost two years. The Board considers that both AP and Gas Alberta had available to them an opportunity to resolve their impasse regarding the billing demand before the Board but neither party chose to use it. Therefore, the Board must consider that both parties contributed to the lack of timely resolution of the billing demand for Gas Alberta.

The Board notes Gas Alberta desired to change to transportation service effective November 1, 2002 and later amended its request to commence transportation service on January 1, 2003. The Board also notes, that in some subsequent communications, Gas Alberta expressed its continued desire for transportation service and associated transportation rates. Notwithstanding that Gas Alberta had communicated its desire to switch to transportation rates on January 1, 2003, AP did not respond by changing Gas Alberta to a transportation rate on January 1, 2003. However in its Phase I application, filed in February 2003, AP forecast revenue from Gas Alberta on demand rates while continuing to bill Gas Alberta on commodity rates.

As indicated, the Board received no application to resolve the lack of agreement between AP and Gas Alberta regarding a proper nominated peak demand and an appropriate transportation rate for Gas Alberta. The Board therefore considers that it should determine a date when it would have been reasonably expected that a demand figure for Gas Alberta should have been agreed to by AP for billing purposes or, failing an agreement, when AP should have provided an interim demand and interim transportation rates for Gas Alberta North as a result of an application to the Board on this issue.

In examining the sequence of events leading up to the extension of 2002 rates into 2003 in the North, given the filing of the Phase I GRA in February, 2003 and the fact that AP was already on notice that Gas Alberta requested a transportation rate, the Board finds that April 1, 2003 would have been the earliest effective date that both parties, AP and Gas Alberta, should have achieved either a resolution to the differences or, after an application to the Board for adjudicating the differences, the Board would have made an order resolving the demand issue and commencing the application of demand rates.

With respect to the demand rate for Gas Alberta North in the period April 1, 2003 to October 31, 2004, the Board notes that for 2003, Gas Alberta requested a rate equal to the AG 2003 demand rate[177] and for January and February 2004, Gas Alberta proposed that its rate would be equal to the AG 2003 demand rate discounted for meters and for the period March 1, 2004 to October 31, 2004, the rate would be equal to the AG interim rate[178] discounted for meters. FGA submitted that Gas Alberta's final rate should be \$0.293/GJ less than the AG rate to reflect the purchase of meters and that UFG CTM were not required to provide service to Gas Alberta.

[176] Decision 2004-023 P9
[177] \$1.806/GJ/month.
[178] \$1.436/GJ/month.

For the period April 1, 2003 to February 29, 2004, the Board considers it appropriate that the demand rate for Gas Alberta North be set equal to the AG 2003 demand rate, and for the period March 1, 2004 to October 31, 2004, the demand rate should continue to be set equal to the AG interim rate. The Board does not consider it appropriate for Gas Alberta North to receive the requested discounts. The Board considers that the rationale provided above in respect of denying a credit for meter ownership, and the rationale provided in Section 5.4.1 in respect of a single rate and rate class for Distributing Companies, are equally applicable with respect to FGA's request for a discount given that all members of the Distributing Companies class must share all class costs as they also share class benefits. Accordingly, all members should bear a share of the costs of UFG CTM. As noted above, the Board also considers that Gas Alberta should not be given a reduction in its rate related to Gas Alberta's ownership of certain metering equipment.

As indicated, the revenue forecast by AP for the 2003 and 2004 test years was determined on AP's proposed demand rates for transportation service to utilities, including Gas Alberta. However, the actual billings to Gas Alberta for the period from January 1, 2003 to March 1, 2004 were on commodity rates, which produced a higher amount of revenue. The Board considers that AP's billings on commodity rates generated revenue in excess of the revenue forecast prepared on a demand basis. Therefore, the excess non-forecast revenue should be refunded to Gas Alberta without any adjustment to other revenue forecasts or other rates to recover the refund. The Board directs AP to calculate the refund as part of the Compliance Filing based on the findings in this Decision.

With respect to the Fort Saskatchewan/Beaverhill production asset refund, the Board has determined that the effective date for Gas Alberta North switching to transportation rates would have been April 1, 2003. Since all sales customers of record on February 21, 2003 were eligible for the distribution of funds, the Board considers there is no issue regarding the appropriateness of the refund and amount.

Adjustments to Gas Alberta South Rate

The Board notes that, for 2003 in the South, Gas Alberta requested a rate of $1.283/GJ/month instead of the MOU demand rate of $1.95/GJ/month. Gas Alberta established the proposed rate by applying a discount to the AG demand rate because of its ownership of master meters and its claim that it should not contribute toward UFG CTM expenses. For 2003, the Board considers it reasonable that the MOU demand rate for Gas Alberta South should continue. The Board also notes that in 2002, Gas Alberta South was paying about 29.6 ¢/GJ more than AGS. The Board considers that for 2002 the Gas Alberta South MOU rate and the AGS rate were both approved as reasonable. The rate differential between the 2002 rates continued at approximately the same level in 2003 and 2004. Therefore the Board does not see a compelling reason to change the rates to decrease or eliminate the differential for 2003 and for the period in 2004 from January 1 up to the date new final rates commence pursuant to the Board's decision on the Compliance Filing.

In addition the Board does not consider that Gas Alberta South should receive the requested discount. As noted above, the Board considers that the rationale provided above in respect of denying a credit for meter ownership, and the rationale provided in Section 5.4.1 in respect of a single rate and rate class for Distributing Companies is equally applicable with respect to FGA's request for a discount given that all members of the Distributing Companies class must share all class costs as they also share class benefits and accordingly all members should bear a share of the costs of UFG CTM. As noted above, the Board also considers that Gas Alberta should not be given a reduction in its rate related to Gas Alberta's ownership of certain metering equipment.

For 2004, FGA submitted that Gas Alberta's final rate should be $0.293/GJ less than the AG rate to reflect the purchase of meters and that UFG CTM were not required to provide service to Gas Alberta. As noted above, the Board considers that Gas Alberta should not receive the requested discount and as discussed in Section 5.4.1, for 2004, the Board determined that the South FSU demand rate was appropriate for Gas Alberta South.

Town of Redwater and Samson Cree Nation

With respect to FGA's submission that the Samson Band and Redwater were also eligible for an adjustment to the actual cost of providing service from the beginning of the test period to the time of implementation of final rates, the Board notes that AP submitted that these customers had not requested AP to convert their service to a demand rate, nor had any peak demand been established for these customers. The Board also notes that FGA submitted that the Federation managed its anticipated transition from sales to transportation service by providing maximum daily operating demands for Redwater and the Samson Band to AP on September 24, 2003. FGA also indicated that AP did not explain why it did not include the demand numbers in its revised Phase II application, its Phase I compliance filing or its 2004 Interim rate application.[179]

Similar to the Gas Alberta situation, the Board considers that both AP and the Federation had the opportunity to pursue the transportation service issue further. Therefore, the Board considers that all affected parties contributed to the lack of timely implementation of a suitable transportation service for the Samson Band and Redwater. The Board therefore considers that it should determine a date when it would have been reasonably expected that transportation service could have been implemented for these customers.

Given the date of the submission of the billing demands for Samson Band and Redwater to AP, the Board considers that March 1, 2004 would have been the earliest effective date that AP, Samson Band and Redwater could have agreed upon appropriate billing determinants or, after an application to the Board for adjudicating the appropriate rate, the Board would have made an order commencing the application of demand rates.

The Board notes that FGA indicated that a fair rate would be based on the rate for AG, less a $0.078/GJ adjustment for the UFG CTM. As noted earlier, the Board does not consider it appropriate to adjust the rates for the UFG CTM. Therefore, for the period March 1, 2004 to the date new final rates commence pursuant to the Board's decision on the Compliance Filing, the Board considers it appropriate that the AGN interim demand rate[180] should also be applied to service provided to the Samson Band and Redwater.

As indicated, the revenue forecast by AP for the 2003 and 2004 test years was determined on AP's proposed demand rates for transportation service to utilities, including Rate 5 customers. However, the actual billings to Samson Band and Redwater for the period from March 1, 2004 to the date of commencement of final rates in 2004 will have been on commodity rates, which produced a higher amount of revenue. The Board considers that AP's billings on commodity rates generated revenue in excess of the revenue forecast prepared on a demand basis. Therefore,

[179] FGA evidence, p. 4, lines 20 – 29.
[180] $1.436/GJ/month.

the excess non-forecast revenue should be refunded to Samson Band and Redwater without any adjustment to other revenue forecasts or other rates to recover the refund. The Board directs AP to calculate the refund as part of the Compliance Filing based on the findings in this Decision.

With respect to demand billing determinants in the refund period, the Board directs AP to use the maximum daily quantity shown for Samson Band[181] and Redwater[182] in the FGA argument.[183]

7.9 Dually Connected Stations

NGTL requested that the Board prohibit AP from exchanging volumes to the NGTL Alberta System that it receives at dually connected receipt stations.

Views of the Applicant

With respect to NGTL's claim that most of the volumes AP sent to NGTL were originally received at dually connected plants, AP submitted that the year 2002 was the last year that exchange fees were reduced for volumes attributed to dually connected plants and with the change in the exchange fees, the 2002 data used by NGTL could not be relied upon to reflect the current situation.

AP submitted that in the North, where most of the dually connected plants are found, AP only physically flows volumes to NGTL for a few months of the year.

AP submitted that the physical flows of volumes do not track the exchange (paper) flows of volumes on the AP system. AP also submitted that there were dually connected plants with firm contracts to deliver onto the AP system. AP argued that once the gas was on the AP system it could result in delivery transactions to an Industrial, a Distributing Company, a Marketer, another Producer, or onto an Other Pipeline. AP submitted that whether or not AP requested gas to physically flow to NGTL from that dually connected plant did not impact the paper transaction. AP argued that it utilized the most cost effective interconnections to physically flow excess gas to NGTL, which might include dually connected plants. Therefore, AP submitted that it was not simply a "middleman", as alleged by NGTL, for dually connected plants to flow to NGTL.

With respect to NGTL's statement that AP accepts and has constructed facilities to accommodate volumes at dual connections which are destined to be sent to the NGTL Alberta System through exchange service, AP argued that it had the first pipelines connected to many of these gas plants, with NGTL constructing facilities to become the second connection.

In response to NGTL's request that the Board either prohibit AP from exchanging volumes to NGTL that it receives at dually connected stations, or require stand alone OPD rates, AP submitted that NGTL's first request was not practical because of the disconnect between physical flows and paper transactions. With respect to NGTL's second request, AP argued that it was inconsistent with AP's rate design proposals.

181 2,230 GJ/day
182 1,852 GD/day
183 Page 46

AP submitted that parties did not have an opportunity to test NGTL's proposals as presented in its argument and in addition, NGTL's claims in support of its proposals were not valid. Therefore, AP requested that the Board deny NGTL's proposals.

AP noted that NGTL filed no evidence in this proceeding and stated that argument was not the appropriate place for NGTL to be making recommendations that would significantly impact customers and the operations of the AP system.

Views of the Interveners

IGCAA

With respect to NGTL's request to the Board to limit AP's access to exchange capability at dually connected gas plants, IGCAA agreed that NGTL was directly affected by AP's use of its NIT account. However, IGCAA did not believe that it would be appropriate for the Board to grant NGTL the relief it requested at this time because this issue was being raised for the first time in argument, and unlike IGCAA's request regarding FT-P service, other parties did not have an opportunity to explore this relief requested by NGTL. IGCAA argued that the Board did not have a sufficient record before it to grant NGTL any relief on this point.

IGCAA submitted that if NGTL wanted to pursue the exchange issue it should be done through an application to amend its own tariff by making a specific proposal as to exactly how it would limit AP's exchange capacity.

NGTL

NGTL noted that AP's systems are connected to receipt stations that are also connected to the NGTL Alberta System and that AP and NGTL compete to provide service to parties at these locations.

NGTL submitted that a significant portion of the total volumes that AP ultimately exchanges to the NGTL system through its NIT account originate on its systems from dually connected stations. In 2002, NGTL indicated that more than 80% of all volumes exchanged from AP's North system, and more than 35% of all volumes exchanged from AP's South system, originated at dually connected receipt points. NGTL argued that in other words, most of the volumes AP sent to the NGTL system were originally received at dual connections.

NGTL noted that some of the dually connected stations also serve as interconnects between AP's system and the NGTL system. NGTL submitted that AP sometimes exchanges volumes from these stations directly to the NGTL system without the gas ever physically contacting the AP system. In these circumstances, NGTL submitted that AP simply nominates volumes directly to the NGTL system under its name through the connected plant operator and a commercial or paper transaction results, but no AP facilities are used for the physical transaction. NGTL submitted that AP collects a toll from its customer for notional receipt service that physically moves directly to the NGTL system and argued that there was no tenable reason for AP to play the "middle man" in these circumstances and extract a fee for it.

NGTL objected to AP accepting, and having constructed facilities to accommodate, volumes at dual connections that are destined to be sent to the NGTL system through exchange service. In these cases, NGTL indicated that it might not receive a receipt toll for these volumes on a direct one-to-one basis, because the volumes are netted against other volumes that AP may exchange through its NIT account to and from its system and the NGTL system.

NGTL argued that shippers at single connected stations have no other existing physical options for production. NGTL indicated that if these shippers ultimately sought to be on the NGTL system, then their volumes would at least physically move through AP's facilities before being exchanged to the NGTL system.

NGTL submitted that producers have historically nominated to AP's system rather than the NGTL system at dually connected stations because it represented their lowest cost alternative to ultimately get the gas on to the NGTL system, and argued that this historical behaviour may continue under the unusually low rates that AP proposed for its OPD services.

NGTL requested that the Board prohibit AP from exchanging volumes to the NGTL Alberta System that it receives at dually connected stations. If producers at dually connected stations ultimately want to be on the NGTL Alberta System, NGTL argued that they should be required to contract directly with NGTL.

Views of the Board

The Board notes that NGTL raised this issue in argument. The Board agrees with AP and IGCAA that this issue should have been presented in evidence. The Board believes this matter is of sufficient weight that all parties should have had an opportunity to consider and test it. Therefore, the Board will decline to address NGTL's request at this time.

The Board considers that this matter may be an appropriate issue for the Competitive Proceeding. The Board will canvass parties in later months as to the issues to be dealt with in that proceeding.

7.10 Pipeline Competition

Views of the Applicant

AP submitted that it did not adopt competitiveness or growth opportunities as principles of toll design.[184] AP also submitted that its COSS was not driven by competitive concerns but was based on fully allocated costs to determine where the costs of its system come from.

AP agreed, however, that competitive factors do come into play in some aspects of rate design, in particular with respect to the pricing impacts that a commodity OPR rate would have on the on-system price of gas.[185] AP indicated that it does need to ensure that its rate structure does not have any inappropriate impacts on the price of gas.[186]

AP submitted that the applied for rates and rate design have pluses and minuses and argued that there were aspects of the rates and rate design that detract from AP's competitive position.[187]

184 Exhibit 002-02(i-1) – AP Response to IGCAA-AP-6(b).
185 T2 page 171, lines 8-19; T2, page 217, line 11 to page 218, line 13.
186 T3 page 236, line 14 to page 237, line 9.
187 T7 page 693, lines 10-11; T3 page 258, line 25 to page 259, line 6; and T3 page 228, line 17 to page 229, line 13.

AP argued that in recent proceedings it has proposed the policies that it considered appropriate to level the playing field and the outcome of the NGTL and Competitive Proceedings would indicate whether AP was right regarding its policies. AP indicated that if the Board finds NGTL's applied for rates and policies acceptable, and if major players demonstrate a willingness to tolerate NGTL's practices, then this would impact AP's future applications to the Board.

With respect to the relationship between the Application and other proceedings, including the pipeline competition proceeding, AP submitted that delaying a decision on the Application was not appropriate, particularly since the scope of the Competitive Proceeding was uncertain, a hearing would not be likely until sometime in 2005 and a Board decision would logically be well into 2005. AP indicated that it was requesting 2004 final rates.

AP submitted that a bigger picture or blanket TBO policy, such as that which NGTL had in place from 1980-84, and which AP took forward in the NGTL 1995 GRA, is not possible without Board intervention and resolution. Therefore, AP urged the Board to first deal with cost accountability, cost allocation and LCA policy (including the issue of pricing an LCA TBO) as the first step. AP argued that the issue of dual tolling has not disappeared as the 2001/02 EDA deficits and the current exchange fee volatility point out. AP submitted that NGTL's current rate design does not facilitate the movement of gas between AP and NGTL in a manner that sends the correct intra-Alberta pricing signals and should NGTL retain their basic rate design, TBO will undoubtedly be an issue.

Views of the Interveners

CALGARY

Calgary was concerned that AP's proposal to reallocate the costs of OPD and OPR services to the general transportation rates would eliminate the price transparency required for the development of the overall competitive market. Calgary submitted that pipeline services should be transparently priced in order for the market place to fully evaluate service offerings.[188] Calgary argued that inter-utility pipeline competition would be enhanced and a level playing field would be developed when pipeline rates for services were cost based, transparently priced and were provided under known terms and conditions for service.

Calgary submitted that the Competition Proceeding should occur following the issuance of the Board's Phase II decisions for both NGTL and AP, and argued that through the competitive hearing process or module, both entities could then propose changes to COSS methodology and rate design for consideration. Calgary indicated that all parties could then address whatever competitive inequities or equities were deemed to exist as a result of the Board's decisions.

CAPP

CAPP submitted that the CG's TBO proposal should not be considered in the AP Phase II proceeding.

CCA

The CCA submitted that AP was clearly attempting to compete with NGTL by lowering producer rates and moving costs to core customers, which was not in the public interest. The

[188] T 9 Pages 984, 986, 988 and 1010

CCA submitted that this cost shift was a result of the failure of NGTL to provide TBO service to AP sourced natural gas and argued that the Board should reject the cost shifting as proposed by AP and order a TBO option instead, because TBO was a much fairer and favourable outcome than inappropriate cost shifting.

The CCA also submitted that AP was continuing to capture exchange revenue from core customers and using it to subsidize AP sourced natural gas.

The CCA considered it appropriate that other relevant matters that impact competitive issues between AP and NGTL be included in the joint Competitive Proceeding. The CCA submitted that key issues included rates, investment policies, mainline versus lateral definitions and TBO.

CG

The CG submitted that the competition influence of NGTL unquestionably had specific impact on the services, rate design and COSS that AP presented. The CG submitted that the identification and development by AP of new OPR and OPD cost centers was a response, at least in part, to the competitive situation.

The CG submitted that it was not logistically possible for the Board to issue a final decision on the AP Phase II proceeding on the proposed new rate design and resultant rates without regard to the NGTL Phase II decision on rate design. In addition, the CG submitted that it was unlikely that the Board could then determine a final rate design for either utility without regard to the further matters that would be considered in the upcoming Competitive Proceeding.

The CG submitted that TBO was the key issue to be considered in the Competitive Proceeding. The CG indicated that the record of this proceeding included what might be considered bookends of possible TBO approaches. The CG noted that the Phase II Applications of neither AP nor NGTL contained any recommendations for implementation of TBO and at the other extreme, the full TBO approach of CAPP would completely eliminate, for rate-making purposes, the facilities of AP. The CG submitted that the summer and winter TBOs proposed by the CG represented an intermediate position that would eliminate the need for OPR and OPD rates, at least as they apply to NGTL.

IGCAA

IGCAA submitted there were two obvious examples where competition between NGTL and AP had an influence on the rate design proposed in the AP Phase II proceeding:

- Reallocation of OPR system costs based on nominations rather than implementation of a direct demand or a commodity charge, which IGCAA considered consistent with the promotion of fair competition between NGTL and AP; and
- AP's refusal to accept NGTL FT-P deliveries, which IGCAA submitted was unacceptable for reasons described in Section 7.6 of this Decision.

IGCAA did not believe the Board should delay the AP Phase II decision pending either the NGTL Phase II decision or the Competitive Proceeding. The most efficient process would be to use the Competitive Proceeding for both NGTL, AP and their respective customers to react to Board approved rate designs for AP and NGTL and propose any further measures that might be necessary to address competitive issues between the two companies.

NGTL

NGTL submitted that AP's competitive position relative to NGTL appeared to be a significant factor in AP's determination to reallocate costs associated with the provision of its OPR and OPD services to other customer groups and with respect to its toll levels for OPR and OPD services.[189] Further, if the Board accepted that competition between regulated utilities was a legitimate basis for the reallocation of costs and determination of rates, NGTL stated that it would like the Board to provide guidance on whether this factor equally applied to the determination of rates for other regulated utilities, i.e. NGTL.

NGTL suggested that AP's access to, and use of, its NIT account provided AP with economic and operational advantages that worked to tilt the "playing field" in AP's favour. Apart from specific concerns about the unavailability of FT-P service at interconnects, NGTL indicated that it was not currently requesting that the Board prohibit AP's access to, or use of, its NIT account. Rather, this issue should be included and further considered in the Competitive Proceeding.

Rate 13

Rate 13 submitted that competitive concerns, primarily with the producers and to a lesser extent the industrials, appeared to drive AP's rate proposal, rather than traditional cost causation. Rate 13 argued that it was obvious that the distributing companies were the most captive of AP's three real customer classes and it was therefore telling that AP proposed to load significant costs onto the distributing company rate, both indirectly and directly. AP chose to compete with NGTL by rate engineering, rather than competing by providing the most economic service to customers.

Views of the Board

The Board has reviewed the submissions of parties on competitive issues and the impact of competition on the development and design of rates in the Application. The Board considers that competition between the regulated pipelines is a very broad issue and can cover a number of aspects, including competition for existing receipts and deliveries (shifts between the pipelines of existing customer volumes), competition for new or incremental receipts and deliveries, TBO policies, costing practices and rate design practices. In addition, the Board deals with competitive matters in other areas, including load retention issues and facilities proliferation.

NGTL requested clarification as to whether competitive concerns would apply equally to rate determination for all utilities under the Board's jurisdiction. The Board notes that it considered competitive gas pipeline issues and their impact on the development of rates as early as 1993, as indicated in the following passage from Decision E93098:

> The Board notes that, in today's marketplace, the presence of competition for natural gas utilities is a factor which cannot be ignored and which can appropriately be considered in designing rates.[190]

The Board believes, generally speaking, that this view is still valid today. Because competition is a factor that cannot be ignored by any affected party, and because competitively motivated positions by the pipeline companies are to some degree inevitable, the Board considers that these

[189] T171, l. 8 to T172, l. 25; and T579; NGTL Argument, P. 15-17
[190] PUB Decision E93098, page 61, dated December 30, 1993, Re CWNG 1992/93 GRA Phase II

motivations and their impacts on rates, where material, must be considered as they arise. This applies to AP and NGTL alike.

In the present case the Board believes there are clear instances of competitive positions being brought forward from both AP and NGTL. Two examples are AP's proposal to shift the collection of UFG/Fuel to receipts, which was explicitly proposed for consistency and elimination of competitive mismatches between AP and interconnecting pipelines[191], and NGTL's request that the Board require shippers at dually connected stations to nominate volumes directly to NGTL rather than through AP, so that NGTL would not forego receipt revenues.[192]

The Board continues to recognize, as it has in the past, that the regulated pipeline utilities may be required to respond to a competitive environment and that an appropriate response can achieve benefits for all users of the system. For example, the Board has accepted AP's non-standard contracts for loads obtained using competitive rates, on the basis that they have provided a net benefit to the system. Conversely the Board recognizes that competitively motivated proposals could result in detrimental effects overall. The Board believes at this time that balancing these effects will continue to be an issue, and that, broadly speaking, the Board should continue to focus on whether a particular proposal results in a net overall benefit to customers in total.

With respect to this Application in the context of other proceedings, the Board tends to agree with IGCAA that the most efficient process is to make rate determinations in the respective AP and NGTL Phase II proceedings, and to use the Competitive Proceeding for AP, NGTL and their customers to react to the respective rate designs. At that time parties may propose further measures that might be necessary to address competitive issues between the two companies.

As the Board recently indicated in Decision 2004-069 (NGTL 2004 GRA Phase I), the Board considers that there are a number of unresolved competitive issues, and confirms its intent to conduct a Competitive Proceeding involving the years 2005 and beyond. Following this proceeding it may be that further rate proceedings for either or both of AP and NGTL would be appropriate. The Board again confirms that it will canvass interested parties, likely in the fall of 2004, to assist in developing the scope of the Competitive Proceeding.

8 SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. The Board notes that AP identified amounts of $8.063 million (2003) and $30.529 million (2004) that were included in the revenue requirement as placeholders. The Board recognized that the 2003/2004 revenue requirements would be impacted by the outcome of various ongoing proceedings and benchmarking processes. 4

[191] AP Argument, p. 63, lines 1-5.
[192] See Section 7.9 of this Decision.

11. Given the timing of this Decision and the follow-up Compliance Filing, the Board does not believe that AP would have enough time to discuss potential OPR and OPD services with its customers in order to establish stand alone OPR and OPD services for 2004. The Board is prepared to accept AP's position that OPR and OPD services should not be stand alone services at this time. The Board directs AP to confer with its customers to determine whether stand alone OPR and OPD services are practical and cost effective and to address this matter in its next GRA. 47

12. In this case, the Board considers that it is reasonable to base the reallocation on actual historical usage. Therefore, the Board directs AP in the Compliance Filing to use 2002 actual exchange receipt nominations made by the Primary Service Classes to reallocate the income credits and expenses determined for the OPR service class. 48

13. In this case, the Board considers that it is reasonable to base the reallocation on actual historical usage. Therefore, the Board directs AP in the Compliance Filing to use 2002 actual other pipeline delivery nominations made by the Primary Service Classes to reallocate the income credits and expenses determined for the OPD service class. Section 7.7, 2002 Versus 2004 Data provides Board directions with respect to the 2002 actual other pipeline delivery data. 49

14. The Board directs AP to describe in the Compliance Filing its process for assigning a particular nomination (other pipeline receipt and other pipeline delivery) made by a given customer to one of the Primary Service Classes. 49

15. Accordingly, the Board directs AP to ensure in the Compliance Filing, that the rates are increased by no more than 25% for any customer class in both the North and the South above the rates that were in place as of January 1, 2003. 52

16. Given that the Board approved the rate relationships proposed by AP with respect to the FSR demand and OR rates and FSR demand and interruptible receipt transportation (ITR) rates, the Board recognizes that as AP's shifts Net Revenue Requirements to/from the Producer Receipt service class, the FSR OR revenue and IRT revenue will be impacted. The Board directs AP to take this revenue impact into account when establishing the Net Revenue Requirements for the Producer Receipt service class. 53

17. At this time, the Board is of the view that the rate differential due to system differences between the North and the South is of a magnitude that would not permit the use of a province wide weighted average rate. Therefore the Board directs AP to submit separate North and South rates for each customer class in its Compliance Filing. 54

18. With respect to the Rate Schedules, the Board directs AP to file an updated version of all schedules in the Compliance Filing based on Board determinations in this Decision. 54

19. The Board agrees with FGA that AP should develop planning procedures with the Distributing Companies that would satisfy the needs of both the distributing companies and AP. Therefore the Board directs AP to discuss this matter further with the Distributing Companies and to file a proposal in its next GRA. It appears to the Board that the details on such a proposal could be included in AP's BP&P. 76

20. Therefore, the Board directs AP to refile the rate schedule for Delivery Transportation Service to Other Pipelines (Rates OPDM and OPDC) as part of its Compliance Filing in such a way that the OPDM and OPDC services are clearly defined and that the service provisions and service requirements with respect to the other pipelines (NGTL, Alliance and MIPL/TransGas) are clearly distinguished for both OPDM and OPDC. The Board requests

that unique aspects of the OPDM and OPDC services with respect to each connecting pipeline be clearly defined. The rate schedules should also clearly indicate the responsibility of the customer with respect to charges from the other connecting pipelines. 80

21. As noted in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues, the Board has determined that a fully cost based OPD service with stand alone rates would not be required at this time. At present, the Board is prepared to accept AP's proposed methodology for establishing the OPDC rate. However the Board considers that the rate will have to be updated by taking into account the revisions to AP's cost allocations as reflected in this Decision. Therefore the Board directs AP to recalculate the OPDC rate for the North and South as part of the Compliance Filing. The new OPDC rate should be established by using the same expense and revenue categories that AP used in its proposed methodology, but the values assigned or allocated to the three delivery service classes for these expense and revenue categories will have to be updated based on the Board's revised allocation and assignment methodologies described in this Decision.. 81

22. Therefore, the Board directs AP, in the Compliance Filing, to revise the SPD rate to the OPDC rate without deductions and to effect the required changes in the income credit allocation section of the rate design... 83

23. In respect of the CCA concern, until some evidence is provided that demonstrates to what extent the monthly fee may present with the MAS rate, a barrier to smaller customers use of the account, the Board does not consider the rate to be unreasonable. Therefore, the Board approves the MAS rate schedule as proposed by AP. However, the Board directs AP to file a market barrier analysis on the MAS rate when it applies for any future variance in the rate, which may be on a stand alone basis or as part of its next Phase II GRA. 84

24. The Board considers it appropriate for AP to apply for rate riders as required, separate and apart from this proceeding. However, for completeness, the Board directs AP to include the current rate rider schedules for both the North and South in the Compliance Filing. 84

25. The Board views that the item related to contract term will be an integral requirement of the revised schedule of rates approved in this Decision. Therefore, the Board directs AP, in its Compliance Filing, to include the issue of contract term, currently Section 2.3 of the BP&P, into the appropriate sections of its RS. 96

26. The Board also directs AP to file updated TSR in the Compliance Filing based on Board determinations in this Decision... 96

27. Having concluded that Section 51 of the GUA does not prevent the discontinuation of the sales service, that the provision of such a service would not be within the customary activities of AP, and that the provision of such a service would create additional costs going forward, the Board agrees with AP that it should cease to provide the sales service to Rate 5 customers. The Board considers that the Rate 5 customers should receive FSU service on a demand rate basis as proposed by AP. Where a demand figure has not been settled between a Rate 5 customer and AP, or otherwise determined, the Board considers that AP's forecast of customer demand should be used for the test years, since no evidence was submitted to the contrary on this point. However, as discussed in Section 7.8.1, for refund purposes to Samson Band and Redwater, the Board has directed AP to use the maximum daily quantity shown for these Rate 5 customers in the FGA Argument. AP's forecast demand number should be adjusted as necessary to reflect the Board's direction in Section 7.1 that the four-hour peak demand be used for billing purposes. 122

28. As discussed in Section 5.4.1, it appears beneficial to smaller Distributing Companies to be a part of a larger service class. As part of a larger service class, smaller Distributing Companies may be insulated to a degree from potentially higher cost of service charges (and associated rates) reflecting the physical realities of providing service in geographically large areas with lower population densities. Although the Board appreciates FGA's argument that ownership of certain metering facilities should directionally lower their overall costs, the Board considers that this is one element of many that the Board must consider when making its determination of whether or not the overall rates charged to FGA continue to be fair and reasonable. Accordingly, the Board has determined that Gas Alberta should not be billed on a rate separate and distinct from the rates for the Distributing Companies, and that there should not be a reduction in the rate related to Gas Alberta's ownership of certain metering equipment. The Board declines to provide for a credit for meter ownership in the calculation of the refund owed to Gas Alberta by AP. 148

29. As indicated, the revenue forecast by AP for the 2003 and 2004 test years was determined on AP's proposed demand rates for transportation service to utilities, including Gas Alberta. However, the actual billings to Gas Alberta for the period from January 1, 2003 to March 1, 2004 were on commodity rates, which produced a higher amount of revenue. The Board considers that AP's billings on commodity rates generated revenue in excess of the revenue forecast prepared on a demand basis. Therefore, the excess non-forecast revenue should be refunded to Gas Alberta without any adjustment to other revenue forecasts or other rates to recover the refund. The Board directs AP to calculate the refund as part of the Compliance Filing based on the findings in this Decision. 150

30. As indicated, the revenue forecast by AP for the 2003 and 2004 test years was determined on AP's proposed demand rates for transportation service to utilities, including Rate 5 customers. However, the actual billings to Samson Band and Redwater for the period from March 1, 2004 to the date of commencement of final rates in 2004 will have been on commodity rates, which produced a higher amount of revenue. The Board considers that AP's billings on commodity rates generated revenue in excess of the revenue forecast prepared on a demand basis. Therefore, the excess non-forecast revenue should be refunded to Samson Band and Redwater without any adjustment to other revenue forecasts or other rates to recover the refund. The Board directs AP to calculate the refund as part of the Compliance Filing based on the findings in this Decision. 151

31. With respect to demand billing determinants in the refund period, the Board directs AP to use the maximum daily quantity shown for Samson Band and Redwater in the FGA argument. 152

9 ORDER

IT IS HEREBY ORDERED THAT:

(1) ATCO Pipelines shall comply with all Board directions in this Decision.

(2) ATCO Pipelines shall refile its 2004 Phase II GRA (the Compliance Filing) as required by this Decision, on or before October 4, 2004, incorporating the findings and directions in this Decision.

(3) In the Compliance Filing, ATCO Pipelines shall include all necessary supporting schedules for the Board to make its final determination respecting ATCO Pipelines' 2004 rates. The Compliance Filing shall be at a level of detail sufficient to reconcile with the original Application and to demonstrate compliance with the Board's findings and directions in this Decision.

Dated in Calgary, Alberta on September 24, 2004.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

C. Dahl Rees
Presiding Member

(original signed by)

B. T. McManus, Q.C.
Member

(original signed by)

M. W. Edwards
Acting Member

APPENDIX 1 – PARTIES PARTICIPATING IN THE PROCEEDING

Principals and Representatives (Abbreviations used in Report)	**Witnesses**
ATCO Gas L. Smith	G. Schmidt
ATCO Pipelines N. Gretener M. Buchinski	D. Belsheim E. Jansen D. Rochon R. Johnston
Aboriginal Communities and Care Centre Group A. Ackroyd J. Graves	R. Bellows
Alberta Irrigation Projects Association H. Unryn D. Hill	
AltaGas Utilities Inc. J. James R. Koizumi R. Jeerakathil L. Meyer	
BP Canada Energy Company P. Raina	
Burlington Resources Canada Partnership D. Fleming	
Canadian Association of Petroleum Producers (CAPP) N. Schultz R. Fairbairn	G. Stringham R. Moore
Cargill Power & Gas Markets A. Bianchi	
Compton Petroleum Corporation T. G. Millar	
Consumers Coalition of Alberta (CCA) J. Wachowich J. Jodoin	

Principals and Representatives (Abbreviations used in Report)	**Witnesses**
Consumers Group (CG) Alberta Urban Municipalities Association (AUMA)/City of Edmonton (EDM) J. A. Bryan Public Institutional Consumers of Alberta (PICA) N. McKenzie	R. Liddle R. Retnanandan
Coral Energy Canada Inc. K. McKnight	
Direct Energy Regulated Services K. Miller G. Newcombe	
EnCana Corporation R. Powell	
Federation of Alberta Gas Co-ops and Gas Alberta Inc. T. D. Marriott	D. Symon D. Campbell K. Dannacker
Husky Energy Marketing Inc. D. Danyliw	
Imperial Oil Resources R. Moore	
Industrial Gas Consumers Association of Alberta (IGCAA) B. Roth	N. MacMurchy G. Sproule K. Wazney
Nexen Marketing D. Cameron S. Young	
NOVA Gas Transmission Ltd. P. Keys I. Berbekar	
Petro-Canada R. Cameron S. Miller	

Principals and Representatives (Abbreviations used in Report)	**Witnesses**
Producers Marketing Ltd. J. Gerwing	
Rate 13 Group L. Manning	
Shell Canada Ltd. R. Gall	
Talisman Energy Inc. F. Basham	
The City of Calgary (Calgary) B. Meronek	M. Lively H. Vander Veen
University of Alberta P. Smith N. Chymko A. da Silva	
Weyerhaeuser Company Limited K. Logan	
Alberta Energy and Utilities Board Board Panel C. Dahl Rees, Chair B. T. McManus, Member M. W. Edwards, Acting Member Board Staff B. McNulty, Board Counsel D. Popowich M. Hagan M. McJannet A. Laroiya	

APPENDIX 2 – ABBREVIATIONS

Abcom/CCG means Aboriginal Communities and the Care Centre Group
AG means ATCO Gas
AGN means ATCO Gas North
AGS means ATCO Gas South
AP means ATCO Pipelines
APN means ATCO Pipelines North
APS means ATCO Pipelines South
AUMA/EDM means Alberta Urban Municipalities Association and The City of Edmonton
Board or EUB means the Alberta Energy and Utilities Board
BP&P means Business Policy and Practices
CALGARY means The City of Calgary
CAPP means Canadian Association of Petroleum Producers
CCA means Consumers Coalition of Alberta
CD means Contract Demand
CG means the Consumer Group
COSS means Cost of Service Study
CTM means Custody Transfer Meter
CWNG means Canadian Western Natural Gas Company Limited
DERS means Direct Energy Regulated Services
DGP means Delivered Gate Price
DSP means Default Supply Provider
EDA means Exchange Deferred Account
FCS means Facilities Connection Service
FGA means the Federation of Gas Co-ops and Gas Alberta Inc.
FSD means Firm Service Delivery or Firm Delivery Transportation Service
FSR means Firm Service Receipt
FSU means Firm Service Utility or Firm Delivery Service for Distributing Companies
FSRS means Firm Short-term Receipt Transportation Service
FT-A means Firm Transportation - Alberta Delivery Service
FTEs means Full-time Equivalents
FT-P means NGTL's Firm Transportation Point-to-Point Service
GCRR means Gas Cost Recovery Rate
GJ means Gigajoule
GRA means General Rate Application
GS means General System
GUA means Gas Utilities Act, R.S.A. 2000, c. G-5
GURDI means Gas Utilities Rate Design Inquiry
IGCAA means Industrial Gas Consumers Association of Alberta
I/P means Industrial and Producer
IT means Interruptible
ITR means Interruptible Receipt Transportation
LCA means Least Cost Alternative
LDC means Local Distribution Company
LRS means Load Retention Service
MAS means Market Account Service
MAV means Minimum Annual Volume
Mcf means Million cubic feet

MIPL/TransGas means Many Islands Pipeline/TransGas
MOU means Memorandum of Understanding
M&R means Measurement and Regulating
NCP means Non-Coincident Peak
NGTL means NOVA Gas Transmission Ltd.
NIT means NGTL Inventory Transfer
NUL means Northwestern Utilities Limited
O&M means Operating and Maintenance
ODC means Oversupply Delivery Costs
OPDC means Other Pipeline Delivery Commodity
OPD means Other Pipeline Deliveries
OPDM means Other Pipeline Delivery – Must Flow
OPR means Other Pipeline Receipts
OR means Overrun
PICA means Public Institutional Consumers of Alberta
RS means Rate Schedules
SPD means Straddle Plant demand
TBO means Transportation by Others
TCPL means TransCanada Pipelines
TJ means Tera Joules
TSA means Transportation Service Agreement
TSR means Transportation Service Regulation
UFG means Unaccounted for Gas

APPENDIX 3 – RELATED DECISION REPORTS/PREVIOUS BOARD DECISIONS REFERENCED

Decision E90024	Canadian-Montana Gas Company Limited Application by Canadian-Montana Gas Company Limited for an order of the Public Utilities Board pursuant to the *Public Utilities Board Act* declaring that Canadian- Montana Gas Company Limited is not an owner of a public utility, and pursuant to the *Gas Utilities Act*, declaring that Canadian-Montana Gas Company Limited is not an owner of a gas utility. Dated March 2, 1990
Decision E93098	Canadian Western Natural Gas 1992/93 GRA Phase II Dated December 30, 1993
Decision U96055	NOVA Gas Transmission Ltd. 1995 General Rate Application - Phase II Dated June 12, 1996
Decision U97096	NOVA Gas Transmission Ltd. Application for Approval of a New Service Offering the Load Retention Service (LRS) Including Applicable Terms and Conditions of Service. Dated November 14, 1997
Decision U99034	Alberta Power Limited 1996 General Rate Application – Phase II Dated August 10, 1999
Decision 2000-6	NOVA Gas Transmission Ltd. 1999 Products and Pricing Dated February 4, 2000
Decision 2000-84	ATCO Pipelines North and South Transmission Transportation Service Interim Rates Dated December 22, 2000
Decision 2001-53	ATCO Pipelines Approval of Rates, Tolls, Charges, and Transportation Service Regulations; Approval of Amendments to North and South Transmission Transportation Agreements Dated June 11, 2001
Decision 2001-97	ATCO Pipelines South 2001-2002 General Rate Application Phases I and II Dated December 12, 2001

Decision 2002-111	ATCO Pipelines South 2001/2002 General Rate Application, and Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues Dated December 17, 2002
Decision 2003-019	Aquila Networks Canada (Alberta) Ltd. 2002/2003 Distribution Tariff Dated February 28, 2003
Decision 2003-035	ATCO Pipelines North and South 2003/2004 General Rate Application Phase I – Request for Approval to Commence a Negotiated Settlement Dated April 30, 2003
Decision 2003-040	ATCO Group Affiliate Transactions and Code of Conduct Proceeding, Part B: Code of Conduct Dated May 22, 2003
Decision 2003-051	NOVA Gas Transmission Ltd. 2003 Revenue Requirement and Tariff Settlement Applications Dated June 24, 2003
Decision 2003-100	ATCO Pipelines 2003/2004 General Rate Application - Phase I Dated December 2, 2003
Decision 2003-105	NOVA Gas Transmission Ltd. Request for 2004 Interim Rates, Tolls, and Charges Dated December 16, 2003
Decision 2004-003	ATCO Pipelines 2003/2004 General Rate Application – Phase I Errata of Decision 2003-100 Dated January 15, 2004
Decision 2004-022	ATCO Gas South 2004/2005 Carbon Storage Plan Dated March 9, 2004
Decision 2004-023	ATCO Pipelines 2003/2004 General Rate Application 2004 Interim Rates Application Dated March 9, 2004

Decision 2004-038	ATCO Pipelines 2003/2004 General Rate Application – Phase I Compliance Filing Dated April 30, 2004
Decision 2004-059	ATCO Pipelines 2003/2004 General Rate Application Second Compliance Filing Dated July 13, 2004
Decision 2003-042	ATCO Pipelines North Application for Approval of UFG Methodology Dated May 29, 2003
Order U2002-1034	ATCO Pipelines 2003 Interim Rates, Tolls and Charges Dated December 20, 2002
Order U2003-401	ATCO Gas and Pipelines Ltd. Interim Application For Other Pipelines Receipts Commodity Rate Dated November 7, 2003

APPENDIX 4 – BOARD ADJUSTMENTS TO AP COSS COMPONENTS – NORTH

Item	AP February 2, 2002 COSS	Board Approved	Section Reference
Distribution Company Billing Demand	1 hour (1,343 TJ/day)	4 hour (1,316 TJ/day)	7.1
Distribution Company 4 Hour Peak Demand	1,321 TJ/day	1,316 TJ/day	7.1
Marketing Expense Allocator	Sum of all other costs excluding a few items.	Throughput	3.5.1
UFG CTM Expense Allocator	50% direct to Distribution. 50% throughput	100 % throughput	3.5.5.2
ODC Allocator	4 hour peak demand	Direct to OPD	3.5.6.4
OPD Reallocation Allocator	4 hour peak demand	OPD nominations	3.7
OPDC Revenue Allocator	4 hour peak demand	OPD nominations	3.7
IT/OR Allocator	4 hour peak demand	Direct to Producers	3.6
OPR Nomination Allocator	2002 data including OPR nominations for non-standard contracts	2002 data excluding OPR nominations for non-standard contracts	7.7
Throughput Allocator	2002 data including throughput for non-standard contracts	2002 data excluding throughput for non-standard contracts	7.7
Industrial 4 Hour Peak Demand (for cost allocation)	Included Straddle Plant demand (662 TJ/day)	Excluded Straddle Plant demand (609 TJ/day)	7.1
Straddle Plant Revenue Allocator	Direct to Industrial	All classes based on 4 hour peak demand	3.6
SPD Rate	OPDC rate less Salt Cavern expenses and Other Directly Allocated Expenses	OPDC rate.	5.6
OPR Rate	1.5 cents/GJ	1.4 cents/GJ	5.2
OPR “Demand”	1,026 TJ/day	968 TJ/day	7.1

APPENDIX 5 – BOARD ADJUSTMENTS TO AP COSS COMPONENTS - SOUTH

Item	AP February 2, 2002 COSS	Board Approved	Section Reference
Distribution Company Billing Demand	1 hour (1,137 TJ/day)	4 hour (1,112 TJ/day)	7.1
Distribution Company 4 Hour Peak Demand	1,115 TJ/day	1,112 TJ/day	7.1
Marketing Expense Allocator	Sum of all other costs excluding a few items.	Throughput	3.5.1
UFG CTM Expense Allocator	50% direct to Distribution. 50% throughput	100 % throughput	3.5.5.2
ODC Allocator	4 hour peak demand	Direct to OPD	3.5.6.4
OPD Reallocation Allocator	4 hour peak demand	OPD nominations	3.7
OPDC Revenue Allocator	4 hour peak demand	OPD nominations	3.7
IT/OR Allocator	4 hour peak demand	Direct to Producers	3.6
Throughput Allocator	2002 data including throughput for non-standard contracts	2002 data excluding throughput for non-standard contracts	7.7
OPR Rate	1.5 cents/GJ	1.4 cents/GJ	5.2
OPR "Demand"	769	766	7.1

APPENDIX 6 – OTHER RATE CHANGES DUE TO BOARD ADJUSTMENTS – NORTH AND SOUTH

Item
FSR Demand Charge
FSR Overrun Charges
FSRS Demand Charge
FSRS Overrun Charges
ITR Charges
FSD Demand Charges
FSD Overrun Charges
FSU Demand Charge
OPDM Overrun Charge
OPDC Charge

Decision 2007-086

ATCO Electric Ltd.

2008 Distribution Tariff Phase II

November 8, 2007

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2007-086: ATCO Electric Ltd.
2008 Distribution Tariff Phase II
Application No. 1500878

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Contents

List of Tables

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

ATCO ELECTRIC LTD. **Decision 2007-086**
2008 DISTRIBUTION TARIFF PHASE II **Application No. 1500878**

1 INTRODUCTION

The Alberta Energy and Utilities Board (EUB or Board) received Application No. 1500878 (the Application) dated February 5, 2007 from ATCO Electric Ltd. (AE or the Company) requesting approval of AE's 2008 Distribution Tariff (DT) Phase II Application.

Notice of the Application was published in major Alberta newspapers, distributed by e-mail and posted on the Board's website. In the Notice of Application, the Board set out the preliminary steps of a process to deal with these matters, which ultimately followed the schedule below:

Process Step	*Deadline Date*
Application Registered	February 5, 2007
Notice Issued	February 14, 2007
Filing of Issues requiring Clarification at AE Technical Meeting	February 28, 2007
Statement of Intent to Participate	March 6, 2007
Preliminary Issues List	March 7, 2007
Technical/Information Meeting	March 9, 2007
Filing of Additional AE Material Re: Technical Meeting (if any)	March 16, 2007
Comments on Issues List	March 20, 2007
Revised Issues List	March 27, 2007
Information Requests to Applicant	April 3, 2007
Intervener Budgets	April 10, 2007
Applicant Budget	April 11, 2007
Board Comments on Budgets	April 18, 2007
Information Responses from Applicant	April 24, 2007
Intervener Evidence	May 15, 2007
Information Requests to Interveners	May 28, 2007
AAMDC/AFREA Intervener Evidence	May 18, 2007
Information Responses from Interveners	June 11, 2007
Rebuttal Evidence	June 18, 2007
Hearing – EUB Edmonton Office 12th Floor, 10055 - 106 Street	June 25, 2007

A public hearing was convened in Edmonton, on June 25, 2007 before Board members Mr. A. J. Berg, P.Eng. (Presiding Member), Ms. L. J. Bayda (Acting Member), and Mr. M. W. Edwards (Acting Member). The oral evidentiary part of the process was completed on June 29, 2007. The Board set dates of July 23, 2007 and August 9, 2007 respectively for Argument and Rebuttal Argument.

Accordingly, for the purposes of this Decision, the Board considers the record to have closed on August 9, 2007.

In reaching the determinations contained within this Decision, the Board has considered the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this Decision to specific parts of the record are intended to assist the reader in understanding the Board's reasoning relating to a particular matter and should not be taken as an indication that the Board did not consider other relevant portions of the record with respect to that matter.

2 RESPONSES TO BOARD DIRECTIONS

In response to previous Board directions in Decision 2005-025,[1] AE undertook several studies and incorporated the results in its Terms and Conditions of Service, cost of service model, investment policy design and rate design. In this section the Board examines the results of studies for which issues arose in this proceeding and provides its findings on those issues.

2.1 Power Factor Study

In Decision 2005-025, the Board directed AE to undertake a comprehensive study with respect to the causes of poor power factor, the associated penalty and solutions to resolve the issues brought forward by interveners. AE engaged the services of RCGI Consulting (RCGI) to undertake all aspects of the study, including an analysis of the costs to provide service to sites with low power factor. As a result of this study, AE proposed to change the power factor tariff from 29.59¢ per kVA per day to 16.14¢ per kVA per day for customers on the large general service/industrial rates and from 29.59¢ per kVA to 37.12¢ per kVA per day for customers on AE's oilfield rates.

Stakeholder input sessions in the development of the study and in the preparation of the final report were provided and the input received from parties was reflected in the study.

The Public Institutional Consumers of Alberta (PICA) noted that AE's proposed power factor charges were based on system degradation costs at an 85% power factor, however, the study revealed incremental system capacity resulting from low power factor increases from 108% at a power factor of 85% to 115% and 124% at power factors of 80% and 75%. PICA submitted that for customers with power factors lower than 85%, the low power factor costs would be materially higher than the charges based on an 85% power factor. PICA questioned AE's assumption that power factor charges based on an 85% power factor would reflect the average power factor for customers in all rate classes with low power factor.

To address this uncertainty, PICA recommended that AE be directed to monitor the average power factors by rate class and propose any changes to the power factor charges necessary to recover low power factor costs at the average power factor for each class as part of its next DTA Phase II.

AE submitted that there were several difficulties with PICA's proposal. First, AE does not monitor "average power factor" for each rate class. Further, low power factor is not limited to any one class. Rather, it spans all rate classes as low power factor occurs where motors are

[1] Decision 2005-025 – ATCO Electric Ltd. 2004 Phase II Distribution Tariff (Application 1349514) (Released: April 6, 2005)

running lightly loaded. AE submitted that the proposed power factor charge was designed to address this situation. Second, the concept of "average power factor" for a rate class had no practical value, as a customer's power factor fluctuates as it turns motors on and off.

AE submitted that there was no practical means of determining the aggregate power factor of all customers within a rate class at any point in time.

2.1.1 Views of the Board

The Board notes that AE's power factor study reflected input from interested parties, and was not opposed by any party. The Board has reviewed the study and finds that it addresses the issues and concerns expressed by the Board in the last Phase II application. The Board finds that the changes AE proposed to its power factor tariff should be implemented in order to improve cost recovery from the customers that cause low power factor costs and to provide an incentive for those customers to improve their power factors.

The refinements to the power factor study recommended by PICA, are not supported by any evidence respecting the usefulness or practicality of monitoring average power factor charges by rate class. From the record, the Board observes that aggregate total load is used for system planning and that AE works with individual customers to improve load factor. In this context, the Board questions the usefulness of a class average load factor. Further, AE suggests, that there would be significant costs involved in determining the average power factor of each rate class and refining the study in an attempt to determine an appropriate charge for each rate class. The Board is not convinced that such costs should be incurred at this time. Therefore the Board does not accept the recommendation made by PICA.

Accordingly, the Board approves AE's proposed power factor charges of 16.14¢ per kVA per day for customers on the large general service/industrial rates and 37.12¢ per kVA per day for customers on AE's oilfield rates.

2.2 Average Age Study and Investment Levels

AE prepared an average age study[2] (the Average Age Study) to determine the average age of customer facilities by rate class in response to Direction No. 48 from Decision 2005-025. AE indicated in the Average Age Study that it does not track asset ages by rate class, so it used yearly customer counts (net additions) as a proxy method to determine average age. AE indicated that this method was employed because it measures average age consistently across all rate classes. A copy of the information used for the derivation of the results was provided by AE in response to UCA-ATCO-2.

AE explained that the Rural Capital Costs Assignment (RCCA) study results were not used by AE as part of this exercise, since the RCCA study only examined rural work orders, whereas approximately 75% of customers are non-rural based.

AE stated that average ages were used in combination with additional factors to derive the maximum allowable investment per unit.

[2] Application, Section 8, Attachment 5

Similar to the approach utilized by AE in the 2004 DTA, AE stated that the factors considered in the development of the proposed investment levels, include the average historical local extension cost per rate class, the calculated maximum allowable investment per unit from the study and the capping of the change in investment levels at 10%, in consideration of intergenerational equity.

Based on a review of the Average Age Study and related information requests, PICA recommended that the study be accepted by the Board.

The Office of the Utilities Consumer Advocate of Alberta (UCA) questioned AE's contention that its proposed methodology measures average age correctly for all rate classes. UCA noted that a comparison of the two methods revealed that a RCCA Farm average age of 19 years as shown in UCA-ATCO-2(b) did not match the Average Age Study age of 29 years for that class. Similarly, the RCCA Industrial average age of 15 years did not match the Average Age Study of 20 years.

UCA also questioned the proxy method used by AE in the Average Age Study. The Average Age Study used a combined rural versus non-rural group of customers, and showed that oilfield customers had nearly the same average age excepting farm customers. Yet, the RCCA calculations in UCA-ATCO-2(b) showed nearly the same average age of all rural customer classes (i.e. approximately 18 years) with the exception of industrial customers who have an average age of 15 years.

UCA noted that the RCCA study used specific work order information dating back a number of years, and that this information had been considered to be robust, therefore, this information should be reliable and useable.

The UCA did not recommend any changes to the calculation of investment levels that utilized the average age of assets but recommended that the Board direct AE to further investigate the proxy method it has used in the Average Age Study. In particular, the UCA recommended the Board direct AE for its next GTA, to further split the Average Age Study into a rural versus non-rural examination to determine the robustness of the proxy methodology when compared to the RCCA results shown in UCA-ATCO-2(b).

AE noted that while the proposed investment levels for the industrial and farm rate classes may be reduced somewhat if the RCCA Study were utilized, the UCA was not recommending any changes in investment levels. AE submitted that the fact that the RCCA and proxy methods yielded similar results should provide additional comfort that the proposed proxy methodology is valid.

2.2.1 Views of the Board

The Direction in Decision 2005-025[3] that triggered the Average Age Study was as follows:

> The Board also notes the issue raised by PICA that investment levels are tied in part to the average age of assets. The Board considers that for AE's next Phase II application, it would be useful in assessing the investment level to have a study that determines the average age of assets. Therefore, the Board directs AE, in its next Phase II application, to

[3] Decision 2005-025, pages 61-62

> provide support for the average age of customer facilities by rate class used for calculating RCN (replacement cost) by rate class. (Parenthesis added)

The Board considers that the Average Age Study used a consistent approach across all rate classes which would not be possible if AE used the RCCA study as that study only concerned the rural rate classes.

While the Board notes that the UCA raised in Argument several seeming inconsistencies between the RCCA study and Average Age Study, the Board would have expected some differences in the results of the studies since they were conducted on entirely different bases.

Nonetheless, the Board has some difficulty with the treatment of the negative customer numbers in the Average Age Study for Farm and Commercial Customers in UCA-ATCO-2 Schedule 1. The Board notes that using a negative number increases the average age of all customers in the class even though the average age of the customers leaving is unknown. It appears to the Board that if those numbers are set to zero in the study, then the average age for farm customers is reduced to 26 years. For this reason the Board would prefer to use 26 years as the average age for farm customers and notes that doing so will not affect AE's investment levels for this proceeding since AE is already increasing its investment for farm customers by the 10% maximum.

This change reduces the difference between the RCCA and Average Age Study from 10 years to 7 years (29-19 vs. 26-19). The Board does not consider that the changes in investment levels that would arise from differences of a few years in average class age would have significant impact on inter-generational customer class equity, even if the investment levels were determined based only on RCN generated maximum investment levels.[4] Accordingly, the Board is not persuaded that the impact of changes in average class ages, even if they could somehow be reconciled or corrected as between the two studies, would be enough to warrant the costs of further study.

The Board considers that AE has complied fully with the above direction by providing the Average Age Study which it used in assessing the investment levels proposed in the Application.

2.3 Load research: Distribution Loss Study

The Distribution Loss Study proposed by AE in the Application was based on a stratified sample of distribution feeders in the AE system. Each of the feeder systems was studied to analyze the customers and losses associated with that system. AE stated that the information from all of the sample feeder systems was then combined to produce an estimate for the entire distribution system. AE stated that the results of these studies, which extended back five years, were combined and used to forecast distribution system energy and demand losses and to allocate these losses to AE rate classes and subgroups.

UCA submitted that AE's calculation method using MW-mile, which kept loss factor constant, did not recognize the basis for electrical losses and therefore favoured customers closest to the point of delivery (POD). UCA proposed the use of I^2R methodology on the primary system to allocate losses, which increases or decreases the loss factor with the loading on a line.

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[4] Application, Section 8, Schedule 8-B-4

UCA questioned the randomness of samples used in AE's 2004 Loss Study and was concerned that detailed data on losses by segment was not used to allocate total losses to customer classes. UCA also argued that AE's averaging of the results of the 2004 Loss Study with four previous loss studies did not satisfy its concerns with the lack of sensitivity in the 2004 Loss Study. UCA explained that AE had not provided the results of the standard industry method for assessing the results of the sample selection process or a sensitivity analysis regarding the average of the five loss studies. UCA urged the Board to direct AE to report on the appropriate industry standard means to assess the precision of results produced from a random sample in its next loss study.

UCA also recommended the Board should direct AE to use the detailed loss data[5] and the information by class[6] to develop loss factors by class of customers, and that AE should be directed to use a different procedure in the next loss study. UCA recommended the Board should direct AE to work with UCA and other interested parties to develop other methods to improve the adequacy of loss determination for all customers.

The Alberta Sugar Beet Growers and Potato Growers of Alberta (ASBG/PGA) was concerned with the supporting documentation provided by AE, and contended that the details of the model were a black box that did not allow interveners the opportunity to fully test and examine the underlying rationale of the results. ASBG/PGA disagreed with the AE method of using a kw-kilometer or kilometer basis for allocating losses to a customer class and submitted that losses were a function of I^2R which would cause more losses in heavily loaded lines closer to the transmission POD than in more lightly loaded lines closer to the customer meter.

ASBG/PGA further submitted that AE's use of a flow program that simulates the distribution network at the winter peak conditions and then utilizes the same flow data for summer peak conditions overstates the amount of losses in the summer peak condition, as the summer peak was 90% or less than the winter peak. Instead, ASBG/PGA urged the Board to direct that irrigation services primary losses be based on the UCA study of 2.5%. In the alternative, if the UCA Study was not accepted, then ASBG/PGA recommended that the Board consider the decision made by the Board in the FortisAlberta Inc. (FAI) proceeding (Decision 2006-099,[7] page 54) where farm loss factors were limited to 5% and loss factors were prorated for all other rate classes to achieve the same forecast overall losses. A further alternative proposed for consideration would be to cap the primary losses at the mid-point of the AE and UCA studies at 4.85% (average of 7.2% and 2.5%) pending a new study for the next GTA that takes into account the I^2R factor in a transparent manner. ASBG/PGA recommended that, due to the need for a cap on the primary losses and potential overstatement of secondary losses, it would be more appropriate to limit the overall 2008 GTA irrigation losses to the 2004 GTA losses level being 6.5%.[8]

The Industrial Power Consumers Association of Alberta (IPCAA) was concerned that AE had not utilized the same level of detail in the allocation of secondary distribution losses as for primary losses. IPCAA submitted that secondary distribution losses were significantly misallocated under AE's practice of allocating losses on the basis of energy sales and

5 Exhibit 002-16, AE Cover letter and Rebuttal Evidence, page 8
6 Exhibit 002-13-06, ASBG/PGA-ATCO-8 Customer Details.xls
7 Decision 2006-099 – FortisAlberta Inc. 2006/2007 Distribution Tariff Phase II and Other Matters (Application 1434992) (Released: October 16, 2006)
8 Technical Meeting, Slide 44

recommended that the Board direct AE to modify its secondary distribution allocation method to reflect a MW-mile approach for wires losses. IPCAA estimated that industrial secondary losses should be 1/3 lower (i.e. 2% rather than 3%) which would indicate an annual misallocation of $4 million in energy costs to D31 customers.

IPCAA stated that when allocating losses, the segment-by-segment approach suggested by UCA recognized the diseconomy of scale of the larger aggregate loads (and therefore higher current) on the conductor segments nearer the POD, whereas the MW-mile approach proposed by AE did not. In this way, the segment-by-segment approach could be said to better reflect cost causation.

IPCAA submitted that an approach to allocating losses that recognized diseconomies of scale (such as the segment-by-segment approach advocated by the UCA) ought also to be properly balanced by recognizing the economies of scale in respect of the cost of the assets which are also present. Recognizing the economies of scale in respect of the assets requires the allocation of primary distribution costs to also be undertaken on a segment-by-segment basis.

IPCAA requested the Board direct AE to:

1. allocate primary distribution losses on a segment by segment basis, with recognition of larger conductor nearer the POD;
2. allocate primary distribution costs on a segment by segment basis, with recognition both of the slightly higher costs of larger conductor nearer the POD and that customer classes nearer the POD use less conductor mileage; and
3. modify its secondary distribution allocation method to reflect both lower losses associated with larger transformers and the shorter length of secondary distribution lines utilized to serve large customers.

PICA recommended the loss percentages by rate class proposed by AE should be accepted by the Board, without change, for purposes of this proceeding.

PICA noted the inconsistency in the allocation method of primary and secondary losses to rate classes under AE's loss study, and recommended that comparable methods of allocation should be applied to both the primary and secondary lines for consistency. If the Board accepted UCA's proposed segment by segment analysis, that analysis could be applied to both the primary and secondary portions of the sample feeders. PICA also recommended that AE should be directed to address and reflect, to the extent feasible, any refinements to the loss study resulting from the issues raised by UCA respecting segment by segment analysis of losses and to address PICA's concern respecting the inconsistency in treatment of primary and secondary line loss allocations as part of its next DTA Phase II.

AE explained that the current study was combined with the other four most recent studies making the sample size five times that incorrectly assumed by UCA. AE samples were selected using a random number generator.[9] AE did not attempt to manipulate its sample selection process; it accepted the results of the sample selection process as they occurred.

AE disputed ASBG/PGA's assessment that the Distribution Loss Study model used was a black box. AE submitted that the basis upon which the Distribution Loss Study had been conducted

[9] Transcript Volume 1, pages 118-119

was fully explained; and sufficient background information provided in order for parties to understand the manner in which AE's model operated. Summer and winter peaks were not being mixed as alleged by ASBG/PGA. The model was the same because the line was the same, but the loading on the line was different for the summer and winter peak hours. AE confirmed that no overstating of summer peak hour losses occurred.

AE also noted that a large portion of the secondary losses occur in transformers, which are not impacted by a distance factor, so that a MW-mile approach was simply not appropriate. AE explained that adopting a MW-mile approach for allocating the remainder of the losses would have a materially diminished impact on the overall end result. In addition to length of line and conductor size, the characteristics of the load being distributed must also be considered in the secondary loss allocation.

AE maintained that its approach to allocating losses on the primary and secondary systems was appropriate. AE allocated secondary losses based on load (MW) only, as a large portion of the secondary losses are transformer losses, which are independent of distance. The secondary system differed from the primary system in that it contained all distribution transformers, the capacities were typically much smaller and it served a different function.

AE stated that software enhancements costing approximately $100,000 would be required to implement the allocation of primary losses by line segment while spending in the order of $1,000,000 would be required to implement a similar Loss Study by component for the secondary system. AE submitted that incurring such costs would far outweigh any benefits that might potentially be derived as the net result of implementing a more detailed allocation methodology was expected to be insignificant.[10]

The Consumers Coalition of Alberta (CCA) submitted that when AE corrected two deficiencies in the UCA loss study, the differences between the UCA study and AE's 2004 Loss Study were marginal, and would have minimal impact on the Cost of Service Study (COSS) and rate design. Further, a more detailed allocation method for primary system losses was not appropriate without undertaking a similar study for the secondary system losses.

CCA was concerned with the cost to pursue the distribution feeder loss alternative proposed by UCA and noted that any sensitivity associated with the use of a single year's feeder results was mitigated when AE combined these results with the previous four studies to provide a more balanced, larger sampling of feeders. On this basis, CCA recommended the Board accept AE's approach for determining primary system losses for each customer class.

2.3.1 Views of the Board

The Board considers there are several possible ways (kilometer basis, segment basis, I^2R, postage stamp, etc.) to allocate distribution system losses. Selection of an approach must weigh accuracy against the potential costs associated with that approach.

AE's approach is based on a stratified sample of distribution feeders in the AE system and is consistent with the way in which losses have been allocated in the past. However, the Board

[10] Transcript Volume 2, page 347

notes that several interveners have expressed concern with this approach and/or have suggested an alternative method for allocation.

UCA expressed concerns with AE's loss study regarding the randomness of the samples used and with available detailed data on losses by segment not being used to allocate total losses to customer classes.

The Board notes from the evidence in the proceeding that a random number generator was used to select the samples.[11] The Board considers the evidence also shows that all customer groups were adequately represented in the approximately 200 sample feeders.[12] From this evidence, the Board finds that AE has developed a process that reasonably ensures the randomness of the samples used in the loss allocation study.

ASBG/PGA indicated that it had difficulty in obtaining a fully working model for testing and that the method used was based on the kilometer basis rather than the I^2R approach. Since the proposed loss factor impacts were material, ASBG/PGA wanted the overall 2008 irrigation losses capped at the 2004 GTA level of 6.5% rather than at the 7.2% level recommended by AE. The Board finds that the difference between these two loss factors is not material, particularly since that the Irrigation Distribution Revenue to Cost Ratio is about 26% using the 10% rate increase cap approved by the Board in this Decision.

ASBG/PGA was concerned the proposed loss factor for irrigation, based on a flow program simulating winter and summer peak conditions used the same flow data, even though the summer peak was less than the winter peak. The Board finds the difference between the use of summer peak hours and winter peak hours for calculating annual energy losses is not material, being in the magnitude of 1% of the loss percent.[13]

ASBG/PGA had recommended that if the UCA Study was not accepted, then the Board should consider the recent FAI Decision[14] where farm loss factors were limited to 5% and loss factors were prorated for all other rate classes to achieve the same forecast overall losses. The Board notes that the circumstances leading to that finding were different than the current evidence. The Board finds that AE's method for allocating losses in the current Application is a consistent approach, which balances calculation cost and accuracy, and therefore the irrigation losses should not be capped as requested by ASBG/PGA.

IPCAA disagreed with AE's approach for allocation of primary and secondary feeder losses, and suggested that secondary distribution losses were significantly misallocated. IPCAA recommended that the segment by segment approach recommended by the UCA be used for allocating both primary and secondary feeder losses as it reflected better cost causation.

Both PICA and CCA recognized that once AE adjusted the UCA loss study, the difference between the studies was small. On this basis, both PICA and CCA recommended that the Board accept AE's proposed methods for allocating primary and secondary losses. PICA highlighted

[11] Transcript Volume 1, pages 118-119
[12] Transcript Volume 1, pages 133-141
[13] Transcript, Volume 3, pages 447-450
[14] FortisAlberta Inc. Decision 2006-099, page 54

however, that the method used by AE was different for primary vs. secondary loss allocations. PICA recommended similar methods be used for both allocations.

The Board finds that once AE adjusted the UCA loss study, the difference in accuracy of results between the studies was not material. However, the costs to implement UCA's alternate loss allocation method appear to be significant. It is AE's evidence that software enhancements would cost $100,000 to implement the allocation of primary losses by line segment. AE submitted that an additional $1,000,000 would be required to implement a similar loss study by component for the secondary system. The Board finds that UCA's recommendation will not result in a cost effective change.

The Board considers AE's 2004 Loss Study to allocate primary and secondary system losses represents a reasonable balance between accuracy, cost and intergenerational equity. Accordingly, the Board approves AE's 2004 Loss Study as filed.

2.4 Load Research: Diversity Study

AE prepared the Diversity Study, a study of rate class contributions to POD peaks, in response to Board directions from Decision 2005-025. The purpose of the study was to determine the class responsibility for POD non-coincident peak (NCP) demand and then calculate the diversity factors associated with class responsibility for POD NCP demand and class NCP demand for comparison purposes.

AE stated that the intent of the Diversity Study was to determine class responsibility for the total POD NCP demands, not the class responsibility for each POD peak. In the study, AE utilized load research data to estimate the contribution of each rate class to the sum of the POD peak demands. In the Diversity Study, AE calculated the contribution to each monthly POD peak for each sample customer. These contributions were accumulated for each rate class (effectively by weighting them by annual energy consumption) and extrapolated to the entire rate class (based on annual energy consumption).

AE stated that the averaging and extrapolation of contribution to POD peaks utilizes the same techniques as have been previously used to calculate rate class NCP demand.

In this study, AE stated that class responsibility for POD NCP demand was determined for two different sets of time frames:

1. Monthly. Class responsibility for POD NCP demand was determined for each month based on monthly POD peaks for each POD. These are appropriate cost of service allocators for demand transmission service (DTS) capacity charges if the Alberta Electric System Operator (AESO) was to bill them based on a 0% ratchet.
2. Annually. Class responsibility for POD NCP demand was determined for a complete year based on the annual POD peak for each POD. This is an appropriate cost of service allocator for DTS capacity charges if the AESO was to bill them based on a 100% ratchet.

AE stated that a blended class responsibility for POD NCP demand for each month was developed from the results for the two time frames to account for ratchets. The month by month results were weighted in proportion to the number of POD bills based on the POD peak in the forecast year. AE stated that to this amount for each month was added a contribution from the annual results weighted in proportion to the number of POD bills based on a ratchet or a contract amount in the forecast year.

ASBG/PGA expressed concern with the diversity results for the monthly and annual class responsibility for POD NCP demand and its calculation and applicability to seasonal services such as irrigation service (Rate D25). ASBG/PGA stated that AE's proposed changes to the allocation of costs to irrigation services resulted principally from these class responsibility studies. ASBG/PGA highlighted that the Revenue Cost (RC) Ratio for irrigation service has decreased from 98.0% in the last DT proceeding to a forecast 46.5% in this proceeding.[15] ASBG/PGA argued that AE's proposed approach to cost allocation was inequitable because it allocated costs to irrigation service for each and all months of the calendar year, including those months where irrigation service was disconnected from the system.

ASBG/PGA submitted the basic problem with AE's proposed methodology was not having the association of customers through feeders to the POD for the study.[16] The utilization of only selected site sample data for determination of overall contributions to aggregate POD demands (class responsibility for total POD NCP demand) ignored the reality of all customer demand contributions to each specific POD (class responsibility for each POD peak) and the effect of diversity on these contributions.

ASBG/PGA was concerned that, when determining the class responsibility for POD NCP demand, AE does not determine the class responsibility at each POD[17] but allocates DTS capacity charges for all PODs combined to rate classes. However, ASBG/PGA stated that the AESO determines DTS capacity charges by POD. The cost driver is therefore the demands at each POD and further it is the rate class contribution to each POD demand that recognized this cost driver. With the AE proposed methodology, the cost driver was not explicitly recognized, as the rate class contribution was determined separately for each rate class and assumed this cumulative contribution to overall DTS demands.

ASBG/PGA submitted that the AE proposed methodology was a concern for seasonal customers who only utilize a small number of PODs in the system, and that AE had not conducted any studies or analysis that demonstrated that the aggregate rate class contribution to POD NCP demand aligned with a proper rate class contribution to each POD. ASBG/PGA stated there should not be an irrigation contribution to POD NCP demand in the non-irrigation months as irrigation service was not utilizing the system for those months.

ASBG/PGA argued that to account for diversity upstream of the customer meter at the POD level, all sites connected to the POD should be included to ensure a fair evaluation of all these sites as to their contribution to the class NCP at the POD. ASBG/PGA argued that AE only utilized data from sample sites without preparing a reconciliation of the total contribution to the POD peaks of all sites connected to that POD. ASBG/PGA argued that AE's approach excluded all the remaining sites connected to the POD when these sites were not part of the sample.

[15] Transcript Volume 2, page 368
[16] Transcript Volume 3, pages 436-437
[17] Exhibit 002-13, IPCAA-ATCO-7(e)

ASBG/PGA submitted that the lowest amount of load diversity was in the service lines which connect the individual customer. The secondary distribution system represents the next segment, and the load diversity was important since these lines connected the individual service lines with winter peaking and summer peaking. The primary distribution lines connect the secondary distribution lines and they have the largest amount of load diversity.

Finally, ASBG/PGA submitted the sample size may not have been adequate to calculate the class responsibility for POD NCP demand given the small number of PODs sampled for irrigation service as the irrigation sample customers were connected to 9 PODs[18] out of a total of 130 AE PODs or some 7%.

PICA also expressed concern that AE reconciled total POD loads with the metered POD loads in only 2 out of the 60 months it sampled. PICA argued that reconciling and verifying the demands derived from the samples against metered demands was a fundamental step necessary to validate the reasonableness of the sampling, even though AE indicated reconciling each of the months would be time consuming.[19]

PICA submitted that AE should be directed to validate its sample results for each of the sample months in its next DTA Phase II. PICA accepted using the proposed POD NCP demands estimated from the samples for purposes of the current proceeding.

IPCAA filed evidence recommending that AE calculate a revision to the Diversity Study which would allocate monthly demand costs using a weighted average rather than a simple average.[20]

AE accepted this recommendation and advised that it would reflect IPCAA's refinement to its proposal as part of its Refiling if this were determined appropriate by the Board. While AE stated the impact of the proposed change would be minimal in the current proceeding, it conceded that the magnitude of such impact could change in the future.

AE submitted that its sampling was reasonable, as it was derived on a random basis, in order to avoid inconsistency in the results over the 60-month sample period.[21] AE stated any customer over 500 kW was interval metered and was therefore included in the sample.[22] This included 400 to 500 customers whose contribution to the POD peak was accurately calculated and were all included in the sample.[23] AE submitted that the load factors calculated for classes with smaller customers are consistent over the years, even though they were obtained from more than one random sample. AE stated that the vast majority of PODs had sample customers connected to them, and the same calculation procedures are used for each month.

AE stated that comparing the class responsibility for POD NCP demands for all classes to the sum of POD NCP demands for sample months for two historical months was an additional check on the results performed by it to confirm the reasonableness of the results.[24]

18 ASBG/PGA Argument, page 8
19 Transcript Volume 1, page 76, line 13
20 Exhibit 010-04, IPCAA Evidence, page 8
21 Transcript Volume 1, pages 73-74
22 Transcript Volume 1, page 75
23 Transcript Volume 1, pages 75-76
24 Transcript Volume 1, pages 76-77

In response to concerns regarding the adequacy of the irrigation class sample size, AE explained that hourly consumption was gathered on approximately 20% of the irrigation customers using Automatic Meter Reading (AMR) technology once it became available for this class. AE contended that this actual measured information averaged over two years was very good for a class of this size.[25] As well, AE advised that no costs associated with the primary distribution system were assigned to the irrigation class, and that the Energy Demand and Loss Analysis (EDLA) Model showed that the previous and proposed cost allocators for DTS capacity charges do not differ materially for the irrigation rate class. Therefore, the proposed change in methodology will not have a material impact on the portion of costs allocated to the irrigation class. Last, contrary to ASBG/PGA's view, AE indicated that DTS costs should be allocated to irrigation service for each and all months of the calendar year because irrigation customers contributed to annual POD peaks which set the POD ratchet that used in calculating DTS capacity charges for the next 12 months.

2.4.1 Views of the Board

AE prepared the Diversity Study to address Directions from Decision 2005-025. The purpose of the study was to determine class responsibility for POD NCP demand and to calculate the related diversity factors. The Board finds that the results of the Diversity Study are sound, and the proposed approach is superior to the information previously used by AE in prior Phase II filings.

In regard to PICA's concern that reconciliations should be prepared between the total peak loads estimated from sampling with the metered POD loads for all sixty months that were sampled, the Board accepts AE's explanation that the reconciliations were prepared for two months as a reasonability check of the results only. Therefore, the Board will not require reconciliations for the remaining months in the sample period.

The Board accepts AE's explanation addressing the concerns raised by ASBG/PGA that the proposed methodology change will not have a material impact on the portion of costs allocated to the irrigation class. No costs associated with the primary distribution system are assigned to the irrigation class, and the EDLA Model shows that the previous and proposed cost allocators for DTS capacity charges do not differ materially for the irrigation class.

The Board notes that ASBG/PGA requested that the Board direct AE to provide a working model of the diversity study to allow intervener testing. The Board finds that the calculation and use of the Diversity Study information represents an area suitable for technical meetings to address any misunderstandings through open questions and discussion. The Board directs AE, prior to the next Phase II proceeding, to provide to interveners a working model of the diversity study. AE shall organize a technical meeting which can include this area for discussion, and the working model should be provided sufficiently before the meeting allowing enough time for interveners to examine it and address their questions at the technical meeting.

The Board notes that IPCAA, in its filed evidence, recommended a refinement to the Diversity Study in which the monthly demand costs would be allocated using a weighted average rather than a simple average. Further, AE supported this refinement. (See Section 3.1 Allocation of Certain AESO DTS Charges Using Ratcheted Blended Monthly Class NCP Demand).

[25] Transcript Volume 3, pages 423-427

The Board accepts the Diversity Study with the refinement proposed by IPCAA, and the Board directs AE, in the Refiling, to include the revised Diversity Study.

2.5 Brushing Study

AE presented the Brushing Study[26] it undertook in response to a Direction in Decision 2005-025 The Brushing Study examined actual brushing costs for the years 2001 to 2005. The results of this study indicated that AE should adopt a 95%/5% rural/non-rural allocation of these costs, compared to the 70%/30% split used in AE's 2004 DTA. In the 2004 DTA, brushing costs had been allocated to each rate class on the basis of total forecast mid-year gross plant in service for the test year.

UCA supported the results of the AE Brushing study and the use of the results in AE's COSS study and rate design.

The Alberta Association of Municipal Districts & Counties/Alberta Federation of REA's Limited (AAMDC/AFREA) submitted that the record does not support the approval of the AE brushing study and its results for the following reasons:

- the percentage of coverage by the study sample size of the population was grossly overstated by AE, making the methodology unsound; and
- the accuracy of the current proposal to change the Rural/Urban allocation to 95/5 from 77/23 is a concern because such a large increase from a simple adjustment of the number of study locations indicates that the methodology is neither accurate nor robust.

AAMDC/AFREA submitted two more issues should also be taken into account by the Board:

1. The increases proposed to certain rate classes are significant. The REA Farm Rate D51 will have brushing costs increased by 24% or $57,700 and the Farm Service Rate D56 will experience an increase of 24% or $175,000.
2. The response to Direction 17 appears to have a substantially different bearing as compared to the expectations of the Board that brushing costs associated with providing service to farm customers would likely be lower than brushing costs associated with providing service to oilfield customers, given that oilfield service is generally located in remote regions, while farm service crosses cultivated land.

AAMDC/AFREA submitted that this study should be rejected by the Board. In the interim, AAMDC/AFREA proposed that the status quo 77/23 rural/non-rural allocation remain in place. AAMDC/AFREA further recommended that the Board should order this study to be redone at a time when the level of precision for data collection procedures for brushing costs reaches a level that justifies a location allocation.

AE submitted that the fact that a number of geographic locations appeared more than once over the five year period does not reflect double counting, but simply means that different areas within the same geographic location were the subject of brushing activity over the brushing cycle. AE submitted that this did not diminish the legitimacy of including this information in the study. AE submitted that the suggestion that the population size is 1,615 was simply not

[26] Application, Section 4, Attachment 3

supportable as AE has 323 available locations and it examined actual brushing costs for 149 separate locations[27] of those locations at least once.

AE submitted that the fact that further refinement of results may be achievable in the future (when more detailed information is available) does not mean that the results of the current study, based on the information presently available, are not valid. AE stated that further refinement may be possible if it can be done on a cost effective basis.

AE also submitted that the Board's expression of an expectation, without any study or evidentiary basis, in the context of a past proceeding does not in any way diminish the validity of the results of the actual study examined.

2.5.1 Views of the Board

The Board has reviewed AE's Brushing Study and AAMDC/AFREA's criticisms of it.

With respect to the concerns expressed about the sample size of the study, the Board finds that a study of 149 of the available 323 locations is a large enough sample to support the study's conclusions. The Board also notes that, even if the locations where brushing occurred more than once were eliminated, and the Board is not convinced that is necessary, the results of the study are essentially unchanged.[28]

This study of actual costs incurred has improved the allocation of the costs of brushing to rural and non-rural customers over the former method which allocated costs based on forecast mid-year gross plant in service for the test year. Given this finding, the Board does not accept AAMDC/AFREA's suggestion that the reallocation of brushing costs should await a more precise study. Further, the Brushing Study indicates that under the existing allocation methodology the non-rural customers paid more than their fair share of brushing costs in the 2001-2005 time period. A delay in the implementation of the study's results would perpetuate that inequity.

Accordingly, the Board accepts the Brushing Study.

However, the Board notes that AE indicated that more precise results may be achievable in the future and in Decision 2007-071[29] the Board directed AE to forecast its brushing costs by volumes to be brushed in its next GTA and to track the volumes brushed in 2008. The Board considers that the tracking of volumes brushed in 2008 should also include tracking the location of the brushing to facilitate more accurate allocation of brushing costs in future GTAs.

Accordingly, the Board directs AE, in its next Phase II application, to submit the results of its tracking of the volumes brushed in 2008 and its views as to whether the allocation of brushing costs to customer classes should be adjusted.

27 Transcript Volume 3, page 416
28 Transcript Volume 3, page 416
29 Decision 2007-071 – ATCO Electric Ltd. 2007-2008 General Tariff Application - Phase I (Application 1485740) (Released: September 22, 2007)

3 COST OF SERVICE STUDY: TRANSMISSION ACCESS COST

3.1 Allocation of Certain AESO DTS Charges Using Ratcheted Blended Monthly Class NCP Demand

AE proposed to allocate all non-energy related AESO DTS charges using a blended POD NCP approach as described in its Diversity Study. AE proposed to allocate DTS charges related to monthly POD peaks on the basis of contribution to monthly POD peak demands, and to allocate charges related to ratcheted peak demands or contract demands to rate classes on the basis of contribution to annual POD peak demands.

AE utilized a blended weighting factor combining these two separate allocation methods (and then allocated costs in one step using this blended factor), rather than separately allocating costs to the DTS components that are related to annual and monthly POD peak demands.

IPCAA filed evidence[30] that recommended that the costs relating to each of the two types of demand charges be allocated separately and then combined after the allocation. IPCAA submitted that its approach reflected the fact that the majority of demand charges in the winter are based on monthly POD peak demands whereas the majority of demand charges in the summer are based on ratchets driven by annual POD peak demands or contract demands.

IPCAA indicated[31] that, the difference between the AE and IPCAA methods is sensitive to the relative proportion of AESO demand billing determinants paid by AE. The split of AESO determinants between monthly demand, demand ratchets and contract ratchets determinants is impacted by the status of the ratchet on bulk transmission charges in the AESO tariff[32] as well as AE DTS contract levels. Therefore, IPCAA submitted that its approach was a more accurate allocation than the AE approach.

AE filed rebuttal evidence characterizing IPCAA's proposal as a refinement that accounted for the seasonality in class responsibility for monthly POD peaks by assigning weights to the annual and monthly POD NCP demands using the billing demand MW portions for contract, ratchet and peak for each month.

AE indicated that it had the data to implement IPCAA's approach in a cost effective way and that it would not be opposed to adopting it.

AE agreed that while the difference between the AE and IPCAA allocations was relatively small under the present application, it would increase if either the AESO ratchet is not approved or AE continues to reduce DTS contract coverage.

CCA submitted that given the insignificant difference, there was no need for further changes to the method proposed by AE to allocate the AESO's DTS Charges.

ASBG/PGA did not support AE's proposed method or the proposed IPCAA modifications. ASBG/PGA recommended an allocator based on reduced irrigation monthly NCP demands.

[30] Exhibit 010-04

[31] Transcript Volume 3, page 671, line 7 to page 672, line 9

[32] AE's allocation is based on the AESO draft tariff that includes ratchets on bulk transmission charges. The existing AESO tariff does not include ratchets on bulk transmission charges.

Alternatively, it proposed that the existing allocation method should be continued for this DTA as it submitted that irrigation customers should not be charged for months when no irrigation service was required.

PICA recommended that AE be directed to reflect IPCAA's method in the Phase II Refiling.

3.1.1 Views of the Board

In Direction 8 of Decision 2005-025 the Board indicated that AE should bring a proposal forward that addresses ratchet provisions for irrigation customers. The Board finds that AE's approach of using the blended class responsibility for POD NCP demand allocator to allocate DTS capacity charges addresses the ratchet provisions for irrigation customers, since using this approach results in the irrigation contribution to monthly POD peaks being appropriately accounted for.

Further, the Board finds that IPCAA's modification to AE's proposed approach would more appropriately account for seasonality in both costs and class responsibility for monthly POD peaks. As such, IPCAA's modification would provide a more accurate allocation of costs to the classes causing them than the other proposals put forward for consideration. The Board recognizes that this additional accuracy could result in a material change in results in future test years if circumstances change.

The Board directs AE, in its Refiling, to use IPCAA's modified approach to allocate DTS charges.

3.2 Allocation of Certain AESO DTS Charges Using Energy

AE proposed that bulk rate energy and DTS operating reserve costs be allocated to each rate class using monthly energy. AE indicated that this conformed to its past methodology and that no change had arisen that would warrant making a change at this time.

In addition, with respect to DTS voltage control, AE proposed that these costs be allocated to each rate using monthly energy use because these costs are incurred as energy costs and, as such, it would be appropriate to classify and allocate them on the basis of energy.

ASBG/PGA supported the allocation of AESO DTS charges that are energy related on the basis of rate class energy. ASBG/PGA submitted that AE should ensure in the Refiling that the rate class forecast monthly energy for the irrigation rate class pertains to the forecast months of consumption and not to a monthly average over each of the 12 months. In this way the seasonal customer cost responsibility corresponds to the consumption months.

3.2.1 Views of the Board

The Board finds that AE's allocation of the AESO bulk rate energy, DTS voltage control and DTS operating reserve costs to each rate class using monthly energy is an appropriate reflection of cost causation and its use is approved.

3.3 Incorporation of Final AESO Rates in AE's Rates

When the record closed on this proceeding, the Board's Decision on the AESO's 2007 GTA had not yet been issued.

AE indicated that, in preparing its Application, it had to make an assumption regarding the outcome of the AESO 2007 GTA. AE structured the forecast AE rates on the basis that the AESO billing changes would be approved as filed. AE advised that should the approved AESO rates have a different structure from the rates that were applied for, no changes to the AE proposed rates would be made until the next AE DT Phase II Application as AE would not be able to update its COSS before its Refiling to incorporate any decision on the AESO's application. AE indicated that it is practical and reasonable to flow through costs on the same basis they are incurred and that it would propose a practical approach to achieve this objective at the time of the disposition of its Transmission Access Payment deferral account for 2008. AE would conduct another COSS study using the appropriate AESO rates for its next Phase II DT application.

ASBG/PGA submitted that any changes that may be required after the Board releases its decision on the AESO's 2007 GTA should be reflected in a subsequent AE filing.

PICA submitted that AE should be directed to provide an assessment of the impact of the 2007 AESO tariffs on AE's DT tariffs proposed in this application and AE's proposal for changes to the DT tariffs in its Phase II Refiling.

IPCAA indicated that AE's T-31 (transmission connected industrial) customers pay transmission charges as a flow through of the AESO tariff in effect for the billing month. IPCAA submitted that having AE's D-connected customers billed on the basis of the AESO's draft rate proposal could lead to a disconnect, with some AE customers paying transmission charges on the basis of a CP based AESO tariff and others effectively paying on the basis of an NCP based tariff.[33] IPCAA noted that the DTS charges paid by AE on behalf of its D-connected customers are subject to deferral account treatment, but submitted that AE did not intend to settle the deferral account in a manner that would effectively charge rate classes as if the approved AESO tariff had been in place through the deferral period.

IPCAA submitted that there would be no reason why the deferral account related to transmission service for D-connect customers could not be settled in a fashion that effectively flows through transmission charges to AE's D-connected customers on the basis of the AESO's final 2007 tariff. IPCAA recommended that the Board direct AE to develop an approach that seeks to effectively pass through the approved AESO tariff at the time of AE's application to settle its Transmission Access Payments deferral account to ensure that AE's T-connected and D-connected customers are treated similarly.

IPCAA supported PICA's proposal on the basis that the proposal would appear capable of achieving a reasonable and fair result by incorporating the final AESO tariff into the AE rates in a timely fashion. Similar results could be achieved through a direction to AE to propose settlement of its transmission deferral account in a manner that would effectively pass through the actual AESO final 2002 tariff.

[33] Transcript Volume 2, page 313, line 17 to page 314, line 6

3.3.1 Views of the Board

The Board finds that given the anticipated timing of the release of the AESO's 2007 GTA Decision, it is not possible to incorporate the final AESO tariff in the COSS at the time of AE's Refiling. Accordingly, the Board directs AE to provide a summary of the approach and timing that AE proposes to deal with the changes, if any, required to reflect the final AESO tariff on as timely a basis as practical but no later than February 1, 2008.

4 COST OF SERVICE STUDY: DISTRIBUTION COSTS

4.1 Allocation of Primary System Distribution Costs

AE proposed to classify all primary system (25 kV distribution system directly connected to the transmission POD) distribution costs as demand related because AE's primary system is planned to meet the peak demand on the individual feeders. AE indicated that its predominant system planning criteria is to satisfy voltage requirements under peak conditions.[34] AE also indicated that its system is predominantly rural and its primary system is a radial/open looped system that differs considerably from other utilities, particularly municipal utilities such as EPCOR.

In past applications, AE used Class NCP as the allocator for the primary system distribution costs. The Class NCP was used as a proxy for peaks on the individual feeders. In response to Board Direction 14,[35] AE studied the possibility of allocating primary system related demand costs using a POD NCP approach as discussed in its Diversity Study. AE reviewed the allocation methodology and concluded that annual class responsibility for POD NCP demand was a more appropriate allocator for the allocation of primary distribution assets but that class NCP demand remained the most appropriate allocator for the secondary distribution assets.

AE explained that the annual class responsibility for NCP was appropriate for the primary system rather than the blended class responsibility used for AESO DTS charge allocation for two reasons:

- unlike DTS capacity charges, no ratchet billing is associated with primary distribution system costs; and
- the primary distribution feeders are designed to meet the feeder peak regardless of the month in which the peak occurs.

As such, AE proposed to use annual class responsibility for POD NCP as the allocator for the Primary System distribution costs.

AE advised that because it has the load research data necessary to implement the proposed allocation methodology, which may not be the case with other electric utilities, its approach is superior to those adopted by other utilities.[36]

IPCAA noted that AE's primary distribution loss allocation method allocates costs among rate classes based on a MW-mile approach recognizing the relative distance various rate classes'

[34] Transcript Volume 1, pages 58-59; Transcript Volume 3, page 465 and 469
[35] Decision 2005-025
[36] Transcript Volume 1, pages 58-59; Transcript Volume 3, pages 284-287, 297-298

loads are from the POD. IPCAA provided a table[37] derived from AE's distribution loss study[38] that it argued demonstrated the average distance that customers of various rate classes are located from the POD.

IPCAA submitted that, since not all rate classes are equidistant from the POD, not all rate classes utilize primary distribution assets to the same extent per MW of load. For example, large (greater than 2 MW) industrial loads are significantly closer to the PODs, on average, than other rate classes.

IPCAA questioned AE's inability to use a MW-mile approach on the basis of unavailable cost data as IPCAA submitted that this explanation would only be true if cost allocation were going to be implemented on a vintage embedded cost basis for each segment of line.[39] However, IPCAA submitted that such data was unnecessary as the usual practice using a MW-mile approach would be to utilize the average cost of all primary lines. IPCAA submitted that since all of AE's primary lines are 25 kV three phase lines, averaging is an acceptable approach.

IPCAA noted that the FAI allocation methodology utilizes what is, in effect, a MW-mile methodology for both primary and secondary distribution lines. FAI utilizes a uniform cost per unit of conductor (total costs are reconciled to the total rate base). IPCAA submitted that AE could employ a similar approach.[40] IPCAA submitted that the Board should direct AE to also allocate primary distribution costs on a MW-mile basis or alternatively, that the Board should direct AE to adopt a segment-by-segment allocation for primary distribution costs (and primary distribution losses). IPCAA submitted that both the MW-mile and segment-by-segment approaches recognize the relative distance of loads from the POD. IPCAA submitted that the two approaches vary in that the MW-mile approach assumes costs and losses are linear with distance while the segment-by-segment approach recognizes that costs are not linear with load (for cost allocation) and losses are not linear with load (for loss allocation).

ASBG/PGA submitted that the class NCP method used in the last proceeding should be used in this proceeding. It contended that AE's proposed methodology does not adequately recognize customer class contributions to the POD peak and the diversity of load. This load diversity is particularly important in the consideration of seasonal load impacts on the primary system. An assumption of no load diversity is only applicable to high load factor loads and thus the contribution of low load factor loads to the minimization of primary distribution costs is not recognized in a MW-mile approach, which was advocated by IPCAA but which ASBG/PGA rejected. Last, ASBG/PGA submitted that AE had not provided the necessary supporting data to substantiate that the sample distances by customer classes are representative of the total class population.

CCA supported AE's proposed method because it recognized the diversity that exists in the primary system by taking the NCP demand of each rate class at POD's, as opposed to taking a single NCP hour. The proposed method also recognizes POD peaks may occur in any month and at any hour of the day. Further, it recognizes the benefits of diversity provided by the lower load factor customers which do not have as much of a chance of contributing to the POD peak as

[37] IPCAA Argument, page 5
[38] Derived from Exhibit 002-01, Section 10, Attachment 1, page 23 of 28, Table A-3 Average Distance for Energy
[39] As ATCO apparently assumes it would be. See Transcript Volume 2, page 340, line 20 to 25.
[40] ATCO acknowledged that an average cost could be utilized. See Transcript Volume 2, page 341, lines 15 to 16.

larger load factor customers who proportionately contribute more to such POD peaks. CCA submitted that the result was a closer reflection of usage and cost causation of AE's primary distribution system since AE's method gives specific recognition to classes which contribute to the NCP POD peaks.

However, CCA noted AE indicated that the energy flows from a transmission POD may, or may not be, transmitted on a single primary distribution feeder circuit since, on average, AE's electric distribution system contains approximately three feeder circuits per POD. AE's use of the annual class responsibility for POD NCP demand to allocate primary distribution system costs makes no accommodation for this difference. Each of the feeders that make up a particular POD represent a large number of customers from each rate class, and the class contribution to the NCP peaks of these feeders may or may not be coincident with the class contribution to the NCP peak of that POD.

To refine the allocation to the feeder level while containing the expense associated with the proposed refinement, CCA recommended that AE undertake a study using a sample of the 110 PODs (and each of the feeders supporting the PODs in the sample) to determine the class responsibility for NCP demands at each of these feeder circuits. For the balance of the PODs not in the sample, it may be appropriate to continue with the proposed class responsibility for POD NCP demand. Given the five-year planning horizon for primary system, and the fact that it is the larger loads that appear to drive the need for new feeders, CCA submitted that AE should be directed to provide a study for its next GTA that provides an assessment of the rate classes that drive the need for new feeders. This study should identify all cases where the feeder is installed to serve just one rate class or primarily one rate class. As well, to the extent feeder peak load is designed for a five-year period, this study should incorporate an assessment of average excess capacity in the feeders and explain whether such excess capacity is related to demand or energy.

PICA did not support AE's proposed change in method of allocation of primary lines, and was of the view that AE had not carried out any analysis to substantiate AE's conclusion that diversity characteristics of customer loads at feeder peaks are directionally similar to the diversity characteristics of customer loads at POD peaks. PICA argued that there is a significant shift in costs to Rate D31 from other classes as a result of the proposed change in allocation for primary lines advocated by AE. PICA noted that each POD has, on average, three primary lines associated with it and the diversity on each of these lines is also influenced by the downstream loads served by the lines. In PICA's view, the further downstream from the POD a primary line segment is, the more likely it is to reflect the diversity of the downstream load than the diversity at the POD because, as load drops off along the length of the line, the remaining segments of the line would increasingly reflect the downstream loads.[41] PICA submitted the further away a segment of primary line is from the POD, the more it will tend to resemble the secondary system in terms of load diversity.

In that regard, PICA noted that AE uses the Class NCP method to allocate demand related secondary system costs. On that basis, PICA submitted that AE's rationale was flawed because the diversity at each segment of each line will also be different based on the respective downstream loads.

[41] See the diagram in Exhibit 013-002.

PICA also rejected AE's proposed change because it was based solely on a consideration of diversity and did not give any consideration to cost causation due to distance. PICA submitted that if a refinement is to be made, other refinements, which may result in changes in costs going in the opposite direction, must also be considered.

PICA submitted that while AE claimed to be different from the other utilities which classify a portion of primary system costs to customers because AE's primary lines include only 25 kV lines while other utilities include lower voltage lines as part of the primary system, AE could not substantiate this claim.[42] PICA submitted that AE has not demonstrated why an element of primary lines costs related to serving new customers in distant geographic areas should not be considered customer related, particularly for a radial system with relatively long lines as compared with more urban systems. PICA submitted that the allocation method for primary lines should not be changed without the benefit of solid evidence indicating why classification of a portion of primary lines costs to customers is inappropriate.

PICA recommend AE's proposed allocation of primary lines on the basis of POD NCP be denied. PICA submitted the class NCP allocation method used in prior proceedings provides a reasonable proxy for cost causation on primary lines since it reflects the downstream loads with due adjustment for diversity to the primary level. Although the class NCP method is not a perfect substitute for a method reflecting customer class contributions to primary line peak demands by segment; it is still a reasonable proxy in the absence of such data.

PICA submitted that the best way to address the criticisms of AE's proposed classification methods is by adopting an allocation method for the primary and secondary systems based on the MW-mile approach, as recommended by IPCAA. Any piecemeal adjustment of AE's classification percentages without due consideration of a major cost driver, namely the distance of haul as measured in MW-miles, would not be appropriate nor fair to all customer classes. PICA submitted IPCAA's recommendation be considered for adoption in ATCO's next Phase II proceeding. PICA submitted that, for the purposes of these proceedings, AE's proposed classification percentages, which reflect methods traditionally accepted for AE, be accepted by the Board.

4.1.1 Views of the Board

The Board recognizes that there are alternative approaches that can be used to allocate primary line costs and the Board has reviewed each of the alternative approaches advocated by the intervener parties.

To begin, the Board does not agree with the suggestion that some portion of the 25 kV primary system should be classified as customer related. Several thousand small customers can be attached to each feeder. If one large customer that accounted for three-quarters of the peak demand and 999 small customers were attached to the same feeder, a customer based allocation would allocate the large customer responsibility for only 1/1000 of the costs of the feeder. The 25 kV primary system is built to serve total load and its size is not based upon the number of customers to be served. Accordingly, the Board does not find that a customer-based allocation approach could be considered more equitable than the class responsibility for POD NCP approach.

[42] Exhibit 013-017

While a distance-based approach may have some potential as an appropriate allocation methodology for a 25 kV primary system, the Board considers that there is insufficient evidence in this proceeding to support a direction from the Board to adopt this approach. The distance-based proposal was introduced in Argument, which did not permit proper testing of this alternative approach.

The diversity study that led to the new demand allocation proposed by AE was intended to refine AE's demand-based allocation method for primary system costs. As a result of the study, annual class responsibility for POD NCP has been proposed as a more suitable allocator than class NCP demand which had been used in the past. Use of annual class responsibility for POD NCP as an allocator is premised on the assumption that all feeders connected to a POD peak at the same time, while the class NCP demand method was premised on the assumption that all feeders on the system peak at the same time.

The Board finds the assumption that feeders connected to a POD peak at the same time to be more realistic. Further, the Board finds that the use of feeder peak loading criteria for feeder planning strongly supports the view that primary system cost causation is reflected by annual class responsibility for POD NCP.

Accordingly, the Board approves use of annual class responsibility for POD NCP as an allocator for primary system costs.

4.2 Classification and Allocation Factors

Direction 13 of Decision 2005-025 required AE to refine the classification methodology for secondary overhead conductors. AE retained Mr. James Sarikas of Foster Associates, Inc. (Foster) to update the Classification Study from the 2004 AE DTA. Foster examined new data for the years 2004 and 2005, in addition to the historical data for the period 1995-2003 used in the prior Classification Study.[43] The work completed by Foster which resulted in the 2006 study was a refinement and enhancement to Foster's previous study and followed an approach that was consistent with the original study that had been accepted by the Board.

The theory and logic of a customer/demand classification and the appropriateness of the Minimum Plant and Zero Intercept studies were again utilized by Foster in the context of this update. The approach adopted by Foster expressly attempted to respond to the issue of minimum costs not being lower than installed costs.

AE further outlined in its Rebuttal Evidence[44] that the Board had approved the customer-demand split to classify secondary distribution costs, and that this methodology was used throughout Canada.[45]

AE proposed to continue to use the previously approved allocator and submitted that it remained the most appropriate approach for allocating general plant. AE noted that it would update its study as appropriate in the future, but there was no need to repeatedly examine the same issue in successive Phase II applications.

43 Application Section 4 – 2006 Update of ATCO Electric's Demand/Customer Classification Study
44 Exhibit 002-16-01, page 21-27, Sarikas Rebuttal Exhibit 3
45 Exhibit 002-16-01, page 21

AAMDC/AFREA was concerned with the increase in allocated and direct assigned costs to the streetlight rate class. AAMDC/AFREA considered that the Board must not rely on the Foster Report or AE's cost of service study as any indication of AE's actual cost of providing streetlight services.

AAMDC/AFREA noted that AE based its classification of plant between demand and energy on a 50-50 average of the results of the minimum-system and zero-intercept methods.[46] AAMDC/AFREA submitted that both the minimum-system and zero-intercept methods overstated the percentage of costs that were driven by customer numbers and not by load, and noted several flaws in these methods and the application of these methods.

AAMDC/AFREA argued that customer numbers did not drive area-spanning costs and considered that the development of alternative classification methods was an issue that must be addressed in order that the COSS accurately reflected how costs were caused on AE's system.

Further, AAMDC/AFREA considered that the Foster study incorrectly assigned the minimum cost or zero-intercept cost to every piece of equipment on the system, overlooking the effect of load growth on the number and type of units, as well as on their size.[47]

CCA raised a number of issues with respect to AE's classification and allocation factors, as noted below:

- General Plant
- Transformers
- Secondary Lines
- Growth
- Minimum System and Zero Intercept Methods

CCA noted that there were a number of large balances in the General Plant account, and that these amounts were allocated based on the sub-total of all other gross PP&E. Given the significance of the amounts accumulating in the General Plant Account,[48] CCA requested that the Board direct AE to study the allocation of such plant and determine first if there were any assets within the General Plant that were capable of being directly allocated. In addition, the study should provide a detailed assessment of any other allocation methodology other than the use of the sub-total of all other plant, including practices of other utilities with respect to such plant.

With respect to transformers, CCA noted that AE had rounded up the result from the regression analysis to arrive at the customer portion of transformer costs.[49] CCA submitted that the rounding up was arbitrary, and recommended that the Board direct AE to change the customer portion of the transformer costs as follows for the current COSS:

[46] Exhibit 002-03, Section 4-Attachment 2, page 7
[47] Exhibit 003-07, page 28-30
[48] Per Exhibit 002-10-01, Schedule 4-B-23s, page 22 of 36 (223,969/1,838,112 = 12.2% of total Property Plant and Equipment)
[49] Exhibit 002-01, Foster Study, Tables 13.2 (page 13) and 13.5 (page 15)

Table 1. CCA Recommendation for Customer Portion of Transformer Costs

Urban	From 60% to 55%
Rural Assigned	From 45% to 45% (no change)
Rural Non-Assigned	From 40% to 35%

CCA noted that AE allocated secondary lines based on a 30/70 demand/customer allocation; however, Foster indicated that a number of utilities appear to use much lower ratios for the customer-component i.e. in the range of 33% to 51% except for BC Hydro which uses 75%.[50] CCA noted that no further analysis was undertaken to further understand why, when using similar zero intercept/minimum plant methods, there would be such divergence in classification results. CCA recommended that the Board direct AE to provide, at its next GTA, a detailed assessment of how and why AE's classification results for secondary lines were different than the results of other utilities in Alberta.

CCA noted that in AE's classification studies, it was assumed that load growth was due to attaching new customers and not due to increased demand from existing customers. Further, AE had not studied the extent to which the increased load in the test years was due to new customers or, due to expansion of facilities of existing customers.[51] CCA submitted that it was important that proper price signals be provided by recognizing whether the secondary facility costs were caused by demand or customers. CCA considered that most of such load growth comes from non-residential customers.[52] Hence, while secondary facilities are built to serve both new customers and demand on the system, if over time, more and more of these facilities are used by larger customers as they experience organic growth, an adjustment should be made to reflect the fact that facility costs were more demand-related than customer-related. As a result, CCA recommended that the Board direct AE to study this matter further and provide results of the study at its next GTA.

CCA considered that the greater the amount of costs AE was able to shift to the customer component, the more assured it was of recovering these costs compared to recovering these costs through the Energy Charge in the case of Rate D11.[53] CCA noted that over the last two to three GTAs, AE had shifted a significant portion of its secondary system costs from being demand-related to customer-related.[54]

Based on these arguments, CCA recommended that the Board direct AE to adopt the recommendations of AAMDC/AFREA, or at a minimum, that the Board should relax its requirement that AE design rates with a revenue to cost ratio of unity by component.

Finally, CCA requested that any direction the Board could provide AE to make its COSS simpler at its next GTA would be in the interests of all parties.

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50 Exhibit 002-013, Response CCA-ATCO-13, Attachment 2, page 1 of 9
51 Transcript Volume 3, page 616
52 Transcript Volume 3, page 617
53 As Rate D11 does not have demand charges, the demand-related costs are recovered through the Rate D11 Energy Charge
54 For example, Exhibit 002-01. Section 4, Attachment 1, Page15, Table 13.4 indicates the 2004 and 2006 regressions result in 70% of poles, towers and fixtures as being customer-related whereas in the "prior study" it was only 55%. Likewise, Table 13.6 illustrates 70% of the Overhead conductors are classified as customer related in 2004 and 2006, compared to only 30% in the "prior study".

PICA noted AAMDC/AFREA's concern with respect to the zero intercept method, and submitted that these concerns were not new and have been raised before in other Board proceedings. PICA submitted that the approach to classification of secondary system assets adopted by AE was appropriate and should be accepted by the Board subject to the concerns that it had with regard to transformer costs.

PICA noted that transformer costs were classified to demand and customer on the basis of the minimum system and zero intercept methods. The customer portions of the costs were then allocated on the basis of weighted customer numbers with the weights derived from the number of customers per transformer.[55] Given that the customer related costs to which the weightings were applied represent a zero, or minimum size transformer, determined in the classification step, in theory, there should be no weighting once the cost applicable to a zero size transformer was determined. PICA submitted that the use of weighting factors based on number of customers per average size transformer by rate class to allocate customer related transformer costs was inconsistent with the minimum system/zero intercept concept, given that the customer portion of costs determined by this method represented a minimum, or zero size, transformer; not an average size transformer. A more consistent, method of allocating transformer costs would be to use the average transformer replacement cost per customer by customer class. A similar method based on average replacement cost was used by AE for allocation of services. PICA recommended that AE be directed to use the average transformer replacement cost per customer by customer class for allocation of transformer costs, as a refinement to its present transformer allocations as part of its next DTA Phase II.

PICA also noted AAMDC/AFREA's position that the development of alternative classification methods was an issue that must be addressed so that the COSS appropriately reflects how costs were caused on AE's system. PICA submitted that the best way to address the criticisms of AE's proposed classification methods was by adopting an allocation method for the primary and secondary systems based on the MW-mile approach, as recommended by IPCAA.[56] Any piecemeal adjustment of AE's classification percentages without due consideration of a major cost driver, namely the distance as measured in MW-miles, would not be appropriate nor fair to all customer classes. Therefore, PICA submitted that IPCAA's recommendation be considered for adoption in AE's next Phase II. For these proceedings, PICA submitted that AE's proposed classification percentages, which reflected methods traditionally accepted for AE, be accepted by the Board.

UCA reviewed AE's proposed changes to classification and allocation factors and did not dispute the proposals of AE, with the exception of those related to Streetlight and Sentinel Light customers.

UCA also noted the generic tendency to continue to split classifications and allocations between rural versus non-rural customers. UCA recommended that the Board direct AE, in its next GTA, to address the issue of whether the additional work and costs for all parties to examine rural versus non-rural classifications, allocations and direct assignments, was still appropriate.

[55] For example, non rural residential transformers are weighted by a factor of .15, indicating there are 6.6 customers per transformer; whereas small general service non rural transformers are weighted by a factor of 0.4, indicating there are 2.5 customers per transformer. (Exhibit 002-09-09, mif 3;Tab Misce Input)

[56] IPCAA Argument, pages 5-6

Alternatively, if the Board determined that there remained a need to conduct separate rural versus non-rural studies, allocations and direct assignments, UCA recommended that the Board direct AE to conduct a high level study to determine if separate rural versus non-rural rates may be required given different unit costs per customer associated with each.

4.2.1 Views of the Board

The Board notes interveners raised a number of issues with respect to the classification and allocation factors proposed by AE. In particular, AAMDC/AFREA was critical of the minimum system and zero intercept methods used to determine the classification of plant between demand and energy. CCA also agreed with the views of AAMDC/AFREA.

The Board finds that the classification study undertaken by AE was a refinement of the classification study used in AE's 2004 Ph II, and while some parties may be critical of AE's approach, the minimum system and zero intercept methods are used to guide the expert in making a recommendation with respect to the allocation of costs.

This refinement of the classification study was undertaken in order to address the concern that minimum cost should not be lower than the installed costs.[57] AE reported that:

> This 2006 study has been refined and shows a $4.88 minimum plant (system) wire cost $0.37 above the minimum installed cost of $4.51.[58]

On this basis, the Board finds that the results of AE's classification study are reasonable and is approved as filed.

CCA also made a number of recommendations. First, CCA recommended that AE should be directed to examine the assets associated with General Plant in order to consider whether it would be possible to direct assign any of these assets. AE opposed this request on the basis that it would not support studies that had not been justified on an evidentiary basis. The Board agrees that recommendations should be supported by evidence, and in this case, finds that the current approach for allocating General Plant is sufficient.

Notwithstanding, the Board is mindful of AE's approach to direct assign costs and its practice of refining current approaches. As such, the Board suggests that AE review these and other costs that might have the potential for direct assignment but will leave it to AE to determine and report if any further direct assignment of costs are warranted.

CCA also made a recommendation with respect to the rounding of the results of the transformer study to obtain the customer portion of the transformer costs. The Board has reviewed Table 13.5[59] and notes that the customer portion of transformer costs for urban customers increased 5% while the regression results remained constant. The other two groups of customers, Rural Assigned and Unassigned customer portions remained constant at 2004 levels despite reductions in the regression results. While CCA argued that the rounding was arbitrary, the Board understands that professional judgment was used to determine the final allocations.

[57] Decision 2005-025, Direction 13, page 17
[58] AE Application, Section 4, Attachment 2, page 6
[59] AE Application, Section 4, Attachment 2, page 15

Given the variation across the results, the Board does not see any value in attempting to recast the customer portion for allocating transformer costs. Therefore, the Board approves AE's proposed recommendations as filed.

CCA also recommended that AE be directed to assess the customer allocation of secondary lines in comparison to other utilities in Alberta. The Board considers that there is minimal value in comparing the allocation methods between utilities without also having a uniform system of accounts for the costs to be allocated. The Board therefore will not direct AE to complete this assessment at this time.

CCA also argued that AE was shifting costs to the customer component to realize a greater assurance of cost recovery. The Board notes that for residential customers, the customer component of rates was proposed to go from 68.97¢ per day to 71.76¢ per day, which would amount to roughly an 83.7¢ per month increase for a 30 day month. The Board does not find this to be a significant shift to support a change to AE's application.

PICA recommended that AE be directed to use the average transformer replacement cost per customer, by customer class as a refinement to the transformer allocations as part of AE's next application. The Board considers that there may be some merit in PICA's recommendation however, there is insufficient evidentiary support in this proceeding to direct this change for the next GTA. Rather, the Board directs AE in its next Phase II to provide an analysis of PICA's recommendation.

With regard to PICA's support of IPCAA's suggestion that the criticism of its allocation system could be addressed by undertaking a MW-mile approach similar to that of FAI, the Board will only state that there would be considerable expense that would need to be fully justified before any such approach was undertaken.

UCA noted the costs associated with testing AE's allocation methodology and questioned whether the rural/non-rural split was still required. The Board notes that AE developed this methodology in part to address the issue of oilfield costs being allocated to farm customers, however, this methodology should not necessarily evolve into the creation of separate rural and non-rural rates. Whatever methodology AE's management proposes to allocate costs, it should be transparent and fully explained. The Board finds that the rural/non-rural split is still appropriate for AE's cost allocation methodology at this time.

4.3 Streetlights

In Decision 2005-025, the Board directed AE to directly assign streetlight costs and to study the definition of a streetlight customer and allocation of load settlement costs, as noted below:

> PICA also argued that the treatment of streetlights within the RCCA Study would likely result in misallocation of costs given that the costs for streetlights were in an unassigned pool and allocated on the basis of customer and demand. The Board notes that AE readily acknowledged this issue and was willing to conduct further work on this item for the next Phase II application. PICA stated that if the Board were to accept the RCCA Study, AE should be directed to address the assignment of specific costs for streetlights at the next GTA. The Board agrees with this approach, therefore, the Board directs AE, in its next

> Phase II application, to update the RCCA Study in order to direct assign the costs associated with streetlights.[60]
>
> …
>
> Given that AE has noted that this area deserves further study, the Board accepts AE's suggestion that a further study should be conducted into the subject of lights, in particular the definition of and the calculation of customer counts as they pertain to load settlement. Therefore, the Board directs AE, in its next Phase II application, to further study the definition and calculation of customer counts for Streetlight Rate D61 and Sentinel Light Rate D63 customers and the allocation of load settlement costs.[61]

AE engaged the services of Mr. James Sarikas of Foster Associates Inc. to assist in responding to these directions. Mr. Sarikas produced a report titled "2006 Responses to Directive Numbers 11, 13, 14, 15, 20 and 24" (Foster Report or Streetlight Study). The distribution plant allocated to streetlights resulted in the following proposed revenue requirement amounts being assigned to streetlights, as shown in Schedule 5-B-1 and 5-B-2 of AE's 2008 Distribution Tariff that was revised March 16, 2007. Included in these schedules was the revenue on proposed rates and revenue on existing rates as noted:

Table 2. AE Summary of Streetlight Revenues and Costs

	Costs ($000)				Revenue on Proposed Rates ($000)				R/C on Proposed Rates (%)			
Customer Rate Class	T	D	S	TOTAL	T	D	S	TOTAL	T R/C	D R/C	S R/C	TOTAL R/C
Streetlight Rate D61	240	6,573	1,087	7,900	240	4,091	677	5,008	100	62	62	63.4%

Table 3. AE Summary of Revenues on Existing and Proposed Rates

	Revenue on Proposed Rates ($000)				Revenue on Existing Rates ($000)			Existing vs. Proposed Rates (%)		
Customer Rate Class	T	D	S	TOTAL	T	D&S	TOTAL	T Change	D&S Change	TOTAL Change
Streetlight Rate D61	240	4,091	677	5,008	375	4,178	4,553	-36%	14%	10.0%

In order to mitigate the impact of its proposed rate changes, AE proposed that a 10% rate cap per rate class be imposed on its tariff design.

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60 Decision 2005-025. page 15
61 Decision 2005-025, pages 25-26

The Board will address these issues in the subsections that follow:

- Direct Assignment and Allocation of Costs to Streetlight Customers, and
- Definition and Calculation of Customer Counts for Streetlight Customers.

4.3.1 Direct Assignment and Allocation of Costs to Streetlight Customers

In response to a direction from the Board to directly assign costs to streetlights,[62] collecting work orders covering the period 1950 through 2002. Work orders with some level of investment that was closed to streetlights Account 47-810 were selected.[63] A total of 4, 475 work orders were selected.

The work orders selected by AE were provided to Mr. Sarikas who, in turn, conducted a work order study; cleaned up the information to avoid double-counting; excluded costs that did not make sense, and statistically analyzed the information. As a result of this exercise, Mr. Sarikas eliminated two work orders that, based on his professional judgment, did not belong.

Mr. Sarikas confirmed that all of the 4,475 distribution work orders identified contained some level of investment that was capitalized to Account 47-810. His analysis determined that 30% of these work orders contained only streetlight plant and did not require any additional allocation of secondary distribution system investment. He further determined that the remaining 70% of distribution work orders contained both streetlight and distribution system streetlight “related” plant investment that was capitalized to AE’s non-streetlight accounts (e.g. poles, conductors, conduits, underground services and transformers).

The total value of the work orders in the study was $41.6 million. Of this total, the Account 47-810 portion of the work orders was $30.7 million, while the non-streetlight account plant in the study was $10.9 million. Mr. Sarikas determined that all of the $41.6 million in the work orders studied should be directly assigned to streetlights.

In other words, Mr Sarikas determined that 38¢ of secondary distribution system plant (i.e. non-streetlight plant) should be directly assigned, for purposes of the COSS, to the streetlight class for every dollar of Account 47-810 investment.

For 2008, AE estimated that the value of Account 47-810 would be $46.4 million. For purposes of the COSS, Mr. Sarikas developed the 2008 directly assigned secondary distribution system plant of $17 million on that basis (i.e. $46.4 million of Account 47-810 x 38% = $17 million directly assigned to streetlights).

Additionally, a review of sample work orders showed that related secondary distribution system investment included in the work orders contained capacity that could be used to serve other rate classes in the future. Mr. Sarikas, also noted that metal davits do not serve as part of the secondary distribution; but rather only serve streetlights. For these reasons, he recommended that the billing determinants used to allocate secondary distribution system plant to streetlights be reduced by 50%.[64]

[62] Decision 2005-025, page 14
[63] Transcript Volume 3, page 538, line 22 to page 540, line 5
[64] Exhibit 002-01, Foster Study, page 4-5

AE noted that investment in non-streetlight distribution system assets (meters, overhead services, land and land rights and substations) were less than 1% of the $10.9 million total non-streetlight investment.

AE provided the following table showing how distribution plant was allocated to the streetlight rate class.[65]

Table 4. AE Derivation of 2008 Streetlight Rate Plant Investment

	Streetlight Function (direct assignment) ($ Million)	General Plant (allocated) ($ Million)	Streetlight Rate (D61) ($ Million)
Streetlight Plant (Account 47-810) *Directly Assigned*	46.4		46.4
Secondary Distribution System (Non-Streetlight Plant)			
Directly Assigned	17.0		17.0
Allocated	2.4		2.4
Total Secondary Distribution System	19.4		19.4
Total Distribution Plant	65.8		65.8
General Plant *(allocated)*		9.1	9.1
Total Gross Plant - Streetlight Rate *(both Assigned and Allocated)*			74.9

AAMDC/AFREA argued that the explanation provided by Mr. Sarikas with respect to the direct assignment associated with streetlights was cursory and inappropriate for such a large change in the method of direct assignment. Further, the record did not support the direct assignment of 100% of the non-streetlight investment in the work order study to streetlights.

AAMDC/AFREA argued that a substantial number of work orders should have been excluded from the Streetlight Study based on the proportion of non-streetlight investment to streetlight investment Account 47-810 costs, and produced the following table to highlight this issue:

Table 5. AAMDC/AFREA Work Order Comparison

Work Order	Streetlight Cost (Account 47-810)	Non-Streetlight Cost (Non-Account 47810)	Status
C30111	4%	96%	Excluded from the Study
C9722-6	4%	96%	Included in the Study

AAMDC/AFREA argued that for 2008, the $17.0 million[66] of secondary distribution system plant directly assigned to the streetlight class was substantially overstated, and that the $46.4 million[67] of Account 47-810 was also overstated because if more work orders had been properly excluded from the Streetlight Study, the costs of the streetlight assets (Account 47-810) inherent in those work orders would not have been directly assigned to streetlights.

AAMDC/AFREA argued that the Streetlight Study had not adequately documented the basis for the 50% adjustment to secondary distribution system plant allocators,[68] and provided no support

65 AE Rebuttal Evidence, page 11
66 Exhibit 002-16-01, Rebuttal Evidence, Appendix 1, p.11
67 Exhibit 002-16-01, Rebuttal Evidence, Appendix 1, p.11
68 Exhibit 003-07, pages 21-25

for the claim that the 50% reduction was sufficient to address the large amount of non-streetlight assets already directly assigned to streetlights and the sharing of streetlight plant by other rate classes. Further, the 50% adjustment did not correct the direct assignment because any adjustment for an excess direct assignment should be applied to the direct assignment, not to the allocators of secondary distribution system plant. The effect of the 50% reduction in allocators was probably too small to reflect the amount of streetlight-assigned plant that serves other classes and services.

AAMDC/AFREA noted that the possibility of double counting plant existed given the replacement of some facilities and argued that the double counting problem arising from replacements in the work order database had not been addressed appropriately.

AAMDC/AFREA took issue with AE's assessment that because the actual amount of non-streetlight assets in the work orders was only 1% of total distribution plant, that it would have a negligible effect on the direct assignment. AAMDC/AFREA considered that although 1% was only a small portion of the system total, it was a substantial portion of the plant directly assigned to streetlights.

AAMDC/AFREA also noted that Contributions In Aid of Construction (CIAC) appeared to cover a large portion of Account 47-810 and other plant dedicated to streetlights. While Mr. Sarikas indicated that CIAC was allocated to streetlight customers in the COSS, AAMDC/AFREA indicated that it was not able to track this credit in the COSS.

AAMDC/AFREA also noted that in response to Board Direction 24 from Decision 2005-025, Mr. Sarikas developed customer weighting factors for transformers, service drops, and meters. However, for streetlights, weighting factors were derived only for transformers, since streetlights were not allocated any share of meters and non-assigned service drops.[69] Having reviewed the methodology for allocating transformer costs, AAMDC/AFREA submitted that the relative weighting factor for streetlights was unreliable, for three reasons:[70]

1. Mr. Sarikas provided limited documentation of the derivation of the factors;
2. The assignment of particular transformers to particular customer groups was not tied to how the system actually works. Mr. Sarikas simply assumed that certain types of customers are served by certain sizes of transformers. A large transformer can serve a cluster of residential customers; a bank of smaller transformers can serve one large customer, and a single transformer can serve a mix of customer types; and
3. Mr. Sarikas chose to group streetlights, the smallest of loads, with the large demand-metered customers, including the Large General Service customers. Mr. Sarikas computed a single hypothetical ratio of customers per transformer for this extremely heterogeneous group. As a result, the smallest customers were assumed to use as much of a transformer as the largest customers.

AAMDC/AFREA concluded that the Streetlight Study was flawed and should be rejected by the Board. In the interim, AAMDC/AFREA submitted that fairness required that the COSS must return to the 2004 DTA allocation of distribution plant, and that the Board should direct AE to recalculate the 2008 COSS using its 2004 DTA allocations. Further, AE should be directed to

[69] Exhibit 003-07, pages 39-40
[70] Exhibit 003-07, pages 39-40

redo the Streetlight Study for their next DTA, this time setting out clear criteria, and implementing the study consistently with respect to which streetlight assets and secondary distribution system plant should be directly assigned to streetlights.

PICA argued that the record did not support the direct assignment of 100% of the non-streetlight assets in the work orders, for the following reasons:

1. As Mr. Sarikas acknowledged, some of the 1950-2002 non-streetlight plant served a mix of customers and functions when installed, or has since come to serve such customers and functions. Mr. Sarikas explained that he made an adjustment “prior to the allocation of related secondary distribution” to account for shared plant, but this adjustment was never identified.[71]
2. Some of the work orders may include replacements of plant installed in previous work orders, resulting in double-counting. There is no indication that Mr. Sarikas corrected his data base for these replacements.
3. CIAC appear to cover a large portion of Account 47-810 and other plant dedicated to streetlight. Mr. Sarikas indicated that CIAC was allocated to streetlight customers, but this allocation seemed to be driven by plant in service. From the work-order database, it appears that CIAC for plant dedicated to streetlights was a higher percentage of plant investment than for the same type of plant (e.g., poles) in general service. Mr. Sarikas may have greatly overstated the net plant investment for streetlights.

PICA submitted that while there were a number of adjustments made to the recorded streetlight costs, AE did not explain how these adjustments impact the three issues identified above.

PICA recommended that AE be directed to address the concerns noted above with the streetlight assignment and allocations in the next DTA Phase II application. Given the 10% cap on rate increases proposed by AE for streetlights, PICA recommended that the filed COSS assignment and allocations be accepted by the Board for purposes of this proceeding.

PICA also submitted that streetlight costs as a percentage of total investment may be influenced by a number of factors, including service territory and system growth. To the extent feasible, AE should provide streetlight cost per fixture information for comparable utilities and explain any material differences in cost per fixture at the next DTA Phase II.

UCA supported AAMDC/AFREA’s position that the detail provided in the Streetlight Study was inadequate to properly assess its reasonableness. UCA agreed with AAMDC/AFREA that the direct assignment of streetlight costs was inaccurate and over-stated.

UCA also noted that the streetlight work order exclusions[72] further demonstrated that the Streetlight Study, while large in nature, had not been properly constructed and conducted. UCA submitted that AE and Mr. Sarikas’ conclusions and recommendations should be rejected and that the work be completed in a more appropriate manner for the next GTA.

CCA noted that AE had recognized a certain portion of the work orders’ non-streetlight investment in the secondary distribution system may be used by other rate classes, and removed

[71] PICA Argument, page 20
[72] Exhibit 002-16-01, page 14

50% of the secondary distribution system plant allocation from the streetlight rate class. CCA submitted that on balance, in light of the increase in costs to the streetlight rate class proposed in this GTA, the 50% adjustment appears appropriate, even though there may be a case that this adjustment should be somewhat lower.[73]

4.3.1.1 Views of the Board

Having reviewed the issues raised by interveners, the Board makes the following findings with respect to the Streetlight Study and related distribution plant direct assignments and allocations.

The Board finds that the Streetlight Study filed in AE's Application was not well documented. Further, a clear and understandable methodology was not established in the initial filing. The Board still has concerns whether more work orders should or should not have been excluded from the work order study. If the Streetlight Study had been well-documented, the Board considers that it would have been easier to test whether the amounts of streetlight plant and secondary distribution system plant directly assigned were reasonable.

The Streetlight Study caused confusion and misunderstanding for interveners and resulted in some in-efficiencies in the hearing process. The Board will further consider this matter in the cost award process.

In spite of those inefficiencies, the Board considers that the evidence that was eventually placed on the record will result in a fair allocation of costs to streetlight customers as follows:

Table 6. Board Approved Allocation of Streetlight Plant Investment

	Account	AE Proposed	Board Approved
Streetlight Plant (Account 47-810) *Directly Assigned*	streetlight plant (Account 47-810)	46.4	46.4
Secondary Distribution System (non-Streetlight Plant)	non-streetlight plant (non-Account 47-810)		
Directly Assigned		17.0	8.5
Allocated		2.4	4.8
Total Secondary Distribution System		19.4	13.3
Total Distribution Plant		65.8	59.7

When costs are directly assigned to a rate class, the costs should be 100% caused by that rate class. Accordingly, if a portion of the secondary distribution system cost directly assigned to streetlights by AE relates to equipment that will, over time, serve customer classes other than streetlights, then that portion should not be directly assigned to streetlights. Accordingly, the Board finds that the 50% reduction was incorrectly applied to the secondary distribution system (Allocated costs) rather than the secondary distribution system (Directly Assigned costs) as set out under "AE Proposed" in Table 6 above.

To correct for this excess direct assignment, the Board agrees with AAMDC/AFREA that it is the secondary distribution system direct assigned costs that must be reduced by 50% as set out under "Board Approved" in Table 6 above.

[73] Transcript Volume 3, pages 607-608

As a consequence, the Board finds that the 50% proposed reduction to the allocators for the secondary distribution system (Allocated costs) should not be applied. The Board considers that the allocation methodology AE uses for secondary distribution system (Allocated costs) costs already reflects an appropriate sharing between rate classes.

The Board finds that the amount of secondary distribution system plant directly assigned to the streetlight class for 2008 should be reduced to $8.5 million (i.e. 50% of the $17 million). In other words, the Board finds that 19¢ of secondary distribution system plant should be directly assigned to streetlight for every dollar of Account 47-810 investment. In its determination of the 50% reduction from the 38¢ used by AE, the Board took into account the:

- treatment of pole attachment revenue offsets (see Section 4.3.2);
- the portion of the secondary distribution system cost directly assigned to streetlights that will, over time, serve customer classes other than streetlights; and
- other sharing of facilities and benefits set out below.

The Board finds that it is reasonable for AE to assign/allocate most costs identified as Account 47-810 directly to streetlights. While it is clear that the majority of the items that comprise Account 47-810 are streetlight costs, the Board considers that some items such as pavement work and sidewalk work may be costs that benefit other rate classes. However, the Board considers that the 50% reduction to the amount of secondary distribution system costs directly assigned to streetlights is sufficient to account for this possibility of sharing.

The Board also makes the observation that provision of streetlights by the municipalities could be considered a public good as streetlights benefit all customers. Given the benefits associated with streetlights, the Board finds that it would be reasonable for all customers to share some of the costs associated with streetlights.

Based on these findings, the Board directs AE in the Refiling, to:

- Reduce the amount of secondary distribution system directly assigned to the streetlight rate class in the COSS by 50%, and to reallocate these amounts to all rate classes using the same allocators used to allocate other secondary distribution system plant.
- Increase the amount of secondary distribution system plant allocators from the proposed 50% level to the 100% level.

The Board notes that a change in the definition of the streetlight customer numbers (see Section 4.3.2), that will be effective as of January 1, 2009, will result in an appropriate reduction to the wholesale billing costs assigned to streetlight customers at that time.

4.3.2 Definition and Calculation of Customer Counts for Streetlight Customers

AE stated that it had derived its streetlight customer allocator so that it would be consistent with the way a customer was defined prior to the segregation of retail and wires functions. AE stated that the rationale attempted to mimic what would determine a new customer account being opened for a municipal or provincial streetlight customer.

To determine the relationship of lamps to customers, Mr. Sarikas used the May 2006 amount of lamps (e.g. 35,800 lamps) as the ratio's numerator, as it reflected the most up to date information available with respect to the number of lamps in service. This was combined with the 2002 number of attachments in the denominator. Mr. Sarikas stated that this approach was intended to add a measure of conservatism to the determination of the ratio as it essentially assumed that the growth in lamps between 2002 and 2006 was not attributable to the growth in the number of unique customer attachments. Further, Mr. Sarikas stated that this approach was conservative in the amount of customer related secondary distribution system costs allocated to streetlights. AE also stated that the CIS data was only used as a cross check of reliability and was not used in the determination of the ratio.

AE stated that it knew the number of wires customers it served, however this information did not provide specific insight into how these customers were being billed. As AE does not bill customers directly but rather provides bills to retailers, AE stated that it was difficult for them to know how any streetlight customers received bills.

AE explained that the wholesale bill to retailers was by site and the monthly bill was presented on a light by light basis. AE stated that this detail was required for the administration of lights and in order to give information to customers and respond to inquiries and audits. AE explained that it used one system for administration and maintenance purposes and, even though it could aggregate the lights using a different system (with resulting incremental costs), it would still need to manage streetlights on an individual basis. AE explained that it needed a sophisticated system to manage the more than 40,000 streetlights on its system and to be able to explain the details to its customers.[74]

AAMDC/AFREA submitted that AE and Mr. Sarikas had provided several inconsistent definitions of customer that were applied in various circumstances and for various purposes. AE's first definition for a customer within its COSS was a "unique customer attachment."[75] AAMDC/AFREA considered that this definition was a wide-ranging concept when applied to streetlight customers. AAMDC/AFREA submitted that using this definition would result in an inequitable and unreasonable allocation of distribution costs.

For the purposes of allocating customer-related distribution costs, Mr. Sarikas computed that the average number of lamps per customer was 34.2. AAMDC/AFREA submitted that any secondary equipment added to serve a streetlight customer was already captured in the direct cost assignment. Therefore, AAMDC/AFREA submitted that there was no causal justification for allocating customer-related costs to streetlights in addition to directly-assigned costs.

AAMDC/AFREA pointed out that streetlights do not incur any metering expenses, as streetlights have no meters. Further, the bookkeeping and collection expenses associated with streetlight was now the responsibility of the retailer, and the minimal cost of service wiring and installation and connection of streetlights was already captured in Mr. Sarikas' study of work orders. On that basis, AAMDC/AFREA submitted that no customer costs should be allocated from the distribution plant to streetlight as a result of Mr. Sarikas' study.

74 Transcript Volume 3, pages 481-483
75 Exhibit 002-16-01 at page 33ff

Each streetlight was also defined as a customer for billing purposes. AAMDC/AFREA submitted that, as with the "unique customer attachment" definition, this definition of customer may work for metered and unmetered customers that take service at a unique point or even a limited number of points, but the lamp-site definition does not work for the streetlight customer. Unlike most customers, streetlight customers were responsible for a large number of devices that receive unmetered service over a dispersed area. Despite the large number of service points, there was only one responsible party who ordered the service and incurred billing costs on the system.

AAMDC/AFREA considered that the unique customer attachment definition relied on Mr. Sarikas' speculation as to how ATCO I-Tek handled the information that was passed on by AE. However, it was the customer's load profile that was relevant to the energy consumed by the customer, which represented a cost relevant to the retailer, and not to the fixed costs of the wires provider.

AAMDC/AFREA argued that AE's application of the unmetered customer rate of $1.66 per site was unfair to municipal streetlight customers, as these customers would pay on average, 34.2 times as much in I-Tek charges as the customer with a single point of service. Mr. Chernick testified that such an arrangement for billing streetlights was unknown in his experience.[76]

AAMDC/AFREA considered that FAI's methodology of allocating load settlement costs was a fair method of allocation, and would also be fair for AE. AAMDC/AFREA submitted that the Board should direct AE to consolidate its streetlight sites/accounts to correspond to the actual customer who ordered the streetlights.

Until the Benchmarking process was completed, AAMDC/AFREA recommended that the allocation of wholesale billing costs be based on the number of streetlight customers, consistent with the allocation of wholesale billing costs for other customer classes and with the allocation of wholesale billing costs as practiced by FAI. Further, the number of sites should be reduced by a factor of 34.2, and only $20,036 in wholesale billing costs should be allocated to streetlight customers.

AAMDC/AFREA noted the 2008 forecast annual revenue from pole attachment was $708,000.[77] Further, as a result of the way AE accounted for pole attachments, customers could not determine whether these services recovered the appropriate amount of costs and if customers were being asked to subsidize the users of pole attachment services through their rates. Mr. Sarikas' study did not allocate any cost of poles to pole attachment services. AAMDC/AFREA argued that the inequities of pole attachments should be dealt with by treating the pole attachment services as a separate class of services, and recommended that the Board provide a direction to AE that the COSS be altered to allocate and assign all costs and revenues to pole attachments as a separate rate class as it would to any other rate class.

As a second-best solution, AAMDC/AFREA proposed that AE allocate its pole attachment revenue as a credit (revenue offset) to each rate class in proportion to their share of the distribution pole asset costs.

[76] BR-AAMDC/AFREA-3(a)
[77] AAMDC/AFREA-ATCO-3(b)

PICA noted that the number of streetlight fixtures was divided by 34.2 to arrive at the number of streetlight attachments to the secondary distribution system for customer related cost allocation purposes. Similarly, the number of sentinel lighting fixtures was divided by 1.5 sentinel lights per customer to arrive at the number of sentinel lighting attachments to the secondary distribution system.[78]

PICA noted the following comment from AE:

> The 35,800 lamps-sites used in the numerator overstated the ratio of the number of lamps-sites per *unique customer attachment* for all attachments and thereby under-allocated customer-related secondary distribution system costs to streetlighting customers. To be conservative, I assumed the growth in lamps between 2002 - 2006 (e.g., 6,811 lamps representing the difference between the 2006 figure and the lowest CIS result, Sum of Customer Count) was not attributable to growth in the number of *unique customer attachments*.[79]

Based on the foregoing, PICA understood that AE may have erred on the high side in estimating the number of fixtures per attachment. PICA also noted other evidence reviewed by AE, such as the CIS, may indicate a lower number of lamps per attachment. PICA submitted that AE should be directed to provide full validation of its estimate of the number of fixtures per attachment in its next DTA. However, for purposes of the current proceeding, PICA did not object to acceptance of the proposed number of fixtures per attachment for streetlights and sentinel lights.

Subject to the results of the ATCO I-Tek customer care benchmarking studies being completed, UCA did not object to the allocations proposed by AE.

4.3.2.1 Views of the Board

The Board notes AE indicated that the definition of customer count required to properly allocate customer-related secondary distribution costs is different from the definition of customer count (e.g., one lamp-site equals one customer) used for billing purposes.[80] AE uses a 34.2 streetlight sites per customer (35,800/1,046) for allocation of the customer-related secondary distribution costs. The Board considers that since the streetlight site attachment is at the secondary distribution level, it is appropriate that they have cost responsibility on the same basis as other customers that attach at the secondary distribution level. Accordingly, the Board accepts AE’s 34.2 sites per customer as the appropriate definition for allocation of customer-related secondary distribution costs.

The Board deals with the definition of customer count used for billing purposes below.

In Decision 2005-025, the Board directed AE as follows:

> However the Board directs AE, in its next Phase II application, to provide an analysis regarding the possibility of aggregating streetlights within a town in some reasonable fashion; either by vintage, by number, by location or any other reasonable measure. For example, for the purposes of billing, all streetlight additions requested on a specified date would be considered as a site; or all streetlights on a specified street or streets are

[78] Exhibit 002-01, Section 20 Attachment 2 Response to Direction No. 20
[79] Exhibit 002-16-01, Rebuttal Appendix 1, page 37
[80] Appendix 1 of AE Rebuttal pages 30-31

> considered to be a site. The Board expects that AE will address why it is necessary to continue to treat each individual streetlight as an individual site and to consider alternate options that reflect the cost of providing the service. The Board will not make any adjustment to the charge for connecting new streetlight sites at this time.[81]

The Board reviewed AE's response:

> AE responded that a review of the connection process for lighting customers following the 2004 Phase II Distribution Tariff Application determined that the $10.00 connection fee was no longer required since streetlight accounts require far less setup than metered services. Thus, the grouping of lights for these purposes is not required.
>
> ATCO Electric proposes to continue with no initial connection charges for lights and will revise the Terms and Conditions for Distribution Service Connections to clarify.[82]

The Board finds that AE did not comply with the above Board direction.

The Board notes the issue raised by AAMDC/AFREA regarding the definition of customer for allocating billing costs. The Board understands that each streetlight may receive associated customer charges and other charges beyond energy consumption from the retailer, in addition to charges from AE. These charges can be significant, particularly for municipalities. However, any charges that are related to the services provided by Direct Energy Regulated Services (DERS) or other retailers are not the subject of this proceeding. The Board is concerned, in this proceeding, with ensuring that customers are responsible for the costs that they cause AE to incur by providing service.

AE's evidence is that the definition of customer count for billing costs is one customer equals one lamp-site. AE indicated that it incurs billing charges and wholesale billing costs on an individual site basis while its current Master Service Agreement (MSA) with I-Tek is in effect. The Board is concerned with the costs incurred by AE.

AE explained that the wholesale bill to retailers was by site and the monthly bill was presented on a light by light basis. The Board notes, however, that AE indicates that there are only 1046 unique attachments to the distribution system for streetlight fixtures and 487 streetlight customers. Although it is possible that each of the 1046 attachments may require a separate load settlement activity, the Board does not accept that each of the 35,800 individual streetlight fixtures requires such settlement activity. AE has not provided any persuasive reason that streetlights should be treated differently from other equipment attached to the distribution system and it would appear that all other equipment requires load settlement only at the point of unique attachment to the distribution system, regardless of how many electrical devices are behind the unique attachment point.

Accordingly, the Board directs AE at the time of its next GTA to adjust its definition of a streetlight customer for billing purposes so that one streetlight fixture does not equal one customer. The Board considers that the billing charges in AE's revenue requirement should not reflect separate customer charges for each streetlight fixture, but rather only billing charges for the number of unique attachment points to the distribution system for streetlights. The charges

[81] Decision 2005-025, page 51
[82] Application, Section 3, Attachment 1, page 6-7

for each unique attachment of streetlight fixtures can then be aggregated for each streetlight customer on that basis.

AE indicated that site by site detail was also required for the maintenance and administration of streetlights and in order to give information to customers and respond to inquiries and audits. AE indicated that even though it could aggregate the streetlights using a different system than for billing, there would be incremental costs. However, the Board notes that FAI aggregates its lights for billing and therefore, the Board has not been persuaded by AE that these incremental costs would be significant.

AAMDC/AFREA also recommended that AE be directed to assign revenues and costs to the category of pole attachment as a separate rate class or at least to allocate its pole attachment revenue as a credit (revenue offset) to each rate class in proportion to their share of the distribution pole asset costs. The Board considers that the evidentiary record cannot support such a change to AE's current practice. The Board finds AE's existing treatment of the revenues associated with third party pole use as a revenue offset that benefits all customers to be reasonable for the purposes of this proceeding given the Board's findings in Section 4.3.1.

5 OVERALL TARIFF DESIGN PRINCIPLES

The following table sets out the revenues and costs for each rate class under the rates AE proposed in the Application:

Table 7. Summary of Proposed Revenues and Costs

	Costs ($000)				Revenue of Proposed Rates ($000)				R/C on Proposed Rates (%)			
Customer Rate Class	T Costs	D Costs	S Costs	TOTAL Costs	T Revenue	D Revenue	S Revenue	TOTAL Revenue	T R/C	D R/C	S R/C	TOTAL R/C
Residential Rate D11	13,477	63,458	13,349	90,284	13,477	64,351	13,537	91,365	100	101	101	101.2
General Service Rate D21	8,671	25,026	2,550	36,247	8,671	25,420	2,590	36,681	100	102	102	101.2
Irrigation Rate D25 & D26	65	161	14	239	65	42	4	111	100	26	26	46.2
Industrial Rate D31 & D32	75,720	69,517	3,796	149,032	75,720	70,172	3,832	149,724	100	101	101	100.5
Opportunity Rate (D-connect) D33	0	0	0	0	0	0	0	0				
T-Connect T31 & T33	21,544	775	301	22,620	21,544	825	522	22,891	100	106	173	101.2
Oilfield Rate D41	4,361	18,145	1,491	23,997	4,361	18,411	1,513	24,285	100	101	101	101.2
REA Farm Rate D51 (inc D52)	2,197	1,667	1,062	4,926	2,197	1,695	904	4,795	100	102	85	97.4
Farm Service Rate D56	3,745	10,183	1,895	15,823	3,745	10,354	2,103	16,202	100	102	111	102.4
Street Light Rate D61	240	6,573	1,087	7,900	240	4,091	677	5,008	100	62	62	63.4
Sentinel Light Rate D63	43	521	286	849	43	525	289	857	100	101	101	100.9
Total:	130,063	196,024	25,831	351,918	130,063	195,885	25,970	351,918	100	100	101	100.0

Source: Application, Schedule 5-B-1 as revised March 16, 2007

The following table sets out the increase in revenues by rate class (capped at a 10% maximum) as proposed by AE in the Application:

Table 8. Summary of Revenues on Existing and Proposed Rates

	Revenue on Proposed Rates ($000)				Revenue on Existing Rates ($)			Existing vs. Proposed Rates (%)		
Customer Rate Class	T Revenue	D Revenue	S Revenue	TOTAL Revenue	T Revenue	D&S Revenue	TOTAL Revenue	T Change	D&S Change	TOTAL Change
Residential Rate D11	13,477	64,351	13,537	91,365	15,721	72,090	87,811	-14	8	4.0
General Service Rate D21	8,671	25,420	2,590	36,681	9,456	26,298	35,754	-8	7	2.6
Irrigation Rate D25 & D26	65	42	4	111	30	71	101	116	-35	10.0
Industrial Rate D31 & D32	75,720	70,172	3,832	149,724	74,062	62,050	136,112	2	19	10.0
Opportunity Rate (D-connect) D33	0	0	0	0	0	0	0			
T-Connect T31 & T33	21,544	825	522	22,891	21,544	789	22,333	0	71	2.5
Oilfield Rate D41	4,361	18,411	1,513	24,285	4,394	17,787	22,181	-1	12	9.5
REA Farm Rate D51 (inc D52)	2,197	1,695	904	4,795	2,820	2,351	5,171	-22	11	-7.3
Farm Service Rate D56	3,745	10,354	2,103	16,202	4,759	11,105	15,865	-21	12	2.1
Street Light Rate D61	240	4,091	677	5,008	375	4,178	4,553	-36	14	10.0
Sentinel Light Rate D63	43	525	289	857	67	712	779	-36	14	10.0
Total:	130,063	195,885	25,970	351,918	133,228	197,432	330,660	-2	12	6.4

Source: Application, Schedule 5-B-2 as Revised March 16, 2007

5.1 Maximum Rate Class Increase

AE continued to rely upon the rate design principles and methodology previously accepted by the Board in the context of past DTAs. AE set transmission charges so as to recover 100% of the forecast demand related costs allocated to any rate class through a demand charge; and 100% of the forecast allocated energy related costs through an energy charge (with the exception of price schedules D11 and D22, since they do not contain demand charges and price schedules D61 and D63, since they do not contain energy charges). With respect to the distribution and service functions, AE deviated from the 100% recovery approach in order to provide flexibility in setting rates and to avoid rate increases that would exceed 10%.

AE indicated that it attempted to maintain a 95% to 105% revenue to cost ratio band for all rate classes, but that this was not achievable for streetlights and irrigation customers, given the desire to limit a rate increase to 10%. AE proposed that other rate classes would absorb the relatively small amount needed to limit the increases for those classes. Since, the rate impact on other rate classes of this approach was small, AE submitted that it was appropriate to transition these rates to the desired revenue to cost ratio and not make changes of greater than 10% at this time.

As the Board has utilized a rate cap of 10% for any increases in recent Board decisions, ASBG/PGA submitted that AE’s 10% cap was appropriate to mitigate rate shock for a particular year. However, AAMDC/AFREA submitted that based on its submissions, it was not clear that a significant change in the streetlight allocated costs was warranted or that the streetlight rate actually needed the 10% cap applied.

CCA submitted that the proposal to limit the maximum rate increase to any one rate class to 10% was reasonable.

UCA supported the use of a generic 10% maximum increase as proposed by AE.

5.1.1 Views of the Board

The Board finds that it is appropriate to limit the increase to any rate class to 10% for the rates arising out of this Phase II proceeding. The Board notes that the 10% rate cap will be applicable to the irrigation rate and possibly to the streetlight classes. Both of these rate classes are comparatively small and therefore the effect on keeping these two rate classes outside of the generally accepted revenue to cost range of 95% to 105% will be relatively minor to the other rate classes.

Accordingly, the Board directs AE, in its Refiling, to use the 10% increase cap, as required.

5.2 Transitioning of Rate Classes to 100% RC Ratios

AE submitted that its proposal to transition all rate classes to the 95% to 105% revenue to cost ratio band using only Phase II proceedings was fair and appropriate, particularly given the minor nature of the impact on other rate classes. AE submitted that the use of other proceedings, such as Rider G Application is not warranted in the circumstances particularly since the revenue to cost ratio for all other classes still remains within the tolerance range discussed above.

As Table 6 of this Decision set out, AE proposed a RC ratio in this Application for Irrigation Rate Classes D25/26 of 46%; in the 2001/02 GTA and in the 2004 GTA, the RC ratios were 100% and 98%, respectively. Likewise, the proposed RC ratio for Streetlight Rate Classes D61 is 63% in this Application; in the 2001/02 GTA and in the 2004 GTA, the RC ratios were 100% and 96%, respectively. As such, the RC ratios for Rate classes D25/26 and D61 reflect a significant decrease from that approved by the Board in the prior two GTAs. In this Application, AE proposes to collect only 26% of the Distribution costs from the irrigation rate classes and 62% of the Distribution Costs from the streetlight rate classes.

The total subsidy to the irrigation and streetlight customers is approximately $3.0 million/annum. Of this, about a third, or $1.1 million, is provided by the Rate 11 customers. AE estimated that it may take more than one or two DTAs for the ratios for these rate classes to revert to the 95% to 105% range in light of the 10% maximum rate increase constraint.

AE submitted that annual increase in the rates for D25/D26 and D61 beyond the test years would not be effective and would only lead to further complications in the rate design for the following reasons:

- AE's experience is that distribution tariff applications occur every two to three years. In between, AE is required to submit yearly interim rate applications that may see an increase or decrease in customer rates based on changes to proposed/approved revenue requirements or other cost drivers (for example, AESO tariffs). Any adjustments to D61 and D25/D26 would still have to be tempered with rate adjustments resulting from the interim rate applications.

- AE submits yearly rider applications (Rider G) to help dispense of deferral account balances and true-up of previous approved riders. This rider is generally filed in the first or second quarter of the year for an effective period between August to December. An automatic annual increase of 10% to D25/D26 and D61 should be taken within the context of what impact Rider G will have on customer bills in order to minimize further rate shock. The timing of Rider G application and the interim rate application makes it difficult to determine whether further changes to D61 and D25/D26 are possible, while recognizing the maximum rate increase of 10%.

- AE is concerned that adjusting rates without recognizing the effects of cost drivers may cause significant rate swings (by component and by function) from application to application to occur. For instance, if rates are increased by a maximum of 10% and a change in AESO rates occur this may pose a rate design problem in the following DTA when attempting to balance the changes in cost drivers for each of the transmission, distribution and service functions.

- Considering that the impact to other customers in this application as a result of absorbing the revenue deficiency from rate classes D61 and D25/D26 is approximately 1%, AE is of the view that the overall impact is small enough that any benefits gained from this approach would be offset by the administrative difficulties incurred.

Further, AE submitted that using other mechanisms, such as the Rider G or Interim Rate Applications, to implement further rate increases between Phase II DTAs was unnecessary given the minor impact on other customer classes and the difficulty in assessing what will occur regarding cost drivers year over year. AE submitted that such an approach would significantly complicate what has become a rather straightforward Rider G (or Interim Rate) Application process and would not permit such a process to be completed in a timely manner, as is currently the case.

CCA submitted that there is a significant and on-going annual subsidy to the irrigation and streetlight rate classes by all other rate classes which are proposed to have in excess of a 100% RC ratios and suggested that annual rate increases of 10% be applied in each of the intervening years between this GTA and the next GTAs until RC ratio for these rate classes have been brought into tolerance.

CCA submitted that the disparity in the RC ratios between the irrigation and streetlights rates and those of the other rate classes could also become further exacerbated depending on the allocation of costs arising from AE's yearly interim rate applications based on changes to proposed or approved revenue requirements or other cost drivers (for example, AESO tariffs or Rider G). As such, further true-ups may also be necessary based on the RC ratios proposed in AE's next GTA.

ASBG/PGA submitted that the maximum rate cap should apply for the test periods as there is no basis to assume the present proposed methodologies will endure in the future and it is inappropriate to lock-in any future R/C ratio increases without the benefit of a thorough examination in a future GTA Phase II proceeding.

UCA supported transitioning to 100% revenue to cost ratios without rate increases between Phase II rate proceedings. UCA submitted that CCA's approach, if properly conducted, would require the re-running or re-basing of the COSS to determine the revenue to cost ratios. This would be required on at least an annual basis, if not more frequently, depending on the number of true-up or reconciliation applications that are filed over the course of a year. In UCA's view, re-basing rates with a COSS is not required on such a frequent basis and would be time consuming and costly for all parties.

5.2.1 Views of the Board

The Board recognizes that, in certain situations, there may be a long transition period to bring the revenue to cost ratios for a rate class that is outside the 95% to 105% band into the band using 10% maximum increases after Phase II proceedings. However, the Board finds that rate changes to improve revenue to cost ratios outside of the 95% to 105% band should normally be approved only in the context of Phase II proceedings where current COSS and billing determinant forecasts may be fully tested. Therefore, the Board approves AE's proposed transitional approach.

6 INDIVIDUAL RATES AND RIDERS

6.1 Billing Determinants

AE explained that changes in the forecast billing determinants for the 2008 Test Year for the irrigation class resulted from AE's improvements in tracking billing determinant actuals for this rate class.[83] AE now has the information available to it to be able to better track billing determinants and ensure that the irrigation rate class is paying an appropriate share of costs.[84]

ASBG/PGA objected to AE's position that the proposed methodology was the cause of the decreased irrigation revenue to cost ratio. ASBG/PGA argued the proposed methodology, class responsibility for POD NCP demand, provided billing determinants for irrigation service for each of the 12 months even when irrigation service was not connected. ASBG/PGA submitted this does not determine class responsibility on a POD basis and fails to consider seasonal load diversity.

6.1.1 Views of the Board

The Board notes ASBG/PGA's concern that the decreased irrigation revenue to cost ratio resulted from higher cost allocations due to the changed methodology rather than the improvement in tracking of billing actuals as explained by AE.

The Board notes that AE indicated that previously the irrigation class was being allocated a lower amount of costs than is now considered appropriate based on the improved billing determinant information currently available.[85] In that regard the Board notes that the improved information is available due to the use of the AMR meter technology in 2004 and 2005.[86]

The improved information indicates that the irrigation rate class will pay approximately $100,000 less than its allocated costs (or 46% of its allocated costs) in 2008 considering the Board's use of a cap in rate increases for a rate class of 10%. In addition the Board's acceptance of AE's proposal that adjustments should only be made in the context of the Phase II applications ensures that AE will have more actual billing determinant information for irrigation customers when it files its next GTA.

Accordingly, for the purposes of this GTA, the Board accepts AE's explanation that changes in the forecast billing determinants for the irrigation class resulted from improvements in the tracking of billing determinant information for the irrigation rate class.

6.2 Oilfield Class D41 – Grandfathering and Customer Migrations to D31

AE identified a concern with the current rate structure of Price Schedule D41 which has a low crossover between Price Schedules D41 and D31.[87] It discovered this following a review that was conducted in response to Directive 29 from Decision 2005-025. With the existing rate structure in place, new oilfield customer additions with billing demand greater than 30 kW generally seek to be billed under Price Schedule D31, and are then billed at the minimum demand of 50 kW. The low cross-over has resulted in more of the higher cost customers seeking to be billed under a lower cost rate.

As detailed in PICA-ATCO-11, certain customers are grouped together because they incur and share similar costs. Lower load oilfield customers are traditionally rural based, with larger and more expensive distribution facilities (on a per unit dollar/kilowatt basis). As well, as

83 Exhibit 002-01, Application, Section 5; Transcript Volume 2, page 367
84 Transcript Volume 3, pages 370-371 and 439
85 Application, page 5-9
86 Transcript Volume 2, pages 424-426
87 Application, page 5-13 to 5-14

demonstrated in AE's cost of service schedules and 2004 Loss Study, oilfield class customers tend to have longer primary distribution lines than industrial rate class customers.

AE proposed that it would address interclass rate equity concerns by limiting the applicability of oilfield and pumping load services under the Rate D31 price schedule to only those operating loads above 50 kW. AE's proposed that small oilfield and pumping power loads under or equal to 50 kW be required to be served under Price Schedule D41.[88] AE submitted that a 50 kW cap will allow for a smooth transition to Price Schedule D31, which has a current rate minimum of 50 kW. AE noted that its proposal is consistent with the companion rate schedule currently approved by the Board for FAI (Rate Schedule 45), which has a cap of 75 kW.

AE proposed that it would grandfather existing customers who may not satisfy the new eligibility criteria for the price schedule if AE's proposed cap is accepted by the Board. AE indicated that it has been its practice not to force customers from one price schedule to another in circumstances where they were eligible for service under the applicable price schedule at the time such service commenced. Additionally, AE explained that mandating an approach where current customers are forced to convert could be extremely disruptive for customers, as well as the utility. Customers would be required to buy-down remaining contracts and AE would have to determine an appropriate investment amount applicable to the new contract under the new price schedule. AE submitted that the administrative difficulties associated with such a disruptive process were simply not warranted.

PICA noted that AE indicated Rate D41 was developed to recognize oilfield customers (below approximately 50 kW), on average, tend to have higher distribution costs than other customers. PICA noted that AE indicated that there was no cost causation basis for selecting 50 kW for the cut off for small oilfield versus large oilfield customers and submitted that there was no requirement for the Rate D41 cap to coincide with the rate minimum for Rate D31 because small oilfield service is a distinct service with distinct cost characteristics and can be identified as such.

PICA submitted that, in absence of a cost causation basis, the proposed 50 kW cap must be evaluated against the rate offerings of other utilities providing similar service to oilfield customers. PICA noted the comparable cap on the oilfield rate offered by FAI is 75 kW.[89] PICA submitted that, given the FAI cap of 75 kW has been approved by the Board, a similar cap on rate D41 for AE would provide a reasonable degree of comparability. PICA recommended oilfield customer with loads up to 75 kW should not be eligible for service under Rate D31.

In response to AE's intention to grandfather existing oilfield loads below the proposed cap within Rate D31, PICA noted that AE does not even know how many oilfield customers under 50 kW are included in Rate D31.[90] PICA was also surprised that AE, knowing the cost implications for Rate D31, had allowed a substantial number of high cost oilfield customers into Rate D31 over the years. PICA notes from Table A-3, provided as part of the loss study, the under 2 MW industrial class (Rate D31) has over 9 miles of primary distribution associated with it; whereas the small general service class (Rate D21) has about 6 miles associated with it.[91] If

[88] Response to PICA-ATCO-11
[89] Exhibit 002-01, Application, page 5-14
[90] Transcript Volume 1, page 121, line 13
[91] Application, Section 10 Attachment 1; page 23 of 28

not for oilfield customers; PICA questioned whether the under 2 MW sub class of D31 would still have shown primary line length significantly higher than for small general service.

PICA submitted that AE appeared to confirm the assumption that, in the past, the contribution policy would make the company somewhat indifferent as to whether an oilfield customer was served under Rate D41 or Rate D31 because, although Rate D31 is a lower rate than D41, the company investment levels are lower for Rate D31 than for Rate D41.[92]

PICA noted that Rate D31 customers are being called upon to continue to bear the burden of any higher costs resulting from the inclusion of smaller oilfield customers in Rate D31 through the proposed grandfathering of existing small oilfield customers into Rate D31.

PICA submitted that AE should be directed to assess the feasibility of moving all oilfield customers with loads less than 75 kW from Rate D31 to D41 as part of the Phase II Refiling and, if feasible, propose a plan for moving oilfield customers with loads below 75 kW from Rate D31 to Rate D41 and reflect the impact of this change on the cost of service and rates for Rate classes D31 and D41.

AE indicated that, in AE's 1998 DTA, it proposed to incorporate a rate minimum of 75 kW on rate D31 customers to assist in addressing the cross-over issue it had identified as far back as that proceeding (Decision U99034, page 67).[93] AE noted that the Board did not approve its request in the context of that proceeding. AE indicated that it has never opposed a 75 kW cap and has attempted to address this issue for an extended period of time.

6.2.1 Views of the Board

Following its review conducted in response to Directive 29 from Decision 2005-025, AE stated that it had identified a concern with the current rate structure for the Rate D41 rate class. AE stated that the low cross-over has resulted in more of the higher cost customers from Rate D41 seeking to be billed under a lower cost rate in Rate D31. The Board notes that both AE and PICA are in agreement that there should be a minimum customer size for new oilfield customers to be eligible to be served under Price Schedule 31.

While AE had at one time proposed that the minimum customer size for oilfield customers to be served under Price Schedule 31 should be the 75 kW level, it now indicated that the 50 kW level would be appropriate. AE also indicated that it has never opposed a 75 kW cap. Given the concerns identified by AE about the rate structure, the concerns of PICA that Rate D31 customers are bearing a burden of higher costs from the inclusion of smaller oilfield customers, and the lack of objection from AE or any other party, the Board finds that AE should use a 75 kW minimum for new Price Schedule 31 oilfield customers. The Board notes that this 75 kW cap would also be consistent with FAI's approach.

Accordingly, the Board directs AE to maintain its current 50 kW minimum for non-oilfield customer and to use a 75 kW minimum for oilfield customers for determining eligibility for Price Schedule 31 commencing January 1, 2008 and to file a revised price schedule clearly setting out this change.

[92] Transcript Volume 1, page 125, line 111 to page 126, line 10

[93] Decision U99034 –Alberta Power Limited 1996 General Rate Application - Phase II (Released: August 10, 1999)

The Board agrees with AE, for purposes of this Phase II, that grandfathering existing oilfield customers that do not meet the 75 kW minimum is preferable to the disruptions and administrative difficulties of forced conversion and therefore the Board approves the grandfathering provisions AE proposed for all existing Rate D31 customers.

However, the Board agrees with PICA that AE should be directed to assess the feasibility of moving all oilfield customers with loads less than 75 kW from Rate D31 to D41 and directs AE in the next Phase II application, to conduct the aforementioned assessment.

7 AMENDMENTS TO THE TERMS AND CONDITIONS FOR DISTRIBUTION SERVICE CONNECTIONS

7.1 Updates to Proposed Investment Levels

The maximum investment level defines the amount that a distribution wires owner will invest when extending service to new customers. AE has requested some adjustments to its current investment levels based on an Investment Level Study which considered the effects of intergenerational equity, the maximum allowable investment, and the average historical local extension cost per rate class. AE's proposal would hold changes within +/- 10% for the primary investment term of five years. The following table[94] summarizes the changes:

[94] Exhibit 002-01, Application, Section 8, page 8-4

Table 9. AE Proposed Investment Levels

Rate Class	Term Investment	Existing Investment Level	Proposed Investment level	% Change
D11 Residential	5	$890/site	$980/site	10%
D21 General Service	5	$320/kW	$350/kW	9%
D25 Irrigation	5	$65/kW	$65/kW	0%
D31 Large General Service / Industrial	5	$350/kW first 500 kW	$365/kW first 500 kW	4%
		$235/kW above 500 kW	$245/kW above 500 kW	4%
	4	$116/kW first 500 kW	$116/kW first 500 kW	0%
		$78/kW above 500 kW	$78/kW above 500 kW	0%
	3	$90/kW first 500 kW	$90/kW first 500 kW	0%
		$61/kW above 500 kW	$61/kW above 500 kW	0%
	2	$63/kW first 500 kW	$63/kW first 500 kW	0%
		$42/kW above 500 kW	$42/kW above 500 kW	0%
	1	$33/kW first 500 kW	$33/kW first 500 kW	0%
		$22/kW above 500 kW	$22/kW above 500 kW	0%
D41 Oilfield	5	$510/kW	$510/kW	0%
	4	$205/kW	$200/kW	-2%
	3	$160/kW	$156/kW	-3%
	2	$111/kW	$108/kW	-3%
	1	$58/kW	$56/kW	-3%
D56 Company Farm	5	$360/kVa	$395/kVa	10%
D61 Street Lights	5	$1,120/light	$1,230/light	10%
		$280/light	$305/light	9%
D63 Sentinel Lights	5	$915/light	$915/light	0%
		$230/light	$230/light	0%

AE submitted that the process used in the current Application to derive the maximum allowable investment per unit was the same as the process that had been used for the 2004 DTA but with the addition of 2004 and 2005 work order data.

AE recommended that the investment levels proposed in the current Application be accepted by the Board because the criteria used had been previously accepted by the Board. Additional factors considered in the development of the proposed investment levels included the average historical local extension cost per rate class, the calculated maximum allowable investment per unit from the study and the capping of the change in investment levels at 10% to address intergenerational equity.

UCA did not oppose the recommended investment levels of AE in this Application and was the only intervener to offer comments on this section.

7.1.1 Views of the Board

The Board continues to monitor situations where intergenerational equity of investment levels could arise due to changes in policy or the level of investment or otherwise. The Board notes that AE has addressed this concern in their application by capping the change in investment levels at 10%. The proposed increases, to some degree, represent the impact of inflation or construction costs since the last time changes were made for these classes.

The Board finds that the proposed investment levels in the Application are reasonable, and the Board approves them as filed.

7.2 Rate D11 Direct Funding to Developers

CCA expressed concern that the maximum investment level is paid to subdivision developers instead of being credited to the individual home purchaser who is the end customer.

CCA stated there was no transparency in whether these maximum investment levels paid to developers were in fact passed on to the ultimate end customer at the site since AE does not track whether the investment was passed on.

CCA submitted that Rate 11 customers pay the costs associated with having these maximum investment levels amounts form part of rate base, but the related benefits are going to the developers who are in a different rate class. The CCA stated that AE's current practice results in an inter-class subsidy.

CCA recommended the Board direct AE to study Rate 11 direct funding to developers and to file at its next GTA, a mechanism where the maximum investment level amount is credited to the site directly rather than flowing to the developer initially. The CCA stated this option would keep the costs and benefits contained within the utility customer relationship and within the one rate class.

UCA supported the conclusions and recommendations of CCA on this issue.

AE rejected CCA's position that AE should make the payment of contributions directly to residential customers. AE explained the contribution in aid of construction was paid to the person requesting service and this policy was administered consistently across all rate classes. AE confirmed that its practices are consistent with those of other Alberta distribution companies.[95]

AE stated that when dealing with residential subdivisions it does not deal directly with the end use customer, unless the end use customer happens to be the developer. AE indicated that it has no ready way to track and monitor relationships between the developer, house builder and end use customer. Further complexities would arise when the type of dwelling is taken into consideration, including whether it was rented or owned.

AE submitted the administrative complexities associated with attempting to track end use customers and ensure that they receive the contribution would not be workable, especially given the significant number of residential extensions. Each lot's meter and service cost, less the

[95] Transcript Volume 1, pages 204-207 and 214

respective company investment, would need to be charged to the end use customer separately. Plus, a determination of whether the customer should contribute to its shared portion of the mainline costs would need to be made. Instead, AE relies upon the competitive operation of the marketplace to ensure that the benefits of such funding are passed through to end-use customers.

7.2.1 Views of the Board

Alberta distribution utilities credit the maximum investment level to the person requesting service. The Board recognizes the administrative difficulties that AE indicated would arise if utilities were required to track end use customers, given the significant number of residential extensions.

The Board notes that no evidence was submitted to quantify the impact of any potential inter-class subsidy raised by CCA nor were the costs of implementing procedures necessary for tracking under the CCA's proposal identified. Given the amount of potential administrative work and cost that would be required to implement CCA's recommendation, the Board rejects this proposal and is not persuaded that any further study on this matter is required by AE.

7.3 Roles and Responsibilities of Utility to RRO Eligible and Non-eligible Customers

UCA advised that it had been contacted by a number of customers who had been automatically switched from a Regulated Rate Service to Default Supply without sufficient advance warning that their estimated annual consumption requirements exceed 250 MW hours per year.

UCA requested that the Board direct AE to amend its Terms and Conditions for Distribution Access Service to include a clause that clearly identifies the contractual responsibilities of the retailer to assess and determine the eligibility requirements of each customer on at least an annual basis, and that no less than 4 months prior written notification be given to each customer before any change or switch is made from eligible to non-eligible or vice-versa because of the 250 MW hour per site threshold.

AE determines Regulated Rate Option (RRO) eligibility upon the initial request for a connection or upon a change to a customer's facilities. However, the responsibility for performing AE's RRO functions has been transferred to DERS and as such, AE does not provide any forecast of customer consumption to any party for the determination of eligibility. AE does provide historical consumption for up to twelve months upon a specific request but given the segregation of roles pursuant to the current legislation, any review of a customer's eligibility subsequent to the initial determination is conducted by DERS. If DERS determines that the customer's eligibility has changed, AE will validate the change. AE argued that this matter should be pursued in the context of proceedings related to retailers and not in an AE Phase II proceeding. Moreover, for the very small number of sites whose eligibility changes after the initial connection, AE considers the current process is adequate and appropriate and that the Board should reject UCA's suggested addition to the Terms and Conditions.

7.3.1 Views of the Board

The issue raised by UCA concerns those customers, who, but for the size of their load, would not be eligible to access a regulated rate but would either have to enter into a retail service contract for electricity services from a retailer or be served as a default customer.

Section 1(d) of the *Regulated Rate Option Regulation* (RRO Regulation) determines eligibility requirements for customers seeking to receive a regulated rate and defines an eligible customer as:

> …
> (ii) any other customer, if the owner's reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 megawatt hours of electric energy at that site;

As set out in this provision, it is the owner's forecast that is used to determine a customer's annual consumption therefore it follows that it is the owner's responsibility to ensure RRO eligibility.

Section 1(g) defines an owner as:

> (i) the owner of an electric distribution system, or
> (ii) if the owner makes arrangement under which one or more other persons perform any or all of the duties or functions of the owner, the owner and those one or more other persons;

It is the evidence of AE that it determines RRO eligibility upon the initial request for a connection or upon a change to a customer's facilities but that DERS is responsible for determining a customer's continuing eligibility.

The Board finds that the statutory definition above supports the approach of AE and DERS. As it is DERS who is the RRO provider, the Board considers that the concerns of UCA would be more appropriately addressed in a DERS proceeding and the Board will not direct AE to amend this section of its Terms and Conditions.

8 REFILING

AE proposed to incorporate in its Refiling any changes to its 2008 revenue requirements resulting from the Board's Decision with respect to its 2007/2008 GTA. Any true-ups taking place after the Refiling will be disposed of via future Rider applications.

UCA submitted that, given the potential for significant changes as a result of the ATCO I-Tek benchmarking of Customer Care and Billing costs for streetlight and sentinel light customers, upon completion of the benchmarking if costs have changed significantly, a re-calculated COSS and rate design would be required. UCA submitted that the arguments on the specific issue of the ATCO I-Tek benchmarking process results can be dealt with once the results are known as part of a separate dispensation process. UCA does not oppose the treatment proposed by AE for this application on the remaining true-ups and placeholders.

No party objected to the changes to AE's terms and conditions of service that AE proposed.

8.1 Views of the Board

The Board considers that it would be premature to provide for any process at this time in regards to the ATCO I-Tek benchmarking proceeding. Upon completion of the benchmarking proceeding, the Board expects parties to recommend a fair approach to incorporate the results of the benchmarking process into AE's rates and riders.

The Board directs AE to provide its Refiling to the Board and to all parties on or before November 29, 2007. Further, AE shall advise all parties that any comments on the Refiling are due on or before December 13, 2007. Further, AE shall advise all parties that reply comments are due on or before January 7, 2008.

The Board notes that comments on AE's Phase I Refiling ordered in Decision 2007-071 are due on or before, November 1, 2007. Given that the decision on AE's final 2008 distribution revenue requirement is unlikely to issue prior to the Phase II Refiling, the Board directs AE to appropriately incorporate in its Phase II Refiling any changes to its 2008 revenue requirements that are reflected in its Phase I Refiling. Any further adjustments that arise out of the Phase I Refiling process should be handled via a future rider application.

The Board directs AE, in the Refiling, to provide the rates that it considers would be appropriate for implementation effective January 1, 2008.

Further, the Board directs AE, in its Refiling, to file the customary rate impact and comparison schedules/information showing the impacts of this Decision on customer bills for the various rate classes, including any proposed Riders for which AE is seeking approval. These comparisons should include updated Schedule 5-B-1 and Schedule 5-B-2.

The Board intends to approve the refiled rates in a decision to be released shortly after AE's Phase II Refiling is received to provide retailers with notice of the rates to be effective January 1, 2008. The final determination on this matter will depend on the refiled rates and any other rate impacts that need to be addressed in a comparable time frame to minimize the number of rate changes communicated to customers from other factors such as deferral accounts.

Accordingly, the Board directs AE, in its Refiling, or earlier, to advise the Board of other potential rate changes affecting customers, the estimated impact of those rate changes and the timing of submission, estimated Board decision date and notice period for implementation assuming normal processing times for parties and the Board. The Board would appreciate AE's advice as to the implementation of new rates.

The Board has reviewed the changes AE proposed to its terms and conditions of service. The Board finds the changes are appropriate. The Board directs AE to refile a clean version of its terms and conditions in its Refiling with a summary of any changes required to reflect the findings of the Board in this Decision. The Board intends to approve the refiled terms and conditions of service in a decision to be released shortly after AE's Phase II Refiling is received to provide retailers and customers with notice of AE's terms and conditions to be effective January 1, 2008.

9 ORDER

For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

ATCO Electric Ltd. shall refile its 2008 Distribution Tariff Phase II to reflect the findings, conclusions and directions in this Decision by November 29, 2007.

Dated in Calgary, Alberta on November 8, 2007.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

A. J. Berg, P.Eng.
Presiding Member

(original signed by)

Laurie J. Bayda
Acting Member

(original signed by)

M. W. Edwards
Acting Member

APPENDIX 1 – HEARING PARTICIPANTS

Name of Organization (Abbreviation) Counsel or Representative (APPLICANTS)	Witnesses
ATCO Electric Ltd. (AE or the Company) L. G. Keough A. Sears	S. Pahar J. Janow K. Koenig B. Ramsay N. Palladino J. Sarikas
Public Institutional Consumers of Alberta (PICA) J. McKenzie	
Office of the Utilities Consumer Advocate of Alberta (UCA) T. A. Shipley R. Henderson	H. Vander Veen M. Lively
Alberta Association of Municipal Districts & Counties (AAMDC) and Alberta Federation of REA's Limited (AFREA) T. D. Marriott	P. L. Chernick
Consumers Coalition of Alberta (CCA) J. A. Wachowich	
Industrial Power Consumers Association of Alberta (IPCAA) M. S. Forster	R. Mikkelsen
Alberta Sugar Beet Growers (ASBG) and Potato Growers of Alberta (PGA) J. H. Unryn	
Aboriginal Communities (ABCOM) J. L. Graves	

Alberta Energy and Utilities Board Board Panel A. J. Berg, P.Eng., Presiding Member L. J. Bayda, Acting Member M. W. Edwards, Acting Member Board Staff C. Wall (Board Counsel) B. Ploof D. Cherniwchan C. Burt A. Rabiu	

APPENDIX 2 – SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. The Board notes that ASBG/PGA requested that the Board direct AE to provide a working model of the diversity study to allow intervener testing. The Board finds that the calculation and use of the Diversity Study information represents an area suitable for technical meetings to address any misunderstandings through open questions and discussion. The Board directs AE, prior to the next Phase II proceeding, to provide to interveners a working model of the diversity study. AE shall organize a technical meeting which can include this area for discussion, and the working model should be provided sufficiently before the meeting allowing enough time for interveners to examine it and address their questions at the technical meeting. 13
2. The Board accepts the Diversity Study with the refinement proposed by IPCAA, and the Board directs AE, in the Refiling, to include the revised Diversity Study. 14
3. Accordingly, the Board directs AE, in its next Phase II application, to submit the results of its tracking of the volumes brushed in 2008 and its views as to whether the allocation of brushing costs to customer classes should be adjusted. 15
4. The Board directs AE, in its Refiling, to use IPCAA's modified approach to allocate DTS charges. 17
5. The Board finds that given the anticipated timing of the release of the AESO's 2007 GTA Decision, it is not possible to incorporate the final AESO tariff in the COSS at the time of AE's Refiling. Accordingly, the Board directs AE to provide a summary of the approach and timing that AE proposes to deal with the changes, if any, required to reflect the final AESO tariff on as timely a basis as practical but no later than February 1, 2008. 19
6. PICA recommended that AE be directed to use the average transformer replacement cost per customer, by customer class as a refinement to the transformer allocations as part of AE's next application. The Board considers that there may be some merit in PICA's recommendation however, there is insufficient evidentiary support in this proceeding to direct this change for the next GTA. Rather, the Board directs AE in its next Phase II to provide an analysis of PICA's recommendation. 28
7. Based on these findings, the Board directs AE in the Refiling, to:
   - Reduce the amount of secondary distribution system directly assigned to the streetlight rate class in the COSS by 50%, and to reallocate these amounts to all rate classes using the same allocators used to allocate other secondary distribution system plant.
   - Increase the amount of secondary distribution system plant allocators from the proposed 50% level to the 100% level. 35
8. Accordingly, the Board directs AE at the time of its next GTA to adjust its definition of a streetlight customer for billing purposes so that one streetlight fixture does not equal one customer. The Board considers that the billing charges in AE's revenue requirement should not reflect separate customer charges for each streetlight fixture, but rather only billing charges for the number of unique attachment points to the distribution system for streetlights.

APPENDIX 3 – SUMMARY OF BOARD APPROVALS

This section is provided for the convenience of readers. In the event of any difference between the Approvals in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. Accordingly, the Board approves AE's proposed power factor charges of 16.14¢ per kVA per day for customers on the large general service/industrial rates and 37.12¢ per kVA per day for customers on AE's oilfield rates. 3
2. The Board considers AE's 2004 Loss Study to allocate primary and secondary system losses represents a reasonable balance between accuracy, cost and intergenerational equity. Accordingly, the Board approves AE's 2004 Loss Study as filed... 10
3. Accordingly, the Board accepts the Brushing Study. 15
4. Accordingly, the Board approves use of annual class responsibility for POD NCP as an allocator for primary system costs. 23
5. CCA also made a recommendation with respect to the rounding of the results of the transformer study to obtain the customer portion of the transformer costs. The Board has reviewed Table 13.5 and notes that the customer portion of transformer costs for urban customers increased 5% while the regression results remained constant. The other two groups of customers, Rural Assigned and Unassigned customer portions remained constant at 2004 levels despite reductions in the regression results. While CCA argued that the rounding was arbitrary, the Board understands that professional judgment was used to determine the final allocations. 27
6. Given the variation across the results, the Board does not see any value in attempting to recast the customer portion for allocating transformer costs. Therefore, the Board approves AE's proposed recommendations as filed... 28
7. The Board agrees with AE, for purposes of this Phase II, that grandfathering existing oilfield customers that do not meet the 75 kW minimum is preferable to the disruptions and administrative difficulties of forced conversion and therefore the Board approves the grandfathering provisions AE proposed for all existing Rate D31 customers........................ 49
8. The Board continues to monitor situations where intergenerational equity of investment levels could arise due to changes in policy or the level of investment or otherwise. The Board notes that AE has addressed this concern in their application by capping the change in investment levels at 10%. The proposed increases, to some degree, represent the impact of inflation or construction costs since the last time changes were made for these classes........ 51
9. The Board finds that the proposed investment levels in the Application are reasonable, and the Board approves them as filed.. 51

Alberta Energy and Utilities Board
Decision U99034
Released: Aug 10, 1999

ALBERTA POWER LIMITED

1996 GENERAL RATE APPLICATION – PHASE II

TABLE OF CONTENTS

APPENDICES

1. INTRODUCTION AND BACKGROUND

Alberta Power Limited (APL) provided its 1996 Phase II filing (the Application) to the Alberta Energy and Utilities Board (the Board) on 17 July 1998. Notice of hearing was published on 30 July 1998 and served on the interested party list from APL's 1996 General Tariff Application.

On 6 May 1999, APL notified the Board that its name had been changed to ATCO Electric Ltd. (AE). In the remainder of this Decision the Board will refer to both AE and its predecessor APL as AE.

The Board heard the Application and intervenor evidence at a public hearing held in Edmonton from 2 December to 11 December 1998 before B. T. McManus, Q.C., J. P. Prince, Ph.D., and H. Jainarine, Acting Member. The applicant and intervenors were required to provide written argument on 11 January 1999 and written reply on 25 January 1999. Interested parties participating in the proceedings have been listed in Appendix 1.

Most of AE's existing customer retail rates had been approved on an interim basis commencing 1 January 1996 in Order E95121, dated 21 December 1995. In Decision U97154, dated 19 December 1997 the Board approved an interim across the board rider which allowed AE to collect its 1996 revenue requirement on a forecast basis. Other interim across the board riders (based on negotiated settlements and approved by the Board in Order U98027, dated 30 January 1998 and Order U98081, dated 19 May 1998) allowed AE to collect its 1997 and 1998 distribution revenue requirements on a forecast basis.

AE submitted the Application as a 1998 Phase II filing, since the retail rates proposed in it were based upon AE's 1998 distribution revenue requirement (the transmission, power purchase and distribution costs forecast to be incurred by AE's distribution company [DISCO]) negotiated with customers and approved in Order U98081. In the Application AE requested approval of new rates to be effective 1 April 1999.

AE significantly revised its Application on 30 September 1998, and again filed amendments on 19 November 1998.

AE requested that its amended Application, subject to further changes agreed upon at the hearing, be approved. AE also requested that the Terms and Conditions (T&C) contained in the Application be approved as filed, subject to being later updated for those aspects specifically made the subject of a negotiated settlement process.[1]

In this Decision the Board summarizes the relevant positions of parties and sets out the reasons for the Board's findings on significant matters regarding the Application. Two matters were dealt with in other Decisions; conversion of Pool Opportunity Rate (POR) service to firm service as dealt with in Decision U99006, dated 25 January 1999 and Temporary Direct Access Tariffs

[1] As per Exhibit 51

(TDAT) dealt with in Decision U99014, dated 8 February 1999 (the TDAT will cease to be available to new customers as of the date of issuance of this decision, as noted in Section 4(h)). A third matter, those aspects of the T&C subject to the ongoing negotiated settlement process, remains outstanding.

Also, in this Decision the Board finalizes AE's interim retail rates in effect from 1 January 1996 until 31 December 1998. The Board also sets out a process to arrive at new customer retail rates, tolls and charges forecast to generate total revenues based on the 1999 distribution revenue requirement included in a negotiated settlement for 1999/2000 as approved by the Board in Decision U99046, dated 10 May 1999.

2. COST OF SERVICE

(a) General

In its Phase 1 proceeding AE forecast that it will incur certain costs to serve its customers (in total the DISCO's revenue requirement). The purpose of a cost of service study (COSS) is to analyze the costs forecast to be incurred by the DISCO and to allocate those costs to the customers or customer classes expected to cause them. The COSS enables rates to be designed which fairly pass through the forecast costs to the appropriate customers.

This section will review AE's methodology used in its 1998 COSS.

AE first separated the costs making up its DISCO's revenue requirement by function:

Generation Costs
Transmission Costs
Distribution Costs

Second, AE classified the functionalized costs as:

Customer related
Demand related and
Energy related

Third, AE allocated the classified costs to its customer classes by using allocation factors based on the number of customers, demand contributions (kW) of classes of service and energy sales (kWh) by classes of service. Customer related costs are costs that vary with the number of customers served. Demand related costs are costs that vary with kW demand. Energy costs vary with the kWhs of energy used.

(1) Appropriate Cost and Pool Price Data for the Cost of Service Study

AE indicated that the COSS was based on the 1998 distribution revenue requirement (the forecast costs to AE's DISCO of transmission, power purchases and distribution) as approved by the Board in Order U98081. The AE DISCO revenue requirement of $518.4 million was increased to $524.2 million to reflect the increase in total pool payment required by an increase in sales volume agreed to in the 1998 Negotiated Settlement.[2] The forecast total revenue on the proposed rates was $524.15 million.[3] AE's distribution costs were not explicitly set out in the negotiated settlement of AE's 1998 DISCO revenue requirement. The transmission and generation costs were explicitly set out. The distribution costs were the residual remaining after subtracting transmission and generation costs from the negotiated 1998 DISCO revenue requirement.

[2] Phase II Filing, Revenue Requirement p.2
[3] Revised Schedule 2.a-3

In allocating its distribution related revenue requirement, AE used 1997 actual closing balances of gross assets, accumulated depreciation and customer contributions. AE adjusted distribution costs to 1998 forecast levels to determine most of the costs to be allocated to customers. However, it used a 1998 pool price forecast for the purpose of developing time-of-use (TOU) differentials. To derive the shares of forecast 1998 Transmission Administrator (TA) billings, AE used actual energy use and transmission losses for 1995 in conjunction with forecast 1998 demands.

Several intervening parties argued that AE's COSS was flawed since it used potentially out of date costs and allocation factors. Parties questioned the appropriateness of a pool price forecast based on information that was several years old, particularly given the consideration that pool prices had risen dramatically since 1997 and customer loads had changed since 1996.

Board Findings

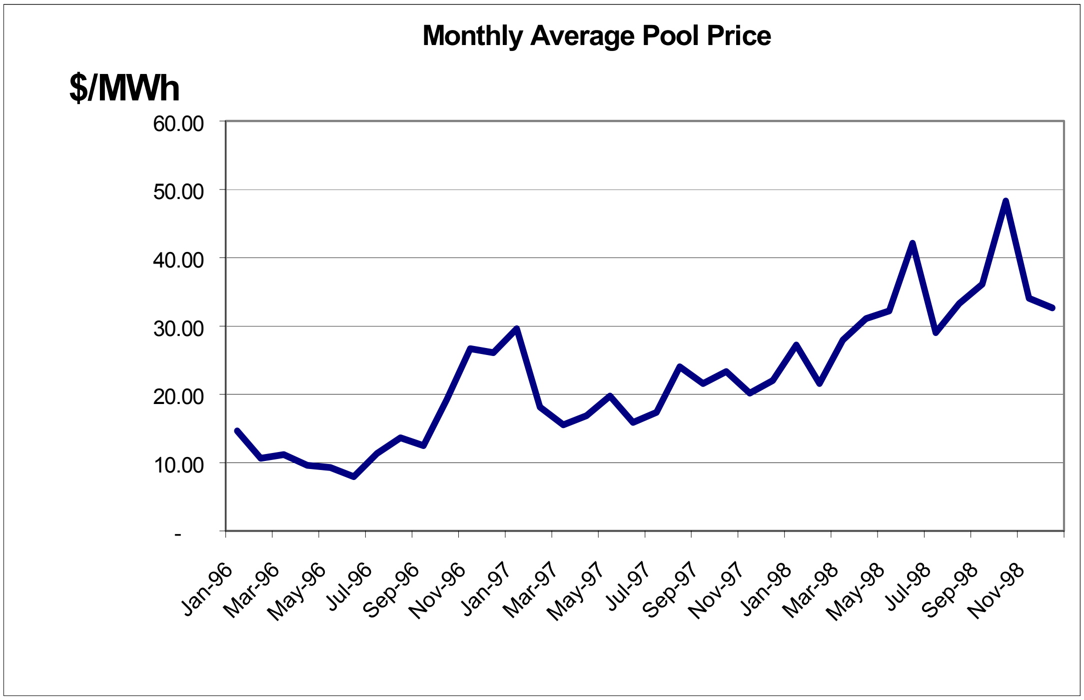
The Board recognizes that the forecasts of pool prices, energy, demand and number of customers, reflected in the COSS, were open to examination by intervenors in AE's 1998 Phase I Negotiated Settlement. However, in Decision U98081 the Board approved the negotiated settlement in its entirety without examination of specific cost components. The Board's last examination of all of the components of AE's distribution revenue requirement was for the 1996 test year.

The *Electric Utilities Act*, R.S.A. 1995, c.E-5.5 (the EU Act) came into force in May 1995, setting the stage for gradual and significant restructuring of Alberta's electric industry. As a result, the 1996 Phase I proceeding and the current Phase II proceeding take place in a period when the electric industry is in transition toward a competitive market. The restructuring in the electric industry has led to many changes, with potential changes yet to occur; the current period is truly unique and represents more of an exception rather than the norm.

Consequently, the Board shares intervenors' concerns that the magnitude of costs and their appropriate allocation among customer classes has changed substantially since 1996 and will continue to change. The Board sets out its view on how these changes should be dealt with in Section 3(a).

The graph, on page 9, demonstrates the extent of the increases in the pool price since 1997. With respect to the significant increases in pool prices and changes in TOU differentials, the Board considers that pool price signals must be the basis for appropriate market responses. AE provided a forecast for 1998 that was prepared well before the end of 1998. The Board considers that the actual 1998 pool price record and loads (see Section 3(b)) would provide a more appropriate basis for forecasting the annual average cost of energy for 1999 fixed rate classes including the TOU classes.

The Board therefore directs AE to use actual 1998 pool prices for the purpose of determining the cost of pool purchases used in the refiling. The actual 1998 pool price record should be utilized in the calculation of pool purchases, Unit Obligation Values (UOVs), TOU rates and annual average energy costs. (See also Section 3(b))



(b) Allocation of Generation-Related Costs

Background

The transition to competition implicitly defined in the EU Act provides for the recovery of costs related to generation using three components: the pool price, the reservation price, and the UOV. The allocation of these generation-related components to distributors was prescribed in a way that attempted to ensure the DISCO ultimately paid the fixed plus variable costs of generation (paralleling the demand component and energy component of traditional regulation).[4] The EU Act allows the possibility that the method of allocating these costs to end-use customers may differ from the method by which they were allocated to distributors. However, the allocation must include the legislated hedges: reservation payment (RP) and UOVs.

[4] The RP approximately covers fixed costs. Pool Receipts minus the UOV yields variable generation costs (for sales up to the UOA). This is discussed in detail in the Phase 1 Decision U97065, and will not be dealt with in detail here.

AE proposed to allocate UOVs to end-use customers in a manner similar to that used to allocate entitlements to distributors in that it was based on forecast hourly energy use by customer class. Parties generally accepted that approach for UOVs, but there were differences in their views of the details appropriate to the allocation.

AE proposed to use a method to allocate the RP to end-use customers that differed only slightly from the method used to allocate the RP to distributors. The company proposed to allocate the RP on a 3 winter/9 non-winter (3W/9NW) demand basis.[5] IPCAA and IPPSA/SPPA also proposed methods using 3W/9NW demand allocation.

The FIRM Customers submitted that the allocation of the RP to customers should be based on the forecast UOV refund allocated to each customer class. The UOV allocation was to be based on forecast energy use.[6]

AE's Allocation Methods

The hourly cost of pool purchases was allocated to each rate class based on its share of the total energy forecast to be purchased by the DISCO in the hour. The sum of the obligation value refunds for all generating units in each hour was allocated to each rate class based on its share of the total energy forecast to be purchased by the DISCO in the hour less POR and Rate 38 energy.

AE split its forecast RP into a demand cost and energy cost pool based on the total Alberta Integrated System (AIS) fixed demand and fixed energy cost pools used in the modeling of the reservation price shares. Then the fixed demand costs were allocated to each rate class based on its share of 3W/9NW demand, excluding the demand of Class III interruptible load. The fixed energy costs were allocated to each rate class based on its share of the annual energy usage.

AE maintained that this RP allocation method represented the manner in which fixed costs are actually incurred by AE with respect to the regulated generating units. In the process used to determine DISCO RP shares, total AIS generation costs had been split into fixed demand cost, fixed energy cost and variable energy costs pools. Then the fixed demand and energy cost pools were allocated to AE based on its share of 3W/9NW demand and energy usage at what was the Electric Energy Marketing Agency (EEMA) interface.

Some intervenors suggested that such allocation was no longer appropriate given the manner in which AE's system operates today. The expert witness for the FIRM Customers, Mr. Marcus, acknowledged that neither the pool price nor the maximum AIS load affect the RP payable by AE DISCO. AE stated that when one views this issue from a "cost causation" point of view, the

[5] Reservation payments had been allocated to distribution companies, under the EU Act, using the similar EEMA demand allocation.

[6] The allocation method was to be that proposed by TransAlta in its 1996 Phase II Application and would be done on an hourly basis for each customer class.

continued use of the 3W/9NW demand approach remains appropriate. It represents both the way the existing generating units were planned and built and the way the costs were allocated to the entitled distributors. AE submitted that its approach was just and reasonable and should be accepted by the Board.

On "bumplessness," AE noted that prior to the EU Act, the level and structure of retail rates changed frequently, as utility costs changed and newer rates were developed and refined. This continues to be particularly true in the context of unbundled rate options. AE's proposed rate design and cost allocation lead to just and reasonable tolls and, therefore, do not offend any consideration regarding "bumplessness."

Position of the Parties

FIRM Customers

The FIRM Customers opposed AE's approach to allocating generation costs, preferring the energy based approach TransAlta Utilities Corporation (TransAlta) had used. The FIRM Customers submitted that TransAlta's approach was forward looking, reflected current cost causation, provided customers with the hourly pool price signals, was consistent with market pricing of hedges and would create a smooth transition towards the new market structure.

Section 38(1) of the EU Act refers to costs "not significantly different" for "entitled electric distribution systems." It does not apply to cost allocations between customer classes or individual rates. The restructuring has resulted in many changes including a significant portion of DISCO transmission payments now being based on energy. There can be no guarantee of a "bumpless cost" allocation to customer classes.

Following three years of "bumpless" restructuring, the Board should consider new goals and alternatives in customer rate design to support the creation of a new, competitive market rather than duplicating the past. TransAlta's generation allocation reflects the costs and recognizes the flatter loads that are being experienced. TransAlta's approach provides hedges at the same price per kilowatt-hour hedged for all customers.

The FIRM Customers submitted that the 3W/9NW demand allocation method AE uses was not valid for allocation of RP and UOV since it does not reflect current market conditions. Unlike TransAlta's method, the demand method does not recognize the value of a hedge to the customer. The UOV can be viewed as providing a hedge against the pool price to the customer, with the value of the hedge related to the energy hedged and the difference between the hedged and unhedged price. This value should be reflected in the price paid for the hedge by the customer. The cost of the hedge is the RP, representing the fixed costs paid to obtain the hedged energy. TransAlta's proposal was consistent with market pricing, since kilowatt-hours are to be hedged at the same per unit price for all customers and value is aligned with cost.

In contrast, the 3W/9NW allocation method would result in high load factor customers paying less to hedge a certain amount of energy than lower load factor customers. It would be unsustainable for one group of customers to pay the same amount for a hedge as another group of customers, but be allowed to hedge twice as much energy. The industrial approach is only sustainable under regulation and represents a barrier to the development of a true competitive market. Similarly under the stranded cost/residual value (SC/RV) method, the residual value benefits from the embedded system would be disproportionately allocated to high load factor classes. It is not logical that firm, low load factor customers who have disproportionately paid for the system's fixed costs should not realize its benefits in a significant manner.

The 3W/9NW allocation method is no longer appropriate due to the high load factor of the Alberta system, the relatively even monthly peaks and the spread of unreliability (as represented by high pool prices) into many periods across the year. The 3W/9NW demand no longer reflects the cost structure of the Alberta generation system since there is no significant "load valley" created by the Alberta winter peak. For the 12 months from September 1997 to August 1998 the average difference in on-peak loads between the three winter and nine non-winter months was only eight percent or 554 MW. The only remaining "load valley" was in April and May.

When generation capacity is short, power pool prices reach high levels. The data provided by Mr. Marcus demonstrated that high pool prices can occur throughout the year, not predominantly in winter months and not just at the peak hour of the month. Power shortages and capacity cost incurrence are no longer coincident with monthly peak loads and occur over large numbers of peak hours over the year.

Even without restructuring, this analysis supports a shift towards a broader measure of capacity cost allocation. TransAlta's allocation of RP in proportion to UOV ensures a higher allocation of RP to all high pool price hours. Such allocation better reflects prevailing flatter load conditions.

However, the FIRM Customers submitted that if the Board approves allocation of RP using a demand-based allocator, then UOVs should also be allocated using the same demand-based allocator. This would effectively allocate the same number of hedged kilowatt-hours per kilowatt to each customer, resulting in a more market-oriented hedge. On-peak energy use (the GSS allocator) should be the demand allocator, since it is a better measure of the need for capacity on the Alberta system. The 3W/9NW demand allocator no longer represents the current distribution of unreliability across the Alberta Interconnected Electric System.

In response to TransCanada's submission that the monthly winter peaks of 1997-98 were non-representative because of El Nino, the FIRM Customers noted that monthly peaks were related to conditions on a single day of the month and cold days occur even in winters which are mild overall.

The FIRM Customers considered that the reduction in DISCO RP that occurred due to Class III interruptible loads was captured and shared appropriately by AE. The Class III customers no longer exist and the benefits should be shared amongst all firm loads, rather than just amongst Rate 31 customers as IPCAA proposed. Otherwise, a disproportionate benefit would arise to Rate 31 customers simply because it was the rate class where the interruptible loads used to reside.

Parties Supporting the 3W/9NW Allocation Method

IPCAA, TransCanada and IPPSA/SPPA generally supported AE's allocation methods. These parties were concerned that TransAlta's method departed from the demand intensive approach to generation cost allocation by adopting an energy intensive method. Under TransAlta's allocation of generation supply costs on an energy basis there would be little difference in total per kWh generation cost between classes. This was very different from the past, even though the nature of overall provincial generation costs had not significantly changed since restructuring and legislated hedges were established to preserve this reality at the DISCO level. The parties supported methods that essentially tied the allocation of the RP to the levels of demand associated with customer classes and advocated the 3W/9NW demand allocation accepted in recent EEMA proceedings. A summary of each party's significant argument follows.

IPCAA

IPCAA agreed with AE that generation costs should be allocated the way in which they were incurred. The point of contention was what "causes" RP. TransAlta's "energy only" allocation of legislated hedge costs ignored the underlying fundamentals on which the hedges were designed. The manner in which DISCOs pay for generation costs from existing plants had not changed in nature. The DISCO's variable cost was equivalent to energy purchases at pool prices less UOV refunds. Fixed costs were represented by the RP.

To the extent that the overall make-up of costs had remained unchanged, it was reasonable to allocate the fixed costs and variable costs in keeping with the past. The way the DISCO has incurred these costs was a result of the way the reservation price and the legislated hedges were designed and that's what should be taken into account in the Phase II cost study. Legislated hedges were designed to carry the cost structure of existing, regulated generation into the New World of electricity restructuring wherein other generation costs can be guided by the market.

TransAlta's new method ignored how generation and transmission costs were incurred by the DISCO. Since the nature of fixed costs and variable costs have remained unchanged it was logical to continue to allocate RP using the 3W/9NW demands. The way DISCOs pay for costs from existing generation has not changed in nature.

IPCAA's detailed analysis indicated that DISCO RP shares were within roughly 10% of generation 3W/9NW demand shares. The 10% difference was a result of setting the DISCO RP shares to maintain each DISCO's total generation and transmission costs as they would have been under EEMA. The original allocation of RP shares was based on 3W/9NW with the "bumplessness" adjustment. The RP shares were reset based on the same principle in 1997 to offset transmission cost reallocation among DISCOs due to the TA rate design. IPPCA submitted that, if there is a cost-causative method to allocate the RP among customer classes, it should be based on maintaining total generation and transmission costs for each class as they would have been under EEMA.

The share of RP allocated to the DISCOs is fixed so changes in usage by customers will not influence the shares. DISCOs do not incur RP on the basis of hourly energy usage. Hence, it would be inappropriate to allocate RP in terms of hourly price signals.

IPCAA submitted that legislated hedges were designed to accomplish a specific purpose, and not to reflect commercial terms as the FIRM Customers suggested. Otherwise there would have been no need to create them by a piece of legislation. Mr. Marcus acknowledged in cross-examination that there was not a market in which commercial terms for hedges could be established. It would also be inappropriate to send a price signal to customers that is different from the one being sent to the DISCOs themselves; particularly since most end-use customers will continue to purchase energy from the DISCO while those rates are in effect.

The FIRM Customers' submission that the old 3W/9NW approach would have changed even without restructuring ignores both the past and the future. Mr. Drazen indicated that legislated hedges were designed to be in place during the period extending from surplus generation to load/resource balance. Load/resource balance appears to be occurring during the 1998-1999 period. Thus, the hedges were designed to coexist with changing supply/demand conditions in the electricity market. As a result of new generation coming on stream, the load/resource situation will be quite different two years hence. Mr. Marcus did not claim that the load pattern in the province is any "flatter" than was expected when the hedges were designed. In fact, utility and provincial load factors have not changed significantly and are lower than expected. The Board has not followed similar recommendations from Mr. Marcus in past proceedings, even when the non-winter demands were a higher percentage of winter demands.

The "fixed-variable" methodology advocated by AE is similar to the "bumpless" method supported by IPCAA. The difference between the two is that the "bumpless" methodology takes into account the need to adjust the allocation of generation costs to offset the shift of transmission costs from 100% demand-related to partly on-peak energy related. Also the benefit of 73 MW of Class III load not attracting generation demand costs for AE DISCO in the allocation of RP to DISCOs should be allocated to Rate 31 only and not across all rate classes as AE proposed. In a previous Phase II AE had allocated all of that benefit to Rate 31, the class in which Class III load resided.

IPPSA/SPPA

IPPSA/SPPA submitted that legislated hedges represented a measurement of SC/RV. SC/RV was equal to the RP less the UOV credit. The SC/RV represented the difference between the costs that the utilities would be allowed under regulation and the costs that they can potentially recover in the market. No causal basis exists in the restructured world for allocating SC/RV since it is not caused by any identifiable characteristics of demand or customers. Instead allocation and rate design for SC/RV should rely on fairness, value of service and historical considerations.

Various jurisdictions in the U.S. are pursuing similar restructuring wherein customer classes are being asked to continue to carry the costs allocated to them when restructuring commenced. Similarly in Alberta, equity and consistency suggested that SC/RV should be allocated such that total generation costs for each class approximated cost allocation results from the pre-restructuring fixed-variable scheme. Each class' SC/RV would then be the difference between allocated generation costs under the previous EEMA method and the market generation costs allocated each class using hourly 1999/2000 pool prices.

The FIRM Customers ignored the fact that the costs being recovered were incurred when generation planning did reflect 3W/9NW considerations. Absent industry restructuring the 3W/9NW methodology would most likely have been carried forward. Further, no generation planner would base his analysis on only 12 months history, a warmer than average period with dampened winter peaks, and pool prices tainted by the impact of market power and the regulatory structure imposed on generators. Absent that flawed analysis there was no credible evidence that 3W/9NW allocation was inappropriate.

IPPSA/SPPA agreed with the FIRM Customers that the legislated hedges would impede the development of a competitive market and that was precisely why IPPSA/SPPA had proposed the SC/RV method of dealing with the legislated hedges. With no market for hedges, there was not a market basis on which to view the legislated hedges as the FIRM Customers do.

TransCanada

The FIRM Customers' argument that the need for generating capacity, as measured by high pool prices, no longer occurs primarily in the winter months was made on one year of non-normalized data and that year was a mild "El Nino" weather year. Further, the FIRM Customers' assumption was that unreliability was directly related to high pool prices, but to the extent that pool prices may be influenced by market power and units down for maintenance, they are only rough indicators of generating capacity.

TransCanada emphasized that the RP is related to the recovery of those fixed costs related to generating plants added to rate base prior to 1996. In prior Board Decisions over many years, the Board has repeatedly considered and approved the modified fixed variable method, with the result that fixed costs have been classified as demand related and allocated based on demand in prior cost of service studies. The Board has also indicated that it places "a heavy historical perspective on cost causation"[7] and that "embedded costs are the result of several decades of

[7] Decision E88080, p.35

decision making based on historical planning and operational considerations."[8] In light of those well established principles, the 3W/9NW demand allocation should continue to apply.

TransCanada submitted that the legislation was designed to prevent attempts, such as that by the FIRM Customers, to shift to low load factor customers the value of benefits previously assigned to high load factor customers. Hence, argument that there was an inequity in treatment of hedged energy was without merit.

Board Findings

The parties directed much of their attention to the question of how and why the allocation of the RP and the UOV to distributors was done in the way that it was, and whether or not the allocation to end-use customers should mirror that approach. The Board found this discussion useful, but after considerable reflection on the objectives of restructuring, the Board has concluded that a forward-looking approach to allocation is more appropriate. In particular, the Board has attempted to identify the desired end result of restructuring and places considerable weight on making specific decisions that would assist in achieving that result. The rationale for adopting an energy-based allocation approach includes the considerations set out below.

- In evaluating the view of some parties that the Board should emphasize a "bumpless" transition, the Board reviewed its position taken in Phase I, Decision U97065, dated 31 October 1997. The conclusion in Phase I was that the act assigned responsibility for that issue to the legislature and left the Board free to emphasize other principles. That conclusion is reaffirmed here.

  > The Board considers that its Decision should reflect efficient cost causation and encourage economic decision-making by customers to the greatest extent possible subject to the provisions of the EU Act. . . . . In allocating costs among functions, the Board will continue to have regard to factors that reflect efficient cost causation and encourage economic decision-making. The Board also considers that the cost allocations it may ultimately approve in the design of customer rates are not constrained by any bumpless principle.[9]

- The EU Act established legislative hedges to ensure the low embedded costs of existing generation were passed on to customers during the transition to a competitive environment. The resulting framework was necessarily somewhat distorted in allocating fixed and variable costs to distributors because of steps taken to minimize the potential "bump" in overall generation and transmission costs and preserve each DISCO's costs as they would have been under EEMA. Over time, since the framework was put in place, the

[8] Decision E87100, p.122
[9] Decision U97065 Pages 76-77, 31 October 1997

distortion has increased.[10] Therefore, the relationship to cost-causation is increasingly tenuous, and the Board is concerned that allocating costs to customers under some adaptation of this historical framework, which would likely require significant assumptions and compromises, could result in an unfair allocation.

- Restructuring has altered the nature of the benefits that flow to customers. For example, the new system provides a less reliable expectation that power will always be available. Previously the system ensured, through a planned minimum surplus, that there was always adequate supply to handle the foreseeable level of demand. In future, the availability of power will depend on the efficient functioning of the market. The achievement of balance in supply and demand, in the short term, may require some response by customers to high prices to bring the market into equilibrium through reducing quantities demanded.[11] Since customers no longer get the specific benefits associated with planned reserve capacity normally sufficient to meet peak demands, there is no justification for allocating costs related to that capacity as is done through a differential demand charge. As well, there is no longer a guarantee that power will be provided at approximately the embedded costs of generation. The market determined price will increasingly dominate the actual cost of power to consumers, and, at least in the short term, the market price may exceed the embedded costs of generation.

- The province is in the third year of its five-year transition from regulated generation to competitive generation. As the transition has proceeded, the relevance of demand-based cost allocation methods has declined.[12] In a competitive market, all costs are variable in the long term and demand-based allocation would be inappropriate. The only costs incurred for generation will be reflected in the pool price. In fact, continuing to use a demand-based approach to allocation might involve a degree of unfairness to some customers.

- The method of allocating costs of generation through the RP, and the associated UOV, should not conflict with the operation of the power pool as a competitive market. That means the method of allocation should not interfere with the pool price signal being passed through to customers. This implies that the method should not allow the allocation of the UOV to vary with pool prices. Ensuring that the pool price signal is the essential cost of energy seen by customers will help ensure that market prices work to provide

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[10] The increase is attributable to the changes in transmission cost allocation and DISCO loads relative to the forecasts used in the initial allocation.

[11] In the long term, imbalance, even potential imbalance, in the market will provide an incentive for the development of new sources of supply.

[12] To the extent entitlements exceed load, there is more support for allocating them according to historical allocation methods. However, as demand has grown in the province, the use of entitlements has increased until each DISCO's load will exceed its entitlements in most hours. The benefits of existing low-cost generation are now essentially fully used by customers. Therefore, new load will affect DISCO costs in the same way regardless of class and arguments related to historical cost-causation have less force.

> maximum incentives for efficient behavior on both the supply and demand sides of the market. The method of allocating costs should also fairly allocate the hedges among existing and new customers. Discrimination against new customers is not consistent with competitive markets, historically accepted criteria of fairness, or with one of the key purposes of the EU Act of 1996.[13] Similarly, discrimination or differentiation in pricing based on load factor is no longer appropriate since load factor does not affect the generation costs incurred by the DISCO to serve incremental load.

In brief, the desired end result of restructuring is a competitive market for selected electrical services . There are at least two implications important to this Decision, relating to generation costs, that follow from that:

- First, historical approaches to allocating generation costs (to either DISCOs or end-use customers) will not be relevant once a competitive market is fully developed. At that time, costs will have to be recovered through market prices. In the short term, some energy may be sold at prices that do not cover all costs. But in the long term such an anomaly cannot continue. Generators who cannot cover their costs through market prices will exit from the market.[14]

- Second, there should be no difference in the price charged any customer for a kWh purchased from the pool by the DISCO in a given hour.

The transition from the Old World has advanced to the point where the Board believes demand-based allocation of generation costs is no longer appropriate. There is a need at this time to align the emerging system with the requirements of a competitive marketplace. That requires that both RP and UOV be allocated based on energy use and in a manner that ensures they do not diminish the strength of the connection between market-determined prices and customer behaviour. The pool price will be the implicit basis of allocation when a functioning market is fully developed. The Board believes it would enhance the transition to accept that reality and implement a parallel approach now. That is another reason why the Board is not willing to accept the demand-based approach proposed by AE, IPCAA and IPPSA, which would inevitably postpone the time at which players must directly engage the market.

However, the Board does not fully support TransAlta's RP allocation method as proposed by the FIRM Customers either. Although TransAlta's approach of allocating on an energy basis does

[13] The EU Act section 6(a)(i) reads as follows: "The purposes of this Act are (a) to establish a framework that replaces the *Electric Energy Marketing Act* so that averaging of generation costs is phased out as regulated generating units are removed from regulated service and new arrangements are made so that (i) the benefits of and responsibilities for costs associated with electricity produced by regulated generating units are shared by all consumers of electricity in Alberta, and,…"

[14] This is the theoretical result of competitive markets but is somewhat unlikely in the current circumstances. If it were to happen, the generating units involved could continue to operate since new owners would be likely to purchase them at a significant discount, in effect reducing their cost to the system.

more closely approximate a market result, the method introduces a distortion to the price signal by linking the allocation of RP to the allocation of the UOV. The distortion occurs because the UOV is higher during periods of high prices, leading to a higher allocation of RP to high pool price hours.[15] In consequence, the variation in the net hourly energy cost seen by a customer would differ from the variation in the pool price (as illustrated in Appendix 4). The signal that should be seen by customers is the pool price. Only pool price signals will generate the appropriate market response since they alone reflect the relation of demand and supply that exists in the market during any given period.

Moreover, under AE's and TransAlta's method of allocating the UOV refund, customers forecast to use energy in a particular hour of the year would get the benefit of the called entitlements available to reduce the net cost of energy in that hour. For those customers, the result would be to reduce the effective pool price in that hour. Such a result was appropriate at the DISCO level, given the initial objective to ensure power was priced at its embedded costs. However, for purposes of moving toward a competitive market, the Board believes it is not appropriate to effectively hold the net price the customer sees at the level of the UOP. This is particularly relevant for actual pool price DAT customers, who are intended to be exposed to the full variation of the pool price.

Therefore, the Board considers the annual forecast UOV refund should be treated as a benefit that is spread equally across forecast annual DISCO energy use. That will ensure that the benefit related to existing low-cost generation is equitably shared by customers while also allowing customers to be exposed to the full pool price variation (see Appendix 5). Similarly, the Board considers that the variation of the pool price signal will not be distorted if the RP is spread equally across forecast annual DISCO energy use. Therefore, in the COSS the Board considers that the cost allocated to customer classes for each kWh should be the hourly pool price adjusted by a constant factor "H", which captures the net amount of the legislated hedges for each kilowatt hour of energy use. H is defined as the net amount calculated by deducting the annual total UOV from the annual total RP and dividing the result by annual energy use. The resulting allocation can be summarized as follows:

Cost allocation/kWh = cost of energy purchased from the pool + H,

$$\text{Where } H = \frac{\text{forecast annual DISCO RP} - \text{forecast annual total of DISCO UOV refunds}}{\text{Forecast DISCO total annual energy use}}$$

H is the same constant amount for all customer classes.

[15] The Board acknowledges the concerns raised by intervenors regarding the potential for the exercise of market power. While the Board does not necessarily accept that market power has been exercised, it views the prevention of that result in future as being a matter for other bodies and/or proceedings. It would not be efficient to address that possibility through the allocation process under discussion here.

This approach to allocation will cause variation in the hourly total generation cost to match the variation in pool price for all customer classes, thereby ensuring that the pool price signal will begin to influence customer energy use. For rate design purposes, pass through of the pool price the DISCO faces may be on a forecast basis for fixed rate customers or on an actual basis for pool price flow-through customers. For fixed rate customers, consumption will not be affected in the short term by the actual hourly pool price. Changes in their patterns of use will occur gradually. However, variable rate Direct Access Tariff (DAT) customers will clearly see, and be able to respond to, the variation in the actual hourly pool price.

The Board considers that the H factor will provide the fair allocation, required by the EU Act, of the value and cost of the legislated hedges among all future users of electric energy in Alberta. The demand based allocation methods would have given some customer classes a greater share of, or right to the net benefits of the legislated hedges, even though the DISCOs incur the same cost, the pool price, for incremental energy to serve customers in any class.

The DISCO should allocate the same cost for each kWh of energy to be consumed by a customer in an hour regardless of the customer's rate class. There should no longer be any demand-based charges in the generation component of the rate. The charges in each rate to pass through the average cost of energy purchased from the pool and allocated costs of the legislated hedges should be as follows:

- For fixed rate classes the separate charges per kWh would be H and the forecast class annual average pool price;

- For actual pool price DAT classes (see Section 4(h)) the separate charges per kWh would be H and the actual hourly pool price; and

- For TOU classes the separate charges per kWh would be H and the forecast average annual pool price in each TOU period (presumably a different value for each TOU period)

Each class's annual average cost of energy and the DISCO H component should be separated in each applicable rate schedule. Ideally the rates would reflect a tested forecast for the year they are in effect. For fixed rate classes, forecast hourly load profiles developed from the hourly total energy forecast, load research data and load growth statistics would provide hourly energy usage characteristics for each customer rate class. Then hourly pool price forecasts and hourly load profiles would be used to determine each fixed rate class's annual average cost of energy. Similarly, the H component would reflect current forecast annual DISCO RP, forecast total DISCO annual UOV refund and forecast DISCO annual energy use. The Board sets out how the cost of energy and the H component will be determined for the rates arising out of this Decision in Section 3(a).

(c) 25 kV Reclassification

AE's Application included costs, associated with the 25 kV plant, as distribution costs. During the proceeding, most intervenors supported reclassifying 25 kV facilities and costs to transmission on an estimated basis. AE estimated the affects of the reclassification in a revised cost of service filed as Exhibit 79.

Position of AE

AE stated that it intended to recognize the reclassification of 25 kV costs from distribution to transmission as reflected in the amendments to the applicable legislation. However, AE did not incorporate this proposal into the original filing as the costs had not been finalized and, therefore, further refinements would be required. During the proceedings, AE conceded that sentiment appeared to support a reclassification of 25 kV costs even if done on an estimated basis. AE subsequently refiled, as Exhibit 79, a revised cost of service study reflecting this change in classification.

AE proposed to make the necessary revisions in the refiling following the decision on the Phase II application and to incorporate the final adjustments once the final numbers were available from the TA.

AE stated the increase to the transmission access payments was based on the TA's revised rates effective 1 October 1998. AE submitted that the TA's rates, then, included a charge to both GIS and GSS rate schedules. AE submitted that TransCanada's position on transmission payment allocation was more properly debated during the ESBI Alberta Limited rate proceeding and not during the AE Phase II proceeding.

Position of the Intervenors

The MI indicated that although AE had not included 25 kV costs as transmission, AE had proposed to flow the changes through to the distribution tariffs via an across-the-board adjustment rider at a later date. MI submitted that the change proposed by AE and filed as Exhibit 79 should be recognized in the cost allocation of any subsequent rate design the Board may direct AE to conduct.

The MI requested the Board to convene a mini Phase II proceeding to reflect the changes in cost based rates subsequent to AE's anticipated refiling. The MI noted that AE concurred since AE's refiling would incorporate all Board decisions as well as the impact of other settlements and matters on the final rates.

The MI opposed TransCanada's suggestion that the reclassified transmission costs be deferred and dealt with at the time of the TA's tariff proceeding. The MI suggested that a decision might not be available until the year 2000 and that the submission by AE in Exhibit 79 was a better approximation of cost causation than ignoring the legislative change until a decision on transmission rates.

AIPA/AAMDC/REA stated that AE had divided the property between rural and non-rural elements and allocated costs using a split between customer and demand costs. AIPA/AAMDC/REA criticized this approach as contrary to previous practice whereby the property was considered to be demand-related on a system basis. As well, AIPA/AAMDC/REA criticized AE for not following the law when AE allocated 25 kV costs to farm and irrigation customers.

AIPA/AAMDC/REA further stated that AE had not reflected the transfer of substation assets back to transmission required by recent legislation. AIPA/AAMDC/REA agreed with AE's Exhibit 79, not to allocate costs to farm customers and to reclassify 25 kV substation costs to transmission.

TransCanada suggested that AE had "mechanistically" appeared to reclassify the 25 kV substation costs to transmission. TransCanada further submitted that AE had not reviewed the allocation method for the costs being allocated and that only "some of the 25 kV costs" were adjusted. TransCanada submitted that the mechanistic and piecemeal approach to adjusting the cost of service should not be used for rate design.

TransCanada stated AE did not provide the impact that reclassifying the proposed 25 kV costs to transmission would have on transmission rates. TransCanada submitted that all 25 kV substation costs should appear in the Grid Interconnection Service (GIS) charge to provide consistency with Decision U97065. TransCanada challenged the appropriateness of AE's "across-the-board" assumption on the TA's rates when AE reclassified 25 kV costs to transmission. TransCanada asserted that the COSS provided in Exhibit 79 did not just deal with an issue of classification between transmission and distribution but also between rate classes. TransCanada submitted that the treatment of the reclassified 25 kV facilities should be resolved in the tariff proceeding of the TA.

Board Findings

The Board, in Decision U97065, directed the Utilities to identify the 25 kV facilities between the low-voltage terminals of the step down transformer and the substation fence and to reclassify the costs of these facilities from transmission to distribution. The Board, in Part 1 – General, Section 5(c) of Decision U97065 further directed the Utilities to reclassify the 25 kV facilities to the distribution function for 1996 refiling purposes. The Board notes AE has designed customer rates using a COSS based on the 1998 Board approved revenue requirement.

However, the Board notes that section 2(b) of the *Electric Utilities Amendment Act* amended, for purposes of tariffs that have effect in and after 1998, the definition in subsection (1)(dd) to the extent that subclause (v):

includes all equipment in a substation that is used to transmit electric energy

(a) from the low voltage terminal referred to in subsection (1)(dd), and

(b) to the electric distribution system lines that exit the substation and are energized at 25,000 volts or less.

The Board considers that the applicable legislation takes precedence over Decision U97065 for rates effective in 1999.

Therefore, the Board considers that 25 kV facilities should be classified as transmission costs. In Exhibit 79, AE provided the cost of service based on certain assumptions after the inclusion of 25 kV costs in transmission. In Section 3(b) the Board directed AE to prorate the 1998 distribution cost allocations (as adjusted for the removal of the 25 kV costs from distribution) in the Application to the 1999 residual in the refiling to determine a level for the DISCO Services components in the refiled rates.

The Board recognizes that removal of these costs from the distribution function, means these costs must be recovered in the TA's rates. The Board notes TransCanada's comments on AE's "across-the-board" assumption on how the TA would incorporate the additional transmission costs into the transmission rates. However, in Section 3(b) the Board directed AE to update its 1998 forecast transmission costs using the TA's interim 1999 rates which are adjusted for the effect of reallocating the 25 kV plant to transmission. Therefore, the Board considers that AE's per kWh and kW charges to recover TA Billings will be appropriately adjusted for the effect of reallocating the 25 kV plant to transmission.

(d) Allocation of Transmission Administrator Billings

The TA Billings charged the DISCO by the TA must be allocated to customers. The TA's GIS charge recovers the cost of system support services and the cost of the local portion of the transmission system required to meet the non-coincident peak (NCP) demand of the local area load. The TA's Grid Standard Service (GSS) charges recover the bulk portion of the transmission system required to meet the coincident peak of the local area loads.

AE allocated GIS payments on the monthly NCP.[16] On-peak Transfer charges (GSS)[17] were allocated based on the on-peak energy of each rate class. On-peak Losses and Off-peak Losses charges were allocated based on estimated losses during on-peak hours and off-peak hours by

[16] Schedule 3.B-5 and 3.B-6
[17] Schedule 3.B-7 and 3.B-10

rate class.[18] The Grid Import Opportunity Service/Grid Export Opportunity Service (GIO/GXO) charges and the Interim Adjustment Rider were allocated on the sub-total of GIS.[19]

Customers expressed concerns with the way the Grid Interconnection Services (GIS) and the Grid Standard Service (GSS) charges were allocated (Section 4(h)).

(1) Grid Interconnection Service

AE's transmission rate was structured to include recovery of the cost of the TA's GIS billings. AE allocated the 1998 forecast monthly GIS payments based on the monthly NCP of each rate class.

Position of the Intervenors

Mr. Marcus, on behalf of the FIRM Customers, stated that customers who are served at transmission voltage should receive an allocation of costs based on customer NCP (the sum of customer loads) rather than class NCP. These customers are served from a single delivery point subject to ratcheted demand charges. There are 14 substations where a single customer represents 100% of the load, where a customer-based allocation would be appropriate. Mr. Marcus also stated that customers served at 25 kV distribution voltage through either a dedicated substation or a substation where they are the principle customer, should also be allocated costs based on customer NCP.

IPCAA noted that AE allocated the monthly GIS payments to rate classes based on the monthly NCP of each rate class. The TA bills the DISCOs on a point of delivery (POD) basis utilizing (annual) contracted POD demand. IPCAA concluded that the AE cost allocation method does not reflect how the cost is incurred. Further, IPCAA considered that, if a POD serves a single customer, the TA charges can and should be explicitly defined. IPCAA stated the DISCOs should pass through the TA costs as accurately as possible.

The FIRM Customers noted that GIS demand costs are charged to distribution utilities based on ratcheted demands at transmission/distribution substations. The FIRM Customers agreed with Mr. Marcus that loads served at transmission voltage should receive an allocation of costs based on customer NCP rather than class NCP. The FIRM Customers stated that AE's method does not allocate adequate amounts of costs to certain industrial customers.

The FIRM Customers recommended that the Board adopt the customer NCP allocation of GIS transmission costs for any single customer that represents 100% of the load at a delivery point as a conservative first step in this proceeding. The FIRM Customers noted that IPCAA and IPPSA/SPPA agreed that large industrials served at transmission voltage or dedicated substations should pay for transmission on a customer non-coincident basis.

[18] Schedules 3.B-8, 3.B-9 and 3.B-10
[19] Schedules 3.B-11 and 3.B-12

Position of AE

AE noted the proposal of Mr. Marcus was another reasonable approach, but cautioned that Mr. Marcus' approach mixes average and incremental approaches while AE's proposal fully averages all GIS costs across all PODs. AE submitted that its proposal is the fairest and most reasonable treatment in the circumstances and should be adopted.

Board Findings

In Decision U97065, at page 624, the Board stated that the TA's GIS rate should be structured to recover the costs of the local portion of the transmission system required to meet the NCP demand of the local area load, without regard to the overall system coincidence. The TA's billing for GIS service to AE is based on a ratcheted demand metered at each POD. The Board notes that AE has used the NCP method to allocate total forecast GIS demand charges to customer rate classes. The Board considers that the NCP method is appropriate.

However, the FIRM Customers and IPCAA recommended that if a POD serves a single customer a customer-based NCP allocation should be used rather than the NCP of the class.

Generally, to speed the unbundling during the transition to competitive markets, the Board considers that where a more accurate allocation of costs can be determined the more accurate method should be used. Specifically, the Board considers that pass through of customer specific TA Billings will help ensure that more accurate unbundled costs to serve customers arise out of this proceeding and the Distribution Tariff proceeding. Therefore, since in Section 2(c), the Board finds that 25 kV costs should now be in transmission, the Board directs AE to pass through the actual TA Billings to every customer served at 25 kV or higher who is the only customer at a POD.

Further, in Section 3(b), the Board directs AE to use its actual 1998 TA invoiced kWh and kW and actual customer and class NCP and usage to determine its kWh and kW charges relating to TA Billings in its refiling. Using this method, a forecast of excess billings is not required to ensure appropriate allocation of TA Billings to customers and classes.

(e) Classification and Allocations

Using each 1997 actual distribution asset account, AE classified and allocated the costs as customer-related, demand-related or both based on the customer/demand splits approved by the Board in Decision E95102, dated 20 October 1995. The customer-related portion is to recognize that portion of distribution facilities related more directly to the number of customers served than to demand or energy. To allocate the costs, the demand related portion of 1997 assets were allocated to each rate class on the forecast 1998 NCP demand of that rate class. The customer-related portion of assets was allocated based on the 1998 forecast number of customers. For the allocation of meters, services, and the customer-related portion of line transformers, a weighted customer count was used. This resulted in weighted gross assets, weighted net assets, weighted gross rate base, weighted net contributions and weighted net rate base.[20] Gross distribution assets were used to allocate General Plant assets. Customer contributions were assigned to the customer groups from which they were collected.

AE provided a summary of the allocated distribution related costs, excluding franchise taxes, on Schedule 3.B.14. A summary of the allocated franchise taxes was provided on Schedule 3.B-27. To allocate downstream Operation and Maintenance (O&M) costs, AE included the distribution assets of those REAs endorsing the pooling contract. Distribution O&M was allocated to each rate class as follows:

- Distribution brushing O&M was allocated on the basis of 1997 actual gross balances of Poles, Towers and Fixtures, and Overhead conductors;
- Street and sentinel lights were directly assigned; and
- Other Distribution O&M was allocated on the basis of weighted gross distribution assets.

Marketing O&M expense was allocated 15% based on the number of customers, and 85% based on energy sales.

Customer Accounting O&M expense was allocated 98% on the number of customers and the remaining 2% on kWh sales. Some customer accounting O&M was allocated to street and sentinel lights by using the number of bills issued for street and sentinel lights as a proxy to represent the number of customers.

General Plant O&M was allocated on the basis of weighted gross General Plant Assets.

Administrative and General (A&G) Expense was allocated using the Service Cost Allocation Method.

Secondary depreciation expense was allocated based on weighted net secondary assets. The primary depreciation expense was allocated on the basis of the total weighted net primary assets. Amortization of contributions was allocated on the basis of contributions. The general plant depreciation expense was allocated in proportion to the gross general plant assets.

Return and Income tax was allocated on the basis of weighted rate base. Franchise taxes were allocated on the basis of 1997 actual Rider A-1 revenue collected by rate class.[21] Revenue offsets were allocated based on the sum of all service costs excluding A&G.

[20] Schedules 3.B-21 to 3.B-25
[21] Schedule 3.B-27

During the proceeding several parties questioned certain classifications and allocations used by AE. The parties were concerned with both the methodology and the factors used to classify or allocate costs as customer related and demand related. These concerns are addressed in this section.

Position of the Intervenors

The CCA noted that the distribution cost classification factors were classified as “customer related” versus “demand related” based on a 1990 Phase II COSS. The CCA also noted that AE indicated a willingness to examine the appropriate distribution cost allocation factors.

The CCA stated that because of the growth in the distribution system, it could be expected that the distribution classification factors would change from an analysis done some eight years ago. The CCA submitted that AE should undertake, for purposes of its next Phase II Rate Filing, minimum system and/or zero intercept studies and use the results of these studies in its next Phase II General Rate Application (GRA).

The CCA noted that AE allocated customer accounting costs using the Board approved factor of 98% customer and 2% energy from Board Decision E95102. The 2% weighting for energy recognized that higher costs are incurred to serve large customers, which are hand billed by billing clerks. The CCA also noted that AE acknowledged the 2% weighting was based on judgement.

The CCA submitted that the Board should direct AE to provide a detailed study, on the extent of manual billing involvement and costs incurred to serve large industrial customers, for the next GRA.

IPCAA considered that AE’s allocation of distribution cost was imprecise because the distribution revenue was simply determined on a residual amount, the residual amount was prorated based on 1996 data, the allocation of distribution marketing cost was inappropriate and it used assumptions regarding the effect of reclassifying 25 kV facilities back to transmission. IPCAA recommended that the COSS should not be used for revenue reallocation and rate design purposes and that AE be required to prepare a COSS for its next Phase II application that corrects the deficiencies identified by IPCAA.

The MI agreed with AE’s use of the 1997 actual closing balances of gross assets, accumulated depreciation and customer contributions in the allocation of the distribution related revenue requirement. MI considered this to be a reasonable approach since there was no specific agreement on forecast 1998 capital additions in the negotiated settlement. The MI noted that the classifications were last approved in Board Decision E95102 and that the classification factors are unchanged from the 1989/90 Phase II proceeding.

The MI considered that the costs AE classified as customer related are substantially higher than those derived in a survey of utility practices, those used by TransAlta, or those in alternatives presented by Mr. Marcus. The MI submitted that AE's classification method appears to overstate the costs classified to customer, a fact that the Board should take into consideration when approving final rates following the filing of an updated COSS.

The MI noted AE's statement that minimum height requirements for poles, towers, and fixtures are necessary regardless of the number of customers served. The MI considered that this statement, in itself, suggests that the 56% weighting to customer may be too high.

The MI noted that AE's allocation of marketing costs has been based on a specific analysis of its Marketing Department conducted in 1993. AE proposed to disregard this analysis and allocate marketing costs on a purely arbitrary method which allocates these costs based 15% on number of customers and 85% on energy sales, notwithstanding the evidence has indicated "the functions are basically the same today." The MI was concerned that AE had abandoned a fairly detailed analysis of marketing costs in favour of the arbitrary 15%/85% method. The MI considered that the changes in the role of the Marketing Department would cause relatively minor changes in the classification of costs, whereas the new method produces significant changes compared to the detailed analysis of 1993 marketing expenses.

The MI submitted that the percentages of marketing costs allocated to rate classes in 1993 would be a better allocator for 1998 than the arbitrary 15%/85% used by AE. The MI recommended that AE use the 1993 percentages to update its COSS.

The MI noted that PICA stated that the classification of primary distribution assets should be based on AE's filed method which assumed "that maybe the primary system was taking on some characteristics of the secondary system." What PICA failed to mention was that AE recognized that the 100% demand classification was a reasonable alternative. AE indicated that it is prepared to recognize this change in its revised COSS.

PICA noted that AE indicated the higher customer allocation for poles, towers and fixtures is appropriate and consistent with cost causation.

PICA did not agree with the AIPA/AAMDC/REA that small customers would be charged twice when a minimum system is used for customer costs without a deduction for the demand per customer. PICA stated that the aggregate demands of small customers may or may not be less than that of larger customers served on the same secondary system. Further, it is the aggregate demands of customers served by the system that are relevant; not the individual customer demands. PICA noted that there did not appear to be any evidence to indicate the sizing of poles, towers and fixtures was driven any more by large customer demand than by aggregate small customer demands. PICA submitted that the claim of double charging was unsupported by the evidence.

PICA submitted the safety requirements elaborated by AE make the mechanical interpretation of any minimum system study meaningless. For example, it is very likely that the minimum height and minimum clearance requirements may vary by service territory. As a result, classification percentages in different jurisdictions may not necessarily be comparable. PICA recommended AE's classification for poles, towers and fixtures be approved.

AIPA/AAMDC/REA noted that AE's 1993 study showed that only 32% of the cost of poles are customer-related based on a minimum intercept study conducted at that time. Based on the current cost of poles, Mr. Marcus calculated that a zero intercept method using today's data would classify 100% of the cost of poles as demand related. Mr. Marcus also updated the minimum system calculation using the current costs provided by AE, and found that a minimum system would classify only 50% of the cost as customer-related instead of the 75% used by AE since 1989.

Further, AIPA/AAMDC/REA noted that Mr. Marcus pointed out that a minimum system method double-charges small customers where a zero intercept method does not. When a minimum system is used for customer costs, and no deduction is made for the demand per customer carried by the minimum system, small customers are double-charged. They are charged for demand costs based on their total demand, even though much of their demand is carried on the minimum system, which is already charged to them on a customer basis.

The AIPA/AAMDC/REA recommended that the Board use TransAlta's 35–65 split for all secondary distribution equipment or use a 30% customer 70% demand basis for poles, towers, and fixtures.

AIPA/AAMDC/REA noted that AE's treatment of secondary distribution costs between customer and demand is very different than the mainstream opinion in North America. AE classifies 52% of secondary distribution costs as customer-related, the survey provided by AE shows the average is 24% customer-related. Further, TransAlta classifies its secondary system as 35% customer-related and 65% demand-related.

The AIPA/AAMDC/REA also submitted that the split of secondary distribution assets between rural/non-rural for determining the allocation of distribution costs results in an unfair allocation of costs to the Company Farm rate class (Rate 56). In response to BR-AE.14, AE explained that the revenue cost ratio of 68% was set at that level because of the results in the COSS. The AIPA/AAMDC/REA recommended the Board direct AE to take steps to rectify the deficiency in the current COSS.

The AIPA/AAMDC/REA noted that AE's cost allocation method for customer accounting costs is based 98% on the number of customers and 2% on total revenue. The AIPA/AAMDC/REA considered that AE failed to recognize that some customer classes, including REA's, have lower meter reading and billing frequency than average. The AIPA/AAMDC/REA recommended that the Board revise AE's cost study to consider billing and meter reading frequency.

AIPA/AAMDC/REA stated that AE's COSS erroneously overstates costs to company farm customers and noted that TransCanada demands major increases in farm rates based on this erroneous study. AIPA/AAMDC/REA submitted that the best way to get rid of the errors would be try to resurrect the property records system. Otherwise farm customers' rates should be benchmarked to the property and associated O&M costs per customer of REA farms.

IPPSA/SPPA considered that revenue-to-cost ratios should migrate to 100% for each customer class. Put another way, inter-class and intra-class subsidization should be minimized as the industry moves towards retail competition.

IPPSA/SPPA noted that the myriad of changes proposed by AE and other parties would likely lead to a COSS different than that filed to date. IPPSA/SPPA submitted the revenue-to-cost ratios should be 100% for Rate 31 and Rate 41. Further, with the changes resulting from industry restructuring and changes to cost of service methodology, there is an excellent opportunity to move all customer classes to a revenue-to-cost ratio at unity.

TransCanada noted that AE indicated that several intervenors preferred that primary distribution costs be allocated 100% to demand. AE stated it was prepared to recognize this change and incorporated the 100% demand allocation into the revised COSS. AE had originally allocated a portion of primary distribution assets to customers because some customers were served directly from these facilities.

TransCanada considered that the 100% demand classification method may not be any more accurate than AE's and agreed with PICA's position that the Board should approve AE's original proposal since some customers are served directly from the primary distribution system.

Position of AE

AE stated that it did not propose customer and demand classifications different from that used in the 1993 GRA. AE looked at this issue, but did not find any basis which would warrant a departure from the 1993 methodology. AE maintained the view that the approach is reasonable and should be accepted by the Board.

AE noted that certain parties disagreed with AE's allocation of costs related to poles/towers/ fixtures of 75% to customers and 25% to demand. AE's method was compared to methodologies in use by other utilities. AE cautioned that its circumstances may or may not be comparable to such other utilities. AE stated that its proposed methodology is reflective of considerations like the minimum height requirements for poles etc., which are required regardless of the number of customers served or the maximum demand of those customers. AE submitted that the proposed allocation is fair and appropriate and requested that the Board approve its proposal.

AE submitted that the evidence of Mr. Marcus, which relies on the conduct of certain zero intercept studies, demonstrates that the results (being that the regression line intercepts the y-axis at a negative value) do not in any way support a zero percent customer related share of the poles, towers and fixtures account. AE submitted that the results are unreliable and, quite possibly, based on a flawed hypothesis.

AE noted that the Argument of AIPA/AAMDC/REA suggested that AE had not done a new analysis of this issue since 1989. AE stated it had conducted various studies to test the continued appropriateness of the 1990 approach, did not trust the results and, therefore, did not propose any change in the context of these proceedings.

AE responded to the AIPA/AAMDC/REA's suggestion that AE employ the use of location codes to achieve a more precise allocation of assets between rate classes. AE stated that the use of location codes is currently being examined and is prepared to adopt the use of location or customer class usage codes on a "go forward" basis. AE submitted that while these codes may be accurate at the beginning of the useful life of any asset, in terms of identifying customer class usage, the accuracy and usefulness of these codes will likely be eroded over time. When change in usage occurs, some sort of allocation method will have to be adopted to allocate costs to customer classes.

AE also submitted that to use location codes for existing plant would render very inaccurate and imprecise results. As well, the suggestion that AE simply divide its existing distribution assets according to rate class usage would oversimplify the problem, and would not yield reliable results. AE requested that the Board approve the current split it has adopted, with the understanding that AE will attempt greater precision through the use of the location or customer class usage codes in the future.

AE stated it had changed the allocation of marketing costs from the 1993 approach previously utilized. The change was made because there was no agreement on specific amounts in the 1998 Negotiated Settlement and AE's investigations determined that the 1993 study would no longer provide accurate or reliable results. AE stated that the proposed allocation in the current Application is superior to a continuation of a methodology that would not yield appropriate results. AE urged the Board to approve the allocation of marketing costs as put forth in its Application.

AE submitted that the use of AE's 1993 study put forward by the MI respecting the allocation of marketing expense is another reasonable approach that could be used. However, AE noted its concern that since the size and role of the marketing department has changed somewhat since 1993, that using the percentages from the 1993 study may not give an accurate and reliable allocation of marketing expenses in 1998. AE recommended that the 85%/15% customer/energy allocation of marketing expense be accepted.

Board Findings

The Board notes that AE used actual 1997 closing asset balances as the basis for allocating distribution related revenue requirement. Ordinarily, the Board would consider a mid-year calculation for asset balances as the preferred basis to allocate revenue requirement. However, since the revenue requirement was determined through the negotiated settlement process and there was no detail contained in the settlement to calculate a 1998 mid-year asset balance, the Board accepts AE's use of the 1997 closing asset balances for the purposes of the COSS.

The Board notes that AE used the same customer and demand classification in this proceeding as was originally approved in Decision E90050. AE stated that matters related to rate design and cost allocation are not a precise science and that a COSS is an effort to allocate a common pool of costs in a reasonable and fair manner. AE considered that using the classifications from Decision E90050 in this proceeding was a reasonable approach. Several parties did not agree with AE's conclusion. The CCA stated that, because the analysis is eight years old and the distribution system has grown over that period, one could expect classification factors to change. The MI submitted that the classification method appears to overstate the costs classified to customer. The AIPA/AAMDC/REA noted that AE uses a very different method to classify costs between customer and demand than most of North America.

The Board notes that AE stated it was prepared to use location codes on a go forward basis. AE also cautioned that the accuracy of the codes would erode over time and some sort of allocation method will have to be adopted to allocate costs to customer classes.

The Board considers that the customer and demand classifications are an important step in creating a COSS that can be used to allocate costs on a reasonable basis to customer classes. The classifications need to fairly represent the principle of cost causation, reflect changes over time, and adjust for changes in the mix of customers as the distribution system grows.

In Decisions E90050, E93035 and again in E95102, the Board accepted the classification of costs to demand and customer as filed by AE**.** Further, the Board agrees with AE that the comparisons made of AE's classifications to other utilities might not reflect AE's situation. The Board also considers that use of the TransAlta factor would be arbitrary and not supported by the evidence.

The Board considers that AE's offer to use location or customer class usage codes on a "go forward" basis would not be helpful in the classification of costs to customer and demand. The mix of identifiable costs and existing costs that have a mix of usage would only make a determination of current usage more complex.

The Board notes that AE used a classification factor of 75% to customer and 25% to demand for the costs related to poles, towers and fixtures account. Intervenors considered that a customer factor of 75% was excessive when compared to other utilities and proposals made by other parties. Most parties considered that a factor of 30% to 35% would be a more reasonable classification for AE.

Therefore, the Board directs AE to provide, at its next GRA, a study that applies the principle of cost causation, reflects changes in asset use since Decision E90050, and considers changes in the mix of customers in the customer and demand classifications. The Board is not persuaded that there is sufficient reason to change the classification factor in this proceeding and, therefore, accepts AE's customer and demand classifications as filed.

In respect of the classification of primary distribution assets the Board notes that PICA and TransCanada agreed with AE's classification because it recognized the primary system was taking on some characteristics of the secondary system. AE stated that the 100% allocation to demand was a reasonable alternative and was prepared to recognize this change in this proceeding.

The Board accepts AE's 100% allocation to demand for the primary system in this proceeding.

The Board notes that AE used 85% customer, 15% energy, to allocate marketing expense to customer classes rather than the detailed study used in the 1993 proceeding. AE stated that using the detailed study would not produce reliable results but conceded the study would be a reasonable approach. The Board notes the MI considered that using the 85%/15% is arbitrary and that the 1993 detailed study is preferred since AE indicated that the functions of the marketing department are basically the same today.

The Board considers that a detailed study is preferable to an arbitrary percentage allocation. The Board, therefore, directs AE to incorporate the 1993 study for marketing expenses into this proceeding. The Board also directs AE to update its marketing expense study for future Phase II applications.

The CCA considered AE's allocation of customer accounting costs using a 2% weighting for energy to be based on judgement. The AIPA/AAMDC/REA submitted that the allocation did not account for meter reading frequency and fewer bills for certain customer classes, including REA's.

The Board directs AE to include meter reading and billing frequency as part of the allocation of customer accounting costs and to undertake a study to assess the reasonableness of the 2% weighting to energy, for its next Phase II proceeding.

The Board notes IPPSA/SPPA recommended that all rate classes should migrate to a 100% revenue-to-cost ratio. The Board has stated in the past that the revenue-to-cost ratio should migrate to 95% to 105% revenue to cost over time. The Board considers 95% to 105% is still a valid target for rate classes during the transition to 2001.

3. RATE DESIGN

(a) Design of Proposed Rates

Position of AE

AE indicated that the proposed rate schedules had been designed based on the 1998 distribution revenue requirement. AE indicated that prior to developing new tariffs, it had consulted with customers and intervenor groups about issues and preferences regarding tariff and product design. Customers supported functionalization of charges, minimization of cross-subsidization and cost reflective rates. Some requests and suggestions were accommodated, but others were too complex or inconsistent with the rate design criteria used by AE. AE stated that the rate design criteria of previous filings were still valid since it was still providing its customers with fully bundled service. The criteria were

- Recover total revenue requirement including required increases or decreases in revenue, together with the allocation of increased or decreased revenue to each class of customer.
- Recognize the cost of service as determined by cost studies and the cost of existing and future facilities required to provide service.
- Promote efficient and cost effective usage of power and discourage wasteful or inefficient usage and where possible, promote desired behavior through price signals built into the rate structure.
- Recognize the value of service provided, specifically, competition with alternative sources of energy services and the price sensitivity of different consumer groups. Recognition of the value of service provided or market prices of customer alternative may suggest pricing levels above or below those based on embedded cost of service.
- Avoid undue discrimination between and within customer classes.
- Consider the rate levels, structures and policies of other utilities, particularly those with similar load and service conditions.
- Promote ease of understanding and acceptance by customers, as well as ease of administration and economy of billing.
- Recognize the level and structure of existing rates and their historical development.

AE indicated that the rates were appropriate for traditional rate classes and allowed AE to start to manage the costs and risks of the distribution function more directly. To facilitate further unbundling, distinct charges were presented to indicate the various component costs (i.e. explicit charges for generation, transmission and distribution) of the bundled tariff but they may or may not be appropriate for a distribution access tariff. AE's ability to match the associated cost causation was generally mitigated by historical rate structure and levels. AE considered the application an intermediate step in the move from fully integrated, bundled services to a more competitive environment.

AE set the revenue-to-cost ratios (by generation, transmission and distribution) as close as possible to the 95%–105% range established by the Board (with the exception of company farm rate), while still recognizing the other rate design principles that may impact upon the development of specific rates. Noting suggestions that greater refinements be made to the revenue-to-cost ratios to move them closer to 100%, AE stressed rate design is not a precise science. AE further submitted that there is little basis to justify establishing rates with greater precision than falling within the range of 95%–105%.[22]

AE indicated that it would incorporate various changes (either as a result of data that was not yet finalized or due to rulings of the Board) into its COSS and Rate Design. AE submitted that the most expeditious way to deal with any rate revisions arising from its revised COSS would be to reconvene a one day proceeding to examine the relevant issues, following issuance of a Board Decision. A package of revised revenue-to-cost ratios, sample bill comparisons and price schedules would be provided for review by all interested parties.

AE submitted that the scope of questioning at the reconvened proceeding must be limited only to items that have changed as a result of the Board's Decision. The appearance of AE witnesses should not be an opportunity to re-examine all issues.

Position of the intervenors

The MI and AIPA/AAMDC/REA all supported the concept of a mini-hearing after AE's refiling. IPCAA also supported the concept if all parties were afforded opportunity to question AE witnesses and make submissions to the Board on relevant issues.

Dr. Rosenberg supported unbundled rates based on the cost of service. Generation rates should be embedded cost based until full competition sets their levels. In particular standby rates must be cost based to ensure economically efficient decisions on new generation to supply Alberta's power needs and fairly compete with existing generation companies.

Mr. Drazen supported rates which convey the proper signals and information to allow customers to respond effectively. A properly designed DAT would result in more price responsive load alleviating the need for curtailable load and brownouts. Since there is a provincial generation and transmission market, the DAT rate and the generation service charge must be consistent among DISCOs.

[22] Argument, p.8

Mr. Drazen contended that the focus should be on redesigning AE DISCO's rates to facilitate price responsive load and real competition. The transmission component should reflect the actual costs incurred from the TA to serve each rate class or the individual customer at single customer substations. The generation component should be separated into the forecast pool price, UOV Refund and RP. This would alert customers to the likely pool price and resulting hedge value. Each DISCO rate component would vary for each year the rates were to be in effect (i.e. 1998 and 1999). The rate components would also be adjusted each year for sales growth and changes in pool price, UOV credits and RP. Contracts should also be unbundled into the functional components of generation, transmission and distribution.

Mr. Drazen relied on the COSS for re-allocation of revenue responsibility between rate classes for four reasons. Restructuring was supposed to be "bumpless" and not shift revenue responsibility among DISCO's or among customers. The underlying generation and transmission costs have not changed substantially. The allocation of legislated hedges AE proposes is on a different basis than upon which those hedges were designed. Lastly the costs and usage data in AE's study are out of date 1996 data while the rates would be in effect in 1999. Mr. Drazen noted that while overall revenue is reduced by only 0.1% from existing rates, the proposed rates impact on rate classes ranges from a decrease of 9.0% for REA Farm Customers to an increase of 27.4% for customers on the POR.[23] Mr. Drazen further noted that, since the1998 Negotiated Settlement did not explicitly set out the distribution function's revenue requirement, AE determined it as a residual by subtracting generation and transmission costs from the total DISCO revenue requirement. Mr. Drazen submitted that existing rates should be unbundled with no cost reallocation in response to revenue-to-cost ratios which vary from unity.

Mr. Drazen also wanted a more current and a more detailed analysis of the distribution charge which separates costs of the wires function and retailing functions including metering, customer accounting and customer services. Neither customers nor future competitors would receive accurate information on the current cost of distribution service from a 1998 distribution revenue requirement determined on a residual basis and prorated to component costs based on the 1996 distribution component costs.

IPCAA considered that reallocation of revenue responsibility among rate classes was unnecessary and inappropriate. The primary focus should be on unbundling. The costs are to a great extent those "inherited" from the Old World. The COSS suffers from allocation method problems. IPCAA submitted that rate unbundling was essential and should lead to a form of rates which are consistent with and contribute to the development of a competitive market open to all customers. Customers must be able to choose to pay for energy at a fixed price or a price which varies with the pool price. Current customers must able to choose whether to use the distribution system. Future customers must be able to choose their supplier of energy, metering and billing. The Board should promote the development of a competitive market by directing that unbundled

[23] Drazen Evidence, p.18

information be made available to customers. AE had unbundled by function but should further unbundle generation to into pool price, RP and UOV components and distribution into "wires" and retailing.

IPPSA/SPPA also recommended unbundling generation charges into market and RP/UOV components.

To the extent that the Board unbundles generation charges into market and RP/UOV components, a relevant pool price forecast is necessary. Since these rates will go into effect in 1999 and presumably remain in effect through 2000, IPPSA/SPPA submitted that common sense dictates that the market generation charge be based on expectations for that period. Moreover, IPPSA/SPPA noted that the EU Act required AE to submit a pool price forecast a part of its DAT, "during the period in which the tariff is to be in effect."[24] Since AE is required to prepare such a price forecast, it makes sense to use that forecast for developing the market generation charge. To send reasonable price signals, the market generation charges should be based on expectations for that period.

TransCanada acknowledged AE's unbundling efforts. However, TransCanada supported even further unbundling of generation charges as IPPSA/SPPA advocated. Separating the components would provide useful price signals and customer education benefits.

TransCanada strongly objected to the use of the "95%–105%" as a blanket defense of a rate design that results in cross-subsidization. In the absence of other mitigating rate design criteria, such as rate shock, TransCanada submitted that revenue-to-cost ratios for all rate classes should be set equal to 100%. Failure to do so would result in two obvious rate design defects: perpetuation of cross-subsidies and potential for discrimination. In the interest of fairness, where a customer class has had revenue-to-cost ratios either over (below) unity for a period of time, the Board should direct AE to balance revenue-to-cost ratios for that customer class proportionally below (over) unity for a reciprocal period of time. Alternatively, TransCanada submitted that the Board should direct AE to set revenue-to-cost ratios equal to 100% for all rate classes where it is possible to do so without violating other rate design principles.

Board Findings

The Board notes that distribution rates based on Old World generation cost allocation methods have been in effect for the first three years (1996–1998) of the five year transition to deregulation in 2001. Across-the-board rate riders were agreed to in the 1997 and 1998 Negotiated Settlements. The Board does not consider that it would be appropriate to revise those rates retroactively and accordingly deems the interim rates in place from 1 January 1996 to 31 December 1998 to be final rates.

[24] Section 31.6(3)(b)

In this first phase II proceeding in the New World the Board must determine an appropriate form and level for customer rates during the remainder of the transition to fully competitive markets in 2001. As in the allocation of generation costs, the Board considers it important to look ahead in performing that role.

A major objective of the EU Act is to separate the integrated utility's costs by function as much as possible in order to provide distinct functional segments in a competitive world.

As discussed in Decision U97065:

> Section 48(1)(a) of the EU Act provides, in part, that an owner of an electric utility shall keep books, records and accounts in a manner that provides a reasonable understanding of the operation of the electric utility, including keeping track separately of the costs of regulated generating units, transmission facilities and electric distribution systems, as well as of common costs, in accordance with rules established by the Board.[25]

In Decision U97065, the Board further directed the utilities:

> …to develop a method of accounting for regulatory purposes that keeps track separately of the gross revenues and costs pertaining to the operation of the GENCO, TRANSCO and DISCO functions and to file these revenues and costs at the next GRA.[26]

Thus, the direction of the EU Act is very clear in regards to the separation of costs by function at the integrated utility level. The DISCO's revenue requirement is the distribution function's portion of the integrated utility's costs.

The DISCO's revenue requirement must also be unbundled. AE "functionalizes" the costs in its DISCO's revenue requirement into generation, transmission and distribution. The Board considers that it would be clearer if the revenue requirement were unbundled by cost source since the source of the costs are not necessarily well described by those functional categories. The cost sources to be used in the refilings and rate unbundling are: Energy Supply (currently including the benefits of legislated hedges and later the balancing pool cost/benefit), TA Billings and DISCO Services.

However, the Board considers that the separation of distribution costs by cost source is only the first step in the move towards customer choice in 2001. Customers supported functionalization of charges, cost reflective rates, and minimization of cross-subsidization. The Board agrees and notes that the new industry structure allows for competition in many areas commencing in 2001.

[25] Part 1 – General, section 5(a) p.78 (Functionalization section)
[26] Part 1 – General, section 5(a) p.81 (Functionalization section)

The pass through of more realistic costs to customers will allow them to begin considering and responding to market conditions. The Board considers that the second step is to ensure each rate has a separate component charge representing any separable component cost which may be subject to competition for the DISCO or which customers might benefit from seeing. The third step is to ensure the component charges are equal to the component costs.

The first step towards cost pass through is the unbundling of the DISCO's costs by cost source. Moving the DISCO's revenue-to-cost ratio to 100% for each cost source will also allow for easier adjustment of rate levels as required by any new DISCO cost levels arising out of the TA's rate proceeding and the distribution tariff proceeding. Therefore, the Board directs AE to set its DISCO's overall revenue-to-cost ratios to 100% for each cost source.

The second step is to separate component charges within each rate to pass through each identifiable component cost within the cost sources. The cost sources are defined to contain the component costs as follows:

- Energy Supply costs include the cost of energy purchases from the pool, the legislated hedges, pool trading fees and commercial hedges;
- TA Billings costs include the separable portions of the charges the DISCO pays the TA; and
- DISCO Services costs include separable costs related to the wires function, metering, customer accounting and customer services.

Separate cost of energy charges and legislated hedge values would help customers choose between the pool price, TOU rates and other fixed price rates and also to assess market hedging possibilities. Cost reflective unbundled charges would help customers understand and minimize the transmission charges they cause the DISCO to incur from the TA.

The third step is to move each component charge to a level equal to the component cost from which it arises. The Board considers that the cost components in Energy Supply and TA Billings may be unbundled and set to appropriate levels at the present time.

Customers also indicated that they would like to see unbundled delivery charges to help them choose between connection at the distribution or transmission level and future customer choice options. However, the distribution tariff proceeding is the appropriate forum for setting component charges which reflect the level of the component costs of DISCO Services. The information is not required for retail customer choice until 2001 and more current component costs will be available for consideration in the distribution tariff proceeding. At any rate, use of 1996 distribution costs, or the residual or prorated distribution costs from the recent negotiated settlements, would not necessarily result in unbundled charges reflecting current DISCO Services component cost levels. Further, customer evaluation of the differences between connection at the distribution or transmission level may also be impacted by the TA's rate redesign.

Therefore, at this time the Board considers that the primary focus in the design of rates should be to provide cost reflective charges for the separable component costs of Energy Supply and TA Billings and to recover the DISCO's total 1998 revenue requirement. This will require that the portion of revenue requirement attributed to DISCO Services be a residual. The revenue-to-cost ratios for total DISCO revenue from each cost source should also be set at 100%.

Customers would then see rates which reflect current cost levels and, if a new cost level for any one cost source arises from a future proceeding, it may be efficiently incorporated into customer rates without the need to examine the other cost sources. Theoretically, rate stability, energy conservation, value of service, historical development, and customer acceptance concerns should not prevent either customers or future competitors from beginning and continuing to receive the accurate cost information they require to make market driven choices. Practically, the Board recognizes that rate stability concerns and shortcomings of record keeping systems may in specific instances require overall rate class revenue-to-cost ratios other than 100%. In those cases, to keep the signals from Energy Supply and TA Billings clear and since the DISCO Services component is a residual at any rate, the DISCO Services components should be adjusted as required.

To ensure some degree of rate stability in moving to accurate cost signals, the Board directs that in the refiling, the DISCO keep any overall increase in revenue arising from the rate redesign at less than 10% for any rate class. The revenue-to-cost ratio for both the Energy Supply and TA Billings components of each rate should be moved to exactly 100%, with the DISCO Services component (which is a residual) adjusted to ensure the overall increase in revenue is less than 10% for every rate class. The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.

In summary the Board directs AE to design rates so that:

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amount to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

(b) Rate Levels for 1999

The Board considers that the most appropriate basis upon which to set 1999 rate levels for the Energy Supply and TA Billings cost sources would be tested 1999 forecasts broken down by component cost. Unfortunately, tested 1999 forecasts broken down by component costs are not available at this time. The 1999/2000 Negotiated Settlement only provides the 1999 and 2000 total DISCO revenue requirements.

For the market to function as efficiently as possible in line with the findings above, the Board also considers that the charges reflecting 1999 Energy Supply costs and TA Billings in the rates should be as representative as possible of the 1999 component costs. The rates should also be easy to adjust for changes in TA rates.

Customer response to pool price improves the efficiency of the market and the Board is particularly concerned that there should be no artificial incentives to keep customers on fixed rates if they prefer the actual pool price DAT or the TOU DAT. The Board considers that all relevant values[27] should reflect the best forecasts available for 1999 for fixed rate customers who are eligible to take DAT rates. Then DAT customers who do respond to the pool price will more likely be better off than customers on fixed rates. DAT customers must be allowed to respond to the hourly variation in pool prices without being overcharged because of the difference between forecast and actual average pool price. With proper forecasts the DAT rates will provide a benefit on a forecast basis for customers who assume that they will respond to the TOU rate (See Section 4(h)).

The Board notes that AE used actual 1995-1996 load data to derive the forecast 1998 customer numbers, hourly class loads and billing determinants. Then AE used the 1998 class data along with forecast 1998 hourly pool prices to calculate the 1998 sales and cost data used in the 1998 Negotiated Settlement and the Application.

The Board considers that the 1998 forecast levels of transmission and generation costs AE proposes to incorporate in rates are not necessarily reflective of the current costs arising from the Energy Supply and TA Billings cost sources. Considering the increase in pool prices since early 1998, the class annual average cost of energy and AE “H” as calculated from the 1998 data AE used in the Application may be quite different than current levels. In light of its findings in this Decision, the Board considers that use of the Application’s 1998 forecast data would not necessarily result in rates reflecting 1999 costs and the Board has no component cost breakdown for 1999/2000.

In the absence of tested 1999 forecast data broken down by component costs, the Board considers that the 1998 forecast hourly pool prices should be updated. The Board directs that AE apply the actual 1998 hourly pool price record to AE’s actual 1998 class load data in AE’s

[27] The annual average cost of energy for each class, the DISCO annual reservation payment, total annual UOV refund, H amount (see Section 2(b)) and total annual load.

refiling. The Board directs AE to apply its actual metered class hourly load to the actual 1998 hourly pool price record to determine a more appropriate annual average cost of energy for each fixed rate class. Similarly, the Board directs AE to use the average actual pool price in each TOU period in 1998 as the cost of energy components in the TOU rates. The Board directs AE to use the fixed amount “H” charge calculated using the 1998 pool price record and total 1998 AE DISCO annual energy usage. This approach will, in the Board’s view, provide appropriate levels for each class’s annual average cost of energy and AE’s “H” component. The Board considers that the resulting 1999 rates will provide better market signals than would rates based on the 1995-1996 load data and 1998 pool price forecasts in the Application. This approach will, in the Board’s view, provide more appropriate levels for each class’s average annual pool price and AE’s H component.

The Board also considers AE’s 1998 forecast transmission costs based on 1995-1996 load data outdated and therefore inappropriate for use in the rates arising out of this proceeding. The Board directs AE to use the TA’s interim 1999 rates (as approved in Order U99018, dated 11 February 1999) and AE DISCO’s actual 1998 TA invoiced kWh and kW to determine updated TA Billings. The allocation to rate classes and transmission served customer classes should use actual 1998 hourly class load and NCP data to determine the kWh and kW charges. AE’s per kWh and kW charges to recover TA Billings will then reflect the 1999 TA rates which are adjusted for the effect of reallocating the 25 kV plant to transmission (See Section 2(c)). The Board also directs AE to indicate the separate charges for the TA Billings and DISCO Services components on each rate schedule.

The total Energy Supply cost and the updated TA Billings will be different from AE’s transmission and generation costs in the Application. AE is directed to deduct the resulting total updated 1998 forecast costs of Energy Supply and updated TA Billings from AE DISCO’s 1999 negotiated revenue requirement (as approved by the Board in Decision U99046) and use the resulting 1999 residual as the cost of AE’s DISCO Services in the refiling. This will keep the price signals from the Energy Supply and TA Billings cost sources accurate, while allowing AE to recover the 1999 DISCO revenue requirement negotiated with its customers. The Board directs AE to prorate the 1998 distribution cost allocations (as adjusted for the removal of the 25 kV costs from distribution) in the Application to the 1999 residual in the re-filing to determine a level for the DISCO Services components in the refiled rates. The Board further directs AE to attempt to confine the entire effect of any riders arising out of the 1999/2000 settlement agreements to the DISCO Services components of the rates. For those customers served at the transmission level the effect of any riders should be confined to the TA Billings components.

While the foregoing procedure is not ideal with respect to determining appropriate DISCO Services costs, the Board considers that more accurate unbundled Energy Supply costs and TA Billings are available and should appear as unbundled charges in customer rates at this time. The DISCO Services cost is a residual and cannot be entirely cost reflective if AE is to recover the 1999 and 2000 DISCO revenue requirement negotiated with its customers.

The Board directs AE to refile its COSS and rates on 1 September 1999. To confirm compliance to the Board's directions, the Board directs AE to supply tables setting out revenue-to-cost ratios for each rate by cost source (Energy Supply, TA Billings and DISCO Services) and to confirm that overall DISCO revenue-to-cost ratios by cost source are at 100%.

(c) Distribution Function Management of Risk

AE categorized management of the risks arising from the new structure under: market structure, purchase power costs, transmission tariffs and suspension of generator UOVs.

A change in the structure of the Alberta electricity market might necessitate changes in the distribution rates proposed to alleviate any new distribution function risk arising. Examples of significant changes were the removal of the pool price cap and changes in the accountability or obligations of generators, transmission owners, service providers or distribution companies.

Risk related to purchase power costs arises with load growth as the distribution function's energy purchases from the pool exceed its legislated hedges and the excess is subject to the volatility of the pool price. Mitigation strategies include purchase of additional hedges or flowing through pool price to customers through tariffs such as the direct access tariff and pool opportunity rate.

AE pays transmission tariffs and contracts with the TA for transmission service at each POD. In order to terminate or reduce contract demand AE would have to pay the TA for any unrecovered investment and/or provide notice of reduced load at a POD. To mitigate the associated risks, AE proposed unbundling of its customers' contracts and investment terms and explicit definition of the commitments and obligations for each service.

Most of these issues were to be dealt with in the negotiations pursuant to Exhibit 51.

AE was also concerned that suspension of a generator's UOVs might result in changes in the cost of power purchased from the pool. AE proposed a generator adjustment rider to mitigate risk from any suspension

Position of the Intervenors

IPCAA noted that such a rider had not been contemplated in the 1996 Phase I, would shift risk to customers, and amount to an automatic increase in revenue requirement. IPCAA submitted that the 1999/2000 Phase I was a more appropriate forum to consider such issues. IPCAA considered that approval of such a rider would place an obligation on AE to intervene in any GENCOs temporary suspension application to minimize costs to customers.

IPCAA requested that the Board reject the proposed generator adjustment rider on the basis that it would have the effect of shifting risks to customers.

Position of AE

AE submitted that there was no evidence on the record of these, or for that matter of other proceedings, which supported the view that AE's distribution function should bear the risk of increased cost due to the temporary suspension of obligations of the owner of a generating unit. That argument should be dismissed by the Board.

Board Findings

The Board notes that the operation of the rider AE proposes has not been fully explained in this proceeding. The Board requested that AE fully explain the working of the rider but, in its response to BR-APL-10, AE indicated only that the rider "would likely be applied on an across-the-board basis to all applicable base rates, riders and options that contain a fixed generation component."

The Board is not convinced that there is a need for an automatic adjustment rider since AE would be able to apply for an adjustment to its rates in the event a plant has its obligation temporarily suspended. The Board considers that issues relating to an appropriate adjustment level and method would be clearer at that time.

Therefore, the Board will not approve an automatic generation adjustment rider for AE in this Decision.

4. INDIVIDUAL TARIFFS

(a) Residential

(1) Price Schedule 11 – Standard Residential Service

AE is proposing this Price Schedule for use by single and separate households, throughout the territory served by the company, for single-phase electric service at secondary voltage to a single meter. This Price Schedule would not be applicable to any commercial or industrial use.

Price Schedule 11 would include the following components:

- a generation charge of 3.304/kWh for all energy consumed;
- a delivery charge of 3.664/kWh for all energy consumed, and
- a monthly customer charge of $16.10.

This replaces the rate currently in place:

- An energy charge of 7.484/kWh, and
- A monthly customer of $11.90.

AE's proposed residential rate would recover $20.2 million, or 29% of revenue, from fixed demand/customer charge and $49.3 million, or 71% of revenue, from the energy component.

AE's revised COSS indicated the revenue-to-cost ratio for the combined Price Schedule 11 and Price Schedule 18 to be 101%.

Position of the Intervenors

CCA

The CCA argued that increasing the fixed monthly charge for residential customers implied that a greater proportion of revenues from residential customers is assured of recovery. The CCA further argued that if fixed charges were maintained at $11.90 per month, there would only be a slight reduction in the percentage of the customer charge recovered. They noted that only three utilities in Canada have a customer charge in excess of $16 per month.

The CCA noted that the proposed reduction in energy charge reduces the total bill of the more energy intensive residential customers. As 62% of the customers in this rate class consume less than 700 kWh per month, the proposed rate is punitive. The higher the fixed charge component of the customer bill, the less incentive there is to conserve energy. The design of Price Schedule 11 has historically been set to recover a portion of the customer cost through the energy charge, because the rate does not contain a demand charge.

The CCA argued that AE should be indifferent as long as it recovers its revenue requirement and the rate has customer acceptance. Finally the CCA submitted that there is no need to change the fixed charge component of Price Schedule 11.

MI

The MI stated that AE's revised COSS does not reflect all of the changes proposed by the FIRM Customers' consultant or by the MI. Therefore, the revised revenue-to-cost ratio would likely be in excess of 105%. On that basis, the MI argued that the residential rate class should be entitled to a significant decrease.

Position of AE

AE stated that it is seeking to increase the customer charge components of its residential rates, to better reflect the cost causation for this rate class. Even with this higher customer charge, much of the fixed charge component of a customer's costs would be recovered through the energy charge. AE argued that, even though there may not be significant negative consequences for AE if this change is denied, the new charge is a step towards true cost causation.

Board Findings

The Board notes that AE's proposed residential rates would recover less than the costs allocated to the rate class for the fixed components (demand and customer). Conversely, the rate would recover more from the energy component than the energy costs allocated to the rate class. Had AE designed a residential rate that would have recovered costs according to the proportions of its COSS, the fixed component of the rate would have been significantly higher than the fixed component in its proposed residential rates. By recovering more costs from energy and less costs from demand/customer charges, AE designed a residential rate that has a fixed monthly charge of only $16.10 but the rate nevertheless represents a cross-subsidy of the fixed components from the energy component.

The Board recognizes the possibility that, in the future, wire ownership may be separated from energy sales, billing and metering activities. These latter functions may be carried out by an affiliate of the DISCO or by independent retailers selling directly to consumers. In either event, AE DISCO's wire cost may be largely recovered as a fixed component in the customer bill. Therefore, AE's proposed increase in the fixed charge of its residential rate might be justified as an appropriate price signal to prepare customers to accept future rates that directly reflect costs. Currently, AE DISCO still carries out the functions of buying energy from the pool, selling energy to consumers, metering, and billing customers. Therefore, as a multi-function DISCO, AE can still cross-subsidize costs within its functions as long as such cross-subsidizations result in rates that are just and reasonable.

In this particular case, the Board notes that the proposed fixed monthly charge of $16.10 represents a 34% increase over the current residential rate's monthly charge of $11.90. Although this is a large increase to implement all at once, given the likelihood that future industry restructuring will lead to higher fixed charges, the Board considers the increase to be appropriate at this time.

The Board, therefore, approves AE's proposed monthly fixed charge of $16.10.

In Section 3(a), the Board directed AE to design rates so that

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

(2) Price Schedule 18 – Lloydminster Residential Service

Price Schedule 18, Lloydminster Residential Service, was a special rate developed to ensure price competitiveness with residential customers in Lloydminster served by SaskPower Corporation (SaskPower).

AE proposed withdrawal of Price Schedule 18, Lloydminster Residential Service and transfer of all residential customers to Price Schedule 11, Standard Residential Service. The price differential between SaskPower's applicable residential rate for Lloydminster and the proposed Price Schedule 11 has narrowed. AE considered that the differential between Rates 11 and 18 was acceptable.

Position of the Intervenors

None of the intervenors took issue with the proposal to withdraw Price Schedule 18.

Board Findings

The Board accepts AE's proposal to withdraw Price Schedule 18 – Lloydminster Residential Service and to offer service to Lloydminster residents under Price Schedule 11. Given the narrowing differential between Rates 18 and 11, the Board considers that Lloydminster residential customers should pay the same rate as other AE residential customers.

For further details on other issues around AE residential rates see Section 4(a)(1), Price Schedule 11.

(b) Farm and REA

(1) Price Schedule 51 – REA Farm Service

This rate is for use by bona-fide farming operations served by an REA. The intent of the price schedule is unchanged.

AE proposed a customer charge and a demand charge in place of the monthly O&M charge on the previous rate schedule, as follows:

- the energy charge is reduced from 5.26¢/kWh to 4.3¢/kWh for all energy;
- the Customer charge is reduced from $11.05/service to $9.00/service, for REA farms in O&M Pool; and
- the demand charge is increased from $1.98/kVA to $2.45/kVA (for farms outside of O&M Pool, the demand charge is $0.50/kVA).

Proposed Conditions: If AE determines that a 25 kVA breakered service may be overloaded, AE may require replacement of the breaker with a demand meter and modification of service facilities in accordance with the T&C.

For non-breakered REA farm services of 25 kVA or greater, the kVA capacity for billing purposes is the greater of: (i) the highest metered kVA demand during the billing period; (ii) the estimated demand; or (iii) 25 kVA.

Position of AIPA/AAMDC/REA

AIPA/AAMDC/REA recommended that REA rates be established at 100% revenue-to-cost ratio to ensure competitiveness. They noted that if REAs are over-charged, AE can make REAs appear less competitive relative to company farm customers.

AIPA/AAMDC/REA argued that the revenue-to-cost ratio rises to 116.1% in Mr. Marcus' updated cost study. They also noted that Exhibit 95 indicated that the distribution component of AE's proposed REA farm rates were 140% of costs after the changes in 25 kV line cost allocation. The AIPA/AAMDC/REA proposed a rate design that would have 100% revenue-to-cost ratio for REA farm customers both for generation and transmission and for distribution service. The rate would have generation and transmission components identical to those for Company Farm customers.

The distribution rates proposed by AIPA/AAMDC/REA were $7.15/customer/month with demand charges of $1.30/kVA.

Board Findings

The Board considers that AIPA/AAMDC/REA's concerns are addressed, since in Section 3(a) the Board directed AE to design rates so that:

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

The Board considers that those findings address concerns regarding the level of the distribution related charges in AE's proposed REA rates.

(2) Price Schedule 56 – Farm Service

The Farm Service rate is designed for all bona-fide farming customers served directly by AE. The intent of the price schedule is unchanged.

AE proposed a customer charge and a demand charge in place of the monthly O&M and capital recovery charges on the previous rate schedule. To ensure correct billing and prevent overload damage to the company's facilities, a provision has been added to the price schedule to allow AE to install demand metering on 25 kVA breakered services.

The proposed price schedule is as follows:

- the energy charge is reduced from 5.26¢/kWh to 4.30¢/kWh for all energy,
- the customer charge is reduced from $18.62/service to $17.08/service, and
- the demand charge is increased from $3.85/kVA to $4.40/kVA.

The refiled revenue-to-cost ratio for this Price Schedule was approximately 76%.

Position of AE

AE defended the proposed design of this rate by stating that in this instance, circumstances warrant a departure from trying to achieve a 100% revenue-to-cost ratio. The increase in gross distribution assets in its rural service area has largely been due to increases in industrial and oilfield sites, yet farm services were allocated a portion of these costs. Fairness dictates that an "offset" be included in the rates to this customer class to reflect this anomaly. Company farm customers fall into the rural category with virtually all of the oilfield and industrial customers.

AE stated that it was examining the use of location codes to achieve a more precise allocation of assets between rate classes and was prepared to adopt the use of location or customer class usage codes on a go forward basis. It further stated that although these codes may be accurate at the beginning of the useful life of any asset, over time the usefulness of those codes would likely be eroded. Some sort of allocation method will have to be adopted to accurately reflect the customer classes making use of the assets. Attempts to use location codes for existing plant would render inaccurate results.

AE requested that the Board approve current allocation of asset splits, with the understanding that AE will attempt greater precision in the future.

Position of the Intervenors

TransCanada

TransCanada argued that AE has not explained why its proposed rates provide a revenue cost ratio of 66% (which was later revised to 76%), when the revenue-to-cost ratio for this rate previously was 82%.[28] TransCanada further argued that as generation and transmission components are a significant part of the cost of service and the change was not attributed to them, it believes that AE was more concerned with being competitive with REA's. TransCanada submitted that AE should increase Farm revenues above 82% and apportion the revenues to classes with revenue to cost above 100%.

AIPA/AAMDC/REA

The AIPA/AAMDC/REA recommended the Company Farm Rate 56 be established using the revenue proposed by AE. It argued that AE's cost of service data provided no reliability given the rural growth pattern in recent years. However, it accepted the overall rate proposed by AE as being within the range of reasonableness.

Nevertheless, AIPA/AAMDC/REA proposed rates somewhat different from AE's. Using energy based allocation of generation costs prepared by their consultant, their recommended generation rates were 0.5¢/kWh below AE's. Transmission rates were 0.07¢/kWh higher than AE's. The remaining 0.43¢/kWh that AE would collect as generation costs were proposed to be collected as distribution costs in their rate design, raising the charge per kVA from $3.90 to $4.72.

AIPA/AAMDC/REA noted that AE admitted that its COSS overstated the cost to serve company farm customers. AIPA/AAMDC/REA stated that other parties were advocating significant increases in farm rates based on this erroneous study. AIPA/AAMDC/REA argued that the best way to rectify this situation was to try to resurrect the property record systems of AE, and if that could not be done, then company farm customers' rates should be benchmarked to the property costs and associated O&M costs per customer for REA farms. The property records for REAs do not suffer from the problems of misallocation of distribution assets between rate classes. AE

[28] Decision E95102

should be directed to bring forward property records into its next GRA. Otherwise, the costs of company farm customers should be explicitly based on a benchmark to REA costs.

IPPSA/SPPA

IPPSA/SPPA submitted that it is possible that some of the cost growth for distribution assets was related to replacing and upgrade of obsolete assets that serve farm customers. IPPSA/SPPA agreed with AE that direct assignment of specific assets is extremely complex. IPPSA/SPPA considered it a common practice for utilities and regulators to adopt investment policies and customer cost or contribution policies to address the problems in this rate class.

IPPSA/SPPA noted that AE can not accurately allocate cost to its Rate 56 customers and to compensate for this inability, set the revenue-to-cost ratio for Rate 56 at 68%. IPPSA/SPPA noted that as a result, the rate would see an average reduction of 4.9%.

AE has tried to justify the costs allocated to Rate 56 by calculating unit capital costs spent on REA assets and applying them to the company farm load (Tr. p.344, ll.6-26). The result of this study was a Rate 56 revenue-to-cost ratio of about 93 to 94%, which presumably was acceptable to AE. AE also claimed that the Rate 56 class has had “little to no load growth” (Tr. p.343, ll.21-22) while BR-APL.14 indicated that the Rate 56 class has had a simple annual load growth of 2.0%.

IPPSA/SPPA submitted that the appropriateness of AE's solution and the assumptions made in setting the level of Rate 56 is are not clear. Based on Exhibit 36, the average decrease is 1.0% (col. G, line 15, including Rider J). It seems inappropriate to give Rate 56 an average 4.9% rate decrease, almost five times the company average, when based on the evidence the “derived” revenue-to-cost ratio is 93 to 94%. In the absence of any solid evidence, IPPSA/SPPA proposed that Rate 56 should be given a rate decrease equal to that of AE DISCO in aggregate. The precedent for this is Rate 31 A, where in the absence of better data, Rate 31 A was given the average rate decrease.

With subsequent revisions to AE's application, the resulting average reduction may change and the final approved average rate reduction should be used.

The alleged cost increases caused by load growth in the oilfield sector have been deemed to be acceptable by the Board, and shared with existing ratepayers in accordance with existing investment policy. IPPSA/SPPA expressed the view that a quantitative cost allocation study is preferable to vague qualitative assertions. IPPSA/SPPA submitted that there was no need for special considerations for Price Schedule 56 so the rate class should not be assigned a rate decrease greater than system average. The rate decrease should be the average decrease for the AE DISCO.

TransCanada

TransCanada stated that it is not surprising that AE is forced to propose a reduction in the farm revenue-to-cost ratio to address the problem in the AE COSS. TransCanada did not acknowledge the magnitude of the disproportionate industrial/oilfield growth that has occurred since the last Phase II proceeding.

TransCanada noted that in setting the POR, AE expressed a reluctance to deviate from the optimal 100% revenue/cost ratio. However, in this instance AE has defended its decision to maintain company farm class revenue cost ratios well below unity. Where customer classes had revenue-to-cost ratios over or below unity for a period of time, TransCanada suggested that AE be directed to balance revenue-to-cost ratios for that class proportionately below or above unity for a reciprocal period of time. Alternatively, AE should be directed to set revenue-to-cost ratios equal to 100% for all rate classes where it is possible to do so without violating other rate design principles.

Board Findings

In Section 3(a), the Board directed AE to design rates so that:

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

However, the Board accepts that distribution capital costs caused by rapid growth in the oilfield sector have been unfairly allocated to farm customers. Moreover, the Board considers that IPPSA/SPPA's method of adjustment is fairer than AE's. On that basis, the Board directs AE to refile company farm rates that reflect, in their DISCO Services component, the average change in the DISCO Services component of AE rates.

The Board notes the concerns of the AAMDC/REA with respect to the property record system of AE. The Board considers that the lack of proper records are a deterrent to being able to properly establish fair Farm Service and REA rates. Therefore, the Board directs AE to confer with the REAs to attempt to establish an appropriate level for the distribution wire and metering costs for company farm rates based on a benchmark of REA farm costs, prior to the Preliminary Distribution Tariff (PDT) hearing.

(c) Small General Service

(1) Price Schedule 21 – Standard Small General Service

Price Schedule 21 is for all customers throughout AE's territory served with single or three phase electric service at secondary voltage. The Price Schedule is not available for any service in excess of 500 kW.

The intent and application of this price schedule is unchanged from previous Rate Schedule 21 B, demand and energy pricing option.

The proposed Price Schedule would consist of:

- Demand Charge of $7.00/kW of billing demand,
- Energy Charge of:
  - 5.044/kWh for first 200 kWh per kW of demand
  - 3.354/kWh for all energy in excess of 200 kWh

The previous rate was comprised of:

- Demand charge of $4.05/kW of billing demand,
- Energy charge of:
  - 7.534/kWh for first 200 kWh per kW of demand
  - 3.384/kWh for all energy in excess of 200 kWh

The minimum monthly bill is the demand charge, but not less than $35.00. An 85% demand billing ratchet applies to demand in excess of 150 kW.

Position of AE

Proposed Price Schedule 21 provides for gradual transition to the fully ratcheted Large General Service Price Schedule 31. As in Price Schedule 31, the charges have been weighted more heavily towards demand in order to better reflect cost causation.

Position of the Intervenors

The MI submitted that the proposed Price Schedule 21 has a revenue-to-cost ratio of 109%. Therefore, the MI argued that this price schedule should receive an above-average decrease.

Board Findings

The Board notes that no specific issues were raised with respect to the proposed rate, except for concerns regarding its overall revenue-to-cost ratio.

In Section 3(a), the Board directed AE to design rates so that:

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

(2) Price Schedule 22 – Standard Small General Service-Energy Only Option

Price Schedule 22 is available to all customers throughout AE's territory served with single or three phase electric service at secondary voltage. Price Schedule 22 is not available for any service in excess of 500 kW.

The intent and application of this price schedule is unchanged from previous Rate Schedule 21 A, energy only option.

The proposed Price Schedule 22 would consist of

- Energy Charge of
  - 24.0¢/kWh for first 50 kWh per kW of demand
  - 6.0¢/kWh for all energy in excess of 50 kWh
  - The minimum annual charge is $420.00

The previous rate was

- Energy Charge of
  - 16.0¢/kWh for first 50 kWh per kW of demand
  - 8.0¢/kWh for all energy in excess of 50 kWh
  - The minimum annual charge was $243.00

This price schedule provides small general service customers with an option to avoid demand charges.

Board Findings

The Board notes that no specific issues were raised with respect to the proposed rate, except for concerns regarding its overall revenue-to-cost ratio.

The Board expects rates to reflect the costs incurred to serve the customers. The Board also recognizes that some customers may want the option to pay entirely variable charges instead of fixed demand or customer charges. If AE is willing to provide such a rate and there is no evidence of cross-subsidization between rate classes, the Board considers it appropriate to approve such a rate.

In Section 3(a), the Board directed AE to design rates so that:

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

Therefore, AE should design the energy charge(s) to collect all of the TA Billings, Energy Supply and DISCO Service costs to be recovered from Rate 22 customers.

(3) Price Schedule 25 – Irrigation Pumping Service

Price Schedule 25 is applicable to separately metered irrigation pumping services, less than 150 kW, for service between 1 April and 31 October.

The proposed Price Schedule would consist of:

- Seasonal service charge of $29.20/kW of billing demand,
- Energy charge of 3.98¢/kWh, and
- A minimum seasonal service charge of $146.00.

This replaces the rate currently in place comprised of:

- Seasonal service charge of $27.60/kW of billing demand,
- Energy charge of 3.70¢/kWh, and
- A minimum seasonal service charge of $138.00.

The intent and application of this Price Schedule is unchanged. The service charge and a minimum seasonal charge has been increased to bring the revenue-to-cost ratio for this schedule closer to 100%.

Position of the Intervenors

The AIPA/AAMDC/REA argued that, as Price Schedule 25 is a rural service, the same disproportionate allocation of distribution assets would occur for this servi1ce as for Farm rate Price Schedule 56. AE acknowledged that this is likely.

With respect to transmission cost allocation, the AIPA/AAMDC/REA supported the general approach of the FIRM Customers for GIS allocations in exhibit 95, schedule 4, as a first step in adjusting the AE COSS. The AIPA/AAMDC/REA stated that, however, the ratcheted demand GIS allocation provides a full annual cost allocation to irrigation service although the service is only connected to the system for the summer season. This would tend to overstate the allocated costs to irrigation customers and is inconsistent with AE's approach to other partial services, such as standby service.

The AIPA/AAMDC/REA further noted that AE's application of its design criterion does not provide a comparison to the natural gas alternative or neighboring utilities' irrigation rates. The AIPA/AAMDC/REA recommended that the irrigation revenue-to-cost ratio be no higher than farm rate Price Schedule 56, and that the AE irrigation pumping rate be set no higher than the similar rate by TransAlta.

Board Findings

The Board notes the position taken by AIPA/AAMDC/REA that the irrigation revenue-to-cost ratio be no higher than Farm Price Schedule 56, and that AE's irrigation pumping rate be set no higher than the similar rate by TransAlta. The Board notes that the revenue-to-cost ratio proposed for Price Schedule 25 is 81% (BR.APL-7) and has increased from 68% (Decision E95102). The revenue-to-cost ratio at the existing rates would be 73%. The Board does not accept that TransAlta's revenue-to-cost ratios should influence AE's rate levels.

The Board concurs with the design criteria and methodology used by AE to ensure that an appropriate share of capital costs be borne by all customers, including irrigation customers. The Board is of the view that since irrigation customers use existing distribution infrastructure they should pay appropriate distribution capital and O&M costs.

The Board accepts that rapid oilfield and rural industrial growth would likely cause the same disproportionate allocation of distribution assets to this service as for Farm Price Schedule 56. However, assuming 100% recovery of transmission and generation costs, the Rate 25 revenue-to-cost ratio of 80% implies that 66% of the distribution costs allocated to Rate 25 customers would be recovered from them.[29] This may be compared to only 44% recovery of distribution costs

[29] On Schedule 3.B-1 for Rate 25 Total Costs of $253,000 only 80% or $202,000 are to be recovered. Assuming 100% recovery of generation and transmission costs, implies 66% or $100,000 of $151,000 recovery of distribution costs.

allocated to Rate 56.[30] AE should account for any such difference in the refiled Rate 25 and Rate 56.

In Section 3(a), the Board directed AE to design rates so that:

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

(4) Price Schedule 26 – Irrigation Pumping Service (REA Farm Services)

Price Schedule 26 applies to irrigation pumping services for REA farm customers. It is available throughout the service territory of AE between April 1 and October 31 for seasonal irrigation pumping loads of REA customers and individual cooperative and colony farms with their own distribution systems. It is not applicable for any service in excess of 150 kW.

Proposed Rate Level		**Previous Rate Level**	
Customers in the REA O&M pool			
Energy Charge:	3.98¢/kWh	Energy Charge:	3.70¢/kWh
Seasonal Service Charge:	$11.55/kW	Seasonal Service Charge:	$11.20/kW
Minimum Season Charge	$57.75	Minimum Season Charge	$56.00
Customers outside the REA O&M pool			
Energy Charge:	3.98¢/kWh	Energy Charge:	3.70¢/kWh
Seasonal Service Charge:	$3.70/kW Plus REA specific charges	Seasonal Service Charge:	
Minimum Season Charge	$18.50	Minimum Season Charge	$56.00

[30] On Schedule 3.B-1 for Rate 56 Total Costs of $32,230,000 only 66% or $202,000 are to be recovered. Assuming 100% recovery of generation and transmission costs, implies 44% or $8,579,000 of $19,378,000 recovery of distribution costs.

Proposed Conditions: Billing demand may be estimated or measured and will be the greater of the following: (i) the highest metered demand during the billing period; (ii) the estimated demand; (iii) the contract demand and (iv) 5 kW.

For non demand metered services, demand shall be estimated based on equipment named plate ratings as follows: (i) Billing Demand = kW Name plate Rating and (ii) Billing Demand = Name plate hp x 0.746

When a customer's power factor is found to be less than 90%, the company may require the customer to install corrective equipment

One half of the Season Minimum Charge will be billed before service connection in the spring but no later than July 1; the balance of the charges will be billed following service disconnection in the fall.

In the event the service remains idle for two consecutive seasons, the company may remove its facilities, unless the customer pays the minimum charge for the upcoming season prior to December 31, of the preceding year.

The following price option may apply: Option H, Service for Non-standard Transformation and Metering Configurations

Board Findings

The Board notes that no specific issues were raised with respect to the proposed rate, except for concerns regarding its overall revenue-to-cost ratio.

In Section 3(a), the Board directed AE to design rates so that:

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

(d) Lighting

(1) Price Schedule 61 – Street Lighting Service

Price Schedule 61 is applicable for street and highway lighting, but is not available for private lighting. The intent and application of Price Schedule 61 is unchanged. The price schedule retains the two existing options, and AE proposed a new option for customer owned lighting. The charges have been increased overall in order to bring the revenue-to-cost ratio closer to unity for this rate class.

Option 61(A)

AE proposed to reinstate Part 1 of Price Schedule 61, and rename this as Investment Option (61A). AE applied for one customer charge of $6.40 per fixture and one demand charge of 3.60¢/watt of billing demand.

Option 61(B)

AE proposed to retain Part 2 of Price Schedule 61 where the customer pays the full cost of installation, and to rename this part as No Investment Option (61B). For Decorative Lamps, the customer charge was $4.50 per fixture and the demand charge was 3.60¢/watt of billing demand. For all Other Lamps, the customer charge was $3.30 per fixture, with a demand charge of 3.60¢/watt of billing demand.

Option 61(C)

AE proposed a new option for lighting supplied, installed, owned and maintained by the customer, the Distribution Investment Option (61C). This option included installation and maintenance by AE of distribution facilities up to, but not including light fixtures. It was intended to allow customers the freedom to choose any type of light fixture from any supplier, while AE would still provide and maintain the associated distribution facilities. The charges for this option consisted of a customer charge of $4.00 per fixture and a demand charge of 3.60¢/watt of billing demand.

Position of the Intervenors

The MI noted that AE’s revenue-to-cost ratio for Price Schedule 61 was 81%, but based on the analysis conducted by Mr. Marcus, the revenue-to-cost ratio was 132%. The MI noted that AE has proposed a 7.1% increase in this rate, and submitted that a significant decrease in this rate is in order.

Board Findings

The design and the intent of this rate was not challenged by any of the participants. The Board notes the MI’s suggestion that the actual revenue-to-cost ratio was considerably higher than the 81% stated by AE.

In Section 3(a), the Board directed AE to design rates so that:

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

(2) Price Schedule 63 – Private Lighting Service

This Price Schedule is applicable for private off street and summer village sentinel lighting. Five price options were proposed:

Price Schedule 63A—Investment Option

For private sentinel lighting fixtures installed by AE

Proposed Rate Level		**Previous Rate Level**	
Customer Charge:	\$5.22/fixture	Customer Charge:	\$5.80/fixture
Demand Charge:	3.60¢/watt	Demand Charge:	2.95¢/watt

Price Schedule 63B—No Investment Option

For customers who pay the full cost of lighting installation

Proposed Rate Level		**Previous Rate Level**	
Customer Charge:	\$2.77/fixture	Customer Charge:	\$3.17/fixture
Demand Charge:	3.60¢/watt	Demand Charge:	1.90¢/watt

Proposed Conditions: Available for new installations only. For standard lighting fixtures installed by AE. Includes maintenance only.

Price Schedule 63C—Distribution Investment Option

For lighting supplied, installed, owned, and maintained by the customer. This option includes installation and maintenance of distribution facilities up to, but not including, light fixtures

Proposed Rate Level		Previous Rate Level	
Customer Charge:	$3.40/fixture	Not applicable	
Demand Charge	3.60 ¢/watt		

Price Schedule 63D—Summer Village Option

For seasonal use only (six-month minimum period) by Municipal Corporations in summer villages

Proposed Rate Level		Previous Rate Level	
Customer Charge:	$10.70/fixture	Customer Charge:	$10.23/fixture
Demand Charge:	2.60¢/watt	Demand Charge:	2.95¢/watt

This option remains closed with no change to its intent or application.

Price Schedule 63E—Metering Option

For service through the customer's meter

Proposed Rate Level		Previous Rate Level	
Customer Charge:	$4.39/fixture	Customer Charge:	$5.91/fixture
Demand Charge:	3.60¢/watt	Demand Charge:	1.90¢/watt

This option remains closed with no change to its intent or application.

Board Findings

Neither the design nor the intent of these rates was challenged by any of the participants.

In Section 3(a), the Board directed AE to design rates so that:

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customer; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

(e) Large General Service / Industrial

(1) Price Schedule 31 – Large General Service / Industrial

Price Schedule 31 is a rate intended for larger commercial enterprises, including large oilfield customers.

Minimum billing demand for the rate is 50 kW. Minimum billing demand for oilfield customers was to be increased to 75 kW. Charges on this Price Schedule are collected through energy and demand charges.

Current Rate Level

Demand Charge

1st block 500 kW @ $16.88/kW
2nd block 1500 kW @ $15.11/kW
All consumption over 2000 kW @ $11.79/kW

Energy Charge

1st block 400 kWh per kilowatt of demand @ $0.0193
All consumption over 400 kWh per kilowatt of demand @ $0.015

Proposed Rate Level

	Demand Charge First 500 kW of billing demand (per kW)	All billing demand over 500 kW (per kW)	Energy Charge First 400 kWh per kW of billing demand (per kWh)	All energy in excess of 400 kWh/kW of billing demand (per kWh)
Generation	$1.41	$1.41	2.424	2.304
Transmission	$1.77	$1.77	0.584	0.704
Distribution	$1.67	$2.40	-	-
Service	$1.73	-	-	-
Total Price	$7.58	$5.58	3.004	3.004

(A) Rate Design and Overall Cost Levels

Position of AE

The proposed Price Schedule 31 continues to reflect the AIS average incremental energy costs as previously approved. The price for energy is set in accordance with the 1998 pool price forecasts used in the 1998 Negotiated Settlement.

Price Schedule 31 now includes explicit charges for generation, transmission, and distribution services. The proposed rate provides a realistic, incremental energy price signal, resulting in the recovery of a much greater proportion of the costs via the energy charge rather than the demand charges when compared to historical rates. The increase to the energy charges results in a decrease to the demand charges, so forecast revenues continue to match total costs allocated to the rate.

The charge levels have been adjusted to more appropriately collect costs from customers of various sizes. This was done by analyzing the costs associated with various sizes of customers within the class, and redistributing the weighting of the charges to more appropriately collect costs where they are incurred. The revenue-to-cost ratio for Price Schedule 31 in aggregate was targeted to be near 100%.

The cost-reflective distribution charge allows AE to free those customers who do not utilize distribution facilities from paying average distribution costs.

A time of use rate is not proposed, as experience shows the customers do not greatly change their consumption patterns with changing prices. Customers who opt for time differentiated rates can use the proposed DAT.

Position of the Intervenors

In direct evidence, the ACC noted that AE proposed to increase the revenue-to-cost ratio of Price Schedule 31 from the historical level of just under 100% to 104%. The ACC considered it neither necessary nor appropriate to go beyond the 100% revenue-to-cost level. It recommend that AE design rates to produce a revenue-to-cost ratio of 100% for each function separately.

IPPSA/SPPA agreed with the ACC that the revenue-to-cost ratio should be 100% to the maximum extent practical. IPPSA/SPPA noted that Price Schedule 31 serves as the customer alternative for direct access, oilfield, and standby customers.

IPPSA/SPPA argued that the generation charge should be segregated into market generation, RP, and UOV components. RP and UOV components should be recovered in a demand charge based on a 3W/9NW demand allocation. Further, generation charges should be a time of use rate like that proposed by TransAlta. Finally, IPPSA/SPPA suggested that the energy transmission charges should be time of use rates. It argued that the proposal from AE penalized high load factor customers.

IPCAA provided its own proposal for Price Schedule 31, in direct evidence from the Drazen Consulting Group, Inc. (DCGI). It noted that Price Schedule 31, as proposed by AE, shifts charges from demand to energy. IPCAA argued that this ignores that AE's energy purchases are almost totally hedged. IPCAA expressed concern that customers are not able to get "realistic" pool prices because of a concentration of market power in the Alberta electrical generation market.

IPCAA responded to criticism by the MI and PICA. IPCAA reiterated that it was inappropriate for the DISCO to pass on a flow-through of the Pool price to customers for every kWh, when the price signal to the DISCO is based on embedded cost for nearly all of its load. IPCAA was also concerned with how closely the Pool price forecast from the 1998 Negotiated Settlement would approximate the incremental energy costs in 1999.

The FIRM Customers, PICA, and the MI were concerned with the IPCAA proposal. The FIRM Customers argued that the IPCAA rate design would constitute a move away from the competitive market prices expected to occur in 2001 and would make any changes to DISCO rates at that time even more difficult to implement.

PICA argued that revenue-to-cost ratios for small and midsize customers within Price Schedule 31 should be brought closer to unity. They also agreed with Mr. Knecht that transmission voltage customers should pay full GIS demand charge in the transmission component of the rate, while distribution level customers should be credited for diversity.

Board Findings

In Section 3(a), the Board directed AE to design rates so that

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%.
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers.
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

The revenue-to-cost ratio for the DISCO Services charges for this rate and Price Schedule 41 should be set above the 100% revenue-to-cost level to the extent required to adequately compensate customers on Price Schedule 56 for the unfair allocation of distribution assets to their rate class caused by the rapid growth in the rural oilfield sector (see Section4(b)(2), Price Schedule 56).

(B) Totalization of Multiple Demand Meter Readings

Demand charges are typically payable based on a customer's peak monthly demands over an extended period of time, usually one year. This is called a ratcheted demand. A customer with two or more demand-metered services must pay based on the peak demands on each service, even if those peak demands are set at different times. However, customers with multiple demand-metered services downstream of a single of POD only cause transmission and distribution costs to be incurred by the DISCO based on the combined peak demands of all of those services. Totalization would allow these customers to be charged based on that combined peak demand.

Position of the Intervenors

IPPSA/SPPA

IPPSA/SPPA proposed that meter totalization should be allowed on a case-by-case basis and proposed a Totalization Rate Rider (TRR) to this effect. It argued that this would result in a win-win situation where costs are reduced for the customers and for AE. It also argued that although there may be difficulties in isolating customers for totalization, there are technical means to accomplish this now.

IPPSA/SPPA stated that the goal of totalization is to reduce the coincident peak demand, which is the same goal as Option T, the DAT, and the Pool Opportunity Rate. It argued that its proposal would lead to production optimization, increased life of oil and gas reserves, and environmental and economic benefits of flare gas generation. IPPSA/SPPA argued that its case-by-case TRR would be similar to AE's existing buy-down policy and the determination of costs related to "system" versus "customer."

In reply to the AE argument that a TRR would shift costs to other customers, IPPSA/SPPA stated that its proposed TRR would be calculated such that revenues prior to totalization will equal revenues after.

IPPSA/SPPA argued that customers with multiple service points should be allowed to optimize their use of the system. Currently, a customer with multiple sites served from the same POD can reduce load at one site and increase load at another site then receive a double charge through ratchets for generation and transmission service even though AE's upstream costs are unchanged.

TransCanada

TransCanada agreed with IPPSA/SPPA, that calculating a TRR on a case-by-case basis, will ensure that all customers are kept whole as a result of this process. The proposed Rider would only reduce costs to a customer if the customer made changes to its operation that resulted in an upstream cost reduction for AE. TransCanada stated that the evidence does not indicate that totalization undermines rate class averaging as AE alleged. TransCanada submitted that the Board should approve the TRR, as outlined by IPPSA/SPPA.

Position of AE

AE opposed a TRR. The proposed rates were designed assuming non-totalized loads. Allowing totalization would require the rates to be redesigned. Demand charges for oilfield customers were intended to recover distribution costs for remote services.

AE argued that by totalizing loads, the billing demand would no longer be representative of the sum of individual distribution requirements. Totalization would arguably result in inequities since certain customers have multiple service points while others do not.

With regards to the specific proposal by IPPSA/SPPA that individual TRRs be calculated based on customer costs, AE argued that it is impractical to design customer specific rates. All customers whose incremental costs are less than the average would request an incremental rate, all others would prefer the average approach.

Board Findings

The Board considers approval of IPPSA/SPPA's proposed TRR would give oilfield customers, who currently may have several accounts/meters servicing their oilfield facilities, the right to approach AE and negotiate a rate resulting in a single account/meter servicing collective oilfield facilities. The Board notes that under the proposal a single account/meter would translate into oilfield customers paying less demand/fixed transmission and distribution charges but they would pay an additional negotiated rate-rider to AE such that the utility would recover the same fixed/demand charges as without totalization.

Such a TRR might encourage oilfield customers to modify their pattern of consumption of electric power towards a more efficient use. At the same time, the TRR would keep the utility whole, as the rider would compensate the utility for the decreased demand/fixed charges due to totalization.

The Board, however, is concerned that approval of the proposed TRR, which requires case-by-case negotiation between the utility and oilfield customer, may impose an administrative burden on AE, because of the number of oilfield accounts that may be totalized. Since the Board has accepted generation charges which are purely energy based, generation costs are effectively totalized and any saving arising from totalization would be from TA Billings and DISCO Services components only.

Accordingly, the Board will not direct AE to provide for the totalization of meters and a TRR as requested by IPPSA/SPPA.

(C) Minimum 75 kW Demand for Oilfield Customers.

Position of AE

Price Schedule 31 is proposed to be unavailable to oil and gas production loads less than 75 kW. Price Schedule 41 is designed for loads less than 75 kW to recognize their higher distribution costs. All oil and gas customers should be on Price Schedule 41, however the limit is set at 75 kW to provide for a gradual migration to Price Schedule 41. It would not be appropriate to shift all oilfield customers currently on Price Schedule 31 onto Price Schedule 41 since the COSS was based on the current customers by rate class.

Position of the Intervenors

IPPSA/SPPA proposed that the Price Schedule 31 demand minimum of 75 kW should apply to all accounts, not just oilfield accounts, if the minimum should be changed. However, it preferred the minimum be left at 50 kW. Existing Price Schedule 31 accounts of less than 75 kW should not be required to move to Price Schedule 41.

TransCanada supported IPPSA/SPPA's recommendation that the Board leave the Rate 31 minimum at 50 kW. If the Board should allow AE to increase the Rate 31 minimum to 75 kW for all customers, TransCanada requested that the Board direct AE to quantify the impact of revenue migration in its rate design.

Board Findings

In establishing rate classes, the goal must be to group customers with similar service cost characteristics to the greatest extent practical. It will almost always be the case that some variation in cost of service will occur amongst customers in a rate class.

In this instance, AE has proposed to change the conditions of service for one subgroup, oilfield customers, within the rate class. While these customers may be more remote than the average in the rate class and require more expensive distribution facilities to serve them, the Board is not persuaded that changing one condition of the Price Schedule is a fair method to address any cost misallocation. In Section 4(f)(1)(A) the Board directed AE to provide a study which recommends an appropriate rate class or classes for oilfield customers based on the costs to serve them. Therefore, the Board does not approve increasing the minimum demand level for Price Schedule 31 to 75 kW for oilfield customers at this time.

(D) Meter Reading Frequency

Position of the Intervenors

IPPSA/SPPA

IPPSA/SPPA proposed that AE should read oilfield meters every two to three months as this will reduce meter reading costs.

Position of AE

AE argued that a proposal on frequency of meter reading was micro-management of the utilities operation and that this request should be denied.

Board Findings

The Board is not persuaded that there is sufficient reason to require a change in AE's policy with respect to meter reading frequency.

(2) Price Schedule 32 – Standby

Price Schedule 32 is a charge for standby service used by customers with on-site generation and to provide for a default price schedule where a customer otherwise on Price Schedule 33 has contracted for insufficient capacity and exceeds the contracted amount. The Price Schedule under consideration was the third version of this rate to be submitted by AE during the proceeding.

The proposed rate included separate demand charges for transmission, distribution, and service costs. Energy charges were included for generation costs and transmission costs incurred from GSS and GIS charges of the TA. Energy charges for generation were set as the hourly pool price.

The following definitions were used in setting rates for this Price Schedule:

- Base Demand: the demand level supplied on another Price schedule (i.e. Price Schedule 31 or 39)
- Standby Capacity: the difference between the customer's forecast maximum demand and the Base Demand
- Distribution Contract Demand: the contract demand level specified in the initial customer contract, this demand level is used to determine Company capital contributions for distribution plant.

Proposed Rate Level

Demand Charges

Transmission: A monthly demand charge of $2.20/kW for the greater of
(1) the nominated Standby Capacity; and
(2) the highest metered demands minus the Base Demand for the twelve month period including and ending with the billing period

Distribution: A monthly distribution charge of \$2.67/kW for the first 500 kW of and \$2.40/kW for the remaining kW for the greatest of

(1) the nominated Standby Capacity;
(2) the highest metered demands minus the Base Demand for the twelvemonth period including and ending with the billing period; and
(3) the Distribution Contract Demand.

Service: A monthly service charge of \$1.73/kW for the first 500 kW for the greatest of

(1) the nominated Standby Capacity;
(2) the highest metered demands minus the Base Demand for the twelve month period including and ending with the billing period; and
(3) the Distribution Contract Demand.

The Base Demand is exempt from the otherwise applicable distribution and service demand charges on the associated Price Schedule (i.e. Price Schedule 31 or 39), since these charges will be covered within the distribution and service demand charges for Price Schedule 32.

Energy		
Generation:	All kWh above the Base Demand level are charged the Hourly Pool Price.	
Transmission:	(1)	All On-Peak kWh above the Base Demand level are charged at 0.181¢/kWh.
	(2)	On-Peak energy above the Base Demand level and in excess of 41 kWh per kW of Transmission Billing Demand is charged at 1.06¢/kWh.
	(3)	All Off-Peak kWh above the Base Demand level are charged at 0.123¢/kWh.

Additional Charges and Penalties

Annual Load Factor Penalty: If the average demand consumed on Price Schedule 32 (kWh/8760 hr) over the 12 month period, including and ending with the billing period, divided by the maximum billing demand as determined for the Transmission Demand Charge exceeds 15%, then the Generation Demand Charge on Price Schedule 39 multiplied by the billing demand will apply during the last billing period of the 12 month period and will continue until the Annual Load Factor is less than or equal to 15%.

Noncompliance with Curtailment Directive: Load supplied under this Price Schedule is curtailable only when there is a generation supply contingency. The first instance of noncompliance with such a curtailment directive in a 12 month period will result in a penalty charge equal to six times the Reservation Demand Charge on Price Schedule 39 multiplied by the billing demand. Each subsequent instance of noncompliance in a 12 month period will result in a penalty charge equal to twelve times the Reservation Demand Charge on Price Schedule 39 multiplied by the billing demand.

Position of AE

The proposed rate replaces all other existing standby options. AE considered that standby is a higher value service that requires firm transmission to be planned and available. It is arguable that standby customers expect a level of reliability at least as high as firm load. Price Schedule 32 was designed for a small group of customers who have unpredictable loads. AE has four customers on this rate, all of whom are directly connected to the transmission system.

AE acknowledged that the proposed rate may not be adequate for distribution-connected customers, as there was no diversity considered in the transmission charge. Its proposal would be revised to reflect this. Incremental cost allocation was used in this rate design.

AE submitted that an unhedged energy charge is appropriate for this type of use. The proposed rate recognizes that the outage of a large generator could affect the occurrence of a high pool price. In particular, AE was concerned that this rate could be used as a hedge for a large, regulated generating station in its service territory. It argued that a revenue-to-cost ratio based on an embedded COSS is not meaningful in the context of this standby rate and that an embedded cost rate would not recognize the actual incremental cost incurred at a POD when standby power is used. AE incorporated the fact that the TA does not have a specific standby rate.

The rate would be applicable only to customers with onsite generation. AE maintained that with its proposed adjustments, to be brought forward in the anticipated refiling, the proposed Standby Rate would appropriately reflect the nature of this service and the benefits derived.

In response to the ACC, AE submitted that the changes between the original and revised version of Rate 32 did not constitute a change in rate design philosophy. The charge for transmission did not change. The energy charge in the original proposal was set at the average forecast pool price of three cents/kWh and the second block was set such that the rate “backs into” the embedded cost of service for Rate 31 by crossing over at a 15% load factor. The difference between the original and revised proposal was that the revised energy rate is a full flow through of pool price. The revised revenue forecast for Rate 32 is in fact lower than the revenue forecast on the original rate.

In response to IPCAA, AE stated that the generation demand charge on Price Schedule 32 was set to engage at 15% load factor so that customers with significant load factors are given a price signal to move to a full service rate. Loads with significant load factors should share in the long term fixed costs and benefits of existing generation and not simply continue to pay incremental costs. This concept has been approved in previous Board decisions regarding standby route design.

Position of the Intervenors

ACC

In direct evidence for the ACC, Dr. Rosenberg argued that cost of service should be a primary consideration for the design of standby service. Anything else would send false price signals to customers requiring standby service. Further, an artificially high standby rate would discourage what would otherwise be an economic self-generation project, and customers would remain dependent on more expensive GENCO units.

Dr. Rosenberg considered Price Schedule 32 service would generally have a much lower coincidence factor than Price Schedule 31 service. Since customers with higher coincidence factors impose higher demand related costs, standby users, and particularly reliable self-generators, would require less generation reserve than full service customers. Price Schedule 32 users should pay less than Price Schedule 31 users with the same load factor.

Dr. Rosenberg proposed that the following charges be included in Price Schedule 32:

Generation and Distribution Charges

Demand Charge	\$0.15/kW
Energy Charge	
First 70 hrs	\$0.03/kWh
Next 40 hrs	\$0.0455/kWh
Over 110 hrs	\$0.0242/kWh

Transmission Charges

Demand Charge	\$0.96/kW
Energy Charges	
All On Peak Energy	1.241¢/kWh
All Off Peak Energy	0.123¢/kWh

The ACC noted that Price Schedule 32 is the only service provided to customers that rely primarily on competitively sourced electricity, making them characteristically different from full requirement customers. In all, 35 states and provinces have separate identifiable rates for that purpose. It argued that AE had changed the basis of Price Schedule 32 from the embedded cost rate first proposed. AE claimed that the standby rate would also apply to regulated generating units. The ACC argued that regulated units do not need protection from the Board.

The ACC found that Price Schedule 32, as proposed, discriminated against standby customers. It was the only rate schedule with a revenue-to-cost ratio over 200%. The transmission demand charge proposed was 24% higher than the transmission demand charge for Price Schedule 31. The ACC also noted that standby was the only class of service which would not have protection of the regulatory hedges.

The ACC argued that the use of a different standard for standby service would be discriminatory. Self-generating customers must make investment and usage decisions. False price signals would lead to economically inefficient decisions. Imposing artificially high standby charge would frustrate potential competition, stop the building of additional generation, and raise costs for all customers.

The ACC stated that AE has a clear profit motivation to deter and discourage onsite generation by developing a Standby rate that is too expensive. AE made no pretense that its rate has any relationship to the cost or providing service. AE stated that the standby rate use is of "high value," however, this does not justify monopoly rents.

TransCanada

TransCanada noted that the revenue-to-cost ratio for this rate is 244%. The proposed rate design is no longer based on embedded costs. TransCanada agreed with Dr. Rosenberg that the Board should direct AE to base its standby power rate design on embedded costs and design the rates so as to achieve a revenue-to-cost ratio in the range of 95 to 105%. It noted that the transmission demand charge for Price Schedule 32 was proposed to be higher than the transmission charge for Price Schedule 31 whereas these should be consistent. TransCanada agreed with Mr. Knecht that AE should offer fully hedged and pool price exposed options for generation charges in its standby design

TransCanada supported the position of the ACC and recommended that the AE provide a rate for Price Schedule 32 that would reflect 100% revenue-to-cost ratio for the rate class.

IPPSA/SPPA

IPPSA/SPPA argued that the proposed standby tariff would discourage the development of new co-generation projects. It agreed that AE's proposal, that Price Schedule 31 be used as a hedged standby rate, has some merit. However, it noted that the demand charges would be very expensive.

IPPSA/SPPA recommended that both AE and TransAlta should offer a pool price charge and a flat or time of use energy charge. Price Schedule 32 should include residual values/stranded cost credits and charges the same as Price Schedule 31. This would fairly and efficiently allocate values to generators.

AE proposed that transmission demand in energy charges be structured such that they reflect the 15% minimum on peak load factor specified in the TA's GSS tariff. This would only be appropriate for customers attached at transmission voltage and which represent a single POD for billing purposes. IPPSA/SPPA argued that demand rates for distribution voltage customers should be lower than for transmission voltage customers. AE recognizes lower load factor customers have lower coincidence factors. IPPSA/SPPA were of the view that this cost saving should be reflected as a credit in the incremental generation attachment tariff.

In an embedded cost rate for distribution-connected customers there should be a deep discount to the transmission demand charge in the standby rate to recognize diversity. Since distribution voltage standby customers would not comprise the total demand of any POD for transmission billing purposes, the 15% on peak load factor minimum should not apply. The demand charge should match Price Schedule 31 distribution customers. The energy charge should be consistent with on peak energy charge in the TA's tariff.

Board Findings

The Board notes that much of the diversity in parties' positions results from the very broad set of circumstances which are addressed by this Price Schedule. On the one hand, the Company is concerned that this Price Schedule may be taken up by large, transmission-connected generators. On the other hand, the intervenors are concerned that the Price Schedule, as proposed, will seriously affect the economics of small, distribution-connected generators. Even consumption by Price Schedule 33 customers which exceeds their contracted amount is addressed.

The Board considers that this one Price Schedule cannot accommodate all of these circumstances. The Board directs that Price Schedule 32 should be modified to work exclusively for small distribution-connected generators in conjunction with Price Schedule 91. The Board is of the view that the actual pool price DAT would be the appropriate schedule to meet the standby power requirements of very large distribution-connected or transmission-connected generators and Price Schedule 33 customers whose consumption exceeds their contracted amount.

The Board recognizes the unpredictable nature of providing backup supply to generators. To the extent that the shutdown of large generators may influence the pool price, AE would bear a disproportionate risk if it provided a fixed rate for energy supply for standby service. Further, generators who are scheduling outages for maintenance can reduce their exposure to high energy prices by conducting maintenance during low-price periods. If a generator is large enough to affect the pool price by an outage, any increase in the pool price will act as an incentive for the owner to reduce the outage duration.

Therefore, the Board considers that the energy charges should flow through the pool price on Price Schedule 32 and that transmission-connected generators should only be eligible for the actual pool price DAT. Accordingly, the Board directs that AE incorporate the same Energy Supply charges as established for the actual pool price DAT in its refiled Price Schedule 32.

The Board is persuaded by the evidence and argument presented by the ACC that the transmission charges proposed for Price Schedule 32 are inappropriately high for the distribution-connected generators it will now apply to. However, there was insufficient evidence adduced in this proceeding to set an exact peak demand coincidence factor for distribution-connected generators at this time. The Board's findings in Decision U97065 (p.628) were based on more substantial evidence.

> The Board notes Gridco=s [the previous TA] position that the 15% minimum on-peak load factor applies only during the month that a peak-period energy transfer occurs and that the charge would have minimal effect on standby customers. The Board considers the minimum 15% on-peak load factor to be appropriate, given that at low-load factors the probability of coincidence is much higher than the actual load factor.[31] (Square brackets added)

Therefore, the Board directs that AE design a TA Billings component consistent with a 15% peak demand coincidence factor for distribution-connected generators. These demand charges are to be levied on the standby portion of the customer's load, not on Base Demand. Base Demand should be billed on the applicable underlying Price Schedule. On-peak and off-peak energy charges should mirror the TA charges.

Under Price Schedule 91 distribution-connected generators will be required to pay for all upgrades to the distribution system required for their service. Therefore, the Board directs that DISCO Services charges only be levied on demand above the Base Demand plus the demand contracted under Price Schedule 91. The DISCO Services charges should be the same as for the applicable underlying Price Schedule.

The Board has determined that it is inappropriate to allocate generation related costs via a demand charge or discriminate between customers on the basis of load factor in charges related to Energy Supply. Therefore, the Board considers that it would not be appropriate to include an annual load factor penalty in Price Schedule 32.

AE proposed a noncompliance with curtailment directive penalty. The Board considers it would be inappropriate to charge standby customers a penalty for not curtailing load when customers on other rate schedules that provide firm energy are not charged a penalty. Therefore, the Board considers that it would not be appropriate to include a noncompliance with curtailment directive penalty in Price Schedule 32.

(3) Price Schedule 33 – Pool Opportunity Rate

This Price Schedule was proposed to be applicable only to customers who, as determined by AE, would not have purchased the additional energy under any other rate schedule.

In order to be on this Price Schedule a customer must demonstrate that it requires the TA's Grid Opportunity Service (GOS) and/or a discount on DISCO services in order to operate. The POR was a new offering in 1997 designed for customers on Rate Schedule 33 and Rate Schedule 35. Several former Rate 33 customers subscribed as of 10 March 1997, and Westcoast Energy Inc./Canadian Utilities Power (WESCUP) as of 3 November 1997.

[31] Tr. p.7691

The POR was designed to recover all incremental costs and make a contribution to fixed costs equivalent to that collected under existing Rates 33A, 33B, or 35. The POR incorporates the TA charges for opportunity service (i.e. GOS).

The POR was the sum of:

- Access Charge – a negotiated demand charge,
- A flow-through of applicable TA charges to recover all incremental transmission costs,
- An energy charge based on actual pool price, and
- A flow-through of the trading charge from the Power Pool Administrator.

Proposed Rate Level

	Transaction Charge	Demand Charge	Energy Charge	Energy Loss Charge
Generation	Power Pool Trading Charge	Negotiated $/kW per month	Power Pool Hourly price For all energy	-
Transmission	$200/month	-	0.34/kWh	Hourly Pool Price X loss factor
Service	$200/month	-	-	-

Proposed Conditions:

1. The POR is available only when AE determines that there is sufficient generation and transmission capacity. Energy purchases may be curtailed for system security reasons.
2. The POR is available only to customers who meet the approved eligibility requirements and terms and conditions established by the TA for this type of service (i.e. GOS).
3. AE will work with eligible customers to qualify their loads for GOS.
4. The POR is available throughout the territory served by AE from the AIS for eligible loads greater than 1,000 kW.
5. The POR is applicable to WESCUP (In addition a monthly charge of $53,545, for WESCUP's transmission facility, is part of the Rider E Schedule.)

AE sought to stop POR customers from converting to firm service with its 19 November 1998 revision. In Decision U99006 the Board found that it would be unfair to treat an existing POR customer any differently than other customers seeking new or expanded Rate 31 service in a similar circumstance. However, the Board accepted that the proposed revisions to the POR were acceptable, since they did not stop conversion, and indicated that the Board would approve the revisions in its Phase II Decision.

Position of the Intervenors

IPCAA

IPCAA submitted that because the POR is available only when AE determines that there is sufficient generation and transmission capacity, the company still views itself as an integrated utility. IPCAA argued that the DISCO has no role in determining generation capacity and the TA should determine the adequacy of transmission capacity.

IPCAA noted that Price Schedule 33 can be more expensive than Price Schedule 31. The purpose of Rate 33 is to make possible sales that would not otherwise occur on regular retail rates. At present, all users are treated as DISCO customers, even if they take service from the TRANSCO.

IPCAA stated that the POR serves two purposes: load retention and fuel switching. The rate proposed by AE should more properly be called "DISCO Opportunity Service." It is a rate that applies whenever a customer is served from the distribution system, but can be interrupted for distribution system constraints. As a result it does not impose incremental costs other than losses. AE should only qualify customers on the distribution system for opportunity service.

IPCAA argued that there is no reason for the distribution function to extract additional charges from the POR customer, especially in light of the high-level of pool prices. The POR distribution charge should be lower. AE should negotiate opportunity rate service with customers, but the maximum charge should be lower than the firm distribution service charge in Rate 31. POR charges should receive the same Rider J reduction as all other rates.

TransCanada

TransCanada supported IPCAA's position on this issue and recommend that AE adopt the changes to Price Schedule 33 as outlined in IPCAA's argument.

Board Findings

The Board considers that it is reasonable to have a POR to encourage full use of the AE system and to avoid stranded costs.

The Board notes that the TA's GOS rate includes a Transfer Charge[32] which is based on a 50/50 sharing between the TA and the DISCO of margin the DISCO negotiates with the end-use customer, but cannot be less than $0.0030/kWh. The Board, therefore, considers that the DISCO is negotiating on behalf of the TA and Alberta customers to maximize the contribution towards the fixed costs of both the distribution system and transmission system. Therefore, the Board

[32] Decision U97065, p.629

does not accept IPCAA's position that the demand charge negotiated should not exceed the DISCO Service charges under refiled Price Schedule 31 in some circumstances.

As the total charges payable by customers under the POR are negotiated, the Board considers that it would be inappropriate to change the overall rate level payable under this Price Schedule by including the H credit in the Energy Supply charges or a Rider J reduction. However, in light of the Board's intent in this Decision to remove all demand charges related to Energy Supply, the Board directs that the negotiated demand charge included under generation costs in the AE rate schedule be included instead under DISCO Service charges in the refiling.

In respect to the conditions of service under this rate, the Board also agrees with certain of the points raised by IPCAA. The availability of generation services is determined by the market and since the rate flows through the pool price there is no risk to AE with respect to Energy Supply to POR customers. Further, while AE should work with eligible customers to qualify their loads for Grid Opportunity Service (GOS), ultimately, the availability of transmission opportunity service should be determined by the TA. Therefore, the Board directs AE to consider only distribution related constraints when its customers otherwise qualify for the POR.

Therefore, the Board directs AE to adopt the following conditions for Price Schedule 33:

- The POR is available only when the TA determines that there is sufficient transmission capacity. Energy purchases may be curtailed at the TA's request for transmission system reasons.
- The POR is available only when the TA determines that there is sufficient distribution capacity. Energy purchases may be curtailed at TA's request for distribution system security reasons.
- The POR is available only to customers who meet the approved eligibility requirements and terms and conditions established by the TA for this type of service (i.e. GOS).
- AE will work with eligible customers to qualify their loads for GOS.
- The POR is available throughout the territory served by AE from the AIS for eligible loads greater than 1,000 kW.
- The POR is applicable to WESCUP (In addition a monthly charge of $53,545, for WESCUP's transmission facility, is part of the Rider E Schedule.)

The Board considers that it would be appropriate to approve Price Schedule 33 at the same time that it approves AE's other rates, after the refiling.

(4) Price Schedule 36 – Rainbow Lake Gas Processing Plant

AE stated that the design of Price Schedule 36 was based on Board directives contained in Decisions E91074 and E92039 that define the Rainbow Lake Gas Processing Plant as a full-requirements customer, and specify that the Rainbow Lake Gas Plant must effectively receive a bill based on Price Schedule 31 with separate arrangements for the fuel gas supplied to AE.

Parties did not comment on proposed Price Schedule 36.

Board Findings

The Board reiterates its view that it is fair for the Rainbow Lake Gas Processing Plant to be treated as a full-requirements customer. The Board finds that Price Schedule 36 should continue to be based on Price Schedule 31, including all changes as directed by the Board.

(5) Price Schedule 38 – Short Term Energy

Price Schedule 38 is available to customers also taking service under Price Schedule 31, Price Schedule 32, or the DAT to provide short-term energy which is not part of day-to-day operations (i.e. planned maintenance of customer generating equipment or testing of motor drives). It is available only when requested in advance and the Company determines that there is sufficient generation and transmission capacity available. This Price Schedule is available at the Company's discretion and may be curtailed for system security reasons in order to perform emergency transmission maintenance. Customers on this Price Schedule must have revenue-approved time of use metering installed. The customer is responsible for the costs of time of use metering.

Charges for generation services are the Power Pool trading charge plus pool price.

Charges for transmission are $200/month plus 4.0¢/kWh for all energy consumed in on-peak periods and 2.0¢/kWh for all energy consumed in off-peak periods. The on-peak period is from 08:00 to 21:00 Monday through Friday inclusive, with the exception of statutory holidays.

The transaction charges and energy transfer charges will be the approved charges established by the Power Pool Administrator and the TA and will be revised in accordance with the Power Pool and TA's charges (i.e. Grid Temporary Service).

Short Term Energy Demand must be established in a contract with AE. Charges for this Price Schedule will be measured above the highest demand recorded in the last six months for Price Schedule 31 or 39 and any reservation capacity associated with Price Schedule 32. Minimum charges are equal to 75% of Short Term Energy Demand times the number of hours in the contract period times the applicable energy charges for the contract period.

When a load curtailment directive is given, the customer's load must not exceed the Price Schedule 31 or DAT Base Demand. If the customer fails to curtail all load served under Price Schedule 38 for the entire interruption period, they will be charged in each instance a surcharge of $25/kW for each incremental kW of Short Term Energy which was not curtailed.

Parties did not object to the proposed Price Schedule 38.

Board Findings

The Board finds it reasonable to have a Short Term Energy Rate to serve temporary customer needs for energy. The Board considers that the customers who require temporary energy can reduce their exposure to high energy prices by taking energy during low-price periods. AE should not be exposed to the risk of providing a fixed rate for temporary energy customers. However, as with most other rates, the Board considers that Rate 38 customers should share in the costs and benefits of the legislated hedges when they use energy. Therefore, the Board directs AE to incorporate the same Energy Supply charges as established for the actual pool price DAT in the refiled Price Schedule 38.

Because this is not a firm rate and results in lower overall costs than taking service under a firm rate, the Board approves the proposed noncompliance charge.

(6) Fletcher Challenge Energy Canada Inc. Bypass Tariff

Fletcher Challenge Energy Canada Inc. (FCE) operates an oil battery and five well pads in the Consort area and has been served by AE since 1991. FCE determined that it was technically and economically feasible to construct its own distribution facilities to serve its well site and battery load using onsite flare gas generation. FCE indicated that they would proceed with construction unless an equivalent pricing arrangement could be negotiated with AE.

AE determined that FCE's claims were credible and negotiated a bypass pricing arrangement with FCE in order to prevent the construction of duplicate distribution facilities and minimize the resulting revenue impact on other customers. The terms of the bypass tariff are as follows:

1) Service to the well pads continues under the standard AE tariff;

2) The supply contract for battery load was terminated, exit fees were paid by FCE;

3) The battery load is supplied by local generation with net generation being sold to the Power Pool;

4) Standby and maintenance rates are applied to the battery load when the FCE generator is off-line;

5) AE agreed to pay FCE 3.25¢/kWh minus pool price for all net generation supplied to the Power Pool to a maximum of the kWh consumed at the well sites.

Parties did not object to the proposed FCE Bypass Tariff.

Board Findings

The Board accepts that the best interest of customers is served by avoiding stranded investments through allowing the FCE Bypass Tariff. Therefore, the Board approves the FCE Bypass Tariff as proposed.

(f) Oilfield

(1) Price Schedule 41 – Small Oilfield and Pumping Power

Price Schedule 41 applies to the energy requirements for production in the petroleum and natural gas industries, including related operations. The proposed structure of the rate has been simplified in aggregate and now contains one demand block of $12.01/kW and one energy block of 3.10¢/kWh. The energy charges were increased to reflect marginal energy costs. AE is also introducing a new time of use option for oilfield customers, Price Schedule 49 – Direct Access Tariff for Oilfield customers.

AE proposed to reduce the demand charge from $16.88/kW to $12.01/kW. The current energy charge of 1.93¢/kWh for the first 400 kWh/kW of billing demand and 1.5¢/kWh for all remaining kWh would be replaced by a single charge of 3.10¢/kWh for all energy.

Where it is impractical to meter a customer's service, the Company may bill on the basis of estimated maximum demands. In such a case, the monthly bill shall be the demand charge applied to the estimated demand, plus a flat rate of $12.40 per kilowatt in lieu of the charge for energy.

(A) Rate Level and Structure

Position of AE

AE submitted that the evidence presented in the proceedings clearly indicated that the costs incurred to serve Price Schedule 41 customers differ significantly from those of other general rate classes. It countered that IPPSA/SPPA provided a flawed assessment of the revenue-to-cost ratio for this rate class.

Position of the Intervenors

IPPSA/SPPA

IPPSA/SPPA argued that the revenue-to-cost ratio for this rate class should be moved to 100% to the maximum extent practical.

IPPSA/SPPA argued that AE should be required to perform a detailed study of the need for a separate oilfield customer class. The results of this study should be filed in the next AE GRA. It suggested that a General Service Urban and General Service Rural categorization be considered.

According to IPPSA/SPPA the demand ratchet should be based on 85% of the highest billing demand in the previous 11 months, to be consistent with Rate 31. In its opinion, this would encourage customers to upgrade meters. AE could adjust the rate levels as appropriate to account for this change. It noted that Price Schedule 41 is the only rate with a 100% demand ratchet and that Price Schedule 21 has eliminated the demand ratchet altogether.

IPPSA/SPPA submitted that to promote energy management practices and to reflect that an increasing number of Price Schedule 41 accounts are getting demand meters, the Price Schedule 41 demand ratchet should be reduced to 85%. AE noted that the reason for an 85% Price Schedule 31 demand ratchet is that there will be diversity in loads. IPPSA/SPPA argued that Price Schedule 41 accounts, being smaller, would exhibit even greater diversity. IPPSA/SPPA noted AE's statement that plans are in place to convert all Price Schedule 41 accounts to demand meters over the next four years. IPPSA/SPPA argued that, because of this, a change in demand ratchet is appropriate at this time. As a result of this change, revenue requirement from Price Schedule 41 would be reduced by 4%.

MI

MI disagreed with IPPSA/SPPA that the oilfield rate class could be amalgamated with other rural rate classes. The MI stated that Oilfield customers tend to have higher distribution costs relative to farm and general service customers. The MI submitted that there is no basis for rolling costs up to average across a larger customer base. AE proposed a lower revenue-to-cost ratio for farm customers, compared to the 1993 Phase II application, to reflect that the high load growth in the industrial and oilfield customer classes has resulted in a disproportionate share of distribution capital assets being allocated to the company farm rate class.

Board Findings

The Board notes IPPSA/SPPA's concerns that Rate 41 customers face a 100% ratchet. Since the Board has determined that all generation costs will be allocated on an energy basis, the demand ratchet will apply to a much smaller portion of a customer's total bill. However, the Board considers that a demand ratchet of 100% is only required for customers taking service at the transmission level to appropriately pass through the TA's rates. In light of the load diversity that exists at the distribution level the Board considers a demand ratchet of 85% to be more appropriate for the TA Billings component of the rate for customers taking service at the distribution level. For such customers an 85% demand ratchet would also seem more appropriate for the DISCO Services components of the rate, since those components charge for marketing, metering and other DISCO Services not related to the size and cost of the distribution facilities. The Board directs AE to change its Price Schedule 41 ratchet to 85% for those customers served at the distribution level.

IPPSA/SPPA also questioned the need for a separate oilfield customer class. The Board notes that issues have arisen concerning the higher rate of growth of oilfield customers compared to other rural customers and the question of cost causation between oilfield and other rural customers. Therefore the Board considers that a study of the appropriateness of a separate oilfield customer class could be beneficial. The Board considers that such a study would determine whether or not the cost of oilfield facilities should be allocated to other customer groups because of benefits they receive. The Board therefore directs AE to include a study, with its PDT filing, that examines the commonalties and benefits shared between, oilfield, general service and farm customers and recommends an appropriate rate class or classes for these customers based on the costs to serve each customer type.

In Section 3(a), the Board directed AE to design rates so that:

- the DISCO's total charges related to Energy Supply, TA Billings and DISCO Services are unbundled, with the revenue-to-cost ratio for each set at 100%;
- the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for every rate class; and to the extent possible the revenue-to-cost ratios for Energy Supply and TA Billings are each set at 100% for individual customers; and
- the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the "residual" DISCO Services amounts to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)

The Board also directed AE to include a table showing the revenue-to-cost ratios for each cost source (Energy Supply, TA Billings and DISCO Services) for each rate class.

(B) Harmonic Effects – Accuracy of Proposed Electronic Demand Meters

The presence of harmonic effects leads to the possibility that new electronic demand meters read higher peak demand on services that power variable frequency electric motors than would the older standard electromechanical demand meters. Variable frequency motors use high capacity electronic controllers to change the frequency of the electric current sent to the motor to improve energy efficiency at different output levels. This type of equipment generates significant harmonic currents, which can be registered on the new demand meters but would not be registered on the older type. IPPSA/SPPA contended that, as billing determinants have been established using data from the old meters, changing to the new meters could over-charge customers.

Position of the Intervenors

IPPSA/SPPA submitted that when AE upgrades its meters, the measured demands from the new meters are higher because of the new meters' abilities to register harmonic currents. The higher measured demand results in increased revenues without an associated change in costs. IPPSA/SPPA submitted that a 20% increase in measured demand should be taken into account. IPPSA/SPPA noted that TransAlta accepted the influence of harmonic currents on billing determinants and proposed a conversion factor to account for the effect.

AE stated that it had not conducted any studies to show the effect of harmonic currents on different metering technologies. Due to AE's reluctance to provide the required date, IPPSA/SPPA submitted that AE should prepare a study on this issue at the time of the next Phase II submission.

Position of AE

Although IPPSA/SPPA submitted that studies by TransAlta and SaskPower contradicted the evidence presented by AE, these studies were not entered as evidence. The submissions by IPPSA/SPPA on this matter should be disregarded.

Board Findings

The Board finds that there is insufficient evidence on this matter to determine an appropriate adjustment to AE's rates at this time. The Board is concerned that changing meter types without changing billing determinants would unduly discriminate against demand-metered customers. Therefore, the Board directs AE to provide a comprehensive review of the effects of changing demand meter types prior to the PDT hearing.

(C) Assumed Load Factor for Unmetered Accounts

IPPSA/SPPA noted that AE assumed a 400 kWh/kW for Price Schedule 41 unmetered accounts based on the expected average load factor for the class.

IPPSA/SPPA noted that AE admitted that the average load factor for the class is about 325 kWh/kW[33] and that Exhibit 68 indicated that the 400 kWh/kW factor had been used since 1969.

IPPSA/SPPA submitted that the average load factor for unmetered accounts could be approximated using the evidence from Exhibit 14 which provided the average load factor by size category and Exhibit 54 which provided the number of unmetered accounts in each size category. Then with the assumption that the unmetered accounts have a load factor equal to the average, the weighted average load factor for unmetered accounts would be 177 kWh/kW (24%). As noted in the SPPA Evidence, small oilfield facilities tend to have relatively constant loads and are the accounts that usually do not have a meter and 88% of the unmetered accounts are in the smallest size category.

IPPSA/SPPA submitted that unmetered Rate 41 accounts will typically have load factors significantly less than the proposed 400 kWh/kW (55%), less than the average 325 kWh/kW (45%) and more likely in the 200 kWh/kW (27%) size range. IPPSA/SPPA submitted that Price Schedule 41 should be revised to reflect an assumed 200 kWh/kW load factor for unmetered accounts.

Board Findings

The Board is not persuaded by IPPSA/SPPA's analysis, which contains some assumptions, that a 27% load factor would be appropriate. However, the Board notes that AE indicated that the

[33] Tr. p.248, l.16-p.249, l.1

325 kWh/kW was more accurate at the time of the hearing and the Board has directed that in most cases the actual 1998 values be used to determine cost of service for the rates arising out of the refiling. Therefore, the Board directs AE to use the 325 kWh/kW for Price Schedule 41 unmetered accounts in its refiling.

(D) Meter Totalization

The issue of meter totalization relating to oilfield accounts is discussed under Price Schedule 31. (See Section 4(e)(1)(B))

(g) Distribution Use for Generators

(1) Price Schedule 91 – Distribution Connected Generators

AE proposed a new rate, Price Schedule 91, applicable to generators connecting to the distribution system. Generating capacity was to be contracted for minimum of five years. Demand charges or proposed to be $3.07/kW for the first 500 kW and $1.20/kW for all capacity above 500 kW.

AE proposed to charge generators for distribution services at a rate of 50% of the average distribution charges, plus the service charge allocated to large general service customers (i.e. Price Schedule 31). The TA tariff applicable to existing generators for use of the transmission system has a similar basis, but the share of average costs is only 10%.

This allocation was AE's attempt to acknowledge that generators will tend to have a more significant effect on a distribution system than on transmission. The transmission system is 'deeper' with more diverse loads and generation, and therefore is more stable. On the other hand, a rate less than 100% of full distribution cost was deemed appropriate since generators are assumed on average to offset local loads, possibly reduce line losses, and possibly defer distribution facility upgrades.

In conjunction with the proposed rate, AE proposed to invest in distribution extensions for generators. For a minimum 5 year contract period, the investment level is $165/kW for the first 500 kW of generating capacity plus $105/kW for all additional kW.

Proposed Rate Level:

Demand Charge

	For the first 500 kW of Generating Capacity	For all Generating Capacity over 500 kW
DISTRIBUTION	$1.34/kW	$1.20/kW
SERVICE	$1.73/kW	-
TOTAL PRICE	$3.07/kW	$1.20/kW

Position of AE

AE argued that its approach to developing a stable rate was appropriate as the uncertainty associated with incremental pricing over time poses difficulties to new generators in their economic evaluations. Rate 91 suitably reflects the use of the entire distribution system and not just the local interconnection and other incremental costs. AE submitted that the proposed rate was consistent with accepted rate design and will provide a stable pricing signal for potential generation developers. AE also argued that the accompanying investment may provide a significant benefit to the potential generators as it would remove up-front connection costs.

Position of the Intervenors

IPPSA/SPPA

IPPSA/SPPA argued that to be consistent with TransAlta and the TA, the generator should be assigned all costs (and savings) associated with connecting to the system. No capital recovery charges would apply. It added that if self-generator load is served on a retail rate then AE investment can be applied to the retail load and that Price Schedule 91 should only apply to capacity in excess of on-site load.

IPPSA/SPPA recommended that all distribution level generators should be assigned all incremental capital costs/savings associated with connecting to the system, including the present value of loss credits or costs. No incremental investment in wires would be required to serve a generator and no ongoing wires recovery charge should be assigned.

IPPSA/SPPA stated that AE's embedded cost rate approach does not send efficient price signals in this instance. Under the proposed Price Schedule, generators which locate at or near load sites will pay the same as remote generators. IPPSA/SPPA submitted that an incremental cost tariff would provide for more efficient locating of new generators.

IPPSA/SPPA submitted that AE's tariff design would serve to reduce interest in competitive generation to the benefit of AE. AE acknowledged that a distribution connected generator in its service area will face different charges than a transmission connected generator or generator connected to TransAlta.

IPPSA/SPPA noted that AE has forecast no revenue from Price Schedule 91. Therefore any revenue received would be for the benefit of AE shareholders. IPPSA/SPPA submitted that an incremental cost tariff is not a subsidy. As long as the tariff paid equals or exceeds the incremental cost, no costs are assigned to other customers. Customers would benefit from increased competition in generation.

TransCanada

TransCanada argued it was inappropriate for AE to ask for approval of a non-incremental tariff when AE has only one distribution connected generator. TransCanada submitted that it would not encourage a fair and competitive market if AE is allowed a different tariff from other DISCO's in Alberta. TransCanada also noted that regulators for other utilities do not consider charging only one party in a transportation arrangement to be unfair. TransCanada recommended that the Board reject AE's proposed Price Schedule 91 and direct AE to develop an incremental tariff as outlined by IPPSA/SPPA.

AIPA/AAMDC/REA

The AIPA/AAMDC/REA argued that the Board should not unduly burden generators located anywhere, whether on the transmission or distribution system. The Board should not discourage distributed generation by adopting an embedded cost rate such as AE's.

The AIPA/AAMDC/REA submitted that generators should pay up-front costs as a contribution for incremental costs incurred on the AE system. These costs should include any cost required to upgrade portions of the distribution system beyond the interconnection. Generators should also pay the future O&M costs on an ongoing basis for that incremental plant (similar to the operations and maintenance charge contained in AE's Rider E). AE should provide the option to finance payment for the facility over time on a basis similar to Rider E.

The AIPA/AAMDC/REA noted that the usual treatment in the U.S. was that loads, not generation, paid for embedded distribution costs. The AIPA/AAMDC/REA recommended that the distribution tariff should be zero for embedded capital, and operations and maintenance costs. Loads, not generation, should pay for embedded distribution costs.

The AIPA/AAMDC/REA recommended that, for projects under 5 MW, charges/credits for losses be zero and that the party proposing to change charges for losses from zero should pay for a specific local engineering study. For projects over 5 MW a study funded by the generator should be required. Such a study could also show loss credits for generators in the event that a generator pays to increase the capacity of a distribution line and, as a result, reduces distribution losses to customers.

The AIPA/AAMDC/REA argued that IPPSA's request to pay credits to generators for avoidance of distribution costs should be rejected. Avoidance of distribution costs is so site specific that it should be assumed zero for general tariff applicability and this was the common method in the U.S.

However, the AIPA/AAMDC/REA recommended that AE be allowed to negotiate agreements in unusual cases providing some kind of payment, (e.g.: if AE recognizes that a generator can avoid a significant distribution investment by locating in a particular area, and a generator otherwise would not build there).

Board Findings

The Board finds much of the position put forward by AIPA/AAMDC/REA persuasive. The Board considers that it achieves an appropriate balance between the problem of providing the correct economic incentives for the location of distribution connected generators and the practical difficulties of estimating the value of the location credits for small generators.

Therefore, the Board directs that AE require each generator to pay all of the incremental cost required to allow it to use the distribution system. All costs of connection, and any costs required to upgrade upstream distribution facilities, will be payable by the generator. The Board directs AE to provide an option to allow generators to pay the costs of interconnection to AE over time, in the manner similar to Rider E.

The Board also considers that each generator should be responsible for incremental operation and maintenance costs caused by any distribution upgrades it requires. The Board also directs AE to propose an appropriate charge for these incremental costs based on the operation and maintenance charges in Price Schedule 31.

The Board further directs AE to set location credits or charges to zero for all generators less than 5 MW. If the generator or AE believes that losses are significantly affected by the location of a generator, the party seeking the change shall be responsible to pay for a local engineering study to calculate the effect of their operation on line losses. All proposed generators of capacity greater than 5 MW will be responsible to pay for a local engineering study, by a party agreed upon by the generator and AE, to calculate the effect of their operation on line losses. The Board directs AE to provide all information required for these studies and to reflect the results of the study in the particular generator's rate.

Location credits or charges will be payable on a monthly basis based on the expected generator output and the results of the local engineering study. Reductions or increases to expected losses will be assigned a value equal to the average pool price. At the end of each year the credits or charges payable should be adjusted to reflect the actual output of the generator.

(h) Direct Access Tariff

Section 31.4 (1) of the EU Act requires AE to prepare a DAT. A DAT is a rate option to be provided to large energy users that would allow customers to have access to the pool price and, if they so desire, to settle with the power pool for their energy purchases. Section 31.6 of the EU Act and sections 4, 5(2), and 6 of AR 168/98 of the EU Act, the Distribution Regulation, set out the requirements in designing a DAT. Section 4(1) of AR 168/98 states:

> **4(1)** Instead of setting out a charge for the rate referred to in section 31.6(1)(c) of the Act, the direct access tariff required under section 31.4(1) of the Act must set out a charge that represents a fair and reasonable allocation to direct access customers of the costs of operating the electric distribution system.

Section 4 of the Distribution Regulation requires that the DAT have a fair and reasonable charge for RPs and a fair and reasonable credit for entitlements. The Distribution Regulation also requires that the DAT be designed to encourage customers to respond to the pool price.

A further requirement is that customers be allowed to elect to pay one of two charges for the purchase of energy where each charge is based on the prevailing pool price. One election is to pay a charge equal to the actual hourly pool price (actual pool price DAT). The other election is to pay a charge based on the forecast average pool price in TOU period the energy is used (TOU DAT). The Distribution Regulation[34] requires that a DAT customer give six months notice of the effective date of the change if it elects to be billed pursuant to another tariff offered by the distributor.

AE proposed a DAT in the Application to be effective 1 April 1999. On 30 September 1998 AE revised its application including the proposed DAT. The proposed DAT was submitted to comply with the EU Act regulation, Section 31.6 would replace the Pool Access Rate. The DAT was based on a common understanding between TransAlta, EP and AE on the principles used to derive the components of the tariff.

AE submitted that its DAT rates were designed to pose no additional risk or benefit to either the customer or AE as compared to standard rates. AE used the transmission, distribution, and RP charges it proposed for Price schedules 31 and 41 the fixed price rates serving the large industrial and oilfield customers who are expected to be users of the DAT. The RP was allocated to rate classes based on 3W/9NW demands. The entitlement credit was to be the average actual unit (per kWh) received by AE in the billing period. This mirrors the way the entitlement value is received by the utilities, and retains the relative pool price signal for customers on Option 1 or 2.

AE proposed a DAT consisting of three Options. Options 1 and 2 charge for energy on the basis of hourly pool price with Option 1 customers settling directly with the power pool for the energy they purchase. Option 3 charges fixed on- and off-peak forecast TOU energy rates.

[34] EU Act, Section 31.6 (8)(9)(10)

The Board issued Decision U99014 dated 8 February 1999 approving AE's proposed DAT as a TDAT pending a final Decision on the Application. The Board considered that implementation of some form of DAT might reduce the potential supply shortage on the Alberta system by providing a mechanism that would allow customers to reduce or curtail load in response to pool price

Position of Intervenors

FIRM Customers

The FIRM Customers submitted that a DAT should be designed according to the legislative requirements, consistent with the cost of service and cost causation in the New World. Any resulting DAT rate should be consistent with the design criteria for all rates.

The FIRM Customers noted that AE's DAT assumed that only Industrial customers (embedded Rate 31) and Oilfield customers (embedded Rate 41) are interested in using the DAT Rate. RPs are allocated on a demand basis, whereas UOV credits are allocated on an energy basis. Lower load factor customers are discriminated against as high load factor customers are allocated lower RPs and receive relatively higher UOV credits. The Board should adopt the TransAlta's method of allocating RPs in proportion to the UOV credits. The Board should approve a consistent DAT for AE based on the TransAlta DAT which is the simplest and fairest design.

Option 3 could be useful to smaller customers if AE would arrange a financial hedge for these customers and pass the cost of the hedge through to the customers.

The FIRM Customers recommended that the Board reject the Knecht proposal. The Knecht proposal would allocate RPs and UOV credits on a demand basis using the 3W/9NW method and adjust the UOV credit each month to approximate the actual UOV received by AE. Use of the 3W/9NW demand allocation is not consistent with the concept of legislated hedges for an hourly pool price. The demand-based allocation does not recognize hourly variations in the value of legislated hedges. UOV credits based on demand would be a disincentive to curtail load on an hour to hour basis since the customer would receive the UOV whether he curtails or not.

The FIRM Customers did not support either Drazen proposal.

Under the first Drazen proposal the UOV would be set on a forecast basis for a two-year period. Customers would receive the UOV to the baseline whether they take energy or not. The customer would not pay the pool price when load is curtailed but would still receive the UOV according to the baseline. The Drazen proposal assumes that entitlements are always freed up when a DAT customer curtails load. Entitlements may or may not be available which can add risk to the DISCO and can have adverse impacts on non-DAT customers. In comparison, the AE method does not pay the UOV when load is reduced.

Further, the baseline may be difficult to establish due to data availability and customer confidentiality. Another concern is how to ensure that the DAT customer becomes unhedged at the same rate as the DISCO. While the Drazen proposal includes a strike price component to ensure this happens, this method would be complex, difficult and contentious. Additionally, the method provides a disproportionate incentive to contract new load to lock-up entitlements to the detriment of non-DAT customers.

The second Drazen proposal is similar to the first except that the customer would pay the regular rate for the contract demand and contract energy. Then if the actual energy taken in an hour were less than the contract energy, the customer would be paid the pool price for the difference. If actual energy taken exceeds contract energy the customer pays the pool price for the excess. The second proposal also requires that a baseline be determined. Also, there could be a shift in risk between the DISCO and the DAT customer, since the method would force the DISCO to purchase the curtailed load whether or not it needs the energy.

The FIRM Customers supported on-going dialogue on the DAT design issue. However, the dialogue should include interested parties, including non-DAT customers, as well as the utilities and the industrial customers.

IPCAA

DCGI provided an alternative DAT rate design. The design reflected their recommendation that all rates be unbundled into generation, transmission and distribution components. DAT customers would purchase at the hourly pool price. The UOV refund for each hour would be the difference between a base energy cost and the pool price, where the base energy cost AE’s net energy cost. The RP would be calculated ($/kW) on the basis of contract amount.

Mr. Drazen submitted a second DAT that was mathematically equivalent to the initial proposal, but composed somewhat differently. Under the second DAT the customer would pay the regular rate (e.g., Rate 31) for the contract demand and contract amount of energy each month. If the actual energy use were greater than the contract amount, the customer would be charged the pool price; if the actual energy taken in any hour were less than the contract energy, the customer would be paid the pool price. This method would expose the customer to the incentives provided by the pool price.[35]

IPCAA submitted that its evidence was the only evidence to address the question of whether AE’s DAT would work and whether customers would sign on to the proposed DATs. IPCAA stated that customers would not use the AE DAT if the Board approved it, but customers would use Drazen’s proposed DAT.

[35] Exhibit 64

IPCAA was surprised that AE had difficulty in obtaining a better understanding of the DCGI proposal. However, IPCAA was appreciative that AE recognized the potential merit in the proposal.

IPCAA proposed that AE discuss DAT structure with IPCAA. IPCAA submitted that including all parties in the discussion of a DAT structure would make the process more complicated and cumbersome. IPCAA stated that any resulting DAT would be presented to the Board for final approval and all parties could have their say at that time.

IPCAA recommended that the Board approve Drazen's DAT for AE customers.

IPPSA/SPPA

Mr. Knecht proposed a version of a DAT that varied from AE's and IPCAA's DAT. The UOV credit be should be demand-based, with an adjustment factor computed monthly as the ratio of actual AE UOV for each month divided by the forecast UOV for the month, rather than based on actual average UOV per kWh received by AE. When a DAT customer curtails load AE does not lose entitlements since a DISCO's entitlement is not based on actual usage but on a pre-set amount. Further, an increase in load does not provide any additional legislated hedges. Therefore entitlements and obligations should be limited to existing customers and existing load.

The important questions around the DAT are the level of unbundling, the amount of RP and UOV for each rate class, and whether demand or energy should be used to recover the RP and UOV.

IPPSA/SPPA submitted that forecast generation charges should be combined with forecast SC/RV charges in the regular rate tariff and actual market generation charges should be combined with actual UOV credits in the DAT. The SC/RV charges should be as fixed as possible. The DAT rate as proposed will not attract customers under the current proposal.

IPPSA/SPPA also submitted that transmission charges in AE's DAT should more closely follow the actual tariff of the TA.

To achieve consistency in the AE and TransAlta DAT there must also be consistency in their allocation of the RP and UOV. More of AE's customers would adopt AE's DAT than would adopt a DAT like TransAlta's.

IPPSA/SPPA opposed AE's position that its DAT rate was the only viable option at this time. The key objective of the DAT is to develop price responsive load. Customers will not fully utilize AE's proposed DAT. Changes must be made to the AE DAT to provide the customer with the incentive to respond to the price responsive load. Knecht's proposal requires only a relatively simple modification to the AE proposal to be implemented quickly. Further, AE did not challenge the Knecht proposal in rebuttal evidence or cross-examination. DAT legislation was to allow a customer exposure to the pool price without interference from its distribution company to allow for transition to a competitive market. AE has frustrated this objective.

IPPSA/SPPA agreed with TransCanada that proposed Option 3 provides much less incentive to shift load from on-peak to off-peak than presently exists with Option T. IPPSA/SPPA expected that many Option T customers will opt for embedded rate service.

Option 3 should be further unbundled into market generation, RP and UOV charges parallel to that of the DAT. Mr. Knecht noted that the EU Act states, the DAT tariff must contain a pool price forecast for the period in which the tariff is to be in effect. The Option 3 rate is inconsistent in that it uses 1998 forecast values for market generation, RP, and market hedge costs with a 1999/2000 UOV actual credit. Since the market based generation charges are not based on the forecast period for which the tariff is in effect, the tariff would violate the letter of the law.

TransCanada

TransCanada submitted that the legislation indicates that the DAT should be designed to encourage customers to alter their consumption of electric energy as the pool price changes. There is an immediate need for price responsive load in Alberta due to a supply shortage in Alberta. Further, there is a need for customers to shift consumption from on-peak periods to off-peak periods.

Option 3 has merit as it is a fully hedged, unbundled tariff with separate energy charges for on-peak and off-peak consumption. This option could provide an incentive to shift consumption that may not exist in a standard tariff. However, AE's Option 3 is priced too high.

TransCanada supported the DAT proposed by Drazen. Apart from the need for establishment of a customer base line, AE does not appear to provide any reason that the Drazen approach is unworkable.

Position of AE

AE had submitted that it was not practical to have a DAT that is consistent for AE and TransAlta on an interim basis. AE's DAT would be different in regards to the difference in the distribution wire charges and the difference in the allocation of RPs between the two utilities. AE was amenable to a DAT that has a consistent methodology in the long term.

AE noted that the Drazen DAT proposal for AE was the same as that proposed for TransAlta. AE submitted that the Drazen proposal required significant additional development, including the negotiation of baseline contract amounts, before it could be workable. AE considered that there might be merit in pursuing the underlying approach of the Drazen DAT, but opposed the Drazen DAT at this time. AE submitted that its DAT was fair to all rate payers regardless of whether or not IPCAA's members would use it.

AE agreed that its DAT would be more attractive to high load factor customers although this was not the intended outcome. This result, however, may be the proper result as these are the customers that would be on peak when the pool price is high. The customer has the choice to curtail load to avoid the high pool price.

AE noted that its current filing was for the 1998 test year and therefore did not require a 1999/2000 pool price forecast. AE submitted that the Knecht proposal of limiting obligations and entitlements to existing customers was discriminatory and contrary to the EU Act.

AE agreed with TransCanada that its DAT does not hold the promise of an equivalent price for the majority of customers nor a discount versus embedded rates. The rate is not intended to include a subsidy for assuming exposure to the pool price.

Board Findings

Although a new DAT will not be available until after the Board's review of AE's refiling, the Board considers it inappropriate for the Temporary DAT approved in Decision U99014 to continue to be available to new customers under terms that differ from the new DAT. Therefore, the Board directs that AE close the Temporary DAT to new customers as of the date of this Decision.

To the extent that DAT customers reduce load in the highest price hours, the pressure on the interconnected system will be relieved to the benefit of all customers and the DISCOs which supply them. There will be a downward pressure on the cost of energy, particularly at very high pool price times. The demand response of customers will thus enhance the efficiency of the market. Therefore, the Board considers that a properly designed DAT is important to the interconnected system. The Board does not consider that the DAT should be applicable to customers served by isolated generation since the costs incurred by the DISCO to serve them may be significantly different from the Energy Supply costs on the AIS.

To improve the efficiency of the demand side of the market, the Board would prefer that all large customers move to the actual pool price DAT and be exposed to the actual hourly variation in pool price. The advantage to the actual pool price DAT is that customers would see and might respond to actual short term spikes in the pool price. However, the Board recognizes that some customers may not be prepared to move away from fixed rates at this time.

The Board considers that there is a clear differentiation in average pool prices between the TOU periods and also notes the differentiation in TA rates (TA Rate GSS) between on-peak and off-peak periods. Therefore, TOU rates embody a price signal to customers by reflecting the typically higher costs during peak hours and lower costs in off-peak hours and seasons. The Board considers that a properly designed TOU DAT will provide superior price signals as compared to the single fixed rate. A single fixed rate can only reflect the forecast average cost of energy throughout all of the year for the entire class based on forecast average class consumption patterns. The TOU rate can reflect the average expected variation in pool price with the season, day of the week and time of the day and allows customers the opportunity to vary their actual consumption to take advantage of lower energy cost periods. The Board considers market efficiency will be enhanced if customers who would have been on a non-TOU fixed rate subscribe to TOU DAT rates.

In determining an appropriate design for the DAT, the Board must look at the appropriate charges for the Energy Supply, TA Billings and DISCO Services. The Board considers that the DAT should be designed so that DAT customers make a decision on when they will take energy based on the prevailing pool price. The DAT should not include a discount or incentive payment relative to fixed price rates.

The Board agrees with parties that the Power Pool of Alberta hourly price is the appropriate Energy Supply price signal that should be seen by DAT customers. To eliminate any incentive or disincentive which is not related to pool price, the Board considers that the TA Billings, DISCO Services and any other ancillary charges should be the same for DAT as for firm fixed price rates. The Board notes that AE's proposed DAT was designed so that its non-generation charges for proposed Rates 31 and 41 also apply to the DAT.

Section 4 of the Distribution Regulation requires that the DAT have a fair and reasonable charge for RPs and a fair and reasonable credit for entitlements. The Board finds that a fair and reasonable charge and credit is reflected in the "H" amount which is derived as described in Section 2(b). Using the same per kWh fixed amount "H" for DAT and fixed rate customers should, on a forecast basis, leave TOU DAT customers with typical usage characteristics no worse off than if they had chosen fixed price rates. The TOU DAT will provide a benefit on a forecast basis for customers who plan to respond appropriately to the TOU energy price differentials. As a result of the energy-based allocation of RP even customers with low load factors who are able to shift load in response to pool price will benefit from the DAT.

The Board agrees with AE that DAT Option 3 is the appropriate tariff for use by customers who can benefit from TOU rates. However, the Board is not convinced that AE's proposed charges under Option 3 are appropriate. AE adds a premium to the forecast pool price under its proposed Option 3. The EU Act 31.6(2)(b) specifies that the charges to apply for certain hours reflect an expected average cost calculated using only a forecast of pool prices for those hours. As a general principle the Board does not consider that there should be any premium over forecast costs in any rate the DISCO charges its customers. The risk that those costs may be higher or lower should be the DISCO's risk, unless the customers agree to assume some of the risks or the Board determines a risk premium is appropriate. The risk to the DISCO of pool price variance from forecast on load exceeding the DISCO's entitlements was considered as part of the DISCO's risk in Decision U97065. Therefore, the Board is not persuaded that there should be any risk premium inherent in the DISCO's TOU DAT rates or for that matter any other fixed rate arising out of this proceeding.

Therefore, the Board considers that the TOU energy charges should reflect the forecast pool price, without any premium, during the TOU period each charge is in effect. In Section 3(b) the

Board concludes that the forecast for rates arising out of this proceeding should be based on the actual 1998 pool price record. The Board also considers that the TOU option should pass through to customers the variation with TOU in the TA's charges to AE. The TA's rates have separate off-peak and on-peak energy transfer charges. Therefore, the Board directs AE to design its TOU DAT rate with the following separated components:

- the average actual pool price in each TOU period in 1998 representing the cost of energy components in the TOU rates;
- the fixed amount "H" charge calculated using the 1998 pool price record and 1998 total AE DISCO annual energy usage; and
- TA Billings charges which pass through the TOU charges in the TA's rates.

The Board considers that actual pool price DAT customers should also see TA Billings charges which pass through the TOU charges in the TA's rates. All DAT customers should see separate TA Billings and DISCO Services charges mirroring those charged under the fixed rate which would otherwise serve them.

The Board considers that the "H" factor works well for the fixed TOU charge DAT option intended for customers who are able to shift their loads to off-peak periods. The response of such customers is unaffected by the variation in the actual pool price from forecast. However, for the actual pool price DAT customer, the Board recognizes that if the "H" factor is used, with no adjustments, the risk of an extended period of pool prices above forecast might be so large as to bias customers against the option of taking the actual pool price DAT. The Board considers that the actual pool price DAT is the DAT that will lead to the greatest market efficiencies. Therefore, an adjustment to the H factor is required to protect actual pool price DAT customers from any significant increases in the average levels of pool prices over the 1998 prices used in the calculation of "H" (as set out in Section 3(b), the actual 1998 pool prices are to be used in the calculation of H).

If actual future pool prices tend to be higher than those forecast using the 1998 actual pool price record, the adjustment should leave customers who choose the actual pool price DAT generally no worse off than customers who choose fixed price rates or TOU DAT. If the actual total UOV received by the DISCO during each billing month is used to calculate the monthly refund or credit due each actual pool price DAT customer, then the changes in the overall UOV would generally offset the changes in overall pool price level. Then, if pool prices move markedly higher, actual pool price DAT customers will not automatically be worse off than customers on fixed rates. DAT customers who do respond to the pool price will more likely be better off than customers on fixed rates. DAT customers must be allowed to respond to the hourly variation in pool prices without being overcharged because of the difference between forecast and actual average pool price. Therefore, the Board considers that the appropriate monthly adjustment per kWh billed in the month would be defined as:

$$\text{Adjustment} = \frac{\text{billing month's total actual DISCO UOV refund} - \text{1998 month's total DISCO UOV refund}}{\text{1998 DISCO monthly energy use}}$$

The Board considers that the adjustment should only be passed on when it is positive and benefits actual pool price DAT customers. Otherwise, when the adjustment is negative (i.e. pool prices are lower than forecast), a DAT customer might end up worse off than fixed rate customers even if the DAT customer were reducing load during high pool price periods. In the case of lower than forecast prices, the impact on the DISCO of providing the adjustment is minimal since the DISCO will likely have saved more than the amount of the adjustment through lower than forecast purchase costs for other customers. Also the DISCO will potentially benefit from the downward pressure on the cost of energy. In the case of higher than forecast prices the DISCO would pay the extra at any rate if all customers remained on fixed rates.

Therefore, the Board directs AE to design its actual pool price DAT rate with the separated components which follow:

- the actual pool price in each hour less the adjustment amount if the adjustment is positive as the cost of energy component;
- the fixed amount "H" charge calculated using the 1998 pool price record and 1998 total AE DISCO annual energy usage; and
- TA Billings charges which pass through the TOU charges in the TA's rates.

The Board also considers that the viability of the DAT will be enhanced if a customer is able to take all or only part of its service under the DAT rate. In other words, a customer must also have the option to take a portion of its energy on the DAT after taking some set amount on another rate.

The Distribution Regulation (EU Act Sec 31.6 (8)(9)(10)) requires that a DAT customer give 6 months notice of the effective date of the change if it elects to be billed pursuant to another tariff offered by the distributor. However, the Board considers that the risk to the DAT customer of inaccurate pool price forecasts is much reduced by the adjustment and stacking. Further, the Board considers it evident that a customer could choose to take a DAT rate in a low pool price season and revert to an averaged rate when pool prices are expected to be high, taking advantage of seasonal price fluctuations to the detriment of the DISCO and/or other customers. Therefore, the Board considers it appropriate to direct that DAT rates include the provision that notice can be given only after a customer has been on the rate for six months. The Board will only shorten the notice period if the direct access customer satisfies the Board that financial arrangements have been entered into by the customer that compensate the distributor and its other customers for any costs resulting from the shorter notice period.

(i) Options

(1) Price Option F – Idle Service

This option is intended for customers who will not require electric service for extended periods, but wish that the facilities remain in place as there is a reasonable expectation of future use. The intent of the idle service charge is to lessen the cost burden of idle services carried by other customers in the same rate class and to encourage the salvage of services remaining idle for extended periods.

Proposed Rate Level

Price Schedule 11: the idle service charge is the price schedule minimum monthly charge

Price Schedules 51 or 56: the idle service charge is one-half the total customer and kVA charges applicable to a 3 kVA service

Price Schedules 21,22,31,39, 41 or 49: the idle service charge is the greater of the rate minimum or the contract minimum, where the rate minimum is the greater of

(1) the minimum of the schedule on which the service was billed immediately prior to becoming idle, and

(2) the minimum of the schedule under which the service was billed during the majority of its service life (If the last Price schedule change occurred at least two years previously, the minimum is as per the most recent schedule.)

Price Schedule 61: the idle service charge is 75% of monthly customer and demand charge for company installed lighting, 35% for installations paid by customer

Charges based on demand ratchets are excluded from the minimum charge unless the service is reconnected within twelve months. If a service is reconnected within the twelve months of disconnection, the reconnection charge will include an amount to recover the ratcheted demand charges for each month that the service has been idle.

Proposed Conditions

This price option will apply to services that are disconnected for more than twelve months. Services that are disconnected for less than 12 months are covered in T&C 4.19.

The following customers are exempt from paying idle service charges:

- Residential Price Schedule 11 and Small General Service Price Schedules 21 and 22 customers within cities, towns, villages, Hamlet’s, Indian reserves and Metis settlements
- private lighting Price Schedule 63
- Irrigation Price Schedules 25 and 26

Board Findings

The Board notes that no specific issues were raised with respect to the proposed price option. The Board finds that this is an appropriate service offering to maintain customer service options.

The Board expects that AE will examine the Board's findings in this Decision and make any changes necessary to the idle service price option in its refiling.

(2) Price Option H – Service for Non-Standard Transformation and Metering Configurations

Option H has various forms of credits and charges for service rendered under Price Schedule 21, 22, 31, 32, 36, or 39 where metering and/or delivery voltage are non-standard.

Price Option H(a)

The purpose of Option H(a) will be to reimburse customers who have supplied their own transformation. As the distribution charges associated with those price schedules recover average transformation costs, those customers who have supplied their own transformation should be reimbursed for the portion of the charge relating to those costs. With the new feature proposed in Price Schedule 31 which would absolve transmission connected customers from paying distribution charges, the option H(a) credit is no longer needed for those customers.

Proposed Rate Level	Previous Rate Level
$0.80/kW	$0.50/kW

Price Option H(b)

Option H(b) is for service which has primary or higher voltage delivery metering which is desirable for the convenience of AE or to improve accessibility. In this case, demand and energy measurements are reduced by 1% so as to approximate secondary voltage delivery conditions.

Price Option H(c)

Option H(c) is for when primary or higher voltage delivery is made to a customer owned sub-station, but metering is at secondary or utilization voltage for AE's convenience. In this case, demand and energy measurements are increased by 1% so as to approximate primary or transmission voltage delivery conditions and the discount, as specified in Option H(a) shall apply.

Price Option H(d)

AE proposed a new option, Option H(d) for customers connected directly to a transmission sub-station, who are utilizing transformation facilities (to receive service at 25 kV), but who do not supply their own transformation. Option H(d) is proposed to be a surcharge equivalent to the credit under option H(a).

Proposed Rate Level

$0.80/kW

AE submitted that its estimate of transformer loss factors was reasonable contrary to the positions of IPPSA/SPPA and TransCanada.

Position of the Intervenors

TransCanada

Transformer losses are lower than calculated by AE, for example: a 15 MVA transformer loaded 75% at 100% power factor has 0.41% losses compared to 1% assumed by AE. This would cost an additional $1,500 per month. TransCanada suggested that the wording of Option H should be modified to add: "At the request of the customer, the loss percentage of 1% may be replaced with actual transformer loss data provided by a transformer supplier for typical loading conditions in relation to the specific transformer." IPPSA/SPPA agreed with TransCanada.

Board Findings

The Board notes that although, in the example provided by TransCanada, customers may be slightly over-charged for energy services, other customers under Price Option H(b) would receive a slight benefit from the same assumed 1% transformer loss factor.

The Board is not convinced that striving to achieve this level of accuracy for one portion of the rate setting process is worth the administrative burden that TransCanada's request would create. The Board notes that the one percent is used as a reasonable estimate of actual transformer losses. The Board is not satisfied that a study of transformer loss data done at one point in time will provide a sufficient indication of transformer losses over time. The Board considers that the one percent adjustment, represents a reasonable estimate of actual transformer losses for all customers. Therefore, the Board accepts AE's proposal to maintain the 1% transformer loss factor.

The Board also accepts the other modifications to Price Option H as proposed by AE.

The Board expects that AE will examine the Board's findings in this Decision and make any changes necessary to idle service price option in its refiling.

(3) Price Option N – Plant Commissioning Energy

This option is intended to be used by customers for up to three months when they are starting and testing new equipment. Price Option N modifies the billing demand such that demand charges are less onerous during a customer's commissioning phase. AE proposed that the billing demand calculation under Option N be adjusted in order to better reflect the charges AE incurs from the TA for peak demand set during the customer's commissioning phase.

Proposed Rate Level	**Previous Rate Level**
Billing demand equal to 150% of average hourly energy during the billing period	Billing demand equal to 125% of average hourly energy during the billing period

Position of the Intervenors

The CCA submitted that the period of three months relief may be excessive. No other Alberta electric utility offers a program similar to Option N, and the use of the option is rare. The CCA recommended that the period of discount be limited to four weeks and at the next GRA the need for this rate offering should be reviewed.

TransCanada argued that contrary to the argument of the CCA, AE states that "new facilities could require a month to six weeks in the testing mode of operation." TransCanada submitted that it is unclear how long new facilities will require for testing operations, but some facilities may require a longer period than six weeks. Although the CCA argues that none of the other Alberta electric utilities provide a similar rate offering, if the proposed AE Option N meets its intended objective, other utilities may consider adding such a rate. TransCanada supported AE's proposal as filed.

Board Findings

The Board notes that both AE and TransCanada recommended a longer time period than CCA suggested should be available for this price option. As these parties have experience in commissioning new equipment and facilities, the Board is persuaded to accept the time period allowed for this price option.

The Board also notes that, although this is not entirely a cost based option, AE has endeavored to make this price option more cost reflective by increasing the billing demand charge by 20%. The Board accepts Price Option N as filed, but directs AE to provide justification if it wishes to continue pricing this Option below cost in its next Phase II proceeding.

(4) Price Option P – REA Distribution Price Credit

This option is available to REA Farm customers and is intended to provide pooled O&M REA Farm customers who wish to take service under Price Schedule 21 or 31, a credit to reflect the costs of distribution facilities already recovered in these Price schedules.

Proposed Rate Level	Previous Rate Level
For REA farm customers electing to take service under Small General Service Price Schedule 21, a credit adjustment of 23% will be applied to the base bill	For REA farm customers electing to take service under Small General Service Price Schedule 21, a credit adjustment of 14% will be applied to the base bill
For REA farm customers electing to take service under Large General Service Price Schedule 31, a credit adjustment of 6% will be applied to the base bill	For REA farm customers electing to take service under Large General Service Price Schedule 31, a credit adjustment of 7% will be applied to the base bill

Board Findings

The Board notes that no specific issues were raised with respect to the proposed price option.

In light of the findings regarding the allocation of the costs of transmission and distribution facilities, the Board directs AE to refile the Price Option P credit with any adjustments required to reflect the revised allocations.

(5) Price Option T – Off Peak Demand

This Price Option is a time of use differentiated rate, applicable to customers whose off peak demand was expected to exceed their on peak demand

AE proposed to withdraw Price Option T. Option T was offered in conjunction with existing Rate 21 and 31. There were no Price Schedule 21 customers using the option. Price Schedule 31 customers may be served under Price Schedule 39 (Direct Access Tariff).

Position of AE

AE indicated that while this option was had been useful for “off peak” valley filling, in today’s environment it is more effective to decrease usage during peak periods. AE submitted that the significant decrease in demand charges for Price Schedule 31 mitigates the benefits of Option T. AE also stated that, based on its experience customers have not been able to get the benefits associated with this rate.

AE also noted that the differential between on and off peak demand costs has shrunk with respect to both generation and transmission and, therefore, greater costs must be recovered off peak than compared to when Option T was introduced. Since, proposed Price Schedule 31 has been modified with a much higher energy rate and a much lower demand rate compared to the existing Rate 31, adding Option T to the proposed Price Schedule 31 may not provide a cost reflective outcome.

For these reasons, AE submitted that Option T should be discontinued.

Position of the Intervenors

TransCanada

While AE proposed that the DAT would replace Option T, TransCanada argued that Option T provides a proven means of reducing peak load. TransCanada submitted that AE had not provided documented evidence to support the assertion that it is "more effective to simply decrease usage during peak periods, as opposed to shift usage to non-peak periods." There was no evidence that a DAT would be more effective at providing peak load reductions than Option T. Further, although AE argues that the decrease in demand charges for Rate 31 reduces the customer benefits of Option T, Exhibits 49 and 50 indicate that AE's proposed Price Schedule 31 with Option T provides better incentive to shift load to off peak periods than Price Schedule 31 alone. Lastly, AE's proposed DAT will not have a significant impact on reducing peak load because of its poor market appeal.

TransCanada submitted that Exhibit 94 refuted AE statement that its experience has been that customers are not able to shift their loads to take advantage of this option. Exhibit 94 indicates that Option T provided 1,491 kW of peak load reductions. The Board should not be persuaded that the existing Option T price sensitive load should lose its off peak incentive.

TransCanada concluded that option T should be retained.

IPPSA/SPPA

IPPSA/SPPA submitted that Option T should not be replaced with the proposed DAT. In the current shortage of supply, it is inappropriate to replace Option T with a DAT rate which would provide less incentive to encourage reduction of consumption during peak hours. A TOU option for Price Schedule 31 would be a better substitute for Option T.

Board Findings

In Section 4(h), the Board finds that the DAT provides an appropriate TOU rate with the correct incentives for customers to reduce consumption during peak periods. The Board will allow AE to withdraw this Price Option when the Board approves a final TOU DAT. The Board directs AE to keep Option T in effect until that time. In Section 5(b)(1) the Board examines issues related to an unapproved tariff AE termed a "modified Option T."

(6) Price Option U – Ratchet Buydown

This Price Option is intended for seasonal loads, and is an alternative pricing arrangement to Price Schedule 31. It replaces the standard demand ratchet with a surcharge on metered demand such that monthly bills follow consumption patterns more closely. Due to a shifting of charges from the demand to the energy components in the proposed Price Schedule 31, AE proposed to increase the demand surcharge on Option U from 20% to 75%.

Proposed Rate Level	**Previous Rate Level**
Demand charge: 175% of billing demand	Demand charge: 120% of billing demand

Billing demand will be the greatest of

- the highest metered demand during the billing period
- the estimated demand
- the contract demand
- 50 kW

Proposed Conditions

This Option is available for a minimum period of 12 months and 12 months notice is required to discontinue billing under the provisions of this Price Option. Furthermore, discontinuation is permitted only upon the anniversary of the Option U contract anniversary date. It is not available for use as supplemental, maintenance, or standby power to customer owned generation facilities.

Board Findings

In Section 2(b), the Board determines that costs of Energy Supply should be recovered entirely through energy charges. Therefore, the Board directs AE to refile Price Option U adjusted as required to reflect this and other findings in the Decision.

(j) Additional Charges (Riders)

(1) Rider A-1 – Municipal Assessment

This Rider is used to collect amounts for municipalities in accordance with individual municipal franchise agreements. The following are exempt from the surcharge: (a) Farm customers Price Schedules 51 and 56 (b) Irrigation pumping Price Schedule 25 (c) Customers within Indian reservations (d) Rainbow processing plant Price Schedule 36 (e) Rider E, special facilities.

The proposed charges are unchanged from the previous Municipal Assessment Rider.

Board Findings

The Board notes that this Rider is modified and adjusted from time to time in accordance with any changes in the agreements between AE and the municipalities. No change is proposed in the Application.

(2) Rider A-2 – Isolated Service

This Rider is applied to higher than typical energy usage in isolated areas and is intended to discourage wasteful energy consumption where the isolated generation costs substantially exceed AIS generation costs. This surcharge would apply after the first 600 kWh of monthly energy consumption for residential customers and after the first 4,500 kWh of monthly energy consumption for general service customers.

Proposed Rate Level	**Previous Rate Level**
Residential: 4.0 cents/kWh	Residential: 4.2 cents/kWh
Commercial: 4.0 cents/kWh	Commercial: 4.2 cents/kWh

Proposed Conditions

Special arrangements will be required to supply loads exceeding 20 kW in these areas. Electric service will not be offered for electric eating purposes.

Position of the Intervenors

IPPSA/SPPA argued that even though proposed Rider A-2 will collect less than 50% of the fuel related cost for isolated customers, AE proposed a 4.76% reduction in the level of Rider A-2. It argued that a rate decrease is not appropriate and that in the interest of fairness a 10% increase for RiderA-2 would be appropriate.

Board Findings

Throughout this decision, the Board has moved to align rates more closely with costs. Therefore, the Board agrees with IPPSA/SPPA that it is inappropriate to reduce the level of this Rider while costs still exceed the rate charged.

In light of the findings in Section 3(a), the Board directs AE to redesign Rider A-2 to collect an additional 10% in overall revenue.

(3) Rider E – Special Facilities Charge

This Rider is to collect monthly charges for the capital costs of industrial distribution facilities. The fixed monthly charge of $53,545 for the WESCUP transmission facility has been added to Rider E schedule

No intervenors argued against this proposed charge.

Board Findings

The Board finds that this Rider continues to be appropriate and approves the Rider as submitted.

(4) Rider G – Temporary Refund Rider and Rider J – Interim Adjustment Rider

These riders arose from the rate reduction specified in Order U98081. In the initial filing, the riders applied to electric service bills rendered up to 31 December 1998 as per Order U98081. In the refiling by AE on September 30, 1990, these riders were left to serve as generic riders applicable to all electric service throughout the service territory served by the Company when a change or refund is approved by the Board.

Board Findings

The Board notes that although these riders were included in the Application, these riders have expired and the Board does not approve of their continuation. The Board prefers to approve new refund or adjustment riders when required.

(5) Rider R – Generator Adjustment Rider

AE proposed that Rider R be applied if the owners of a regulated generating unit temporarily suspended their obligation to pay the UOV for a regulated generating unit and in the event that changed the cost of power purchased from the Power Pool of Alberta.

Board Findings

In Section 3(c), the Board provides reasons why it will not approve a generation adjustment rider at this time.

5. TERMS AND CONDITIONS OF SERVICE

(a) Characterization of Matters Regarding the Terms and Conditions of Service

During the course of the proceeding, the Board allowed certain portions of the T&C (set out in Exhibit 51) to be extracted from the Phase II proceeding on the basis set out below:

> Another aspect of it is that the parties would propose to file tomorrow a list of the issues that would be in a generic sense and not a constraining sense, but at least these parties have agreed to that will be the subject of the negotiated settlement. Obviously parties who had not been involved to date, if they wished to have additional input on issues or whatever, it wouldn't be like this is a closed list. This is just what the parties see as being some subject areas that would benefit from the process. …
>
> … So it's proposed that that would be filed with the Board so that you have an idea of the types of things that the parties are, if I could use the word, extracting from these proceedings and planning to discuss further.[36]

AE indicated that:

> … it's certainly not the intention to have the document that's filed tomorrow be a constraining list that would prevent other parties from saying, okay, I would like to address this other issue as well because it's something that's been bugging me.
>
> I think we're prepared to have -- obviously we appreciate that all parties have to have input into this process, and it's more to I guess provide the Board with some understanding of the types of issues that the parties are looking at extracting from the current proceeding and discussing further, but we certainly have no intention of foreclosing all parties from having the level of input they desire.[37]

A note on Exhibit 51 indicated that the negotiated changes applicable to AE's T&C would only apply to Electric Service Agreements (ESA) executed after 1 December 1998. While parties envisioned that a negotiated settlement would be filed with the Board on or about 15 February 1999, nothing has yet been filed.

In argument parties sought to categorise issues related to the T&C as:

(1) Matters in the proposed T&C subject to the negotiated settlement process.
(2) Matters in the proposed T&C not subject to the negotiated settlement process.
(3) Issues related to the existing Electric Service Agreements

[36] Tr. pp. 434-435
[37] Tr.p.436

Parties desired different treatment for each category and appeared to differ as to which issues belonged in each category.

Position of AE

AE requested that the proposed T&C be approved as filed and updated, subject to those aspects specifically made the subject of the negotiated settlement process.

AE noted Canfor's comments in argument on the scope of the negotiated settlement process. AE indicated that the issues to be addressed in the settlement process were limited to those identified in the List of Issues filed during the Phase II proceedings (Exhibit 51).

AE submitted that "essentially" all of the matters TransCanada raised in argument were the subject of ongoing negotiations between parties, including TransCanada, and outside the hearing process. The Board should not take any action on those aspects of the T&C pending receipt of the results of the negotiated settlement process. AE noted that it was attempting to prepare a first draft by 15 February, but that the process would not likely be fully completed by that date.

Position of the Intervenors

Noting the potential for new rate offerings with the era of full customer choice, and distribution access tariffs, Canfor submitted that there might be a requirement for a higher level of customer information than currently provided by AE, or available from metering presently at a customer's site.

Canfor submitted that a customer should have a right to any customer data AE has regarding its account. This includes data regarding energy consumption, load factor, power factor, demand levels, billing determinants and the like.

Canfor considered that AE was generally in agreement with that position. But submitted that it is one thing for a customer to "generally" be provided with their own customer data and another for customers to have an unequivocal right to such data.

While Canfor understood that AE would continue to own most meters, it noted in s.6.1 of AE's T&C, that:

> …the company shall provide, install and seal all meters necessary for measuring the energy supplied to a customer, unless otherwise specifically provided in a contract with a customer.

Canfor considered that Section 6.1 of the T&C contemplated AE installing new meters necessary to provide the new level of customer data which may be required as customers' needs change and better meter data is required. Section 6.1 also allowed a customer to specify other arrangements for meters in its contract. Canfor was not aware of whether in such circumstances a customer can make arrangements to own and control the meter data. Regardless of the possibility of "special" contractual arrangements, AE should be required to provide each customer its meter data on request. Canfor understood that AE's position was that such data is owned by AE, although the T&C do not speak directly to this point.

Canfor indicated that it intended to make its concerns more fully known to AE in the negotiated settlement of the T&C. Canfor noted AE's comments to the effect that the issues deferred to the negotiation process were meant to be in a generic sense, and not a constraining sense. Canfor hoped its concerns would be adequately addressed in the negotiated settlement process and form part of the "settlement."

TransCanada recognized that AE's investment policy would be a matter for negotiation with AE to develop AE's future investment and buydown policy and commended AE's initiative to involve customers.

TransCanada noted that a "contract buydown" methodology for existing customers who have an executed ESA was not part of the negotiated settlement process as a result of the note on Exhibit 51.

TransCanada fully supported AE's decision to work with customers to define and document its investment policies, on a go-forward basis, by a negotiated settlement approach. TransCanada also submitted that the Board should direct AE to document its methodology for contract buydowns of existing customers in its T&C in order that customers may understand the policies and be able to address such issues through the hearing process and complaint procedures.

TransCanada noted that AE intends to unbundle its contracts with customers. TransCanada supported AE's contract unbundling, but was unable to determine from the evidence when AE proposes to have its contracts fully unbundled. In order to ensure the unbundling of contracts occurs in a timely manner as part of the industry restructuring, TransCanada requested that the Board require AE to unbundle and apply for approval of its customer contracts on an expedited basis in light of the possible implementation of the DAT by 1 April 1999, or earlier.

TransCanada took no position as to whether or not the issue of ownership of billing data was properly part of the negotiated settlement process on investment policy. However, TransCanada submitted that if it was not to be part of the negotiated settlement, then the Board should direct AE to explicitly include as part of its T&C that a customer has the right to access its own metering data.

IPPSA/SPPA supported Canfor's position of allowing customers "to have unequivocal rights to such (metering) data." IPPSA/SPPA support the initiative to have the negotiated settlement process deal with this issue. Ultimately the T&C of service should reflect a customer's rights to ownership of its meter data.

The CCA argued that incremental operations and maintenance costs to service new facilities required for an increase in a customer's load should be charged to that customer directly. They also argued that AE should define specifically what notice periods are required for customer service changes. They requested that customer security deposits should be set no higher than those of TransAlta.

Board Findings

The Board notes that TransCanada argued that matters related to AE's existing ESAs should be settled in this proceeding. The Board considers that those issues would more appropriately be a part of the negotiations and that AE did not appear to rule out that possibility in its Reply, in spite of the note on Exhibit 51. Similarly the Board considers the negotiations are the appropriate forum for several of the issues the CCA wished to address.

Since the Board allowed certain portions of the T&C (set out in Exhibit 51) to be extracted from the Phase II proceeding, the Board considers that it would be inappropriate to deal with those portions in this Decision. AE is directed to provide an update on the status of those portions of the T&C extracted, the negotiations, and a plan for dealing with any matter discussed but not resolved through the negotiations.

The Board notes that AE indicated at the Hearing that there was a great deal of flexibility in the matters subject to the negotiation process and that the Board indicated its support for such flexibility. The Board was disappointed to see that AE changed that approach in respect to the issue of a customer's rights to its billing data as raised by Canfor. In this time of transition the Board would like to see as much consultation between parties as possible to ensure resolution of as many matters as possible and to properly focus issues that can only be resolved through the hearing process.

The Board considers that, as a matter of principle, a customer is entitled to any and all of the customer data AE acquires as a result of serving that customer. Only with that data will a customer be able to verify its billing and compare new retailer and rate options. That said, the matters that Canfor raises would appear to be more appropriately dealt with in the upcoming distribution access proceeding than in this Decision. Customer billing data requirements and rights will likely be more fully canvassed at that time.

(b) Other

(1) Application of Unapproved Tariffs

TransCanada cross-examined AE regarding an unapproved variation of Option T on which AE had been billing a customer on the isolated Jasper system for over a year. The testimony of AE's panel included the following comments:

> So we revisited the terms and conditions of Option T as it was designed, and it's clearly intended for use on the AIS using the AIS costs and the AIS time profile. So when we looked at the application in this isolated area, which is the Town of

> Jasper, we from our evaluation determined that it clearly wasn't appropriate to apply the standard Option T to that customer's use because of different fuel cost in an isolated area and a concern that the load profile might be different.
>
> The other consideration with this particular customer is that they comprise up to 40 percent of the peak in the isolated area so we carefully considered whether it was in the best interests of all customers to apply Option T in its standard form, and from that determined that because of the difference in fuel costs and the difference in time periods that it was appropriate, and in the interests of all customers to modify Option T.
>
> …we didn't think it was necessary to put together a modified version of the rate (to file with the Board) since it was going to be withdrawn in its entirety. (Parenthesis added)[38]
>
> What we're trying to do in this case is come up with an arrangement that is going to be fair to all customers, and it was an arrangement that was commercially acceptable to the customer. So with the spirit and intent of trying to provide the customer with an option that would meet his needs, and a rate that was in the spirit and intent of a published tariff, we made those adjustments.
>
> Just to add that, it's our understanding that it's consistent with the Board's policy to encourage parties to resolve these and come up with a mutually satisfactory arrangement.[39]

TransCanada

TransCanada summarized AE's application of an unapproved tariff as follows:

In April of 1997, AE offered to charge an industrial customer, served on Rate 31 with Option T, charging 40% of the Rate 31 demand charge for off-peak use instead of the 10% prescribed in its Board approved price option.

AE continues to ignore the approved tariff and has indicated that it intends to increase the charge for off-peak use from 40% to 70%.

AE has not filed this modified tariff for Board approval.

The Board's examination of the AE Panel indicates that AE was fully aware of the process to obtain Board approval for rates.

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[38] Tr.pp. 457-458
[39] Tr.pp. 460

TransCanada noted that Price Schedule 33 (POR) does outline a provision for discretionary application of the rate; however, Price Schedule 31 and Option T do not.

TransCanada submitted that AE's action ignored established regulatory practices and subverted the Board's authority and that the Board should direct AE to immediately provide this customer service on approved Option T. Furthermore, any variance between the rates that the customer has paid from the date AE offered the modified Option T to that which the customer would have paid under the approved Option T to date should be immediately refunded to that customer, with interest. Lastly, the Board should also consider some mechanism to address the losses customers experience when denied access to approved tariffs and to discourage Discos from exercising such discretion in the future.

Board Findings

With respect to the applicability of Option T, the Board notes that Section 4.4 of APL's Electric Service Regulations (ESR) reads:

> 4.4 Application of Price Schedules
>
> The company will endeavour to apply the price schedule which applies to the service and is most favourable to the customer…
>
> A customer may elect to have service billed on any other rate schedule applicable to that customer's service requirements.

The Board also notes that parties agreed that AE's ESR would take precedence over the terms of the individual customer's ESA. Therefore, the Board considers that under AE's existing ESR a customer may only elect to have service billed on a rate schedule which is applicable to the customer's service requirements.

While TransCanada argues that DISCOs should be discouraged from exercising such discretion in the future, the Board considers that such discretion has been important. It is not reasonable to expect that all possible scenarios involving customer rates will be foreseen in the rate design stage and decided prior to their occurrence. Such discretion has kept the integrated utilities from going through the costly exercise of ensuring that every possible scenario was spelt out in their rate schedules and terms and conditions of service. The costs of such an exercise would have been recovered from customers. The complaint process would normally provide a forum for customers to object to AE's application of rates. The Board recognizes that these principles may change at some point in the future deregulation of the industry.

In this specific case, the Board has reviewed Option T and notes that there is no explicit restriction forbidding Rate 31 customers in isolated areas from taking this price option. However, since AIS costs and the AIS time profile were used in its development, it is obvious to the Board that Option T was developed for customers connected to the AIS, rather than for customers served in isolated areas. Therefore, because the design of Option T would make its use in an isolated area unfair, the Board is not convinced that the approved Option T was or is applicable for any customer in an isolated area.

Therefore, since the Jasper customer is in an isolated area, the Board would expect that the customer be served under Rate 31 which was developed for all service areas and that Option T would not be available to the customer. However, the Board notes that AE stated that it agreed to serve the customer under a “modified” Option T. The Board considers that the “modified” option would be more properly characterized as a new customer, or area, specific option, say the “Jasper Option.”

The Board considers that once the agreement was made AE should have filed the Jasper Option with the Board for acknowledgment, as is normally the process when a new rate is designed that offers a new service to a customer or class of customers. The Jasper Option would have then been acknowledged as filed or allowed on an interim basis and open to examination at the next Phase II. Any customer complaints regarding the level of the rate could have been dealt with as warranted. However, the Board also notes that, agreement was reached between AE and the customer, without any complaint coming to the Board prior to this rate hearing. A customer complaint would have placed this matter before the Board.

The Board would generally approve any similar new rate offerings which result in a savings to customers between GRAs, particularly optional offerings. Generally the Board would not look at an increase to any rate offering in as favorable a light. Therefore, since the new rate was an optional offering which the customer could have refused to take and the option was a discount to the Rate 31 which was the only rate applicable to the customer and the customer agreed to be billed under the option, the Board is not convinced that the customer was harmed by AE’s oversight.

With respect to the level of the rate, the Board notes that it was open to TransCanada to dispute the rate level during the Phase II proceeding to ensure that the Jasper Option was priced only to recover the costs of serving the customer. It was also open to other customers to ensure that the new option would not result in other customers bearing some portion of the costs of the customer served under the Jasper Option. The only evidence as to the appropriate level of the Jasper Option was placed on the record by AE.

The Jasper Option was apparently developed for an individual customer whose load could comprise 40% of the peak demand on the isolated system serving it. That customer would clearly have a far more significant impact on Jasper system costs, on-peak or off-peak, than would any customer served on the AIS. Further there is a combination of gas and diesel generation serving the Jasper system which results in incremental costs which are very different from those of the AIS (Tr. p.459). Therefore, any discount to encourage off-peak usage should be less for those customers than for a customer on the AIS. Since the customer agreed to the option at 40%, the Board will approve the Jasper Option at the 40% level. However, the Board is not convinced by the evidence on the record that there is reason to increase the charge from 40% to 70%. The only evidence is that there is an increase in gas prices from the time when the 40% was set and that the rate is somehow indexed to the price of gas. The Board was not provided explicit information on how the determination of the 70% level was arrived at and hence does not find an increase in the Jasper Option to the 70% appropriate.

The Board directs AE to prepare a Filing for Acknowledgement for any new rate on a timely basis.

(2) Firm Load Curtailment

Certain parties submitted that firm customers should be entitled to compensation when load is curtailed for generation supply shortages.

IPPSA/SPPA stated that interruptible customers provide a valuable service to the utility and its firm customers and are compensated in the form of reduced rates. When firm customers provide that service, AE avoids paying the extremely high pool prices of those periods.

IPPSA/SPPA's witness Mr. Knecht suggested that to increase the demand side commitments of the discos, a rider be added to AE's tariff that applies to customers who have their load curtailed as a result of a generation shortage. By curtailing load, the disco should be obligated to purchase that power back from those customers at its avoided cost if the disco has not arranged for sufficient generating capacity to meet the needs of its customers. In effect, customers get a credit for being curtailed that reflects their value to the system of being interrupted.

TransCanada agreed with IPPSA/SPPA's position that firm customers be compensated when they have their load curtailed. TransCanada considered that compensation is especially important if AE is not bound to procure new capacity to ensure continuous energy supply to its retail customers.

Position of AE

AE considered IPPSA/SPPA's proposal to compensate customers for events of firm load curtailment is without merit. AE exercises all reasonable efforts to curtail other classes of customers and/or purchase the necessary power before it will curtail a firm customer. Given that AE no longer is responsible for ensuring that adequate generation is available this measure would be unfair and punitive. AE submitted the Board should reject this suggestion.

Board Findings

The Board understands that firm load customers are only curtailed for reasons of system emergencies and not for economic reasons.

The Board considers that the obligation to provide distribution services does not include an obligation to compensate firm customers for load curtailment during system emergencies.

(3) Obligation to Serve

Electric distribution systems provide the delivery service for energy available from the power pool. Parties questioned whether the obligation to serve or AE's T&C required that AE ensure all energy needs of the customer will be met.

Position of the Parties

The MI considered it is extremely important for the municipalities to know who has the responsibility or obligation to provide the municipalities with sufficient electrical energy for their customer.

The MI noted the Board's statement in Decision U97065 at p.72:

> Since the definition of an electric distribution system is specific to plant, works, equipment, systems and services necessary to distribute electricity, it follows that the obligation set out in section 58 [of the Electric Utilities Act] are in respect of providing and maintaining the distribution function. They cannot be extended to confer upon a DISCO an obligation to ensure sufficient generation capacity to satisfy its customers needs. ......

Although a DISCO may not be obliged to ensure sufficient generation capacity, the MI stated that a positive obligation should exist on the DISCO to serve its customers. The MI noted that the T&C proposed by AE do not include an obligation to provide adequate power to customers.

The MI submitted that AE's T&C ought to include:

(a) AE shall use its best efforts to determine the energy requirements of each customer class; and

(b) AE shall use its best efforts to supply the electric energy to its customers that is required to be provided through the legislated hedges.

TransCanada considered that AE enters into a contractual arrangement to provide service. This contractual relationship is to "make all reasonable efforts to maintain a continuous supply of energy to its customers, but the company cannot guarantee an uninterrupted supply."[40]

TransCanada submitted that AE has a contractual commitment to make all reasonable efforts to maintain a continuous supply of energy to its customers and that AE should be required to prudently procure (but not necessarily construct) generation capacity to ensure the continuous supply of energy required by its customers. Further, TransCanada submitted that if AE is unable to maintain a continuous supply of energy to its customers and the Board rules that AE does not

[40] Terms and Conditions, s. 9.1

have an obligation to procure capacity, the Board should prescribe a mechanism that would allow customers to acquire their own supply.

Position of AE

AE noted that the MI considered that AE's obligation to serve should exist. AE considered that it is the legal obligations imposed on AE by s. 58 of the EU Act that is important. The Board specifically addressed this issue in its U97065 Phase I Decision.[41] AE stated that it is on this basis that AE governs its activities

AE disagreed with TransCanada that AE must prudently procure generating capacity to ensure that it can meet its contractual obligations.[42] AE stated that AE is no longer responsible to ensure that adequate generating capacity is available. AE will fulfill its contractual obligations to its customers through AE's T&C.

Board Findings

The Board notes that the EU Act states:

> 58(1) The owners of electric distribution systems and the Transmission Administrator
>
> (a) shall provide and maintain service that is safe, adequate and proper, and
>
> (b) shall not withhold a service that the Board has ordered it to provide.
>
> (2) Subsection (1) does not apply to an electric distribution system that is not an electric utility.
>
> (3) The owners of electric utilities and the Transmission Administrator shall not act in a manner that is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this or any other enactment or any law.

In Decision U97065, as quoted above by the MI, the Board concluded that the duties of the DISCO are to provide distribution services for the energy that is available from the power pool. The market provides the energy and capacity. The Board notes that customers who require greater certainty than the market driven power pool can supply have the option to self generate.

[41] p. 72
[42] p. 21

The DISCO's obligation to serve is to provide and maintain distribution service that is reliable and safe. AE provides the distribution facilities and services to serve the needs of its customers. The Board considers AE's T&C are consistent with AE DISCO's obligation to serve.

(4) Shared Use of Overhead Facilities

The CCA noted that AE monitored the TransAlta 1996 Phase 2 Rate application, wherein TransAlta applied for a new tariff (Rate 9100) for the shared use of its overhead facilities.

The CCA noted that AE is currently operating under contracts for the shared use of its overhead facilities with other electrical utilities and with cable and telephone companies. The contracts have expired and AE is negotiating to develop new contracts. The CCA also noted that AE would apply to the Board for approval of an appropriate tariff if negotiations were not successful.

The CCA submitted that if the Board approves Rate 9100 for TransAlta, AE should make a similar rate available.

Position of AE

AE submitted that the TransAlta matter is not at issue in AE's case and AE should be permitted to deal with third parties on a commercial basis.

Board Findings

The Board notes that AE is negotiating new contracts in respect of the shared use of overhead facilities. The Board agrees with AE that the TransAlta Rate 9100 issues are not issues in AE's case as is evidenced by the lack of intervention by cable or telephone companies in this proceeding.

6. OTHER MATTERS

(a) Interest on Rate Refunds

When a utility has interim rates in place it will normally collect revenues either surplus to, or deficient from, the revenue requirement which the Board ultimately approves. In the past the Board has not allowed interest on such a deficiency or surplus. Instead the Board has approved a rate adjustment intended only to refund the forecast surplus or to collect the forecast deficiency.

This practice has been questioned in some recent proceedings. The Board therefore initiated a generic proceeding to deal with the question of whether or not it is appropriate for the Board to change its policy on the awarding of interest on rate adjustments for both electric and gas utilities. The Board stated in a letter dated 25 August 1998 that it would

> …hold a proceeding in writing to deal with the matter of the payment of interest on adjustments to rates and other payments where necessary approval, and subsequent disposition, has been delayed in the normal course of proceedings. This matter is to be addressed in a more specific context in the Phase II portions of the 1996 Electric Tariff Applications and has also been raised in other proceedings.

Near the end of the Phase I portion of this application, in October 1997, IPCAA raised the issue of whether interest should be paid to customers on the refunds resulting from Decision U97065 (the 1996 Phase I decision). The Board responded to IPCAA by stating that the Board has the jurisdiction to deal with the question of interest on adjustments in the Phase II portion of the proceedings. The Board later clarified that the issue was to be addressed in the Phase II portion of the proceedings.

Position of Intervenors

IPCAA submitted that AE should pay interest on any amounts that it has been ordered to refund to customers. IPCAA stated that the EU Act does not prevent the payment of interest. IPCAA submitted that the payment of interest on rate adjustments arises from a principle of fairness. IPCAA submitted that rates that do not account for the time value of money cannot be just and reasonable.

IPCAA noted that the concept of carrying charges is recognized by virtually every other rate regulating board and commission in Canada. These carrying charges whether or not they are calculated as interest, are applied to monies owed to or by the regulated entity in order to protect against the impacts of regulatory lag and other delays. This ensures that a party, either the utility or customer, is not unduly burdened if it does not receive timely payment of an amount that it is owed.

IPCAA stated that amounts collected in excess of the approved revenue requirement are provided by customers at no cost. The utility is then able to finance a portion of its operations with these excess earnings even though the utility's approved revenue requirement assumed a financing cost. IPCAA submitted that this enables a utility to earn in excess of the approved return on their investment.

IPCAA further stated that any order or direction that the Board might issue in this proceeding regarding the payment of interest must stipulate that the interest obligation be for the account of the shareholder of AE and not be recoverable from customers. Interest should be payable at a rate equal to the composite rate of return on rate base of AE on all outstanding amounts until the refunds have been completed.

IPPSA/SPPA submitted that fairness, and common sense should prevail on this issue and AE should be directed to refund to customers' interest on over-collected funds resulting from the 1996 Phase I decision. The rate of interest should be set equal to AE's 1996 approved composite rate of return on rate base (9.2%). In addition, the interest expense should be for the account of AE shareholders, and not AE customers.

Position of AE

In Reply Argument AE noted IPCAA's submission that the Board should direct that interest be payable on any rate refunds which result from this Phase II proceeding. AE stated that the Board is aware, the matter of the payment of interest is the subject of a separate proceeding currently ongoing before the Board. AE has made a submission in that proceeding. AE stated that it is prepared to accept the outcome of the Board's Decision in that proceeding and have it applied to this Phase II Application. Should the Board find that this matter should be addressed separately in these proceedings, AE would simply request that the positions taken by AE in the written proceeding be incorporated into this argument by reference.

Board Findings

The Board is in the process of considering a general policy with respect to interest on rate adjustments. The Board considers, however, that IPCAA's frequent requests for a change to the Board's policy provided sufficient notice to parties in these proceedings that the Board might consider the issue of interest on adjustments. Absent the Board's finalization of its policy the Board will make a determination with respect to the payment of interest as it pertains to this application.

The Board considers that interest may be awarded on over collections or under collections in certain circumstances where the amount is material and may be awarded to either the customers or the utility. The Board notes that the Board approved, in Board Order U97154, AE's revenue requirement and determined a revenue surplus of $200,000.

The Board is not convinced that, in this case, the amount on which interest is to be awarded meets the criteria of materiality. Therefore, the Board will not direct AE to refund interest on the rate adjustments that resulted from Decision U97065.

(b) Interest Penalties on Late Payments

In general, an amount is added to a customers bill if a customer does not pay the bill by the specified due date. The amount is usually expressed as a percentage of the amount due.

Position of Intervenors

The CCA noted that the Supreme Court of Canada issued a decision that a utility's late payment charge was a contravention of the Canadian Criminal Code provision respecting excessive interest. In particular, the Code prohibits receiving interest at an effective annual interest rate greater than 60.00%.

The Supreme Court found that for a specific number of days, the late payment charge amounted to interest at a criminal rate. This was dependent on certain circumstances, including when the payment was received and what billing and payment program a customer was using. The result was the Court recognized the fact while the utility company charges a monthly penalty for late payments, customers pay bills on a daily basis, including late payment penalties.

Based on this recent decision, the CCA requested the Board direct AE to obtain a report from an independent certified/licensed actuary confirming whether its existing and proposed late payment charge and collection practices offend s.347 of the Criminal Code of Canada. Based on the findings of the actuarial report, review its records for the last ten years to determine the level of any over-collection, if any, provide such information at the time of the 1999/2000 GRA proceeding, and track all late payment charges received by the Utility in a separate account for future regulatory proceedings.

Position of AE

AE opposed CCA's suggestion that the Board require AE to retain an Actuary to calculate the interest on late payments, as well as, conduct a retroactive review of such payments for a ten-year period. While a Court action involving this issue would require actuarial support, it is not the role or responsibility of the Board to require information that is not relevant to fulfilling its mandate. CCA provided no basis to justify such action.

AE stated that the interest collected by AE on overdue accounts is pursuant to Board approved T&C. As well, for each Test Year AE estimates the amount of revenue it will receive from such payments and includes this amount as an "offset" to its overall revenue requirement, thereby reducing the rates payable by all customers. It must be understood that this is not a provision that results in benefits to AE.

Board Findings

The Board accepts AE's position that it does not benefit from interest on late payments since it is forecast for a Test Year and the forecast amount is offset against AE's revenue requirement thereby reducing the rates to all customers. The Board also recognizes that the late payment interest charge has two important purposes. One is to encourage customers to pay their bills on time. The other is to penalize those customers that do not.

The Board notes that the CCA was the only intervenor to comment on AE's interest charge on late payments. The Board is currently reviewing the interest on late payments for all Alberta utilities in a separate process, in response to the Supreme Court of Canada decision. Therefore, the Board will not deal with the issue in this Decision

(c) Data and Documentation

Intervenors considered that had AE provided its COSS in a computerized format efficiencies and cost savings, for both the Board and Intervenors, would have resulted. The efficiencies and cost savings would have benefited all parties.

Position of Intervenors

AIPA/AAMDC/REA noted that several parties requested AE to provide the COSS in a computerized format. AE claimed that its COSS was proprietary and declined to provide any computerized information regarding that study.

AIPA/AAMDC/REA stated that by not providing the computerized information, AE greatly increased the cost and burden on intervenors. Each time an intervenor wanted to analyze a relevant subset of AE's numbers in the cost of service, the data had to be retyped by hand. Even without formulas the intervenors were able to determine that some kind of mistake or problem existed with AE's analysis. Without the formulas intervenors could not determine how the problems arose or how the calculation carried through from one portion of AE's analysis to another. The failure to provide computerized information also made it difficult to understand how certain costs were allocated to customer classes.

AIPA/AAMDC/REA noted that, TransAlta in its proceeding, provided intervenors with a computerized format, making it much easier to analyze and process the results.

AIPA/AAMDC/REA agreed with the witness for the Alberta Co-generation Council on the consequences of AE not providing an electronic version of the COSS. Provision of an electronic version of the COSS would have:

- greatly facilitated the task of verifying the accuracy of the study and its calculations
- made it easier and more accurate for intervenors to perform "what if" scenarios
- ensured that all changes proposed would emanate from a common starting point
- lowered the cost of intervention

AIPA/AAMDC/REA submitted that the Board should order AE to provide computerized information in its next Phase II.

AIPA/AAMDC/REA also submitted that the Board, in recognizing intervenor costs in this proceeding, should take into account the extra burden that AE unnecessarily placed upon intervenors by refusing to provide a computerized version of its cost of service filing.

IPPSA/SPPA submitted that a thorough, analytical review of the AE proposed COSS in this proceeding was substantially frustrated both by the structure of the proceeding and the behavior of AE. First, AE submitted a COSS with its filing which did not contain an electronic version of the study, nor was it complete, nor did it include the backup working papers needed to evaluate the study. Without the necessary working papers intervenors were limited to asking for the backup materials as part of the interrogatory process and attempting to evaluate the COSS from the summary paper tables. Despite the limitations, the intervenors' interrogatories uncovered numerous flaws in the study, and AE eventually produced (paper copy only) a substantially revised, full study on September 30. At that point, no serious discovery regarding this study was practical, and effective intervention was limited.

IPPSA/SPPA agreed with Dr. Rosenberg's assessment:

> I believe there are two main areas where AE has been less than helpful. First is their refusal to supply their class COSS in an electronic format. Second, the Company habitually takes the position that actual information, for example actual billing determinants, is irrelevant to a Phase II hearing.[43]

Many aspects of AE's study have therefore not been adequately reviewed. IPPSA/SPPA believed that interventions could be both more effective and efficient if filing requirements were imposed on the utilities. For the COSS, these include a full COSS and any underlying computer files or code, working papers used to develop classification factors and allocators, and detailed load research information and results used to derive billing determinants.

IPPSA/SPPA submitted that as part of its next Phase II filing, AE should submit a detailed COSS of distribution costs, including electronic and other working papers, backup data, and any specific studies upon which it relied for allocation of costs.

ACC stated that for the reasons enunciated in Exhibit 91, urged the Board to direct AE to share its COSS, in electronic form, with intervenors in future rate cases.

Position of AE

AE noted that, in Final Argument, a number of parties referred to the fact that AE refused to file an electronic copy of its models as requested during the Information Request phase of this proceeding. Certain parties stated that TransAlta had filed such electronic models and that cost savings and efficiencies would have resulted had AE filed its electronic models. AE stated that this issue was the subject of a specific preliminary motion, which was denied by the Board. AE

[43] Rosenberg Pre-filed Evidence, p.3

indicated that its models contain confidential information, as they have been designed with the understanding that they would be maintained in confidence. AE stated that should disclosure be required, AE would have to redesign its models in order to ensure that confidential client information was protected. The manner, in which this issue should be handled in the future, should it arise, should be left to the hearing panel dealing with such a case.

AE also noted that the fact that TransAlta provided electronic models did not appear to expedite either the Information Request phase or the public hearing process in that proceeding. AE further noted that the tangible benefits foreseen by certain intervenors have not been demonstrated.

Board Findings

The Board generally agrees with the parties that the availability of electronic models would have assisted the Board and intervenors with the analysis of data included in the model. The extra time spent analyzing data manually might have been spent analyzing other issues in greater depth.

The Board notes that its letter of 14 October 1998, provided to all parties, required AE to provide only the data for this proceeding in electronic format; in essence accepting AE's indications that it would have to redesign its models in order to ensure that confidential client information was protected. However, the Board considers that the letter put AE on notice that it should be prepared to provide its COSS in a working electronic format if so requested in future proceedings. The Board directs AE to develop a format that will allow it to provide future COSS in working electronic format.

7. SUMMARY OF BOARD DIRECTIONS

This section is a summary of Board directions and has been prepared for the convenience of all parties. The directions in the main body of the Decision shall prevail over this summary if there are any differences.

1. The Board therefore directs AE to use actual 1998 pool prices for the purpose of determining the cost of pool purchases used in the refiling. The actual 1998 pool price record should be utilized in the calculation of pool purchases, Unit Obligation Values (UOVs), TOU rates and annual average energy costs. (See also Section 3(b)) [Section 2(a)(1)] p. 9

2. Therefore, since in Section 2(c), the Board finds that 25 kV costs should now be in transmission, the Board directs AE to pass through the actual TA Billings to every customer served at 25 kV or higher who is the only customer at a POD. [Section 2(d)(1)] p.25

3. Therefore, the Board directs AE to provide, at its next GRA, a study that applies the principle of cost causation, reflects changes in asset use since Decision E90050, and considers changes in the mix of customers in the customer and demand classifications. [Section 2(e)] p.33

4. The Board, therefore, directs AE to incorporate the 1993 study for marketing expenses into this proceeding. The Board also directs AE to update its marketing expense study for future Phase II applications. [Section 2(e)] p.33

5. The Board also directs AE to update its marketing expense study for future Phase II applications. [Section 2(e)] p.33

6. The Board directs AE to include meter reading and billing frequency as part of the allocation of customer accounting costs and to undertake a study to assess the reasonableness of the 2% weighting to energy, for its next Phase II proceeding. [Section 2(e)] p.33

7. Therefore, the Board directs AE to set its DISCO's overall revenue-to-cost ratios to 100% for each cost source. [Section 3(a)] p.39

8. To ensure some degree of rate stability in moving to accurate cost signals, the Board directs that in the refiling, the DISCO keep the overall increase in revenue arising from the rate redesign at less than 10% for any rate class. The revenue-to-cost ratio for both the Energy Supply and TA Billings components of each rate should be moved to exactly 100%, with the DISCO Services component (which is a residual) adjusted to ensure the overall increase in revenue is less than 10% for every rate class. [Section 3(a)] p.40

9. The Board directs that AE apply the actual 1998 hourly pool price record to AE's actual 1998 class load data in AE's refiling. [Section 3(b)] p.41

10. The Board directs AE to apply its actual metered class hourly load to the actual 1998 hourly pool price record to determine a more appropriate annual average cost of energy for each fixed rate class. [Section 3(b)] p.42

11. Similarly, the Board directs AE to use the average actual pool price in each TOU period in 1998 as the cost of energy components in the TOU rates. [Section 3(b)] p.42

12. The Board directs AE to use the fixed amount "H" charge calculated using the 1998 pool price record and total 1998 AE DISCO annual energy usage. [Section 3(b)] p.42

13. The Board directs AE to use the TA's interim 1999 rates (as approved in Order U99018, dated 11 February 1999) and AE DISCO's actual 1998 TA invoiced kWh and kW to determine updated TA Billings. The allocation to rate classes and transmission served customer classes should use actual 1998 hourly class load and NCP data to determine the kWh and kW charges. [Section 3(b)] p.42

14. The Board also directs AE to indicate the separate charges for the TA Billings and DISCO Services components on each rate schedule. [Section 3(b)] p.42

15. AE is directed to deduct the resulting total updated 1998 forecast costs of Energy Supply and updated TA Billings from AE DISCO's 1999 negotiated revenue requirement (as approved by the Board in Decision U99046) and use the resulting 1999 residual as the cost of AE's DISCO Services in the refiling. [Section 3(b)] p.42

16. The Board directs AE to prorate the 1998 distribution cost allocations (as adjusted for the removal of the 25 kV costs from distribution) in the Application to the 1999 residual in the re-filing to determine a level for the DISCO Services components in the refiled rates. [Section 3(b)] p.42

17. The Board further directs AE to attempt to confine the entire effect of any riders arising out of the 1999/2000 settlement agreements to the DISCO Services components of the rates. For those customers served at the transmission level the effect of any riders should be confined to the TA Billings components. [Section 3(b)] p.42

18. The Board directs AE to refile its COSS and rates on 1 September 1999. To confirm compliance to the Board's directions, the Board directs AE to supply tables setting out revenue-to-cost ratios for each rate by cost source (Energy Supply, TA Billings and DISCO Services) and to confirm that overall DISCO revenue-to-cost ratios by cost source are at 100%. [Section 3(b)] p.43

19. On that basis, the Board directs AE to refile company farm rates that reflect, in their DISCO Services component, the average change in the DISCO Services component of AE rates. [Section 4(b)(2)] p.52

20. Therefore, the Board directs AE to confer with the REAs to attempt to establish an appropriate level for the distribution wire and metering costs for company farm rates based on a benchmark of REA farm costs, prior to the PDT hearing. [Section 4(b)(2)] p.52

21. The Board directs that Price Schedule 32 should be modified to work exclusively for small distribution-connected generators in conjunction with Price Schedule 91. [Section 4(e)(2)] p.73

22. Therefore, the Board considers that the energy charges should flow through the pool price on Price Schedule 32 and that transmission-connected generators should only be eligible for the actual pool price DAT. Accordingly, the Board directs that AE incorporate the same Energy Supply charges as established for the actual pool price DAT in its refiled Price Schedule 32. [Section 4(e)(2)] p.73

23. Therefore, the Board directs that AE design a TA Billings component consistent with a 15% peak demand coincidence factor for distribution-connected generators. These demand charges are to be levied on the standby portion of the customer's load, not on Base Demand. Base Demand should be billed on the applicable underlying Price Schedule. On-peak and off-peak energy charges should mirror the TA charges. [Section 4(e)(2)] p.74

24. Under Price Schedule 91 distribution-connected generators will be required to pay for all upgrades to the distribution system required for their service. Therefore, the Board directs that DISCO Services charges only be levied on demand above the Base Demand plus the demand contracted under Price Schedule 91. The DISCO Services charges should be the same as for the applicable underlying Price Schedule. [Section 4(3)(2)] p.74

25. However, in light of the Board's intent in this Decision to remove all demand charges related to Energy Supply, the Board directs that the negotiated demand charge included under generation costs in the AE rate schedule be included instead under DISCO Service charges in the refiling. [Section 4(e)(3)] p.77

26. Therefore, the Board directs AE to consider only distribution related constraints when its customers otherwise qualify for the POR. [Section 4(e)(3)] p.77

27. Therefore, the Board directs AE to adopt the following conditions for Price Schedule 33:
    - The POR is available only when the TA determines that there is sufficient transmission capacity. Energy purchases may be curtailed at the TA's request for transmission system reasons.
    - The POR is available only when the TA determines that there is sufficient distribution capacity. Energy purchases may be curtailed at TA's request for distribution system security reasons.
    - The POR is available only to customers who meet the approved eligibility requirements and terms and conditions established by the TA for this type of service (i.e. GOS).
    - AE will work with eligible customers to qualify their loads for GOS.
    - The POR is available throughout the territory served by AE from the AIS for eligible loads greater than 1,000 kW.
    - The POR is applicable to WESCUP (In addition a monthly charge of $53,545, for WESCUP's transmission facility, is part of the Rider E Schedule.)

    [Section 4(e)(3)] p.77

28. Therefore, the Board directs AE to incorporate the same Energy Supply charges as established for the actual pool price DAT in the refiled Price Schedule 38. [Section 4(e)(5)] p.79

29. The Board directs AE to change its Price Schedule 41 ratchet to 85% for those customers served at the distribution level. [Section 4(f)(1)(A)] p.81

30. The Board therefore directs AE to include a study, with its PDT filing, that examines the commonalties and benefits shared between, oilfield, general service and farm customers and recommends an appropriate rate class or classes for these customers based on the costs to serve each customer type. [Section 4(f)(1)(A)] p.82

31. Therefore, the Board directs AE to provide a comprehensive review of the effects of changing demand meter types prior to the PDT hearing. [Section 4(f)(1)(B)] p.83

32. However, the Board notes that AE indicated that the 325 kWh/kW was more accurate at the of the hearing and the Board has directed that in most cases the actual 1998 values be used to determine cost of service for the rates arising out of the refiling. Therefore, the Board directs AE to use the 325 kWh/kW for Price Schedule 41 in its refiling. [Section 4(f)(1)(C)] p.83

33. Therefore, the Board directs that AE require each generator to pay all of the incremental cost required to allow it to use the distribution system. [Section 4(g)(1)] p.87

34. All costs of connection, and any costs required to upgrade upstream distribution facilities, will be payable by the generator. The Board directs AE to provide an option to allow generators to pay the costs of interconnection to AE over time, in the manner similar to Rider E. [Section 4(g)(1)] p.87

35. The Board also considers that each generator should be responsible for incremental operation and maintenance costs caused by any distribution upgrades it requires. The Board also directs AE to propose an appropriate charge for these incremental costs based on the operation and maintenance charges in Price Schedule 31. [Section 4(g)(1)] p.87

36. The Board further directs AE to set location credits or charges to zero for all generators less than 5 MW. If the generator or AE believes that losses are significantly affected by the location of a generator, the party seeking the change shall be responsible to pay for a local engineering study to calculate the effect of their operation on line losses. All proposed generators of capacity greater than 5 MW will be responsible to pay for a local engineering study, by a party agreed upon by the generator and AE, to calculate the effect of their operation on line losses. The Board directs AE to provide all information required for these studies and to reflect the results of the study in the particular generator's rate. [Section 4(g)(1)] p.87

37. Therefore, the Board directs that AE close the Temporary DAT to new customers as of the date of this Decision. [Section 4(h)] p.93

38. Therefore, the Board directs AE to design its TOU DAT rate with the following separated components:
    - the average actual pool price in each TOU period in 1998 representing the cost of energy components in the TOU rates;
    - the fixed amount "H" charge calculated using the 1998 pool price record and 1998 total AE DISCO annual energy usage; and
    - TA Billings charges which pass through the TOU charges in the TA's rates.

    [Section 4(h)] p.95

39. Therefore, the Board directs AE to design its actual pool price DAT rate with the separated components which follow:
    - the actual pool price in each hour less the adjustment amount if the adjustment is positive as the cost of energy component;
    - the fixed amount "H" charge calculated using the 1998 pool price record and 1998 total AE DISCO annual energy usage; and
    - TA Billings charges which pass through the TOU charges in the TA's rates.

    [Section 4(h)] p.96

40. Therefore, the Board considers it appropriate to direct that DAT rates include the provision that notice can be given only after a customer has been on the rate for six months. [Section 4(h)] p.96

41. The Board accepts Price Option N as filed, but directs AE to provide justification if it wishes to continue pricing this Option below cost in its next Phase II proceeding. [Section 4(i)(3)] p.100

42. In light of the findings regarding the allocation of the costs of transmission and distribution facilities, the Board directs AE to refile the Price Option P credit with any adjustments required to reflect the revised allocations. [Section 4(i)(4)] p.101

43. The Board will allow AE to withdraw this Price Option when the Board approves a final TOU DAT. The Board directs AE to keep Option T in effect until that time. [Section 4(i)(5)] p.102

44. Therefore, the Board directs AE to refile Price Option U adjusted as required to reflect this and other findings in the Decision. [Section 4(i)(6)] p.103

45. In light of the findings in Section 3(a), the Board directs AE to redesign Rider A-2 to collect an additional 10% in overall revenue. [Section 4(j)(2)] p.104

46. Since the Board allowed certain portions of the T&C (set out in Exhibit 51) to be extracted from the Phase II proceeding, the Board considers that it would be inappropriate to deal with those portions in this Decision. AE is directed to provide an update on the status of those portions of the T&C extracted, the negotiations, and a plan for dealing with any matter discussed but not resolved through the negotiations. [Section 5(a)] p.109

47. The Board directs AE to prepare a Filing for Acknowledgement for any new rate on a timely basis. [Section 5(b)(1)] p.113

8. ORDER

Therefore, it is ordered that:

(1) ATCO Electric Ltd. shall refile its proposed Rates and Options and its Terms and Conditions, on or before 1 September 1999, incorporating the findings of the Board in this Decision.

(2) ATCO Electric Ltd., in its refiling, shall include a cost of service study incorporating the findings of the Board in this Decision

(3) ATCO Electric Ltd., in its refiling, shall include the revenue-to-cost ratios for each rate by cost source (Energy Supply, TA Billings and DISCO Services).

DATED in Calgary, Alberta on 10 August 1999.

ALBERTA ENERGY AND UTILITIES BOARD

B. T. McManus, Q.C.
Presiding Member

J. P. Prince, Ph.D.
Member

H. Jainarine, FCCA
Acting Member

APPENDIX 1

PARTIES PARTICIPATING IN THE PROCEEDING

PRINCIPALS AND REPRESENTATIVES

ATCO Electric Ltd. (AE)	Mr. L. G. Keough
Municipal Intervenor (MI)	Mr. J. A. Bryan, Q.C.
Industrial Power Consumers Association of Alberta (IPCAA)	Mr. D. E. Crowther
Alberta Association of Municipal Districts and Counties (AAMDC)	Mr. L. J. Burgess, Q.C.
Alberta Irrigation Projects Association (AIPA)	Mr. H. Unryn
TransCanada Energy Ltd. (TransCanada)	Ms. B. Andriachuk
Alberta Federation of REAs Ltd. (REA)	Mr. K. L. Sisson
Public Institutional Consumers of Alberta (PICA)	Ms. N. J. McKenzie
Consumers' Coalition of Alberta (CCA)	Mr. J. A. Wachowich
EPCOR Utilities	Mr. J. Liteplo
Slave Lake Pulp Corporation (SLPC)	Mr. M. Forster
Canadian Forest Products Limited (Canfor)	Mr. T. E. Vanderveen
Independent Power Producers Society of Alberta and Senior Petroleum Producers Association (IPPSA/SPPA)	Mr. L. L. Manning
Enmax Corporation (Enmax)	Mr. R. Brander
Alberta Co-generators Council (ACC)	Mr. R. C. Secord

WITNESSES

ATCO Electric Ltd.	Mr. W. Frost Ms. H. Kirrmaier Mr. J. Olsen
Industrial Power Consumers Association of Alberta	Mr. M. Drazen Ms. B. S. Hoffman Mr. R. Mikkelson Mr. R. Gallant Mr. D. Macnamara
The FIRM Customers	Mr. W. B. Marcus
Alberta Federation of REAs Ltd.	Mr. W. B. Marcus
Senior Petroleum Producers Association	Mr. K. Wilford Mr. D. Hildebrand Mr. C. Samuels Mr. J. Clark
Independent Power Producers Society of Alberta and Senior Petroleum Producers Association	Mr. R. D. Knecht
Alberta Co-generators Council	Dr. A. Rosenberg

APPENDIX 2

ABBREVIATIONS

A&G	Administrative and General
AAMDC	Alberta Association of Municipal Districts and Counties
ACC	Alberta Co-generators Council
AE	ATCO Electric Ltd. (formerly Alberta Power Limited)
AIPA	Alberta Irrigation Projects Association
AIS	Alberta Integrated System
APL	Alberta Power Limited
Board or AEUB	Alberta Energy and Utilities Board
Canfor	Canadian Forest Products Limited
CCA	Consumers Coalition of Alberta
CGCL	Consumers' Gas Company Limited
COSS	Cost of Service Study
DAT	Direct Access Tariff
DCGI	Drazen Consulting Group Inc.
DISCO	Distribution Company
EEMA	Electric Energy Marketing Agency
ESA	Electric Service Agreements
ESR	Electric Service Regulations
EU Act	*Electric Utilities Act*
EUA Act	*Electric Utilities Amendment Act*
FCE	Fletcher Challenge Energy Canada Inc.

FIRM Customers	Alberta Association of Municipal Districts and Counties, Alberta Federation of REAs Ltd., Alberta Irrigation Projects Association, Consumers Coalition of Alberta, Municipal Intervenors and Public Institutional Consumers of Alberta
GENCO	Generation Company
GIO	Grid Import Opportunity Service
GIS	Grid Interconnection Service
GOS	Grid Opportunity Service
GRA	General Rate Application
Gridco	Grid Company of Alberta
GSS	Grid Standard Service
GXO	Grid Export Opportunity Service
IPCAA	Industrial Power Consumers Association of Alberta
IPPSA	Independent Power Producers Society of Alberta
kV	Kilovolt
kVA	Kilovolt ampere
kW	Kilowatt
kWh	Kilowatt hour
MI	Municipal Intervenors
MVA	Mega volt amperes
NCP	Non-Coincident Peak
O&M	Operating and Maintenance
PDT	Preliminary Distribution Tariff
PICA	Public Institutional Consumers of Alberta

POD	Point of Delivery
POR	Pool Opportunity Rate
REA	Alberta Federation of REAs Ltd.
RP	Reservation payment
SaskPower	Saskatchewan Power Corporation
SC/RV	Stranded cost/residual value
SLPC	Slave Lake Pulp Corporation
SPPA	Senior Petroleum Producers Association
T&C	Terms and Conditions
TA	Transmission Administrator
TDAT	Temporary Direct Access Tariff
TRR	Totalization Rate Rider
TOU	Time-of-use
TransAlta	TransAlta Utilities Corporation
TransCanada	TransCanada Energy Ltd.
TRANSCO	Transportation Company
UOA	Unit Obligation Amount
UOV	Unit Obligation Value
WESCUP	Westcoast Energy Inc./Canadian Utilities Power
3W/9NW	3 winter months/9 non-winter months

APPENDIX 3

REFERENCES

ORDER/ DECISION/ REPORT NO.	DATE	PARTICULARS
E87100	18 December 1987	Alberta Power Limited, Edmonton Power and TransAlta Utilities Corporation (Decision – 1986 Electric Energy Marketing Agency Application)
E88080	23 December 1988	Alberta Power Limited, Edmonton Power & TransAlta Utilities Corporation (Decision – 1987 Electric Energy Marketing Agency Application)
E90050	15 October 1990	Alberta Power Limited (Decision – 1989/1990 General Rate Application – Phase II)
E91047	24 July 1991	Alberta Power Limited (Order – Fix the municipal revenue tax rate surcharge to be applied as an addition to its customers rates in the Town of Swan Hills)
E92039	18 May 1992	Alberta Power Limited (Decision – 1992 General Rate Application B Phase I)
E93035	25 May 1993	Alberta Power Limited (Decision – 1991/1992 General Rate Application – Phase II)
E95102	20 October 1995	Alberta Power Limited (Decision – 1993 Expedited – Phase II)
E95121	21 December 1995	Alberta Power Limited (Decision – 1996 Interim Electric Tariffs)
U97065	31 October 1997	Alberta Power Limited, Edmonton Power Inc., TransAlta Utilities Corporation and Grid Company of Alberta (Decision – 1996 Electric Tariff Application)
U97154	19 December 1997	Alberta Power Limited (Order – 1995 Electric Tariff Refiling
U98027	30 January 1998	Alberta Power Limited (Decision – 1997 Tariff Application)
U98081	19 May 1998	Alberta Power Limited (Decision – 1998 Rates)

U98093	3 June 1998	TransAlta Utilities Corporation (Order – 1998 Rate Application)
U99006	25 January 1999	Alberta Power Limited (Decision – 1996 General Rate Application, Phase II – Conversion of Pool Opportunity Rate Service to Rate 31 Service)
U99014	8 February 1999	Alberta Power Limited (Decision – 1996 General Rate Application, Phase II – Temporary Direct Access Tariff)
U99018	11 February 1999	ESBI Alberta Ltd. (Order – 1999 tariffs on an interim refundable basis)
U99046	10 May 1999	ATCO Electric Ltd. (Decision – 1999/2000 Tariff Application – Phase I – Negotiated Settlement)

APPENDIX 4

HOW THE RP ALLOCATION METHOD MAY DISTORT THE POOL PRICE SIGNAL

Example Hours	Example Pool Price (PP)	Assuming that Load = Called Entitlements: TAU Method Reservation Payment (AvgRP*UOV/AvgUOV) (19.69*e/26.55)	Example AVG UOP (Estimates)	UOV (PP-UOP) (b-d)	HOURLY GENERATION COST ALLOCATION TO CUSTOMER USING: TRANSALTA'S PROPOSED METHODS: L 10%<Centitlem ALL CLASSES PP+1.11*(RP-UOV) (b+1.11*(c-e))	L=Centitlem ALL CLASSES (PP+RP-UOV) (b+c-e)	L 10%>Centitlem ALL CLASSES PP+.909*(RP-UOV) (b+.909*(c-e))	BOARD METHOD (For any ratio of Load/Centitlem) ALL CLASSES (PP+Avg RP- Avg UOV) (b+19.69-26.55)	VARIATION FROM PRIOR HOUR: IN PP	IN GENERATION COST ALLOCATION: TRANSALTA (Assuming L=Centitlem In each hour)	TRANSALTA (Assuming that L 10%>Centitlem In each hour)	BOARD (For any ratio of Load/Centitlem)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
1	32.00	20.77	4.00	28.00	23.97	24.77	25.42	25.14				
2	40.00	25.59	5.50	34.50	30.11	31.09	31.90	33.14	8.00	6.32	6.47	8.00
3	20.00	12.24	3.50	16.50	15.27	15.74	16.12	13.14	-20.00	-15.35	-15.77	-20.00
4	100.00	69.71	6.00	94.00	73.04	75.71	77.92	93.14	80.00	59.98	61.80	80.00
5	500.00	366.36	6.00	494.00	358.32	372.36	383.98	493.14	400.00	296.65	306.05	400.00
6	50.00	32.63	6.00	44.00	37.38	38.63	39.67	43.14	-450.00	-333.73	-344.31	-450.00
Annual Avg Example	31.25	19.69	4.70	26.55	23.64	24.39	25.01	24.39	-18.75	-14.24	-14.65	-18.75
	31.25	19.69	4.70	26.55								
		-6.86										

H= Forecast annual DISCO RP- Forecast Disco total annual UOV refund / Forecast Disco annual energy use

H= Annual Avg RP - Annual Avg UOV = 19.69 - 26.55 = - 6.86

Centitlem=	hour's called entitlements
L=	hour's load
PP=	hour's pool price
AVG UOP=	estimated MWh weighted average UOP of units running in the hour
Annual Avg UOV=	total forecast annual Disco UOV/total forecast Disco annual energy use
Annual Avg RP=	total forecast annual Disco RP/total forecast Disco annual energy use
"H" Factor=	Annual Avg RP - Annual Average UOV
Generation Cost=	pool price plus net value of legislated hedges

This Attachment illustrates how variation in the generation cost allocated to customers does not match variation in the pool price signal when RP is allocated per TransAlta's UOV based energy method (Column(c)). Column (c) shows how the RP allocated would be higher in high PP hours (Column (b)). As a result TransAlta's method (Columns (k)&(l)) results in a distortion, since the generation cost allocated does not vary directly with variation in the pool price signal (Column (j)). The Board's method (Column (m)) using the "H" Factor (H = annual avg RP-annual avg UOV) the variation in the generation cost allocated equals the variation in the pool price signal. (i.e. In hour 2 the pool price has increased from $32 to $40 or by $8, but the generation cost allocated under TransAlta's method would increase by $6.32 or $6.14 (depending on the ratio of load to called entitlements and assuming that ratio remained constant). Under the Board's method (Column (m)) the variation in hourly pool price would be exactly matched by the increase in generation cost allocated.) The annual average RP and UOV and the hourly PP and average UOP are numbers provided to illustrate the principles demonstrated herein and are not necessarily representative.

Explanation of column:

(a) example hour

(b) example pool price per MWh in example hour

(c) calculated RP per MWh allocated to the example hour: using TransAlta's allocation method

RP = (Avg Annual RP)*(Hour's Forecast UOV)/(Avg Annual UOV)

(d) estimated MWh weighted average UOP of the units running in the example hour per MWh

estimated AVG UOP=sum of each called unit's UOA*(that unit's UOP)/(sum of all units' called UOAs)

(e) calculated UOV per MWh in example hour if load is equal to called entitlements

UOV = PP - AVG UOP

(f) calculated total generation cost per MWh to be allocated to customer if the load is 10% less than the called entitlements in the hour using TransAlta's allocation methods

Generation Cost = $\dfrac{\text{Hours Load *PP + 1.11*(Hour's Load)*RP - 1.11*(Hour's Load)*UOV}}{\text{Hour's Load}}$ = PP +1.11*RP - 1.11*UOV

(g) calculated total generation cost per MWh to be allocated to customer if the load is equal to the called entitlements in the hour using TransAlta's allocation methods

Generation Cost = $\dfrac{\text{Hour's Load *PP + (Hour's Load)*RP - *(Hour's Load)*UOV}}{\text{Hour's Load}}$ = PP + RP - UOV

(h) calculated total generation cost per MWh to be allocated to customer if the load is 10% greater than the called entitlements in the hour using TransAlta's allocation methods

Generation Cost = $\dfrac{\text{Hour's Load *PP + .909*(Hour's Load)*RP - .909*(Hour's Load)*UOV}}{\text{Hour's Load}}$ = PP +.909*RP - .909*UOV

(i) calculated total generation cost per MWh to be allocated to customer for any ratio of load to called entitlements using Board's allocation method

Generation Cost = PP + H

(j) calculated variation from the prior hour in the pool price

Variation = (PP in prior hour) - (PP in hour)

(k) calculated variation from the prior hour in the total generation cost per MWh allocated, if the load is assumed to be equal to the called entitlements in each hour, using TransAlta's allocation methods

Variation = (Generation Cost in prior hour) - (Generation cost in hour)

(l) calculated variation from the prior hour in the total generation cost per MWh allocated, if the load is assumed to be 10% greater than the called entitlements in each hour, using TransAlta's allocation methods

Variation = (Generation Cost in prior hour) - (Generation cost in hour)

(m) calculated variation from the prior hour in the total generation cost per MWh allocated for any ratio of load to called entitlements using Board's allocation method

Variation = (Generation Cost in prior hour) - (Generation cost in hour)

APPENDIX 5

HOW THE METHOD OF ALLOCATION OF UOV REFUNDS MAY DISTORT THE POOL PRICE SIGNAL

		Assuming that Load = Called Entitlements			HOURLY GENERATION COST ALLOCATION TO CUSTOMERS USING: TRANSALTA'S PROPOSED METHODS			BOARD METHOD	VARIATION FROM PRIOR HOUR: IN PP	IN GENERATION COST ALLOCATION TRANSALTA	TRANSALTA	BOARD
Example Hours	Example Pool Price (PP)	Reservation Payment (Set to 0)	Example AVG UOP (Estimates)	UOV (PP-UOP) (b-d)	L 10%<Centitlem ALL CLASSES PP+1.11*(RP-UOV) (b+1.11*(c-e))	L=Centitlem ALL CLASSES (PP+RP-UOV) (b+c-e)	L 10%>Centitlem ALL CLASSES PP+.909*(RP-UOV) (b+.909*(c-e))	Any Load/Centitlem ALL CLASSES (PP+Avg RP- Avg UOV) (b+0-26.55)		(Assuming L=Centitlem In each hour)	(Assuming that L 10%>Centitlem In each hour)	(For any ratio of Load/Centitlem)
(a)	(b) $/MWh	(c) $/MWh	(d) $/MWh	(e) $/MWh	(f) $/MWh	(g) $/MWh	(h) $/MWh	(i) $/MWh	(j) $/MWh	(k) $/MWh	(l) $/MWh	(m) $/MWh
1	32.00	0.00	4.00	28.00	0.92	4.00	6.55	5.45				
2	40.00	0.00	5.50	34.50	1.71	5.50	8.64	13.45	8.00	1.50	2.09	8.00
3	20.00	0.00	3.50	16.50	1.69	3.50	5.00	-6.55	-20.00	-2.00	-3.64	-20.00
4	100.00	0.00	6.00	94.00	-4.34	6.00	14.55	73.45	80.00	2.50	9.55	80.00
5	500.00	0.00	6.00	494.00	-48.34	6.00	50.95	473.45	400.00	0.00	36.40	400.00
6	50.00	0.00	6.00	44.00	1.16	6.00	10.00	23.45	-450.00	0.00	-40.95	-450.00
Annual Avg Example	31.25	0.00	4.70	26.55	1.78	4.70	7.12	4.70	-18.75	-1.30	-2.89	-18.75
	31.25	0.00	4.70	26.55								
		-26.55										

H= Forecast annual Disco RP- Forecast Disco total annual UOV refund / Forecast Disco annual energy use

H= Annual Avg RP - Annual Avg UOV = 0 - 26.55 = - 26.55

DEFINITIONS:

Centitlem=	hour's called entitlements
L=	hour's load
PP=	hour's pool price
AVG UOP=	estimated MWh weighted average UOP of units running in the hour
Annual Avg UOV-	total forecast annual Disco UOV/total forecast Disco annual energy use
Annual Avg RP=	total forecast annual Disco RP/total forecast Disco annual energy use
"H" Factor=	Annual Avg RP - Annual Average UOV
Generation Cost=	pool price plus net value of legislated hedges

This Attachment illustrates how variation in the total cost of generation does not match variation in the pool price under TransAlta's method of allocating the UOV. The RP is set to 0 (Column (c)) so that the distortion caused can be clearly seen. Use of TransAlta's UOV allocation method (Columns (k)&(l)) results in a distortion since the variation in generation cost allocated is not equal to the variation in the pool price signal (Column (j)). Under the Board's method (Column (m)) using the "H" Factor (H = annual avg RP-annual avg UOV) the variation in generation cost allocated is equal to the variation in the pool price signal. (i.e. In hour 2 the pool price has increased from $32 to $40 or by $8, but the generation cost allocated under TransAlta's method would increase by $6.32 or $6.14 (depending on the ratio of load to called entitlements and assuming that ratio remained constant). Under the Board's method (Column (m)) the increase in pool price would be exactly matched by the increase in generation cost allocated regardless of the ratio of load to called entitlements in either hour.) The annual average RP and UOV and the hourly PP and average UOV are numbers used to illustrate the principles demonstrated herein and not necessary representative.

Explanation of column:

(a) example hour

(b) example pool price per MWh in example hour

(c) RP has been set to zero to so as not to mask the effect of the UOV allocation methods

(d) estimated MWh weighted average UOP of the units running in the example hour per MWh

estimated AVG UOP=sum of each called unit's UOA*(that unit's UOP)/(sum of all units' called UOAs)

(e) calculated UOV per MWh in example hour if load is equal to called entitlements

UOV = PP - AVG UOP

(f) calculated total generation cost per MWh to be allocated to customer if the load is 10% less than the called entitlements in the hour using TransAlta's allocation methods

$$\text{Generation Cost} = \frac{\text{Hour's Load *PP + 1.11*(Hour's Load)*RP - 1.11*(Hour's Load)*UOV}}{\text{Hour's Load}} = \text{PP + 1.11*RP - 1.11*UOV}$$

(g) calculated total generation cost per MWh to be allocated to customer if the load is equal to the called entitlements in the hour using TransAlta's allocation methods

$$\text{Generation Cost} = \frac{\text{Hour's Load *PP + (Hour's Load)*RP - *(Hour's Load)*UOV}}{\text{Hour's Load}} = \text{PP + RP - UOV}$$

(h) calculated total generation cost per MWh to be allocated to customer if the load is 10% greater than the called entitlements in the hour using TransAlta's allocation methods

$$\text{Generation Cost} = \frac{\text{Hour's Load *PP + .909*(Hour's Load)*RP - .909*(Hour's Load)*UOV}}{\text{Hour's Load}} = \text{PP +.909*RP - .909*UOV}$$

(i) calculated total generation cost per MWh to be allocated to customer for any ratio of load to called entitlements using Board's allocation method

Generation Cost = PP + H

(j) calculated variation from the prior hour in the pool price

Variation = (PP in prior hour) - (PP in hour)

(k) calculated variation from the prior hour in the total generation cost per MWh allocated, if the load is assumed to be equal to the called entitlements in each hour, using TransAlta's allocation methods

Variation = (Generation Cost in prior hour) - (Generation cost in hour)

(l) calculated variation from the prior hour in the total generation cost per MWh allocated, if the load is assumed to be 10% greater than the called entitlements in each hour, using TransAlta's allocation methods

Variation = (Generation Cost in prior hour) - (Generation cost in hour)

(m) calculated variation from the prior hour in the total generation cost per MWh allocated for any ratio of load to called entitlements using Board's allocation method

Variation = (Generation Cost in prior hour) - (Generation cost in hour)

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

APPLICATION FOR APPROVAL OF RATES BETWEEN
BC HYDRO AND FORTISBC INC. WITH REGARDS TO RATE SCHEDULE 3808,
TARIFF SUPPLEMENT NO. 3 – POWER PURCHASE
AND ASSOCIATED AGREEMENTS,
AND TARIFF SUPPLEMENT NO. 2 TO RATE SCHEDULE 3817

DECISION

May 6, 2014

Before:

L.A. O'Hara, Panel Chair and Commissioner
B.A. Magnan, Commissioner
R.D. Revel, Commissioner

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

LIST OF FIGURES AND TABLES

EXECUTIVE SUMMARY

This Decision considers an application by the British Columbia Hydro and Power Authority (BC Hydro) to replace the existing 1993 Power Purchase Agreement between BC Hydro and FortisBC Inc. (FortisBC or Co-signatory) under Rate Schedule (RS) 3808 with a new Power Purchase Agreement (New PPA) and three supplemental agreements (Application). They include the Imbalance Agreement, the Energy Export Agreement and the Master Accounting Agreement (the Associated Agreements). The Application also seeks approval for associated amendments to RS 3808 and for amendments to the existing General Wheeling Agreement under Tariff Supplement No. 2 to Rate Schedule 3817. BC Hydro requests that the Commission approve the Application pursuant to sections 58 to 61 of the *Utilities Commission Act* (*UCA*), as the rates are not unjust or unreasonable.

FortisBC as the Co-signatory, and for the purpose of purchasing energy and capacity a BC Hydro customer with Intervener status, filed submissions in support of the New PPA and the Associated Agreements. BC Hydro points out that the New PPA and Associated Agreements have been negotiated under the same basic parameters of service as the 1993 PPA. BC Hydro states the only change relates to the addition of a provision for FortisBC to purchase PPA power while simultaneously exporting in relation to the Waneta Dam Expansion (WAX) Project capacity.

The New PPA is a 20-year fixed term agreement that continues to provide for up to 200 megawatts (MW) of capacity and 1,752 GWh/year of associated energy for FortisBC to meet a portion of its load service obligations. The New PPA has a two-tranche pricing structure for energy. Tranche 1 up to 1,041GWh/year reflects an energy charge based on embedded cost rates equal to that of BC Hydro's industrial customers on RS 1827, currently at 3.724 cents/kWh. The Tranche 2 price reflects BC Hydro's long run marginal cost, currently at 12.97 cents/kWh. In contrast, the 1993 PPA provided FortisBC with the entire 1,752 GWh/year at the lower embedded cost rate.

Assessment of Agreements

Some Interveners expressed concerns about the fairness of including conditions in the New PPA that impact those customers that are not parties to the agreements. Specifically, concerns related to the continued restrictions on self-generating customers in the FortisBC service area. As a result, the Panel conducted two separate evaluations of the New PPA and Associated Agreements. The first evaluation assessed the fairness of the agreements without consideration of the self-generator restrictions. A second, separate parallel evaluation of the self-generator issues focussed specifically on section 2.5 of the New PPA.

With regard to the first evaluation, the Panel gave weight to the fact that the New PPA and Associated Agreements were a result of an extensive and complex negotiation process by two sophisticated parties involving a series of trade-offs. By way of a summary, the Panel concluded that the New PPA and Energy Export Agreement pass the Bonbright fairness and efficiency principles test and that the other Associated Agreements were not unjust, unreasonable, unduly discriminatory or unduly preferential. Therefore, the New PPA and Associated Agreements represent a balanced package and, without consideration of the restrictions on FortisBC relating to its self-generating customers, are fair.

The second evaluation raised concerns of such magnitude that the Panel decided to seek supplemental submissions from the registered participants on December 13, 2013. This step resulted in valuable additional submissions, but in the end did not alleviate the earlier key concerns which were as follows:

- Significant erosion in FortisBC's customer protection as the customer is excluded from having any meaningful input into what its appropriate customer-specific baseline should be — and the potential for different treatment of self-generating customers in BC Hydro's and FortisBC's service territories;
- Concerns related to the 2012 Information Report, which BC Hydro and FortisBC intend to use as guide for setting customer-specific baselines or Contracted Generator Baselines (GBLs);
- Section 2.5 of the New PPA neither enforces the self-generation policy in the FortisBC service territory nor protects ratepayers. It only protects BC Hydro's ratepayers against potential detriment caused by arbitrage in FortisBC's service area.

Context for the Remaining Concerns

The Panel finds that lack of consistent, clear Province-wide policies regarding self-generators is the likely underlying reason for the ongoing regulatory cases in FortisBC territory. This absence is compounded by uncertainty surrounding the applicability of the 1999 Access Principles to self-generators and lack of GBL Guidelines or other methodology consistently applied by FortisBC. The Panel also accepts that past Commission rulings may have contributed to the current predicament. This lack of high level principles highlighted the need for a separate proceeding to provide more certainty and set principles on a go-forward basis as outlined in the following.

Several Interveners requested that regulation for FortisBC's self-generator customer exports should be addressed in a separate, stand-alone document. The Panel further found that it is in fact extra-ordinary for a policy issue of a regulated utility to be addressed through a rate schedule of another utility — even if that rate schedule is between the two utilities. Thus the self-generation policy issues must be addressed in the FortisBC service territory. As a result, FortisBC is directed to initiate a consultation process in its service territory to address or ensure:

(i) the potential benefits of self-generation;
(ii) the 1999 Access Principles in the context of self-generating customers;
(iii) if the GBL methodology is proposed, GBL Guidelines for both idle historic self-generation and new self-generation; and
(iv) arbitrage is not allowed.

Panel's Preferred Solution

In the interest of regulatory efficiency, the Panel's preferred solution would be to immediately remove the restrictions from section 2.5 as it finds that due to the characteristics of the New PPA BC Hydro's ratepayers no longer require the protection, especially in the short term. However, the Panel also concludes that it may be somewhat premature as FortisBC's self-generation policies are not sufficiently developed, articulated and approved by the Commission.

Intermediate Solution

The amendments to section 2.5 of the New PPA proposed by BC Hydro on April 9, 2014 offer a practical solution to move forward with prompt approval of the New PPA and Associated

Agreements. They allow for a separate BC Hydro consultation process with FortisBC and stakeholders, which is intended to increase transparency for determination of customer-specific baselines and Contracted GBLs. Customer-specific baselines will now be determined in accordance with Commission-approved guidelines and in consultation with the customer. Furthermore, FortisBC as the Co-signatory and most of the other Interveners provide their overwhelming support. For this approach complements the Panel's directive for FortisBC to start its own concurrent consultation process to establish high level self-generation policy principles in its own service territory.

Accordingly, the Panel approves the New PPA and Associated Agreements for an effective date of July 1, 2014. BC Hydro is directed to initiate a consultation process that will result in an application for the New PPA Section 2.5 Guidelines by November 1, 2014. Once the Guidelines have been approved by the Commission, they are to be added to the New Power Purchase Agreement as an appendix.

In the interest of an efficient process, the Panel encourages collaboration between BC Hydro and FortisBC to the extent possible as these two concurrent consultation processes are carried out. The Panel is hopeful that once these undertakings have resulted in well documented Commission-approved principles, the Commission will seek submissions from parties to determine whether it would be reasonable to eventually remove the restrictions from section 2.5 of the New PPA — in pursuit of improved regulatory efficiency.

1.0 INTRODUCTION

The British Columbia Hydro and Power Authority (BC Hydro, the Applicant) has supplied electricity to FortisBC Inc. (FortisBC, the Co-signatory) for 20 years, pursuant to a Power Purchase Agreement dated October 1, 1993. The energy supply provided is to meet a portion of FortisBC's load service obligations, at rates established by the British Columbia Utilities Commission (Commission or BCUC) and set out in BC Hydro's Rate Schedule 3808. This Decision considers an application by BC Hydro requesting approval to replace the 1993 Power Purchase Agreement (1993 PPA).

The 1993 PPA expired on September 30, 2013. Both BC Hydro and FortisBC provided the Commission with written acceptance to continue the current Commission approved Rate Schedule (RS) 3808 and the 1993 PPA until such time as the Commission determines otherwise. (Exhibit B-15; Exhibit C1-23)

BC Hydro is a Crown corporation with a mandate to generate, transmit, distribute and sell electricity and is the largest generator of electricity in the Province of British Columbia. BC Hydro is the main distributor of electricity for most areas within the Province with a few exceptions, including the Kootenay region, where FortisBC provides electric service. FortisBC is an integrated utility that generates, transmits and distributes electricity to approximately 163,000 customers including residential, commercial, wholesale and industrial users. The map of the FortisBC service territory is enclosed as Appendix A.

1.1 The Application and Orders Sought

On May 24, 2013, BC Hydro filed an application with the Commission requesting approval, pursuant to sections 58 to 61 of the *Utilities Commission Act* (*Act* or *UCA*), to replace the existing 1993 PPA between BC Hydro and FortisBC (the Parties) under Tariff Supplement No. 3 to RS 3808 with a new Power Purchase Agreement (New PPA) containing three supplemental agreements. The three supplemental agreements include the Imbalance Agreement (IA), the Energy Export Agreement (EEA) and the Master Accounting Agreement (MAA). The Application also requested approval for associated amendments to RS 3808 and for amendments to the existing General Wheeling Agreement (GWA) under Tariff Supplement No. 2 to Rate Schedule 3817 (Exhibit B-1, p. 3). The New PPA, Supplemental Agreements and the Amended and Restated Wheeling Agreement (ARWA) are collectively referred to as the 'New PPA and Associated Agreements' or the 'Application' and are further described in Section 4.0 of this Decision.

On May 27, 2013, FortisBC filed, with the Commission, a 25 page letter supporting the Application as filed (Letter of Support). FortisBC states that the New PPA will be an important component of FortisBC's power supply portfolio, and conveys meaningful benefits to its customers through the continuation of this long term, secure, flexible, reliable and cost effective resource supplied by BC Hydro.

BC Hydro submits that the agreements work together as a package and, as such, it is not possible to alter a component of these agreements without affecting the overall balancing of interest negotiated by BC Hydro and FortisBC (the Parties) and reflected in the package. BC Hydro further submits that in circumstances of this Application, the Commission ought to exercise restraint in considering whether to nevertheless impose changes as an exercise in discretion. BC Hydro states that the New PPA and Associated Agreements have been negotiated under the same basic parameters of service as the 1993 PPA and the only change relates to the addition of FortisBC's ability to purchase RS 3808 power while simultaneously exporting in relation to WAX Project capacity. BC Hydro requests that the Commission approve the Application as filed, as the rates are not unjust or unreasonable. (BC Hydro Final Submission, pp. 4, 6 and 16)

FortisBC states that the development of the New PPA and Associated Agreements was the result of extensive and complex negotiations and required a series of trade-offs. FortisBC agrees that the New PPA and Associated Agreements operate together as a unified package and, as such, it is not possible to alter specific aspects of these agreements without affecting the parties' position in other areas. FortisBC supports the Application and requests that the Commission approve the New PPA and Associated Agreements as filed. (Exhibit C1-2, p. 4; FortisBC Final Submission, p. 7)

1.2 Interveners

FortisBC registered as an Intervener in the Proceeding and since it is the Co-signatory to the New PPA and Associated Agreements it was granted additional regulatory process privileges not normally extended to an Intervener.

British Columbia Municipal Electrical Utilities (BCMEU), British Columbia Pensioners and Seniors Organisation et al. (BCPSO), British Columbia Sustainable Energy Association and Sierra Club of British Columbia (BCSEA), Commercial Energy Consumers Association of British Columbia (CEC), Norman Gabana, Industrial Consumers Group (ICG), Morgan Stanley Capital Group Inc., Vanport Sterilizers Inc.(Vanport), Alan Wait and Zellstoff Celgar Partnership Limited (Celgar) also Intervened in the proceeding.

Willis Energy Services Ltd. and Shell Energy North America registered as Interested Parties.

1.3 Regulatory Process

The Application was heard by way of a Written Hearing that consisted of two rounds of Information Requests (IRs), Final Submissions and two additional rounds of Supplemental Submissions. One Procedural Conference was also held after the responses to the first set of IRs were filed with the Commission.

Interveners were given the opportunity to send IRs to BC Hydro on the Application and to FortisBC on its Letter of Support. FortisBC was permitted to file its Final Submission one week before the other Interveners and was also given a right of reply. None of the other Interveners filed evidence.

The regulatory process for this proceeding is fully summarized in Appendix B.

2.0 REGULATORY AND POLICY FRAMEWORK

In reviewing the Application, the Commission Panel first considered the applicable sections of the *UCA*, various relevant provincial government energy policies and Heritage Special Direction No. 2. In addition, a number of relevant past Commission decisions as well as current related pending applications were considered as components of the framework.

2.1 Relevant Sections of the *UCA*

The Application requests that the Commission approve the New PPA and Associated Agreements as rates pursuant to sections 58 to 61 of the *UCA*.

BCPSO raised concern as to "whether or not the New PPA and associated agreements represent an energy supply contract for FortisBC… and therefore whether the Commission must also make a determination, pursuant to section 71 of the *Act*, as to whether or not the contract is in the public interest" (BCSPO Final Submission, pp. 5–6).

BC Hydro responded to this concern stating:

> "FortisBC is not required to [obtain section 71 approval] because none of the agreements included in the Application fall within the *UCA*'s definition of 'energy supply contract':
>
> > '"energy supply contract" means a contract under which energy is sold by a seller to a public utility or another buyer, and includes an amendment of that contract, but does not include a contract in respect of which a schedule is approved under section 61 of this *Act*." (BC Hydro Reply Submission, p. 2).

The Commission Panel notes that the New PPA and Associated Agreements have been filed as rates under sections 58–61 of the *UCA* and hence the definition of "Energy Supply Contract" as set out in section 68 of the *UCA* does not apply.

Accordingly, the Commission Panel finds that approval of the Application pursuant to section 71 of the *UCA* is not required; however, particular attention was given by the Panel to the following sections of the *UCA* in reviewing the Application:

Discrimination in Rates — Section 59 of the *UCA*

- A public utility must not make, demand or receive an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia (s. 59(1)(a));
- A public utility must not as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage (s. 59(2)(a)); and
- It is a question of fact, of which the commission is the sole judge, (a) whether a rate is unjust or unreasonable, (b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or (c) whether a service is offered or provided under substantially similar circumstance and conditions (s. 59(4)).

Setting of Rates — Section 60 of the *UCA*

- In setting a rate under the *Act*, if the public utility provides more than one class of service, the commission must (i) segregate the various kinds of service into distinct classes of service, (ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self-contained unit, and (iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates fixed for any other unit (s. 60(1)(c)).

2.2 Provincial Government Energy Policies

The Commission's mandate and jurisdiction is defined by the *UCA*. The Lieutenant Governor in Council may also issue regulations and special directions to the Commission with respect to the exercising of powers and the performance of the duties of the Commission. In addition, the Commission pays attention to Government policies in its deliberations; however, those policies do not directly provide the Commission with a mandate to act. Ultimately the Commission's task is to determine whether the Application is in the public interest within the regulatory framework.

The Provincial Government is responsible for economic development in all parts of the Province. It has recently concluded its Industrial Electricity Policy Review. Currently, there are many new opportunities for economic development in the Province, any number of which are likely to increase the demand for electrical energy. This in turn can be expected to result in rate increases for both BC Hydro's and FortisBC's service territories. Because of this on-going economic development, the role of the self-generators and their access to embedded cost power supply among the other industrial loads continues to be the subject of debate. Consequently, in this Decision, the role of self-generators will also receive significant attention.

One of the cornerstones of the 2002 BC Energy Plan "Energy For Our Future: A Plan for BC" (2002 Energy Plan) was low electricity rates and public ownership of BC Hydro. The 2002 Energy Plan stated:

> "BC Hydro ratepayers will benefit from a legislated heritage contract that locks in the value of existing low-cost generation (heritage energy)…The BC Utilities Commission will conduct an inquiry and recommend the terms and conditions of the heritage contract legislation. To benefit ratepayers and taxpayers alike, public ownership of BC Hydro generation, transmission, and distribution assets will continue." (2002 Energy Plan, p. 7)

The Commission conducted a public review process and made recommendations to the Provincial Government, most of which were implemented by way of Special Directions, including the establishment of the "Heritage Contract" between BC Hydro's generation line of business and its distribution line of business under Special Direction No. HC2 (OIC 1123, November 27, 2003).

2.3 Past Commission Decisions

The Commission Panel also considered the determinations made in certain Orders regarding self-generation, as listed in Section 8.3 of this Decision and summarized in Appendix C.

3.0 CONTEXT FOR THE NEW PPA AND ASSOCIATED AGREEMENTS

As summarized below, several events and decisions set the context for the New PPA and Associated Agreements (Exhibit B-1, pp. 7–13).

3.1 Era Prior to the 1993 Power Purchase Agreement

- The 1961 **Columbia River Treaty** is reflected in the Canal Plant Agreement. The Treaty requires the Canadian and United States entities to coordinate the operation of the Libby Dam on the Kootenai River in Montana with hydroelectric plants located on the Kootenay River and elsewhere in British Columbia. The purpose of the treaty is to manage water flows and maximize total power.
- **The formation of BC Hydro** in 1964. BC Hydro was designated as the Canadian Entity for purposes of implementing the Canadian portions of the Columbia River Treaty. BC Hydro owns and operates the Canadian Treaty dams.
- **The Canal Plant Agreement** was created in 1972 by BC Hydro, FortisBC and Teck Resources Ltd. to better regulate the water flows in the southern interior of the Province and maximize power production. The practical effect of the interconnection, integration and coordination under the Canal Plant Agreement is that for most purposes the plants of the Entitlement Parties and BC Hydro are operated as parts of a single integrated system to optimally utilize provincial water resources. In return, a defined amount of energy and capacity is allocated to the Entitlement Parties in the form of an "Aggregate Entitlement" consisting of "Entitlement Energy" and "Entitlement Capacity".

<u>History of the Power Supplied to FortisBC by BC Hydro</u>

<u>1978 to 1985</u>

The original Canal Plant Agreement provided for BC Hydro to sell electricity to FortisBC through the 1978 to 1985 period. The agreement contemplated that after 1985, the amounts of capacity and energy to be supplied to FortisBC, and the terms and conditions of such supply, would be by a further agreement.

<u>1986 to 1993</u>

The rates, terms and conditions of a long-term PPA between BC Hydro and FortisBC became the subject of a public hearing in 1986. Following the issuance in October 1986 of Commission Order G-61-86, BC Hydro and FortisBC signed a Power Purchase Agreement (1986 PPA) with rates, terms and conditions for a period to expire at the end of 1990. The 1986 Decision determined that beyond 1990 the principles employed in determining the power purchase rates should be the same as those used to determine rates applicable to other BC Hydro customers (Reasons for Decision to Order G-27-93, p. 4). During this time BC Hydro supplied power to FortisBC under RS 3807 in accordance with the terms and conditions of the 1986 PPA.

Order G-61-86 also set out firm wheeling rates covering the transmission of FortisBC's energy over BC Hydro's transmission facilities (Reasons for Decision to Order G-27-93, p. 5). In early 1990 BC Hydro and FortisBC began negotiations for a new Agreement but were unable to agree before the expiration of the 1986 PPA, accordingly the Commission extended the term of the 1986 PPA.

3.2 1993 Power Purchase Agreement

In December 1992, BC Hydro applied to the Commission for approval of a 20-year Power Purchase Agreement with FortisBC under Rate RS 3808 based on BC Hydro's Transmission Rate RS 1821.

The proceeding concluded with the Commission issuing Order G-27-93 and accompanying reasons in April 1993. The Order, among other things, directed BC Hydro and FortisBC to enter into negotiations leading to a revised Power Purchase Agreement to incorporate the findings and directions as set out in the Commission's Reasons for Decision and for BC Hydro and FortisBC to jointly file the agreement with the Commission.

The Commission determined in Order G-27-93 that the ratemaking principles that most appropriately reflect the unique relationship between BC Hydro and FortisBC is one which characterizes that relationship as a hybrid, in which FortisBC is partly a BC Hydro customer and partly an independent utility.

Further, the Commission determined that BC Hydro had an ongoing obligation to serve FortisBC and that FortisBC had a right to a specific amount of electricity from BC Hydro at the rates extended by BC Hydro to comparable customers. However, the Commission also recognized that as an independent utility, FortisBC has the responsibility for its own resource planning at rates reflective of fair market arrangements on a utility to utility basis. On that basis, the Commission determined that BC Hydro had a further obligation to provide any additional energy that FortisBC wished to purchase to serve its customers but at rates that reflect the utility to utility relationship.

The Commission's Decision determined the limits of BC Hydro's customer obligation to FortisBC as:

- The Customer Demand Limit is to be set at 200 MW (capacity). The energy limit is to be determined by FortisBC's use of the available capacity (commencing on September 30, 1995). For service below the 200 MW limit, the rates shall be comparable to those charged to RS 1821 customers.

In regards to the utility to utility relationship, the Commission directed that:

- For service above the 200 MW limit, offered pursuant to a separate agreement between the parties, the rates shall be established by negotiations between the parties on a utility to utility basis.

Order G-27-93 also directed BC Hydro to provide FortisBC with reasonable wheeling access and fair wheeling charges for non-BC Hydro electricity supply intended to serve FortisBC's customers.

In August 1993 BC Hydro and FortisBC jointly filed RS 3808 and the supporting Power Purchase Agreement (1993 PPA) in compliance with Order G-27-93. The RS 3808 that was filed did not include an energy limit; as a result, the associated available energy volume was set at 1,752[1] GWh/year. In September 1993, pursuant to Order G-85-93, the Commission approved the 20-year Agreement covering the period October 1, 1993 through September 30, 2013.

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[1] 200 MW X 24 hours X 365 days = 1,752 GWh.

The 1993 PPA stipulated that the electricity purchased under the Agreement was solely for the purposes of supplementing FortisBC's resources to enable it to meet its service area load requirements and was not available to export or store. Specifically, FortisBC was prohibited from exporting any electricity out of its service area during any given hour while FortisBC was taking energy requirements from RS 3808 for that hour. (Exhibit B-1, p. 13)

3.3 Changes since the 1993 Power Purchase Agreement

After the implementation of the 1993 PPA, several changes to the BC energy environment came about which BC Hydro states affected the negotiations of the New PPA and Associated Agreements. The key changes are summarized as follows:

3.3.1 Accords, Acts and Agreements

- **Columbia Basin Accord** — the Province incorporated the Columbia Power Corporation (CPC) in 1994 to facilitate the purchase of the Brilliant Plant from Teck along with the Expansion rights to the Brilliant and Waneta Dams.

- **Columbia Basin Trust Act** — this Act was passed by the Province in 1995 creating the Columbia Basin Trust (CBT). The CBT was created to manage the funding provided to it by the Province for the economic, environmental and social benefit of the Columbia Basin region. Part of the funding is sourced from the Province's share of the downstream power benefits under the Treaty. Under the Columbia Basin Accord and the 1995 agreement, the Arrow Lakes Generating Station, the Brilliant Expansion and the Waneta Expansion (WAX) projects were identified as core power projects to be developed by CBT and CPC.

- **Canal Plant Agreement** — this Agreement was amended in 2005 by BC Hydro and the Entitlement Parties (including FortisBC). Further amendments occurred in 2011 under which the parties agreed to continue to cooperate in the operation of their storage and generating facilities in the Columbia Basin region for the purpose of obtaining optimum generation.

- **Additions to existing power plants** have been ongoing since 1993 with the WAX project scheduled to be completed in 2015 thus adding new generation to the region. This particular project is the subject of allowing FortisBC to export energy, under certain conditions, while taking RS 3808 energy from BC Hydro.

3.3.2 Heritage Contract

As addressed in Section 2.2 of this Decision, the 2002 BC Energy Plan mandated that the Commission conduct a Heritage Contract Inquiry to ensure the benefits of BC Hydro's low-cost generation was secured for British Columbians. The Terms of Reference provided to the Commission for the Inquiry specifically included RS 3808 as a customer rate eligible to benefit from BC Hydro's heritage energy. (Exhibit B-5; ICG IR 1.1.2)

3.3.3 Open Access Transmission and Regional Electricity Markets

The advent of the open, non-discriminatory transmission tariffs, which did not exist in 1993, gave access to electricity markets in adjacent jurisdictions enabling market participants including FortisBC and some of its customers to take advantage of opportunities to buy and sell electricity when market prices are favourable (Exhibit B-1, pp. 13–19). The events that led to this opportunity are as follows:

- Open Access Transmission became a reality in 1995 when BC Hydro joined two Regional Transmission Groups;
- in 1997 BC Hydro implemented Wholesale Transmission Tariffs for open access transmission services on its system;
- in 1998 BC Hydro and FortisBC filed a joint proposal with the Commission for harmonizing the transmission wheeling rates between the two utilities. In accordance with Order G-12-99, transmission wheeling customers are charged only the transmission service rate of the utility within whose service area the customer taking service is located; and
- in 2005 the Commission approved an Open Access Transmission Tariff (OATT) for BC Hydro (at the time the British Columbia Transmission Corporation was responsible for BC Hydro's transmission system).

3.3.4 Changes to BC Hydro's Transmission Service Rates

Prior to 2006, RS 3808 was based on the energy and demand charges for BC Hydro's transmission service rate customers as set out in RS 1821. In 2006 RS 1821 was cancelled and replaced with RS 1823 Transmission Service Stepped Rate, RS 1827 — Transmission Service Rate for Exempt

Customers and RS 1825.[2] RS 1823 is a two tiered inclining block rate that is designed to incent conservation. Pursuant to Heritage Special Direction No. 2, the second tier is set as a proxy for BC Hydro's Long Run Marginal Cost (LRMC) of new supply and the rate is designed to be revenue neutral. From 2006 onward RS 3808 has been based on the flat rate structure in RS 1827.

3.3.5 Changes to Section 2.1 of the 1993 Power Purchase Agreement

Section 2.1 of the 1993 PPA stipulated that FortisBC was prohibited from exporting any electricity out of its service area during any given hour while FortisBC was taking energy requirements under RS 3808 for that hour (Exhibit B-1, p. 13).

In September 2008, BC Hydro applied to the Commission to amend section 2.1 of the PPA to clarify that, in addition to the limitations placed on FortisBC regarding exporting electricity, RS 3808 electricity purchased by FortisBC could not be sold to any FortisBC customer when such customer was selling self-generated electricity which is not in excess of its load (Exhibit B-1, pp. 20–26). The Application was approved by Order G-48-09.[3] However, the Decision indicated the relief granted was only for the remaining term of the 1993 PPA.

The Commission Panel noted the short-term nature of the issue by acknowledging that the 1993 PPA between BC Hydro and FortisBC was to expire on September 30, 2013 and that the two parties were negotiating a potential renewal and extension hopefully resulting "in a comprehensive renewed PPA". The Commission Panel stated "[t]herefore, the relief sought by BC Hydro is for the remaining term of the PPA". (Reasons, Order G-48-09, p. 10)

3.3.6 Actual Purchases under the 1993 Power Purchase Agreement

FortisBC states that the New PPA and Associated Agreements were also influenced by the way FortisBC has purchased power from BC Hydro under the 1993 PPA (Exhibit C1-2, p. 12).

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[2] Transmission Service Rates also include RS 1825 which is a Time-of-Use Rate; however, this rate has not been used.
[3] Proceeding summarized in Appendix C.

The maximum energy volume available to FortisBC under the 1993 PPA was 1,752 GWh/year; however, FortisBC only purchased 794 GWh in F2004 and peaked at 974 GWh in F2007. Energy purchases have since declined to 513 GWh and 338 GWh in F2012 and F2013, respectively. This occurred in spite of the fact that FortisBC's network energy growth from 1993 to 2013 was 15.8 percent, average demand growth was 19.7 percent and peak demand growth was 14.2 percent. (Exhibit C1-3, BCUC IR 1.8.1)

BC Hydro states that the degree of variability between FortisBC's forecasts and actual purchases in recent years has created uncertainty for its system operations and planning. BC Hydro, as the major power generator and distributor of electrical energy in the Province, serves as the balancing authority and is responsible for ensuring the system is in load resource balance. BC Hydro takes a variety of measures to maintain the systems load resource balance. These can include running additional generation, obtaining additional imports, or decreasing exports in order to meet unexpected FortisBC service territory obligations.

3.4 Embedded Cost Power

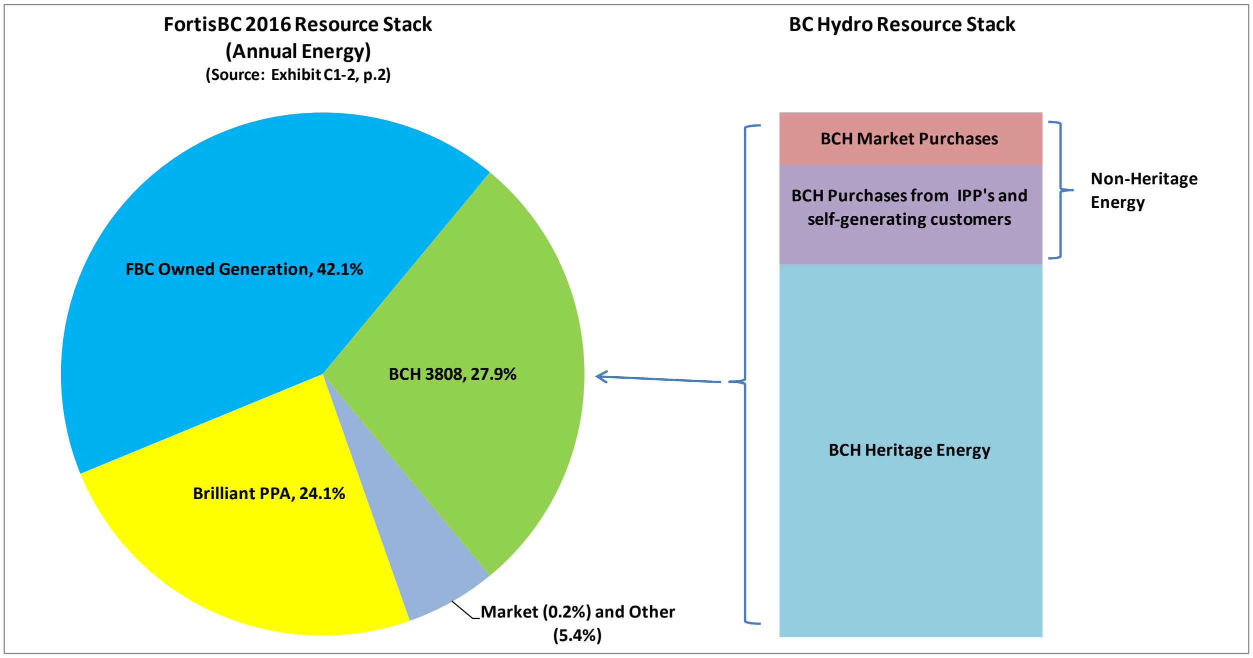
Embedded cost power, as it applies to BC Hydro and FortisBC, can be defined as the weighted average cost of power supplied from all sources available to the utility.

In the case of BC Hydro, embedded cost power refers to the cost of "Heritage Energy", along with the cost of energy procured from "Non-heritage" sources including Independent Power Producers (IPPs), BC Hydro's self-generating customers, and market import purchases (Exhibit A2-1, Appendix E, p. 3). The term "Heritage Energy" stems from the Heritage Contract which preserves the value of BC Hydro's low-cost electricity generation for the benefit of all customers. Heritage Energy is generated by BC Hydro's "Heritage Assets" which include its large hydroelectric system and storage reservoirs. (Exhibit A2-1, Appendix E, p. 3)

Figure 1 below illustrates FortisBC's access to BC Hydro's embedded cost power through RS 3808. This resource forms a portion of FortisBC's own resource portfolio which includes power generated by its own generation assets, the Power Purchase Agreement with the Columbia Power Corporation for power generated from the Brilliant Dam (Brilliant PPA), purchases from IPPs and from market imports. FortisBC's cost of power from all of these sources is referred to herein as FortisBC's embedded cost power.

Figure 1

BC Hydro and FortisBC Resource Stacks



Source: Derived from Exhibit C1-2, p. 2 and Exhibit A2-1, Appendix E, p. 3

4.0 OVERVIEW OF THE AGREEMENTS

4.1 Introduction

The New PPA and Associated Agreements are specialized agreements that BC Hydro states are designed to reflect the unique historical and ongoing relationship between BC Hydro and FortisBC. The agreements apply only to service provided to FortisBC and not to the service BC Hydro provides to any other customer. BC Hydro further states that the negotiations which resulted in the New PPA and Associated Agreements took place within the context of the Canal Plant Agreement, the Commission's 1986 and 1996 decisions and the relevant subsequent events that have occurred since 1993. (Exhibit B-1, p. 7)

The following summary table has been included for the benefit of the reader. The table provides a comparison of the 1993 PPA and the New PPA (Exhibit B-1, Appendix E). The table is followed by a summary of the key terms of the New PPA and Associated Agreements.

Table 1
Summary Comparison (1993 PPA vs. New PPA)

	1993 PPA	New PPA
Term	20 years (section 2.5)	20 years, and can be terminated early in certain circumstances (section 2.1)
Contract Demand	200 MW, maximum (section 7.1)	200 MW, maximum (section 1.1(r))
Points of Delivery	The Points of Interconnection and the Points of Supply, as defined in the GWA (sections 3.1-3.2)	The Points of Interconnection and the Points of Supply, as defined in the GWA (section 3.1)
Scheduled Energy	Take or pay for prescheduled amounts (section 8.2)	Take and pay for Scheduled Energy subject to and in accordance with Agreement (section. 4.1)
Deliveries of Energy not Scheduled	Permitted, but FortisBC subject to Excess Energy Charges and Excess Demand Charges	Only Scheduled Energy is delivered to FortisBC (section 4.1) Any Imbalance Energy is in accordance w/ Imbalance Agreement (section 6.5)

		1993 PPA	New PPA
Pricing			
Energy Charges	Base Rate	Energy charge (equivalent to RS 1827) for 1,752 GWh/year (section 8.2 and RS 3808)	Tranche 1 Energy Price (equivalent to RS 1827), up to Maximum Tranche 1 amount of 1,041 GWh/year; plus Tranche 2 Energy Price (equivalent to BC Hydro LRMC) for energy above Maximum Tranche 1 amount (711 GWh/year) (sections 7.1–7.4 and RS 3808)
	Excess Energy Charges	For energy taken above prescheduled amounts (Total Excess Energy), 1.15 times the Energy Charge (sections 8.3, 9.2–9.3 and RS 3808)	Not applicable. Energy deliveries under the PPA cannot exceed Scheduled Energy. Any excess deliveries are in accordance with the Imbalance Agreement.
Demand Charges	Base Rate	Demand Charge (equivalent to RS 1827) and ratchet provisions similar to RS 1827 for Billing Demand. Demand charger and ratchets are calculated using prescheduled and unscheduled amounts. (section 6.2 and RS 3808)	Demand Charge (equivalent to RS 1827) and ratchet provisions similar to RS 1827 for Billing Demand. Demand charges and ratchets are calculated using Scheduled Energy. (sections 8.1–8.2 and RS 3808)
	Excess Demand Charges	Ratchet provisions also include an additional charge of 1.2 times the amount capacity exceeding Nominated Demand (Total Excess Capacity) (sections 9.2–9.3 and RS 3808)	Not applicable. Energy deliveries to be allocated among the point of delivery with no Nominated Demand limitations.

		1993 PPA	New PPA
Nominations & Scheduling			
Annual Nominations and Forecasts	Nominated Demand	By October 1 of each year, FortisBC provides a Nominated Demand for each point of delivery for the 5th ensuing year (sections 7.1–7.3)	Nominated Demand limitations removed to allow FortisBC to use the full amount of the Contract Demand, but transmission capacity issues for operational and planning purposes to be incorporated in amended/restated General Wheeling Agreement
	Energy Nominations	None. However, any energy delivered in excess of a Nominated Demand deemed to be Excess Energy (sections 9.2–9.3)	By June 30 each year, FortisBC to provide an Annual Energy Nomination (AEN) for the following Contract Year (single nomination for all points of delivery) If the AEN is exceeded, then a surcharge of 1.5 times the Tranche 1 Price or 1.15 times the Tranche 2 Price "Take or pay" for 75% of AEN AEN can change by +/-20% each year (sections 5.1–5.4)
	Load Forecasts	By June 30 of each year, parties to exchange forecasts for the next 10 years (section 5.2)	By June 30 of each year, FortisBC to provide forecasts of load and annual PPA purchases for the next 10 years (section 9.2)
Energy Scheduling	Daily Prescheduling	Hourly preschedule submitted for each day 2 times per week (section 8.1)	Hourly preschedule submitted each day by 5:30 am in accordance with industry scheduling practices (section 6.1)
	Preschedule Changes and Deliveries	No preschedule changes. However, energy can be delivered in excess of prescheduled amount (section 8.3)	FortisBC is permitted real-time hourly changes for +/-25MW (and during freshet only +25MW) (section 6.2)
Limitations	By FortisBC	No export or storage permitted while PPA energy is being delivered (sections 2.1, 8.3 and 9.4)	No export or storage permitted while taking Scheduled Energy, except in accordance with Energy Export Agreement (sections 2.5–2.6)
	By FortisBC self-generation customers	No sale of PPA energy to a FortisBC customer when such customer is selling self- generated electricity not in excess of its load (section 2.1)	No sale of PPA energy to a FortisBC customer when such customer is selling self-generated electricity not in excess of a customer-specific baseline, consistent with BC Hydro generator baseline principles (section 2.5)

Source: Exhibit B-1, Appendix E

4.2 The New Power Purchase Agreement

Capacity and Energy Volumes

The New PPA is a 20-year, fixed term agreement that continues to provide for up to 200 MW of capacity and 1,752 GWh/year of associated energy for FortisBC to meet a portion of its load service obligations (Exhibit C1-2, p. 18).

Under the 1993 PPA, FortisBC could request additional capacity over the 200 MW threshold that BC Hydro was obligated to make reasonable efforts to provide; in the New PPA, BC Hydro no longer has this obligation (Exhibit C1-2, p. 7, lines 23–31).

Scheduling

The provisions in the New PPA related to nominations and scheduling of energy place an increased responsibility on FortisBC to forecast its requirements for RS 3808 power on an annual basis and reduce the ability of FortisBC to use RS 3808 power to address imbalances in its own system. Under the 1993 PPA, FortisBC was not required to provide energy nominations but rather to provide a 10 year, annually updated load forecast.

Under the 1993 PPA, FortisBC was required to nominate the maximum PPA delivery for each point of delivery with the total to not exceed 200 MW. In the event that the load at a point did not materialize as nominated, FortisBC was not able to redistribute the resulting excess capacity to other points of delivery. Under the New PPA, FortisBC will continue to take delivery of electricity at multiple points of delivery; however, these deliveries will be scheduled on a system-wide basis.

Under the terms of the New PPA, FortisBC is required to provide a single energy nomination for the aggregate of all points of delivery for the following year (the Annual Energy Nomination). FortisBC has the ability to reduce contract demand, but is restricted from changing the nomination from one year to the next by no more than +/- 20 percent. FortisBC is obligated to “take or pay” at least

75 percent of the Annual Energy Nomination. Energy taken in excess of the Annual Energy Nomination attracts a surcharge as described below.

On a daily basis, FortisBC is required to pre-schedule deliveries of electricity on an hourly basis for electricity to be consumed the following day. FortisBC has the ability to change the schedule by up to +/- 25 MW for any hour with 30 minutes notice before the hour. (Exhibit B-1, pp. 34–35)

Pricing

The New PPA has two-step pricing for energy. The threshold where the rate transitions from the Tranche 1 price to the Tranche 2 price is 1,041 GWh/year.

The price for energy purchased up to the Tranche 1 threshold is equal to the energy charge component of BC Hydro's RS 1827, which is currently set at 3.724 ¢/kWh and is based on BC Hydro's embedded costs. Tranche 2 energy (between 1,041 GWh/year and 1,752 GWh/year) is priced at BC Hydro's LRMC excluding distribution losses and including an adjustment for inflation. The Tranche 2 price will start at $0.1297/kWh. (Exhibit A2-1, Appendix E, p. 3)

Energy taken in excess of the Annual Energy Nomination attracts a surcharge based on the Tranche 1 and Tranche 2 prices. For purchases of RS 3808 power exceeding the Annual Energy Nomination, but less than or equal to the Tranche 1 amount, FortisBC will pay 150 percent of the Tranche 1 energy price. For purchases in excess of both the Annual Energy Nomination and the Tranche 1 amount, FortisBC will pay 115 percent of the Tranche 2 energy price.

Demand charges applicable to RS 3808 purchases are equal to the demand charge component of BC Hydro's RS 1827. The current demand charge is $6.353/kVA/month and is applied to the highest of: (i) the maximum amount of electricity scheduled during any hour of the billing month, (ii) 75 percent of the maximum amount of electricity scheduled during any hour in the previous 11 months, and (iii) 50 percent of the contract demand. (Exhibit B-1, pp. 35–38)

Limitations (Exports)

Section 2.1 of the 1993 PPA stipulated that FortisBC was prohibited from exporting any electricity out of its service area during any given hour while FortisBC was taking energy under RS 3808 for that hour. By way of Order G-48-09 further restrictions were placed on FortisBC such that RS 3808 electricity purchased by FortisBC could not be sold to any FortisBC customer when such a customer was selling self-generated electricity which was not in excess of its load. However, as made clear in the Reasons for Decision attached to Order G-48-09, this further restriction was only approved for the remaining term of the 1993 PPA. This will be further addressed in Section 8.5.1 of this Decision.

The New PPA provides FortisBC with some additional flexibility regarding its ability to export electricity while it is taking energy under RS 3808. Section 2.5 of the New PPA allows for FortisBC to, in accordance with the Energy Export Agreement, export new incremental "Eligible Energy" using "entitlement capacity" attributable to the new WAX Project while FortisBC is taking electricity under RS 3808. Otherwise, FortisBC is prohibited from scheduling exports of electricity out of its service area during any hour when FortisBC is taking electricity under RS 3808. (Exhibit B-1, pp. 4–5)

However, the New PPA maintains the restriction against increases in purchases of RS 3808 power arising from the sale of some of this power to FortisBC's self-generating customers. Section 2.5 of the New PPA updates the conditions under which FortisBC may supply its self-generating customers with RS 3808 power. The New PPA allows FortisBC to sell electricity purchased under RS 3808 to a self-generating customer that is selling electricity if a portion of the customer's load equal to or greater than their "customer-specific baseline" is being served by power from resources other than RS 3808. This is a change from the net-of-load requirement contained in section 2.1 of the 1993 PPA.

The customer-specific baseline is to be set in a manner consistent with how BC Hydro establishes a Customer Generation Baselines (GBL) for its own customers and is to be agreed upon between BC Hydro and FortisBC. BC Hydro refers to its "Transmission Service Rate Customer GBL

Information Report June 2012"[4] (Exhibit A2-1) filed in response to a Commission request in Letter L-106-09, as providing a description of the principles, process and considerations used by BC Hydro in establishing a baseline in cases where a customer sells electricity to BC Hydro. BC Hydro states that this document provides guidance to FortisBC for establishing a customer-specific baseline that meets the requirements of section 2.5. (Exhibit B-1, p. 39)

Dispute Resolution

The New PPA provides for the resolution of any dispute, question or difference of opinion arising between BC Hydro and FortisBC. If a dispute cannot be resolved by the representatives of the parties to the agreement, it is escalated to arbitration under the *Commercial Arbitration Act*. If a dispute relates to an amendment of the New PPA, then either BC Hydro or FortisBC may submit the dispute to the Commission as an application or a complaint. (Exhibit B-1, pp. 39–40)

4.3 The Associated Agreements

4.3.1 The Imbalance Agreement

The Imbalance Agreement (IA) is a new, associated agreement that sets out the terms under which FortisBC will settle with BC Hydro for any inadvertent flows of electricity between the BC Hydro system and the Entitlement Parties' system due to unexpected conditions or circumstances.

Under the terms of the 1993 PPA, any unscheduled flows to the FortisBC system were treated as purchases of excess energy and capacity. The new IA includes financial disincentives for the use of RS 3808 power for system balancing and should result in FortisBC using its own resources to balance the FortisBC system.

The payments FortisBC must make to BC Hydro in the event of any imbalances are linked to market prices and are structured to act as financial disincentives. FortisBC is required to pay BC Hydro an

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[4] Summarized in Appendix C.

amount equal to the greatest of: (i) $5,000; (ii) $100/MWh of imbalance energy; or (iii) for each MWh of imbalance energy, 200 percent of the higher of the Mid-C, California market prices or, if FortisBC is scheduling to Alberta, the Alberta market prices. Lower disincentives are applicable during the first year of the IA to reflect the expectation that BC Hydro and FortisBC will require a period of adjustment to the energy nomination provisions of the New PPA and other provisions of the new agreements.

If imbalance energy transfers to the BC Hydro system, BC Hydro will own the energy but will have no obligation to pay FortisBC for the imbalance amount. If the hour in which the transfer occurs is an hour in which the Mid-C price is reported as being a negative price, then FortisBC will be required to pay to BC Hydro 150 percent of the absolute value of the Mid-C price.

4.3.2 The Energy Export Agreement

Under the terms of the 1993 PPA, FortisBC was restricted from exporting electricity while simultaneously taking deliveries under RS 3808. This restriction was put in place to prevent FortisBC from increasing RS 3808 purchases to support higher value export activities. However, this restricts the ability of FortisBC to dispose of surplus power produced by any new resources built or acquired to meet its long-term resource requirements. Without relief from this export restriction, a portion of the power provided by such new resources could displace the supply of RS 3808 power available from BC Hydro and be at odds with FortisBC's overall responsibility to obtain cost-effective, secure long-term sources of supply.

The Energy Export Agreement (EEA) provides FortisBC the flexibility to export "Eligible Energy" using capacity from the WAX (WAX capacity) while simultaneously purchasing power under RS 3808. To ensure that exports do not result in increased purchases of electricity under the New PPA, Eligible Energy excludes energy sourced from FortisBC's existing owned or contracted resources, including the New PPA, that were in place to serve its customers requirements prior to entering into the WAX Capacity Purchase Agreement. More specifically, Eligible Energy is obtained from a variety of resources including the wholesale energy markets in or outside of BC, IPPs either in or outside of FortisBC's service territory, and Entitlement Energy acquired by FortisBC other than that purchased pursuant to the Brilliant Power Purchase Agreement. Energy acquired from a self-generating customer may qualify as Eligible Energy if such acquisitions do not result in increased purchases of RS 3808 power.

The EEA sets out the consequences if FortisBC exports when it is not authorized to do so. If such an event happens, FortisBC is required to pay BC Hydro the greatest of 150 percent of the hourly Mid-C market index or the profits earned by FortisBC on the transaction. If FortisBC exports when unauthorized on more than four occasions in a year or reaches a volume of 75 MWh of unauthorized exports in a year, this triggers a right for BC Hydro to issue a notice of suspension, and can ultimately result in termination proceedings before the Commission. (Exhibit B-1, pp. 44–45)

4.3.3 The Master Accounting Agreement

The purpose of the Master Accounting Agreement (MAA) is to reconcile the scheduled energy and capacity amounts under the New PPA, the accounting of entitlement energy and capacity amounts under the Canal Plant Agreement, imports and exports to and from the FortisBC system, and energy and capacity amounts under the Energy Export Agreement, the General Wheeling Agreement and the OATT. For each hour, the MAA sets out the method for reconciling FortisBC's deliveries of electricity to its customers and to its export markets, with all of its resources. The use of entitlement resources available under the Canal Plant Agreement, and the flows deemed to be associated with them, are contractual (although not necessarily physical) and therefore, an accounting agreement is required to reconcile contractual flows with physical flows that are directly metered. (Exhibit B-1, pp. 45–47)

4.3.4 The Amended and Restated Wheeling Agreement

The existing General Wheeling Agreement enables FortisBC to use its generation resources at South Slocan to serve its remote load centres at Princeton, Okanagan and Creston. Electricity sourced from FortisBC's resources, including electricity purchased under RS 3808, is transmitted, or “wheeled” through BC Hydro’s transmission system to the FortisBC load centres not directly connected to FortisBC’s main transmission system. (Exhibit B-1, p. 47)

Modifications to the existing GWA, in effect since 1986, are required in order to align with the new accounting required under the New PPA, the IA and the MAA. More specifically, the ARWA adds provisions that (i) ensure firm transmission capacity at each of the Points of Interconnection taking into account both general wheeling nominations and RS 3808 firm deliveries, (ii) allows FortisBC to use its own resources for system balancing at its remote load centres, and (iii) prohibits the unauthorized use of BC Hydro’s transmission system for the purpose of managing FortisBC’s energy imbalances. (Exhibit B-1, p. 47)

A draft of the final agreement was filed as a supplement to this Application on July 16, 2013. The final executed version of the ARWA was filed on July 26, 2013. (Exhibit B-1-1; Exhibit B-3)

5.0 ISSUES WITHIN SCOPE

5.1 Order G-117-13 and Supplemental Submissions

To ensure an effective and efficient review of the Application the Commission Panel established the specific issues that were within the scope of review by way of Order G-117-13, issued following the Procedural Conference held July 29, 2013.

The Commission Panel concluded, as provided in the Reasons attached to that Order, that even though the New PPA and Associated Agreements were negotiated and agreed to by two sophisticated parties, a comprehensive review of the Application was still required to ensure that the proposed rates are not unjust, unreasonable, unduly discriminatory, or unduly preferential. As such, the Panel concluded that a complete evidentiary record was necessary.

The Commission Panel noted that the circumstances of the energy markets may have changed significantly since 1993 as well as BC Hydro and FortisBC's respective roles within those markets. Further, in the dynamic energy markets of today, it is difficult to predict what the next 20 years will look like.

The Panel also noted that although the New PPA and Associated Agreements have been negotiated by BC Hydro and FortisBC, ultimately it is FortisBC's customers, and to some extent BC Hydro's customers, that will be affected by the resulting benefits and costs.

Accordingly, by Order G-117-13 the Commission Panel determined that the following broader scope issues are to be considered:

- whether the relationship between BC Hydro and FortisBC characterized by the Commission in the 1993 PPA Decision as unique (a hybrid in which FortisBC is partly a BC Hydro customer and partly an independent utility) is still relevant today and into the future;
- whether the Bonbright Principles are relevant when assessing the New PPA and Associated Agreements as a rate; and

- the impact on BC Hydro, FortisBC and their respective customers including the risks and rewards as well as the costs and benefits of the New PPA and Associated Agreements.

The Commission Panel also determined that the following issues relating specifically to self-generating customers were within the scope of review of this Application:

- whether FortisBC's self-generating customers should receive the benefit of BC Hydro's embedded cost power which includes a British Columbia heritage power component;
- whether restrictions to FortisBC and/or its customers' access to RS 3808 power is consistent with BC Hydro's obligation to serve;
    - o if access is to be restricted, on what basis will those restrictions be implemented?
- the concept of a Customer Baseline (CBL), GBL, and Net-of-Load constructs for the purpose of setting limitations for use of energy under RS 3808; and
- consideration of the June 20, 2012 Transmission Service Rate and Customer Generator Baselines Information Report filed by BC Hydro (2012 Information Report) (Exhibit A2-1) but only on a prospective basis as it applies to RS 3808.

The Commission Panel declined to consider certain matters, which it determined not relevant to the evaluation of the Application including:

- any utility to utility rate comparisons including a comparison of BC Hydro rates with FortisBC;
- how BC Hydro established GBLs in its service area prior to the submission of the 2012 Information Report;
- how BC Hydro implements and operates its agreements with self-generators established prior to the submission of the 2012 Information Report;
- establishment of a GBL for any particular customer; and
- Merchant Pump Storage and related policies.

During the Commission Panel's deliberation it became apparent that even though the evidentiary record was closed and the Final Submissions had been filed, an unresolved concern regarding the proposed section 2.5 in the New PPA remained. The Panel determined that it was necessary to reopen the evidentiary record and, as such, the Commission issued a letter requesting Supplemental Submissions on the following four questions on section 2.5 of the New PPA as they related to the restrictions on providing RS 3808 energy to FortisBC's self-generator customers.

1. Why are the restrictions relating to FortisBC's self-generator customers still necessary in the New PPA under the current environment?
2. What risks, if any, is BC Hydro still exposed to under the New PPA, and do those risks result in any significant negative impacts to BC Hydro or its ratepayers?
3. If FortisBC was free to establish GBLs, or other mechanisms, with its self-generator customers without any restrictions to RS 3808 power, what benefits would this provide to FortisBC, and what risk would it pose to BC Hydro and its ratepayers?
4. On the assumption that the Commission finds section 2.5 of the New PPA to be unjust, unreasonable or unduly discriminatory because self-generator customers have no meaningful input in setting their GBL's for service in the FortisBC service territory, how can the Commission Panel approve the Application as just and reasonable under sections 58–61 of the *UCA*?

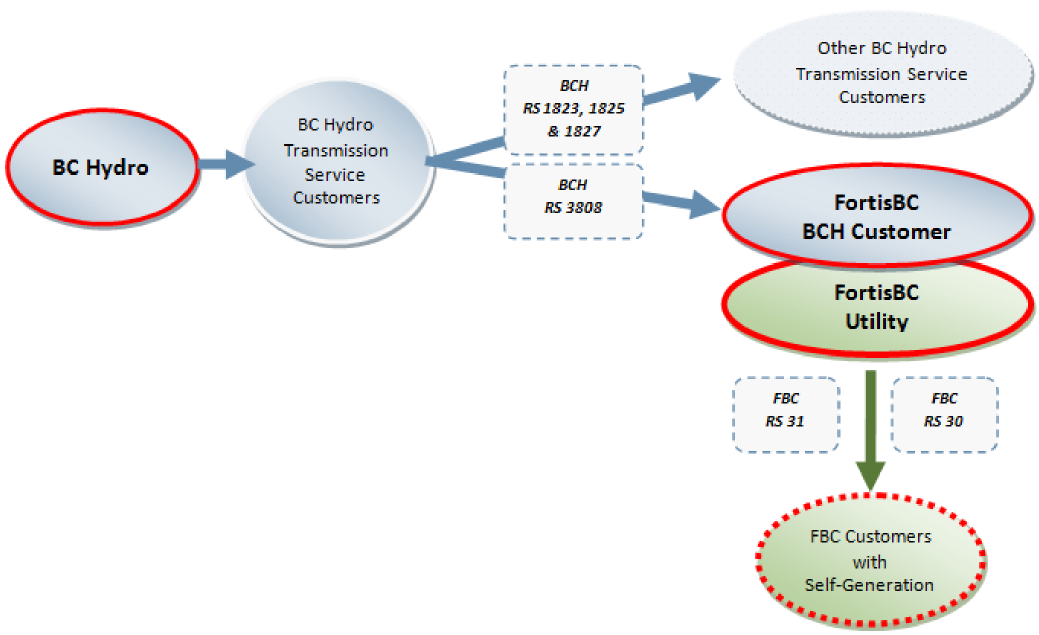
6.0 APPROACH TO THE REVIEW OF THE APPLICATION

6.1 Parties to the New Agreements

The various utility and customer relationships are simplified in Figure 2 below. This illustration shows that FortisBC is a customer of BC Hydro under RS 3808, and FortisBC, as a utility, also has a direct relationship with its own customers, including those with self-generating capabilities. However, BC Hydro does not have a customer relationship with FortisBC's customers.

Figure 2

Parties to the Agreements



Source: Derived from Exhibit B-1, Exhibit C1-2

For the most part, the New PPA and Associated Agreements are reflective of a relationship between BC Hydro and FortisBC, which will be further addressed in Section 7.1.1 of this Decision. However, certain parts of section 2.5 of the New PPA also affect FortisBC's self-generating customers, which are not parties to the agreement.

6.2 Approach to the Review of the Application

The Commission Panel considered the Application within the regulatory and policy framework identified earlier while being mindful of the broader scope issues and the nature of the relationship of the parties involved.

In its review of the Application, the Panel considered the issues relating to FortisBC's self-generating customers separately. Section 7.0 of this Decision considered the New PPA and Associated Agreements without taking into account the restrictions placed on FortisBC regarding its self-generating customers contained in section 2.5 of the New PPA. Section 8.0 considered the restriction contained in section 2.5 of the New PPA. It then became evident that the Self-Generation Policy issue in general in the FortisBC territory needed to be addressed in Section 9.0. Section 10.0 concludes the Decision resulting from BC Hydro's proposed amendment.

The Panel considered that a comprehensive review of the restrictions relating to FortisBC's self-generating customers included in section 2.5 of the New PPA are necessary for the following reasons:

- the New PPA includes conditions that directly impact those that are not Parties to the agreements;
- Order G-48-09, which approved amendments to section 2.1 of the 1993 PPA was granted only for the remaining term of the 1993 PPA;
- to determine if some of the updated terms of the New PPA reduce the risk of harm to BC Hydro's ratepayers;
- the challenges and complexities occurring during FortisBC's efforts to establishing rates that comply with the restrictions established by Order G-48-09;
- Interveners' concerns regarding the continued restrictions on self-generating customers in the FortisBC service area which the Commission Panel identified to be within the scope of review of this Application; and
- the long-term nature of the New PPA.

7.0 EVALUATION OF THE NEW PPA AND ASSOCIATED AGREEMENTS

7.1 Overview

The Panel has considered the New PPA and Associated Agreements, without taking into account the restrictions placed on FortisBC regarding its self-generating customers, by first determining the nature of the relationship between BC Hydro and FortisBC for each of the New PPA and Associated Agreements. In the case of the New PPA, the EEA and the ARWA, where a utility to customer relationship was determined to exist, an evaluation under the Bonbright framework was undertaken. For the MAA and the IA, where the relationship is more of a utility to utility one, reliance on the sophistication of the parties negotiating the agreements was given considerable weight and a Bonbright evaluation was not performed.

The assessment of various contracts has not identified anything that would indicate to the Panel that overall, without taking into account the restrictions placed on FortisBC regarding its self-generating customers in section 2.5 of the New PPA, the rates proposed are unjust, unreasonable, unduly discriminatory, nor unduly preferential. As explained in this section of the Decision, the Bonbright evaluation regarding the New PPA, the EEA and the ARWA, and the evaluation of the MAA and IA assisted the Panel in coming to this conclusion.

Table 2 below provides an overview of the approach taken and a summary of the results.

Table 2
Evaluation of PPA and Associated Agreements: Summary Results

	New PPA and the Energy Export Agreement	**Amended and Restated Wheeling Agreement**	**Master Accounting Agreement**	**Imbalance Agreement**
Nature of the Relationship	Utility to customer	Utility to customer	Utility to utility	Utility to utility
Evaluation Framework	Bonbright Principles: focus on fairness and efficiency		Greater reliance on the sophistication of the Parties.	
Fairness Approach	No revisiting of previous fairness decisions unless there is clear evidence of a change in circumstance which renders the previous fairness determination questionable.			

	New PPA and the Energy Export Agreement	Amended and Restated Wheeling Agreement	Master Accounting Agreement	Imbalance Agreement
	Compare to the rates offered to BC Hydro's other transmission service customers.	Compare to the rates offered to BC Hydro's other wheeling customers.		
Efficiency Approach	Consider effect (from a BC perspective) on (i) efficient customer consumption and investment decisions, (ii) efficient utility investment and operational decisions and (iii) innovation.			
Evaluation Result	**Fair compared to other BC Hydro transmission service customer — T1 cap reflects FortisBC network load profile and past use; benefit of greater flexibility offset by no increase for load growth. While the rate is not an 'inclining block rate structure', the price is fair.** **Net improvement in efficiency.**	**Existing contract does not expire until 2045 and amendments do not change the nature of the service.** **No inefficiency concerns raised.**	**No areas of concern identified**.	

7.1.1 Relationship between BC Hydro and FortisBC

In the 1993 Decision (Order G-27-93) the Commission described the relationship between FortisBC and BC Hydro as unique — a hybrid in which FortisBC is partly a customer of BC Hydro and partly an independent utility.

BC Hydro submits that its relationship with FortisBC is still appropriately described as 'unique' because

> "FortisBC is both an independent utility with its own generation resources, transmission system, wholesale market access and resource planning obligations (unlike any other BC Hydro customer), and a customer that is dependent on BC Hydro for secure, reliable, cost-effective capacity and energy at least over the short to medium term". (Exhibit B-1, Appendix G. p. 27; BC Hydro Final Submission, p. 18)

FortisBC agrees that the hybrid characterisation of the relationship between BC Hydro and FortisBC remains valid (FortisBC Final Submission, p. 4). BCSPO also considers the FortisBC and BC Hydro relationship to be a hybrid one (BCSPO Final Submission, p. 4). BCMEU, however, submits that the relationship between FortisBC and BC Hydro is that of a utility to utility relationship, but notes that "the historic relationship has seen a customer-type contract dating from the 1993 decision of the Commission" (BCMEU Final Submission, p. 2). CEC also submits that "the relationship between the utilities is increasingly that of arrangements between independent utilities" (CEC Final Submission, p. 5).

Commission Determination

The Commission Panel concludes that the relationship between FortisBC and BC Hydro continues to be unique, one that is characterized as a hybrid, in which FortisBC is partly a customer of BC Hydro and partly an independent utility. The Panel determines that the ratemaking principles should continue to be applied in this context. The Panel continues to consider BC Hydro's obligations to serve FortisBC as a customer is limited, and beyond those limits the relationship is to be that of two independent utilities. The Commission recognizes that as an independent utility, FortisBC has the responsibility for its own resource planning at rates reflective of fair market arrangements.

7.1.2 Evaluation Framework

In reviewing rate design applications, which typically reflect a utility to customer relationship, the Commission is typically guided by the eight Bonbright Principles. These principles are described on page 5 of the Reasons for Decision to Order G-45-11:

> "Principle 1: Recovery of the revenue requirement;
>
> Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates);
>
> Principle 3: Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy);
>
> Principle 4: Customer understanding and acceptance;
>
> Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives);
>
> Principle 6: Rate stability (customer rate impact should be managed);
>
> Principle 7: Revenue stability; and
>
> Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained)."

In the 1986 PPA Decision, the Commission stated: “In reviewing these submissions, the Commission has had regard to two overriding rate-making principles: efficient resource allocation and fairness” (Exhibit B-1, Appendix F, p. 32).

BC Hydro submits that the New PPA and Associated Agreements do not represent unilaterally designed rates developed for services provided to a large class of end-use customers, and were not negotiated to meet specific rate design criteria such as those articulated by the Bonbright Principles. However, BC Hydro states it has not asserted that the Bonbright rate design criteria are “irrelevant” to the review of the Application, and considers that the Agreements and RS 3808 do align with the Bonbright rate design criteria, in particular the efficient resource allocation and fairness criteria. (BC Hydro Final Submission, pp. 20–21)

BC Hydro further states:

> “The New PPA in its entirety, in conjunction with the Energy Export Agreement, encapsulates the terms and conditions by which BC Hydro provides electricity service to FortisBC as a load customer. In addition, FortisBC is a customer of BC Hydro’s under the terms and conditions of the General Wheeling Agreement and for other services, such as wheeling services under BC Hydro’s Open Access Transmission Tariff (OATT).” (Exhibit B-4, BCUC IR 1.2.1)

BC Hydro considers that the MAA (an enabling agreement with no financial commitment) and the IA (not a service, but designed to provide a financial disincentive for FortisBC against taking imbalance energy) are more appropriately characterized as utility-to-utility agreements. (Exhibit B-4, BCUC IR 1.2.1; Exhibit B-1, pp. 42, 43, 46)

FortisBC submits that although the New PPA primarily describes the customer relationship between BC Hydro and FortisBC, it is appropriately structured in a manner that recognizes the overall relationship. FortisBC states that if the New PPA were to reflect only the customer relationship, it may mean FortisBC would no longer have an option to purchase RS 3808 Tranche 2 energy. (FortisBC Final Submission, p. 4; Exhibit C1-17, BCUC IR 2.4.2.1)

BCSPO and ICG do not object to the evaluation of the New PPA as a customer rate, although BCSPO submits that the terms and conditions must recognise and account for the unique relationship (BCSPO Final Submission, p. 4; ICG Final Submission, p. 5).

BCMEU considers that the Bonbright Principles are relevant, but that “significant weight should be attributed to the utility to utility relationship and to the sophistication of the parties who negotiated the agreements” (BCMEU Final Submission, p. 2). BCSEA holds a similar view, stating “while the Bonbright Principles are relevant... the Commission should also take into account... that the proposed RS 3808 is a unique rate embodying complex trade-offs negotiated between two public utilities” (BCSEA, Final Submission, p. 7).

CEC states that “it is oriented to look at the agreement as a special inter utility agreement… [and] is less inclined to look at this rate with all of the same cost of service perspectives that it looks at other rates...” CEC submits that the Commission should “see the agreement move away from being approved as a rate as opposed to being an inter-utility agreement in the future.” CEC also submits that “negotiations between two utilities does [sic] not necessarily result in an optimal solution for the Province, but can be limited to the interests of the utilities that do not necessarily bear the end expense of the arrangements”. (CEC Final Submission pp. 4, 12)

Commission Determination

The Panel finds that an evaluation under the Bonbright Principles is appropriate for agreements that describe the utility to customer relationship. For agreements that describe the utility to utility relationship, the Panel finds the reliance on the sophistication of the parties negotiating the agreements should be given considerable weight and a Bonbright evaluation is not required.

The Panel also finds that where an evaluation under the Bonbright Principles is appropriate, the evaluation should focus on the Bonbright Principles of fairness (Principles 2 and 8) and efficiency (Principle 3). This approach is consistent with BC Hydro’s position and in the Commission’s 1986 PPA Decision evaluation.

With regard to the Bonbright Fairness Principle, the Commission Panel maintains the view that fairness is critical to a sound rate design and that cost causation is basic to fairness (i.e. similar customers should be charged similar rates). However, the Commission Panel also acknowledges that existing rates are, by necessary implication, not unjust, unreasonable, unduly discriminatory or unduly preferential if they have already been approved by the Commission.

Because the 1993 PPA was approved by the Commission as fair, the Commission Panel will only evaluate fairness where there is clear evidence that changes in circumstances require the previous fairness determination to be revisited.

7.1.2.1 The New PPA, the EEA and the ARWA

The Panel agrees with BC Hydro and FortisBC that the Tranche 1 energy pricing reflects a utility to customer relationship. However, the Panel disagrees with FortisBC that the Tranche 2 energy may reflect a utility to utility relationship. FortisBC has an option, but not an obligation, to purchase Tranche 2 energy. The Panel considers that BC Hydro would be unlikely to provide such an option at no cost under a utility to utility relationship.

The Commission Panel determines that an evaluation against the Bonbright Principles is appropriate for the New PPA (including Tranche 1 and Tranche 2 energy), the EEA and the ARWA, as these reflect BC Hydro's relationship with FortisBC as a customer.

7.1.2.2 The MAA and the IA

The Commission Panel agrees with BC Hydro that the MAA and IA are more appropriately characterized as utility to utility agreement. **As such, the Panel determines an evaluation against the Bonbright Principles is not applicable, and instead places greater reliance on the utility to utility relationship and the sophistication of the parties who negotiated the agreements.**

7.1.3 Customer Class and Rate Comparison

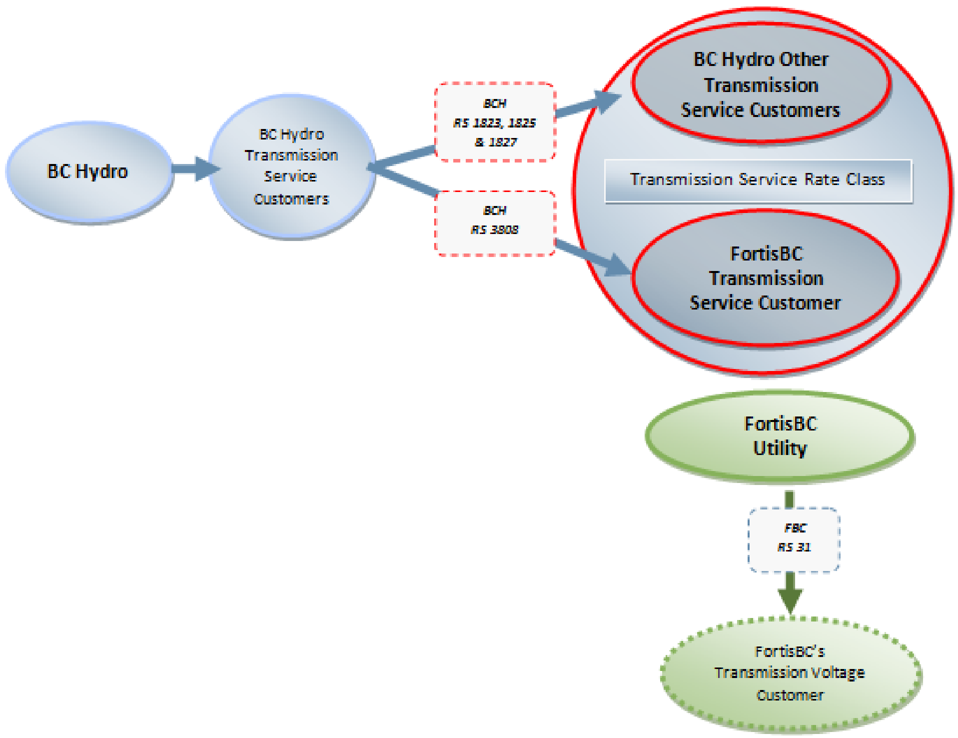
BC Hydro submits that the primary issue before the Commission Panel is whether the proposed rates for the services provided to FortisBC are unjust or unreasonable (BCH Final Submission, p. 12). A key issue for the Commission Panel to determine is from whose perspective the rate is not unjust, unreasonable, unduly discriminatory or unduly preferential.

BC Hydro does not believe that the New PPA and Associated Agreements can be compared to any other BC Hydro rates. BC Hydro submits that, given the rates are unique because they apply to a unique customer, one could not conclude that the rates are unduly discriminatory or preferential (BC Hydro Final Submission, p. 14). BCSEA concurs with this opinion (BCSEA Final Submission, p. 3). However, BC Hydro has included FortisBC in its transmission service customer class for cost of service purposes, and BC Hydro is not proposing any changes to this approach (BC Hydro Final Submission, p. 39).

The following Figure 3 illustrates the BC Hydro's transmission service rate class and the rates applicable to transmission service customers.

Figure 3

BC Hydro Transmission Service Rate Class



Source: Derived from evidence filed by BC Hydro and FortisBC.

CEC does not accept BC Hydro's submission that one could not conclude that the rates are unduly discriminatory or preferential because the customer is unique. CEC submits that even if the Commission limits its determinations to whether the rate is "unjust" or "unreasonable" it retains wide latitude in this regard in that by section 59(4) of the *UCA* it has been designated as the sole judge of this question and notes that section 59(5)(c) of the *UCA* states that a rate may be found unjust and unreasonable "for any other reason." Accordingly, CEC argues that "the Commission should not find limitations in its scope with respect to dealing with rate setting for this application." (CEC Final Submission, p. 4)

BC Hydro states that the 1993 PPA Decision determined that the energy and demand charges of RS 3808 be the same as those in the prevailing transmission service rate or its equivalent, and that it is reasonable to continue to include FortisBC in the transmission service class as this has been historic practice. BC Hydro also states that within the transmission service rate class, there are some customers that pay more than their cost and some that pay less. In order for all customers within the class to pay their individual cost, BC Hydro would require individual rates for each customer. However, this would be inefficient and administratively costly to design and implement. BC Hydro further notes that section 58.1 of the *UCA* caps any increases in revenue-to-cost ratios (R/C ratios) compared to the previous year to no more than two percentage points. (Exhibit B-13, BCUC IR 2.4.1, 2.4.2.1 and 2.4.4)

BC Hydro confirmed that R/C ratios outside of an acceptable range (say +/-10 percent) are generally considered an unfair cross-subsidy between customer classes. BC Hydro also noted that if FortisBC was treated as a separate customer class, for 2012 it would have had an R/C ratio of 88 percent. This would improve to 103 percent if FortisBC had maximized Tranche 1 purchases. By comparison, BC Hydro's transmission service customer class (excluding RS 3808) had a 2012 R/C ratio of 103.7 percent. (Exhibit B-13, BCUC IR 2.4.2.1.1, 2.4.3; Exhibit B-14, BCSPO IR 2.10.1)

FortisBC agrees with BC Hydro that the key issue is whether the transmission service customer class R/C ratio is within an acceptable band (FortisBC Reply Submission, pp. 1–2).

BCPSO also submits that there is no justification for departing from current practice, but considers that customer service characteristics, rather than R/C ratios, are the key input in determining which customers belong in the same customer class (BCPSO Final Submission, pp. 9–10). CEC, however, submits that that RS 3808 should be a separate rate class because it is effectively being operated and managed in that fashion (CEC Final Submission, p. 13).

Commission Determination

Customer Class

The Panel agrees with BCPSO that customer classes are generally established to group together customers with similar service characteristics; however, the Panel also considers that a review of R/C ratios is a useful tool in evaluating fairness concerns related to these customer groupings. The

Panel finds that acceptable R/C ratios for existing customers within a particular customer class can be greater than the +/- 10 percent range which has at times been considered acceptable for the total customer class.

The Panel notes the estimated RS 3808 R/C ratio at 88 percent for 2012, increasing to 103 percent if Tranche 1 purchases are maximized, compared to BC Hydro's transmission service customer class of 103.7 percent. Furthermore, no other concerns — such as related to efficiency or energy policy — were raised. As a result, the Commission Panel finds no evidence to justify departing from the current practice of linking the RS 3808 price to that of other BC Hydro transmission service customers. **The Commission Panel finds that it is reasonable to continue to include FortisBC in the transmission service customer class.**

Rate Comparison

The Panel considers that if FortisBC is similar enough to BC Hydro's transmission service customer class to be included in this class for cost of service purposes, it should also be similar enough for it to be compared against BC Hydro's transmission service customers for the Bonbright evaluation purposes.

The Commission Panel determines that, in undertaking a fairness evaluation, the New PPA and the EEA will be compared against the rates charged by BC Hydro to its other Transmission Service Customers. Consistent with this determination, the ARWA will be compared to rates offered by BC Hydro to its other wheeling customers for fairness evaluation purposes.

However, the Panel does not consider that a fairness evaluation should include a comparison of FortisBC's end use customer rates, such as FortisBC's RS 31, to those of BC Hydro. This is consistent with the Commission's previous decision that "Discrimination, when applied to rates for utility service, can only be of an 'intra-utility' nature and not 'inter-utility'" (Reasons for Decision on

BC Hydro's 2007 Rate Design Application Phases II and III[5]). Furthermore, any utility to utility rate comparison has been determined by the Commission Panel to be out of scope for the review of this Application.

7.2 Evaluation of the New PPA and the EEA

The Commission Panel previously determined that an evaluation against the Bonbright Principles is appropriate for the New PPA and the EEA, and the Bonbright evaluation should focus on the Bonbright Principles of (i) fairness and (ii) efficiency. Fairness will be addressed in Section 7.2.1 and 7.2.2, efficiency in Section 7.2.3 of this Decision.

7.2.1 Fairness

The Panel previously concluded that because the 1993 PPA was determined to be fair, the Panel will only consider changes that have occurred since that date which could render those determinations unsuitable. The Panel also determined that, in undertaking a fairness evaluation, the New PPA will be compared against the rates charged by BC Hydro to its other transmission service customers.

The changes since 1993 which the Commission Panel determines to be relevant for consideration are: (i) the 2003 Heritage Contract; (ii) the development of Open Access Transmission and Regional Electricity Markets which have resulted in changes to Energy Nomination and Scheduling Requirements in the New PPA; and (iii) the introduction of Stepped Rates for BC Hydro's Transmission Service Rate Class.

The relevant differences between the New PPA and rates charged to other transmission service customers, as shown in Table 3 below, relate to:

(i) Capacity and Energy Volume as they relate to FortisBC's load growth;

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[5] British Columbia Hydro and Power Authority, 2007 Rate Design Application Phases – II and III, Decision dated December 21, 2007, Order G-171-07.

(ii) Energy Volume as it relates to the Tranche 1 Energy Cap;

(iii) Energy Charge as it relates to the Tranche 1 rate, and Demand Charges; and

(iv) Energy Charge and Energy Volume as they relate to Tranche 2.

Table 3

Comparison of the New PPA and BC Hydro Other Transmission Service Customers Rates

	New PPA	Transmission Service Customers (RS 1823 and RS 1827)
Contract Term	20 years	There is no fixed term for the Electricity Supply Agreement signed by customers
Product	Firm energy and associated capacity	Firm Energy and associated capacity
Capacity	200 MW (contracted)	Up to the customer's contract demand
Energy Volume	Tranche 1–1,041 GWh/year Tranche 2– 711 GWh/year	No limit subject to the contract demand
Energy Nominations and Scheduling Requirements	Contract Demand can be reduced with prior notice for loss of load or acquisition of new generation resources Annual Energy Nomination (AEN) in required for each Contract Year AEN can be changed by ± 20% relative to prior year In any Contract Year, FortisBC will "take or pay" for at least 75% of the ANE for that Contract Year Energy taken in excess of ANE but ≤Tranche 1 attracts a 50% surcharge of the Tranche 1 price. Energy taken >ANE and Tranche 1 attracts a 15% surcharge of the Tranche 2 price	Customer can request an increase or decrease in their contract demand
Pre-scheduling Requirements/ Penalties	Daily Energy Scheduling on an hourly basis with ability to adjust by ± 25 MW in real time. Charges under Imbalance Agreement may apply	N/A
Energy Charges	RS 1827 rate for 1,041 GWh/yr with an 'Option' to purchase up to	RS 1827 flat rate

	New PPA	Transmission Service Customers (RS 1823 and RS 1827)
	1,752 GWh/yr at LRMC	RS 1823 two-tiered stepped rate
Demand Charges	Demand Charges based on RS 1827	RS 1827

Source: Exhibit B-4, BCUC IR 1.9.1, Exhibit B-1, p. 35

Each of the changes since 1993 and the relevant differences between the New PPA and rates charged to other transmission service customers will be considered in determining if the New PPA passes the Bonbright Fairness Principle.

7.2.1.1 Changes Since 1993

(i) 2003 Heritage Contract

In 1993 by Order G-27-93, the Panel determined that FortisBC had a right to a specified amount of electricity from BC Hydro at the rates extended by BC Hydro to comparable customers. The Commission set the demand limit at 200 MW and the associated energy at 1,752 GWh/year. (Exhibit B-1, Appendix G, pp. 30, 31)

As discussed in Section 3.3.2 of this Decision, on November 27, 2003 the BC Hydro Public Power Legacy and Heritage Contract (HC2) became effective (Exhibit B-5, ICG IR 1.1.2). BC Hydro submits that HC2 does not directly affect the New PPA or the 1993 fairness determinations:

> "The Heritage Contract framework does not provide any person with an 'entitlement' to a share or portion of the generation output of BC Hydro's Heritage Resources. With the exception of the design of RS 1823 [stepped rates], the Heritage Contract framework does not require the BCUC to set rate structures in a particular manner nor does it create an obligation to serve where one does not otherwise exist under the *Utilities Commission Act*." (Exhibit B-14, ICG IR 2.9.1)

> "There is no relationship between the 1993 PPA and the Heritage Contract Scheme with the possible exception that the RS 3808 energy and demand charge continued to reflect the cost-based RS 1821 energy and demand charges after April 1, 2004 [as opposed to the Industrial stepped rate]" (Exhibit B-5, ICG IR 1.1.2).

FortisBC disagrees with BC Hydro's aforementioned assertion and submits that the New PPA reflects, amongst other things, FortisBC's continuing access to power supply from the Province's Heritage Assets.

ICG submits that the most important aspect of both the New PPA and the 1993 PPA is access to power as established by the *Heritage and Legacy Act* and by the obligation to serve defined by the 1993 Decision (Exhibit C1-3, BCUC IR 1.1.2.4; ICG Final Submission, pp. 9–10).

Commission Determination

The 2002 BC Energy Plan specifies that the benefits of BC's low cost generation assets belong to all British Columbians. In the Panel's view this includes the ratepayers of BC Hydro and FortisBC, as well as all British Columbians in general.

The Commission Panel finds that the principles established by Order G-27-93 remain relevant in the context of the New PPA.

(ii) Open Access Transmission and Regional Electricity Markets (Contract Flexibility)

Since 1993 the energy markets, and BC Hydro's and FortisBC's ability to participate in those markets, have changed significantly. FortisBC's ability to buy and sell electricity when market prices are favorable did not exist when the parties entered into the 1993 PPA. However, since the advent of open, non-discriminatory transmission tariffs, FortisBC now has access to electricity markets in adjacent jurisdictions.

BC Hydro believes that, as a general principle, it is unfair to allow customers served at BC Hydro's embedded cost rates to access market priced power at times of low market prices and then switch back to embedded cost power at times of higher market prices. BC Hydro also noted that the Commission has been clear that particular customers will not be permitted to benefit unduly at the expense of others by arbitraging between embedded cost rates and market prices. BC Hydro stated its industrial customers cannot make market purchases using the OATT while simultaneously purchasing power from BC Hydro under their Electricity Supply Agreements. (Exhibit B-13, 2.5.1.1, 2.13.4; Exhibit B-14, BCSPO, 2.5.1)

Because of FortisBC's access to energy markets, the Energy Nomination and Scheduling Requirements under the New PPA have changed significantly. FortisBC is now required to provide an energy nomination for the following year (the Annual Energy Nomination), rather than only provide a 10 year, annually updated load forecast, as was allowed under the 1993 PPA. FortisBC still has some ability to reduce contract demand, but is restricted from changing the Annual Energy Nomination from one year to the next by no more than +/- 20 percent. FortisBC is obligated to "take or pay" at least 75 percent of the Annual Energy Nomination.

The terms of the New PPA relating to Energy Nominations and Scheduling place an increased responsibility on FortisBC to forecast its requirements for RS 3808 power on an annual basis and reduce the ability of FortisBC to use market energy to reduce RS 3808 power to address imbalances in its own system.

BC Hydro submits it does not believe it is realistic to assume that FortisBC could be completely prevented from displacing RS 3808 PPA purchases with short-term market purchases. There is no apparent mechanism that could be used to realistically achieve this outcome. (BC Hydro Final Submission, p. 40)

CEC disagrees with BC Hydro on this issue, stating:

> "In the same way BC Hydro has provisions to prevent export sale of power while energy is being purchased from BC Hydro under RS 3808, similar constraints could be imposed in regard to market purchases of energy affecting the FortisBC

> ability to nominate and purchase power under the RS 3808 rates. However, the CEC agrees with BC Hydro that this would significantly change the agreements from a FortisBC perspective and would likely not be a net benefit." (CEC Final Submission, p. 14)

Commission Determination

The Commission Panel finds that the additional flexibility available to FortisBC to displace RS 3808 power with market purchases, which is not available to other transmission service customers, provides FortisBC with a substantial advantage compared to those customers, other things being equal. The Panel notes, however, that the magnitude of this advantage is lessened somewhat by the Energy Nomination and Scheduling terms in the New PPA.

(iii) Introduction of Stepped Rates for BC Hydro's Transmission Service Rate Class

In the 1993 Decision the Commission determined that RS 3808 would continue to have the energy and capacity charges set to match those in RS 1821 or its equivalent (Exhibit B-1, Appendix G, p. 32). In 2006 RS 1821 was cancelled and replaced with Transmission Service Stepped Rate (RS 1823) and Transmission Service Rate for Exempt Customers (RS 1827).

RS 1823 is a two-tiered "inclining block" rate that is designed to incent conservation. Pursuant to HC2, the second tier is set as a proxy for BC Hydro's LRMC of new supply and the rate is designed to be revenue neutral.

RS 1827 is a flat rate based on BC Hydro's embedded cost of energy. The City of New Westminster, the University of British Columbia (UBC) and other customers which are exempt from RS 1823 by the Commission qualify to be on RS 1827. RS 3808 has been based on RS 1827 since 2006.

The Application proposes a rate structure to provide for up to 200 MW of capacity and 1,752 GWh/year of associated energy. The rate is designed in such a way that up to 1,041 GWh/year (Tranche 1 cap) are available at RS 1827 embedded cost rates and an optional amount of energy in excess of 1,041 GWh/year but less than 1,752 GWh/year (Tranche 2) is available at BC Hydro's LRMC.

BC Hydro suggests the energy price for the service provided under the New PPA has an inclining block structure, with the first tranche at an embedded cost-of-service price and the second tranche at a proxy for BC Hydro's long-run marginal cost of new firm energy.

ICG disagrees with this description and submits:

> "The New PPA is not an 'inclining block' structure, at least not an 'inclining block' structure that is comparable to any other structure in either the FortisBC or BC Hydro service areas. All other 'inclining block' structures have a fundamental characteristic that is missing in the New PPA structure, that is, revenue neutrality. In the absence of revenue neutrality, which drives many other rate design elements of an 'inclining block' structure, the New PPA cannot be considered to be an inclining block structure."

ICG concludes that "[t]he applied for rate structure is unduly discriminatory and is a departure from rate design principles that have been accepted by the Commission in the past." (ICG Final Submission, pp. 8–9)

FortisBC also submits that it does not necessarily agree that the practical effect of the two-tranche structure is an "inclining block" rate structure (FortisBC Final Submission, p. 5). Nevertheless, FortisBC stated that having a fixed price Tranche 2 option is of benefit to FortisBC and was part of the overall negotiated package of agreements. FortisBC has a high level of confidence that it will not be required to purchase Tranche 2 energy, and is therefore 'relatively indifferent' to the Tranche 2 price. (Exhibit C1-17, BCUC IR 2.4.2, 2.6.3 and 2.10.4)

CEC does not accept that inclining block rate structures are necessarily appropriate for the sale of power to a utility such as FortisBC. CEC also submits that establishing the Tranche 2 pricing signal at a level which becomes effective in reducing demand from FortisBC at approximately the same time BC Hydro goes into its most significant surplus is inappropriate from a public interest perspective. (CEC Final Submission, pp. 11–12)

Commission Panel Discussion

The Panel agrees with FortisBC and ICG that, given it is not revenue neutral, RS 3808 two-tranche structure cannot be described as an "inclining block" rate structure. However, the Panel disagrees with ICG that this finding makes the New PPA unduly discriminatory.

Inclining block rate structures are normally put in place to incent efficient customer consumption and investment decisions. FortisBC is a utility with the ability to access competitive wholesale markets, not an end use customer, and RS 3808 power is just one component of FortisBC's resource stack. FortisBC can still design its rates to send efficient pricing signals to end-use customers regardless of the Tranche 1 or Tranche 2 energy prices.

The Panel considers there would be little overall benefit (if any) from the RS 3808 rates reflecting the structure and price of BC Hydro's inclining block rate structure (RS 1823) instead of BC Hydro's flat RS 1827 structure. Like FortisBC, the City of New Westminster and UBC (who are both on RS 1827) are not the end users of the electricity they purchased from BC Hydro.

The Commission Panel concludes that RS 3808 is not an "inclining block stepped rate" but rather a flat rate for a limited amount of energy at embedded cost rates with an "option" to purchase some additional energy (but not capacity) at a higher, non-embedded cost, LRMC price. The Panel does not consider this rate structure in itself to be unduly discriminatory as ICG suggests. However, in order to determine if the rate structure is fair the capacity and associated energy volumes as well as the energy and demand charges of the proposed rate need to be evaluated separately.

7.2.1.2 <u>Relevant Differences between the New PPA and Rates Charged to Other BC Hydro Transmission Service Customers</u>

(i) Capacity and Energy Volume as they relate to FortisBC's Load Growth

In 1993, the Commission determined that the Customer Demand Limit for RS 3808 be set at

200 MW, and the energy limit be determined by FortisBC's use of the available capacity (Exhibit B-1, Appendix G, p. 31). However, it is noteworthy that the final RS 3808 developed as a result of the 1993 Decision did not include an energy limit, resulting in a maximum associated energy of 1,752[6] GWh/year at BC Hydro's embedded cost rates.

BC Hydro stated it is not clear if the 1993 Decision indicated that the 200 MW limit would be for the duration of the contract or permanent. However, BC Hydro concluded the Commission might have intended that the 200 MW Customer Demand Limit should continue to apply in PPA renewals after the initial 20 year term as a result of following wording in the Decision:

> "The Commission requires that the [1993] PPA to accompany Rate 3808 have a term of at least 20 years with a provision for negotiated renewals thereafter."
> (Exhibit B-13, 2.10.1)

BC Hydro also stated that FortisBC requested the 200 MW demand limit to continue in the new agreement, and as part of the package it was agreed to. BC Hydro further noted that in the earlier stages of the negotiation (2009) it proposed FortisBC should not have access to additional embedded cost energy for load growth. Accordingly, the maximum Tranche 1 amount was fixed to reflect estimated first year purchases as shown in the FortisBC 2012 Resource Plan. FortisBC subsequently reduced its forecast requirements, but the Tranche 1 amount did not change; therefore, BC Hydro considers that the maximum Tranche 1 amount provides for some load growth. (Exhibit B-14, BCPSO IR 2.4.1; Exhibit B-13, BCUC IR 2.10.1.1)

FortisBC provided the following table showing FBC's service area actual peak and average demands, as well as the annual energy requirements from 1993 to 2013 (2013 data taken from FBC's 2012-2013 Revenue Requirement Application) (Exhibit C1-3, BCUC IR 1.8.1).

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6 This calculation is based on 200 GW X 24 hours per day X 356 days per year.

Table 4

FortisBC Actual Capacity and Energy Requirements

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	
Annual Peak Demand (MW)	640	642	643	667	640	630	548	614	560	572	
Annual Average Demand (MW)	472	476	479	502	469	474	462	467	483	501	
Annual Total Energy (GWh)	3,020	2,938	2,937	3,062	2,915	2,886	2,923	2,993	3,026	3,126	

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Annual Peak Demand (MW)	609	718	708	718	683	746	714	707	669	737	731
Annual Average Demand (MW)	504	515	528	549	541	544	557	532	538	534	565
Annual Total Energy (GWh)	3,182	3,229	3,346	3,403	3,410	3,403	3,478	3,324	3,452	3,415	3,496

Source: Exhibit C1-3, BCUC IR 1.8.1

From this table it is calculated FBC's service area energy growth from 1993 to 2013 was 15.8[7] percent, average demand growth 19.7[8] percent and peak demand growth 14.2[9] percent.

Commission Determination

In determining whether FortisBC has been treated in a manner consistent with other BC Hydro customers with regard to load growth, the Panel considered how BC Hydro deals with load growth for other transmission service customers who expand operations. Those customers can negotiate an increase in contract demand resulting from an expansion of their operations. In contrast, the 200 MW capacity limit and the associated energy have not been increased to reflect FortisBC's load growth of 15.8 percent since 1993.

As a result, the Panel finds it would have been fair under the Bonbright Principles evaluation, all else being equal, for the capacity limit and associated energy to increase to 232 MW to reflect an increase in FortisBC's load growth to serve from 1993 levels.

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7 (3496-3020)/3020 = 15.8%

8 (565-472)/472 = 19.7%

9 (731-640)/640 = 14.2%

This finding does not mean that the New PPA, when considered in its entirety, is unfair to FortisBC when compared to the rates offered to BC Hydro's other transmission service customers. As FortisBC notes, the "flexibility of the PPA is ... very valuable." (Exhibit C1-17, 2.3.1)

(ii) Energy Volume as it relates to the Tranche 1 Energy Cap

The New PPA continues to provide FortisBC with up to 200 MW of capacity; however, the Application proposes to limit FortisBC's access to embedded cost energy to 1,041 GWh/year (Tranche 1 energy) with an option to purchase an additional 711 GWh/year up to 1,752 GWh/year (Tranche 2) at BC Hydro's LRMC.

BC Hydro submits that the Tranche 1 volume limit exceeds the highest amount of energy FortisBC has ever taken under the 1993 PPA (974 GWh in F2007) (BC Hydro Final Submission, p. 35).

ICG identified that by establishing the Tranche 1 cap at 1,041 GWh/year, the New PPA effectively creates a load factor of around 60 percent. This is consistent with FortisBC's own network load which shows a load factor ranging from 51 percent to 60 percent over the past 10 years. (Exhibit C1-22, ICG IR 2.3.1 and 2.3.2)

ICG however, does not support the Tranche 1 cap. ICG submits that "The customer obligations of BC Hydro to FortisBC were then clearly defined [by the Commission in 1993] as 200 MW of capacity and all associated energy" and "the New PPA does not continue to provide the same access to Heritage Assets as did the 1993 PPA." ICG requests that the Commission Panel direct that the New PPA be revised so that the obligation to serve continues to be limited to 200 MW of capacity and all associated energy at embedded cost rates. (ICG Final Submission, pp. 5, 9–10)

BCSPO considers the Tranche 1 cap is reasonable in light of the 'optionality' of the contract. BCMEU and BCSEA are generally supportive of the agreement (BCSPO Final Submission p. 8; BCMEU, Final Submission, p. 2; BCSEA Final Submission, p. 9). BCSPO further submits that, unlike BC Hydro's other customers, FortisBC can purchase electricity from external markets and concludes that overall, the introduction of an inclining block rate for FortisBC at 1,041 GWh is reasonable (BCPSO Final Submission, pp. 7–8).

CEC recommends only temporary approval of the New PPA and Associated Agreements as a result of concerns that the agreements do not provide alternatives for changing circumstances in the future, in particular with regard to future resource planning issues (CEC Final Submission, pp. 5, 15). These concerns are addressed under efficiency in Section 7.2.3 of this Decision.

FortisBC submits that as a result of: (i) the Commission's 2009 decision (G-48-09), (ii) BC Hydro's insistence on a cap, and (iii) the importance of RS 3808 power in its power supply portfolio, FortisBC refocused its negotiation efforts. This was to ensure that, if there was to be a limit on BC Hydro's embedded cost energy under the New PPA, FortisBC would have sufficient flexibility to be able to manage this cap in order to mitigate any impact on its customers to the best degree possible. (FortisBC Final Submission, p. 6)

FortisBC submits BC Hydro's original negotiating position was that the availability of BC Hydro's embedded cost energy would be subject to monthly caps. However, through negotiation, the parties agreed that this limit would be based on an annual cap of 1,041 MWh/year. This provides FortisBC significant flexibility to manage and displace RS 3808 power with market purchases or other supply sources as well as to shape when it takes deliveries of RS 3808 power (subject only to the 200 MW cap). (FortisBC Final Submission, p. 6)

Commission Determination

The Commission Panel determines it is reasonable that the maximum amount of associated energy that should be available at embedded costs rates (Tranche 1 cap) ought to be approximately 60 percent of the total available associated energy.

The Tranche 1 cap of 1,041 GWh/year results in a RS 3808 load factor for FortisBC of approximately 60 percent. This is consistent with FortisBC's own network load which shows a load factor ranging from 51 percent to 60 percent over the past 10 years. The cap therefore ensures that the RS 3808 load shape is reflective of FortisBC's customers' operational requirements and is consistent with BC Hydro's treatment of its RS 1827 customers.

The Panel is aware that BC Hydro's other transmission service customers on RS 1827 do not face a similar cap on the amount of energy they can purchase from BC Hydro at embedded cost rates. However, as BCPSO notes, RS 1827 customers also cannot displace BC Hydro's embedded cost energy with market purchases.

If FortisBC did not have access to the market energy, the Panel would be more persuaded by ICG's argument that FortisBC should have access to at least the same amount of heritage energy as it did under the 1993 PPA. However, because FortisBC has access to these other markets, the Panel concludes that it is reasonable that FortisBC should only be provided with enough embedded cost energy to reflect the load factor of its own load.

The Tranche 1 limit is consistent with the 1993 PPA Decision which states that the energy limit was to be determined by FortisBC's use of the available capacity. The highest amount of energy FortisBC has taken under the 1993 PPA was 974 GWh in F2007.

The Commission Panel finds that based on 200 MW of capacity, the Tranche 1 cap of 1,041 GWh/year appears to be appropriate as it represents approximately 60 percent of associated energy.

(iii) Energy Charge as it relates to Tranche 1 Rate and the Demand Charges

BC Hydro proposes that both the Tranche 1 energy rate and demand charges reflect RS 1827 rates. "BC Hydro submits that consideration of creating a new customer class, and of rebalancing rates to achieve desired revenue-to-cost ratios, should not be undertaken on an individual customer basis in the absence of general rate design review. Rebalancing one rate in the absence of others would be expected to have a net revenue impact." (BC Hydro, Final Submission, p. 39)

FortisBC maintains that there is no evidentiary basis for departing from the 1993 PPA Decision to price RS 3808 power at the same price used for BC Hydro's other transmission service customers (FortisBC, Reply Submission, pp. 1–2).

The Panel has already determined that the 1993 Decision, which gives FortisBC access to BC Hydro's electricity at rates extended by BC Hydro to its comparable customers, remains a valid foundation for the New PPA.

Commission Determination

The Commission Panel finds that there is an insufficient evidentiary basis to depart from the energy and demand charges that have been applied to other transmission service customers under RS 1821 and more recently under RS 1827. Accordingly, the Panel determines that the proposed demand charges and the Tranche 1 energy charge, based on RS 1827, are fair under the Bonbright Principles.

The Panel previously concluded that the proposed rate structure was not an inclining block stepped rate and that, as such, the revenue neutral rate design in RS 1823 is not appropriate for RS 3808.

The Panel considers that changes to existing rates should not be encouraged where they merely move from one definition of fairness to another equally valid definition of fairness, with no net benefit to British Columbia overall. Changes to existing approved rates should therefore focus on addressing non-fairness Bonbright Principles (for example, efficiency or energy policy) unless it can be clearly demonstrated that changes in circumstances render the previous fairness determination questionable.

Another consideration of the New PPA Tranche 1 energy price is whether the Tranche 1 volume flexibility and price could result in inefficient outcomes for BC. For example, if it incents FortisBC or its customers to behave in a way which results in an over-investment in generation capacity in the Province. These issues are addressed in Section 7.2.3 and Section 8.0 of this Decision.

(iv) Energy Charge and Energy Volume as they relate to Tranche 2

BC Hydro proposes that Tranche 2 energy (between 1,041 GWh/year and 1,752 GWh/year) reflects BC Hydro's LRMC excluding distribution losses and including an adjustment for inflation. The Tranche 2 price will start at $0.1297/kWh. (Exhibit A2-1, Appendix E, p. 3)

BCPSO raised a concern that BC Hydro does not plan on increasing the Tranche 2 price annually for inflation, unlike BC Hydro's Residential Inclining Rate. The Tranche 2 energy price will instead reflect BC Hydro's most recent LRMC proxy for firm energy as determined by BC Hydro and accepted by the Commission for ratemaking purposes. BCPSO submits that BC Hydro should either change its planned approach or the Commission should declare an exemption and set a fixed price to resolve the anomaly. (BCSPO Final Submission, pp. 8–9; Exhibit B-1, p. 37)

Commission Determination

The Panel concludes that FortisBC benefits from having the option, but not the obligation, to purchase some additional energy at Tranche 2 prices that other Transmission Service Customers do not have. However, given that Tranche 2 is based on BC Hydro's LRMC of energy, and both FortisBC and BC Hydro have stated that there is no forecast intention to use any Tranche 2 energy over the proposed term of the New PPA, the Panel does not consider this option will result in a material benefit to FortisBC.

The Panel notes BCPSO's concern that the Tranche 2 price will only be updated as BC Hydro's LRMC proxy is updated, and not annually, which could increase the risk that FortisBC will arbitrage Tranche 2 energy by only purchasing it when short-term market prices are high.

Regardless, given the new Energy Nomination and Scheduling Restrictions and the limited expected use of Tranche 2 energy over the duration of the contract, the Commission Panel accepts the proposed Tranche 2 price adjustment mechanism as fair under the Bonbright Principles evaluation.

7.2.2 Commission Summary Determination on Fairness

On balance, the Commission Panel determines that the New PPA and EEA pass the Bonbright Fairness Principle evaluation.

FortisBC's access to Regional Energy Markets allows it flexibility to import electricity to displace some Tranche 1 energy with market priced energy. The Panel considers this a significant advantage that other Transmission Customers do not have. However, the advantage is somewhat offset by the addition of the Energy Nomination and Scheduling Restrictions term in the New PPA.

Further, but to a much smaller extent, FortisBC benefits from the option, but not the obligation, to purchase some additional energy at Tranche 2 prices that other Transmission Service Customers do not have.

In conclusion, the Panel considers that these benefits are fully offset by 200 MW capacity limit and associated energy which has not been increased to reflect FortisBC's load growth since 1993. Thus, the overall finding that, on balance, the New PPA and EEA pass the Bonbright Fairness Principle evaluation.

7.2.3 Efficiency

The Panel has considered whether the New PPA and Energy Export Agreement result in an improvement in efficiency compared to the 1993 PPA. Efficiency benefits can be described as promotion of: (i) efficient customer consumption and investment decisions, (ii) efficient utility investment and operational decisions and (iii) innovation. The Panel also considers any effect on British Columbia social issues, including environmental and energy policy.

BC Hydro stated that the key inefficiencies of the existing PPA are: (i) it allows FortisBC to increase firm energy purchases up to 100 percent load factor at a price below BC Hydro's marginal cost of energy and (ii) it allows FortisBC to plan on the full use of RS 3808 power and then opportunistically displace the planned purchases by buying from the spot market. (Exhibit B-13, BCUC IR 2.7.1)

For example, under the 1993 PPA, FortisBC could plan to purchase 85 MW from the spot market in real time, but if the prices at 30 minutes to the hour are above the PPA Excess price, FortisBC may elect to take 85 MW of PPA Excess instead. BC Hydro must maintain this +/- 85 MW of scheduling flexibility, which in turn requires that BC Hydro hold 85 MW of generation (or back-off room) in reserve until the scheduling deadline has passed. (Exhibit B-5, CEC IR 1.9.1)

Under the New PPA and Associated Agreements, BC Hydro does not have to hold capacity for use as PPA Excess, and so it is available to BC Hydro to meet domestic load or for trade purposes. This scenario is estimated to have occurred as many as 200 hours in a given year in the past. The benefit to BC Hydro flowing from this change is estimated to be less than $100,000 a year. (Exhibit B-13, BCUC IR 2.7.1.1) The New PPA could also result in BC Hydro holding back capacity to meet potential FortisBC Tranche 2 purchases. However, FortisBC stated it has a high level of confidence that it will not be required to purchase Tranche 2 energy. (Exhibit C1-17, BCUC IR 2.6.3)

FortisBC also raised concerns with the 1993 PPA in terms of efficiency. The export restriction under the 1993 PPA made the development or acquisition by FortisBC of new resources challenging, because a portion of the power provided by such new resources could reduce the supplies of RS 3808 power available from BC Hydro. FortisBC submits the New PPA relaxes the export restriction and provides the flexibility FortisBC requires to do its own resource planning. (FortisBC Final Submission, pp. 6–7)

The New PPA, however, does result in an increase in FortisBC scheduling costs. FortisBC estimates incremental capital costs of $150,000 and incremental scheduling costs of $15,000 in each of 2013 and 2014 as a result of the New PPA. (Exhibit C1-6, CEC IR 1.10.1; Exhibit C1-17, BCUC IR 2.13.1)

CEC raised the concern that the rate structure and price signals in the New PPA are not optimal. CEC suggests that better price signals could be developed which would manage consumption based on energy available. For example, CEC proposed that price signals could be developed to disadvantage consumption with a view of deferring the need for Site C which would provide significant swings to BC Hydro's ratepayers. CEC submits it supports only temporary approval of the PPA until these broader issues are resolved. (CEC Final Submission, pp. 11, 15)

Commission Determination

The Commission Panel determines that the New PPA passes the Bonbright Efficiency Principle evaluation, as it results in a net improvement in efficiency from the entire British Columbia perspective compared to the 1993 PPA. The New PPA decreases the amount of generation capacity BC Hydro is required to hold back to meet potential FortisBC load. The Panel considers that these benefits will exceed the incremental capital and scheduling costs associated with the New PPA.

The Panel also considers that the New PPA results in efficiency improvements by relaxing FortisBC export restrictions and thereby reducing market barriers to efficient generation investment on FortisBC's network. However, given the long-term nature of this contract, the Panel remains concerned that some export restrictions still remain in the New PPA. These remaining restrictions could represent unnecessary market barriers to efficient generation investment by FortisBC.

The Panel notes, however:

1. unlike FortisBC's self-generating customers, FortisBC has agreed to these New PPA export restrictions;
2. the WAX Project has reduced FortisBC's need to build new generation in the short to medium term; and
3. FortisBC is able to apply to the Commission to amend these restrictions should they result in inefficient outcomes to BC over the contract term, as BC Hydro did in 2008.

In view of the Panel, these restrictions are therefore not considered unfair to FortisBC, but instead represent a potential inefficiency risk that can be addressed at a later date. Accordingly, the Panel does not consider that removal of all the export restrictions on FortisBC is required in order to approve the New PPA.

Finally, the Panel does not consider that a Tranche 1 price lower than BC Hydro's incremental costs (or LRMC) will result in inefficient customer investment and consumption decisions**.** As determined previously, FortisBC is a utility and not an end-use customer, and can still design efficient rates for its end-use customers regardless of the Tranche 1 price. The Panel also does not consider that the Tranche 2 price could result in inefficient outcomes if the shorter term market price is lower than BC Hydro's LRMC. The New PPA does not prevent BC Hydro and FortisBC from entering into alternative utility to utility energy purchase arrangements at a different price.

7.3 Evaluation of Other Associated Agreements

Having completed the Bonbright evaluation on the New PPA and the EEA, the Panel will now assess the other Associated Agreements.

7.3.1 Amended and Restated Wheeling Agreement

As stated above the ARWA will be evaluated under the Bonbright Principles as the Panel has determined that the agreement reflects the utility to customer relationship.

The existing General Wheeling Agreement, as amended from time to time, has been in effect since October 1986, pursuant to Commission Order G-61-86. The intent of the GWA was to allow FortisBC to wheel power from FortisBC's generating resources in the Kootenay area to FortisBC's loads in the Okanagan area through BC Hydro facilities. The term of the existing GWA expires in 2045 and therefore, unlike the New PPA, the ARWA is not required to replace an expiring agreement.

On November 10, 1995, BC Hydro filed an application with the Commission to provide Wholesale Transmission Services (WTS), referred to as OATT services within its service area. As part of the public hearing process related to BC Hydro's WTS, the GWA was identified by BC Hydro as a prior contractual obligation "grandfathered" under the WTS. On June 25, 1996, the Commission approved a set of WTS tariffs for BC Hydro (Order G-67-96).

The GWA remains in full force and effect as a specifically "grandfathered" pre-WTS contract. BC Hydro submits that the changes introduced in the amended GWA, now renamed the ARWA, do not alter the original intent of the GWA, nor has the nature of the service changed. As such the amendments to the GWA resulting in the ARWA do not affect Powerex's FERC compliance or its ability to access US markets. (BC Hydro Final Submission, p. 41)

The ARWA includes changes to align with the new accounting required under the New PPA, and associated agreements, and to ensure issues related to transmission capacity are properly recognized in the agreements. BC Hydro submits that the amendments made in the ARWA do not impact available transmission capacity on the BC Hydro system and do not impact other BC Hydro customers. BC Hydro also provided notice of the changes to be made to the GWA and no comments or questions were received from OATT stakeholders. (BC Hydro Final Submission, p. 41)

FortisBC agrees with BC Hydro that the ARWA does not change the fundamental terms or structure of the GWA. FortisBC states that it could purchase firm transmission services from BC Hydro under the Open Access Transmission Tariff, and does so to supplement GWA service under peak load conditions. However, the existing GWA and the updated ARWA provide the wheeling service at a much lower cost to FortisBC than what the cost under the OATT would be for the portion of the load met through GWA wheeling. (Exhibit C1-17, BCUC IR 2.21.1 and 2.21.3)

CEC has reviewed the BC Hydro submissions with respect to the ARWA and finds the BC Hydro explanations satisfactory. CEC submits that the ARWA is necessary and should be approved by the Commission. (CEC Final Submission, p. 14)

Commission Determination

The Commission Panel determines that the Amended and Restated Wheeling Agreement passes the Bonbright Principles evaluation.

The Panel previously determined that it will not revisit previous PPA decisions from a fairness perspective unless there is sufficient evidence that changes in circumstances render the previous fairness evaluation questionable. The existing General Wheeling Agreement does not expire until 2045 and has been specifically "grandfathered" as a pre-Wholesale Transmission Services contract. The Panel considers that the ARWA does not change the fundamental terms or structure of the GWA previously approved as fair.

7.3.2 Imbalance Agreement and the Master Accounting Agreement

The Panel has determined that the IA and the MAA are more appropriately characterized as utility to utility agreements, and therefore placed greater reliance on the sophistication of the parties who negotiated the agreement. These agreements are briefly reviewed in the following.

7.3.2.1 Imbalance Agreement

The IA sets out the terms, conditions and prices that will apply if a condition on the Entitlement Parties' system (FortisBC, Teck Metals Ltd., Brilliant Power Corporation, Brilliant Expansion Power Corporation, and Waneta Expansion Limited Partnership) causes an unauthorised transfer of imbalance energy from or to the BC Hydro system. An unauthorised transfer could occur if there is an unexpected condition on the Entitlement Parties' system such a transmission or generation outage, or unexpected load event. (BC Hydro Final Submission, p. 8)

BC Hydro submits that imbalance energy is not a service; instead, it can be described as an unauthorised use or delivery of energy. Accordingly, the IA has terms, conditions and pricing designed to encourage FortisBC to plan for and avoid such unauthorised use or delivery. (BC Hydro Final Submission, p. 8)

FortisBC stated that, while it cannot plan to use Imbalance Energy and must use reasonable commercial measures to avoid imbalances, under the New PPA the consequence of an imbalance due to unexpected conditions, particularly during critical hours, is significantly reduced as compared to the 1993 PPA. Under the 1993 PPA, system imbalances or unscheduled flows were settled through the Excess Energy and Excess Capacity provisions which could result in a significant cost due to capacity ratchet provisions. Under the New PPA, only scheduled energy is delivered so there is no impact to the capacity charges, and any system imbalances would be settled under the IA. (Exhibit C1-21, 2.2.1.2)

FortisBC is required to make all reasonable efforts to avoid taking imbalance energy. This includes holding 15 MW (or 10 percent of FortisBC exports) hourly planning margin, using all available resources and curtailing or adjusting scheduled imports and exports, if allowable, and maintaining continuous real time monitoring of the system to ensure that any issues or potential issues are dealt with as soon as possible. It does not require curtailing load or compensating third parties to curtail load on the system. (Exhibit C1-8, ICG IR 1.7.1) BC Hydro believes that FortisBC can manage its load resource balance to avoid any imbalance energy transfers. (Exhibit B-4, BCUC IR 1.18.1.2.1)

Submissions on the IA were also made by Vanport. However, as they relate to areas determined to be out of scope by Order G-117-13 (Merchant energy storage and/or pump storage hydro operations and development of related policies) these submissions are not addressed further here (Vanport Final Submission, p. 1).

7.3.2.2 Master Accounting Agreement

BC Hydro states the MAA is an enabling agreement with no financial commitment, but is required to administer the other agreements (Exhibit B-1, p. 46).

BC Hydro submits the MAA is required to determine the amount of imbalance energy, if any. The MAA reconciles the contractual energy transactions and financial flows under the New PPA, IA, EEA and ARWA, together with all other transactions under the Canal Plant Agreement and other agreements. (BC Hydro Final Submission, pp. 8–9)

Commission Determination

The Commission Panel finds the Imbalance Agreement and the Master Accounting Agreement as filed are not unjust, unreasonable, unduly discriminatory or unduly preferential.

7.4 Commission Summary Determination

The Commission Panel has accepted the IA and the MAA as filed. Furthermore, the evaluation of the New PPA, EEA and ARWA under Bonbright Principles framework did not identify anything that would cause the Panel to determine that New PPA, EEA, or ARWA[10], were unjust, unreasonable, unduly discriminatory or unduly preferential.

The Commission Panel therefore finds that on balance the New PPA and Associated Agreements, without consideration of the restrictions on FortisBC relating to its self-generating customers in section 2.5 of the New PPA, are not unjust, unreasonable, unduly discriminatory or unduly preferential.

The documents filed as a package represent a balanced agreement[11] negotiated between two sophisticated parties that have the support of most Interveners.

A more comprehensive evaluation of section 2.5 of the New PPA is provided in Section 8.0 of this Decision.

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[10] without consideration of the restrictions on FortisBC relating to its self-generating customers
[11] without consideration of the restrictions on FortisBC relating to its self-generating customers

8.0 EVALUATION OF SECTION 2.5 OF THE NEW PPA

8.1 Introduction

The Commission Panel has already concluded that the New PPA, without consideration of the restrictions on FortisBC relating to its self-generating customers, is not unjust, unreasonable, unduly discriminatory or unduly preferential from the perspective of the Parties to the Agreements.

However, the Panel continued to have serious concerns regarding certain parts of sections 2.5 of the New PPA ("Purpose/Limitation of Use of Scheduled Energy") as they pertain to the restrictions on FortisBC relating to its self-generating customers. What remained to be determined is whether inclusion of these restrictions results in the New PPA being unjust, unreasonable, unduly discriminatory or unduly preferential overall.

During the Panel's deliberations it became apparent that, even though the record was closed and the Final Submissions had been filed, unresolved concerns regarding these restrictions remained. Therefore, the Panel determined it necessary to reopen the record. On December 13, 2013 the Commission issued a letter requesting Supplemental Submissions specifically on certain sub-clauses of section 2.5 of the New PPA relating to FortisBC's self-generating[12] customers.

Finally, on April 9, 2014 the Commission received a letter from BC Hydro which addressed both the Tariff Supplement No. 74 related Order G-19-14 and the potential implications of its reconsideration for the New PPA. In its letter BC Hydro acknowledged a requirement for greater transparency for determination of customer-specific baselines and Contracted GBLs, recommended

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12 The Commission received Supplemental Submissions from BC Hydro, FortisBC, Celgar, BCPSO, BCMEU, BCSEA, CEC, Alain Wait and Vanport.

a new consultation process and proposed amendments to section 2.5 of the New PPA. (Exhibit B-18) These amendments, related submissions and the Panel's final determinations are summarized in Section 10.0 of this Decision.

8.2 Past Decisions

Section 75 of the *UCA* provides that the Commission is not bound by its prior decisions by way of precedent. However, it is prudent to examine relevant past decisions to assess the historical context of such decisions, the degree of congruence with new factual situations addressed, and whether or not there are good reasons to depart from the policy enunciations that led to the past decisions. In general, it is advantageous both for the Commission and those regulated companies that fall within its jurisdiction, to have a consistent and predictable body of decisions that will support informed decision-making.

The following relevant decisions are summarized in Appendix C of this Decision:

- BC Hydro's Obligation to Serve RS 1821 Customers with Self-Generation Capability (Order G-38-01 and G-17-02)
- BC Hydro Application to Amend Section 2.1 of Rate Schedule 3808 Power Purchase Agreement (Order G-48-09)
- BC Hydro's Transmission Service Rate and Customer Generator Baseline Information Report filed in June 2012 (Compliance Filing)
- Application by FortisBC Inc. for Approval of a 2009 Rate Design and Cost of Service Analysis (Order G-156-10)
- West Kootenay Power Ltd. Application for Approval of Access Principles (Order G-27-99)
- Celgar Complaint Regarding the Failure of FortisBC Inc. and Celgar to Complete a General Service Agreement and FortisBC's Application of Rate Schedule 31 Demand Charges (Order G-188-11)
- Guidelines for Establishing Entitlement to Non-PPA Embedded Cost Power and Matching Methodology (Order G-202-12)
- Application by FortisBC Inc. for a CPCN for the Purchase of Utility Assets of the City of Kelowna — Phase 2 (Order G-191-13)

- Application by FortisBC Inc. for Stepped and Stand-By Rates for Transmission Voltage Customers (in progress)
- Application by BC Hydro to Amend Tariff Supplement No. 74 Customer Baseline Load Determination Guidelines for RS 1823 Customers with Self-Generation (Order G-19-14)

8.3 Proposed Section 2.5

In 2008 FortisBC entered into arrangements to provide additional service to Celgar and the City of Nelson, both FortisBC customers with their own self-generating facilities. An effect of these arrangements was that FortisBC would purchase additional service from BC Hydro under the 1993 PPA.

BC Hydro filed a complaint with the Commission requesting changes to section 2.1 of the 1993 PPA stating that FortisBC should not be allowed to use BC Hydro's embedded cost power (RS 3808) to supply additional electricity to its self-generating customers in order to allow them to sell their self-generated electricity into available markets.

In that proceeding (OrderG-48-09 amending section 2.1 of the 1993 PPA), the Commission (i) extended the principles established for BC Hydro's self-generating[13] customers as articulated in Order G-38-01 to FortisBC; and (ii) determined that FortisBC customers engaging in arbitrage should not increase FortisBC's use of RS 3808 energy. Specifically section 2.1 states that RS 3808 electricity shall not be sold to any FortisBC customer when such customer is selling self-generated electricity which is not in excess of its load. The circumstances surrounding this decision and its short-term nature are further addressed in Section 8.5 of this Decision.

Section 2.5 of the New PPA maintains the provisions of section 2.1 of the 1993 PPA, namely that FortisBC is restricted from selling RS 3808 electricity to any FortisBC customer when such customer is selling self-generated electricity:

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13 BC Hydro's self-generating customers are not permitted to arbitrage between embedded cost rates and market prices to the detriment of other ratepayers.

> "Electricity taken under this Agreement shall not be sold to any FortisBC customer with self-generation facilities, or be used by FortisBC to serve such load when such a customer is selling self-generated Electricity unless a portion of the customers load equal to or greater than the customer-specific baseline is being served by Electricity that is not Electricity taken under this a Agreement where such a customer specific baseline **as agreed between the Parties** (acknowledging that such baseline shall be determined in a manner **consistent with how BC Hydro establishes a generator baseline [(GBL)] for its own customers**), failing which agreement either Party may submit the matter for dispute resolution in accordance with Section 13…" (New PPA, section 2.5 (a) (ii)) (emphasis added)

8.3.1 The Generator Baseline Concept

Typically, historical GBLs are contractually agreed to by a utility and its self-generator customer. They have become important due to investment in new generation facilities by self-generators. GBLs determine the amount of self-generation output required, before self-generators can rely on the utility to serve its required additional load. Establishment of historical GBLs in turn gives self-generator an opportunity to consider third-party sales of its own incremental generation.

BC Hydro submits that section 2.5 of the New PPA affords FortisBC somewhat more flexibility with respect to its self-generating customers by allowing FortisBC to establish GBLs that define a self-generating customer's access to RS 3808 power. This is in addition to maintaining the net-of-load construct put in place in 2009 in the amended section 2.1 of the 1993 PPA. The net-of-load construct differs from a GBL construct in that the net-of-load construct unequivocally prohibits a self-generating customer from buying electricity at the same time as it is selling electricity, whereas the GBL construct does not. BC Hydro notes the base case for section 2.5(a)(ii) of the New PPA is the net-of-load mechanism directed by Order G-48-09 but points out the provision also allows FortisBC additional flexibility to schedule and purchase electricity from BC Hydro under the New PPA. (BC Hydro Final Submission, pp. 25–28)

BC Hydro believes the net-of-load approach does not strike the right balance because it is inflexible and can have unintended consequences if a FortisBC customer has an Electricity Purchase Agreement (EPA) with BC Hydro. BC Hydro further submits the net-of-load approach may also be an impediment to the development of cost-effective incremental generation in the FortisBC service area because FortisBC is not permitted to access RS 3808 power for the purpose of serving a customer that wishes to sell any electricity not in excess of load, including new incremental generation. (Supplemental Submission, Exhibit B-19, para. 42 and 44)

Celgar points out that BC Hydro is asking the Commission to expressly permit the application of the GBL approach to regulating self-generating customers in both service areas. Celgar supports the concept in principle and notes that no party opposes the use of GBL methodology for regulating self-generators in FortisBC service territory. (Celgar Final Submission, pp. 10–11, para. 17)

The BCMEU agrees with BC Hydro that the net-of-load approach does not strike the right balance. (Supplemental Submission, Exhibit C4-5, p. 3)

In principle, BCPSO submits the GBL concept is a reasonable construct for protecting BC Hydro customers. However, BCPSO points out the "devil is in the details". (BCPSO Final Submission, p. 12)

8.3.2 Setting the Terms and Principles (Guidelines) of a GBL

Celgar submits that the wording in section 2.5(ii) "*in a manner consistent with how BC Hydro establishes a generator baseline for its own customers"* appears most troublesome. Specifically, Celgar submits, it would require that GBLs for FortisBC's customers be set not between the utility and its customer, as occurs in BC Hydro's service territory, but rather between BC Hydro and FortisBC – without the participation of the self-generating customer. Albeit, Celgar acknowledges a "parallel" process involving the customer is contemplated**.**

Celgar further submits that section 2.5 of the New PPA would mandate the application of BC Hydro's principles governing the establishment of GBLs. This would be the case, even though such principles, as reflected in the 2012 Information Report, have never been the subject of public comment or Commission review and approval for use even in BC Hydro's service territory, not to mention Province-wide. Celgar takes the position that the GBL Guidelines contained in the 2012 Information Report are not precise enough even to permit the computation of a GBL. Finally, Celgar submits the setting of a GBL is a regulatory function, not a utility function and is within the Commission's authority, not BC Hydro's authority. Celgar recommends that the Commission should simply direct FortisBC to negotiate with its customers under the same parameters it has established for BC Hydro in Order G-38-01. (Celgar Final Submission, pp. 3–5 and 9; Supplemental Submission, Exhibit C5-10, p. 1)

BCPSO identified the following issues with the setting of a GBL as proposed in section 2.5 of the New PPA.

Contract Term and Guidelines for GBLs

- "Contracted GBLs are typically set for the term of the contract. Following the termination of the contract, BC Hydro and the customer could agree to enter into a new contract in which case a new Contracted GBL would be set reflecting the then-current conditions. However, in the new section 2.5 there is no contract term."
- It is unclear as to how, or if, the GBLs set using the proposed Guidelines would be reviewed and under what conditions they would be revised. There is ambiguity and perhaps a difference of opinion between BC Hydro and FortisBC on this issue.
- Clarity can only be attained by either establishing a set term that would apply to all GBLs or there being clear documentation as to the principles that would be used in determining when and how GBLs would be reviewed and possibly revised.

Customer Role in Setting Customer-Specific Baselines

- While BC Hydro has no discretion in the setting of Non-Contracted GBLs as they are considered part of a Tariff [Application to Amend Tariff Supplement No. 74], while Contracted GBLs are typically negotiated between BC Hydro and their customer and involve a degree of discretion and subjectivity as commercial contracts.
- Because the GBLs negotiated between BC Hydro and FortisBC can potentially impact FortisBC's self-generating customers, these customers should have recourse to the Commission if they consider the resulting rates to be unjust and unreasonable. As this rate impact is the result of section 2.5 established between BC Hydro and

FortisBC, this baseline should be viewed as legitimately being within the potential scope of any objection to the rate proposal by FortisBC.

Discretion Available in Setting GBLs

- A balance between the need for consistency and transparency in relation to the need for the flexibility and discretions can perhaps be achieved. However, as currently proposed, the balance is decidedly tipped towards discretion and flexibility at the expense of transparency.
- The New PPA is not a commercial contract in the same sense as the contracts BC Hydro enters into to purchase electricity from its customers. Therefore, the Commission may wish to consider establishing a process whereby individual GBLs are approved.
- These concerns about lack of transparency add further support to the recommendation that there be a clear process through which customer concerns (be they self-generators or other customers of FortisBC) about the appropriateness of a GBLS set under section 2.5 of the New PPA can be raised and addressed.

(BCPSO Final Submission, pp. 12–16)

8.3.3 Positions of BC Hydro and FortisBC

In reference to the GBL Guidelines, specifically the June 2012 Information Report, BC Hydro acknowledges that the establishment of a Contracted GBL for a self-generating customer which sells electricity to BC Hydro does not follow a one size fits all formulaic approach. Accordingly, BC Hydro submits it is appropriate that the determination of a GBL for the purposes of section 2.5 of the New PPA would be agreed to by BC Hydro and FortisBC based on a publicly available set of principles. In summary, BC Hydro submits the language in section 2.5 is specifically designed to accommodate whatever mechanism(s) FortisBC might use in its rates for its self-generating customers in relation to simultaneous purchases and exports by such customers. (BC Hydro Final Submission, pp. 25–30)

In response to BCPSO, BC Hydro submits that BCPSO's recommendation is problematic because the determination of a GBL for the purposes of section 2.5(a) of the New PPA involves consideration of FortisBC customer information that the customer could consider commercially sensitive.

Therefore, the suggested Commission review process might not provide the transparency or opportunity BCPSO is seeking. Furthermore, BC Hydro submits section 2.5(b) of the New PPA already contemplates the possibility of Commission involvement if BC Hydro and FortisBC are unable to reach an agreement on the appropriate GBL. (BC Hydro Reply Submission, p. 5)

BC Hydro also challenges the statement that a self-generator would not have meaningful input into the customer-specific baseline [GBL]. BC Hydro states that information on the historic self-generation and how to normalize it would be required from the customer. Further, in order to implement the GBL approach both the customers and the utility would have to be involved in facilitating it. BC Hydro reiterates its position that the GBL Guidelines included in the 2012 Information Report are clear and that the basic principle of such GBL determinations is straight forward. BC Hydro also states that if a customer objected to the GBL they would have the right to complain to the Commission. (Supplemental Submission, Exhibit B-16, pp. 19–21, para. 54, 57–58)

BC Hydro proposes in its Supplemental Submission that if the Commission determined these issues were to result in the rate being unjust, unreasonable, unduly discriminatory or unduly preferential, the Commission could direct that section 2.5 of the New PPA included the following language:

- "the FortisBC self-generating customer must be consulted in relation to determination of a 'customer-specific baseline' [GBL] by FortisBC and BC Hydro, and/or
- any 'customer-specific baseline' [GBL] determined is subject to BCUC approval."

(Supplemental Submission, Exhibit B-16, para. 113)

FortisBC states that self-generating customers would, in fact, have meaningful input in setting the customer-specific baseline [GBL] for service in the FortisBC service territory and agrees with BC Hydro's submission on this issue (Supplemental Submission, Exhibit C1-24, para. 30). FortisBC also supports the additional language proposed by BC Hydro in paragraph 113 of its Supplemental Submission.

Commission Panel Discussion

The Commission Panel notes that, in general, the Interveners do not take exception to the idea of including the GBL construct. BC Hydro, in its 2012 Information Report, stated the application of the net-of-load approach results in the under-utilization of existing generation assets and the avoidance of investments in upgrades or new generation and emphasized this again in its Supplemental Submission.

However, the Panel shares the concerns of BCPSO and Celgar regarding the way the GBL construct is proposed to be applied as set out in section 2.5 of the New PPA. Specifically, the Panel is concerned that the proposal results in the customer-specific baselines being set by agreements between FortisBC and BC Hydro. The Panel believes that this could lead to the potential erosion in customer protection because the Generator Baseline (GBL) is to be established by BC Hydro and FortisBC while the self-generating customer is virtually excluded from having any meaningful input. This differs from the BC Hydro service area where, according to the 2012 Information Report, GBLs are agreed upon directly in negotiations between BC Hydro and its self-generating customer.

In its Supplemental Submission BC Hydro proposes that the Commission could direct BC Hydro to add additional language requiring the self-generator customers be consulted. However, this additional language did not require that the GBL be negotiated with the customer. The Panel does not see this additional language providing any additional protection to the customer.

In addition, section 2.5 stipulates that any GBL must be determined in accordance with the principles set out by BC Hydro in its 2012 Information Report. The GBL Guidelines set out in the 2012 Information Report are fairly general and subject to considerable interpretation and not necessarily transparent. Furthermore, the Guidelines have not been formally reviewed in a Commission proceeding nor does BC Hydro intend to file them for such a review. Finally, BC Hydro sees Contracted GBLs negotiated with its customers as sensitive commercial agreements – and, as such, confidential.

In its Supplemental Submission, BC Hydro also proposes that the Commission could direct BC Hydro to add additional language requiring the customer-specific baseline [GBL] be subject to Commission approval.

In the absence of a full proceeding to determine an appropriate GBL for each self-generating customer the Commission would have to rely on the 2012 Information Report for guidance. However, the 2012 Information Report which has not been approved by the Commission is subject to considerable interpretation, is fairly subjective and deals with the setting of Contracted GBLs for new customer installing self-generation. Clear guidance on how BC Hydro has historically sets GBLs for customers with existing generation facilities, or at what point in time "incremental" generation was determined is not addressed in the Report. As stated in the 2012 Information Report, BC Hydro has granted nine GBLs since 2009 with no Commission oversight or review (2012 Information report, p. 10).

The Panel struggles with how, in the future, the Commission could rely on the 2012 Information Report to determine a GBL for a FortisBC customer with existing self-generation consistent with BC Hydro's approach given the limitations of the 2012 Information Report. On February 17, 2014, in the Tariff Supplement No. 74 Decision, the Commission directed BC Hydro to file updated Contracted GBL guidelines to be incorporated as part of RS 1823. However, it would be expected that those guidelines would be addressing GBLs for customers with new self-generation and not existing self-generation and would therefore be of limited use to RS 3808.

The Panel concludes that gathering the necessary evidence in order to ensure that rates are not unjust, unreasonable, unduly discriminatory or unduly preferential would most likely not be possible by simply relying on the Guidelines contained in the 2012 Information Report. The Panel considers it highly likely that a lengthy regulatory proceeding would be required each time a GBL for a self-generation customer needs to be determined under the New PPA. The Panel sees little regulatory efficiency in this approach. The Panel also notes that because there are no established Guidelines these lengthy proceeding could still result in inconsistent outcomes and uncertainties for self-generators in the FortisBC service territory.

8.4 Rates that Comply with Section 2.5

Since the amended restrictions in section of 2.1 of the 1993 PPA were approved by the Commission in 2009, practical compliance in terms of rate design for FortisBC customers with self-generation has been an ongoing challenge, and has resulted in several decisions by the Commission on the matter.[14] This issue is yet to be satisfactorily resolved, and a further concurrent proceeding continues to refine the definition of what is an appropriate level of service to FortisBC's self-generating customers.[15]

BC Hydro submits: "The restrictions do not dictate how FortisBC is to serve its customers or how FortisBC (or the BCUC) is to design rates to be applied to FortisBC customers… Allocation of FortisBC's cost of energy to its rates is a design matter within the discretion of FortisBC and the BCUC." (Supplemental Submission, Exhibit B-16, para. 40)

FortisBC believes that it is currently free to establish GBLs with its self-generator customers, but their basis and effect is somewhat unclear (Supplemental Submission, Exhibit C1-24, para. 24). FortisBC also submits that the section 2.5 restrictions do impose some administrative and regulatory burden on FortisBC. If the restrictions in section 2.5 were removed the administrative burden would be lessened; however, it may result in BC Hydro being more active in FortisBC's proceedings. (Supplemental Submission, Exhibit C1-14, para. 27)

BC Hydro further submits that:

> "[It] believes that the challenges faced by stakeholders for the FortisBC rates being developed for its self-generating customers who wish to make non-physical deemed purchases and exports of matching blocks of power are not caused by the PPA or any of its terms. The challenges faced by the stakeholders would be largely the same even if there was no PPA." (Supplemental Submission, Exhibit B-16, para. 83)

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[14] G-113-01 (Riverside Application for Exemption), G-48-09 (BCH RS3808 Amendment), G-156-10 (FortisBC Rate Design), G-188-11 (Celgar Complaint), G-202-12 (FortisBC Entitlement and Matching Methodology), G-198-11 (Tolko GBL Reaffirmation).

[15] Application by FortisBC for Stepped and Stand-by Rates for Transmission Voltage Customers.

In regard to the design and setting of rates in the FortisBC territory for self-generating customers, Celgar submits that "[e]liminating the Restrictions in the New PPA will resolve almost all of the controversial issues in the Order G-202-12 proceeding…" (Supplemental Submission, Exhibit C5-10, para. 32).

> "As is the case with Restrictions in the 1993 PPA, Restrictions in the New PPA would unnecessarily encumber the exercise of the Commission's authority regarding rates to be set in future proceedings. This is unnecessary as the Commission will have the authority to mitigate the risk of any (currently non-existent) incentives for a self-generator to engage in 'impermissible' arbitrage should the issue arise. Such authority should not be constrained by the New PPA." (Supplemental Submission, Exhibit C5-10, para. 76)

Celgar goes on to comment on the Stepped and Stand-by Rates Application currently before the Commission that is designed to reflect the restriction in section 2.1 of the 1993 PPA stating "…no Commissioner can possibly think that the entitlement/notional matching/made-for-Celgar stepped rate with NECP rate rider is economically efficient or reflect any sound energy policy" (Supplemental Submission, Exhibit C5-10, para. 78).

Celgar submits that eliminating the restrictions would

> "eliminate the unwieldy (and currently unresolved) matching principle methodology. The fact that FortisBC and Celgar are unable to agree upon a matching methodology speaks to the underlying difficulty in reconciling the effects of the 'obligation to serve' and the 'no harm' principles outlined in earlier Commission Decisions. These difficulties would be eliminated by removal of the Restrictions, resulting in greater transparency, fairness and simplicity." (Supplemental Submission, Exhibit C5-10, para. 99)

BCMEU agrees that it is not in the best interest of the Interveners or the electric utility rate payers in general to have regulatory complexity such as surrounds the self-generation issues. Therefore, BCMEU submits it supports the concept of simplifying the requirements by removing section 2.5 from the proposed PPA. Furthermore, BCMEU submits that the regulations for self-generator exports be handled in a separate stand-alone document. (Supplemental Submission, Exhibit C4-5, pp. 3–4)

In reply, BC Hydro further reiterates its point and states that

> "[t]he New PPA and section 2.5 of it cannot and do not dictate the conditions under which FortisBC sells to its customers. It is a decision of FortisBC, with BCUC approval, whether to incorporate baseline mechanisms like those in section 2.5 of the New PPA into FortisBC's rates for its customers." (Reply Supplemental Submission, Exhibit B-7, para. 9)

Commission Panel Discussion

Section 2.1 (and now 2.5) restricts the use of RS 3808 energy by FortisBC to serve particular customers under certain circumstances. The Commission Panel acknowledges that on the surface this may appear to be simple. However, FortisBC meets its service area load requirements through a combination of sources of electricity supply which make up its resource stack. Approximately 28 percent of the resource stack comes from BC Hydro through RS 3808.

At any given moment a mix of electricity sources makes up what a customer physically receives. Given that it is not possible to physically supply a customer with a particular source of supply, designing a rate that reflects the expected non-physical deemed flow of electricity would most certainly lend itself to complications.

The Panel agrees with BC Hydro that the allocation of FortisBC's cost of energy to its rates is a rate design matter within the discretion of FortisBC and the Commission. The Panel finds, however, the proposed section 2.5 of the New PPA does in fact further complicate the rate design for transmission voltage customers in the FortisBC service territory. If BC Hydro's RS 1823 is any indication, rates designed for this rate class are already very complex, and layering on top of this further complexity will surely result in challenges for FortisBC and its affected customers.

In conclusion, the Commission Panel disagrees with BC Hydro's assertion that "... the challenges faced by the stakeholders would be largely the same even if there was no PPA" (Supplemental Submission, Exhibit B-16, para. 83). It is clear that that this is not the case. The Commission Panel believes that if FortisBC alone was in charge of its rate design for transmission voltage customers, unfettered by additional restrictions due to BC Hydro's concerns, the rate design and regulatory proceedings could be simplified.

8.5 Objective of Section 2.5

The Panel has already concluded that a GBL agreed between BC Hydro and FortisBC and approved by the Commission based on the non-Commission approved 2012 Information Report would lead to regulatory inefficiencies as lengthy regulatory proceedings would likely be required for the setting of each self-generating customer's GBL. Furthermore this approach could result in inconsistent outcomes and would provide little certainty to FortisBC's self-generating customers. The Panel also concluded that complying with the restrictions as proposed in section 2.5 of the New PPA would result in rate design complications in the FortisBC territory for which an agreeable solution has yet to be found.

Given the problematic nature of the GBL construct as proposed in section 2.5 of the New PPA the Panel seeks to clarify why these restrictions remain necessary.

8.5.1 Past Commission Decisions

BC Hydro and FortisBC have relied to a large extent on past Commission rulings in negotiating section 2.5 of the New PPA. A review of Commission Orders G-38-01, G-17-02 and G-48-09,[16] which set limitations to the amounts of heritage power available to self-generators who were also exporting, has shown that those cases, based on applications by BC Hydro, were all of a temporary nature. The Commission was reacting to certain "unique circumstances" and "without prejudice" to the resolution of long term rights of self-generating customers to take their generation to the market.

BC Hydro also noted that the program defined by Order G-38-01 (extended by G-17-02) was established during a period of time when there was a serious energy shortage in western North

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[16] Commission Orders are summarized in Appendix C.

America, and was therefore designed to encourage self-generating customers with idle capacity to generate and sell electricity.

Order G-48-09 was issued by the Commission after BC Hydro filed a complaint with the Commission when it became aware that FortisBC planned to increase sales to its self-generating customers through RS 3808 electricity. BC Hydro claimed that this would result in a fairly large negative impact to BC Hydro's ratepayers and argued those self-generators were engaging in arbitrage. To remedy the situation BC Hydro proposed to incorporate certain restrictions on FortisBC through the 1993 PPA by way of section 2.1 amendments. Specifically, that RS 3808 electricity shall not be sold to any FortisBC customer when such customer is selling self-generated electricity which is not in excess of its load.

Given the particulars of the issues at stake, the Commission considered that a more global solution regarding the business of reselling or "arbitrage" of power would be preferable. In the end, however, the Commission concluded that the record in the proceeding and the limited number of parties participating did not permit or support a more general remedy at the time. The G-48-09 Panel stated that "as the power export market for BC generators and their agents matures, the Commission or Government may choose to establish guidelines, rules or regulations to deal with the market and to spell out the permitted roles and operational rules that will be open to the various players province-wide." (G-48-09 Reasons for Decision, p. 22)

Short Term Nature

In the end the Commission approved BC Hydro's proposed solution by Order G-48-09. However, that Panel highlighted in its reasons the short term nature of the determination. The Panel acknowledged that the 1993 PPA between BC Hydro and FortisBC was to expire on September 30, 2013 and that the two parties were negotiating a potential renewal and extension hopefully resulting in a comprehensive renewed PPA. Therefore, the relief sought by BC Hydro was only granted for the remaining term of the 1993 PPA. (Reasons, Order G-48-09, p. 10)

Celgar submits given that the G-48-09 Decision was specifically intended to provide a temporary solution, and given the subsequent Commission decisions that have further defined the methods available to deal with self-generating customers, the Commission is now in a position to provide a longer term solution that will ensure the approved rate is fair, reasonable and not discriminatory. (Celgar Final Submission, para. 15)

BCMEU submits that

> "…the PPA is not the appropriate place to set regulations for self-generators and that self-generators, FortisBC and BC Hydro would be better served by having self-generator regulation separate and stand alone. [BCMEU] notes that the restrictions on self-generators in the previous [1993] PPA was the result of a unilateral application by BC Hydro (FortisBC opposed), as a regulatory expedient manner to deal with their concerns. To our [BCMEU] knowledge it was not chosen as the best solution only as the quickest." (Supplemental Submission, Exhibit C4-5, p. 2)

BC Hydro submits "…section 2.5 of the New PPA is not justified by the previous BCUC decisions indicating they were to be short-term measures only. Section 2.5 is needed and justified by the consistently applied regulatory principle that 'other utility ratepayers should not be harmed by self-generators' arbitrage of embedded cost of power.'" (Supplemental Submission, Exhibit B-16, para. 80)

Commission Panel Discussion

In light of the observations and submissions above, especially those by BCMEU, the Panel acknowledges the short-term nature of Order G-48-09. Therefore, the length of the New PPA, the temporal nature of Order G-48-09 and the concerns previously identified with adopting section 2.5 of the New PPA as proposed jointly call for further consideration. Accordingly, the Panel assesses in the following the true purpose of the restrictions in section 2.5 of the New PPA before making an overall determination on the Application.

8.5.2 Nature of Protection to Ratepayer

Section 2.5 of the New PPA is a proposed solution to a BC Hydro concern, which the Panel has found problematic because, among other things, it would likely lead to significant regulatory inefficiencies and result in rate design complexities. In order to determine if the proposed restrictions in section 2.5 of the New PPA remain a reasonable solution to effectively address BC Hydro's concern the Panel seeks to clarify precisely what is sought to be achieved through the restrictions contemplated. Ultimately the Panel will determine whether the inclusion of these restrictions results in rates that are unjust, unreasonable, unduly discriminatory or unduly preferential.

BCSEA submits that "[t]he essential purpose of section 2.5 of the New PPA is to prevent customers with self-generation facilities from arbitraging fixed utility rates and market prices to the detriment of other ratepayers" (Supplemental Submission, Exhibit C7-7, p. 1).

BC Hydro submits that

> "The purpose of section 2.5(a)(ii) is to <u>protect BC Hydro's customers</u> from the rate impacts they could incur if BC Hydro had to supply increased electricity to FortisBC as a result of FortisBC self-generating customers simultaneously buying and selling electricity to take advantage of an available price differential. The purpose of section 2.5 in the New PPA is the same as the purpose of section 2.1 of the 1993 PPA as amended by Order G-48-09. Accordingly, the Commission has determined this purpose to be in the public interest." (BC Hydro Reply Submission, para. 51)

Commission Determination

In its Reasons for Decision to Order G-48-09 the Commission made two determinations relevant to the issue currently before the Commission. First, it extended the "Self-Generation Policy Issue" [17] as set out in BC Hydro's Order G-38-01 to the FortisBC service territory. In particular, the

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[17] "The Commission directs B.C. Hydro to allow Rate Schedule 1821 customers with idle self-generation capability to sell excess self-generated electricity, provided the self-generating customers do not arbitrage between embedded cost utility service and market prices. This means that B.C. Hydro is not required to supply any increased embedded cost of service to a RS 1821 customer selling its self-generation output to market."

Commission determined that self-generating customers in FortisBC's service territory should not be permitted to arbitrage, between FortisBC's embedded rates and market prices, to the detriment of FortisBC's other ratepayers.

Second, by amending section 2.1 of the 1993 PPA, it can be concluded, the Commission determined that the Self-Generation Policy Issue also applies between service territories, such that self-generating customers of FortisBC would be prevented from engaging in arbitrage activities to the detriment of BC Hydro's ratepayers as well. Specifically section 2.1 states that RS 3808 electricity shall not be sold to any FortisBC customer when such customer is selling self-generated electricity which is not in excess of its load.

However, section 2.1 of the 1993 PPA only addressed the second issue of ensuring that there would be no detriment to BC Hydro's ratepayers. The first issue was not addressed and protection to FortisBC's ratepayers was not provided. Section 2.1 did not place any restrictions on FortisBC from supplying its self-generating customers with electricity that did not include RS 3808 power.

The Commission Panel therefore finds section 2.1 did not enforce the Self-Generation Policy Issue in the FortisBC territory; it only protected BC Hydro from it. In the Panel's view, what BC Hydro is achieving through the restrictions contemplated in section 2.5 of the New PPA is protection of its own ratepayers against potential detriment caused by FortisBC's self-generating customers arbitraging between fixed utility rates and market prices — and nothing else.

BC Hydro has stated on several occasions that FortisBC is free to provide services to its self-generating customers as it sees fit: "[The] Allocation of FortisBC's cost of energy to its rates is a rate design matter within the discretion of FortisBC and the BCUC" (Supplemental Submission, Exhibit B-16, para. 40). In fact, the allocation of energy to FortisBC's self-generating customers that does not include RS 3808 electricity is currently before the Commission in a separate proceeding.[18]

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[18] Application by FortisBC Inc. for Stepped and Stand-by Rates for Transmission Voltage Customers.

The Panel disagrees with BC Hydro that section 2.5 is needed and justified by the consistently applied “Self-Generation Policy Issue.” That Self-Generation Policy Issue being that other utility ratepayers should not be harmed by self-generating customers’ arbitrage of embedded cost power. It is extraordinary for a policy issue of a regulated utility to be addressed through a rate schedule of another utility, even if that rate schedule is between the two utilities.

However, the Panel agrees with BC Hydro that the Self-Generation Policy Issue in the FortisBC service territory needs to be applied but disagrees that this should be achieved through the RS 3808. The Panel concludes that ensuring the Self-Generation Policy Issue is carried out in the FortisBC territory is of utmost importance, but is better applied by means other than through RS 3808. Hence, the review of section 2.5 of the New PPA in the following will consider whether there is any material risk of harm to BC Hydro’s ratepayers that warrants it reasonable to continue to include these restrictions in the New PPA.

8.6 Current Terms of the New PPA

The relevant terms of the New PPA,[19] including capacity and energy volumes, energy nominations and scheduling, as well as the current energy surplus in the Pacific Northwest will be addressed below to determine if it is reasonable or necessary to continue to provide protection to BC Hydro’s ratepayers under the proposed section 2.5 of the New PPA.

8.6.1 Capacity and Energy Volumes

8.6.1.1 Tranche 1

The New PPA continues to provide for up to 200 MW of capacity and 1,752 GWh/year of associated energy. However, the New PPA sets a fixed cap of 1,041 GWh/year that can be taken at the Tranche 1 rate. The Tranche 1 rate is the same rate offered to BC Hydro’s other industrial customers on the flat RS 1827 rate, and is based on BC Hydro’s embedded cost of power. Anything

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[19] Summarized in Section 4.2 of this Decision.

in excess of the 1,041 GWh/year is priced at the Tranche 2 rate, which is set at BC Hydro's long run marginal cost. The amount of power available to FortisBC in the New PPA at embedded cost rates is significantly less than the 1,752 GWh/year made available in the 1993 PPA.

As shown in the table below for planning purposes,[20] FortisBC expects to be at maximum or close to maximum Tranche 1 volumes to serve a portion of its load service obligation for all but the first couple of years of the New PPA. On an operations basis, FortisBC may displace even more Tranche 1 energy purchases with more economical resources if they are available. (Exhibit C1-8, ICG IR 1.2.13)

Table 5

FortisBC's Expected Use of Tranche 1 Energy under the New PPA

PPA Energy	FBC Forecast Tranche 1 Volume	FBC Forecast Tranche 2 Volume	Tranche 1 Energy Prices[2,3]	BC Hydro Tranche 1 Revenues[1]
Year	GWh	GWh	$/MWh	$000
2013Q4	197	0	$39.10	$7,703
2014	663	0	$39.88	$26,443
2015	771	0	$40.68	$31,366
2016	916	0	$41.50	$38,010
2017	981	0	$42.33	$41,521
2018	1,010.80	0	$43.17	$43,638
2019	1,019.30	0	$44.04	$44,885
2020	1,028.00	0	$44.92	$46,174
2021	1,038.50	0	$45.81	$47,578
2022	1,041.00	0	$46.73	$48,646
2023	1,041.00	0	$47.67	$49,619
2024	1,041.00	0	$48.62	$50,612
2025	1,041.00	0	$49.59	$51,624
2026	1,041.00	0	$50.58	$52,656
2027	1,041.00	0	$51.59	$53,710
2028	1,041.00	0	$52.63	$54,784
2029	1,041.00	0	$53.68	$55,879
2030	1,041.00	0	$54.75	$56,997
2031	1,041.00	0	$55.85	$58,137
2032	1,041.00	0	$56.96	$59,300
2033 Q1-Q3	634	0	$58.10	$36,838

1. Does not include capacity charges
2. Includes BC Hydro Tariff Rate Rider
3. Escalated at assumed CIP (2% a year)

Source: Exhibit C1-8, ICG IR 1.2.13

20 FortisBC's forecast was developed as part of the recent 2014 Revenue Requirement Application.

BC Hydro disagrees with FortisBC's forecast and submits that FortisBC will not purchase the full maximum Tranche 1 amount for approximately 10 years. BC Hydro provided its December 2012 Annual Load Forecast for RS 3808 sales to FortisBC in response to CEC IR 1.1.1 and that forecast is reproduced below.

Table 6

BC Hydro's expected sales of RS 3808 under the New PPA

Fiscal Year	Energy Sales to RS 3808 (GWh)	Capacity Sales to RS 3808 (MW)
Forecast		
F2013	390	200
F2014	526	200
F2015	516	200
F2016	541	200
F2017	512	200
F2018	511	200
F2019	511	200
F2020	511	200
F2021	645	200
F2022	845	200
F2023	1,000	200
F2024	1,041	200
F2025	1,041	200
F2026	1,041	200
F2027	1,041	200
F2028	1,041	200
F2029	1,041	200
F2030	1,041	200
F2031	1,041	200
F2032	1,041	200
F2033	1,041	200

Source: BC Hydro's Supplemental Submission, Exhibit B-16, para. 63

BC Hydro concludes that in 2015 FortisBC will have an additional 535 GWh of Tranche 1 energy available and this will more or less continue through 2020 (Supplemental Submission, Exhibit B-16, para. 66). However, BC Hydro also states "It should be noted that the RS 3808 sales forecast is different than FortisBC's forecast because BC Hydro prepared its forecast in late 2012 based on its assessment of the future spot market prices for electricity" (Exhibit B-5, CEC 1.1.1.1). BC Hydro further acknowledges that it did not conduct any sensitivity analysis using alternative spot market prices for electricity in preparing its forecast and assumed a low market price until 2023 (Exhibit B-14, CEC 2.2.2.1)

FortisBC challenges BC Hydro's forecast and its suggestion that FortisBC has over 500 GWh of Tranche 1 energy available to meet incremental load for customers with self-generation. FortisBC states that the cap on Tranche 1 energy was based on FortisBC's load forecast presented in its 2012 Resource Plan to meet its annual normal load forecast, without consideration of any incremental load associated with self-generating customers. FortisBC observes that BC Hydro' forecast is low because of the current low market price environment and states that under these conditions any additional load on FortisBC's side would likely be served with additional market purchases and not PPA purchase. (Supplemental Submission, Exhibit C1-24, para. 20) Furthermore, it states that if market conditions were to become less favourable, the Tranche 1 cap would be reached to meet normal utility load requirements leaving no excess room to support any additional incremental loads.

FortisBC concludes that "[a]s a practical matter, in the current market environment, FortisBC does not anticipate taking that step and using BC Hydro power to supply the additional self-generator demand associated with arbitrage even if the s. 2.5 restrictions did not exist." Further, "FortisBC anticipates that as an operational matter, on a forecast basis, nothing would change even if the restrictions in section 2.5 of the New PPA were removed." (Supplemental Submission, Exhibit C1-24, para. 19)

FortisBC provides additional strength to its positions by stating that

> "FortisBC is already limited by the 200 MW capacity limit during winter periods, and therefore any growth in PPA used to serve incremental load would only

occur during freshet or summer periods when generally more supply options are available [to FortisBC and BC Hydro]" (Supplemental Submission, Exhibit C1-24, para. 20).

Celgar submits BC Hydro's position that FortisBC will likely not reach the maximum Tranche 1 over the next couple of years and that 500 GWh will be available to meet any incremental load is incorrect for the following reasons:

- There is no ability to take additional energy under the New PPA when the maximum capacity of 200 MW is being utilized, which is most of the winter months.
- The underutilization of the Tranche 1 energy only arises as a result of current real-time market purchase opportunities that are below the cost of Tranche 1.
- If the market prices increase, then the full Tranche 1 amount would be required by FortisBC to meet its existing load. (Supplemental Submission, para. 88–90)

Commission Panel Discussion

FortisBC has forecast reaching the Tranche 1 cap by 2022 and BC Hydro forecasts it will reach it by 2024. Nevertheless, the real issue is how much unused Tranche 1 energy is available during that period to serve any incremental load. FortisBC has forecast on a cumulative basis approximately 900 GWh[21] of unused Tranche 1 energy up to 2022, with a combined 773 GWh (85 percent) available in 2014, 2015 and 2016. BC Hydro forecasts that there will be 5,282 GWh[22] of unused Tranche 1 energy, with about 500 GWh being available in each of the next seven years.

The Panel is persuaded by FortisBC's submissions and is placing reliance on its forecast of available incremental energy over the 20 years of the New PPA in this Decision for the following reasons.

BC Hydro argues that if there is a more economical alternative, for whatever reason, FortisBC would reduce its purchase to serve its normal utility load thus leaving more available Tranche 1

[21] Over the term of the New PPA the sum of the difference between FortisBC's Forecasts Tranche use and 1,041 GWh.

[22] Over the term of the New PPA the difference between BC Hydro's forecast Sales of RS 3808 each year and 1,041 GWh.

energy available to serve any incremental load. However, the Panel agrees with FortisBC that under this scenario it would only be logical that the more economical alternative would also be used to serve any incremental load and therefore there is no real risk to BC Hydro.

The Panel also agrees with FortisBC's argument that under low market conditions (market price lower than RS 3808 rate) there would be little risk that self-generating customers would have the opportunity to arbitrage. Even if they did, it is likely that FortisBC would serve this load with the lower priced market energy and not increase RS 3808 purchases. In the case that market prices were to rise, FortisBC states it would increase its Tranche 1 purchases as much as possible (given the constraints of the Energy Nominations and Scheduling) to meet its normal utility load leaving nothing available for any incremental load.

The Panel is further persuaded that the potential risk of using Tranche 1 energy to supply any incremental load is further mitigated because FortisBC has forecast using the full 200 MW capacities during the winter periods. Any increase in incremental load could only be served with Tranche 1 energy in the freshet and summer periods when generally more supply options are available.

8.6.1.2 Tranche 2

FortisBC does not forecast taking any Tranche 2 energy over the life of the New PPA due to the price differential between the tranches (Exhibit C1-8, ICG IR 1.2.13).

BC Hydro submits that the Tranche 2 energy price will not effectively mitigate the inappropriate arbitrage risk. If the Tranche 2 energy was used to supply any additional sales to FortisBC's self-generating customers this would mitigate, but not eliminate, the detrimental impacts of the arbitrage. (Supplemental Submission, Exhibit B-16, para. 66)

BCPSO submits that

> "[s]hould FortisBC ever exceed the Tranche 1 cap...the higher Tranche 2 energy price may help reduce the impact of potential arbitrage activity by FortisBC's self-generating customers on BC Hydro's ratepayers but it will no eliminate it. The Tranche 2 energy price represents BC Hydro's long run (average) marginal cost. If BC Hydro was required to provide the additional supply required…to serve a self-generating customer circumstances could well be such that BC Hydro's short-term source of additional power exceeded its long-run marginal cost and, indeed, this supply could well come from the same market that the customer is selling into and at the same price." (Supplemental Submission, Exhibit C2-7, para. 6)

Celgar argues that if Tranche 2 energy was used to serve any incremental load that BC Hydro ratepayers would experience no harm because it is set at BC Hydro's long run marginal cost. Celgar states that by design, the Tranche 2 rate is intended to recover the full cost of any Tranche 2 purchases. That is, as long as the Tranche 2 rate reflects BC Hydro's most recent proxy for LRMC, as it is designed to do, then it necessarily follows that any Tranche 2 purchase will not result in any harm to BC Hydro's ratepayers.

Further, Celgar submits that it does not intend, and has never intended (for its below-load energy), to participate in the hour-by-hour markets, as do utilities. It further states that:

> "The load served [by FortisBC] must be predictable and that will ensure that self-generators do not use their self-generation investments for 'short-term opportunistic buy/sell arbitrage'. Indeed, the capacity-related charges in FortisBC's transmission service rate schedules already provide a strong disincentive to such transactions, as the self-generator typically would be obligated to pay capacity charges throughout the contract period based on its peak demand." (Supplemental Submission, Exhibit C5-10, para. 58)

Celgar concludes by stating that all supply of power to FortisBC to meet an incremental load of its self-generating customers must be assumed to be from the Tranche 2 energy. (Supplemental Submission, Exhibit C5-10, para. 58 & 91-94)

Commission Determination

The Commission Panel notes that the Tranche 2 rate is based on BC Hydro's LRMC of energy which is designed to recover BC Hydro's full cost and that neither FortisBC nor BC Hydro expects that any Tranche 2 energy will be used during the term of the New PPA.
The Panel finds that any potential Tranche 2 purchases on an overall basis would not result in any material harm to BC Hydro's ratepayers if it were to be used.

The Panel disagrees with BC Hydro that the Tranche 2 energy price will not effectively mitigate the inappropriate arbitrage risk because there are hours where BC Hydro's short-term source of additional power exceeded its long-run marginal cost. The Panel is persuaded by Celgar's argument that the capacity charges in the underlying rates would be a disincentive for a self-generating customer to participate in hour-by-hour markets for its below-load energy.

8.6.2 <u>Energy Nominations and Scheduling</u>

The provisions in the New PPA related to nominations and scheduling of energy place an increased responsibility on FortisBC to forecast its requirements for PPA power on an annual basis and reduce the ability of FortisBC to use PPA power to address imbalances in its own system.

Under the 1993 PPA, FortisBC was not required to provide energy nominations but rather to provide a ten year, annually updated load forecast. FortisBC was also permitted to take energy in excess of its pre-scheduled amount without providing advance notice. (Exhibit B-1, pp. 20–21)

Under the terms of the New PPA, FortisBC is required to provide an Annual Energy Nomination and is faced with the following restrictions, conditions and pricing:

- FortisBC has the ability to reduce contract demand, but is restricted from changing the nomination from one year to the next by no more than +/- 20 percent;
- FortisBC is obligated to "take or pay" at least 75 percent of the Annual Energy Nomination; and

- Energy cost taken in excess of the Annual Energy Nomination is based on the Tranche 1 and Tranche 2 prices. For purchases of PPA power exceeding the Annual Energy Nomination, but less than or equal to the Tranche 1 amount, FortisBC will pay 150 percent of the Tranche 1 energy price. For purchases in excess of both the Annual Energy Nomination and the Tranche 1 amount, FortisBC will pay 115 percent of the Tranche 2 energy price.

Due to the new energy nomination and scheduling requirements, FortisBC has much less ability to use BC Hydro as the swing supply with which to respond to short-term changes in demand from its customers.

BC Hydro submits that "[t]he 75 per cent take-or-pay obligation operated in one direction only – that is, this provision does not address what happens if FortisBC takes more than its Annual Energy Nomination." Furthermore, "the 75 per cent take-or-pay provision provides BC Hydro with a level of revenue certainty each year and was included in the New PPA as an incentive for FortisBC to make accurate annual nominations." (Supplemental Submission, Exhibit B-16, para. 71)

BC Hydro further submits that

> "[i]f FortisBC wishes to increase its take Above the Annual Energy Nominations…[it's] priced at the applicable Trance 1 Energy Price plus 50 per cent or the Tranche 2 Energy price plus 15 per cent" (Supplemental Submission, Exhibit B-16, para. 73). BC Hydro agrees that FortisBC may only increase or decrease its Annual Energy Nominations by 20 per cent of the preceding year. BC Hydro concludes by stating "[t]he provisions [75 percent take or pay, +/- 20 per cent restrictions, excess surcharges] in the New PPA discussed above do not provide significant protection to BC Hydro from inappropriate arbitrage activities by FortisBC or its self-generating customers." (Supplemental Submission, Exhibit B-16, para. 71-75)

FortisBC responds by stating that

> "FortisBC must make an Annual Energy Nomination prior to the beginning of each contract year. At the time FortisBC makes the nomination it will ensure it has other firm resources in place to meet expected load requirements. If market or load conditions change such that FortisBC requires additional resources [from RS 3808]…there is a 50% premium on the Tranche 1 price. This 50% premium more than offsets the potential for any financial incentives between costs and revenues. In addition, there could be impacts on capacity demand charges if the incremental purchases occurred during high demand periods." (Supplemental Submission, Exhibit, C1-24, para. 20 (b))

Commission Determination

The Commission Panel notes that should market or load conditions change such that FortisBC requires additional resources (from RS 3808) there is a 50% premium on the Tranche 1 price and possibly increased demand charges. This, in the Panels view, provides adequate protection to BC Hydro's ratepayers from FortisBC using any energy in excess of what it has nominated.

Further the Panel concludes that the +/- 20 percent restriction makes it a great deal more difficult for FortisBC to access any excess Tranche 1 energy that may be available.

The Panel understands that the 75 percent take or pay provision does not provide any protection for increased purchases. **However, overall, the Commission Panel concludes that the 75 percent take or pay, +/- 20 percent restrictions, and excess surcharges do provide a moderate amount of additional protection over and above the protection provided by the Tranche 1 cap to BC Hydro's ratepayers. This is protection that did not exist under the terms of the 1993 PPA.**

8.6.3 Pacific Northwest Surplus

BC Hydro states that it expects electricity supply in the Pacific Northwest to remain in surplus for the foreseeable future along with a continuation of relatively low spot market prices. The low market prices also result from lower natural gas prices arising from the extensive shale gas developments in North America. The cost of fuel for gas-fired generation sets the marginal cost of electricity production in most of North America and this relationship is expected to remain or even strengthen for several years to come. (Exhibit B-5, Alan Wait IR 1.3.1)

BC Hydro also provided a forecast of the anticipated surpluses it may be putting into the market over the next 20 years, based on the Base Resource Plans (BRP) from the 2013 Integrated Resource Plan. The BRP without LNG shows surpluses until F2022 and again surpluses from F2024 to F2030. The BRP with LNG shows surpluses from F2012 to F2014 and again from F2024 through F2027. (Exhibit B-14, CEC IR 2.9.1)

BC Hydro agrees that there is no energy shortage at this time that warrants extraordinary measures to enable self-generating customers to make non-physical exports of incremental electricity to market. However, BC Hydro points out that while current projections are for surplus the forecast has uncertainty and history has proven the energy supply-resource balance can change quickly (Supplemental Submission, Exhibit B-16, para. 78). BC Hydro further submits that "[e]ven in current conditions of relatively low market prices on average, there are many hours when market prices are high..." (Supplemental Submission, Exhibit B-16, para. 90).

BCPSO submits that "The New PPA is a twenty-year agreement, during which it is projected by BC Hydro and FortisBC that there will be an expected surplus of energy available in the Pacific Northwest (unlike the 2001 era of serious energy shortage in western North America when Order G-38-01 was established)" (Supplemental Submission, Exhibit C2-7, para. 2).

BCPSO further submits "it is precisely the fact that the New PPA is a 20-year agreement that the section 2.5 provision is required. While there may be no energy shortage at this time the market and market prices may be low, there is no guarantee that such circumstances will exist over the next 20 years." (Supplemental Submission, Exhibit C2-7, para. 9)

Celgar submits that

> "[m]ost relevant to the query regarding the potential risk to which BC Hydro and its ratepayers might be exposed under the New PPA are the changed circumstances of today's energy market, all of which have eliminated the incentive of self-generators to engage in the type of arbitrage feared by BC Hydro (arbitrage between embedded costs rates and market rates)." (Supplemental Submission, Exhibit C5-10, para. 84)

Celgar further submits this market environment eliminates the risk that in the event such arbitrage was to occur, BC Hydro would be forced to purchase incremental replacement energy at prices that would significantly impact its ratepayers. Rather, such purchases would be carried out under the current depressed market prices. Therefore, Celgar concludes by stating that under the current market conditions the risk of harm to BC Hydro's other ratepayers is simply not there. (Supplemental Submission, Exhibit C5-10, para. 87)

Commission Determination

The Commission Panel notes BC Hydro has confirmed that it expects the electricity supply in the Pacific Northwest to remain in surplus for the foreseeable future along with the continuation of low spot market prices. Yet, BC Hydro argues that although spot market prices are low there are hours when they are high. However, as stated previously, the Panel believes the capacity charges in the underlying rates would be a disincentive for self-generating customer to participate in hour-by-hour markets for its below-load energy and as a result they most likely would not be participating in these types of transactions.

The Panel also has already agreed that relatively low spot markets do not incent FortisBC's self-generating customer to arbitrage between embedded costs rates and market rates. Further if they were to do so, FortisBC would likely not use RS 3808 energy to serve them. However, the Panel also agrees with BCPSO's assertion that the New PPA is for a twenty-year term and given the unpredictability of energy supply markets and spot market prices the situation will likely change over at term of the New PPA.

Hence, the Commission Panel determines that as long as there is an energy surplus and spot markets are low there is very little risk to BC Hydro ratepayers of FortisBC using its excess Tranche 1 energy to supply any incremental load.

Based on FortisBC's forecast, which the Commission has accepted, 85 percent[23] of the excess Tranche 1 energy is available in 2014, 2015 and 2016 only. **Therefore, the Panel finds that although the current energy surplus does not necessarily provide protection to BC Hydro's ratepayers over the entire twenty- year term of the New PPA, it does provide protection in the near future where the greatest amount of risk lies.**

[23] (900/773) see details of numbers in Section 8.6.1.1 of this Decision.

8.7 The Continued Need for Section 2.5

One of the concerns that the Commission Panel expressed in its December 13, 2013 letter was whether BC Hydro ratepayers still required the additional protection afforded in section 2.5 of the New PPA when consideration was given to the terms of the New PPA (Exhibit A-17, pp. 1–2).

8.7.1 Supplemental Submissions of BC Hydro and FortisBC

BC Hydro submits that

> "[i]f the New PPA used the No Restrictions Approach [no restrictions included in section 2.5] there could be a significant loss to BC Hydro and its ratepayers due to the inappropriate arbitrage activities the BCUC has consistently opposed" (Supplemental Submission, Exhibit B-16, para. 94). BC Hydro also notes that "the exact dollar figure is not important. The potential for material loss and the policy principle are what matters" (Supplemental Submission, Exhibit B-16, para. 95).

FortisBC acknowledges the regulatory principle that self-generating customers of a utility should not be permitted to arbitrage between embedded cost utility rates and market prices to the detriment of the utility's other ratepayers and supports this principle. However, FortisBC believes that Commission decisions related to the APA have made the status of this principle somewhat unclear. (Supplemental Submission, C1-24, para. 32)

FortisBC submits that under the current regulatory environment BC Hydro continues to require the restrictions for the following reasons:

- the potential further interpretation by the Commission of the APA which could lead to arbitrage in the FortisBC territory;
- the current market conditions could change over the 20 year term of the New PPA; and
- although, under the No Restrictions Approach, FortisBC does not presently anticipate making use of additional RS 3808 power, in particular because of the Tranche 1 cap, if faced with increased self-generation demand, the factors that underpin this constraint may change. (Supplemental Submission, C1-24, para. 6)

However FortisBC states that

> "[i]f self-generator customers were clearly prohibited from arbitraging between embedded cost FortisBC rates and market prices in the FortisBC service territory, the restrictions…would be redundant. The arbitrage that section 2.5 seeks to prevent would not be occurring." (Supplemental Submission, para. 7)

FortisBC further submits that if the same GBL principle used in BC Hydro's service territory clearly applied and was enforced in the FortisBC territory, it would not only eliminate the need for the section 2.5 restrictions but it would provide provincial consistency. FortisBC also states that this would be preferable to the matching methodology. (Supplemental Submission, Exhibit C1-24, para. 6–9 and 24)

FortisBC concludes that clearly, if the restrictions in section 2.5 were not included in the New PPA now, it is reasonable to assume that BC Hydro would likely seek to revisit the New PPA at some future time and be more inclined to continue to intervene in FortisBC's regulatory proceeding in order to ensure its perceived interested were safeguarded. (Supplemental Submission, Exhibit C1-24, para. 21)

8.7.2 Supplemental Submissions of Interveners

Celgar submits that the restrictions in section 2.5 have no place in the New PPA. Celgar states that

> "[f]irst BC Hydro is now in a surplus energy supply position, such that harm to other ratepayers cannot simply be presumed. Second, there is no longer a gap between market rates and embedded cost rates favouring embedded cost rates. Third, given the cap on Tranche 1 energy in the New PPA, FortisBC does not anticipate purchasing additional New PPA power, and, due to changes in the New PPA even if FortisBC were to purchase additional Tranche 2 power, no harm would result to BC Hydro customer." (Supplemental Submission, Exhibit C5-10, para. 74)

In summary, Celgar submits there is no evidentiary basis for concluding that BC Hydro or its ratepayers face any significant or real risk under the New PPA (Supplemental Submission, Exhibit C5-10, para. 97). Celgar recommends that the "Commission reform [s]ection 2.5 of the New PPA so as to delete [s]ections 2.5(a)(ii), 2.5(a)(iii) and 2.5(b)" (Supplemental Submission, Exhibit C5-10, para. 109).

BCMEU states

> "[t]hat in the current environment these restrictions are not required to protect BC Hydro, however we also accept that the environment may change over the course of the PPA. We further believe that the PPA is not the appropriate place to set regulations for self-generators and that the self-generators….would be better served by having self-generator regulations separate and standalone." (Supplemental Submission, Exhibit C4-5, p. 2)

BCMEU agrees that it is not in the best interest of the Interveners nor of the electric utility rates payers in general to have regulatory complexity such as surrounds the self-generator issue. Therefore, BCMEU supports the concept of simplifying the requirements by removing section 2.5 from the proposed PPA and further that the regulation of self-generator energy exports be handled as a separate standalone document. BCMEU also acknowledges that the inclusion of the restrictions facilitates the PPA renewal agreement and recommends that section 2.5 could be left in the PPA with a defined expiry term upon Commission approval of a set of self-generator rules applicable throughout the Province. (Supplemental Submission, Exhibit C4-5, pp. 2–4)

BCPSO submits that the materiality of any negative impact to BC Hydro's ratepayers should not be a deciding factor when fundamental principles are involved. BCPSO further submits that allowing FortisBC to establish GBLs (or other mechanisms) to address the issues of arbitrage from its own customers' perspective will not address the risk that BC Hydro is seeking to mitigate through section 2.5 as proposed. In summary, BCPSO states if their concerns regarding customers input were addressed (as would be by the changes recommended by BC Hydro in paragraph 113 of its Supplemental Submission) the New PPA should be approved without any need to alter the provisions of section 2.5. However, BCPSO recommends that the BCUC establish a proceeding to determine individual GBLs for FortisBC's customers. (Supplemental Submission, Exhibit C2-7, para. 11–14)

Alain Wait submits that both BC Hydro and FortisBC ratepayers must be considered. The restrictions in section 2.5 are necessary as the Pacific Northwest surplus may be reduced in the not so distant future. Mr. Wait further submits section 2.5 should be amended to include defining the criteria used by BC Hydro in developing GBLs. If FortisBC were free to establish their own GBLs it would be difficult to determine them when no parameters have been presented on the setting of GBLs. (Supplemental Submission, Exhibit C6-5, pp. 1–3)

BCSEA submits that section 2.5 of the New PPA is still necessary under the current environment because it is a long-term agreement that must be worded to take into account a wide range of potential future market conditions. BCSEA is of the view that it is far more effective to remove the risk by including section 2.5 than to speculate about the negative consequences that might occur if it was deleted. BCSEA also states that the risk would exist as a matter of legal reality, regardless of the likelihood or magnitude of actual damages due to materialization of the risk. (Supplemental Submission, BCSEA C7-7, pp. 1–2)

CEC submits it supports the general regulatory principle and the inclusion of section 2.5 of the New PPA. CEC suggests that at another time, and in another regulatory process, the Commission should initiate a process to clarify the circumstances for self-generators in the FortisBC territory to clearly align the principles used in the BC Hydro territory with those in the FortisBC territory – this would obviate the need for clarification in the New PPA. (Supplemental Submission, Exhibit C11-7, p. 1)

8.7.3 BC Hydro's Supplemental Reply

BC Hydro submits that

> "[i]n the absence of certainty regarding the rules that FortisBC will apply to its self-generating customers, it is not possible to set conditions in section 2.5(a)(ii) of the New PPA that are tailored specifically to such rules. No FortisBC rules exist. Indeed, the slate has been all but wiped clean in that regard by the recent Order G-191-13 determinations." (Supplemental Submission, Exhibit B-17, para. 23)

For BC Hydro, the issue then is whether section 2.5(a)(ii) of the New PPA should remain or if the New PPA should be silent at this time and be amended in the future after the rules for FortisBC's service area have been resolved (Supplemental Submission, Exhibit B-17, para. 24).

BC Hydro notes that Celgar prefers the second approach, which it does not support as it would have to rely on FortisBC to negotiate arrangements to protect BC Hydro's customers. BC Hydro does not consider that FortisBC or its customers would be motivated to do so. Further, BC Hydro questions whether FortisBC would maintain its support for the principles in section 2.5 if the restrictions were removed on a temporary basis. (Supplemental Submission, Exhibit B-17, para. 23–26)

Regarding the request for further process BC Hydro submits that

> "the BCUC reiterated once again [Reasons to Order G-191-13] that the rights and obligations between FortisBC and its customers are issues to be resolved through negotiations between FortisBC and its customers, taking into account all competing interest and mechanism within the broad book ends. The service agreements that result from such negotiations will need to be presented to the BCUC for approval, BC Hydro suggest that those FortisBC activities are the appropriate context for further consideration of rules for FortisBC self-generating customers." (Supplemental Submission, Exhibit B-17, para. 45)

8.8 Section 2.5 — Commission Summary Determination

The Panel has already highlighted that Order G-48-09 made two significant determinations relevant to this proceeding. The first one addresses the Self-Generation Policy Issue in the FortisBC service territory. The Commission determined that this larger comprehensive issue was not addressed through the proposed section 2.5 New PPA. The second determination was protection for BC Hydro's ratepayers from the risk of harm due to FortisBC's self-generating customers arbitraging between embedded cost rates and market rates. This Panel earlier also noted that section 2.5 of the New PPA was designed by BC Hydro to continue to provide it with that protection.

However, the Panel concluded that the specific way BC Hydro proposes to obtain such protection is problematic. Specifically, the Panel considers that to ensure rates are not unjust, unreasonable, unduly discriminatory or unduly preferential a lengthy regulatory proceeding may be required to set individual GBLs for each self-generating customer. The Panel found little regulatory efficiencies in this approach and noted that it could result in inconsistent outcomes and uncertainties for self-generators in the FortisBC service territory.

The Panel also identified two further issues caused by the restrictions as proposed in section 2.5 of the New PPA. First, the restrictions have led to rate design complications in the FortisBC territory for which an agreeable solution has yet to be found. Secondly, the Panel is concerned that keeping the restrictions in the New PPA would considerably restrict FortisBC`s flexibility in the future to change its regulations for customers with self-generation. Given the long term nature of the New PPA and the changing energy environment there may come a time during the term of the New PPA where the GBL methodology is no longer desirable, even in the BC Hydro service area. If the restrictions are to remain in the New PPA, FortisBC's options to adapt to a changing environment may be constrained.

Therefore, the Panel took closer looks at the terms of the New PPA, including the Tranche 1 Cap, the Tranche 2 price, and the Energy and Nomination Scheduling requirements, to determine whether there remains any material risk of harm to BC Hydro's ratepayers that warrants it reasonable to continue to include these problematic restrictions in the New PPA.

Based upon this further examination the Panel concludes that any embedded cost energy that could have been used to serve incremental load under the 1993 PPA has almost totally been eliminated by the terms of the New PPA due to the introduction of the Tranche 1 cap, the Tranche 2 price and the Energy and Nomination Scheduling requirements. **Accordingly, the Commission Panel determines that under the terms of the New PPA there is no significant material risk of harm to BC Hydro that warrants it reasonable to continue to include the restrictions as originally provided for in sections 2.5(a)(ii), 2.5(a)(iii) and 2.5(b) of the New PPA.**

In summary, in the interest of regulatory efficiency, the Panel's preferred solution would be to immediately remove the restrictions from section 2.5 as it finds that due to the characteristics of the New PPA BC Hydro's rate payers no longer require protection, especially in the short term. However, the Panel also will conclude, for reasons addressed in the following Sections, that it may be somewhat premature as FortisBC's self-generation policies are not sufficiently developed, articulated and approved by the Commission.

9.0 SELF-GENERATION POLICY ISSUE IN THE FORTISBC SERVICE TERRITORY

9.1 Why is a Review Required?

The Panel has concluded that the proposed restrictions in section 2.5 of the New PPA, as they related to self-generating customers in the FortisBC service territory, are no longer necessary. However, it recognizes that the Parties would gain a considerable amount of comfort if the Self-Generation Policy Issue in the FortisBC service territory was formally addressed and resolved once and for all.

The Panel acknowledges the concerns raised by BC Hydro, FortisBC, CEC, BCPSO, Alan Wait, and BCSEA regarding the long term nature of the New PPA and the lack of clarity regarding the Self-Generation Policy Issue in the FortisBC service territory. The Panel especially recognises FortisBC position that if self-generating customers were clearly prohibited from arbitraging between embedded cost FortisBC rates and market prices in the FortisBC service territory, the proposed restrictions in section 2.5 of the New PPA would be redundant. However, FortisBC points out previous Commission rulings appear to have qualified the Self-Generation Policy Principle by reference to FortisBC's obligations under the Access Principles Application (APA).

This Panel continues to agree with the Order G-48-09 determination that extended the principles established for BC Hydro's self-generating[24] customers as articulated in Order G-38-01 to FortisBC. Further, the Panel still agrees that self-generating customers should not be permitted to arbitrage between embedded cost rates and market prices to the detriment of other ratepayers.

Furthermore the Panel agrees with BCMEU, BC Hydro and most of the Interveners that the appropriate place to address the FortisBC Self-Generation Policy Issue in the FortisBC territory is through a separate process. Ideally, this would be a Province-wide review – conducted either by the Government or the Commission.

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[24] Self-generating customers are not permitted to arbitrage between embedded cost rates and market prices to the detriment of other ratepayers.

In the Reasons for Decision to Order G-48-09 the Commission stated that a more global solution to the issue of reselling or “arbitrage” of power would be preferable and that a Commission “rule” or “regulation” might have been a viable way to proceed; however for reasons stated in that Decision it was not possible at the time — this Panel determines that the right time is now.

9.2 Potential Benefits of Self-Generation

In this Decision, and many prior proceedings, the focus has been on the negative impacts to BC Hydro and its ratepayers of a self-generating customer serving its own load with embedded cost power while exporting its own self-generation. At the same time, as BCMEU has pointed out, there has been little discussion of the benefit to BC Hydro of a self-generation customer using its own self-generation to serve its own load first. Perhaps it is the time to ask what benefits there might be to the Province as a whole from an economic development perspective, if the role and responsibilities of self-generators was more clearly defined.

BCMEU states that it is in the interest of its members and, the entire Province, to encourage self-generators to add new generation and to encourage non-generators to add generation. BCMEU points out the current economic incentive to invest in new generation on a net of load basis is very low, at best, the self-generating customers are avoiding power purchases at embedded cost rates. The Panel notes that this is recognized by most parties, and therefore, the concept of incremental generation is used to differentiate from native generation.

BCMEU submits that a clear and concise regulatory regime is needed for the parties to work with. BCMEU suggests examples of rules around self-generation for consideration:

- Defining a marker in time, after which new or renewed generation is deemed to be incremental; and
- A reasonable time period for the incremental generation to be sold on the market, to other entities, or used for serving its own load as best suites the entity building the generation (i.e. Perhaps 20 years, or 10 years after the initial capital is paid for). (Supplemental Submission, Exhibit C4-5)

The Commission would expect FortisBC to address each of these issues as part of a separate proceeding being called for.

9.3 The 1999 Access Principles

In 1998–1999, FortisBC (then West Kootenay Power) took part in a regulatory process aimed at defining the rules governing access to its transmission system. The objective at that time was to facilitate the ability of transmission level customer to purchase power from a source other than the utility, and use the transmission system to deliver it. (Order G-27-99)

In providing the right for customers to do this, the Access Principles contain rules related to:[25]

1. when and how a customer could elect to leave or re-enter utility supply for all or part of its needs; and
2. the treatment of the utility, the customer who leaves embedded-cost service, and those customers who remain.

These sections of the Guidelines are called Re-entry and the Fair Treatment provisions respectively.

In its 2009/2010 rate design proceeding, FortisBC highlighted the concerns related to the broad use of the 1993 Access Principles. FortisBC pointed out that Order G-27-99 does not address such issues as:

1. whether an obligation to serve might be affected by self-generation by a customer;
2. the sources of power that FortisBC would have to access in serving that customer;
3. the cost of supply; or
4. the arbitrage concerns raised by BC Hydro. (FBC 2010 Rate Design Decision, p. 112)

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[25] For further detail, see FortisBC 2012 Entitlement and Matching Guidelines Application, Appendix A, Public Consultation Materials.

Because the Commission has referred to them in a number of recent proceedings, the 1999 Access Principles, as they relate to the potential rights of a self-generating customer in the FortisBC service territory cannot be ignored. These issues need also to be resolved and should be addressed in conjunction with other self-generator policy issues.

9.4 Comprehensive Self-Generation Policy Application

Consequently, the Panel is of the opinion that the best way to resolve the FortisBC self-generation policy issue in the FortisBC service territory is for FortisBC to initiate a consultation process to establish high level principles concerning this matter. The outcome of this process would be a filing of a Comprehensive Self-Generation Policy Application with the Commission. BC Hydro, other FortisBC customer groups and other eligible groups should be encouraged to actively participate in this process.

Although FortisBC would have the discretion and judgment in determining the scope of the consultation process and the resultant application the Commission would want to ensure that (i) FortisBC determines for existing self-generating customers, how much generation must be used for self-supply, and (ii) all FortisBC's customers with idle self-generation capability are able to sell excess self-generated electricity, provided the self-generating customers do not arbitrage between embedded cost utility service and market prices.

While the first objective identified above is fairly self-explanatory, the second one could require consideration of a variety of issues. This might include:

1. Whether customers with new self-generation should be allowed to use their generation to displace their own consumption; and if so, should there be restrictions on generator type, size and/or location?

2. Stand-by rates for self-generating customers who are allowed to use their generation to offset their load.

3. Self-generating customers' access to the market.

4. Identification of any market barriers to efficient investment in self-generation which should be addressed; i.e. interconnection issues and reduction in administrative complexity.

Regardless, FortisBC must establish Self-Generating customer polices for current and future customers at distribution and transmission voltage and to address the following:

1. the potential benefits of self-generation as identified by BCMEU in its Supplemental Submission (Exhibit C4-5);
2. the 1999 Access Principles in the context of their application to self-generating customers; and
3. GBL Guidelines which address both idle historic self-generation and new self-generation, if the GBL methodology is proposed; and
4. ensure, arbitrage is not allowed.

Accordingly, FortisBC is directed to initiate a consultation process in its service territory to address or ensure:

- **(i) The potential benefits of self-generation;**
- **(ii) The 1999 Access Principles in the context of self-generating customers;**
- **(iii) If the GBL methodology is proposed, GBL Guidelines for both idle historic self-generation and new-self-generation; and**
- **(iv) Arbitrage is not allowed.**

FortisBC is further directed to file a resultant Self-Generation Policy application with the Commission by December 31, 2014 that establishes high level principles for its service territory.

10.0 PROPOSED AMENDMENT TO SECTION 2.5 OF THE NEW PPA

On April 9, 2014 the Commission received a letter from BC Hydro, which addresses both the Tariff Supplement No. 74 (TS 74) related Order G-19-14, its pending application for reconsideration and the potential implications of the Order and its Reconsideration for the New PPA Application currently before the Commission (Exhibit B-18). In response, the Commission sought submissions regarding a proposal outlined by BC Hydro in that letter (Exhibit A-18). The proposal and submissions received are summarized in the following.

10.1 BC Hydro's Proposed Amendment

Order G-19-14 relates to BC Hydro's application to amend TS 74 Customer Baseline Load Determination Guidelines for RS 1823 customers. While approving the application, the Commission also directed BC Hydro to file an application with the Commission for approval of updated Contracted Generator Baseline (Contracted GBL) Guidelines to be incorporated in TS 74. BC Hydro notes that Contracted GBLs are established in electricity purchase agreements and load displacement agreements, and not in the context of applying TS 74. BC Hydro views the Commission directive as 'problematic' (Exhibit B-18).

BC Hydro points out that customer-specific baselines proposed for section 2.5 of the New PPA would be used in a different context but acknowledges that, for consistency, the New PPA section 2.5 Guidelines would reflect the principles used to determine Contracted GBLs. BC Hydro also acknowledges a requirement for greater transparency for the determination of customer-specific baselines and Contracted GBLs, proposes to undertake a consultation process with FortisBC and stakeholders and files amendments to section 2.5 of the New PPA. Finally, BC Hydro states the amended version of section 2.5 will effectively maintain the net-of-load methodology proposed in the PPA until the approval of new Guidelines. Later, with the approval of the Guidelines, and inclusion of them as an appendix to the New PPA, FortisBC would obtain additional flexibility to access electricity under the agreement.

The amendment proposed by BC Hydro is shown below:

"2.5 Purpose/Limitation of use of Scheduled Energy

(a) Electricity taken under this Agreement:

…

(ii) shall not be sold to any FortisBC customer with self-generation facilities, or used by FortisBC to serve any such customer's load, when such customer is selling self-generated Electricity unless a portion of the customer's load equal to or greater than the customer-specific baseline is being served by Electricity that is not Electricity taken under this Agreement, where such customer-specific baseline is as determined in accordance with Commission-approved guidelines and in consultation with the customer ~~agreed between the Parties (acknowledging that such baseline shall be determined in a manner consistent with how BC Hydro establishes a generator baseline for its own customers), failing which agreement either Party may submit the matter for dispute resolution in accordance with Section 13;~~ and…"

(Exhibit B-18, Attachment, p. 1)

10.2 Intervener Submissions

FortisBC believes that the proposed amendment to section 2.5 allows for appropriate stakeholder consultation and regulatory review to determine the appropriate guidelines, while at the same time allowing the Commission to proceed expeditiously with the approval of the New PPA and related agreements (Exhibit C1-25).

BCPSO submits that the amendment and BC Hydro's proposal to consult with stakeholders in the development of Commission-approved guidelines for determining customer-specific baselines serve as a good starting point for addressing concerns BCPSO expressed earlier (Exhibit C2-8). BCMEU supports the proposal because it provides a mechanism to move forward with the New PPA, and provide clarity on customer-specific baselines in a separate process (Exhibit C4-6).

Celgar submits the Commission should reject BC Hydro's proposal as being procedurally unfair, and because there should be no restrictions related to self-generating customers included in the New

PPA in the first place; whether consisting of the Original Restrictions or the recently amended Replacement Restrictions. Celgar explains that substantial changes to an application after the record of a proceeding closes should not be accepted because Interveners will not have been provided a reasonable opportunity to test and consider the effects of the proposed amendments. Celgar also expresses concern over the additional delay to a resolution for its interim billings. (Exhibit C5-11) Similarly, Vanport did not support the proposed amendments due to procedural fairness concerns (Exhibit C10-8).

Mr. Alan Wait submits a preference for an arrangement where FortisBC sets the rules for its self-generating customers while keeping in mind that self-generators should not be allowed to game the system. Mr. Wait, however, supports approving the New PPA now, with the understanding that "housekeeping changes will be made to section 2.5 in the near future designed to meet BC Hydro's concerns of self-generators" (Exhibit C6-7). BCSEA and CEC also support BC Hydro's proposal for approval of an amended section 2.5 and confirmation that BC Hydro will consult with FortisBC and stakeholders to develop guidelines for section 2.5 (Exhibit C7-8, Exhibit C11-8).

10.3 BC Hydro Reply

BC Hydro first summarizes the significant support received from Interveners and then provides a specific reply to submissions of Mr. Wait and Celgar as follows.

Mr. Wait recommended that section 2.5 should include the concept of "approval by FortisBC" in conjunction with the Commission-approved guidelines. BC Hydro submits that the proposed amendment removes subjectivity in favour of a more objective test: the customer-specific baseline is to be determined in accordance with Commission-approved guidelines.

With regard to Celgar's concern over procedural fairness, BC Hydro submits that the Commission has the power to control its own processes and has broad discretion to set the procedural steps for reviewing an application or subsequent amendments. BC Hydro further submits that a provision for IRs is not a requirement in general but specifically, Exhibit B-18 clearly is not an amendment that warrants an IR process. (Exhibit B-19)

Commission Determination

The Commission Panel acknowledges the overwhelming support given by most parties to BC Hydro's proposal. The proposed amendments to section 2.5 of the New PPA offer a solution to move forward with prompt approval of the New PPA and Associated Agreements, which is becoming increasingly critical for FortisBC. At the same time, they allow for a separate consultation process, which is intended to increase transparency for determination of customer-specific baselines and Contracted GBLs. The process will culminate in an application to the Commission for approval of guidelines to be added as an appendix to the New PPA for the purpose of applying section 2.5.

With regard to Celgar's concerns, the Panel first accepts BC Hydro submissions. Second, the Panel notes that in its Supplemental Submission of January 27, 2014 Celgar reiterated its earlier alternative proposal. Specifically, Celgar requested in paragraph 110 that section 2.5 be amended to align the GBL process in the FortisBC service area more closely with BC Hydro's GBL process. Further, the amendments would require that GBLs be agreed to between the self-generating customers and its utility, and would remove the requirement that GBLs be established based on BC Hydro`s unilaterally determined and unapproved guidelines. The Panel finds that to a large extent the new amendments approximate Celgar's proposal and address its earlier objections. Therefore, there is no reason for Celgar's claim of procedural unfairness. Regarding Celgar's interim billing concern, the Commission is addressing that issue as part of the FortisBC's Application for Approval of Stepped and Stand-By Rates for Transmission Voltage Customers.

Accordingly, as a result of the amendments which have removed most of the Panel's earlier fundamental concerns with the exception of regulatory efficiency, the Commission Panel finds the following:

1. **BC Hydro is directed to initiate a consultation process that will result in an application for the New PPA Section 2.5 Guidelines by November 1, 2014. Once the Guidelines have been approved by the Commission, they are to be added to the New PPA as an appendix.**

2. **The New PPA, RS 3808, and Associated Agreements are approved for an effective date of July 1, 2014.**

3. **Until the addition of Commission-approved Section 2.5 Guidelines as an appendix to the New PPA, the net-of-load methodology will apply for the purposes of the New PPA.**

In the interest of efficient process, the Commission Panel encourages collaboration between BC Hydro and FortisBC to the extent possible as these two concurrent processes are carried out.

As it has been evident throughout this Decision, the Panel's preferred solution would have been to approve the New PPA without any restrictions in section 2.5. However, that solution now appears premature as FortisBC's self-generation policies are not yet sufficiently developed, articulated and approved by the Commission. BC Hydro has come forward with a solution that most parties see as the first practical step to move forward towards resolutions of the issues. The Panel is hopeful that once the two concurrent consultation processes have resulted in clearly documented Commission-approved principles, the Commission will seek submissions from parties to determine whether it would be reasonable to eventually remove the restrictions from section 2.5 of the New PPA in pursuit of improved regulatory efficiency.

DATED at the City of Vancouver, in the Province of British Columbia, this 6th day of May 2014.

Original signed by:

____

L.A. O'HARA
PANEL CHAIR/COMMISSIONER

Original signed by:

____

B.A. MAGNAN
COMMISSIONER

Original signed by:

____

R.D. REVEL
COMMISSIONER

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-60-14

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

the British Columbia Hydro and Power Authority
Application for Approval of Rates between
BC Hydro and FortisBC Inc. with regards to Rate Schedule 3808,
Tariff Supplement No. 3 – Power Purchase and Associated Agreements,
and Tariff Supplement No. 2 to Rate Schedule 3817

BEFORE: L.A. O'Hara, Panel Chair/Commissioner
B.A. Magnan, Commissioner
R.D. Revel, Commissioner

May 6, 2014

O R D E R

WHEREAS:

A. By Orders G-27-93, G-85-93 and G-48-09 the British Columbia Hydro and Power Authority (BC Hydro or Applicant) has supplied electricity to FortisBC Inc. (FortisBC or Co-signatory) to meet a portion of its load service obligations, pursuant to a 20 year Power Purchase Agreement under Tariff Supplement No. 3 (1993 PPA), at rates set out in BC Hydro Rate Schedule 3808 (RS 3808). The 1993 PPA commenced on October 1, 1993, and was set to expire on September 30, 2013;

B. On May 24, 2013, BC Hydro filed an application with the British Columbia Utilities Commission (Commission) requesting approval, pursuant to sections 58 to 61 of the *Utilities Commission Act*, to replace the existing 1993 PPA with a New Power Purchase Agreement (New PPA), an Imbalance Agreement, an Energy Export Agreement and a Master Accounting Agreement, and to make associated amendments to RS 3808. BC Hydro also requested approval for an amended and restated General Wheeling Agreement under Tariff Supplement No. 2 to Rate Schedule 3817 (Application);

C. On May 27, 2013, FortisBC filed a twenty-six page letter in support of the Application (Letter of Support);

D. FortisBC, the British Columbia Pensioners and Seniors Organization *et al,* British Columbia Sustainable Energy Association and Sierra Club of British Columbia, Commercial Energy Consumers' Association of British

Columbia, British Columbia Municipal Electrical Utilities, Zellstoff Celgar Limited Partnership (Celgar), Industrial Customers Group, Vanport Sterilizers, Mr. Norman Gabana, Morgan Stanley Capital Group (Morgan Stanley) and Mr. Alan Wait registered as Interveners in the proceeding;

E. The Procedural Conference, held on July 29, 2013, was attended by BC Hydro and all of the Registered Interveners other than Morgan Stanley and Mr. Norman Gabana;

F. On August 1, 2013, by Order G-117-13 and attached Reasons for Decision, the Commission defined the scope of the proceeding; ordered that the Application be heard by way of a written hearing in accordance with a set Regulatory Timetable and directed that upon written acceptance from BC Hydro and FortisBC, the 1993 PPA and the currently approved RS 3808 are to remain in effect until such time as the Commission determines otherwise;

G. On September 16, 2013, the Commission received written acceptances from BC Hydro and FortisBC for the continuation of the 1993 PPA and RS 3808 as requested by Order G-117-13;

H. On December 13, 2013, the Commission sought Supplemental Submissions on certain parts of section 2.5 of the New PPA as they related to FortisBC's customers with self-generation;

I. On April 9, 2014, the Commission received a letter from BC Hydro, in which BC Hydro acknowledges a requirement for greater transparency for determination of customer-specific baselines and Contracted Generator Baselines, recommends a consultation process with FortisBC and stakeholders and proposes amendments to section 2.5 of the New PPA; and

J. The Commission sought submissions regarding BC Hydro's proposal from parties in accordance with a timetable that concluded the comment process on April 25, 2014.

NOW THEREFORE for the reasons stated in the Decision issued concurrently with this Order, the Commission orders pursuant to sections 59-61 of the *Utilities Commission Act* as follows:

1. The Application as amended is approved with an effective date of July 1, 2014.

2. BC Hydro is directed to initiate a consultation process that will result in an application for the New PPA Section 2.5 Guidelines by November 1, 2014. Once the Guidelines have been approved by the Commission, they are to be added to the New Power Purchase Agreement as an appendix.

3. Until the addition of Commission-approved New PPA Section 2.5 Guidelines as an appendix to the New Power Purchase Agreement, the net-of-load methodology will be applied.

4. Pursuant to section 61 of the *Utilities Commission Act*, BC Hydro is directed to file the amended tariffs within 15 business days of the date of this Order.

…/3

5. FortisBC Inc. is directed to initiate a concurrent consultation process in its service territory to address or ensure:

   (i) the potential benefits of self-generation;

   (ii) the 1999 Access Principles in the context of self-generating customers;

   (iii) if the GBL methodology is proposed, GBL Guidelines for both idle historic self-generation and new self-generation; and

   (iv) arbitrage is not allowed.

   FortisBC Inc. is further directed to file a resultant Self-Generation Policy application with the Commission by December 31, 2014, that establishes high level principles for its service territory.

DATED at the City of Vancouver, in the Province of British Columbia, this 6th day of May 2014.

BY ORDER

Original signed by:

L.A. O'Hara
Panel Chair and Commissioner

FORTISBC SERVICE AREA

REGULATORY PROCESS

On May 24, 2013, BC Hydro filed an application with the Commission requesting approval of four new agreements between BC Hydro and FortisBC to replace the expiring 1993 PPA, pursuant to sections 58 to 61 of the *Utilities Commission Act* (Application) (Exhibit A-9, Recital C).

On May 27, 2013, FortisBC filed a letter in support of the Application and confirmed its intention to respond to Information Requests (IRs) regarding this submission (Exhibit C1-2; Exhibit A-9, Recital E).

By Order G-87-13, dated May 28, 2013, the Commission established an Initial Regulatory Timetable, which included two Workshops, one round of IRs and a Procedural Conference (Exhibit A-9, Recital F).

On July 23, 2013, the Commission issued a Letter listing the issues that participants at the Procedural Conference should address (Exhibit A-9, Recital H).

The Procedural Conference held on July 29, 2013 was attended by BC Hydro and the following Interveners: FortisBC, British Columbia Pensioners and Seniors Organization *et al,* B.C. Sustainable Energy Association and Sierra Club of British Columbia, Commercial Energy Consumers' Association of British Columbia, British Columbia Municipal Electrical Utilities, Zellstoff Celgar Limited Partnership, Industrial Customers Group, Vanport Sterilizers and Mr. Alan Wait (Exhibit A-9. Recital I).

In Order G-117-13 and attendant Reasons, the Commission ordered that:

1. The Review of the Application will be heard by way of a written proceeding.
2. As explained in the reasons, certain issues were out of scope while six broader within scope issues were to be considered.

3. Information Requests, as provided for in the Regulatory Timetable, can address any issues not determined to be out of the scope of this proceeding.

4. On the basis of the scope limitations established for this proceeding, no provision for Intervener evidence has been made in the Regulatory Timetable.

5. FortisBC Inc.'s request to file its Final Submission at the same time as BC Hydro and to have a right of reply has been provided for in the Regulatory Timetable.

6. BC Hydro's request that the participants be left to interpret and apply the scope limitation to the unanswered Information Requests (IRs) before seeking Commission ruling is granted. Any participant who has unanswered IR No. 1 questions that they wish to have replied to, provided they remain within the scope of this proceeding as defined in the Reasons for Decision accompanying Order G-117-13, must notify the Utility of their request on or before August 7, 2013. The Utility will have an additional five business days to file its IR responses. In the event that common ground cannot be found, the parties can seek the Commission's ruling in accordance with the Regulatory Timetable.

7. Upon written acceptance from BC Hydro and FortisBC by September 16, 2013, the current Commission approved RS 3808 and Tariff Supplement No. 3 – Power Purchase and Associated Agreements are to remain in effect until such time as the Commission determines otherwise.

8. The currently approved RS 3817 and Tariff Supplement No. 2 will remain in effect until the Commission determines otherwise.

9. The deadline for submitting budgets for Interveners intending to apply for participant assistance is Thursday, August 22, 2013. (Exhibit A-9)

REGULATORY TIMETABLE

Commission and Intervener Information Requests No. 2 to BC Hydro and FortisBC	Monday, August 19, 2013
Deadline for filing PACA Budgets	Thursday, August 22, 2013
BC Hydro and FortisBC respond to Commission and Intervener IR No.2	Tuesday, September 10, 2013
Final Submission by BC Hydro	Wednesday, September 18, 2013
Final Submission by FortisBC	Friday, September 20, 2013
Final Submissions by Interveners	Friday, September 27, 2013
FortisBC Reply Submission	Friday, October 4, 2013
BC Hydro Reply Submission	Monday, October 7, 2013

Commission Letter Dated December 13, 2013 Requesting Supplemental Submissions

BC Hydro Supplemental Submission	Monday, January 13, 2014
FortisBC Supplemental Submissions	Monday, January 20, 2014
Other Intervener Supplemental Submissions	Monday, January 27, 2014
BC Hydro Supplemental Reply Submission	Monday, February 3, 2014

BC Hydro Letter Dated April 9, 2014

FortisBC Submission on Exhibit B-18	Tuesday, April 15, 2014
Other Intervener Submissions on Exhibit B-18	Thursday, April 17, 2014
FortisBC Reply to other Intervener Submissions, if any on Exhibit B-18	Wednesday, April 23, 2014
BC Hydro Reply Submission to Comments on Exhibit B-18	Friday, April 25, 2014

RELEVANT ORDERS, APPLICATIONS AND FILINGS RELATING TO SELF-GENERATION

I. Orders G-38-01 and G-17-02

BC Hydro's Obligation to Serve RS 1821 Customers with Self-Generation Order

The matter of what level of service self-generating customers are entitled to was first raised by BC Hydro in the proceeding leading to the issuance of Order G-38-01. On February 23, 2001 BC Hydro advised the Commission that some of BC Hydro's industrial customers with self-generating capability served under Rate Schedule (RS) 1821 (Transmission Service) wished to sell some of the power they generated at market prices.

In Order G-38-01, the Commission concluded that:

> "it [the Commission] must act to meet the complementary objectives of creating conditions which allow B.C. Hydro to safeguard its own supply to British Columbians at lowest cost, assisting British Columbia industries with idle self-generation capability to capitalize on current market opportunities, and helping to mitigate the potential energy shortages in the Pacific Northwest and California." (Order G-38-01, Recital F)

The Commission therefore directed BC Hydro to allow RS 1821 customers with idle self-generation capability to sell excess self-generated electricity, provided the self-generating customers do not arbitrage between BC Hydro's embedded cost utility service rates and market prices. This meant that BC Hydro was not required to supply any increased embedded cost of service to a RS 1821 customer selling its self-generation output to market. In that Decision, the Commission recognized that "considerable debate may ensue over whether a self-generator has met this principle" and directed BC Hydro to "make every effort to agree on a customer baseline, based either on the historical energy consumption of the customer or the historical output of the generator."

The Commission limited the duration of the program to approximately one year, given the "unique circumstances" existing at the time, and noted that the program was "without prejudice to the resolution of long term rights of self-generators to take their generation to the market." It held that the program might be continued beyond one year if conditions warranted and directed BC Hydro to file a "full report on the program...by March 1, 2002."

In its March 1, 2002 compliance report to the Commission, BC Hydro noted that little experience had been gained from the "program" established by Order G-38-01 and that no further conclusions could be drawn. BC Hydro also noted that the program defined by Order G-38-01 was established when there was a serious energy shortage in western North America and was therefore designed to encourage self-generators with idle capacity to generate and sell electricity, although not to the prejudice of BC Hydro and its customers. BC Hydro, in its report, noted that markets had changed since the period of extreme shortage but submitted that the change in market conditions should not "alter the essential principle embodied in ...the Order [G-38-01]: that RS 1821 customers should not be allowed to arbitrage between the low embedded cost rates of BC Hydro and market prices."

By Order G-17-02, the Commission directed BC Hydro to continue to allow its RS 1821 customers with idle self-generation capability to sell excess self-generated electricity, provided they did not arbitrage between embedded-cost utility service and market prices. The Commission further ordered that the conditions established in Order G-38-01 to prevent such arbitrage were to "remain in effect until the Commission determines that future circumstances no longer justify the existence of such a program."

Thus, the requirement for generator baselines, or GBLs, for BC Hydro's self-generating customers which sought to sell into the export market was confirmed. Further, the notion of "arbitrage", as used in relation to GBLs, was the preservation of the "status quo", such that BC Hydro's obligation to serve was limited to the load served at a particular time, and self-generating customers were required to continue to serve that portion of their own load which they had served in the past.

II. Order G-48-09

BC Hydro Application to Amend Section 2.1 of Rate Schedule 3808

FortisBC sought to increase its purchases of power under RS 3808 from BC Hydro pursuant to the 1993 PPA in response to requests from its self-generating customers, including the City of Nelson and Celgar, to increase their purchases of power from FortisBC.

To prevent the export activities of FortisBC's customers from affecting the amount of power that FortisBC drew under RS 3808 BC Hydro applied to the Commission, in September of 2008, to amend section 2.1 of the 1993 PPA. Specifically, BC Hydro requested Commission approval to add conditions to section 2.1 of the 1993 PPA that prohibit FortisBC from reselling RS 3808 purchases to its self-generating customers who wished to increase their energy exports by increasing purchases of FortisBC's embedded cost power.

In that proceeding, BC Hydro stated that in its current form, section 2.1 of the 1993 PPA was unjust or unreasonable because it allows certain [FortisBC] customers to unfairly profit from BC Hydro embedded cost service to the detriment of all other BC Hydro customers. (Exhibit B-1, pp. 20–26; Reasons for Decision, G-48-09, p. 23)

BC Hydro stated that if it is required to provide incremental energy to FortisBC at embedded cost rates for the purpose of supporting the export activities of FortisBC's customers, BC Hydro and its ratepayers will incur an estimated annual loss of $ 16.7 million. The Commission was persuaded that if FortisBC's self-generating customers were permitted to sell all their respective total generation into the available markets, and that if FortisBC was able to pass this risk onto BC Hydro through RS 3808, there would be some fairly large negative impacts on BC Hydro. The Panel was not concerned with the dollar amount of the impact but rather the principle which the Panel stated came into play once there was some material anticipated loss. (Reasons for Decision, G-48-09, p. 27)

However, the Commission also noted that determining whether the actions of FortisBC self-generating customers resulted in inappropriate arbitrage or not is not always clear:

> "The Commission Panel is of the view that Nelson residents, as British Columbians, do share in the overall benefits of the Heritage Power framework but should not be permitted to benefit unduly at the expense of other customers of BC Hydro." (Reasons for Decision, Order G-48-09, p. 25)

The Commission approved the Application by way of Order G-48-09 and, accordingly, approved the amendments to section 2.1 of the 1993 PPA that clarified the restriction on export of RS 3808 power:

> "(a) The electricity purchased under this agreement is solely for the purpose of supplementing FortisBC's resources to enable it to meet its service area load requirements and, shall not be exported or stored, provided that nothing contained herein shall prohibit FortisBC from storing its entitlement resources in its entitlement account pursuant to the Canal Plant Agreement; and
>
> (b) shall not be sold to any FortisBC customer when such customer is selling self generated electricity which is not in excess of its load.
>
> For greater certainty, paragraph (b) above is to prevent FortisBC self-generating customers from purchasing power at regulated embedded cost rates and simultaneously selling an equivalent amount of power into available domestic and export markets."

The practical effect of this Decision was to require FortisBC customers to service 100 percent of their load from self-generation, prior to engaging in export sales, to the extent that their load would otherwise be served indirectly by BC Hydro, under RS 3808. (Reasons for Decision, G-48-09, p. 29)

However, the Panel highlighted in its reasons the short-term nature of the issue. The Panel acknowledged that the 1993 PPA between BC Hydro and FortisBC was to expire on September 30, 2013 and that the two parties were negotiating a potential renewal and extension hopefully resulting in a comprehensive renewed PPA. Therefore, the relief sought by BC Hydro was for the remaining term of the PPA. (Reasons for Decision, Order G-48-09, p. 10)

III. 2012 Information Report

Transmission Service Rate and Customer Generator Baseline Information Report

By Letter L-106-09 dated November 27, 2009, the Commission requested that BC Hydro provide draft guidelines for the determination of Customer Generator Baselines (GBLs) and responses to twenty questions posed by the Commission.

On June 20, 2012, BC Hydro filed the Transmission Service Rate and Customer Generator Baselines Information Report (2012 Information Report) (Exhibit A2-1). The filing included guidelines for establishing GBLs along with responses to the Commission's twenty questions. In the report, BC Hydro introduced the concept of Contracted and Non-Contracted GBLs. The Guidelines relating to Non-Contracted GBLs are before the Commission for review and approval as part of the "BC Hydro Application to Amend Tariff Supplement No. 74 CBL Determination Guidelines for RS 1823 Customers". However, the Guidelines for Contracted GBLs are only contained in the 2012 Information Report and are not part of any Commission pending or approved rate schedule.

In response to one of the Commission's questions, BC Hydro stated that, in its view, the application of the net-of-load approach to BC Hydro's transmission service customers would result in the continued under-utilization of existing generation assets and the avoidance of investment in upgrades or new generation assets. Consequently, under the net-of-load approach BC Hydro and its customers would have reduced access to the benefits of cost-effective electricity from customers with self-generation. (Exhibit A2-1, Information Report, section 3, p. 13)

IV. Order G-156-10

Application by FortisBC for Approval of a 2009 Rate Design and Cost of Service Analysis

Submissions by Celgar made in the FortisBC rate design proceeding challenged the restrictions on its access to FortisBC embedded cost power that included a component of the RS 3808 power (see Figure 1 in this Decision).

In that rate design proceeding, Celgar requested that the Commission determine a GBL for Celgar in relation to its purchases of power from FortisBC. Celgar relied in large part on its argument that a utility has an obligation to serve its customers:

> "Celgar submitted that Orders G-38-01 and G-48-09 cannot be reconciled with the law relating to the obligation to serve. The practical result of the Orders is to prohibit purchases of power from FortisBC by Celgar to serve its mill load at times when Celgar is simultaneously selling power from its own generation. Such a result relieves FortisBC from its obligation to serve to the extent requested by Celgar and is therefore inconsistent with the statutory obligation to serve." (Celgar Argument, para. 72–73, and Reasons, G-156-10, p. 109)

The Commission, however, did not find that the obligation to serve need be extended to an unconditional obligation on a utility to provide service to all customers at embedded costs:

> "It is also clear that since 1980 FortisBC has provided adequate, safe, and efficient service to the Celgar mill at just and reasonable rates. The Commission Panel considers that section 39(i) of the *UCA* gives the Commission the power to establish rates for service to FortisBC's customers, and that sections 60-61 give the Commission the power to set rates that may not necessarily be based on embedded costs." (G-156-10, p. 113)

Furthermore, the Commission maintained its position on the restriction of sale of RS 3808 power to FortisBC self-generating customers as promulgated in Order G-48-09:

> "The Commission Panel considers that what Celgar proposes is expressly prohibited by Order G-48- 09 and that, as long as the Order is in full force and effect, and as long as the PPA between FortisBC and BC Hydro is in effect, FortisBC will be unable to buy any power from BC Hydro under RS 3808 for sale to Celgar when Celgar is exporting power from the mill." (Reasons for Decision, G-156-10, p. 103)

As such, the Commission declined to set a GBL between FortisBC and Celgar in that proceeding. However, the Commission acknowledged the temporal limitation on the directives of Order G-48-09, stating that these are relevant only for the term of the 1993 PPA:

> "The Commission Panel considers that its Order G-48-09 was issued in response to concerns raised by BC Hydro as to the possibility that heritage hydro was being sold to FortisBC customers with self-generation facilities to enable the latter to sell the output of their own generation facilities.
>
> That being said, the Commission Panel notes that the PPA between the two utilities has a termination date and there may come a time when Order G-48-09 no longer has any relevance." (Reasons for Decision, G-156-10, p. 115)

V. Order G-27-99

West Kootenay Power Application for Access Principles

The 1999 Application for Access Principles (APA), which was approved by Order G-27-99, shaped the Commission's later determinations regarding the access of self-generating customers in FortisBC's service territory, including in the FortisBC Rate Design proceeding.

The goal of West Kootenay Power (WKP) [now FortisBC] at the time the APA was negotiated was to allow access to its transmission system to its transmission bundled service customers (Eligible Customers) to encourage the development of a competitive generation market. The purpose of the APA was to ensure that access occurred in a way that resulted in the equitable treatment (Fair Treatment) of the utility's shareholders, its customers who continued to take bundled utility service, and of customers who chose to obtain some or all of their electricity supply from non-utility resources. The APA provided policy definitions in four key areas to ensure fair treatment of all customers: (1) the utility's obligation to serve Eligible Customers; (2) an Eligible Customer's rights should it choose to take only part of its load from non-Utility sources; (3) the treatment of any stranded costs or benefits that may result from an Eligible Customer's partial or total departure from Utility supply; and (4) the re-entry provisions governing an Eligible Customer's return to bundled Utility supply. (Order G-27-99)

In the FortisBC Rate Design decision (G-156-10) the Commission considered that some of the principles of the APA might be relevant to a self-generator's request for service at embedded cost rates. (Reasons for Decision, G-156-10, p. 114)

VI. Order G-188-11

Celgar Application for Reconsideration of Order G-156-10

In March 2011, Celgar filed a complaint against FortisBC. In its complaint, Celgar sought the Commission's assistance in establishing an acceptable General Service Agreement (GSA) and accompanying brokerage agreement with FortisBC that included establishing a GBL and service at RS 31 rates (FortisBC's Large Commercial Service – Transmission) based upon FortisBC's embedded cost rate, which includes RS 3808, applicable at all times, including when Celgar sells power above its proposed GBL.

By Order G-188-11 dated November 14, 2011, the Celgar complaint was denied. The Commission held that a GBL was not a necessary component of a GSA and reiterated its earlier determination that it was up to the parties to decide whether to incorporate a GBL into their GSA. The Commission directed that FortisBC and Celgar were free to incorporate a GBL into the GSA and submit it to the Commission for approval. The Commission also determined that Celgar was prohibited from accessing BC Hydro RS 3808 power while it was selling power, but suggested that this restriction did "not preclude FortisBC from establishing its own principles regarding the supply of non-BC Hydro PPA Power in its resource stack when establishing GBLs with its customers". (Celgar Complaint Decision, p. 28)

In reaching this decision, the Commission sought a balance between achieving compliance with the provisions of section 2.1 of the 1993 PPA, and the "Obligation to Serve" as defined in the APA:

> "...the Utility retains the obligation to serve at embedded cost rates any new load entering its service territory, any additional load attributable to its existing customers, and returning Eligible Customers, under the Re-entry Provisions." (Reasons, G-188-11, p. 37)

However, the Commission tempered its views on FortisBC's obligation to serve self-generating customers:

> "However, clarification is needed as to whether an obligation to serve might be affected by the self-generation by a customer. The Commission Panel also notes that Celgar can access external power markets directly through the FortisBC system, which implies that, in this way, FortisBC is also fulfilling its obligation to serve, although not through the provision of power but through the provision of access to its infrastructure." (Reasons, G-188-11, pp. 37-38)

Noting that the decisions regarding FortisBC's obligation to serve would have implications beyond those for the current self-generating customers, the Commission stated that:

> "In today's evolving energy world FortisBC may find new potential customers who are self-generators other than pulp and paper mills. For instance, businesses that have used natural gas to generate electricity for their own needs may decide to switch to using electricity from FortisBC, there may be new waste incinerators that generate electricity, and there may be other industrial generators operating as independent power producers. Would FortisBC supply electricity to these businesses, and if so, under what conditions and at what price? The eligibility of Celgar to access some of the embedded cost of the FortisBC resource stack, excluding BC Hydro PPA Power, must be considered in this context as well." (Reasons, G-188-11, pp. 38)

Celgar proposed a methodology for ensuring that any additional Celgar load served by FortisBC following the establishment of a FortisBC GBL is notionally matched to and served from additional third party energy purchases. (Celgar Complaint Proceeding, Celgar Final Submission, pp. 20–21) The Commission accepted the concept of matching purchases of non-PPA power for sale to a self-generator and directed FortisBC to establish a methodology for notionally matching sales to Celgar in service of its load, when Celgar is selling power, to FortisBC's supply of energy from its resource stack of non-BC Hydro PPA Power, and submit it by March 31, 2012 to the Commission for approval. (Reasons, G-188-11, pp. 31–32)

VII. Order G-202-12

Guidelines for Establishing Entitlement to Non-PPA Embedded Cost Power and Matching Methodology

Accordingly, in April 2012, FortisBC submitted its Compliance Filing to Order G-188-11 containing a proposed Matching Methodology and Guidelines for establishing a Self-Generator's entitlement to Non-BC Hydro PPA embedded cost power.

The Matching Methodology and Guidelines for establishing the entitlement of a self-generator to non-BC Hydro embedded cost power were approved in principle by Commission Order G-202-12 and accompanying Decision dated December 27, 2012 wherein the Commission reaffirmed the applicability of the APA in regards to the service provided to FortisBC's self-generating customers:

> "In the Commission Panel's view the APA is clear: FortisBC would be obligated to serve any other new Eligible Customer in its service area, or any other existing customer who increases its load. A self-generator is equally entitled to having its load requirements serviced by FortisBC at embedded cost rates, except for BC Hydro PPA power which is specifically excluded by the PPA." (Reasons, Order G-202-12, pp. 8–9)

Although a Matching Methodology was approved in principle by Order G-202-12, a rate by which a self-generating customer is charged had not yet been brought forward for Commission approval under sections 58-61 of the *UCA*. Accordingly, Order G-202-12 also directed FortisBC to design a stepped rate for transmission service customers that reflected the Matching Methodology.

VIII. FortisBC Application for Stepped and Stand-By Rates for Transmission Voltage Service Customers (Currently before the Commission)

In compliance with Order G-202-12, in March 2013, FortisBC applied to the Commission for approval of a new set of rates for its customers served at transmission voltage. Included in this application was a separate rate for self-generating customers taking service at transmission voltage which incorporated the matching methodology.

Submissions by both FortisBC and Celgar in that proceeding have revealed that, despite the lengthy regulatory record through which the Commission has given guidance on the principle of the entitlement of self-generating customers to non-PPA embedded cost power, the parties remain in disagreement as to how this principle should be interpreted and implemented in a Commission approved rate.

The review of the application for approval of a rate for self-generation customers that incorporates restrictions to RS 3808 power in the FortisBC service area is currently in progress.

IX. Order G-191-13

CPCN Purchase of Kelowna Utility Assets by FortisBC — Phase 2

One of the issues which arose during the course of Phase 1 of FortisBC's Application for a CPCN to allow it to purchase the City of Kelowna electricity distribution assets was the possible discrimination arising from the GBL level assigned to Tolko Industries' self-generation facilities by Commission Order G-113-01. Celgar, an existing customer of FortisBC with self-generation capability, argued that its treatment would be different and less beneficial than that afforded to Tolko Industries Ltd. (Tolko), a customer of the City of Kelowna with self-generation facilities, if the purchase took place.

In its ruling, issued as Order G-191-13, the Commission Panel found that a GBL, viewed as the load a self-generator is required to serve, should be tied to an agreement between the self-generating customer and the utility. The Panel found that a utility offering one self-generating customer service on the basis of a GBL set to a level less than the customer's load and offering another self-generating customer service on a net of load basis would create a situation of "undue discrimination, preference, prejudice or disadvantage in respect of a rate or service," within the meaning of section 59(4)(b) of the *UCA*. The Panel further found that, with the removal of the intermediary of the City of Kelowna, Tolko and Celgar, as two self-generating customers of the same utility, should be offered service "under substantially similar circumstances and conditions" within the meaning of section 59(4)(c) of the *UCA*. This result was contrary to section 59(2)(b) of the *UCA*, which states : "[a]public utility must not... extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description."

As a result, the Commission varied Order G-113-01 so as to revoke the exemption from the provisions of the *UCA* other than section 99 (Part 2 is no longer relevant as it was repealed in 2003), provided to Tolko for sales of Incremental Power, defined as "all electricity generation above 2 MW each hour." The corresponding exemption for non-public utility purchasers of that Incremental Power from section 71 of the *UCA* was also revoked. Order G-113-01 was further varied so as to maintain the exemptions for Tolko and any non-public utility purchasers of Tolko power, for power generated by Tolko on a net of load basis only and to recognize that the City of Kelowna was also no longer a possible purchaser of Tolko power. Order G-198-11, which established a priority sequence for potential purchasers of Tolko's Incremental Power, was revoked.

The Commission Panel further stated:

> "The revocation is without prejudice to the ability of FortisBC to negotiate agreements which would result in a similar treatment being afforded to all of its self-generating customers, whether such treatment is by way of GBLs or any other means to prevent true arbitrage in fact. The Commission leaves it to FortisBC to agree with its self-generation customers on the load it will serve."

X. Order G-19-14

BC Hydro Application to Amend TS No. 74 CBL Load Determination Guidelines for RS 1823 Customers with Self-Generation Decision

Electric Tariff Supplement No. 74 (TS 74) provides for the determination of Customer Baseline Loads for industrial customers taking service at transmission voltage under Rate Schedule 1823. The TS 74 Applications requests approval for certain changes to TS 74 to make specific reference to those customers which also have self-generation facilities.

The Commission approved the Application as filed but directed BC Hydro to file an Application with the Commission for approval of updated Contracted GBL guidelines, to be incorporated into Tariff Supplement No. 74, as soon as is reasonably practicable, but no later than six months after the date of the Order issued concurrently with this Decision.

In its ruling, issued as Order G-19-14, the Commission Panel found that:

> "…in the context of Tariff Supplement No. 74, a GBL is a 'rate' within the meaning of the *Utilities Commission Act*, RSBC 1996, c. 473. The Commission Panel further finds that the provision of more detailed guidelines for the determination of Contracted GBLs would be of assistance not only to the Commission, but to all parties which either have self-generation facilities or are considering installing such facilities. The Commission Panel finds that there is considerable merit to the consistency and transparency in the treatment of self-generating customers taking service under Rate Schedule 1823 that will result." (BC Hydro Tariff Supplement 74 Decision Dated February 17, 2014, Executive Summary, pp. ii–iii)

On March 14, 2014, BC Hydro filed a Notice of Application for Leave to Appeal for Commission Order G-19-14 with the Court of Appeal.

LIST OF ACRONYMS

1986 PPA	Commission Order G-61-86, BC Hydro and FortisBC Power Purchase Agreement
1993 PPA	1993 Power Purchase Agreement between BC Hydro and FortisBC
2012 Information Report	June 20, 2012 Transmission Service Rate and Customer Generator Baselines Information Report filed by BC Hydro
Annual Energy Nomination	Single energy nomination for the aggregate of all points of delivery for the following year
APA	1999 Application for Access Principles
Application	Application for Approval of Rates between BC Hydro and FortisBC Inc. with regards to Rate Schedule 3808, Tariff Supplement No. 3 – Power Purchase and Associated Agreements, and Tariff Supplement No. 2 to Rate Schedule 3817
ARWA	Amended and Restated Wheeling Agreement
Associated Agreements	Imbalance Agreement, Energy Export Agreement and Master Accounting Agreement
BC Hydro, Applicant	British Columbia Hydro and Power Authority
BCMEU	British Columbia Municipal Electrical Utilities
BCPSO	British Columbia Pensioners and Seniors Organisation
BCSEA	BC Sustainable Energy Association and the Sierra Club of British Columbia
BCUC, Commission	British Columbia Utilities Commission
Brilliant PPA	FortisBC Power Purchase Agreement with Columbia Power Corporation for power generated from the Brilliant Dam
BRP	Base Resource Plans
CBL	Customer Baseline
CBT	Columbia Basin Trust

LIST OF ACRONYMS

CEC	Commercial Energy Consumers Association of British Columbia
Celgar	Zellstoff Celgar Partnership Limited
CPC	Columbia Power Corporation
EEA	Energy Export Agreement
FortisBC, Co-applicant	FortisBC Inc.
GBL	Generator Baseline
GSA	General Service Agreement
GWA	General Wheeling Agreement
HC2	Special Direction No. HC2 to the BC Utilities Commission November 27, 2003 — BC Hydro Public Power Legacy and Heritage Contract
IA	Imbalance Agreement
ICG	Industrial Consumers Group of FortisBC Inc.
IPPs	Independent Power Producers
IR	Information Request
LRMC	Long Run Marginal Cost
MAA	Master Accounting Agreement
MW	Megawatt
New PPA	New Power Purchase Agreement
OATT	Open Access Transmission Tariff
R/C ratios	revenue-to-cost ratios
RS	Rate Schedule
RS 1823	Transmission Service Stepped Rate
RS 1827	Transmission Service Rate for Exempt Customers

LIST OF ACRONYMS

The Parties	BC Hydro and FortisBC
Tolko	Tolko Industries Ltd.
Tranche 1	Energy charge based on embedded cost rates
Tranche 2	Energy charge reflects BC Hydro's long run marginal cost
UCA	*Utilities Commission Act*
Vanport	Vanport Sterilizers Inc.
WAX	Waneta dam expansion
WAX capacity	The EEA provides FortisBC the flexibility to export "Eligible Energy" using capacity from the Waneta Expansion
WKP	West Kootenay Power
WTS	Wholesale Transmission Services

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

British Columbia Hydro and Power Authority
Application for Approval of Rates between BC Hydro and FortisBC Inc.
with regards to Rate Schedule 3808, Tariff Supplement No. 3
– Power Purchase and Associated Agreements,
and Tariff Supplement No. 2 to Rate Schedule 3817

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter Dated May 28, 2013 – Appointing the Commission Panel for the review of the British Columbia Hydro and Power Authority Application for Approval of Rates between BC Hydro and FortisBC Inc. with regards to Rate Schedule 3808, Tariff Supplement No. 3 – Power Purchase and Associated Agreements, and Tariff Supplement No. 2 to Rate Schedule 3817
A-2	Letter Dated May 28, 2013 – Order G-87-13 Establishing Initial Regulatory Timetable
A-3	Letter Dated May 31, 2013 – Amendment to Commission Panel
A-4	Letter L-38-13 Dated June 17, 2013 – Procedural Conference Location, Date and Time
A-5	Letter Dated June 26, 2013 – Commission Information Request No. 1 to BC Hydro
A-6	Letter Dated June 26, 2013 – Commission Information Request No. 1 to FortisBC Inc. on Exhibit C1-2
A-7	Letter Dated July 4, 2013 – Instructions regarding Procedural Conference
A-8	Letter Dated July 23, 2013 – Procedural Conference List of Items for Discussion
A-9	Letter Dated August 1, 2013 – Order G-117-13 Establishing the Regulatory Timetable
A-10	Letter Dated August 12, 2013 – Request for Comments

Exhibit No.	Description
A-11	Letter Dated August 16, 2013 – Commission Information Request No. 2 to BC Hydro
A-12	Letter Dated August 16, 2013 – Commission Information Request No. 2 to FortisBC Inc.
A-13	Letter Dated August 16, 2013 – Order G-125-13 with Reasons for Decision
A-14	Letter Dated August 22, 2013 – Order G-129-13 Amending the Regulatory Timetable
A-15	Letter Dated August 26, 2013 – Request for Comments regarding Timetable
A-16	Letter Dated August 29, 2013 – Order G-134-13 regarding Celgar's Request to File Evidence
A-17	Letter Dated December 13, 2013 – Letter to All Parties Reopening Evidentiary Record
A-18	Letter Dated April 10, 2014 – Letter Requesting Submissions on BC Hydro Proposal (Exhibit B-18)
A-19	Letter Dated April 16, 2014 – Letter advising Supplemental PACA deadline
A2-1	Letter Dated June 26, 2013 - Commission Staff Filing BC Hydro and Power Authority Transmission Service Rate (TSR) Customer Generator Baselines (GBLs) Information Report June 2012

APPLICANT DOCUMENTS

B-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Letter Dated May 24, 2013 – Application for Approval of New Power Purchase Agreement with FortisBC Inc.
B-1-1	Letter Dated July 22, 2013 – BCH Submitting Errata to Application
B-2	Letter dated June 17, 2013 - BC Hydro's presentation from the Workshops held on June 11, 2013 in Vancouver and June 13, 2013 in Castlegar
B-3	Letter Dated July 16, 2013 – BCH Submitting General Wheeling Agreement
B-4	Letter Dated July 22, 2013 – BCH Submitting Responses to BCUC IR No. 1
B-5	Letter Dated July 22, 2013 – BCH Submitting Responses to Interveners IR No. 1

Exhibit No.	Description
B-6	Submitted at Procedural Conference July 29, 2013 - BCH Submitting ALTERNATIVE SCHEDULES SUBMITTED BY MR. WEBB
B-7	Letter Dated August 8, 2013 - BCH Submitting response to CEC's request Exhibit C11-4
B-8	Letter Dated August 9, 2013 - BCH Submitting response on Celgar request of regarding outstanding information requests in Exhibit B-5
B-9	Letter Dated August 14, 2013 - BCH Submitting comments regarding Exhibit A-10
B-10	Letter Dated August 14, 2013 - BCH Submitting responses to outstanding Celgar information requests
B-11	Letter Dated August 21, 2013 – BCH submitting comment regarding the request by Celgar (Exhibit C5-6)
B-12	Letter Dated August 27, 2013 – BCH Submitting Comment regarding Request to File Evidence
B-13	Letter Dated September 10, 2013 - BCH Submitting Response to BCUC IR No. 2
B-14	Letter Dated September 10, 2013 - BCH Submitting Response to Interveners IR No. 2
B-15	Letter Dated September 16, 2013 - BCH Submitting Written Acceptance of the Commissions' Determination
B-16	Letter Dated January 14, 2014 - BCH Submitting Supplemental Submission regarding section 2.5 in response to the BCUC Panel request in Exhibit A-17
B-17	Letter Dated February 3, 2014 - BCH Submitting Supplemental Reply Submissions
B-18	Letter Dated April 9, 2014 - BCH Submitting Proposed Amendment to Section-2.5
B-19	Letter Dated April 25, 2014 - BCH Submitting Reply Submission

Exhibit No.	**Description**
INTERVENOR DOCUMENTS	
C1-1	**FORTISBC INC. (FBC)** Letter Dated May 27, 2013 – Request for Intervener status by Dennis Swanson
C1-2	Letter Dated May 27, 2013 – FBC Submitting Comments
C1-3	Letter Dated July 22, 2013 - FBC Responses to BCUC IR No.1
C1-4	Letter Dated July 22, 2013 - FBC Responses to BCMEU IR No.1
C1-5	Letter Dated July 22, 2013 - FBC Responses to BCPSO IR No.1
C1-6	Letter Dated July 22, 2013 - FBC Responses to CEC IR No.1
C1-7	Letter Dated July 22, 2013 - FBC Responses to Celgar IR No.1
C1-8	Letter Dated July 22, 2013 - FBC Responses to ICG IR No.1
C1-9	Letter Dated July 22, 2013 - FBC Responses to Vanport IR No.1
C1-10	Letter Dated July 22, 2013 - FBC Responses to Wait IR No.1
C1-11	Letter Dated July 29, 2013 – FBC submitting Correction to statement at Procedural Conference
C1-12	Letter Dated August 12, 2013 - FBC submitting comments regarding outstanding information requests
C1-13	Letter Dated August 12, 2013 - FBC submitting further comments
C1-14	Letter Dated August 16, 2013 - FBC submitting Response to ICG Supplemental IR No. 1
C1-15	Letter dated August 21, 2013 – FBC submitting comment comments regarding the request by Celgar (Exhibit C5-6)
C1-16	Letter Dated August 27, 2013 – FBC Submitting Comment regarding Request to File Evidence
C1-17	Letter Dated September 10, 2013 - FBC Submitting Response to BCUC IR No. 2
C1-18	Letter Dated September 10, 2013 - FBC Submitting Response to BCMEU IR No. 2

Exhibit No.	Description
C1-19	Letter Dated September 10, 2013 - FBC Submitting Response to BCPSO IR No. 2
C1-20	Letter Dated September 10, 2013 - FBC Submitting Response to BCSEA IR No. 2
C1-21	Letter Dated September 10, 2013 - FBC Submitting Response to CEC IR No. 2
C1-22	Letter Dated September 10, 2013 - FBC Submitting Response to ICG IR No. 2
C1-23	Letter Dated September 16, 2013 - FBC Submitting Written Acceptance
C1-24	Letter Dated January 20, 2014 - FBC Supplemental Submission
C1-25	Letter Dated April 15, 2014 - FBC Submitting Response to Exhibit A-18 and Proposed Amendment to Section-2.5
C1-26	Letter Dated April 23, 2014 - FBC Submitting Comments regarding Exhibit C5-11
C2-1	**BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO ET AL)** Letter dated May 29, 2013 – Request for Intervener Status by Tannis Braithwaite, Eugene Kung and Bill Harper
C2-2	Letter Dated June 26, 2013 - BCPSO submitting Information Request No. 1 to BC Hydro
C2-3	Letter Dated June 26, 2013 - BCPSO submitting Information Request No. 1 to FBC
C2-4	Letter Dated August 19, 2013 – BCPSO submitting Information Request No. 2 to FBC
C2-5	Letter Dated August 19, 2013 – BCPSO submitting Information Request No. 2 to BCH
C2-6	Letter Dated August 27, 2013 – BCPSO Submitting BCPSO regarding Request to File Evidence
C2-7	Letter Dated January 27, 2014 – BCPSO Filing Submission
C2-8	Letter Dated April 16, 2014 – BCPSO Submitting Comments
C3-1	**MORGAN STANLEY CAPITAL GROUP INC (MSCG)** Letter dated May 31, 2013 – Request for Intervener Status by Lisa Cherkas
C4-1	**BRITISH COLUMBIA MUNICIPAL ELECTRICAL UTILITIES (BCMEU)** Letter dated June 3, 2013 – Request for Intervener Status by Christopher Weafer

Exhibit No.	Description
C4-2	Letter Dated June 26, 2013 - BCMEU submitting Information Request No. 1 to BC Hydro
C4-3	Letter Dated June 26, 2013 - BCMEU submitting Information Request No. 1 to FBC
C4-4	Letter Dated August 19, 2013 – BCMEU submitting Information Request No. 2 to FBC
C4-5	Letter Dated January 27, 2014 – BCMEU Filing Submission
C4-6	Letter Dated April 15, 2014 - BCMEU Submitting Response to Exhibit A-18 and Proposed Amendment to Section-2.5
C5-1	**ZELLSTOFF CELGAR PARTNERSHIP LIMITED (CELGAR)** Letter dated June 5, 2013 – Request for Intervener Status by Kim Moller, Elroy Switlishoff, Brian Merwin and Robert Hobbs
C5-2	Letter Dated June 26, 2013 - Celgar submitting Information Request No. 1 to BC Hydro
C5-3	Letter Dated June 26, 2013 - Celgar submitting Information Request No. 1 to FBC
C5-4	Submitted at Procedural Conference July 29, 2013 - Celgar submitting LIST OF ISSUES SUBMITTED BY MR. MOLLER MARKED EXHIBIT C5-4
C5-5	Letter Dated August 9, 2013 - Celgar comments regarding outstanding information requests
C5-6	Letter Dated August 12, 2013 - Celgar extension request
C5-7	Letter Dated August 19, 2013 – Celgar submitting Information Request No. 2 to FBC
C5-8	Letter Dated August 23, 2013 – Celgar request for an amendment to the Regulatory Timetable
C5-9	Letter Dated August 28, 2013 – Celgar Submitting Reply Comments regarding Request to File Evidence
C5-10	Letter Dated January 27, 2014 – Celgar Filing Submission
C5-11	Letter Dated April 16, 2014 – Celgar Submitting Comments
C6-1	**WAIT, ALAN (WAIT)** Letter dated June 6, 2013 – Request for Intervener Status by Alan Wait

Exhibit No.	Description
C6-2	Letter Dated June 26, 2013 - Wait submitting Information Request No. 1 to BC Hydro
C6-3	Letter Dated June 26, 2013 - Wait submitting Information Request No. 1 to FBC
C6-4	Letter Dated August 14, 2013 - Wait Submitting comments regarding Exhibit A-10
C6-5	Letter Dated January 27, 2014 – Wait Filing Submission
C6-7	Letter Dated April 17, 2014 – Wait Submitting Comments
C7-1	**BC SUSTAINABLE ENERGY ASSOCIATION AND THE SIERRA CLUB OF BRITISH COLUMBIA (BCSEA)** Letter dated June 7, 2013 – Request for Intervener Status by William J. Andrews and Thomas Hackney
C7-2	Letter Dated June 26, 2013 - BCSEA submitting Information Request No. 1 to BC Hydro
C7-3	Letter Dated August 12, 2013 - BCSEA submitting comments regarding the request by Celgar (Exhibit C5-5)
C7-4	Letter Dated August 19, 2013 - BCSEA submitting Information Request No. 2 to BC Hydro
C7-5	Letter Dated August 19, 2013 - BCSEA submitting Information Request No. 2 to FBC
C7-6	Letter Dated August 21, 2013 – BCSEA submitting comment comments regarding the request by Celgar (Exhibit C5-6)
C7-7	Letter Dated January 27, 2014 – BCSEA Filing Submission
C7-8	Letter Dated April 17, 2014 – BCSEA Submitting Comments
C8-1	**GABANA, NORMAN (GABANA)** Letter dated June 7, 2013 – Request for Intervener Status by Norman Gabana
C9-1	**INDUSTRIAL CUSTOMERS GROUP (ICG)** Letter dated June 7, 2013 – Request for Intervener Status by Robert Hobbs
C9-2	Letter Dated June 26, 2013 - ICG submitting Information Request No. 1 to BC Hydro
C9-3	Letter Dated June 26, 2013 - ICG submitting Information Request No. 1 to FBC

Exhibit No.	**Description**
C9-4	Submitted at Procedural Conference July 29, 2013 - ICG submitting EVIDENCE FILED BY WEST KOOTENAY POWER (NOW FORTISBC) IN THE 1993 PPA PROCEEDING
C9-5	Letter Dated August 19, 2013 - ICG submitting Information Request No. 2 to BC Hydro
C9-6	Letter Dated August 19, 2013 - ICG submitting Information Request No. 2 to FBC
C9-7	Letter Dated August 21, 2013 – ICG submitting comment comments regarding the request by Celgar (Exhibit C5-6)
C10-1	**VANPORT STERILIZERS (VANPORT)** Letter dated June 7, 2013 – Request for Intervener Status by Richard Tennant
C10-2	Letter Dated June 27, 2013 - Vanport submitting Information Request No. 1
C10-3	Letter Dated August 14, 2013 - Vanport submitting comments regarding the request by Celgar (Exhibit C5-5)
C10-4	Letter Dated August 19, 2013 - Vanport submitting Information Request No. 2 to BC Hydro
C10-5	Letter Dated August 20, 2013 - Vanport submitting Comments on Final Submission Date
C10-6	Letter Dated August 27, 2013 – Vanport Submitting Comment regarding Request to File Evidence
C10-7	Letter Dated January 27, 2014 – Vanport Filing Submission
C10-8	Letter Dated April 17, 2014 – Vanport Submitting Comments
C11-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter dated June 20, 2013 – Request for Late Intervener Status by Christopher P. Weafer
C11-2	Letter Dated June 26, 2013 - CEC submitting Information Request No. 1 to BC Hydro
C11-3	Letter Dated June 26, 2013 - CEC submitting Information Request No. 1 to FBC
C11-4	Letter Dated August 7, 2013 - CEC submitting List of Unanswered Information Request No.1 questions
C11-5	Letter Dated August 19, 2013 - CEC submitting Information Request No. 2 to BC Hydro

Exhibit No.	Description
C11-6	Letter Dated August 19, 2013 - CEC submitting Information Request No. 2 to FBC
C11-7	Letter Dated January 27, 2014 – CEC Filing Submission
C11-8	Letter Dated April 17, 2014 – CEC Submitting Comments

INTERESTED PARTY DOCUMENTS

D-1	**WILLIS ENERGY SERVICES LTD. (WES)** Letter dated June 6, 2013 – Request for Interested Party Status by Penny Cochrane
D-2	**SHELL ENERGY NORTH AMERICA (SHELL)** Letter dated June 11, 2013 and Online Registration – Request for Interested Party Status by Andrew Law

IN THE MATTER OF

FORTISBC INC.

APPLICATION FOR APPROVAL OF STEPPED AND STAND-BY RATES
FOR TRANSMISSION [VOLTAGE] CUSTOMERS

DECISION

May 26, 2014

BEFORE:

L.A. O'Hara, Commissioner/Panel Chair
R.D. Revel, Commissioner

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS
(continued)

Page No.

TABLE OF CONTENTS
(continued)

Page No.

LIST OF TABLES

EXECUTIVE SUMMARY

On March 28, 2013, FortisBC Inc. (FortisBC) filed for approval of a new set of rates for its transmission voltage customers and to close the Time-of-Use (TOU) Rate and the existing Flat Rate. The new transmission voltage rates include a Stepped Rate with attached Customer Baseline Load Guidelines (CBLs), a new Flat Rate, the Non-Embedded Cost Power Rate (NECP) Rider, and a Stand-by Service Rate. FortisBC also requested a determination on the retroactive application of rates to Zellstoff Celgar Limited Partnership (Celgar).

On February 3, 2014, by Order G-12-14, the Panel identified certain aspects of the Application, which are to be addressed at a later time, that overlapped with the then pending review of the British Columbia Hydro and Power Authority (BC Hydro) new power purchase agreement with FortisBC (RS 3808 Proceeding). Accordingly, this Decision addresses primarily Stepped Rates (excluding the application to self-generating customers), the Stand-by Rate, and the TOU Rate.

Stepped Rates

The applied for Stepped Rate was in response to a Commission Directive in Order G-188-11. Having complied with the directive, FortisBC subsequently made it clear that the Stepped Rate should not be mandated at this time stating that none of the affected customers had requested such a rate and there was no practical need for it. FortisBC also withdrew its request to close the TOU Rate and the existing Flat Rate if the Stepped Rate was not approved.

In this Decision, the Panel finds that this is not the appropriate time to mandate a stepped rate and therefore does not approve the Stepped Rate, the attached CBL Guidelines, or the new Flat Rate. However, the Panel determines that the potential effectiveness of a stepped rate should still be considered in the future and directs FortisBC to do so in conjunction with its next Resource Plan.

The key reasons that were considered in making this finding include:

1. *Lack of Regulatory Record, Need and Customer Desire;*
2. *Impact on Rates and Cost Shifting; and*
3. *Increase in Cost, Complexity and Process Related to Administration.*

The Panel accepts FortisBC's position that there is no 'problem' at this time given that three of the four affected customers did not indicate any desire for the Stepped Rate, nor did any indicate that such a rate structure would in fact result in positive behavioural changes on their part. The Panel cannot find any efficiency benefits due to the introduction of a stepped rate structure at this time and instead concludes that FortisBC should ensure sufficient focus is given to identifying and addressing Demand Side Management opportunities for these customers as a way of achieving efficiency benefits.

In making its decision the Panel gives little weight to the Impact on Rates and Cost Shifting or the Increase in Cost, Complexity and Process Related to Administration.

Given that the Stepped Rate was not approved, the Commission also accepted FortisBC's withdrawal of it request to close the existing Flat Rate and TOU Rate.

The Stand-by Rate

Stand-by rates are offered to customers with self-generation to ensure that in the event of a planned or unplanned outage of their on-site generator they have the ability to purchase power to replace what would normally be self-generated. Currently Celgar is FortisBC's only transmission voltage customer with self-generation.

The Application proposes a Stand-by Rate for current and future customers with self-generation to be made available in conjunction with an underlying rate (RS 31). The proposed Rate includes an Energy Charge, Restrictions and Availability to use it, Demand Charges in combination with RS 31, and several Special Provision clauses.

The Panel is not able to approve the proposed Stand-by Rate at this time; however, it does support and approve many of the components of the Rate and considers that the remaining outstanding issues can be addressed through this Proceeding.

The Panel finds that there is insufficient evidence regarding the Restrictions and Availability to allow it to make a final determination on those components. More significantly, the Panel finds that the inclusion of Special Provision 2, which is designed to recover infrastructure costs, is unnecessarily restrictive and results in a rate that is unjust, unreasonable, and unduly discriminatory. The rationale includes the following:

FortisBC's Special Provision 2 proposes that stand-by demand charges be based on 80 percent of the highest level of demand ever taken by the customer. Celgar does not support this Provision and proposes that demand charges only apply to firm capacity. Further, it submits that all stand-by service should be offered as non-firm service, which the utility has the option to make unavailable when its system is constrained, and therefore should not attract a stand-by demand charge. Furthermore, Celgar states it has had access to non-firm stand-by service since the late 1990s.

FortisBC disagrees with Celgar and states that it does not offer non-firm service as there is no cost benefit to doing so and it would simply result in cost shifting. FortisBC further states that it must maintain infrastructure that is capable of servicing Celgar's full load, regardless of how intermittent that load may be.

The Panel notes that it is not unusual for stand-by rates to be contentious. Advocates for self-generation seek minimal stand-by rates based on the premise that self-generation provides overall benefits while utilities often argue that low stand-by rates can result in the avoidance of infrastructure costs. This contention is reflected by the two very divergent concepts introduced by FortisBC and Celgar.

Nevertheless, the Panel is persuaded by FortisBC's argument that it should not be required to offer non-firm service given the cost of providing such service is the same as providing firm service. The Panel also agrees with FortisBC that demand charges should apply during periods of stand-by service as these customers should make a fair contribution to the sunk costs of the network. The Panel considers that the key focus in determining the appropriate stand-by demand charge should instead be to ensure that it does not discourage on-site generation that is fully economical and cost-effective but for the inclusion of stand-by charges. Further, the stand-by demand charge should also take into consideration BC energy objectives.

As these considerations can vary by customer and over time, the Panel finds that FortisBC's proposed one size fits all method of recovering these costs as laid out in Special Provision 2 is unnecessarily restrictive. As a solution, the Panel suggests that 'Stand-by Contract Demand' should be established between the customer and the utility at an amount somewhere between zero and 100 percent of the Contract Demand established in the underlying rate. Determining the appropriate Stand-by Contract Demand should take into consideration the potential benefits of self-generation, such as electricity self-sufficiency, reduced greenhouse gas emissions, or a reduction in the need for utility-provided network capacity.

Subject to the remaining issues regarding the Restrictions and Availability being resolved, and subject to comment from the parties, it is likely that the Panel would approve a revised Stand-by Rate if Special Provision 2 was removed and:

i. For future customers Special Provision 2 is replaced, at a future date, with a Tariff Supplement that outlined Commission approved key principles that are to be considered in identifying the potential benefits of self-generation used to determine a customer's Stand-by Contract Demand; and

ii. For the one existing customer, Celgar, a determination on its Contract Demand and Stand-by Contract Demand is made in conjunction with the review of the Stand-by Rate.

In order to keep the Stand-by Rate Application moving forward and to assist in a near term resolution to Celgar's retroactive billing situation, the Commission directs that FortisBC undertake the following:

- File with the Commission, by June 26, 2014, a revised Stand-by Rate incorporating the findings in the Decision and addressing both the Restrictions on, and Availability of, stand-by service; and

- Submit a filing on the appropriate Contract Demand and Stand-by Contract Demand for Celgar in conjunction with the June 26, 2014 filing addressing specifically the last Contract Demand of 16 MVA that the parties agreed to.

Once the Commission has received the FortisBC filings it will determine the appropriate further process required in order to make a final determination on the Stand-by Rate and an appropriate Contract Demand and Stand-by Contract Demand for Celgar.

In regards to the outstanding matters established by Order G-14-12:

- The Commission Panel determines that there is no longer a need to consider the application of Stepped Rates for customers with self-generation facilities as the request for Stepped Rates was denied and, therefore, the rate class does not have stepped rates for which any application to self-generation customers can be made.

- The Commission will shortly be issuing a letter requesting submissions from the parties on how to proceed with FortisBC's request for approval for the NECP Rate Rider now that the Commission has made a final determination on the RS 3808 Proceeding by way of Order G-60-14.

- The Panel will not be seeking submissions on how to move forward with the retroactive billing for Celgar until a final determination is made on the Stand-by Rate.

1.0 INTRODUCTION

By way of Order G-188-11 dated November 14, 2011, the British Columbia Utilities Commission (Commission) directed FortisBC Inc. (FortisBC) to file an application for (i) a rate for self-generator customers based on Rate Schedule (RS) 31 but excluding British Columbia Hydro and Power Authority (BC Hydro) RS 3808 power from its resource stack, (ii) a two-tiered, stepped transmission rate to support conservation objectives, and (iii) a stand-by rate to address Zellstoff Celgar Partnership Limited's (Celgar) circumstances.

1.1 Original Application

On March 28, 2013, FortisBC applied to the Commission pursuant to sections 58-61 of the *Utilities Commission Act* (UCA) for approval of a new set of rates for its customers served at transmission voltage (Application) as directed by Order G-188-11. The Application seeks, among other things, approval for the following rates: RS 34 Stepped Rate, RS 36 Flat Rate, RS 37 Stand-by Service Rate, and to close both RS 33 Time-of-Use (TOU) Rate and the existing RS 31 Flat Rate. (Exhibit B-1, p. 3)

In the Application FortisBC states that it is not convinced that the proposed rates, with the exception of the Stand-by Rate, are in the best interests of its customers at this time and highlights the following reasons:

- lack of support by affected customers;
- regulatory costs associated with processing the Stepped Rate;
- set-up costs such as billing system upgrades;
- on-going operational expenses; and
- conservation results associated with the rates are difficult to project and may not justify the costs. (Exhibit B-2, Cover Letter)

FortisBC submits it has put forward what it considers to be a set of reasonable proposals that satisfy the Commission's directives. FortisBC confirms, however, that it has not identified any practical need for transmission stepped rates, has received no customer requests for such rates, and "would not have put forward an application for their implementation in the absence of the

Commission direction to do so." FortisBC further submits that the applied for Stepped Rates should not be mandated at this time. (FortisBC Final Submission, pp. 3-4)

1.2 Narrowed Scope for the Decision

On February 3, 2014, by Order G-12-14 and accompanying Reasons for Decision, the Commission Panel identified certain aspects of the Application that overlapped with the pending review of BC Hydro's application for approval of a new power purchase agreement with FortisBC (RS 3808 Proceeding). Therefore, the Panel considered those aspects would be better dealt with once a final decision on that application is issued. As a result, the Panel determined that issues that do not overlap with the RS 3808 Proceeding will continue to proceed by way of a written hearing. Specifically, the Panel determined it will be reviewing the Stepped Rate, excluding its application to customers with self-generation (NECP Rate Rider), the Stand-by Rate and the Time-of-Use Rate. The Panel also determined that it will not be reviewing the retroactive application of rates to Celgar at this time. (Exhibit A-15)

FortisBC noted the narrower scope and updated its request for a Final Order that includes the following determinations:

- approving Stand-by Rate (RS 37);
- not approving Stepped Rate (RS 34) and the referent Flat Rate (RS 36);
- not closing Time-of-Use Rate (RS 33) because the Stepped Rate is not being approved; and
- not closing the existing Transmission Rate (RS 31) because RS 34 and RS 36 are not approved. (FortisBC Reply, para. 108)

1.3 Background

FortisBC currently has four Large Commercial Service Customers connected at transmission voltage. These are Roxul (West) Inc. (Roxul) located in Grand Forks, Barrick Gold (Barrick) located outside Hedley, International Forest Products Limited (Interfor) located in Castlegar, and Celgar also located in Castlegar. (Exhibit B-1, p. 14) Of these Celgar is the only customer that has distributed generation (self-generation) capabilities.

As shown in the table below, these four FortisBC Large Commercial Service (Industrial) Customers make up approximately 7 percent of FortisBC's total sales. In contrast, in BC Hydro's territory there were 135 customer sites representing approximately 25 percent of all sales to domestic customers in F2012 for the comparable rate class.[1]

Table 1 Large Commercial Service Customers Percentage of FortisBC's Total Load

	2008	2009	2010	2011	2012
Annual Consumption by TSR customers (kWh)	81,556,337	87,005,587	89,335,022	183,802,609	199,786,993
Annual Consumption by all FortisBC Inc. customers (kWh)	3,087,196,835	3,156,749,340	3,044,439,684	3,144,249,683	3,143,496,000
Percentage of FortisBC Inc.'s total load	2.64%	2.76%	2.93%	5.85%	6.36%

1

Source: Exhibit B-4, BCUC 1.1.1

FortisBC currently has two rate options for Large Commercial Service Customers connected at transmission voltage:

Rate Schedule 31 - Large Commercial Service – Transmission; and
Rate Schedule 33 - Large Commercial Service – Transmission – Time of Use

For both rate schedules, a customer must take service from the Company at a nominal potential of 60,000 volts or higher, and have a load of 5,000 kVA or more. Each of these rates may be subject to a further written agreement.

RS 31 consists of a monthly Customer Charge, a flat Energy Charge for all consumption, and Demand Charges consisting of a Wires Charge and a Power Supply Charge. The Demand Charge was broken out into component parts as a result of the Company's 2009 Rate Design and Cost of Service Analysis Application (2009 RDA, COSA). As the Power Supply Charge is applied only to the maximum demand of the current billing month, without a ratchet provision, it encourages the management of load. The flat Energy Charge, however, does not have an inherent conservation component. The Company also has a wholesale transmission service rate specifically applicable for service to the City of Nelson (RS 41). This rate schedule is not the subject of this Application. (Exhibit B-1, p. 14)

[1] BC Hydro Application to Amend Tariff Supplement No. 74, Decision, p. 6

1.4 The Application and Orders Sought

The original Application requested approval for a new set of rates for FortisBC's customers served at transmission voltage (60,000 volts and above), as well as changes to, and the closing of, other rates as described below.

STEPPED RATES

- **Rate Schedule 34 – Large Commercial Service -Transmission Stepped Rate**

  Approval for RS 34 to become the default rate under which customers served at transmission voltages are provided service.

- **CBL Guidelines**

  Approval for Stepped Rate Customer Baseline Load (CBL) Guidelines as an attachment to RS 34.

- **Rate Schedule 31 – Large Commercial Service –Transmission Flat Rate**

  Approval to close RS 31 and replace it with RS 34 and RS 36 and transfer existing RS 31 customers to a new rate.

- **Rate Schedule 36 – Large Commercial Service –Transmission Flat Rate**

  Approval for a rate which will apply to those customers without sufficient history to be put on RS 34, and as a referent in the development of RS 34.

CUSTOMERS WITH SELF GENERATION - NECP RIDER

- **Non-Embedded Cost Power (NECP) Rider**

  Approval for the NECP which is a provision for charging customers with self-generation that intend to sell any portion of their generation that is not in excess of load.

STAND-BY SERVICE RATES

- **Rate Schedule 37 – Stand-by Service Rate**

  Approval for a rate that applies for power and energy to replace the power and energy ordinarily generated by a customer by means of a private generating facility when that generating facility is not operating due to either a forced outage or a maintenance shutdown.

TIME-OF-USE RATES

- **Rate Schedule 33 – Large Commercial Service –Transmission – Time-of-Use**

  Approval to close this rate.

RETROACTIVE APPLICATION OF RATE TO CELGAR

- A determination on the retroactive application of rates to Celgar.

1.5 Interveners and Regulatory Process

BC Hydro, Celgar, Interfor, British Columbia Pensioners and Seniors Organisation *et al*. (BCPSO), and the British Columbia Municipal Electrical Utilities (BCMEU) intervened in the Proceeding while Tolko Industries Ltd. registered as an Interested Party.

The Regulatory Timetable for the review of the Application was amended or put on hold a number of times due to scope challenges, concerns relating to the overlap with a number of other proceedings before the Commission, as well as the filing of Rebuttal Evidence by FortisBC. An overview of the regulatory process is provided in Appendix A.

In summary, this Decision and related Final Submissions will only address (i) the Stepped Rates, not including its application to customers with self-generation, (ii) the Stand-by Rate, and (iii) the Time-of-Use Rate. The Commission will address the remaining items in due course.

2.0 STEPPED RATES

2.1 Context for Stepped Rates in the FortisBC Service Territory

2.1.1 The FortisBC 2009 Rate Design Application

The genesis of the Application for Stepped Rates can be traced to the FortisBC rate design proceeding that took place in 2009 and 2010. FortisBC filed the 2009 RDA on October 30, 2009. The Commission Panel, in its decision dated October 19, 2010, identified the following threefold purpose for a RDA:

(i) To examine whether the structure of existing rates continues to promote an economically efficient consumption of electricity by the utility's customers;

(ii) To assess whether the charges to customers that result from the application of these rates are fair and reasonable; and

(iii) To provide an opportunity for all parties to examine the relevance of a utility's tariffs including its terms and conditions of service to ensure they remain relevant and valid. (Order G-156-10, Decision, p. 7)

While the review of FortisBC's 2009 RDA was in progress, the *Clean Energy Act* (CEA) was introduced on April 10, 2010 by the Provincial Government. The press release of that date announced the following:

> "British Columbia's new Clean Energy Act sets the foundation for a new future of electricity self-sufficiency, job creation and reduced greenhouse gas emissions, powered by unprecedented investments in clean, renewable energy across the province. Bill 17 builds upon British Columbia's unique heritage advantages and wealth of clean, renewable energy resources."

In its Decision on the 2009 RDA the Commission Panel observed that "recent BC policy and legislative developments have strongly highlighted energy efficiency and conservation" and directed FortisBC to, among other things:

- develop a plan for introducing inclining block rates for residential customers that also incorporate a lower Basic Charge in the immediate future;

- initiate consultations with industrial customers with a goal to introduce a stepped rate for transmission service similar to RS 1823 of BC Hydro; (Order G-156-10, p. 3)

It appears that the intent of the stepped rate directive was to introduce measures to promote conservation and efficiency in order to reduce consumption which in turn would postpone the need for future generation build. In addition, the Commission implied that both major electric utilities in the province should offer stepped rates.

2.1.2 Celgar Complaint to the Commission

After the 2009 RDA Decision was issued, but before FortisBC had made much progress with any stepped rate consultation, Celgar filed a complaint on March 21, 2011, regarding the failure of FortisBC and Celgar to complete a general service agreement (GSA) and FortisBC's application of RS 31 Demand Charges (Celgar Complaint). In reviewing the Celgar Complaint that Commission Panel described Celgar's mill load as being served by a combination of the following:

(i) Celgar's own generation;

(ii) FortisBC supply at embedded cost rates to the extent determined by the application of the Access Principles pursuant to Order G-27-99 (the Entitlement); and

(iii) Additional supply from FortisBC (the Margin).

In that context, the Commission Panel reminded FortisBC of the directive to introduce stepped rates and concluded: "The Panel considers that a stepped rate could be an appropriate mechanism for recovering the cost of power supply to serve the Margin." (Order G-188-11, Decision, p. 40) Accordingly, FortisBC was re-directed to submit an application to the Commission by May 31, 2012, for a two-tier stepped transmission rate to reflect conservation objectives. The Panel indicated that the rate for the second tier should reflect the long term marginal cost of power from sources other than RS 3808.

2.1.3 Consultation Activities

In response to Commission Order G-156-10 regarding the 2009 RDA, FortisBC began the development of transmission stepped rate consultation materials that were intended to gather customer feedback on the customer reception of rates prior to the potential development of a future application.

However, prior to a conventional consultation effort being undertaken, Celgar filed the complaint against FortisBC, as described above, with respect to billing and contract issues. As part of the Celgar Complaint proceeding the rates charged to Celgar and other transmission customers became a central element of consideration.

While the 2009 RDA only directed FortisBC to initiate consultation with its customers regarding a transmission stepped rate, the Celgar Complaint proceeding resulted in Order G-188-11 that simply directed that a transmission stepped rate application be filed. FortisBC noted that this effectively changed its focus and moved discussion into the regulatory forum. (Exhibit B-6, Celgar 1.2.2)

Consequently, FortisBC stated it shifted consultation to the matters that fell from Order G-188-11, which related to customers with self-generation. It acknowledges that the consultation process for this Application did not follow a more usual collaborative path that is typical for applications. FortisBC further stated "given the active, detailed, and often adversarial consideration of the matter provided by the regulatory processes" deviating from the normal process was, to a large extent, unavoidable. (Exhibit B-6, Celgar 1.2.2)

FortisBC believed that there has been ample opportunity for customers to provide input into the rate design through both ongoing regulatory processes as well as in response to information provided directly to the affected customers. While, due to the limited number of customers, public or group open houses were not held, each customer was provided information on the structure and functioning of a two-tier stepped rate and invited to comment generally on the concept and usefulness of such rates. FortisBC stated the options for variation within the rate were limited because both the requirement and the structure of the stepped rate were specified by the Commission. FortisBC further explained that it is incumbent on the utility to (i) provide such information to customers, (ii) invite general feedback, and then (iii) incorporate such feedback, if any (along with other inputs such as Commission directions), is common industry practice in a proposed rate that forms the basis of an application. It would be a divergence from common practice to engage customers down to the level of designing the individual rate parameters. (Exhibit B-4, BCUC 1.9.2)

2.2 Proposed Stepped Rates

FortisBC states it has used the following principles to guide the development of its proposed Stepped Rate:

- Stepped Rate should be designed to include a conservation incentive;
- Stepped Rate will consist of two pricing tiers (G-188-11);
    - Pricing of the second tier will reflect the long term marginal cost of power from sources other than BC Hydro RS 3808 Power (G-188-11); and
- Stepped Rates will be revenue neutral, on an annual, individual customer basis, to an underlying Flat Rate. (Exhibit B-1, p. 18)

FortisBC explains that revenue neutrality exists between the proposed Stepped Rate and the underlying Flat Rate (RS 31) when the customer consumes electricity at 100 percent of its Customer Baseline Load (CBL). Because the CBL is based on historical consumption, for most customers on RS 34 this means that if a customer does not change consumption habits from the previous year, billing will remain the same exclusive of changes due to general rate increases. Therefore, to maintain revenue neutrality at the 100 percent CBL consumption level, the Tier 1 rate needs to be adjusted whenever the Tier 2 rate is changed. (Exhibit B-1, pp. 18-19)

Elements of the proposed Stepped Rate are summarized in Table 2 below.

Table 2 Elements of the Proposed Stepped Rate

Rate Element	Proposed Rate	Details	Guidace
1) Number of Tiers	Two Tiers		Directive 9, G-188-11
2) Tier pricing			
	Tier 2: 9.223¢/kWh	Reflect the long term marginal cost of power from sources other than BC Hydro RS 3808 power	BCUC Order G-188-11, Directive 9
	Tier 1	Determined by formula to ensure revenue neutrality to the equivalent cost based flat rate (RS 31) for customers who consume 100 percent of their CBL	
3) Tier Threshold (Revenue Neutral)	90/10: Tier 1/Tier 2 threshold	90% of a customer's baseline consumption attracts the Tier 1 price Remaining consumption attracts the Tier 2 price	No specific directive to FortisBC. Guided by the Commission's direction in Order G-156-10 stating that the stepped rates should be similar to BC Hydro as set out in HC2. BC Hydro RS 1823 uses the 90/10 ratio of tier 1 to tier 2 consumption, based on a CBL, to set a customer revenue neutral rate.
4) Customer Charge	$2,711.28 per month	Consistent with the currently approved flat rate (RS 31)	No Guidance
5) Demand Charge		Consistent with the currently approved flat rate (RS 31)	No Guidance

Source: Derived from Exhibit B-1, pp 21-23

2.3 Evaluation Approach

By way of background, FortisBC agreed that consideration of the Bonbright Principles is a useful input into the evaluation of rate design options. Other considerations, such as legislative requirements, also impact such an evaluation. (Exhibit B-4, BCUC 1.2.1)

FortisBC also agreed that the proposed Stepped Rate meets the definition of a Demand Side Measure (DSM) in the CEA. (Exhibit B-7, BCUC 2.9.1) FortisBC further stated “The Company believes that the stepped rate would likely pass the [DSM Regulation] tests based upon the measures of avoided costs contained in the DSM regulations, but the costs tests should not be a determinative factor in whether approval of the stepped rate is granted.” (Exhibit B-7, BCUC 2.9.2.1)

Commission Panel Discussion

The Panel considers FortisBC's pricing principles are consistent with Order G-188-11. However, that Order did not predetermine that a rate which met these principles would be approved by the Commission. It only directed that the rate is to be brought forward for review by the Commission.

In this Decision, the Panel will not evaluate the Application against FortisBC's pricing principles. The Panel will instead determine if the Application meets the standard of generally accepted rate design principles. Further, as the rate is considered a demand-side measure under the CEA the Panel will also be guided by the DSM Regulations[2] in determining how to interpret these principles for the purpose of this Application.

2.4 Evaluation

FortisBC has made its position very clear by stating that the Stepped Rate should not be mandated at this time. It submits that stepped rates: lack support and interest from affected customers, were initially ordered without the benefit of an adequate regulatory record, and introduce an administrative burden on both FortisBC and the affected customer for an undetermined and uncertain benefit while potentially raising rates for all customers. (FortisBC Final Submission, para. 18)

Overall BCPSO supports FortisBC's position that the Stepped Rate should not be mandated at this time. BCPSO submits that the need for such a rate and the appropriate basis for determining FortisBC's long term marginal cost of power should be considered in conjunction with FortisBC's next Resource Plan. (BCPSO Final Submission, para. 25)

To justify why the rate should not be mandated at this time, FortisBC provided the following reasoning. Each reason provided will be discussed further.

1. Lack of regulatory record, need, and customer desire (Section 2.4.1);
2. Impact on rates (Section 2.4.2); and

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[2] Ministerial Order M271 – Demand Side Measures Regulation dated November 11, 2008 and Ministerial Order M335 – Demand Side Management Regulation Amendment dated December 8, 2011

3. An increase in cost, complexity, and process (Section 2.4.3).

2.4.1 Lack of Regulatory Record, Need, and Customer Desire

FortisBC's clear evidence is that there is no 'problem' that needs addressing. FortisBC stated that without some legislated mandate it would not make changes to an existing rate structure without first identifying a problem or issue, even including an unrealized opportunity for improving a rate. (Exhibit B-4, BCUC 1.2.2.1)

FortisBC also stated that a stepped rate is not inherently less stable than a Flat Rate. Although there is a threshold at which the price of energy changes, it is fixed and predictable. FortisBC further stated that increased rate instability would only result if prices were fluctuating within a short timeframe in a manner that was not predictable. (Exhibit B-4, BCUC 1.8.1)

Celgar submits that BC Hydro's Industrial Stepped Rate (RS 1823), although not perfect, does send a conservation price signal that prompts customers to respond and for that reason Celgar supports a stepped rate for all FortisBC industrial customers. Celgar goes on to state that an active DSM program for industrial customers, in combination with stepped rates, is imperative. (Celgar Final Submission, p. 40)

BCPSO introduces a potential contrast between conservation and efficient use. First, it points out that the motivator behind the Commission's Directive No. 9 (Order G-188-11) for stepped rates was to support conservation. BCPSO submits that FortisBC has interpreted 'conservation' in this context as encouraging reduced use of electricity with no specific reference as to whether that reduction is economically efficient. Therefore, in BCPSO's submission, encouraging conservation is not synonymous with Bonbright's Principle #3 which states "Price Signals that encourage efficient use and discourage inefficient use." BCPSO explains that if customers' usage is based on marginal cost pricing signals, only then would conservation be 'efficient'. (BCPSO Final Submission, pp. 3-4)

Conversely, BCPSO notes that FortisBC's current plans call for reliance on market purchases in the short to medium term. Over the long term, FortisBC indicates it may rely on market purchases or new generation to meet load growth. Accordingly, BCPSO submits there is a misalignment between the long-run marginal cost (LRMC) for new resources and FortisBC's actual marginal cost of supply, which means that efficient pricing signals are not triggered. For example, BCPSO notes the LRMC of 5.6¢/kWh used for evaluation of DSM programs, is significantly below the 9.223¢/kWh value proposed for the Tier 2 rate by FortisBC. In summary, BCPSO submits that an LRMC based on new resources does not reflect FortisBC's current LRMC of power and is predicated simply on achieving an inclining rate structure that will incent customers to use less electricity. (BCPSO Final Submission, pp. 4-5)

FortisBC does not disagree with the above submissions of BCPSO, but reiterates that the selection of a lower LRMC as suggested by BCPSO would simply result in a rate that is essentially flat, "further reducing the conservation incentive and rendering the rate ineffective." (FortisBC Reply, p. 3)

Commission Determination

The Panel acknowledges the CEA's and Energy Plan's focus on energy efficiency and accepts that an active demand side can be a critical element to an efficient market. An efficient market requires vigorous competition between supply-side and demand-side resources to achieve an efficient, least-cost outcome. Without this, the energy field is left with a one-sided market in which prices are set only by the supply side.

Therefore, the Panel agrees with BCPSO that the key question in determining if a need for the Stepped Rate exists is whether the Stepped Rate promotes efficient customer behaviour rather than merely results in less electricity consumption. For example, a customer may use less electricity by shutting down operations or switching to an alternative fuel, however this may not result in a net benefit overall.

In determining how any efficiency benefits of the stepped rates should be measured, the Panel has looked to the DSM Regulations for guidance. Section 4 (1.1) specifies that benefits should be measured using the Total Resource Cost test, which measures the benefit from a British Columbia perspective rather than a utility, participant or non-participant perspective. Although it is preferable that the utility itself also benefits (for example, if the Stepped Rate addresses an operational need of FortisBC), section 4 (1.8) of the DSM Regulations does not require this.

The Panel also considers that in measuring BC efficiency benefits there are two broad types of customer behaviours – short term operational decisions (such as whether to take on another order) and long term investment decisions (such as when to replace equipment). The Panel notes that Barrick has explicitly stated that due to the nature of its operations it would be unlikely to initiate any conservation activities and Interfor, who registered as an Intervener, did not make final submissions or asked any information requests.

FortisBC has already acknowledged that the consultation process did not follow the usual path due to the circumstances, but assured the Panel that there has been ample opportunity for customers to provide input into the rate design. In light of the lack of customer engagement, the Panel finds it difficult to conclude that the FortisBC stepped rate will have efficiency benefits in the absence of adequate evidence on the price responsiveness of FortisBC's Industrial customers.

The Panel also looked at this issue from a theoretical perspective – specifically, whether it could be assumed that FortisBC's Industrial customers are likely to be at least somewhat price sensitive and whether the Panel could assume that there would be a net efficiency benefit from the proposed Stepped Rate. This was addressed by separately considering the effect the proposed Stepped Rate could have on short term and long term FortisBC customer operational and investment decisions.

For short term customer operational decisions, the Panel agrees with BCPSO and FortisBC that there is a short term surplus in the electricity market at the moment and wholesale prices are expected to be significantly below the proposed Tier 2 energy rate of 9.223¢/kWh. While the Panel does not consider that a rate which over-signals incremental costs at the margin is necessarily inefficient (customers may not over-consume electricity as a result), it does indicate that, at least in the short term, any benefit of introducing the proposed Stepped Rate to improve customer operational decisions would likely be significantly reduced.

For longer-term customer investment decisions, the Panel is aware that customers may make inefficient investment decisions in response to the existing Flat Rate. However, these concerns are mitigated by FortisBC only having four customers who make up less than 7 percent of FortisBC's total load on the Large Commercial Service Transmission Rate, and by the alternative available to FortisBC of addressing any identified problems through DSM programs.

In response to Celgar's argument that the BC Hydro RS 1823 sends a conservation price signal to its customers the Panel notes that BC Hydro has 135 customers who make up 25 percent of BC Hydro's total load. As a result of the larger number of customers it is much more probable that BC Hydro's pool of customers, as a whole, will achieve conservation benefits. Furthermore, given the larger percentage of total load that BC Hydro's Transmission customers represent those benefits, relatively, will be significantly greater than in the FortisBC service area.

The Panel accepts FortisBC's position that that there is no "problem" as customers have not indicated any desire for the Stepped Rate nor have they indicated that a stepped rate structure would in fact result in positive behavioural changes.

The Panel does not disagree with FortisBC that the proposed Stepped Rate ultimately is not inherently less stable than the existing Flat Rate; however, the Panel notes that any change in rate design naturally results in some initial increase in rate instability. As such, the Panel does not see the need to change an existing rate designs unless there is a clear need to do so.

In conclusion, the Panel finds that there is a lack of evidence as to whether the introduction of stepped rates will result in a net improvement in efficiency of customer investment and operational decisions in BC. The Panel could not identify any efficiency benefits of the Stepped Rate at this time. The Panel determines that FortisBC should ensure sufficient focus is given to identifying and addressing DSM opportunities for its Industrial customers as a way of achieving efficiencies benefits. The Panel notes that the FortisBC DSM program is currently being actively discussed in the FortisBC 2014-2018 Revenue Requirements process that is currently underway.

2.4.2 Impact on Rates and Cost Shifting

FortisBC is concerned that any conservation that might occur as a result of stepped rates can have a negative impact on customer rates in general. FortisBC summarizes these concerns as follows.

> "…FBC notes that in the current environment, any conservation by the industrial customers that decreases kWh sales will place an upward pressure on rates generally and that the administrative costs will simply add to the lost margin from the sales.

> When the retail price is high compared to the cost of supply, as it is currently, each kWh of conservation achieved by the customer places an upward pressure on rates. In this case, from the perspective of other customers conservation does not lead to positive result. In the opinion of the Company, a stepped rate may be appropriate when the conservation may lead to rate relief, but current circumstances do not support such a change. The appropriate time to review the potential effectiveness of a stepped rate would be during the preparation of the Company's next resource plan - expected to be filed in 2016."
>
> (FortisBC Final Submission, para. 25, Footnotes omitted)

FortisBC further submits that, in the short term, any resultant upward pressure on rates would have an impact on the rates of other customer classes, as occurred with the introduction of transmission stepped rates by BC Hydro. FortisBC also submits this situation would persist until such a time as a future COSA was performed. The new COSA could lead to rebalancing of rates among the classes, potentially eroding any benefits transmission customers may have achieved. (FortisBC Final Submission, p. 6)

BCPSO explains this cost shifting is taking place in part because the revenue projections for the Stepped Rate RS 34 will be based on forecast load at RS 36 Flat Rates. However, RS 34 rates are only able to recover the same forecast revenues when customers' forecast loads are equal to 100 percent of their CBL. To the extent conservation occurs, there will be a revenue shortfall to be recovered from all other customers until such time as a new COSA is undertaken. BCPSO submits that this cost shift is inconsistent with the expectation that rates will be fair and provides a further reason to reconsider whether the introduction of stepped rates is appropriate at this time. (BCPSO Final Submission, p. 5)

Commission Determination

In order to determine whether cost shifting between customer classes results in a fairness concern, the Panel has looked to the DSM Regulations for guidance. Section 4 (6) of the Regulations prevents the Commission from using a Rate Impact Measure test result (which determines if the measure results in cost shifting from participants to non-participants) to determine that a measure is not cost-effective.

The Panel therefore considers that rates which recover their allocated costs (within a reasonable range) cannot be considered unfair on the basis that they have encouraged customers within that class to use less electricity and, as a consequence, have reduced the level of costs allocated to that class. **As a result, the Panel determines that the proposed Stepped Rate is not unfair from a cost causation perspective.** However, the Panel also notes that fairness concerns have not been raised regarding the existing Flat Rate. **In summary, the Panel finds that neither the existing Flat Rate nor the Stepped Rate raise fairness concerns.**

2.4.3 An Increase in Cost, Complexity and Process

FortisBC submits that there will be an administrative and cost burden for both the Company and the affected customers associated with the introduction of stepped rates and does not support imposing these costs. FortisBC explains the costs are related to:

(i) Initial setting, and on-going review of CBLs;

(ii) Preparation of filing CBL documentation with the Commission;

(iii) On-going manual preparation of complex billing arrangements; and

(iv) Customer monitoring of cumulative annual consumption.

(FortisBC Final Submission, p. 6)

Commission Panel Discussion

The Panel agrees with FortisBC that the stepped rate design will result in an increase in cost, complexity, and process compared to the existing Flat Rate. However, given the small number of customers proposed to be subject to the Stepped Rate, the Panel will give these concerns little weight in the overall determination.

2.5 Commission Summary Determination on Stepped Rates

The Panel considers that before making any changes to previously approved rate design, the Panel should be satisfied that greater efficiencies or cost savings would accrue to the benefit of ratepayers overall, or that the existing rate is now outside of fairness norms from a cost causation perspective. The Panel should also be satisfied before making any changes to previously approved rate design that the magnitude of the changes to the affected parties are acceptable and that benefits in the broad public interest would result.

The Panel acknowledges that FortisBC filed the Application to comply with a prior Commission directive. The specific goal of that directive was to support conservation. The Panel notes BCPSO's concern that FortisBC's Tier 2 price does not reflect FortisBC's current long-run marginal cost of power and is predicated simply on achieving an inclining rate structure that will incent customers to use less electricity. The Panel declines to rule on FortisBC's long-run marginal cost estimate, as this is best addressed in FortisBC's Performance Based Ratemaking (PBR) 2014-2018 Application. However, the Panel is concerned about making significant rate design changes while this uncertainty exists.

The Panel has already accepted that there is no 'problem', as customers have not indicated any desire for stepped rates nor have they indicated that a stepped rate structure would in fact result in positive behavioural changes. Finally, FortisBC, as the applicant, believes that stepped rates should not be mandated at this time.

The Panel agrees with FortisBC and BCPSO that the proposed Stepped Rate should not be mandated at this time. Accordingly, FortisBC's request to open RS 34 and the attached CBL Guidelines and to open RS 36 is denied.

The Panel also accepts FortisBC's withdrawal of it request to close the existing RS 31 Flat Rate.

The Commission Panel determines that the next appropriate time to review the potential effectiveness of a stepped rate and the appropriate basis for determining FortisBC's LRMC should be in conjunction with FortisBC's next Resource Plan expected to be filed in 2016.

Pursuant to Order G-12-14 the review of the application of Stepped Rates to customers with self-generation facilities was suspended. However, as the Commission has not approved a Stepped Rate for the transmission voltage customer's class any application of the unique elements of such a rate to self-generating customers within this class is no longer relevant as these customers will not have a stepped rate. As such, **the Panel determines that there is no longer a need to consider the application of a Stepped Rate for customers with self-generation facilities.**

3.0 THE STAND-BY RATE

3.1 Background and Context for the FortisBC Stand-by Rate

The key party that led to FortisBC's filing of the Stand-by Rate is Celgar. Celgar is a customer of FortisBC and operates a pulp mill at Castlegar, B.C. FortisBC and its predecessor companies have served the electricity needs of Celgar and its predecessors since 1959 (BC Hydro RS 3808 Amendment, Exhibit C2-10). The Celgar mill has a total load of 46.5 MVA and under most circumstances this load is satisfied by Celgar's 52 MW turbo generator. The Celgar pulp mill generates the steam it uses for its operations, including electricity generation, by burning wood waste and black liquor, a by-product of the pulp-making process.

From time to time, the turbo generator may be unavailable due to maintenance shutdowns or equipment failures. The pulp mill can operate independently of the turbo generator and therefore during these times Celgar needs a back-up source of power. (Celgar 2011 Complaint to BCUC, Exhibit B1-2, Appendix A)

More recently Celgar installed a second generator which became operational in September 2010. The newer 48 MW condensing turbine generator is now generating green electricity predominantly for use in the BC Hydro power grid by way of Celgar and BC Hydro entering into an Electricity Purchase Agreement under the 2008 Bioenergy Call.

In order to provide the reader with a background and context for the Stand-by Rate portion of the Application, this section gives an overview of the relevant regulatory rulings and the history of the rates charged to Celgar.

The following table summarizes the rate schedule and demand levels for Celgar between 2005 and the present.

Table 3 Summary of Rate Schedule and Demand Levels for Celgar between 2005 and the present

Date	Celgar Rate Schedule
February 15, 2005 to September 31, 2006	**Rate Schedule 31 and 2000 GSA** The 2000 GSA stipulated a contract demand of 16 MVA. Any excess of the 16 MVA contract demand provided on a reasonable efforts basis. All actual costs for supply above 16 MVA are paid by Celgar if FortisBC is forced to acquire added resources.
October 1, 2006 to January 1, 2011	**Rate Schedule 33 and a 2006 Draft GSA** The 2006 Draft GSA stipulated firm capacity of 10 MVA during the day and 25 MVA during the night and a Demand Limit of 40 MVA with no additional Demand charges for energy over the firm capacity.
January 2, 2011 to Present	**Rate Schedule 31 with no applicable GSA** (the 2006 GSA was deemed invalid by G-188-11) on an interim and refundable basis and ending when the Commission approves the new rate for Celgar that excludes BC Hydro RS 3808 Power from FortisBC's resource stack, and/or an Agreement forwarded by the parties.

3.1.1 Celgar – Pre 2006

On February 15, 2005, Celgar assumed and became party to a general service power agreement with FortisBC dated December 20, 2000 (2000 GSA) that had an Electricity Supply Brokerage Agreement (2000 BA) attached to it that formed part of the 2000 GSA.

The 2000 GSA provided that charges for service would be calculated in accordance with RS 31 with a contract demand of 16 MVA. In the event of a failure of the turbo generator, any requirement in excess of the 16 MVA contract demand was to be provided by FortisBC on a reasonable efforts basis as promptly as possible. In the case where FortisBC was forced to acquire added resource, Celgar was required to pay all actual costs for supply above 16 MVA.

There was also a provision for Demand Charges if stand-by supply occurred at the time of FortisBC's annual system peak and increased FortisBC's demand related charges under BC Hydro's RS 3808.

3.1.2 Celgar - 2006

In 2006 Celgar stopped taking service under RS 31 and the 2000 GSA. On October 1, 2006, Celgar started taking service under RS 33, which is a TOU Rate, pursuant to the terms of a new draft GSA and BA (2006 Draft GSA and BA) with FortisBC; however, the 2006 draft was never signed. (2009 RDA, FortisBC Final Argument dated June 30, 2010)

In the Draft 2006 GSA the parties agree that the 2006 Draft GSA replaced the previous 2000 GSA. The 2006 Draft GSA stipulated that FortisBC make available the firm capacity reservation of 10 MVA during the day and 25 MVA during the night. Further, it stated that the customer shall not exceed the demand limit of 40 MVA unless otherwise agreed in writing.

The Draft 2006 BA attached and the 2006 Draft GSA addressed the issue of back-up power required by Celgar due to the unavailability of its own turbo generator as follows:

> "Since the pulp mill can operate independently of the turbo generator, the Customer would like a backup source of power above the firm supply levels of 10 MVA between 8:00 am and 10:00 pm and 25 MVA between 10:00 pm and 8:00 am. If FortisBC was required to provide this backup by contract purchase from B.C. Hydro, the Customer could incur excessive costs for relatively minimal power consumption as a result of capacity charges imposed under the BC Hydro rate of supply for FortisBC. The intent of this electricity supply brokerage agreement is that should the customer's requirements exceed the Firm Capacity reservation, described above, then the customer shall pay the equivalent of Rate Schedule 33 as more fully described below." [3]

Celgar and FortisBC continued negotiations towards a mutually agreeable GSA. In 2008 a second draft agreement was reached but withdrawn before its execution by FortisBC due to the Commission's Decision by Order G-48-09 that approved BC Hydro's amendment to section 2.1 of Rate Schedule 3808. As a result, Celgar and FortisBC continued to operate largely under the terms of the unsigned Draft 2006 GSA and BA.

3.1.3 2009 - FortisBC Rate Design and Cost of Service Analysis Application

On October 30, 2009, FortisBC filed the "FortisBC 2009 Rate Design and Cost of Service Analysis Application" (2009 RDA) which started a sequence of regulatory proceedings that led to FortisBC filing for approval of the Stand-by Rate.

In the 2009 RDA Decision issued on October 19, 2010, the Commission determined that under the current circumstances Celgar was ineligible to take service under RS 33 and directed FortisBC to

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[3] Agreement dated October 1, 2006 between Zellstoff Celgar Limited Partnership (the Customer) and FortisBC Inc. (FortisBC); FortisBC response to BCUC IR-2, Appendix A34.7 in the FortisBC 2009 Rate Design and Cost of Service

provide Celgar service under RS 31 effective January 2, 2011. This resulted in Celgar and FortisBC operating solely under the terms of RS 31 with no GSA and BA.

The 2009 RDA Decision provided the following key reasons:

- There is no current signed GSA as stipulated by RS 33. The last signed GSA was the 2000 GSA but it referenced RS 31 and therefore was not applicable to RS 33; and
- FortisBC failed to explain how the current low load factor could qualify as "satisfactory" as stipulated by RS 33. (2009 RDA Decision, p. 67)

In regards to the second point, the COSA recommendations highlighted Celgar's situation on RS 33 as compared to other industrial transmission customers of FortisBC on RS 31. The revenue-to-cost (R/C) ratios for Celgar (the only customer on RS 33) were in the 22 percent to 25 percent range, which was very low compared to RS 31 customers whose R/C ratio exceeded 100 percent. The R/C ratio for RS 33 was low largely due to significant under collection of wires-related charges (2009 RDA, Exhibit B-3-4, Celgar 1.24.0). According to this, Celgar was not paying its fair share of transmission costs while being on RS 33. Celgar's self-generation allowed it to avoid the on-peak energy periods most of the time and, therefore, avoid most of the transmission costs. It appears that either the pricing of the TOU Rate or the load was causing the outcome.

The Commission further stated on page 67 of the RDA Decision: "Based on the evidence and determinations related to Celgar…the Commission Panel also recommends that FortisBC and Celgar reconsider the options available for designing a practical and workable rate schedule for Celgar. For instance, a stand-by rate similar to that offered by BC Hydro might still be an option..."

In mid-December 2010, FortisBC and Celgar exchanged drafts of a GSA that was intended to be effective January 2011 (Draft 2010 GSA). The initial draft of the agreement was prepared by FortisBC and had a draft BA appended to it (Draft 2010 BA). The main operating provisions of the Draft BA were, in all material respects, identical to those of the 2000 BA, with revisions essentially limited to the updating of the contract demand to 8 MVA.

3.1.4 2010 - Celgar Application for Reconsideration

On December 3, 2010, Celgar applied for a reconsideration of the 2009 RDA Decision. The Commission denied the request by Order G-3-11, dated 12, 2011, as it did not meet the Commission's threshold test for reconsideration. The Commission reminded the parties that it had urged FortisBC and Celgar to find a negotiated solution and concluded that reconsideration was premature as the outcome of negotiations was yet unknown. However, the Commission suggested that Celgar's recourse should be more appropriately addressed by way of a complaint, in the event that the parties cannot reach an agreement. (Celgar Reconsideration Decision, Order G-3-11, p. 11)

3.1.5 2011 - Celgar Complaint

On March 25, 2011, Celgar filed "A Complaint Regarding the Failure of FortisBC and Celgar to Complete a General Service Agreement and FortisBC's Application of RS 31 Demand Charges," (Celgar Complaint) which in turn resulted in Order G-188-11 dated November 14, 2011. The complaint was regarding FortisBC's application of RS 31 Demand Charges in calculating Celgar's invoices subsequent to January 2, 2011.

Regarding whether Celgar and FortisBC can be said to be operating under the terms of an unsigned agreement or "prior arrangements," the G-188-11 Decision noted that the unsigned 2006 agreement was specific to RS 33. The Commission determined that the terms of the unsigned 2006 Agreement did not apply to RS 31 and therefore there was no pre-existing agreement in effect that modified the billings to Celgar under RS 31 after January 2, 2011 (Order G-188-11, Decision, pp. 10-11).

By way of Order G-188-11 the Commission also directed FortisBC to bill Celgar in accordance with RS 31 on an interim and refundable basis, beginning March 25, 2011 and ending when the Commission approves the new rate for Celgar that excludes BC Hydro RS 3808 Power from FortisBC's resource stack, and/or an Agreement forwarded by the parties. Any differences between the interim rate and that ultimately approved by the Commission are subject to refund/recovery.

The Commission also noted in that Decision that FortisBC had changed its system planning criteria in 2010 to be based on Celgar's actual historical demand, rather than on the 16 MVA that was the contract demand in the 2000 GSA. FortisBC "… commenced using 40 MW for the Celgar load in recognition of the fact that many times in previous years the actual recorded peak demand at the facility was much greater than the 16 MW value which had been used previously." The Commission emphasized that FortisBC should not significantly alter the amount of firm service used in system planning (which in turn affects COSA) without consulting the customer affected. The Commission Panel considered that, if the two transmission lines serving Celgar are lightly loaded, the outcome of its system planning will likely be unaffected by whether 16 MVA or actual historical demand were used as the load remains below capacity. (Order G-188-11, Decision, p. 46)

Order G-188-11 also directed FortisBC to submit an application by May 31, 2012 for a stand-by rate designed to address Celgar's circumstances and also to address how the stand-by rate takes account of its system planning criteria. The Commission contemplated that the stand-by rate would be offered in conjunction with RS 31 and that the Demand Charge of RS 31 will continue to apply to the billing demand as determined by the stand-by rate. In this regard, the Commission referenced BC Hydro's RS 1880 as one example of a stand-by rate whose application appropriately recovers the costs of providing service in BC Hydro's service area. The Commission concluded that the stand-by rate would be the means through which FortisBC would recover its costs associated with the infrastructure used to provide service to Celgar. The Commission made no determination regarding the level of firm versus non-firm service, leaving it to the parties to negotiate.
(Order G-188-11, Decision, pp. 45-46)

3.2 Applicability of Stand-by Rates

3.2.1 Transmission Voltage Customers

The Application before the Commission titled "FortisBC Inc. Application for Stepped and Stand-by Rates for Transmission Voltage Customers" (emphasis added) addresses Transmission customers. However, it appears that the Stand-by Rate filed with the Commission is intended to also apply to Distribution customers.

FortisBC submits the Stand-by Rate (i) is intended to be suitable for all customers, current and future, with self-generation and (ii) is meant to form part of an overall offering when used in conjunction with an underlying Large Commercial Service – Transmission Rate (FortisBC Reply, p. 1).

The Draft Tariff for RS 37– Stand-by Service does not specify that the Stand-by Rate applies only to Transmission Voltage Customers. In fact page 8-8, Special Provisions 1, states: "Underlying Rate – A Customer taking service under this rate must also be contracted to receive service under one of the Company's Commercial rates that incorporates a Demand Charge." (emphasis added) (FortisBC Final Submission, Appendix A, pp. 6-8) The Definition of Commercial customers[4] in FortisBC's Electric tariff included Distribution voltage customers as well as transmission voltage customers.

FortisBC has stated that "A stand-by rate for this rate class [Distribution] could be developed but it would need to be different from the rate proposed in this application as components such as the loss rate and wheeling charges would be different." (Exhibit B-4, BCUC 1.35.1)

Commission Determination

The Commission Panel determines that the Stand-by Rate will be available to Transmission Customers only. FortisBC is directed to update the language in Rate Schedule 37, Special Provision 1, to clearly indicate that the Tariff is only available to Transmission Customers.

The Panel understands that some of the terms of the rate may very well be appropriate for other Commercial customers; however, this was not the subject of the Application currently before the Commission and was not considered by the Panel. For further clarity, a determination on Stand-by Rates for Distribution customers is not within the scope of review of this Application.

Any final approved Stand-by Rate is intended to be suitable for all customers, current and future, with self-generation taking service at Transmission Voltage.

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[4] See Appendix B for a list of what is included in FortisBC's Commercial customers' class.

3.2.2 Retroactive Application to Celgar

In its Reasons for Decision to Order G-202-12, the Commission stated that based on the load behaviour filed by Celgar, stand-by service after March 25, 2011 (interim period) may be appropriate. The Panel further stated that without further information on Celgar's load behaviour after this period, it cannot make any further determination.

On February 3, 2014, by Order G-12-14 in relation to the Application, the Commission determined that it would not be reviewing the retroactive application of rates to Celgar at this time and would address the issue in due course. **As such the Panel makes no determination at this time whether or not a final approved Stand-by Rate will be appropriate for service between March 25, 2011 and the effective date of Rate Schedule 37.**

The Panel will address whether it is appropriate to apply the Stand-by Rate retroactively to Celgar when it reviews the retroactive application of rates for Celgar.

3.2.3 Need for Stand-by Rates and the Divergent View in their Design

A stand-by rate is a rate paid by a customer whose electric requirements are served in part by its own self-generation and in part by services delivered from the utility. Such customers are sometimes referred to as partial requirements service customers. Stand-by tariffs establish the rates, terms, and conditions of service by which the self-generating customer can secure service under certain circumstances.

Customers with self-generation pay stand-by charges to ensure that, in the event of either a planned or unplanned outage of their on-site generator, the customer has the ability to purchase power to replace what would normally be self-generated. The idea of a stand-by rate is that the utility has to be ready in a 'stand-by' mode to deliver the energy whenever the self-generating customer needs it.

Stand-by rates have often been contentious. The following offers a concise overview of the long-standing stand-by rate debate.

> "The instillation of DG [distributed generation or self-generation] reduces utility power sales revenue, may cause the utility to incur costs for power purchases or losses on power sales for power expected to be used by DG customer, and reduces rate revenue from non-power related charges in rates (such as "wires" charges…), and so on. These costs would shift to other non-DC customers if the utility did not recover them specifically from the self-generating customer. This constitutes a subsidy of DC customers by other ratepayers. By the same token, DG systems provide potential benefits to the utility and, by extension other ratepayers. Accordingly, DG customers feel they are subsidizing the utility and other ratepayers."
>
> "Most parties agree that there should be a standby rate structure based on cost causation principles, meaning the rate should allow the utilities to recover all costs that the distributed generation [self-generation] customers impose on the system but nothing more. There is considerable disagreement, however, as to what costs and benefits the distributed generation project actually imposes on the system. Also, the parties dispute how and to what extent such costs and benefits should be incorporated into the standby rate structure. … Utility providers and distributed generation advocates vastly disagree over the factors that should be included in the standby rates."[5]

Advocates for self-generation seek minimal stand-by rates based on the premise that self-generation provides benefits in the form of deferred or permanent reduction in the need for utility-provided generation, transmission, and distribution capacity.

Utilities, on the other hand, argue that the theoretical benefits for self-generation are insubstantial if located in an unsuitable area or operate erratically, and low stand-by rates can result in self-generating customers avoiding infrastructure costs associated with back-up generation and wires services.

This contentious issue was addressed by the Ontario Energy Board. On page 30 of its 2000 Decision on a rate design application by Ontario Hydro (RP-1999-0044) it states:

> "Key aspects of the debate are the positions taken on the responsibility for sunk costs and the user pay principle. The diametrically opposed interpretation of the user pay principle in this case proved of little value to the Board in resolving the issue. To the proponents of gross load billing, the user pay principle means that the sunk costs of the transmission system must continue to be shared by those for

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[5] http://www.michigan.gov/documents/energy/NRRI_Electric_Standby_Rates_419831_7.pdf

> whom the transmission capacity was built. For the proponents of net load billing, the user pay principle dictates that a customer should only pay for the services that the customer uses."

The Panel will bear in mind the Stand-by Rate debate in its deliberations.

3.3 Evaluation of the Stand-By Rate (Rate Schedule 37)

In the Application, FortisBC is applying for the approval of RS 37 Stand-by Service Rate (Stand-by Rate).

The following table summarizes FortisBC's proposed Stand-by Rate including a reference to the applicable section of the Decision where it is addressed.

Table 4 Summary of the Proposed Stand-by Rate and Relevant Charges in RS 31

	RS 37 – Stand-by Rate	**Decision Section**
Availability – Replacement Power	In any hour replacement (Stand-by) power will be available to a maximum of the difference between the power normally supplied by the customer own resources and the customer generation in that hour	Section 3.8.3
Notification Fee	$200 per use	Section 3.4
Energy Charge	Energy charge for replacement power is determined by:	Section 3.5
	a. The hourly Dow Jones Mid-Columbia (Mid-C) per kWh price for the hour in which the stand-by power is taken by the Customer (not to be lower than $0).	Section 3.5.1
	b. System Losses as per Rate Schedule 109 (currently 6.08 cents)	Section 3.5.2
	c. Hourly Transmission Charges per Rate Schedule 102 plus $0.0040 per kWh	Section 3.5.3
	d. Administrative premium of 10 percent	Section 3.5.4
Restrictions • Maintenance (pre-scheduled) Service	Scheduled no less than 30 days prior to its use. Limited to no more than six occurrences and not more than 60 days per year.	Section 3.6
• Back-up (unscheduled) Service	Limited to two occurrences per billing period. Customer must notify FortisBC within 30 minutes of taking this service	Section 3.6

	RS 37 – Stand-by Rate	Decision Section
• Demand Charges	A customer taking service under this rate must also be contracted to receive service under one of the Company's Commercial rates that incorporate a Demand Charge Other than as described in Special Condition #2, the maximum demand recorded during the period of Stand-by service will not be used in the calculation of Billing Demand in the underlying rate schedule	Section 3.4.1 Section 3.8.4.2
• Definition of Contract Demand (Special Condition #2)	Customer's maximum potential Demand. A customer may establish its Contract Demand in its application for service hereunder or at any time thereafter. At any time, including when the customer may be taking service under RS 37, if monthly Demand exceeds the Contract Demand, the monthly Demand will become the Contract Demand thereafter.	Section 3.8.4.3
	Underlying RS 31 Demand Charges[6]	
• Demand Charges: Power Supply Charge	Based on the underlying rate - $2.41 per kVA of maximum Demand in current billing period (per RS 37, not applicable while taking Stand-by service)	Section 3.7
• Demand Charges: Wire Charge	Based on the underlying rate - $4.29 per kVA of Billing Demand. Billing Demand is defined as the greatest of i. Eighty percent of the Contract Demand ii. The maximum Demand in kVA for the current billing month (per RS 37, not applicable while taking Stand-by service) iii. Eighty percent of the maximum Demand in kVA recorded during the previous eleven month period (per RS 37, not applicable while taking Stand-by service)	Sections 3.8.4.1 and 3.8.4.2

Source: Summarized from FortisBC Final Submission, Appendix A

FortisBC's proposed Stand-by Rate is available as either Maintenance Service or Back-Up Service and is strictly for the continued operation of the customer's facilities at times when the customer owned generation is unavailable and cannot be used by the customer in the fulfillment of any power sales obligations.

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6 In its determination on the Stepped Rates, the Panel did not approve RS 36 and directed for RS 31 to remain in effect. Therefore, the applicable Demand Charges in the underlying rate are those in RS 31.

The Notification Fee, Energy Charge, Restrictions to its Use, Demand Charges including Availability, will each be evaluated individually.

3.4 Notification Fee

FortisBC proposes a $200 Notification Fee to be assessed on a per use basis which is intended to recover costs associated with the additional work required to administer the complex billing. (Exhibit B-1, p. 36) FortisBC submits that it provides an incentive for a customer to manage and maintain self-generation assets properly (FortisBC Final Submission, para. 56).

The proposed Notification Fee has not been the subject of much debate although Celgar submits that FortisBC did not provide justification for the Notification Fee and it should not be approved (Celgar Final Submission, para. 101).

BCPSO submitted that "The inclusion of a Notification charge is also reasonable as they recognize that additional work will be required by FortisBC staff to support the provision of Stand-By Service." (BCPSO Final Submission, para. 34)

Commission Determination

The Panel recognizes the requirement for FortisBC to be compensated for its additional costs to administer the billing of RS 37. The Panel considered requesting FortisBC to provide further justification of the costs in its next Rate Design and COSA Application but in the end determined that the amount was relatively insignificant to the overall bill and that the additional work required by FortisBC to do this would provide little cost benefit.

The Panel approves a $200 per occurrence Notification Fee as it provides a reasonable and sufficient estimate for the recovery of the administrative effort related to billing under RS 37.

3.5 Energy Charge

FortisBC proposes an energy charge for energy taken during the period for which stand-by service is requested based upon the Mid-Columbia (Mid-C) market price. The formula proposed is the hourly Dow Jones Mid-C per kWh price for the hour in which the stand-by power is taken by the Customer, adjusted for system losses and transmission charges. FortisBC also proposes the inclusion of a 10 percent administrative premium. (FortisBC Final Submission, p. 12)

FortisBC proposes the hourly charge to be calculated as follows:

*[(Standby Energy x (1 + loss rate %)) x (Mid-C + RS 102 Rate + 0.0040)] * 1.10*

3.5.1 Hourly Rate (Mid-C)

FortisBC states that because stand-by power is required for short term, unplanned periods, and only on an ad hoc basis, the most appropriate basis for pricing such energy is with reference to a market based rate (Exhibit B-1, pp. 36-40). FortisBC explained that customers who are able to leave utility service through the use of self-generation can also arrange for their own stand-by service from the market (Exhibit B-15, BCUC 1.11.1).

FortisBC noted that because RS 37 provides a firm energy service, there is a general risk that for any given hour it may not be able to access Mid-C markets. However, FortisBC considers this would be a relatively rare occurrence, and the risk is no greater or lower than that faced by all FortisBC customers served on rate schedules that make no distinction between firm and non-firm energy. FortisBC further noted that inability to access Mid-C markets most recently occurred in the later part of October 2013 and lasted for about a week; however, during that time, supplies from Powerex remained available. (Exhibit B-15, BCUC 1.11.2)

Commission Determination

The use of a Mid-C based index to price stand-by energy was largely uncontested, although Celgar referenced the hourly Platts, McGraw Hill Financial (Platts) Mid-C index instead of the Dow Jones index referenced by FortisBC (Celgar Final Submission, Appendix C).

The Panel considers there is potential for the energy supplied under the stand-by service to be provided by energy marketers in a competitive environment. However, the current energy market may not yet be sufficiently mature to require that FortisBC's self-generating customers use energy marketers to obtain stand-by energy. The Panel agrees that, until such time as there is a workably competitive market for the provision of this service, FortisBC should be required to provide energy under the stand-by service using a market price estimate.

The Panel notes that there is a risk FortisBC may not be able to access Mid-C markets when it is asked to provide stand-by service. This may result in FortisBC paying a higher price for energy than that received under RS 37, or a reduced level of reliability for its customers (including customers taking stand-by service).

Nevertheless, the Panel accepts FortisBC's assurance that this is expected to be a relatively rare occurrence and notes that FortisBC's proposed RS 37 includes a 10 percent administrative premium which would act to mitigate the financial risk. The Panel also notes that, should the risk of material price separation between the Mid-C market and the FortisBC localised energy market increase significantly, FortisBC could offer curtailment options to its customers (including stand-by customers) to better tailor the energy prices of its products to customers' reliability preferences.

In regards to the Mid-C index, the Commission, in Order G-214-13, approved a request by BC Hydro to replace references in its Electric Tariff and the Open Access Transmission Tariff to Mid-C indices published by Dow Jones Indices with references to equivalent indices published by Platts. BC Hydro stated in its Application that, effective September 13, 2013, S&P Dow Jones Indices ceased calculating the Dow Jones U.S. electricity Indices.

As such, the Panel approves FortisBC's proposal of using the hourly Mid-C per kWh price for the hour in which the stand-by power is taken by the customer (not to be lower than $0) as the starting point for a market price proxy. However, references to the Dow Jones (Mid-C) electricity price index should be replaced with the equivalent index published by Platts, as the Dow Jones Mid-C index is no longer published.

3.5.2 System Loss Rate

FortisBC proposes that the Energy Charge include an adder for System Losses which is currently 6.08 percent as per RS 109. No Interveners took exception with this adder.

Commission Determination

The Commission approves the System Loss Rate Adder as proposed by FortisBC and the use of FortisBC's RS 109 to determine the charge as they are both reasonable and no parties have taken exception to it.

3.5.3 Hourly Transmission Charge

FortisBC proposes that the Energy Charge include an adder for (i) Hourly Transmission Charges (as per RS 102) for wheeling of electricity on FortisBC's network, and (ii) Hourly Transmission Charges from the Mid-C hub to the border of $0.0040/kWh (Exhibit B-1, p. 36).

With the exception of Celgar, no Interveners took exception with either of the adders. Celgar did not include the $0.0040/kWh Hourly Transmission Charges from the Mid-C hub to the border in its proposed RS 37 (Celgar Final Submission, Appendix C). Celgar also argued that the RS 102 Hourly Transmission Charge collected as part of the energy charge, alone, would fully compensate FortisBC for the use of its network (Exhibit C2-6, p. 18).

Commission Determination

The Panel agrees with Celgar that FortisBC's network related costs for the provision of stand-by service are recovered through (i) the contract Demand Charge of RS 31, and (ii) the RS 102 Hourly Transmission Charges. Given the low load factor of stand-by customers, the Panel considers that network costs related to the provision of stand-by service are more appropriately recovered through the Wires Demand Charge than the Energy Charges. The Panel further considers that the transparency and simplicity of RS 37 will be enhanced if FortisBC's network related costs are not also recovered through the RS 102 Hourly Transmission Charges.

The Panel therefore rejects the inclusion of the RS 102 Hourly Transmission Charges in RS 37. The Panel will address the appropriate level of network related Demand Charges for stand-by service separately in Section 3.8.

The Panel does, however, consider that RS 37 should approximate the cost to a stand-by customer purchasing stand-by energy from the market, which includes the cost of wheeling the energy from the Mid-C hub to the border. **The Panel therefore approves the inclusion of the Hourly Transmission Charges from the Mid-C hub to the border of $0.0040/kWh.**

3.5.4 Administrative Premium

FortisBC proposes that the Energy Charge include an administrative adder of 10 percent (Exhibit B-1, p. 36). Mr. Saleba, on behalf of FortisBC, considers that a 10 percent administrative adder applied to a market purchase is standard practice and that FortisBC does face additional costs with managing the power supply required during self-generating customer outages. (FortisBC Final Submission, p. 13)

Celgar argues that FortisBC has not provided any cost-causation evidence to support this administrative premium and that in the absence of evidence relevant to the application of cost causation principles, the administrative premium is excessive and should not be approved. (Celgar Final Submission, para. 100)

BCPSO concludes the inclusion of an administrative mark-up is also reasonable as it recognizes that additional work will be required by FortisBC staff to support the provision of stand-by service. (BCPSO Final Submission, para. 34)

Commission Determination

The Panel finds that FortisBC's administration costs of obtaining the energy related to the provision of stand-by service should be recovered in the Administrative Premium. Further, the Panel has previously noted that FortisBC faces a risk that for any given hour FortisBC may not be able to access Mid-C markets and may have to purchase energy from a more expensive source. The Panel has also previously noted that there is potential for the energy supplied under RS 37 to be provided by energy marketers in a competitive environment.

For these reasons the Panel considers that a 10 percent premium is reasonable in that it both protects FortisBC's ratepayers from pricing risk and promotes innovation over the longer term by encouraging energy marketers to compete with FortisBC in offering this service.

The Panel approves the inclusion of an energy price premium of 10 percent to recover any additional costs with managing the power supply required during self-generating customer outages, protect FortisBC from pricing risk, and encourage competition in the provision of stand-by energy supply.

3.6 Restrictions

The FortisBC proposed RS 37 contains a limitation on the number of times in a billing period that a customer may call upon stand-by service as shown below.

Maintenance service is provided during utility approved scheduled outages for maintenance or downtime of the on-site generation.

> The Customer must schedule maintenance power with FortisBC not less than 30 days prior to its use and is limited to not more than sixty (60) total days during a calendar year.

Back-up service is an on-demand service required during unscheduled outages of the self-generation, ensuring that utility capacity is available for a customer to call on to meet the customer's load.

> Back-up service is limited two occurrences per billing period and the Customer must notify FortisBC within 30 minutes of taking Back-up service. If the customer fails to provide the required notice, service will be charged under the terms of the rate under which the customer is normally supplied.

In the opinion of FortisBC, the limitation on the use of stand-by service is appropriate and required in order to differentiate stand-by customers from any other similar customer who must bear the full cost to provide service (Exhibit B-6, Celgar 1.28.2).

BCPSO agrees with FortisBC on the appropriateness of some limitation on the use of stand-by service, and considers the limitations proposed as reasonable and consistent with the premise that the customer's generators are generally reliable. (BCPSO Final Submission, p. 8)

Celgar, however, argued the limitations on the use of stand-by or back-up power are not justified. Celgar considers that, in order for these limitations to be justified, FortisBC would need to present solid evidence that exceeding these limitations would cause the Company to incur additional costs for which the charges under the rate schedule do not provide fair compensation (Exhibit C2-6, p. 19).

FortisBC submits that the rationale for such a limitation is articulated by Mr. Saleba in his evidence which says in part, "In my experience a total of 24 outages per year is much higher than what would be needed for a typical generating plant of this type, and should therefore not place an undue burden on Celgar if it is adequately maintaining and operating its plant." (FortisBC Final Submission, para. 64) FortisBC also stated that it assumed that any period of load on the FortisBC system that was separated by an instance of Celgar having generation output was a separate stand-by (back-up) period. (Exhibit B-9, BCPSO 2.25.4)

Celgar argues that FortisBC's assumption, which counts every transition between export and load as a separate event, is incorrect and states that in reality transitions occurring during a process ramp-up, which are associated with the initial stand-by (back-up) event, should be considered a single event rather than multiple events.

The following table identifies each separate occurrence of Celgar's load on the FortisBC system between March 2011 and March 2013.

Table 5 Celgar's Occurrence of Load on the FortisBC System

2011		2012		2013	
Month	Occurrences	Month	Occurrences	Month	Occurrences
March	1	January	12	January	1
April	1	February	12	February	2
May	2	March	2	March	6
June	21	April	0		
July	16	May	3		
August	4	June	8		
September	13	July	7		
October	2	August	4		
November	0	September	9		
December	7	October	11		
		November	10		
		December	7		

Source: Exhibit B-9, BCPSO 2.25.4

Celgar notes that it returns to self-supply as fast as reasonably possible. On occasion, this results in a second or third and sometimes fourth occurrence from the same event. (Exhibit C2-6, p. 5) Celgar also submits that once stand-by (back-up) or maintenance service has been invoked, it should continue until the process or equipment interruption has been fully resolved and not simply when generation has returned to a level that exceeds plant load. (Exhibit C2-11, BCPSO 1.2.1)

Mr. Saleba, for FortisBC, states: "It is not the intention of FortisBC to count the starts and stops during a ramp up period after an outage - the election of the standby period is entirely at the discretion of the customer. Celgar has stated its outages occur on average 1.7 times per month. This is well within the 2 occurrences per month." (Exhibit B-13)

Celgar further submits that consumption within the Contract Demand limit of 8 MW should not be considered a back-up event as the underlying transmission tariff recovers costs based on Contract Demand. (Exhibit C2-11, BCPSO 1.2.1)

Commission Determination

Firstly, the Panel agrees with FortisBC that RS 37 should include usage restrictions to ensure that the type of customer using the Stand-by Rate is consistent with customer type assumed by FortisBC in the pricing of the Stand-by Rate. Usage restrictions should encourage self-generators to efficiently maintain their generation equipment and undertake maintenance during off-peak hours thus ensuring that stand-by service is only used for the reasons for which it is designed. However, the Panel is also mindful that the usage restrictions should not be so narrow as to result in inefficient outcomes for stand-by customers – for example by causing stand-by customers to shut down operations rather than access the stand-by service. Usage restrictions must also take into account the generation characteristics of future potential users of stand-by service, not just Celgar.

Secondly, the Panel agrees with Celgar that, in general, once Back-up or Maintenance service has been invoked, it should continue until the process or equipment interruption has been fully resolved and not simply when generation has returned to a level that exceeds plant load.

Lastly, in regards to Celgar's submission that consumption within the Contract Demand limit of 8 MW should not be considered a back-up event as the underlying transmission tariff recovers costs based on Contract Demand, the Panel will address this in its evaluation of "When Stand-by Service is Initiated" in Section 3.8.4.

However, the Panel does not consider that there is sufficient evidence to determine if the proposed usage restrictions strike the right balance between being overly restrictive or too permissive. The issue is further confused by the lack of clarity regarding (i) when an outage occurrence starts and stops; (ii) what a normal level of outages would be for other generating plants who may wish to use stand-by service in the future; and (iii) what is considered a back-up event.

The Panel is therefore unable to make a determination at this time as to whether the usage restrictions proposed in RS 37 are appropriate without additional information and clarification.

The Panel also notes a typographical error in RS 37 (Sheet 121), where under Part B – Back-up reference is made to 'Special Condition 2' rather than 'Special Condition 3' which needs to be corrected.

3.7 Demand Charges – Power Supply

As a result of the FortisBC 2009 RDA the Demand Charges in RS 31 were broken out into two component parts: a Power Supply Charge and a Wires Charge, each of which will be addressed separately.

Demand Charges – Power Supply

FortisBC states that the Power Supply portion of the Demand Charge is not assessed during periods of stand-by service (FortisBC Final Submission, p. 12).

Celgar states that the proposed rate schedules do not include a provision that would serve to exclude the Power Supply portion of the Demand Charge as suggested by FortisBC.

Celgar further submits that the non-firm characteristics and market based energy pricing associated with Celgar's proposed RS 37 make it inappropriate and unfair for there to be any Demand Charge component associated with the provision or consumption of stand-by service including the Power Supply Demand Charge (Celgar Final Submission, p. 39).

Commission Determination

The Panel agrees with FortisBC's and Celgar's position that the Power Supply Demand Charge should not be assessed during periods of stand-by service due to the market based energy pricing nature associated with the proposed RS 37 Energy Charge.

The Panel has reviewed RS 37 and RS 31 and agrees with Celgar that neither rate explicitly excludes the Power Supply Demand Charge during periods of stand-by service. RS 37 does state that maximum demand recorded during a billing period will not be used in the calculation of Billing Demand during periods of stand-by service (subject to certain conditions); however, the Power Supply Demand Charge in RS 31 is not impacted by Billing Demand.

For further clarity and certainty, the Panel determines that RS 37 must include language that explicitly excludes the Power Supply Demand Charge during periods of stand-by service.

3.8 Demand Charges – Wires

The Wires Demand Charge is the most contentious component of the proposed Stand-by Rate. The 2011 Celgar Complaint filed with the Commission drew attention to Celgar's grievance with FortisBC's application of the demand charges in RS 31 in calculating Celgar's invoices. The divergent view was one of the driving forces in Celgar's rates being made interim. The following highlights the continuing divergent views regarding the proposed RS 37 Wires Demand Charge.

<u>RS 37 Wires Demand Charge Proposed by FortisBC</u>

- RS 37 proposes that during periods of stand-by service the Wires Demand Charge is to be based on the customers underlying rate (RS 31). However, the rate explicitly excludes certain RS 31 ratchets and as a result the Wires Demand Charge during periods of stand-by service is ultimately based on 80 percent of Contract Demand.
- RS 37 proposes that Contract Demand be based on the maximum capacity that a customer uses and is reset each time a customer exceeds its current Contract Demand.
- RS 37 proposes that stand-by service be initiated based on self-generation output capability and not on Contract Demand.

<u>Wires Demand Charge Proposed by Celgar</u>

- During periods of stand-by service there should be no Wires Demand Charge. However, Celgar proposes that a period of stand-by service should only commence once a customer has exceeded its Contract Demand (Celgar Final Submission, para. 29).
- For periods of service less than Contract Demand the Wires Demand Charge should be based on RS 31 including the Wires Demand Charge ratchet as well as the Energy Charge.
- Contract Demand should be based on a customer's requirement for firm capacity and once established should not change.
- Stand-by service is initiated based on Contract Demand. Once a customer exceeds its Contract Demand it is considered to be taking stand-by service.

In summary, Celgar and FortisBC have divergent views regarding:

1) The offering of non-firm (interruptible) service;
2) When stand-by service is initiated (availability of stand-by service); and
3) Establishing and resetting of Contract Demand.

There is further disagreement between Celgar and FortisBC regarding certain aspects of the framework for the evaluation of the Stand-by Rate Design. The Panel will address this issue first, followed by an evaluation of the matters where Celgar and FortisBC have divergent views.

3.8.1 Framework for the Evaluation of the Stand-by Rate Design

3.8.1.1 BC Hydro RS 1880

Celgar believes that unjustified differential treatment would exist if (i) Celgar is allowed to access only firm stand-by service whereas BC Hydro industrial self-generator customers are allowed to access non-firm stand-by service, and/or (ii) Celgar is charged for its service on a completely different basis, applying different rate design principles than industrial customers with self-generation in BC Hydro's service territory. (Exhibit C2-9, BCUC 1.1.2) Celgar suggests that while the stand-by rates for BC Hydro and FortisBC may differ, there should be a rational basis for the difference.

The Commission, on page 33 of its Reasons for Decision on BC Hydro's 2007 Rate Design Application Phases II and III (G-171-07) stated "Discrimination, when applied to rates for utility service, can only be of an 'intra-utility' nature and not 'inter-utility'."

In the Reasons accompanying Order G-110-12 in the matter of An Application by FortisBC Inc. for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan, the Commission said at page 20:

> "FortisBC operates with a different set of supply resources and with a different customer base in terms of geography, population density and the residential/commercial/industrial mix it faces. The Commission Panel has no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro. The Commission Panel believes that FortisBC's responsibility is to provide safe and reliable service in a cost-effective manner consistent with British Columbia's energy objectives. To do so, FortisBC must design and manage its system based on the resources available to it and the needs of its customers. This, at times, may result in rates that are greater than those of BC Hydro and potentially times when they are less."

FortisBC states that it "will not seek to be consistent with BC Hydro in cases where it does not believe that the BC Hydro practice is appropriate for the FortisBC service are[a] or system."

FortisBC further states that the Company has long maintained that the BC Hydro stand-by rate is not a standard stand-by rate that appropriately charges for the service received. FortisBC views consistency as “nice to have”, and will attempt to incorporate it where doing so is not an issue, but where the Company’s views or circumstances require it, will propose rates that best suit FortisBC. (Exhibit B-6, Celgar 1.25.4)

Celgar further states that “BC Hydro recognizes the benefits self-generators provide. It makes available to its industrial customers very significant load displacement and other subsidies, such that it has subsidized the investment in virtually all significant self-generation in its territory, both directly through cash grants and loans, and indirectly. …FortisBC, on the other hand, does not provide any subsidies to self-generators. … Thus, whereas BC Hydro recognizes that self-generation is beneficial, and that the direct costs (investment) and indirect costs (resulting from large demand swings) should be spread across all its ratepayers, FortisBC is proposing that it capture the benefits of Celgar’s self-generation for its other customers, but that it stick Celgar with all the costs.” (Exhibit C2-9, BCUC 1.2.1)

Commission Panel Discussion

The Panel understands the benefits of FortisBC designing stand-by rates in its jurisdiction that are as similar as practical for all regulated utilities. However, unless, among other things, the base rates for full service customers are similarly designed it is difficult, if not impossible, to design a similar Stand-by Rate.

The Panel maintains the view that “discrimination, when applied to rates for utility service, can only be of an ‘intra-utility’ nature and not ‘inter-utility’. FortisBC’s Stand-by Rate cannot therefore be considered unfair or discriminatory solely on the basis of a comparison with the stand-by rates offered by BC Hydro.

The Panel agrees with FortisBC’s position that consistency is nice to have, but where FortisBC’s views or circumstances require it, the approved Stand-by Rate must be what best suits the FortisBC service territory.

3.8.1.2 Other Jurisdictions

The Panel could look to other jurisdictions for guidance but tends to agree with FortisBC's position that "there is limited value in examining the stand-by rates of other jurisdictions. There tends to be some commonalities in rate components or approaches between some, however there is also a wide variation in rates that reflect legislative and regulatory requirements as well as the individual operating environments that differ between utilities."

More importantly the Panel agrees with FortisBC that "it is more appropriate to primarily consider its particular circumstances, customers, and operations." (Exhibit B-15, BCUC 1.10.1) The particular circumstances which the Panel considers of particular relevance to the design of the Stand-by Rate are (i) the Single Customer Concern and (ii) Government's Policy on Self-Generation in BC.

3.8.1.3 Single Customer Concern

As noted previously, FortisBC submits that the Stand-by Rate is intended to be suitable for all customers, current and future, with self-generation and is meant to form part of an overall offering when used in conjunction with an underlying Large Commercial Service – Transmission Rate. FortisBC further states that stand-by service should be designed to be properly suited to the FortisBC service area and operating characteristics, apply generally across all eligible customers, and reflect the costs involved in providing the service – including those pertaining to the infrastructure required. (FortisBC Final Submission, p. 9)

However, currently there is only one eligible customer for the proposed RS 37; therefore designing a rate that reflects the costs involved in providing stand-by service to future customers is problematic. If there were several eligible customers in the customer class whose costs were considered in designing the proposed Stand-by Rate there could be an argument that the costs of the group were generally representative of the costs involved in providing stand-by service to future customers. However, given that there is only one customer with unique circumstances, this is a challenge. As such, the Panel strives to evaluate a Stand-by Rate that will apply to future customers; however, it is also aware of the constraints.

3.8.1.4 Government Policy on Self-Generation

The *Clean Energy Act* received Royal Assent on June 3, 2010. It advances 16 specific energy objectives to help achieve British Columbia's energy vision, including new measures to promote electricity efficiency and conservation. Efficiency and conservation objectives are, broadly speaking, to "foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean and renewable resources" and "to reduce waste by encouraging the use of waste heat, biogas, and biomass."

Prior to the introduction of the CEA, the provincial government's emphasis on the promotion of energy efficiency was articulated in both the 2002 and 2007 Energy Plans. Within the 2007 Energy Plan, are two relevant policies: Policy Action #4: Explore with BC utilities new rate structures that encourage energy efficiency and conservation, and Policy Action #21: Ensure clean or renewable electricity generation continues to account for at least 90 percent of total generation.

The 2007 Energy Plan also states: "Government's goal is to encourage a diverse mix of resources that represent a variety of technologies;" and "To close [the] electricity gap will require an innovative electricity industry and the real commitment of all British Columbian's to conservation and energy efficiency." (2007 Energy Plan, pp. 9, 26)

The Celgar pulp mill utilizes wood waste, forest-based biomass and organic material to generate clean Bioenergy. Minister of Energy Bill Bennett is quoted: "I believe that renewable energy like this, its generation and the technology and knowledge around it, is a key to a prosperous future for British Columbia." (BC Hydro News Release, November 12, 2010)

Commission Panel Discussion

The Panel acknowledges that the Government's objective is the promotion of energy conservation and efficiency, including self-generation in the entire Province.

Therefore, the Panel considers that the Stand-by Rate should result in efficient customer investment and consumption decisions – specifically, efficient investment in, and operation of, distributed generation by utility customers and efficient investment in, and operation of, assets required to support the stand-by service by the utility. The Panel also considers that the Stand-by Rate should promote innovation over time. The Panel will be mindful of this in its deliberations.

3.8.2 Offering of Non-Firm (Interruptible) Service

The first matter where Celgar and FortisBC have divergent views is the offering, or rather lack of offering, of non-firm (interruptible) service.

FortisBC argues that certain submissions of Celgar proceed on an apparently different understanding of the intent of the Stand-by Rate. "…namely, its [Celgar's] wish for (1) what it calls "non-firm"/interruptible service." FortisBC goes on to submit that "Whether FortisBC should offer non-firm/interruptible service…are not the subject of this proceeding." (FortisBC Reply, p. 1)

The Panel disagrees with FortisBC's position and considers that the issue of offering interruptible stand-by service is completely within the scope of this Proceeding and finds it is a fundamental issue that requires a Commission Panel determination.

Position of the Parties

Celgar states that "[i]n the past, FortisBC's rate for non-firm service to Celgar was established by means of a brokerage agreement rather than a rate schedule. The brokerage agreements were then attached to a general service agreement that provided for both firm and non-firm service. Past general service agreements were filed with the Commission and approved, just as any other rate would be approved." Celgar further states that it had access to non-firm stand-by service since approximately 1993 when it first invested in self-generation. In summary, Celgar asserts that the 2000 BA made available non-firm stand-by service until approximately 2006. In 2006, for the most part, the parties operated under the unsigned 2006 Draft BA and GSA which continued to provide non-firm stand-by service to Celgar. (Exhibit C2-11, p. 5) Celgar provided several examples of occasions when FortisBC had restricted available power to Celgar (Exhibit C2-9, BCUC 1.9.1).

Celgar goes on to state that "[o]n January 2, 2011, FortisBC proposed a new agreement that would discontinue non-firm service to Celgar. That led to a complaint by Celgar [Celgar Complaint] that ultimately led to the current interim period that is the subject of this proceeding." (Exhibit C2-11,

p. 5) Celgar further stated that “the Commission Panel should consider the precedents established by past approvals of standby service.” (Exhibit C2-9, BCUC 1.1.1)

On the other hand FortisBC stated “it has never had a Stand-by rate under which customers have taken service. The Brokerage Agreement has, at various, times been portrayed by Celgar as a kind of effective stand-by service and FortisBC has not objected to this characterization in the past; however, it is not accurate…” (Exhibit B-6, Celgar 1.30.6)

FortisBC further states “FortisBC conducts transmission planning based on the expected firm customer load. For Celgar, this is the 45 MW that has historically been recorded (Exhibit B-1, p. 40). Presently, FortisBC does not have, or have a need for, a tariff for interruptible service. On that basis, all load is considered firm for system planning purposes. Practically, from the perspective of impact to the Company or the system, there is no difference between firm and non-firm service. Thus, there is also no difference in cost to maintain the system. Given the above, and based on cost causation principles, there should not be a lower rate for any service that may be referred to as non-firm.” (Exhibit B-6, Celgar 1.34.1) FortisBC explained that it “is not facing significant transmission investments at the present time and is not in a situation where its customers would benefit from a rate that induces reduced load …” (Exhibit B-15, BCUC 1.7.3) “Were a distinction put in place between firm and non-firm service it would be in name only and no cost savings would result.” (Exhibit B-15, BCUC 1.5.4) By way of background, FortisBC also stated that “After the Waneta Expansion Capacity Purchase Agreement comes into effect in 2015, FortisBC’s expected peak summer and winter capacity gaps essentially fall to zero.” (FortisBC 2012 Long Term Resource Plan, Appendix B)

Celgar states “The proposed Standby Rate will move Celgar from standby service that FortisBC has consistently made available to Celgar since the late 1990s, which was fair and reasonable, with characteristics appropriate for Celgar, to a Standby Rate with availability characteristics that are not only not required by Celgar but will materially increase the cost of utility service to Celgar.” (Exhibit C2-6, p. 5)

Celgar’s expert witness Mr. Linxwiler testifies that “[u]ltimately, the type of service that is required and that should be offered by FortisBC, or any other utility for that matter, should depend on the type of load that is being served. If the load is non-firm load, in the sense that the customer can withstand or tolerate lower than usual reliability, then non-firm service should be available to serve that load. If the customer is not able or willing to tolerate periodic and possibly frequent interruptions or curtailments, then the load should be considered to be firm, and firm service should be available. In either case, the service should match the customers' requirements as nearly as practicable." (Exhibit C2-6, p. 7)

Celgar also explained that it "has load shedding relays in place, although they are not currently programmed to respond to system supply constraints. The infrastructure is in place to allow the load shedding relays to be armed when FortisBC designates that non-firm backup is unavailable." (Exhibit C2-9, BCUC 1.9.3)

Commission Determination

The Panel agrees with Celgar that its Electricity Supply Brokerage Agreement effectively set out the terms by which FortisBC was to provide stand-by service to Celgar including a distinction between firm and interruptible service.

However, the Panel is persuaded by FortisBC's argument that its situation is different now and that there would be no benefit to FortisBC to provide non-firm service. If, for planning purposes, the costs are the same and the difference between firm and non-firm service would be in name only and no cost savings would result, then the Panel is in agreement that all service should be firm service. The Panel agrees with Celgar's expert witness that ideally the type of service that should be offered by FortisBC should match the customer's requirements as nearly as practicable; however, the Panel concludes that offering non-firm service is not practicable in this case.

The Panel finds that FortisBC does not have to provide non-firm service given there are no benefits to FortisBC of doing so even if it is what the customer is requesting. The Panel therefore determines that offering only firm service does not make the proposed Stand-by Rate, on this basis alone, unjust, unreasonable, unduly preferential or unduly discriminatory.

However, in the Panel's view good rate design gives customers a strong incentive to use electric service more efficiently, to minimize the costs they impose on the system, and to avoid charges when service is not taken.

The Panel is concerned that FortisBC conducts transmission planning based on the expected 45 MW firm customer load. In its Decision to Order G-188-11, the Commission noted that FortisBC had changed its system planning criteria in 2010 to be based on Celgar's actual historical demand, rather than on the 16 MW that was the contract demand in the 2000 GSA. FortisBC "commenced using 40 MW in recognition of the fact that many times in previous years the actual recorded peak demand at the facility was much greater than the 16 MW value which had been used previously."

In that Decision, the Commission emphasized that FortisBC should not significantly alter the amount of firm service used in system planning (which in turn affects COSA) without consulting the customer affected. The Commission considered that, if the two transmission lines serving Celgar are lightly loaded, the outcome of its system planning will likely be unaffected whether Celgar's proposed 8 MVA, the historical 16 MVA, or actual historical peak demand were used as the load remains below capacity. FortisBC was also directed to design a stand-by rate and describe how this rate takes account of its system planning criteria. In the Application, however, FortisBC's only description is to state that "the load modeled in the power flow data use for system studies is the full load the customer may impose upon the FortisBC system, for Celgar this is 45 MW." (Exhibit B-1, p. 40) The Panel reiterates its position that FortisBC did not provide any explanation or support for using 45 MW and questions why FortisBC would do this when the Commission had explicitly indicated that FortisBC should not do this without consulting the affected customer.

FortisBC states that practically, from the perspective of impact to the Company or the system, there is no difference between firm and non-firm service and the Commission Panel has accepted this assertion. However, the Panel still considers that the Stand-by Rate should not result in the utility incurring unnecessary costs with regard to investment and operation of its network if the customer does not require firm service and the utility can benefit from a costs saving by providing that service.

Therefore, if the costs are the same based on either load then there seems to be little harm in using 45 MW. However, in the event that there are cost savings to FortisBC of using an amount less than that the Commission would fully expect FortisBC to only use that amount required for its customer's firm needs.

3.8.3 Availability - When Stand-by Service is Initiated

The second matter where Celgar and FortisBC have divergent views is in determining when stand-by service is initiated.

RS 37 proposes that in any hour replacement (stand-by) power will be available to a maximum of the difference between the power normally supplied by the customer owned resource and the customer generation in that hour.

Celgar submits that Contract Demand and not self-generation output should provide the demarcation point between firm service under the underlying rate [RS 31] and stand-by service (RS 37). (Celgar Final Submission, para. 103) Celgar further stated that consumption within the Contract Demand limit of 8 MW should not be considered a back-up event as the underlying transmission tariff recovers costs based on Contract Demand. (Exhibit C2-11, BCPSO 1.2.1)

FortisBC replies by stating it does not make sense to use Contract Demand to determine what purchases are considered as stand-by power. (FortisBC Reply, para. 56-57)

Commission Determination

Celgar's 8 MW demarcation point between taking service on the underlying rate (RS 31) and taking service under the Stand-by Rate (RS 33) based on firm Contract Demand appear to be a concept associated with the provision of firm and non-firm service. Given that the Panel has determined that FortisBC is not obligated to offer non-firm service it follows that the firm service being the demarcation point is no longer of any significance. The Commission Panel expresses its position on the determination and application of Contract Demand in Section 3.8.4.

The Panel considers that under the net-of-load operating environment,[7] which is currently the default operating environment in the FortisBC service area, it would appear that any time a customer requires supply from FortisBC it would either be for Back-up or Maintenance purposes.

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[7] Without consideration of the entitlement to embedded cost energy and the NECP Rate Rider.

Therefore, unless the customer is offside with one of the Restrictions in the Stand-by Rate, the customer would be always taking supply under the Stand-by Rate.

However, the Panel finds that there is an insufficient evidentiary record to determine if the language in the proposed RS 37 reflects this understanding or if this understanding is indeed accurate. Therefore, the Panel concludes that without additional information and clarification it is unable to make a final determination regarding when stand-by service is initiated.

3.8.4 Contract Demand

The final matter where Celgar and FortisBC have divergent views is with regard to Contract Demand.

There are three areas relating directly or indirectly to Contract Demand that that will be addressed individually.

1. Special Provision 1 (Section 3.8.4.1)
2. Billing Demand in the Underlying Rate (Section 3.8.4.2)
3. Special Provision 2 (Section 3.8.4.3)

3.8.4.1 Special Provision 1

RS 37 proposes the inclusion of the following Special Provision:

> Special Provision 1: Underlying Rate
> "A customer taking service under this rate must also be contracted to receive service under one of the Company's Commercial rates that incorporates a Demand Charge."

In Order G-188-11 the Commission contemplated that the Stand-by Rate would be offered in conjunction with RS 31 and that the Demand Charge of RS 31 will continue to apply to the billing demand as determined by the Stand-by Rate.

Commission Determination

This issue has gone uncontested and is consistent with what was contemplated in Commission Order G-188-11. **Therefore, the Commission Panel approves the inclusion of Special Provision 1 RS 37 other than for it being applicable to transmission voltage customers only as determined in Section 3.2.1.** The issues relating to when stand-by service is available and when do periods of stand-by service begin and end have been addressed by the Panel in Sections 3.6 and 3.8.3 and will not be addressed again here.

3.8.4.2 Billing Demand in the Underlying Rate Schedule

RS 37 proposes the following clause with regard to demand charges (FortisBC Final Submission, Appendix A):

> "Other than as described in Special Condition 2, the maximum demand recorded during a period of Stand-By service will not be used in the calculation of Billing Demand in the underlying rate schedule [RS 31]."

RS 37 proposed that during periods of stand-by service the Wires Demand Charge is to be based on the customers underlying rate (RS 31). However, RS 37 explicitly excludes certain RS 31 ratchets and, as a result, the Wires Demand Charges during periods of stand-by service is ultimately based on 80 percent of Contract Demand.

Commission Determination

The Commission Panel finds that a Wires Demand Charges during periods of stand-by service based on 80 percent of Contract Demand is appropriate. **The Panel approves the inclusion of this clause in RS 37 which eliminates the following demand ratchets included in RS 31 during periods of stand-by service: (i) The maximum Demand in kVA for the current billing month, and (ii) 80 percent of the maximum Demand in kVA recorded during the previous eleven month period. The Panel finds that this is consistent with its finding in regard to Special Condition 2 and no party has taken exception to it.**

3.8.4.3 Special Provision 2

The Panel considers that Contract Demand should result in a fair contribution of the self-generating customer to the sunk costs of the network. However, what remains to be determined is how Contract Demand during periods of stand-by service should be determined and how this should be articulated in the Stand-by Rate.

RS 37 also proposes the inclusion of the following Special Provision:

> Special Provision 2: Contract Demand
>
> "Billing under this rate schedule requires the establishment of a Contract Demand, expressed in kilovolt Amps (kVA). Contract Demand for the purpose of this Rate Schedule means the Customer's maximum potential Demand. A Customer may establish its Contract Demand in its application for service hereunder or at any time thereafter. At any time, including when the Customer may be taking service under the Stand-by Rate RS37, if the monthly maximum Demand exceeds the Contract Demand, the monthly maximum Demand will become the Contract Demand thereafter. A Contract Demand so established is used in the determination of Billing Demand in a Customers underlying rate."

As a result of FortisBC's proposed Special Provision 2, the customer's Contract Demand will increase for the full amount of capacity taken at any time, including during periods of stand-by service, and will remain at that amount permanently. This will effectively result in a stand-by Demand Wires Charge based on the highest demand ever taken by the customer.

FortisBC states that it must maintain infrastructure that is capable of servicing the full load, regardless of how intermittent that load may be, and as the timing of the load is unpredictable, transmission capacity must be available at all times in order to ensure that back-up loads are fully met.

FortisBC takes the position that a self-generating customer that chooses to serve a portion of load from its own resources has the opportunity to reduce its energy related costs by replacing utility supply with low cost self-generation. However, FortisBC points out these customers should not also be able to avoid the costs associated with the provision of the infrastructure required to support the self-generator load during periods when self-generation is unavailable. (FortisBC Final

Submission, p. 9) On the other hand, FortisBC acknowledges that the generators are generally quite reliable and that there is diversity on the system that needs to be recognized in designing these rates. (Exhibit B-1, p. 37) FortisBC further states that it does not have any reason to conclude that Celgar is not properly maintaining its generation assets." (Exhibit B-15, BCUC 1.9.1.1)

FortisBC argued that "The stranded cost issue does not evaporate because a customer has been connected for a given amount of time. If a customer is served by infrastructure that generated revenue based on the billed load of the customer, and the revenue from that customer drops without a commensurate reduction in costs, other customers will be impacted." (Exhibit B-15, BCUC 8.2.2)

Celgar submits that "[t]he proposed rate regime [Special Provision 2] has no precedent in British Columbia, has yet to be approved by the Commission under any circumstances, and should not be approved by the Commission in this Application." (Celgar Final Submission, para. 37)

Linxwiler, on behalf of Celgar states, "The proposed [Stand-by Rate] pricing is excessive because (i) it is not based on legitimate system planning considerations, (ii) it does not properly match capacity and energy prices, (iii) the demand-related rates for the proposed service have not been shown to be appropriate and are likely to be quite excessive, and (iv) certain other aspects of the proposed rate are not cost-based or adequately justified. Furthermore, the rate proposed by the Company is anticompetitive and discriminatory. It provides an undue preference in favor of FortisBC's own generation as compared to potential new customer-owned generation."

Celgar further stated, "Celgar believes that it is accepted industry practice in Canada and elsewhere for utilities to require stand-by capacity charges [wires charge] for firm back-up service. There is, however, considerable diversity in the levels of such charges and the basis for them. That the appropriate bases for such charges are not widely agreed upon seems to be supported by the fact that the Ontario Electricity Board has recently undertaken the referenced consultation process." (Exhibit C2-9, BCUC 1.8.1.2, 1.8.1.3)

Commission Determination

The Panel appreciates that stand-by rates have often been contentious and there is a long-standing stand-by rate debate. As previously highlighted, advocates for self-generation seek minimal stand-by rates based on the premise that self-generation provides benefits in the form of deferred or permanent reduction in the need for utility-provided generation, transmission, and distribution capacity. Utilities on the other hand argue that the theoretical benefits for self-generation are insubstantial if located in an unsuitable area or operate erratically, and low stand-by rates can result in self-generating customers avoiding infrastructure costs associated with back-up generation and wires services.

FortisBC's proposal effectively sets a 'one size fits all' wires charge for stand-by service at a Wires Demand Charge equal to 80 percent of the maximum Contract Demand, which is reset any time the existing Contract Demand is exceeded. Celgar is proposing a similar one size fits all network charge for stand-by service of a Wires Demand Charge equal to 80 percent of the requested firm Contract Demand and no additional Wires Demand Charge for any non-firm stand-by service above that.

The Panel considers that stand-by wires charges should be set such that they do not inadvertently either restrict the growth of cost-effective distributed generation, or promote uneconomic bypass. Wires charges should also result in a fair contribution to the sunk costs of the utility's network, although the Panel notes the difficulty in determining the fairness of a Wires Demand Charge from a cost causation perspective.

The Panel finds that determining the appropriate stand-by network charges (Wires Demand Charge) for self-generating customers is more of an art than a science. For example, the design of an appropriate stand-by wires charge could be different for different customers (depending on where the generator is located, the size of the generator, whether the self-generation is classified as BC clean energy). The appropriate wires charge could also change over time for example, if there are significant changes to the retail rate design. The Panel therefore considers that the one size fits all approach could result in suboptimal BC outcomes over the long term.

The Panel therefore does not approve the inclusion of Special Provision 2 in RS 37 and determines that FortisBC's one size fits all method of recovering a fair contribution is unnecessarily restrictive and would result in the Stand-by Rate being unjust, unreasonable, and unduly discriminatory. Accordingly, the Commission declines to approve RS 37 "Stand-by Service Rate" as proposed in the Application at this time.

3.8.5 Stand-by Contract Demand

The Panel considers that the key focus in determining the appropriate stand-by demand charge should ensure that it does not discourage on-site generation that is fully economical and cost-effective but for the inclusion of standby charges. Further, the stand-by demand charge should also take into consideration BC energy objectives.

As a solution the Panel suggest that 'Stand-by Contract Demand' in RS 37 should be established between the customer and the utility at an amount somewhere between zero and 100 percent of the Contract Demand established in the underlying Rate. This RS 37 Stand-by Contract Demand would ideally remain unchanged over the life of the investment in self-generation.

The Panel would expect that Contract Demand in the underlying rate to be established by FortisBC and its customer with distributed generation on the same basis as it does for any other Transmission Customer on rate (RS 31). The Contracted Demand would define the maximum level of Capacity and Energy that FortisBC would commit to supplying to a self-generation customer whether taking service under the underlying rate (RS 31) or the Stand-by Rate. RS 37 stand-by Contract Demand would then be established to reflect the benefits of self-generation based on a set of Commission approved principles. Given the limitations in a one size fits all network services charge concept, the Panel considers it more appropriate to use a principled base approach to identify the benefits of self-generation.

Any final approved Stand-by Rate is intended to be suitable for all customers, current and future, with self-generation taking service at transmission voltage. The Panel wishes to address current and future customers separately.

3.8.5.1 Future Customers

The resultant RS 37 stand-by Contract Demand should ultimately reflect both the costs and the benefits distributed generation provides to BC, and provide a level of price certainty regarding network charges for stand-by service to customers considering making self-generation investments.

By way of example, the Panel considers that the following principles could be a reasonable starting point in the development of principles used to determine Stand-by Contract Demand for future customers:

1. Economic efficiency: stand-by wires charges should not discourage on-site generation that is fully economical and cost-effective but for the inclusion of stand-by charges. Specifically, stand-by charges should not be (i) so low as to promote uneconomic bypass of the grid or inefficient maintenance of customer owned generation assets, or (ii) so high as to discourage the growth of cost effective self-generation.

2. Fairness: cost-causation principles should be applied in assigning costs to differently situated customers. However, diametrically opposed interpretations of the user pay principle could make it difficult to justify a high or low stand-by rate design solely based on the fairness principle.

3. Consideration of BC Energy Policy: the stand-by wires charge should take into consideration whether stand-by rates should be adjusted higher or lower to support BC energy objectives.

4. Simplicity and transparency: stand-by wires charges should be easy to understand and administer, and designed so that prospective users can estimate what their charges will be, based on a few known cost determinants.

5. Stability: optimal stand-by wires charges can vary between customers and over time. However, once set, stand-by wires charges for a particular customer should not be subject to material changes (other than, for example, where there is a material change to the corresponding retail rate design) during the term of financing a generator project, usually 15-20 years.

However, for future stand-by customers the Panel finds these principles should not be addressed in this Proceeding but are better suited to be determined through the FortisBC's Comprehensive Self-Generation Policy Application that has been directed pursuant to Order G-60-14.

Therefore, in regards to future customers, the Commission would likely approve a revised Stand-by Rate, subject to comment from the parties, if Special Provision 2 was removed (subject to the modifications in the Energy Charge noted in this Decision and pending a final determination on the Restrictions and Availability criteria) and replaced at a future date after the completion of the Comprehensive Self-Generation Policy Application, with language similar to the following: Contract Demand used during periods of stand-by service (Stand-by Contract Demand) is to be agreed to between the customer and the utility based on principles as set out in an attached Tariff Supplement.

3.8.5.2 Existing Customers

Based on the above preliminary recommendation the Panel finds that Stand-by Contract Demand should be established based on a set of principles and not based on a one size fits all formula. However, for current customers this approach could be problematic as any principles will likely not be finalized for some time and the key considerations for future customers could very well be different from those for existing customers.

Given that Celgar is the only existing customer, the Panel finds that the most efficient and effective way to proceed in addressing the Stand-by Rate for the existing customer is the same as for future customers (a final Stand-by Rate that removes Special Provision 2, subject to the modifications in the Energy Charge noted in this Decision and pending a final determination on the Restrictions and Availability criteria) in conjunction with setting a Contract Demand and a Stand-by Contract Demand for Celgar.

3.8.5.3 Contract Demand for Celgar

FortisBC submits that "…it is important to keep in mind when considering Celgar's arguments that they are coloured by wider objectives that are not properly the subject of this process – namely, as noted in the introduction, to obtain (1) non/firm interruptible service (2) above a Contract Demand which Celgar would like to be 8 MV. Celgar's desire to advance those objectives in most proceedings in which it participates [including the 2009 RDA, Celgar Complaint, The FortisBC Purchas of Utility Assets of the City of Kelowna and the RS 3808 Proceeding] infuses its present submissions as well." (FortisBC Reply, p. 7)

In the Decision attached to Order G-188-11 [Celgar Complaint] the Commission directed FortisBC to design a Stand-by Rate to address Celgar's circumstances and file an application for its approval. The Panel fully anticipates being able to approve a Final Stand-by Rate through this Proceeding after which time Celgar will be eligible to take service based on either RS 31 or the Stand-by Rate. However, without a determination on Celgar's Contract Demand and Stand-by Contract Demand, Celgar will not have final rates for service taken under either of these rates, thus the direction in Order G-188-11 will not be met.

Furthermore, an approved Stand-by Rate, an appropriate Contract Demand, and a Stand-by Contract Demand will most certainly be a necessary step that needs to be completed before the Panel can contemplate the retroactive billing for Celgar, which is also the subject of the Application.

The Panel is aware that Celgar has advanced its objectives in many pervious proceedings before the Commission, which is a clear indication that its concerns need to be addressed at some point in time. The Panel finds that without a Contract Demand and Stand-by Contract Demand established for Celgar it will not be possible to move forward. It is critical that this issue be settled and the Panel determines that that time is now. **Therefore, Panel determines establishing a Contract Demand and a Stand-by Contract Demand for Celgar is fully within the scope of this Proceeding.**

3.9 Commission Summary Determination on the Stand-by Rate

The Panel is not able to determine that the Stand-by Rate as proposed by FortisBC is not unjust, unreasonable, unduly discriminatory, or unduly preferential at this time due to the inclusion of the Contract Demand Special Provision 2 and the lack of evidence provided to support the proposed Restrictions and the Availability of the Stand-by Rate.

The Commission wants to move forward as quickly as possible to have an approved Stand-by Rate for transmission voltage customers in the FortisBC service territory. The Panel supports, and has approved, many of the components of the proposed Stand-by Rate as identified in this Decision and considers that the remaining outstanding issues can be addressed through this Proceeding without further delay. The Panel determines that the outstanding material matters are limited to the following:

i. The Restrictions included in the Stand-by Rate; and
ii. The Availability of Stand-by Service.

The Panel does not consider the difference so extreme as to suggest that a final determination on a Stand-by Rate cannot be made within this Proceeding and is hopeful that the Commission's findings can be successfully incorporated into the revised Stand-by Rate.

The Panel directs FortisBC to file a revised Stand-by Rate incorporating the findings in this Decision and addressing the two outstanding matters no later than June 26, 2014. Further process regarding FortisBC's filing will be decided by the Commission Panel in due course.

Regarding the first outstanding matter the Panel requires additional evidence to support the Restrictions proposed by FortisBC especially for Back-up service. Evidence should support Restrictions that are applicable to current and future customers and address different types of self-generation if necessary. The Panel anticipates that a determination on this issue should be rather straightforward.

The Panel further directs FortisBC to submit a filing on the appropriate level of Contract Demand in the underlying rate and the appropriate level of Stand-by Contract Demand applicable during periods of stand-by service for Celgar to be submitted in conjunction with the revised Stand-by Rate.

In addressing the appropriate level of Stand-by Contract Demand for Celgar, consideration should be given to the following.

(i) Consideration of applicable principle proposed for future customers as set out in Section 3.8.5.1 including;
   1. Economic efficiency;
   2. Fairness;
   3. Consideration of BC Energy Policy;
   4. Simplicity and transparency; and
   5. Stability

(ii) Last Contract Demand of 16 MVA that the parties agreed to in the 2000 GSA.

In regards to (i) (2) the Panel would like FortisBC to also consider the following alternative options in determining an appropriate level of Stand-by Contract Demand for Celgar. The Panel appreciates that the first and perhaps the second option in the list below are likely not of relevance to this situation as there is only one customer with existing self-generation, but has provided the full list to reflect the fact that this determination is unique to the FortisBC service area and normally all options could be considered.

- Expected Outage Rate: If there is a large pool of stand-by customers of similar size, the capacity required could be estimated as the total capacity of all stand-by customers, multiplied by the expected outage rate.
- Largest Contract + Expected Outage Rate: If there is one large stand-by customer and several smaller customers, the capacity required could be estimated as the capacity of the largest customer plus the capacity of the other customers multiplied by their outage rate.
- Average Contract + Expected Outage Rate: This adds together the average of the total stand-by capacity to total capacity multiplied by the expected outage rate. This method attempts to recognize the diversity of load states.
- Probabilistic Method: Identify an appropriate threshold level for which the utility will risk not serving the stand-by customer (say, 1 percent). This, together with each customers expected outage rate, is used to determine the network capacity that should be reserved for stand-by customers.
- Target Reserve Margin: This uses the generator reserve margin to determine the required reserved capacity for the stand-by class.
- Reserve Capacity of the Network: For example, if the expected outage rate is 1 percent, the customer should pay for 30 percent of their reserved capacity if this is the reserved capacity of the network that is typically used for 1 percent of the time.

The Panel appreciates that FortisBC stated in an IR response that “FBC does not consider any of the listed sub-categories to be appropriate for use as the allocation for transmission [costs for standby use].” This is because FortisBC does not consider that the network charge should be discounted for Stand-by use. (Exhibit B-15, BCUC 1.6.5) However, the Panel has proposed that Stand-by Contract Demand take into consideration both the costs and benefits and therefore the Panel is interested in hearing FortisBC’s position on these options.

In regards to (ii) "Last Contract Demand of 16 MVA that the parties agreed to in the 2000 GSA" the Panel agrees with Celgar that the Commission Panel should consider the precedents established by past approvals of stand-by service to Celgar. However, the Panel also wants to be clear that while it does consider past approvals to be informative, it is in no way bound by them.

Nonetheless, the Panel notes that the last Contract Demand the parties agreed to was 16 MVA as part of the 2000 GSA. The Panel further notes that no evidence has been provided in this Proceeding that supports this contract demand (effectively pricing the Stand-by Network Charge at approximately one third of what would otherwise occur if network portion of the stand-by service was priced using RS 31 Demand Charge) would result in inefficient investment in, or operation of, Celgar or FortisBC assets.

The Panel also points out that it previously determined (in the evaluation of Stepped Rates) that before making any changes to previously approved rate design, the Panel should be satisfied that greater efficiencies or cost savings would accrue to the benefit of ratepayers overall, or that the existing rate is now outside of fairness norms from a cost causation perspective.

The Panel has previously acknowledged the difficulty in relying on cost causation principles to determine whether the Stand-by Rate is inherently unfair. However, the Panel also notes the difficulty in demonstrating that the last Contract Demand that the parties agreed to is outside of fairness norms.

4.0 TIME-OF-USE RATE – RATE SCHEDULE 33

4.1 Background

RS 33 is a Large Commercial Transmission rate based on time-of-use. In the Application, FortisBC seeks Commission approval to close RS 33 TOU Rate, and indicates that there are currently no customers receiving service under this rate (Exhibit B-1, pp. 14-15). FortisBC further indicates that the closing of this rate is consistent with the treatment of the Residential TOU Rates ordered by the Commission when the Residential Conservation Rate became the default rate for those customers. Finally, in support of its request, FortisBC cites the Commission: "…in its December 31, 2009 Summary Report, the Commission noted that no customers opted for a TOU version of the stepped rate as customers felt the rate is overly complicated and expect it to increase energy costs." (Exhibit B-1, pp. 14-15)

However, in its Final Submission, FortisBC indicates that should Stepped Rates not be approved, FortisBC would withdraw its request to close RS 33 in order to have an optional conservation rate in place for transmission customers. FortisBC submits the rationale for requesting to close RS 33 was to maintain consistency with the Commission's direction at the time FortisBC's Residential Conservation Rate was approved. At that time, the Commission directed FortisBC to make the stepped rate mandatory for all customers not currently served on the TOU Rate. Given that no customers were taking service on the TOU Rate, this effectively made the TOU Rate unavailable for use and the rate was closed. (FortisBC Final Submission, para. 65-66)

Given that no customers are currently of the RS 33 TOU Rate, FortisBC anticipated the Commission's future direction if the Stepped Rate was approved and proposed to have it closed.

4.2 Submissions

BCPSO agrees with the approach with respect to RS 33 as put forth in the FortisBC Final Submission (BCPSO Final Submission, para. 38). Neither Celgar, the BCMEU nor BC Hydro made any final submission related to the RS 33 TOU Rate treatment proposed by FortisBC.

FortisBC reiterates in its Reply that consistent with the treatment of the Residential TOU Rate closure that, if the Transmission Stepped Rate was to be approved by the Commission, closure of RS 33 should follow. However, FortisBC submits that if the Stepped Rate was not approved, then the TOU Rate (RS 33) should not be closed. (FortisBC Reply, para. 107-108)

4.3 Commission Summary Determination on the Time of Use Rate

The Panel observes that FortisBC submitted the Application for Stepped and Stand-by Rates in response to certain Commission directives. Commensurate with those directives, FortisBC also indicated that its Application proposed to implement a Stepped Rate and that if such the Stepped Rates were to be approved that, to be consistent with that conservation Stepped Rate, RS 33, the conservation TOU Rate should be closed. No Interveners raised concerns about this proposed closure. No other FortisBC customers have availed themselves of RS 33 and thus the TOU Rate remains unsubscribed.

As both the proposed Stepped Rate and the existing RS 33 TOU Rate are both conservation rates, FortisBC now requests that RS 33 only be closed if the proposed Stepped Rate is approved and in the event that the Stepped Rate is not approved, FortisBC requests that RS 33 not be closed.

The Panel is not being requested in this Proceeding to make a determination on the merits of the RS 33 TOU Rate**. Given that the Commission Panel has not approved the adoption of the Stepped Rates as proposed in the Application, no Interveners have objected, and there are currently no customers taking service under RS 33, the Panel consents to FortisBC's withdrawal of its request to close RS 33.**

FortisBC is encouraged to review the TOU Rate as part of its next general rate design application.

5.0 STATUS OF OUTSTANDING MATTERS

Pursuant to Order G-12-14 the review of the NECP Rate Rider and the application of the Stepped Rate to FortisBC's customers with self-generation facilities were suspended until the Commission made a final determination on the RS 3808 Proceeding. The Commission further directed that the retroactive application of rates to Celgar will be addressed once the Commission approves either a new rate for Celgar, which complies with the final rate approved in the RS 3808 Proceeding, and/or an Agreement is made by the parties.

As such, the application of the Stepped Rate to customers with self-generation, the NECP Rate Rider, and the retroactive application of rates to Celgar's billing was out of the scope of this Decision. The status of these matters is addressed below.

5.1 Stepped Rates for Self-Generating Customers

The Panel has addressed the application of the Stepped Rate to FortisBC's customers with self-generation facilities in its final determination on the Stepped Rates in Section 2.5.

5.2 The Non-Embedded Cost Power (NECP) Rate Rider

In the Application, FortisBC filed for approval for the Non-Embedded Cost Power (NECP) Rate Rider which is a provision for charging self-generating customers that intend to sell any portion of its generation that is not in excess of load.

The review of the NECP Rate Rider was suspended pursuant to Order G-12-14 until the Commission made a final determination on the RS 3808 Proceeding. By way of Order G-60-14 and the Decision attached to that Order, issued on May 6, 2014, the Commission made its final determination on the RS 3808 Proceeding. The following relevant directives were made:

> 2. BC Hydro is directed to initiate a consultation process that will result in an application for the New PPA Section 2.5 [GBL] Guidelines by November 1, 2014. Once the Guidelines have been approved by the Commission, they are to be added to the New PPA as an appendix.

3. Until the addition of Commission-approved New PPA Section 2.5 Guidelines as an appendix to the New Power Purchase Agreement, the net-of-load methodology will be applied.

5. FortisBC Inc. is directed to initiate a concurrent consultation process in its service territory to address or ensure:

   (i) the potential benefits of self-generation;

   (ii) the 1999 Access Principles in the context of self-generating customers;

   (iii) if the GBL methodology is proposed, GBL Guidelines for both idle historic self-generation and new self-generation; and

   (iv) arbitrage is not allowed.

   FortisBC Inc. is further directed to file a resultant Self-Generation Policy application with the Commission by December 31, 2014, that establishes high level principles for its service territory.

In light of the determinations in Order G-60-14, the Commission will shortly be issuing a letter requesting submissions from the parties on how to proceed with FortisBC's request for approval for the NECP Rate Rider.

5.3 Retroactive Billing for Celgar

The Panel will not be seeking submissions on how to move forward with the retroactive billing for Celgar until a final determination is made on the Stand-by Rate.

DATED at the City of Vancouver, in the Province of British Columbia, this 26th day of May 2014.

Original signed by:

L.A. O'HARA
COMMISSIONER/PANEL CHAIR

Original signed by:

R.D. REVEL
COMMISSIONER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-67-14

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
Application for Stepped and Stand-By Rates for Transmission Voltage Customers

BEFORE: L.A. O'Hara, Commissioner
R.D. Revel, Commissioner

May 26, 2014

O R D E R

WHEREAS:

A. On March 28, 2013, FortisBC Inc. (FortisBC) filed an application with the British Columbia Utilities Commission (Commission) for approval of new rates for transmission voltage customers (the Application) under sections 58-61 of the *Utilities Commission Act*;

B. The Application requests the following:

   i. Approval for a conservation Stepped Rate, with Customer Baseline Load (CBL) Guidelines, for all transmission voltage customers (Rate Schedule (RS) 34), an exempt Flat Rate (RS 36) as well as approval to close the existing Flat Rate(RS 31) and transfer customers to RS 34 and RS 36, as appropriate;

   ii. Approval for a Non-Embedded Cost Power (NECP) Rate Rider which incorporates the Entitlement Principals and the Matching Methodology into a rate;

   iii. Approval for a Stand-by Service Rate (RS 37);

   iv. Approval to close the transmission voltage customer Time-of-Use Rate (RS 33); and

   v. A determination of the retroactive application of rates to Zellstoff Celgar Limited Partnership (Celgar);

C. British Columbia Hydro and Power Authority (BC Hydro), Celgar, International Forest Products Limited (Interfor), the British Columba Pensioners' and Seniors' Organization *et al.*, and the BC Municipal Electric Utilities registered as Interveners and Tolko Industries Ltd. registered as an Interested Party;

D. On April 10, 2013, the Commission issued Order G-55-13, establishing a Regulatory Timetable for its review of the Application that was subsequently amended by Orders G-61-13, G-85-13, G-90-13, G-155-13, G-12-14, and G-18-14;

…/2

E. On May 28, 2013, BC Hydro filed an application with the Commission for approval to replace the existing 1993 Power Purchase Agreement (PPA) with FortisBC with a New PPA under RS 3808 (RS 3808 Proceeding). The RS 3808 Proceeding addresses certain issues which overlap with parts of this Application including issues that relate to the NECP Rate Rider;

F. On January 31, 2014, by Order G-12-14, the Commission determined that its review of the issues in the Application that do not overlap with the issues being considered in the RS 3808 Proceeding would proceed by way of a written hearing (RS 34 and RS 36 excluding its application to customers with self-generation, RS 31, RS 37 and RS 33). The NECP rate rider, the application of the stepped rate to FortisBC's customers with self-generation, and the retro-active application of rates to Celgar would be deferred until after the Commission made a final determination on the RS 3808 Proceeding; and

G. In its Final Submission dated March 19, 2014 FortisBC requested that:

   a) FortisBC's Application for a Stepped Rates (RS 34, CBL Guidelines, and RS 36) should not be approved at this time; and

   b) Its request to close RS 31 and 33 be withdrawn if the Stepped Rates are not approved.

NOW THEREFORE the British Columbia Utilities Commission (Commission) orders as follows:

1. FortisBC Inc.'s (FortisBC) request to open Rate Schedule 34 "Large Commercial Service – Transmission Stepped Rate" and the attached Customer Baseline Load Guidelines is denied.

2. FortisBC's request to open Rate Schedule 36 "Large Commercial Service – Transmission Flat Rate" is denied.

3. The Commission consents to the withdrawal of FortisBC's request to close Rate Schedule 31 "Large Commercial Service – Transmission Flat Rate" and Rate Schedule 33 "Large Commercial Service – Transmission Time-of-Use."

4. The Commission declines to approve Rate Schedule 37 "Stand-by Service Rate" as proposed in the Application at this time.

5. FortisBC is directed to file with the Commission, by June 26, 2014, a revised Rate Schedule 37 "Stand-by Service Rate" incorporating the findings in the attached Decision and addressing both the restrictions on, and availability of, stand-by service. Further process regarding this filing will be decided by the Commission in due course.

…/3

6. FortisBC is directed to submit a filing on the appropriate Contract Demand level in the Underlying Rate and the appropriate level of Stand-by Contract Demand applicable during periods of stand-by service, for Zellstoff Celgar Limited Partnership (Celgar), to be submitted in conjunction with the revised Stand-by Rate.

7. FortisBC is directed to comply with all other directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 26th day of May 2014.

BY ORDER

Original signed by:

L.A. O'Hara
Commissioner

REGULATORY TIMETABLE

On April 10, 2013, Order G-55-13 established a Preliminary Regulatory Timetable which provided for two rounds of Information Requests (IRs), Filing and IRs on Intervener Evidence, and a placeholder for FortisBC to file Rebuttal Evidence.

By letter filed with the Commission on April 18, 2013, Celgar claimed that the Application as filed did not comply with Order G-188-11 or Order G-202-12. Celgar requested the Commission Panel issue further directions to FortisBC regarding the scope of the Application. On April 19, 2013, by Order G-61-13 the Commission suspended the Proceeding and sought comments from the parties on Celgar's request.

On May 24, 2013, by Order G- 85-13, the Commission denied Celgar's request to expand the scope of the Proceeding stating that there is sufficient breadth in the current scope to accommodate the exploration of Celgar's issues. Order G-85-12 also amended the dates in the Preliminary Timetable.

On June 12, 2013, Order G-90-13 further amended certain dates in the Preliminary Regulatory Timetable to provide FortisBC with additional time as per its request. Order G-90-13 also provided for a date for the parties to make submission on further process.

On August 27, 2013, the BCPSO filed a letter with the Commission the issues raised in this proceeding overlap with a number of other proceedings currently before the Commissions, including the Rate Schedule 3808 Application.[1] BCPSO suggests that some thought should be given to the appropriate sequence of these decisions and suggests a logical manner to ensure maximize regulatory efficiency while preserving procedural fairness.

Because of the many amendments to the Regulatory Timetable, the following is reproduced for the record.

---

[1] Rate Schedule 3808 Proceeding

APPENDIX A
to Order G-55-13
Page 1 of 1

FortisBC Inc.

Application for Stepped and Stand-By Rates
for Transmission Customers

PRELIMINARY REGULATORY TIMETABLE

ACTION	DATE (2013)
Intervener and Interested Party Registration	Wednesday, April 17
Commission Information Request No. 1	Thursday, April 25
Intervener Information Request No. 1	Thursday, May 2
Participant Assistance Cost Award Budgets	Thursday, May 9
FortisBC Responses to Commission and Intervener Information Request No. 1	Friday, May 17
Written Submissions regarding whether the review should proceed by way of an Oral or Written Public Hearing or Negotiated Settlement	Monday, June 3
Commission and Intervener Information Request No. 2	Monday, June 3
FortisBC Responses to Commission and Intervener Information Request No. 2	Monday, June 17
Intervener Evidence	Friday, June 21
Information Requests on Intervener Evidence	Friday, June 28
Intervener Responses to Information Requests on Intervener Evidence	Friday, July 12
Placeholder for FortisBC Rebuttal Evidence	Friday, July 19

FortisBC Inc.

Application for Stepped and Stand-By Rates
for Transmission Voltage Customers

FURTHER AMENDED
PRELIMINARY REGULATORY TIMETABLE

ACTION	DATE (2013)
Participant Assistance Cost Award Budgets	Friday, June 14
FortisBC Responses to Commission and Intervener Information Request No. 1	Thursday, July 4
Commission and Intervener Information Request No. 2	Thursday, August 1
FortisBC Responses to Commission and Intervener Information Request No. 2	Thursday, August 15
Intervener Evidence	Thursday, August 22
Written Submissions regarding further process	**Tuesday, August 27**
Information Requests on Intervener Evidence	Friday, September 6
Intervener Responses to Information Requests on Intervener Evidence	Friday, September 20
Placeholder for FortisBC Rebuttal Evidence	Monday, September 30

APPENDIX A
to Order G-155-13
Page 1 of 1

FortisBC Inc.

Application for Stepped and Stand-By Rates
for Transmission Voltage Customers

**UPDATED PRELIMINARY
REGULATORY TIMETABLE**

ACTION	DATE (2013)
FortisBC Rebuttal Evidence	Thursday, October 10
Commission and Intervener Information Requests on Rebuttal Evidence (if any)	Tuesday, October 29
FortisBC Responses to Information Requests on Rebuttal Evidence	Thursday, November 14

Appendix A
To Order G-18-14
Page 1 of 1

FortisBC Inc.

Application for Stepped and Stand-By Rates
for Transmission Voltage Customers
(excluding the NECP Rate Rider)

**AMENDED FINAL
REGULATORY TIMETABLE**

ACTION	DATE (2014)
FortisBC Final Submission	Monday, February 24
Intervener Final Submissions	Friday, March 7
FortisBC Reply Submission	Wednesday, March 19

FortisBC Inc.
Classes of Commercial Customers

Electric Tariff
B.C.U.C. No. 2
Index 1

INDEX

Issued December 20, 2010
FORTISBC INC.

By: Dennis Swanson
Director, Regulatory Affairs

Accepted for filing ______
BRITISH COLUMBIA UTILITIES COMMISSION

By: ______
Commission Secretary

EFFECTIVE (applicable to consumption on and after) January 1, 2011 G-156-10

LIST OF ACRONYMS

2000 BA	Electricity Supply Brokerage Agreement
2000 GSA	General Service Power Contract dated December 20, 2000 between Celgar and FortisBC
2009 RDA	FortisBC 2009 Rate Design and Cost of Service Analysis Application
Barrick	Barrick Gold
BC Hydro	British Columbia Hydro and Power Authority
BCMEU	British Columbia Municipal Electrical Utilities
BCPSO	British Columbia Pensioners and Seniors Organisation *et al*.
CBL	Customer Baseline Load
CEA	*Clean Energy Act*
Celgar	Zellstoff Celgar Partnership Limited
Commission, BCUC	British Columbia Utilities Commission
COSA	Cost of Service Analysis
DSM	Demand Side Measure
FortisBC, the Company	FortisBC Inc.
GSA	general service agreement
Industrial customers	Large Commercial Service Customers
Interfor	International Forest Products Limited
LRMC	long-run marginal cost
NECP	Non-Embedded Cost Power
PBR	Performance Based Ratemaking
Platts	Platts, McGraw Hill Financial
R/C	revenue-to-cost
Roxul	Roxul (West) Inc.
RS	Rate Schedule
TOU	Time-of-Use
TSRs	transmission service rates
UCA	*Utilities Commission Act*

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
Stepped and Stand-By Rates for Transmission Customers Application

EXHIBIT LIST

Exhibit No.	**Description**
COMMISSION DOCUMENTS	
A-1	Letter Dated April 10, 2013 - Order G-55-13 establishing a Preliminary Regulatory Timetable
A-2	Letter Dated April 15, 2013 – Appointment of Commission Panel
A-3	Letter Dated April 19, 2013 – Order G-61-13 Inviting Comments and Suspending Preliminary Regulatory Timetable
A-4	Letter Dated May 24, 2013 – Order G-85-13 Establishing a Revised Preliminary Regulatory Timetable with Reasons for Decision
A-5	Letter Dated June 3, 2013 – Commission Information Request No. 1
A-6	Letter Dated June 12, 2013 – Commission Order G-90-13 issuing Further Amended Preliminary Regulatory Timetable
A-7	Letter Dated August 1, 2013 – Commission Information Request No. 2
A-8	Letter Dated September 6, 2013 – Commission Information Request No. 1 on Intervener Evidence
A-9	**CONFIDENTIAL** Letter Dated September 6, 2013 – Confidential Commission Information Request No. 1 on Intervener Evidence
A-10	Letter Dated September 9, 2013 – Commission Response to Comments on Further Process
A-11	**CONFIDENTIAL** Letter Dated September 13, 2013 – Confidential Request Response regarding Confidential Information Request

Exhibit No.	**Description**
A-12	Letter Dated September 25, 2013 – Commission Order G-155-13 issuing Updated Preliminary Regulatory Timetable
A-13	Letter Dated October 29, 2013 – Commission Information Request No. 1 on FortisBC Rebuttal Evidence
A-14	Letter Dated January 8, 2014 – Extension of Powers for Alison Rhodes
A-15	Letter Dated February 3, 2014 – Commission Order G-12-14 issuing Final Regulatory Timetable
A-16	Letter Dated February 13, 2014 – Commission Order G-18-14 issuing and Amended Final Regulatory Timetable
A-17	Letter Dated March 3, 2014 – Panel Chair Appointment
A-18	Letter Dated March 13, 2014 – Commission Order G-42-14 issuing Reasons regarding Celgar Submission

APPLICANT DOCUMENTS

B-1	**FORTISBC INC. (FBC)** Letter Dated March 28, 2013 - Stepped and Stand-By Rates for Transmission Customers Application
B-1-1	Letter Dated April 8, 2013 - Errata 1 to the Application
B-1-2	**CONFIDENTIAL** Letter Dated March 28, 2013 – Confidential attachment to the Application
B-1-3	Letter Dated July 4, 2013 - Errata 2 to the Application
B-1-4	**CONFIDENTIAL** Letter Dated July 4, 2013 – Confidential Errata 2 to the Application
B-1-5	Letter Dated August 9, 2013 - Errata 3 to the Application
B-2	Letter dated April 30, 2013 – FBC Submitting Response to Celgar (Exhibit C2-2)
B-3	Letter dated June 11, 2013 – FBC Submitting Extension Request
B-4	Letter dated July 4, 2013 – FBC Responses to Information Request No. 1 to BCUC
B-5	Letter dated July 4, 2013 – FBC Responses to Information Request No. 1 to BCPSO

Exhibit No.	Description
B-6	Letter dated July 4, 2013 – FBC Responses to Information Request No. 1 to Celgar
B-6-1	CONFIDENTIAL Letter dated July 4, 2013 – FBC Responses to Information Request No. 1 to Celgar
B-7	Letter Dated August 15, 2013 – FBC Submitting Response to BCUC IR No. 2
B-7-1	CONFIDENTIAL Letter Dated August 15, 2013 – FBC Submitting Confidential Response to BCUC IR No. 2
B-8	Letter Dated August 15, 2013 – FBC Submitting Response to BCMEU IR No. 2
B-9	Letter Dated August 15, 2013 – FBC Submitting Response to BCPSO IR No. 2
B-10	Letter Dated August 15, 2013 – FBC Submitting Response to Celgar IR No. 2
B-11	Letter Dated August 27, 2013 – FBC Submitting Comment regarding Further Process
B-12	Letter dated September 6, 2013 – FBC Submitting Information Request No. 1 to Celgar
B-13	Letter dated October 10, 2013 - FBC Submitting Rebuttal Evidence
B-14	Letter dated November 14, 2013 - FBC Submitting Response to BCPSO IR1 Rebuttal Evidence
B-15	Letter dated November 14, 2013 - FBC Submitting Response to BCUC IR1 Rebuttal Evidence
B-16	Letter dated November 14, 2013 - FBC Submitting Response to Celgar IR1 Rebuttal Evidence
B-17	Letter Dated February 7, 2014 - FBC Filing comments regarding Final Submission
B-18	Letter Dated February 12, 2014 - FBC Request to Withdraw February 7 Request Exhibit B-17
B-19	Letter Dated March 11, 2014 – FBC Submitting comments regarding Celgar Final Submission dated March 7, 2014

Exhibit No.	Description
INTERVENOR DOCUMENTS	
C1-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Online Registration Dated April 16, 2013 – Request for Intervener Status by Janet Fraser
C1-2	Letter dated May 3, 2013 – BCH Submitting Comments
C2-1	**ZELLSTOFF CELGAR PARTNERSHIP LIMITED (CELGAR)** Letter Dated April 17, 2013 – Request for Intervener Status by Kim Moller, Elroy Switlishoff, Brian Merwin, Robert Hobbs
C2-2	Letter received April 18, 2013 – Celgar Submitting Comments
C2-3	Letter dated May 15, 2013 – Celgar Submitting Response Comments
C2-4	Letter dated June 7, 2013 – Celgar Submitting Information Request No. 1
C2-5	Letter Dated August 1, 2013 – Celgar Submitting Information Request No. 2
C2-6	Letter Dated August 22, 2013 – Celgar Submitting Evidence
C2-6-1	**CONFIDENTIAL** - Letter Dated August 22, 2013 – Celgar Submitting Confidential Evidence
C2-7	Letter Dated August 22, 2013 – Celgar Request for Confidentiality
C2-8	Letter Dated August 27, 2013 – Celgar Submitting Comment regarding Further Process
C2-9	Letter Dated September 20, 2013 – Celgar Submitting Response to BCUC IR No. 1
C2-10	**CONFIDENTIAL** Letter Dated September 20, 2013 – Celgar Submitting Response to Confidential BCUC IR No. 1
C2-11	Letter Dated September 20, 2013 – Celgar Submitting Response to BCPSO IR No. 1
C2-12	Letter Dated September 20, 2013 – Celgar Submitting Response to FBC IR No. 1
C2-13	Letter Dated September 20, 2013 – Celgar Submitting Comments regarding Confidential Information Requests
C2-14	Letter Dated October 29, 2013 – Celgar Submitting Information Request No. 3 to FBC
C2-15	Letter Dated February 11, 2014 – Celgar Submitting comments on FBC Request

Exhibit No.	Description
C2-16	Letter Dated February 13, 2014 – Celgar Submitting Extension Request
C2-17	Letter Dated March 12, 2014 – Celgar Submitting Response to FBC Request (Exhibit B-19)
C3-1	**INTERNATIONAL FOREST PRODUCTS LIMITED (INTERFOR)** Letter and Online Registration Dated April 19, 2013 – Request for Late Intervener Status by Andrew Horahan
C4-1	**BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO ET AL)** Letter dated April 19, 2013– Request for Late Intervener Status by Leigha Worth, Eugene Kung and Bill Harper
C4-2	Letter dated May 3, 2013 – BCPSO Submitting Comments
C4-3	Letter dated June 7, 2013 – BCPSO Submitting Information Request No. 1
C4-4	Letter Dated August 1, 2013 – BCPSO Submitting Information Request No. 2
C4-5	Letter Dated August 27, 2013 – BCPSO Submitting Comment regarding Further Process
C4-6	Letter Dated September 6, 2013 - BCPSO Submitting Information Request No. 1 to Celgar
C4-7	Letter Dated October 29, 2013 - BCPSO Submitting Information Request No. 3 to FBC
C4-8	Letter Dated February 3, 2014 – BCPSO Submitting Updated Distribution List
C5-1	**BRITISH COLUMBIA MUNICIPAL ELECTRICAL UTILITIES (BCMEU)** Letter dated June 24, 2013 – Request for Late Intervener Status by Alex Love and Marg Craig
C5-2	Letter Dated August 1, 2013 – BCMEU Submitting Information Request No. 2

INTERESTED PARTY DOCUMENTS

D-1	**TOLKO INDUSTRIES LTD (TOLKO)** Online Registration Dated April 16, 2013 – Request for Interested Party Status by Michael Towers
D-1-1	Letter Dated August 30, 2013 – Tolko Submitting Comment on BCPSO Determinations Request

DECISION **2015 NSUARB 195**
M06760

2015 NSUARB 195 (CanLII)

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION of the **CANSO ELECTRIC LIGHT UTILITY** on behalf of the **Municipality of the District of Guysborough** for Approval of Amendments to its Schedule of Rates for the provision of electric supply and services to its customers

BEFORE: Murray E. Doehler, CPA, CA, P.Eng., Member

APPEARING: **MUNICIPALITY OF THE DISTRICT OF GUYSBOROUGH**
Barry Carroll
Chief Administrative Officer

Gary Cleary
Deputy Chief Administrative Officer

Robert G. Grant, Q.C.
Solicitor

Albert E. Dominie, P. Eng.
Consultant

HEARING DATE: **June 10, 2015**

FINAL SUBMISSIONS: **June 17, 2015**

DECISION DATE: **July 27, 2015**

DECISION: **Schedule of Rates approved.**

I SUMMARY

[1] The Canso Electric Light Utility ("Utility"), which is located in the Municipality of the District of Guysborough ("Municipality"), filed an application for approval of amendments to its Schedule of Rates dated March 13, 2015 ("Application"). Except for pass-through rates related to increases granted to Nova Scotia Power Incorporated ("NSPI") and Efficiency Nova Scotia Corporation, the last increase in rates, based on the Utility's own cost of service, was in 1997. The Utility requires increased rates to meet its revenue requirement.

[2] A Rate Study to support the Application, dated January/February 2015, was prepared by Albert E. Dominie. The industrial category was omitted from the schedule of rates in the Rate Study, as it was not required.

[3] The Utility has applied for:

- an average rate increase of 10% for the domestic class (by increasing the energy charge 11.6%, and leaving the base charge unchanged); and
- a 7.5% increase to its small industrial rate, applied across the energy and base charge.

[4] The Board issued Information Requests ("IRs") on May 1, 2015, to which the Utility responded on May 11, 2015.

[5] A public hearing was held at the Fanning Education Centre in Canso on June 10, 2015. The hearing was advertised in accordance with the provisions of the *Public Utilities Act*, R.S.N.S., c. 380, as amended ("*Act*"). Gary Cleary, Deputy Chief Administrative Officer for the Municipality, Albert E. Dominie, the Municipality's consultant, and Robert G. Grant, the Municipality's counsel, appeared on behalf of the

2015 NSUARB 195 (CanLII)

Utility. There were no intervenors to the Application. No letters of comment were received and no members of the public made presentations during the hearing.

[6] The Schedule of Rates and Charges is approved, as outlined in the Rate Study.

II INTRODUCTION

[7] The Utility distributes power which it purchases from NSPI to residential, commercial, and small industrial customers. The Utility supplies approximately 475 customers in the Canso area.

[8] Upon the dissolution of the Town of Canso in 2012, the administration of the Utility was taken over by the Municipality. Since dissolution, the focus of the Municipality has been to sell the Utility. The majority of maintenance, outage restoration and other emergency services is contracted out to NSPI.

[9] The Utility's fiscal 2015 financial statements were filed during the hearing. As at March 31, 2015, the Utility has a surplus of $86,814 and no debt. It has experienced small operating losses in recent years followed by negligible net income in fiscal 2015.

[10] The Utility's current, and proposed, rates are outside of the 95 – 105% revenue/cost range by customer class established by the Board in other electricity rate decisions.

2015 NSUARB 195 (CanLII)

III REVENUE REQUIREMENTS

1. Operating Expenses

[11] The Rate Study supporting the Application used as a test year a projection of 2015/2016 revenue requirements. The projection was based on the actual 2012/2013 and 2013/2014 and the forecasted 2014/2015 expenditures. The Utility projected (with no change in rates) a net loss for the test year with the accumulated operating surplus reducing to $31,000 as of March 31, 2016. With the proposed rate increases (assuming a July 1 approval date), the Utility is projecting an excess of revenues over expenditures and an accumulated operating surplus of $68,000 at the end of the test year.

[12] Increases in the projections for the test year were kept consistent with historical cost level patterns with the exception of administration. There was a $20,000 increase in administration costs included in the test year in an effort to fully recover the internal cost of the Municipal staff performing administrative functions on behalf of the Utility. The charge for the recovery of administration costs had significantly dropped from the 2011/2012 levels because the Municipality, in the past three years, has not been accurately determining an appropriate charge to the Utility.

[13] During the hearing, there was discussion about the support given by the Municipality to the Utility. This included activities in the finance department, the time by staff to coordinate operations, and an allocation of insurance which is incorporated into the Municipality's overall insurance program.

[14] The 2014/2015 forecast was in line with the actual 2014/2015 results, except for distribution expense. The increase in distribution expense was caused by the net one-time costs related to an ice storm in 2013/2014 and the related insurance

2015 NSUARB 195 (CanLII)

settlement received. The insurance claim listed costs totalling $130,342 which were directly caused by the ice storm, of which insurance reimbursed $110,354. The Utility is confident that these one-time costs have been properly adjusted and the projected expense will be adequate for normal operations.

[15] A property tax expense of $14,534 was incurred by the Utility in 2013/2014. The forecasted 2014/2015, and the test period net income, both contain a tax expense of $15,000. This tax expense was removed from the final 2014/2015 financial statements as the Municipality had determined it had incorrectly charged the Utility for property tax.

[16] As at March 31, 2015, there is an amount of $63,137 recorded on the balance sheet labelled as “Deferred expenses relating to the sale of the electric Utility”. These were legal and professional consulting fees incurred by the Utility in the preparation for its eventual sale.

Findings

[17] The Board accepts the process used to project the test year revenue requirements, including the increase in administration costs. However, the Board notes that the allocation of administration costs is not based on an internal analysis or activity tracking. In future rate applications the Board would expect the allocation to be based upon sound cost accounting principles.

[18] The tax expense, which has been included in the total test year revenue requirement, is incorrectly charged and will not be paid by the Utility. Regardless, the Board accepts the total revenue requirement in the Rate Study as this item is not

2015 NSUARB 195 (CanLII)

material and can be used as a contingency to offset any additional losses that maybe incurred by not having the new rates in effect by July 1.

[19] The Board finds the deferral of the costs related to the eventual sale of the Utility to be appropriate. It is expected that the Utility will suggest an appropriate disposition of these costs upon a future submission to the Board for either its sale or continued operations.

2015 NSUARB 195 (CanLII)

2. Capital Costs

[20] The Utility has not initiated any capital projects since 2010, and currently has no future capital investment planned. The plant and equipment are nearly fully depreciated. It was noted in a report prepared by CBCL Limited (at the time of dissolution of the Town) that the plant is in need of significant investment in capital equipment in the coming years in order to maintain service and avoid serious and potentially sudden peaks in required investment. In the Rate Study Mr. Dominie noted:

> Plant and equipment, with the exception of the recently converted street lighting system, is over 95% depreciated and will require considerable investment in infrastructure in the near future. The costs associated with operating this Utility with its aging infrastructure are a major concern for the Municipality, particularly where an ice storm last year caused damages to the Utility which took $150,000 to repair.
>
> [Rate Study, p. 2]

[21] During the hearing, Mr. Cleary explained that no capital projects have been identified due to the focus of the Municipality on the sale of the Utility:

> Unfortunately as I said, the efforts were put into selling the utility and it appeared very close a few times … so there hasn't been any long-range planning.
>
> [Transcript, pp. 33-34]

[22] It was confirmed during the hearing that no capital expenditures were provided for in the Rate Study:

> The Chair: … Mr. Dominie, in your go-forward, you have no capital out of revenue.

Mr. Dominie: That's correct sir.

[Transcript, p. 29]

[23] As at March 31, 2015, there is a depreciation fund reserve of $370,355.

Findings

[24] The Board understands that the Municipality is focusing its attention on the sale of the Utility at this time. However, if the Municipality is unable to sell the Utility in the near term, the Utility will need to develop a capital budget to address the issues identified in the CBCL Limited report. The Board notes there is a significant depreciation fund that could be used to address any unplanned or needed capital renewals or additions in the current year.

[25] The Board finds the absence of a capital budget for the test year, with the cushion of the depreciation reserve, to be appropriate for this Application only.

3. Non-operating Expenditures and Revenues

[26] The Utility has no long term debt charges and no new debt is projected. There is a small profit of $1,000 projected in the test year.

Findings

[27] On an annualized basis, the Application shows a return on rate base of 5.4%. The Board finds the return on rate base over the test year to be reasonable.

2015 NSUARB 195 (CanLII)

IV ALLOCATION OF THE REVENUE REQUIREMENTS

[28] The methodology used to allocate the revenue requirement to determine the base and consumption charges is consistent with the Utility's previous rate applications. The allocation between customer classes has also been applied consistently. The revenue/cost ratios by customer class that would result from the proposed rate increases are as follows:

Customer Class	Revenue/Cost ratio
Residential	89%
Small General	145%
General	117%
Small Industrial	80%
Street Light	100%

[29] Mr. Dominie explained the objectives of the Application:

> There were … conflicting objectives to of course have the application conform with the requirements under the Act, move rates directionally closer to the 95:105 cost-recovery requirement. And at the same time move towards a more favourable position vis-a-vis NSP rates. …
>
> [Transcript, p. 17]

[30] When asked why the rates could not be moved more to be the same as NSPI rates, Mr. Dominie responded:

> Our understanding is, Mr. Chair, that underneath the Public Utilities Act, rates have to be based on the utility cost. And that would not be … from a legal perspective would not be permitted underneath our interpretation of the Act at this point in time.
>
> [Transcript, p. 16]

[31] Mr. Grant noted that the Municipality assumed that a 10% increase to the residential class and a 7.5% increase to the small industrial category was as far as could reasonably be done in a single step. This was confirmed by Mr. Cleary and Mr. Dominie.

2015 NSUARB 195 (CanLII)

[32] Mr. Dominie commented that moving the rates further towards the 95 – 105% range would be an objective in future years (2017 and 2018) if the Utility is not sold. In response to an IR the Utility said:

> If the Utility is not sold to NSP and continues as a separate Municipal Utility we would anticipate a defined plan to move rates into the approved range. No such plan has presently been developed as pursuit of the sale is our first priority. Sale of the Utility to NSP would eliminate the issue as the customers would be absorbed into NSP's rate structure.
>
> [Exhibit C-4, p. 6]

2015 NSUARB 195 (CanLII)

Findings

[33] The Board finds the allocations of the revenue requirements in the test period to be reasonable, while noting this is being done in the context of the Municipality actively seeking to sell the Utility. If it is not sold in the near term the Board expects the Utility to submit another rate application in the following fiscal year with a main objective of establishing customer class rates that are within a revenue/cost ratio of 95 – 105%.

[34] It is possible that the rates in this Application could be adjusted closer to the 95/105 revenue/cost ratio and NSPI's rates. However, the Board finds the present position of the Utility to minimize "rate shock" to be reasonable and approves the new schedule of rates.

V CONCLUSION

[35] The Application adjusts the rates to cover its revenue requirements. In doing so the rates are moved closer to the 95 – 105% revenue to cost ratio by customer class.

[36] The Municipality has actively been attempting to sell the Utility. As a consequence it has not prepared a long-term capital budget. If the Utility is not sold, then the Board expects the Utility to make a new application in the near future to deal with the capital budget and to bring the revenue/cost ratios for all classes closer to 100%.

[37] The Utility requested an effective date of July 1, 2015, for the new rates. The Board notes that electricity is billed bi-monthly with usage to the end of an even numbered month. The Utility, in a compliance filing, is to file a revised effective date for the new rates.

[38] Upon receipt of an acceptable compliance filing an Order will be issued.

DATED at Halifax, Nova Scotia, this 27th day of July, 2015.

Murray E. Doehler

2015 NSUARB 195 (CanLII)

Roland Lapointe *Appellant*

v.

Domtar Inc. *Respondent*

and

Commission d'appel en matière de lésions professionnelles *Mis en cause*

and

Commission de la santé et de la sécurité du travail *Mis en cause*

INDEXED AS: DOMTAR INC. *v.* QUEBEC (COMMISSION D'APPEL EN MATIÈRE DE LÉSIONS PROFESSIONNELLES)

File No.: 22717.

1993: April 1; 1993: June 30.

Present: Lamer C.J. and La Forest, L'Heureux-Dubé, Gonthier, Cory, McLachlin and Iacobucci JJ.

ON APPEAL FROM THE COURT OF APPEAL FOR QUEBEC

Workers' compensation — Income replacement indemnity — Commission d'appel en matière de lésions professionnelles — Interpretation of s. 60 of the Act respecting Industrial Accidents and Occupational Diseases — Evocation — Standard of review applicable to Commission's decisions — Whether Commission's interpretation patently unreasonable — Whether in the absence of a patently unreasonable error conflicting decisions by two administrative tribunals may give rise to judicial review — Act respecting Industrial Accidents and Occupational Diseases, R.S.Q., c. A-3.001, s. 60.

Judicial review — Standard of review — Appellate administrative tribunal — Workers' compensation — Standard of review applicable to decisions of Commission d'appel en matière de lésions professionnelles.

Judicial review — Basis for judicial intervention — Conflicting decisions by two administrative tribunals — Whether jurisprudential conflict constitutes an independent basis for judicial review.

Roland Lapointe *Appelant*

c.

Domtar Inc. *Intimée*

et

Commission d'appel en matière de lésions professionnelles *Mise en cause*

et

Commission de la santé et de la sécurité du travail *Mise en cause*

RÉPERTORIÉ: DOMTAR INC. *c.* QUÉBEC (COMMISSION D'APPEL EN MATIÈRE DE LÉSIONS PROFESSIONNELLES)

N° du greffe: 22717.

1993: 1er avril; 1993: 30 juin.

Présents: Le juge en chef Lamer et les juges La Forest, L'Heureux-Dubé, Gonthier, Cory, McLachlin et Iacobucci.

EN APPEL DE LA COUR D'APPEL DU QUÉBEC

Accidents du travail — Indemnité de remplacement du revenu — Commission d'appel en matière de lésions professionnelles — Interprétation de l'art. 60 de la Loi sur les accidents du travail et les maladies professionnelles — Évocation — Norme de contrôle applicable aux décisions de la Commission — L'interprétation de la Commission est-elle manifestement déraisonnable? — En l'absence d'une erreur manifestement déraisonnable, un conflit jurisprudentiel entre deux instances administratives peut-il donner ouverture au contrôle judiciaire? — Loi sur les accidents du travail et les maladies professionnelles, L.R.Q., ch. A-3.001, art. 60.

Contrôle judiciaire — Norme de contrôle — Tribunal administratif d'appel — Accidents du travail — Norme de contrôle applicable aux décisions de la Commission d'appel en matière de lésions professionnelles.

Contrôle judiciaire — Motif d'intervention judiciaire — Conflit jurisprudentiel entre deux instances administratives — Un conflit jurisprudentiel constitue-t-il un motif autonome de contrôle judiciaire?

1993 CanLII 106 (SCC)

The appellant, an employee of the respondent company, was injured in an industrial accident three days before the temporary closure of the plant. Citing the closure, the company refused to compensate the employee for more than those three days. The Commission de la santé et de la sécurité du travail and the Bureau de révision paritaire affirmed the company's decision and dismissed the complaint of the employee, who argued that under s. 60 of the *Act respecting Industrial Accidents and Occupational Diseases* ("*A.I.A.O.D.*") he was entitled to an income replacement indemnity covering the entire period of his disability, that is a period of 14 days. On appeal, the Commission d'appel en matière de lésions professionnelles ("CALP") found for the employee and ordered the company to pay him, pursuant to s. 60, 90 percent of his net salary or wages for each day or part of a day he would normally have worked according to his usual work schedule, regardless of the plant closure. The Superior Court dismissed the company's motion in evocation because, in its view, the CALP had acted within its jurisdiction and its decision was not unreasonable. The Court of Appeal reversed this judgment and granted the application for evocation. While of the opinion that the CALP's decision was not patently unreasonable, the court nevertheless observed that with respect to the interpretation of s. 60 it was in the interest of justice to resolve at once the conflicting decisions of the CALP and the Labour Court, which has jurisdiction over penal proceedings under the *A.I.A.O.D.* Abandoning traditional curial deference, the court consequently intervened to resolve the unstable situation and held that under s. 60 an employer is not required to pay a salary or wages to an employee injured in an industrial accident when there is a plant closure. This appeal is to determine whether, in the absence of a patently unreasonable error, conflicting decisions by administrative tribunals may give rise to judicial review.

Held: The appeal should be allowed.

Strictly speaking, the interpretation of s. 60 is within the CALP's jurisdiction. A functional analysis of the *A.I.A.O.D.* clearly demonstrates that the legislature intended to give this tribunal the power to make a final ruling on the meaning and scope of s. 60. As an appellate administrative tribunal, the CALP hears and disposes exclusively of all appeals brought under the *A.I.A.O.D.* and its members have all the powers necessary for the exercise of their jurisdiction, including the power to rule on any question of law or of fact. Protected by a full privative clause, CALP decisions are final and without appeal and every person contemplated

L'appelant, un employé de la compagnie intimée, est victime d'un accident de travail trois jours avant la fermeture temporaire de l'usine. Invoquant cette fermeture, la compagnie refuse d'indemniser l'employé au-delà de ces trois journées. La Commission de la santé et de la sécurité du travail ainsi que le Bureau de révision paritaire confirment la décision de la compagnie et rejettent la plainte de l'employé qui soutient qu'en vertu de l'art. 60 de la *Loi sur les accidents du travail et les maladies professionnelles* («*L.A.T.M.P.*») il a droit à une indemnité de remplacement du revenu couvrant l'ensemble de son incapacité, soit une période de 14 jours. En appel, la Commission d'appel en matière de lésions professionnelles («CALP») donne raison à l'employé et ordonne à la compagnie de lui verser, conformément à l'art. 60, 90 p. 100 de son salaire net pour chaque jour ou partie de jour où il aurait normalement travaillé selon son horaire habituel de travail et ce, sans égard à la fermeture de l'usine. La Cour supérieure rejette la requête en évocation présentée par la compagnie estimant que la CALP a agi dans le cadre de sa compétence et que sa décision n'est pas déraisonnable. La Cour d'appel infirme ce jugement et fait droit à la demande d'évocation. La cour estime que la décision de la CALP n'est pas manifestement déraisonnable. Cependant, elle souligne qu'en ce qui concerne l'interprétation de l'art. 60 il est dans l'intérêt de la justice de trancher immédiatement le conflit jurisprudentiel qui existe entre la CALP et le Tribunal du travail dont relèvent les poursuites pénales intentées en vertu de la *L.A.T.M.P.* Laissant de côté la réserve judiciaire traditionnelle, la cour intervient donc pour mettre fin à l'instabilité de la situation et statue qu'en vertu de l'art. 60 il n'existe aucune obligation pour un employeur de payer un salaire à un employé victime d'un accident de travail lorsqu'il y a fermeture d'usine. Le présent pourvoi vise à déterminer si, en l'absence d'une erreur manifestement déraisonnable, un conflit jurisprudentiel au sein d'instances administratives donne ouverture au contrôle judiciaire.

Arrêt: Le pourvoi est accueilli.

L'interprétation de l'art. 60 relève de la compétence *stricto sensu* de la CALP. Une analyse fonctionnelle de la *L.A.T.M.P.* démontre clairement que le législateur avait l'intention de confier à ce tribunal le pouvoir de se prononcer de manière définitive sur le sens et la portée de l'art. 60. À titre de tribunal administratif d'appel, la CALP connaît et dispose exclusivement de tous les appels interjetés en vertu de la *L.A.T.M.P.* et ses membres possèdent tous les pouvoirs nécessaires à l'exercice de leur compétence, y compris le pouvoir de décider de toutes questions de droit et de fait. Les décisions de la CALP, protégées par une clause privative

1993 CanLII 106 (SCC)

in the decision must comply with them without delay. Further, s. 60 is not only one of the legislative provisions on which the CALP has the express power to rule, it employs concepts which are at the core of its area of expertise. The interpretation of s. 60 by the CALP is thus a function directly relating to the objective sought by the legislature. Since the interpretation of s. 60 is within the tribunal's jurisdiction, the standard of review applicable is whether the decision is patently unreasonable.

The CALP's decision is not patently unreasonable. It can be rationally defended both on the facts and on the law. While the CALP may have overlooked several important aspects which are peculiar to the general system of compensation, this is not a basis for judicial intervention as this would simply be an error of law within jurisdiction.

It is doubtful whether there is a conflict between the decisions of the CALP and the Labour Court with respect to the interpretation of s. 60. For one thing, the Court of Appeal's conclusion on this point is based on a single judgment of the Labour Court in a penal matter and fails to take into account the numerous decisions rendered by the CALP, which has always adopted the same interpretation. The situation created by an isolated decision at variance with a consistent line of authority cannot *a priori* be characterized as a true "jurisprudential conflict". Furthermore, these two bodies interpreted the same legislative provision, but in the particular context of each one's jurisdiction, in the one case a penal one and, in the other, an administrative one. Since these are matters where the ground rules are completely different, a disagreement on the interpretation of a legislative provision does not necessarily place the CALP and the Labour Court in a jurisprudential conflict. In addition, it is wrong to suggest that the CALP's interpretation leads to a dead end as there exists, parallel to the penal remedy, a civil remedy (s. 429 *A.I.A.O.D.*). Finally, the allegedly irreconcilable "conflict" between these two tribunals is mitigated by the fact that the Labour Court's decisions, unlike those of the CALP, can be appealed to the Superior Court under the *Code of Penal Procedure*.

Assuming however, without deciding the point, that the CALP's interpretation and that of the Labour Court create a jurisprudential conflict, such a conflict does not constitute an independent basis for judicial review. When decisions made within jurisdiction are not patently unreasonable, the principles underlying curial

complète, sont finales et sans appel et toute personne visée doit s'y conformer sans délai. De plus, tout en comptant parmi les dispositions législatives sur lesquelles la CALP a le pouvoir explicite de se prononcer, l'art. 60 fait appel à des notions qui sont au cœur de son domaine d'expertise. L'interprétation de l'art. 60 par la CALP constitue donc une fonction qui participe directement à l'objectif poursuivi par le législateur. Puisque l'interprétation de l'art. 60 relève de la compétence du tribunal, la norme de contrôle applicable est le caractère manifestement déraisonnable de sa décision.

La décision de la CALP n'est pas manifestement déraisonnable. C'est une décision qui est rationnellement défendable sous l'angle tant des faits que du droit. Même si la CALP a peut-être omis des nuances importantes qui sont propres au régime global d'indemnisation, cela ne constitue pas, pour autant, un motif d'intervention judiciaire car il ne s'agirait là que d'une simple erreur de droit commise dans le cadre de sa compétence.

Il semble douteux qu'il existe un conflit jurisprudentiel entre la CALP et le Tribunal du travail relativement à l'interprétation de l'art. 60. D'une part, la conclusion de la Cour d'appel à ce sujet repose sur une seule décision du Tribunal du travail en matière pénale et ne tient pas compte des nombreuses décisions rendues par la CALP qui a toujours adopté la même interprétation. La situation créée par une décision isolée à l'encontre d'une jurisprudence constante ne saurait, à priori, être qualifiée de véritable «conflit jurisprudentiel». D'autre part, ces deux organismes interprètent un même texte législatif mais dans le contexte particulier de la compétence de chacun, l'un en matière pénale, l'autre en matière administrative. Puisque ces deux matières ont des règles de base totalement différentes, un désaccord sur l'interprétation d'une disposition législative ne place pas nécessairement la CALP et le Tribunal du travail en situation de conflit jurisprudentiel. De plus, il est faux de prétendre que l'interprétation de la CALP conduit à une impasse puisqu'il existe, parallèlement au recours pénal, un recours civil (art. 429 *L.A.T.M.P.*). Finalement, le caractère prétendument définitif du «conflit» entre ces deux tribunaux est tempéré par le fait que les décisions du Tribunal du travail sont, contrairement aux décisions de la CALP, appelables devant la Cour supérieure en vertu du *Code de procédure pénale*.

Toutefois, assumant sans en décider que l'interprétation de la CALP et celle du Tribunal du travail créent un conflit jurisprudentiel, un tel conflit ne constitue pas un motif autonome de contrôle judiciaire. Dans le cas de décisions intrajuridictionnelles qui ne sont pas manifestement déraisonnables, ce sont les principes sous-jacents

1993 CanLII 106 (SCC)

deference should prevail. Consistency in the application of the law is a valid objective but is not an absolute one. This objective must be pursued in keeping with the decision-making autonomy and independence of members of the administrative bodies. Inquiring into a case of decision-making inconsistency and solving it where there is no patently unreasonable error means altering the institutional relationship between administrative tribunals and courts. Such intervention by a court of law risks eliminating the decision-making autonomy, expertise and effectiveness of the administrative tribunal and risks, at the same time, thwarting the original intention of the legislature, which has already determined that the administrative tribunal is the one in the best position to rule on the disputed decision. Administrative tribunals have the authority to err within their area of expertise, and a lack of unanimity is the price to pay for the decision-making freedom and independence given to the members of these tribunals. Recognizing the existence of a conflict in decisions as an independent basis for judicial review would constitute a serious undermining of those principles given that administrative tribunals and the legislature have the power to resolve such conflicts themselves.

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Disapproved: *Produits Pétro-Canada Inc. v. Moalli*, [1987] R.J.Q. 261; **considered:** *Re Service Employees International Union, Local 204 and Broadway Manor Nursing Home* (1984), 48 O.R. (2d) 225; *United Steelworkers of America, Local 14097 v. Franks* (1990), 75 O.R. (2d) 382; **referred to:** *Tousignant et Hawker Siddeley Canada Inc.*, [1986] C.A.L.P. 48; *Commission de la santé et de la sécurité du travail v. BG Chéco International Ltée*, [1991] T.T. 405; *Dayco (Canada) Ltd. v. CAW-Canada*, [1993] 2 S.C.R. 230; *Canada (Attorney General) v. Public Service Alliance of Canada*, [1993] 1 S.C.R. 941; *Université du Québec à Trois-Rivières v. Larocque*, [1993] 1 S.C.R. 471; *Canada (Attorney General) v. Public Service Alliance of Canada*, [1991] 1 S.C.R. 614; *CAIMAW v. Paccar of Canada Ltd.*, [1989] 2 S.C.R. 983; *U.E.S., Local 298 v. Bibeault*, [1988] 2 S.C.R. 1048; *Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp.*, [1979] 2 S.C.R. 227; *Canada Labour Relations Board v. Halifax Longshoremen's Association, Local 269*, [1983] 1 S.C.R. 245; *National Corn Growers Assn. v. Canada (Import Tribunal)*, [1990] 2 S.C.R. 1324; *United Brotherhood of Carpenters and Joiners of America, Local 579 v. Bradco Construction Ltd.*, [1993]

à la retenue judiciaire qui doivent primer. La cohérence dans l'application de la loi constitue un objectif valable mais il n'a pas un caractère absolu. Cet objectif doit se poursuivre dans le respect de l'autonomie et de l'indépendance décisionnelle des membres des organismes administratifs. Enquêter sur un cas d'incohérence décisionnelle et le solutionner en l'absence d'une erreur manifestement déraisonnable, c'est modifier le rapport institutionnel entre les tribunaux administratifs et les cours de justice. Une telle intervention de la part d'une cour de justice risque de réduire à néant l'autonomie décisionnelle, l'expertise et l'efficacité du tribunal administratif et risque, par la même occasion, de contrecarrer l'intention première du législateur qui a déjà déterminé que le tribunal administratif est celui qui est le mieux placé pour se prononcer sur la décision contestée. Les tribunaux administratifs ont la compétence de se tromper dans le cadre de leur expertise, et l'absence d'unanimité est le prix à payer pour la liberté et l'indépendance décisionnelle accordées aux membres de ces tribunaux. Reconnaître l'existence d'un conflit jurisprudentiel comme motif autonome de contrôle judiciaire constituerait une grave entorse à ces principes, compte tenu que les tribunaux administratifs et le législateur ont le pouvoir de régler eux-mêmes ces conflits.

Jurisprudence

Arrêt critiqué: *Produits Pétro-Canada Inc. c. Moalli*, [1987] R.J.Q. 261; **arrêts examinés:** *Re Service Employees International Union, Local 204 and Broadway Manor Nursing Home* (1984), 48 O.R. (2d) 225; *United Steelworkers of America, Local 14097 c. Franks* (1990), 75 O.R. (2d) 382; **arrêts mentionnés:** *Tousignant et Hawker Siddeley Canada Inc.*, [1986] C.A.L.P. 48; *Commission de la santé et de la sécurité du travail c. BG Chéco International Ltée*, [1991] T.T. 405; *Dayco (Canada) Ltd. c. TCA-Canada*, [1993] 2 R.C.S. 230; *Canada (Procureur général) c. Alliance de la Fonction publique du Canada*, [1993] 1 R.C.S. 941; *Université du Québec à Trois-Rivières c. Larocque*, [1993] 1 R.C.S. 471; *Canada (Procureur général) c. Alliance de la Fonction publique du Canada*, [1991] 1 R.C.S. 614; *CAIMAW c. Paccar of Canada Ltd.*, [1989] 2 R.C.S. 983; *U.E.S., local 298 c. Bibeault*, [1988] 2 R.C.S. 1048; *Syndicat canadien de la Fonction publique, section locale 963 c. Société des alcools du Nouveau-Brunswick*, [1979] 2 R.C.S. 227; *Conseil canadien des relations du travail c. Association des débardeurs d'Halifax, section locale 269*, [1983] 1 R.C.S. 245; *National Corn Growers Assn. c. Canada (Tribunal des importations)*, [1990] 2 R.C.S. 1324; *Fraternité unie des char-*

1993 CanLII 106 (SCC)

2 S.C.R. 316; *Lester (W.W.) (1978) Ltd. v. United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry, Local 740*, [1990] 3 S.C.R. 644; *Bell Canada v. Canada (Canadian Radio-television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722; *University of British Columbia v. Berg*, [1993] 2 S.C.R. 353; *Canada (Attorney General) v. Mossop*, [1993] 1 S.C.R. 554; *Douglas/Kwantlen Faculty Assn. v. Douglas College*, [1990] 3 S.C.R. 570; *Cuddy Chicks Ltd. v. Ontario (Labour Relations Board)*, [1991] 2 S.C.R. 5; *Tétreault-Gadoury v. Canada (Employment and Immigration Commission)*, [1991] 2 S.C.R. 22; *Desmeules et Entreprises B.L.H. Inc.*, [1986] C.A.L.P. 66; *Béland et Mines Wabush*, C.A.L.P., No. 00138-09-8604, November 27, 1986; *Collins & Aikman Inc. et Dansereau*, [1986] C.A.L.P. 134; *Lambert et Vic Métal Corp.*, [1986] C.A.L.P. 147; *Létourneau et Électricité Kingston Inc.*, [1986] C.A.L.P. 241; *Hydro-Québec v. Conseil des services essentiels* (1991), 41 Q.A.C. 292; *Syndicat canadien de la Fonction publique v. Commission des écoles catholiques de Québec*, J.E. 90-176; *Syndicat des communications graphiques, local 509M v. Auclair*, [1990] R.J.Q. 334; *IWA v. Consolidated-Bathurst Packaging Ltd.*, [1990] 1 S.C.R. 282; *Tremblay v. Quebec (Commission des affaires sociales)*, [1992] 1 S.C.R. 952.

pentiers et menuisiers d'Amérique, section locale 579 c. Bradco Construction Ltd., [1993] 2 R.C.S. 316; *Lester (W.W.) (1978) Ltd. c. Association unie des compagnons et apprentis de l'industrie de la plomberie et de la tuyauterie, section locale 740*, [1990] 3 R.C.S. 644; *Bell Canada c. Canada (Conseil de la radiodiffusion et des télécommunications canadiennes)*, [1989] 1 R.C.S. 1722; *Université de la Colombie-Britannique c. Berg*, [1993] 2 R.C.S. 353; *Canada (Procureur général) c. Mossop*, [1993] 1 R.C.S. 554; *Douglas/Kwantlen Faculty Assn. c. Douglas College*, [1990] 3 R.C.S. 570; *Cuddy Chicks Ltd. c. Ontario (Commission des relations de travail)*, [1991] 2 R.C.S. 5; *Tétreault-Gadoury c. Canada (Commission de l'emploi et de l'immigration)*, [1991] 2 R.C.S. 22; *Desmeules et Entreprises B.L.H. Inc.*, [1986] C.A.L.P. 66; *Béland et Mines Wabush*, C.A.L.P., nº 00138-09-8604, le 27 novembre 1986; *Collins & Aikman Inc. et Dansereau*, [1986] C.A.L.P. 134; *Lambert et Vic Métal Corp.*, [1986] C.A.L.P. 147; *Létourneau et Électricité Kingston Inc.*, [1986] C.A.L.P. 241; *Hydro-Québec c. Conseil des services essentiels* (1991), 41 Q.A.C. 292; *Syndicat canadien de la Fonction publique c. Commission des écoles catholiques de Québec*, J.E. 90-176; *Syndicat des communications graphiques, local 509M c. Auclair*, [1990] R.J.Q. 334; *SITBA c. Consolidated-Bathurst Packaging Ltd.*, [1990] 1 R.C.S. 282; *Tremblay c. Québec (Commission des affaires sociales)*, [1992] 1 R.C.S. 952.

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Act respecting Occupational Health and Safety, R.S.Q., c. S-2.1.
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1993 CanLII 106 (SCC)

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Mullan, David J. "Natural Justice and Fairness — Substantive as well as Procedural Standards for the Review of Administrative Decision-Making?" (1982), 27 *McGill L.J.* 250.

Ouellette, Yves. "Le contrôle judiciaire des conflits jurisprudentiels au sein des organismes administratifs: une jurisprudence inconstante?" (1990), 50 *R. du B.* 753.

Ouimet, Hélène. "Commentaires sur l'affaire Produits Pétro-Canada c. Moalli" (1987), 47 *R. du B.* 852.

APPEAL from a judgment of the Quebec Court of Appeal, [1991] R.J.Q. 2438, 39 Q.A.C. 304, reversing a judgment of the Superior Court, [1987] C.A.L.P. 254, dismissing a motion in evocation with respect to a decision of the Commission d'appel en matière de lésions professionnelles, [1986] C.A.L.P. 116. Appeal allowed.

Laurent Roy, for the appellant.

René Delorme and *Martin Roy*, for the respondent.

Claire Delisle, for the *mis en cause* CALP.

Jean-Claude Paquet, *Louise Chayer* and *Berthi Fillion*, for the *mis en cause* CSST.

The judgment of the Court was delivered by

L'HEUREUX-DUBÉ J.—This appeal raises questions which lie at the core of the institutional relationship between courts of law and administrative tribunals. The issue is whether, in the absence of a patently unreasonable error, conflicting decisions by administrative tribunals may give rise to judicial review. The provision at issue here (s. 60 of the *Act respecting Industrial Accidents and Occupational Diseases*, R.S.Q., c. A-3.001 ("*A.I.A.O.D.*")) reads as follows:

60. The employer of a worker at the time he suffers an employment injury shall pay him, if he becomes unable to carry on his employment by reason of his injury, 90% of his net salary or wages for each day or part of a day the worker would normally have worked had he not

Morissette, Yves-Marie. «Le contrôle de la compétence d'attribution: thèse, antithèse et synthèse» (1986), 16 *R.D.U.S.* 591.

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Ouimet, Hélène. «Commentaires sur l'affaire Produits Pétro-Canada c. Moalli» (1987), 47 *R. du B.* 852.

POURVOI contre un arrêt de la Cour d'appel du Québec, [1991] R.J.Q. 2438, 39 Q.A.C. 304, qui a infirmé un jugement de la Cour supérieure, [1987] C.A.L.P. 254, qui avait rejeté une requête en évocation à l'encontre d'une décision de la Commission d'appel en matière de lésions professionnelles, [1986] C.A.L.P. 116. Pourvoi accueilli.

Laurent Roy, pour l'appelant.

René Delorme et *Martin Roy*, pour l'intimée.

Claire Delisle, pour la mise en cause CALP.

Jean-Claude Paquet, *Louise Chayer* et *Berthi Fillion*, pour la mise en cause CSST.

Le jugement de la Cour a été rendu par

LE JUGE L'HEUREUX-DUBÉ—Le présent pourvoi porte sur des questions qui sont au cœur du rapport institutionnel entre les cours de justice et les tribunaux administratifs. Il s'agit de déterminer si, en l'absence d'erreur manifestement déraisonnable, un conflit jurisprudentiel au sein d'instances administratives donne, néanmoins, ouverture au contrôle judiciaire. La disposition ici en cause (l'art. 60 de la *Loi sur les accidents du travail et les maladies professionnelles*, L.R.Q., ch. A-3.001 («*L.A.T.M.P.*»)) se lit ainsi:

60. L'employeur au service duquel se trouve le travailleur lorsqu'il est victime d'une lésion professionnelle lui verse, si celui-ci devient incapable d'exercer son emploi en raison de sa lésion, 90 % de son salaire net pour chaque jour ou partie de jour où ce travailleur aurait nor-

1993 CanLII 106 (SCC)

been disabled, for fourteen full days following the beginning of his disability.

The employer shall pay the salary or wages referred to in the first paragraph to the worker at the time he would normally have paid them to him if the worker has furnished the medical certificate contemplated in section 199.

The salary or wages referred to in the first paragraph constitute an income replacement indemnity to which the worker is entitled for fourteen full days following the commencement of his disability and the Commission shall reimburse the amount thereof to the employer within fourteen days of receipt of his claim, failing which it shall pay him interest determined in accordance with section 323 from the first day it is late.

If the Commission subsequently decides that the worker is not entitled to the whole or part of the indemnity, the Commission shall claim reimbursement from the worker in accordance with Division I of Chapter XIII.

I—Facts

At about 11:30 a.m. on December 17, 1985, the appellant, a joiner permanently employed by the respondent Domtar Inc., was injured in an industrial accident. As a consequence of his employment injury, he was unable to carry on his employment from December 18, 1985 until January 2, 1986. In the days preceding the accident, Domtar had planned and announced the temporary closure of its newsprint plant for the period from 4 p.m. on December 21, 1985 to 8 a.m. on January 2, 1986.

Domtar compensated the appellant for the day of December 18 and for the days of December 19 and 20. Citing the temporary closure of the plant, Domtar refused to compensate the appellant for more than those three days. On January 6, 1986, in a complaint submitted to the *mis en cause* the Commission de la santé et de la sécurité du travail ("CSST"), the appellant argued that he was entitled to an income replacement indemnity covering the entire period of his disability, that is a period of 14 days ending on January 2, 1986. On January 24, 1986, the CSST dismissed the complaint and confirmed that Domtar had paid the correct amount. On January 30, 1986, the appellant asked the com-

malement travaillé, n'eût été de son incapacité, pendant les 14 jours complets suivant le début de cette incapacité.

L'employeur verse ce salaire au travailleur à l'époque où il le lui aurait normalement versé si celui-ci lui a fourni l'attestation médicale visée dans l'article 199.

Ce salaire constitue l'indemnité de remplacement du revenu à laquelle le travailleur a droit pour les 14 jours complets suivant le début de son incapacité et la Commission en rembourse le montant à l'employeur dans les 14 jours de la réception de la réclamation de celui-ci, à défaut de quoi elle lui paie des intérêts, déterminés conformément à l'article 323, à compter du premier jour de retard.

Si, par la suite, la Commission décide que le travailleur n'a pas droit à cette indemnité, en tout ou en partie, elle doit lui en réclamer le trop-perçu conformément à la section I du chapitre XIII.

I—Faits

Le 17 décembre 1985, vers 11 h 30, l'appelant, menuisier permanent à l'emploi de l'intimée Domtar Inc., est victime d'un accident de travail. En raison de sa lésion professionnelle, il est incapable d'exercer son emploi du 18 décembre 1985 jusqu'au 2 janvier 1986. Dans les jours précédant l'accident, Domtar avait planifié et annoncé la fermeture temporaire de son usine de papier journal pour la période du 21 décembre 1985 à 16 heures au 2 janvier 1986 à 8 heures.

Domtar indemnise l'appelant pour la journée du 18 décembre, ainsi que pour les journées du 19 et 20 décembre. Invoquant la fermeture temporaire de l'usine, Domtar refuse d'indemniser l'appelant au-delà de ces trois journées. Le 6 janvier 1986, par le biais d'une plainte adressée à la mise en cause la Commission de la santé et de la sécurité du travail («CSST»), l'appelant soutient qu'il a droit à une indemnité de remplacement de revenu couvrant l'ensemble de son incapacité, soit une période de 14 jours prenant fin le 2 janvier 1986. Le 24 janvier 1986, la CSST rejette la plainte et confirme l'exactitude du paiement effectué par Domtar. Le 30 janvier 1986, l'appelant s'adresse

1993 CanLII 106 (SCC)

pensation branch of the CSST to issue a payment order against Domtar. On February 10, 1986, the compensation branch affirmed the CSST's original decision and denied the application for an order.

On February 21, 1986, the appellant filed an application for review with the Bureau de révision paritaire ("BRP") of the CSST. On April 10, 1986, a majority of the BRP affirmed the original decision. The appellant then appealed to the *mis en cause* the Commission d'appel en matière de lésions professionnelles ("CALP"). On November 27, 1986, the CALP found that on account of his employment injury and in accordance with s. 60 *A.I.A.O.D.*, the appellant was entitled to 90 percent of his net salary or wages for each day or part of a day on which, according to his usual work schedule, he would have worked between December 22, 1985, the date on which the plant closed, and January 1, 1986. The CALP accordingly reversed the decision of the BRP and ordered Domtar to pay the appellant this amount.

On December 23, 1986 Domtar brought a motion in evocation to the Quebec Superior Court from the decision of the CALP. By judgment dated June 30, 1987, the motion in evocation was dismissed. This decision was appealed to the Quebec Court of Appeal. By a unanimous judgment dated September 11, 1991, that court allowed the appeal, granted the motion in evocation and reversed the CALP decision.

II—Legislation

The mechanism set up by the legislature to implement the *A.I.A.O.D.* comprises several decision-making bodies.

The CSST, established by the *Act respecting Occupational Health and Safety*, R.S.Q., c. S-2.1, is the body responsible for administering the *A.I.A.O.D.* (s. 589). Section 349 *A.I.A.O.D.* gives it jurisdiction to decide any question contemplated by the Act:

349. The Commission has exclusive jurisdiction to decide any matter or question contemplated in this Act

au service de réparation de la CSST afin que celui-ci rende une ordonnance de paiement contre Domtar. Le 10 février 1986, le service de réparation confirme la décision originale de la CSST et rejette la demande d'ordonnance.

Le 21 février 1986, l'appelant dépose une demande de révision auprès du Bureau de révision paritaire («BRP») de la CSST. Le 10 avril 1986, ce dernier confirme majoritairement la décision originale. L'appelant interjette alors appel devant la mise en cause la Commission d'appel en matière de lésions professionnelles («CALP»). En date du 27 novembre 1986, celle-ci déclare qu'en raison de sa lésion professionnelle et conformément à l'art. 60 *L.A.T.M.P.*, l'appelant a droit à 90 p. 100 de son salaire net pour chaque jour ou partie de jour où il aurait travaillé, selon son horaire habituel de travail, du 22 décembre 1985, date de fermeture de l'usine, jusqu'au 1er janvier 1986. La CALP infirme ainsi la décision du BRP et ordonne à Domtar de verser cette somme à l'appelant.

Le 23 décembre 1986, Domtar se pourvoit en évocation devant la Cour supérieure du Québec à l'encontre de la décision de la CALP. Par jugement en date du 30 juin 1987, la requête en évocation est rejetée. Cette décision est portée en appel devant la Cour d'appel du Québec. Par jugement unanime en date du 11 septembre 1991, celle-ci accueille le pourvoi, fait droit à la requête en évocation et infirme la décision de la CALP.

II—Dispositions législatives

Le mécanisme mis en place par le législateur pour l'application de la *L.A.T.M.P.* comprend plusieurs instances décisionnelles.

La CSST, instituée par la *Loi sur la santé et la sécurité du travail*, L.R.Q., ch. S-2.1, est l'organisme chargé d'administrer la *L.A.T.M.P.* (art. 589). L'article 349 *L.A.T.M.P.* lui attribue la compétence de décider de toute question visée par celle-ci:

349. La Commission a compétence exclusive pour décider d'une affaire ou d'une question visée dans la pré-

1993 CanLII 106 (SCC)

unless a special provision gives the jurisdiction to another person or agency.

Decisions of the CSST are subject to the following privative clause:

350. Except on a question of jurisdiction, no proceedings under article 33 of the Code of Civil Procedure (chapter C-25) nor any extraordinary recourse within the meaning of the said Code may be taken, nor any provisional remedy be ordered against the Commission by reason of an act performed or decision rendered pursuant to an Act under its administration.

The BRP is an intermediary level of jurisdiction. A person aggrieved by a decision of the CSST may ask this body to review it. Section 358 *A.I.A.O.D.* reads as follows:

358. A person who believes he has been wronged by a decision rendered by the Commission under this Act may, within 30 days of notification of the decision, apply for review thereof by a review office established under the Act respecting occupational health and safety (chapter S-2.1).

However, a person may not apply for the review of any matter of a medical nature in respect of which the Commission is bound under section 224 or of any decision of the Commission rendered under section 256 or the first paragraph of section 365.2, or for the review of a refusal by the Commission to reconsider its decision pursuant to the first paragraph of section 365.

BRP decisions are not protected by a privative clause.

The CALP is the body to which BRP decisions may be appealed. Under s. 397 *A.I.A.O.D.*, the CALP has exclusive jurisdiction to hear and dispose of appeals brought under ss. 37.3 and 193 of the *Act respecting Occupational Health and Safety* and the *A.I.A.O.D.* Section 400 further provides:

400. The board of appeal may confirm the decision or the order brought before it; it may also quash the decision or the order and shall in that case render the decision or make the order that should have been given initially.

sente loi, à moins qu'une disposition particulière ne donne compétence à une autre personne ou à un autre organisme.

Les décisions de la CSST bénéficient de la clause privative suivante:

350. Sauf sur une question de compétence, une action en vertu de l'article 33 du Code de procédure civile (chapitre C-25) ou un recours extraordinaire au sens de ce code ne peut être exercé, et une mesure provisionnelle ne peut être ordonnée contre la Commission pour un acte fait ou une décision rendue en vertu d'une loi qu'elle administre.

Le BRP constitue une instance intermédiaire. Une personne qui se croit lésée par une décision de la CSST peut en demander la révision à cet organisme. L'article 358 *L.A.T.M.P.* se lit ainsi:

358. Une personne qui se croit lésée par une décision rendue par la Commission en vertu de la présente loi peut, dans les 30 jours de sa notification, en demander la révision par un bureau de révision constitué en vertu de la Loi sur la santé et la sécurité du travail (chapitre S-2.1).

Cependant, une personne ne peut demander la révision d'une question d'ordre médical sur laquelle la Commission est liée en vertu de l'article 224 ou d'une décision que la Commission a rendue en vertu de l'article 256 ou du premier alinéa de l'article 365.2, ni demander la révision du refus de la Commission de reconsidérer sa décision en vertu du premier alinéa de l'article 365.

Les décisions des BRP ne sont pas protégées par une clause privative.

La CALP est l'organisme devant lequel il est possible d'interjeter appel des décisions du BRP. En vertu de l'art. 397 *L.A.T.M.P.*, la CALP connaît et dispose, exclusivement à tout autre tribunal, des appels interjetés en vertu des art. 37.3 et 193 de la *Loi sur la santé et la sécurité du travail* et de la *L.A.T.M.P.* Par ailleurs, l'art. 400 dispose:

400. La Commission d'appel peut confirmer la décision, l'ordre ou l'ordonnance porté devant elle; elle peut aussi l'infirmer et doit alors rendre la décision, l'ordre ou l'ordonnance qui, selon elle, aurait dû être rendu en premier lieu.

1993 CanLII 106 (SCC)

CALP decisions are final and not subject to appeal and they are protected by a full privative clause:

405. Every decision of the board of appeal must be in writing and substantiated, signed and notified to the parties and to the Commission.

Decisions are final and without appeal and every person contemplated in the decision shall comply therewith without delay.

409. Except on a question of jurisdiction, no proceedings under article 33 of the Code of Civil Procedure (chapter C-25) nor any extraordinary recourse within the meaning of the said Code may be taken, nor any provisional remedy be ordered against the board of appeal or one of its commissioners acting in his official capacity.

A judge of the Court of Appeal may annul summarily, upon a motion, any action granted, any writ, order or injunction issued or granted contrary to this section.

The Labour Court was established by the Quebec *Labour Code*, R.S.Q., c. C-27, s. 112. Penal proceedings under the *A.I.A.O.D.* are brought before it. Section 473 reads as follows:

473. Proceedings pursuant to this chapter are instituted before the Labour Court created by the Labour Code (chapter C-27) and sections 118, 121, 124 to 128 and 133 to 136 of that Code apply.

No proceedings may be brought except by the Commission or by a person generally or specially designated by it for that purpose within one year after the Commission becomes aware of the offence.

A breach of s. 60 *A.I.A.O.D.* is dealt with in s. 458:

458. Every employer who contravenes the first paragraph of section 32 or 33, section 59, the first or second paragraph of section 60 . . . is guilty of an offence and liable to a fine of not less than $500 nor more than $1 000 in the case of a natural person and to a fine of not less than $1 000 nor more than $2 000 in the case of a legal person.

Decisions of the Labour Court may be appealed to the Superior Court under the *Code of Penal Procedure*, R.S.Q., c. C-25.1.

Les décisions de la CALP sont finales et sans appel et elles sont protégées par une clause privative complète:

405. Toute décision de la Commission d'appel doit être écrite, motivée, signée et notifiée aux parties et à la Commission.

Cette décision est finale et sans appel et toute personne visée doit s'y conformer sans délai.

409. Sauf sur une question de compétence, une action en vertu de l'article 33 du Code de procédure civile (chapitre C-25) ou un recours extraordinaire au sens de ce code ne peut être exercé, et une mesure provisionnelle ne peut être ordonnée contre la Commission d'appel ou l'un de ses commissaires agissant en sa qualité officielle.

Un juge de la Cour d'appel peut, sur requête, annuler sommairement une action accueillie, un bref ou une ordonnance délivré ou une injonction accordée à l'encontre du présent article.

Le Tribunal du travail a été institué par le *Code du travail* du Québec, L.R.Q., ch. C-27, art. 112. Les poursuites pénales intentées en vertu de la *L.A.T.M.P.* sont portées devant lui. L'article 473 se lit ainsi:

473. Une poursuite en vertu du présent chapitre est intentée devant le Tribunal du travail créé par le Code du travail (chapitre C-27) et les articles 118, 121, 124 à 128 et 133 à 136 de ce code s'appliquent.

Cette poursuite ne peut être intentée que par la Commission ou une personne qu'elle désigne généralement ou spécialement à cette fin, dans l'année qui suit la connaissance de l'infraction par la Commission.

L'infraction relative à l'art. 60 *L.A.T.M.P.* est prévue à l'art. 458:

458. L'employeur qui contrevient au premier alinéa des articles 32 ou 33, à l'article 59, au premier ou au deuxième alinéa de l'article 60 [. . .] commet une infraction et est passible d'une amende d'au moins 500 $ et d'au plus 1 000 $ s'il s'agit d'une personne physique, et d'une amende d'au moins 1 000 $ et d'au plus 2 000 $ s'il s'agit d'une personne morale.

Le jugement du Tribunal du travail est appelable devant la Cour supérieure conformément au *Code de procédure pénale*, L.R.Q., ch. C-25.1.

1993 CanLII 106 (SCC)

III—Judgments

Bureau de révision paritaire, [1985-86] B.R.P. 505

The majority summed up the issue as follows (at p. 506):

[TRANSLATION] The issue raised before the Bureau de révision paritaire is whether the worker was entitled to more than two days' compensation for his period of disability from December 19, 1985 to January 2, 1986.

It added (at p. 507):

[TRANSLATION] In order to answer the question raised it must be determined whether, *had he not been disabled*, the worker would *normally* have worked during the 14-day period following the beginning of his disability. Specifically, if the worker had not suffered the industrial accident on December 17, 1985, would he have worked during that 14-day period?

In our opinion, the closure of the plant must be regarded as normal in this case as it was scheduled, and even if the worker had not suffered an accident he would only have received two days of his wages, that is up to December 20, 1985, as indeed most of the workers did. [Emphasis in original.]

In the absence of evidence establishing that the appellant intended to use his seniority right during the layoff period to bump another employee with less seniority, the majority concluded that the application should be dismissed (at p. 507):

[TRANSLATION] We accordingly believe that had he not been disabled, and based on the evidence presented, Mr. Lapointe would normally have worked only 2 days, namely December 19 and 20, during the 14-day period following the beginning of his disability.

The original decision is accordingly upheld.

In the opinion of the dissenting member, Mr. Tardif, there was no doubt that the appellant intended to use his seniority right. Being of the view that, had the appellant not been disabled, this seniority right would have enabled him to work during the layoff period, Mr. Tardif would have overturned the CSST's decision and ordered Domtar to compensate the appellant for each day or part of a day he would have worked during the

III—Jugements

Bureau de révision paritaire, [1985-86] B.R.P. 505

La majorité résume la question en litige ainsi (à la p. 506):

La question soulevée devant le Bureau de révision paritaire est à l'effet de déterminer si le travailleur avait droit à plus de deux jours d'indemnité pour sa période d'incapacité du 19 décembre 1985 au 2 janvier 1986.

Elle poursuit (à la p. 507):

Pour répondre à la question soulevée, il faut rechercher si le travailleur aurait *normalement* travaillé, *n'eût été de son incapacité*, durant la période de 14 jours suivant le début de son incapacité. Plus précisément, si le travailleur n'avait pas subi d'accident du travail le 17 décembre 1985, est-ce qu'il aurait travaillé durant cette période de 14 jours.

À notre avis, la fermeture de l'usine doit être considérée comme normale dans ce cas, car elle était prévue et même si le travailleur n'avait pas été accidenté, il n'aurait reçu que deux jours de son salaire soit jusqu'au 20 décembre 1985 comme la majorité des travailleurs, d'ailleurs. [En italique dans l'original.]

D'autre part, en l'absence de preuve démontrant que l'appelant avait l'intention d'utiliser son droit d'ancienneté afin de déplacer, durant la période de mise à pied, un autre employé ayant moins d'ancienneté, la majorité conclut au rejet de la demande (à la p. 507):

En conséquence, nous croyons que M. Lapointe, n'eût été de son incapacité et compte tenu de la preuve faite, n'aurait normalement travaillé que 2 jours, soit le 19 et le 20 décembre, et ce, pour la période de 14 jours suivant le début de son incapacité.

La décision originale est donc maintenue.

Le membre dissident, M. Tardif, est d'avis que l'intention de l'appelant d'utiliser son droit d'ancienneté ne faisait pas de doute. Estimant que ce droit d'ancienneté lui aurait permis, n'eût été de son incapacité, de travailler durant la période de mise à pied, M. Tardif aurait infirmé la décision de la CSST et ordonné à Domtar d'indemniser l'appelant pour chaque jour ou partie de jour où il aurait travaillé et ce, pour les 14 jours suivant le début de

1993 CanLII 106 (SCC)

14 days following the beginning of his disability. (The dissenting member's reasons are not reported in the B.R.P.)

Commission d'appel en matière de lésions professionnelles, [1986] C.A.L.P. 116

After reviewing the wording and purpose of s. 60 *A.I.A.O.D.*, the CALP found that the expression "would normally have worked" could not be separated from the words "had he not been disabled" which immediately follow it. Accordingly, it considered that, in interpreting this provision, no account whatever could be taken of factors or circumstances extrinsic to the worker's inability to carry on his employment by reason of his employment injury. The CALP referred to its own decision in *Tousignant et Hawker Siddeley Canada Inc.*, [1986] C.A.L.P. 48, to the effect that the suspension or breach of an employment contract by a layoff has no effect on the worker's inability to carry on his employment as a result of an employment injury. Applying these principles to the facts of this case, it added (at p. 119):

> [TRANSLATION] In the present case, the appellant was employed by the party concerned on December 17, 1985, the date on which he suffered an employment injury. By reason of this employment injury the appellant was unable to carry on his employment until January 2, 1986.
>
> Under s. 60 of the *Act respecting Industrial Accidents and Occupational Diseases*, the party concerned was therefore obliged to pay the appellant, regardless of the plant closure, 90% of his net salary or wages for each day or part of a day he would normally have worked, according to his usual work schedule, had it not been for his inability to carry on his employment by reason of his injury for the first 14 full days following the beginning of that disability.

It concluded that Domtar should pay the appellant 90 percent of his net salary or wages for each day or part of a day he would normally have worked according to his usual work schedule, regardless of the plant closure.

son incapacité. (À noter que les motifs du membre dissident ne sont pas publiés au B.R.P.)

Commission d'appel en matière de lésions professionnelles, [1986] C.A.L.P. 116

Après avoir fait état du texte et de l'objet de l'art. 60 *L.A.T.M.P.*, la CALP juge que l'expression «aurait normalement travaillé» ne peut être dissociée des termes «n'eût été de son incapacité», qui la suivent immédiatement. En conséquence, elle estime que l'on ne saurait, aux fins d'interprétation de cette disposition, tenir compte de facteurs ou circonstances extrinsèques à l'incapacité du travailleur d'exercer son emploi en raison de sa lésion professionnelle. La CALP réfère à sa propre décision dans l'affaire *Tousignant et Hawker Siddeley Canada Inc.*, [1986] C.A.L.P. 48, à l'effet que la suspension ou la rupture du contrat de travail par une mise à pied n'a aucune incidence sur l'incapacité du travailleur d'exercer son emploi à la suite d'une lésion professionnelle. Appliquant ces principes aux faits de l'espèce, elle poursuit (à la p. 119):

> Dans la présente instance, l'appelant était au service de la partie intéressée le 17 décembre 1985, date à laquelle il a subi une lésion professionnelle. En raison de cette lésion professionnelle, l'appelant a été incapable d'exercer son emploi jusqu'au 2 janvier 1986.
>
> En vertu de l'article 60 de la *Loi sur les accidents du travail et les maladies professionnelles*, la partie intéressée devait donc verser à l'appelant, et ce, sans égard à la fermeture de l'usine, 90 % de son salaire net pour chaque jour ou partie de jour où il aurait normalement travaillé, selon son horaire habituel de travail, n'eût été de son incapacité d'exercer son emploi en raison de sa lésion pendant les 14 premiers jours complets suivant le début de cette incapacité.

Elle conclut que Domtar devait verser à l'appelant 90 p. 100 de son salaire net pour chaque jour ou partie de jour où il aurait normalement travaillé selon son horaire habituel de travail et ce, sans égard à la fermeture de l'usine.

1993 CanLII 106 (SCC)

Superior Court, [1987] C.A.L.P. 254

Summarizing the CALP's conclusion in this case and in *Tousignant et Hawker Siddeley Canada Inc.*, *supra*, Masson J. recalled the purpose and wording of the *A.I.A.O.D.* Even if the CALP's decision was wrong, he was of the view that the CALP had nevertheless acted within its general jurisdiction (at p. 257):

> [TRANSLATION] We are of the view that, by acting in this way, the respondent Commission d'appel carried out one of the duties imposed on it by law and acted within its general jurisdiction.
>
> The decision of the Commission d'appel may be wrong, but it was nonetheless made within the limits of its jurisdiction.

Adding that the CALP's decision was not unreasonable, Masson J. concluded that the CALP had not exceeded its jurisdiction and he accordingly dismissed the motion in evocation.

Court of Appeal, [1991] R.J.Q. 2438

Mailhot J.A.

Mailhot J.A. first reviewed ss. 405 and 409 *A.I.A.O.D.*, which exclude, respectively, all appeals from decisions of the CALP and extraordinary remedies, except on a question of jurisdiction. She noted that, for the CALP's decision to be reversed, it had to be shown that the CALP had [TRANSLATION] "exceeded its jurisdiction or given the provision in question an interpretation so unreasonable that it could not be rationally supported on the relevant legislation" (p. 2441).

Recalling the wording of s. 60 *A.I.A.O.D.* and the arguments of the parties, Mailhot J.A. considered that the application of the patently unreasonable error test would not satisfactorily dispose of the case. In this regard, she cited the Labour Court's decision in *Commission de la santé et de la sécurité du travail v. BG Chéco International Ltée*, [1991] T.T. 405, where it was held that s. 60 raised a reasonable, significant and insurmountable doubt as to an employer's duty in the event of a layoff occurring within the 14-day period mentioned in that provision. Mailhot J.A. also referred

Cour supérieure, [1987] C.A.L.P. 254

Résumant la conclusion de la CALP en l'espèce ainsi que l'affaire *Tousignant et Hawker Siddeley Canada Inc.*, précitée, le juge Masson rappelle l'objet et la nomenclature de la *L.A.T.M.P.* Même si la décision de la CALP s'avérait mal fondée, il estime que cette dernière a néanmoins agi dans le cadre de sa compétence globale (à la p. 257):

> En agissant ainsi, nous sommes d'opinion que la Commission d'appel intimée a rempli l'une des fonctions dont elle était chargée par la loi et a agi à l'intérieur de sa compétence globale.
>
> La décision de la Commission d'appel est peut-être mal fondée, mais elle a néanmoins été prise dans les cadres de sa compétence.

Ajoutant que la décision de la CALP n'était pas déraisonnable, le juge Masson conclut que la CALP n'avait pas excédé sa juridiction et il rejette, en conséquence, la requête en évocation.

Cour d'appel, [1991] R.J.Q. 2438

Le juge Mailhot

Le juge Mailhot fait d'abord état des art. 405 et 409 *L.A.T.M.P.* qui excluent, respectivement, tout appel des décisions de la CALP et les recours extraordinaires, sauf en matière de compétence. Elle note que, pour que la décision de la CALP soit infirmée, il faut démontrer que celle-ci est «sortie de sa compétence ou a donné une interprétation au texte visé qui soit déraisonnable au point de ne pouvoir rationnellement s'appuyer sur la législation pertinente» (p. 2441).

Rappelant le texte de l'art. 60 *L.A.T.M.P.* et les arguments des parties, le juge Mailhot estime que l'application du critère de l'erreur manifestement déraisonnable ne réglerait pas le litige de manière satisfaisante. Elle cite, à cet égard, la décision du Tribunal du travail dans l'affaire *Commission de la santé et de la sécurité du travail c. BG Chéco International Ltée*, [1991] T.T. 405, où il fut jugé que l'art. 60 laissait subsister un doute raisonnable, sérieux et insurmontable quant à l'obligation d'un employeur dans le cas d'une mise à pied survenant pendant la période de 14 jours prévue à cette dis-

1993 CanLII 106 (SCC)

to the Court of Appeal's decision in *Produits Pétro-Canada Inc. v. Moalli*, [1987] R.J.Q. 261, and observed that it was in the interest of justice for the conflict to be resolved at once, regardless of traditional curial deference, because such deference, while ordinarily leading to dismissal of the application for evocation, did not resolve the unstable situation. Although there were two possibilities which could be rationally defended, in her opinion the ideal of justice, which promotes the rule of law, was not really served. She therefore felt it desirable that the intention of the legislature should prevail.

Concluding that the issue could only be resolved by the exception indicated in *Moalli*, Mailhot J.A. noted that the legislative intent was not to treat injured workers differently from other workers as regards the first 14 days covered by s. 60. In her view, the words "for each day or part of a day the worker would normally have worked" are intended to ensure that the injured person is treated like other workers, in other words, that he is entitled to the salary or wages to which he would have been entitled if the employer had work to give him and could do so, if these days were part of his regular schedule or if his contract was still in effect. Finally, Mailhot J.A. noted that this interpretation is fairer to everyone and is consistent with the other provisions of the *A.I.A.O.D.* She concluded that, as there is no obligation to pay a salary or wages when there is a plant closure, strike, lock-out, layoff, unpaid leave and so on, there can be no obligation on the employer to pay 90 percent of the net salary or wages during these periods.

Mailhot J.A. accordingly would have allowed the appeal and granted the application for evocation.

Baudouin J.A. (concurring)

While concurring in Mailhot J.A.'s conclusion, Baudouin J.A. was of the view that, even though the wording of s. 60 may be open to several inter-

position. Le juge Mailhot réfère aussi à la décision de la Cour d'appel dans l'affaire *Produits Pétro-Canada Inc. c. Moalli*, [1987] R.J.Q. 261, et souligne qu'il est dans l'intérêt de la justice de trancher immédiatement le conflit, laissant de côté la réserve judiciaire traditionnelle, parce que cette réserve, tout en conduisant normalement au rejet de la demande d'évocation, ne mettait pas fin à l'instabilité de la situation. Bien qu'elle soit devant deux thèses rationnellement défendables, selon elle, l'idéal de justice, qui veut que triomphe la règle de droit, n'y trouve pas vraiment son compte. Elle juge donc souhaitable que l'intention du législateur l'emporte.

Estimant que la résolution du litige appelle la voie d'exception indiquée dans l'arrêt *Moalli*, le juge Mailhot note que l'intention du législateur n'est pas de traiter les travailleurs accidentés de façon différente des autres travailleurs en ce qui concerne les 14 premiers jours visés par l'article 60. À son avis, les mots «pour chaque jour ou partie de jour où ce travailleur aurait normalement travaillé» visent à assurer que la personne accidentée soit traitée comme les autres personnes qui travaillent, c'est-à-dire qu'elle ait droit à un salaire comme elle y aurait droit si l'employeur avait du travail à confier et pouvait le faire ou si ces journées faisaient partie de son horaire habituel, ou si son contrat était toujours en vigueur. Finalement, le juge Mailhot note que cette interprétation est plus équitable pour tous et s'harmonise avec les autres dispositions de la *L.A.T.M.P.* Elle conclut que, comme il n'y a pas d'obligation de payer un salaire lorsqu'il y a fermeture d'établissement, grève, lock-out, mise à pied, congé non rémunéré etc., il ne peut en découler d'obligation pour l'employeur de payer 90 p. 100 du salaire net pendant ces périodes.

En conséquence, le juge Mailhot propose d'accueillir le pourvoi et de faire droit à la demande d'évocation.

Le juge Baudouin (motifs concordants)

Tout en partageant la conclusion du juge Mailhot, le juge Baudouin est d'avis que, même si la rédaction de l'art. 60 peut susciter plusieurs inter-

1993 CanLII 106 (SCC)

pretations, it does not automatically follow that no interpretation can ever be patently unreasonable. He disposed of the appeal in the same way as Mailhot J.A. (at p. 2446):

[TRANSLATION] Like my colleague, I am of the view in this case that the function of this Court is to resolve the conflict between the two administrative agencies, a conflict which creates uncertainty and is not in the interests of effective justice. Accordingly, without necessarily finding that the interpretation given by the Commission d'appel is *patently* unreasonable (even though it seems illogical to me, given a rational interpretation of the Act read as a whole, and inconsistent with the resulting philosophy), I believe that this situation is identical to that confronting this Court in *Produits Pétro-Canada Inc. v. Moalli.* [Emphasis in original.]

IV—Issues

As I said at the outset, this appeal raises questions which lie at the core of the institutional relationship between courts of law and administrative tribunals: was the CALP's decision patently unreasonable? If so, it is open to judicial review. If not, does the fact that there were, at least apparently, divergent interpretations of the same legislative provision by two administrative tribunals give rise to judicial review?

V—Analysis

While the first question raises issues which this Court has already had an opportunity to decide on several occasions, the second raises a problem which has been the subject of some controversy. A review of the principles laid down by this Court in recent years will, first, provide the background against which this appeal must be analysed. This review will indicate the principles underlying the standard of review applicable to the CALP's decision and clarify the real issues presented here by the Court of Appeal's intervention.

prétations, il ne s'ensuit pas automatiquement que toute interprétation ne puisse jamais être manifestement déraisonnable. Il dispose du pourvoi de la même façon que le juge Mailhot (à la p. 2446):

En l'espèce, j'estime, comme ma collègue, que le rôle de notre Cour est de mettre fin à ce conflit entre les deux organes administratifs, conflit qui est source d'incertitude et qui n'est pas dans l'intérêt d'une saine justice. Sans donc nécessairement trouver que l'interprétation donnée par la Commission d'appel est *manifestement* déraisonnable (même si elle me paraît illogique, eu égard à une interprétation rationnelle de la loi lue dans son ensemble et peu conforme à la philosophie qui s'en dégage), je crois que nous sommes en présence d'une situation identique à celle à laquelle notre Cour a eu à faire face dans l'affaire *Produits Pétro-Canada Inc. c. Moalli.* [En italique dans l'original.]

IV—Questions en litige

Le présent pourvoi, je le rappelle, soulève des questions qui sont au cœur du rapport institutionnel entre les cours de justice et les tribunaux administratifs: la décision de la CALP est-elle manifestement déraisonnable? Dans l'affirmative, il y a lieu à un contrôle judiciaire. Dans la négative, le fait qu'il y ait, du moins en apparence, divergence d'interprétation d'un même texte législatif de la part de deux instances administratives donne-t-il ouverture au contrôle judiciaire?

V—Analyse

Si la première question fait appel à des notions sur lesquelles notre Cour a déjà eu l'occasion de se prononcer et ce, à plusieurs reprises, la seconde soulève, en revanche, un problème qui fait l'objet d'une certaine controverse. Un rappel des principes élaborés par notre Cour au cours des dernières années permettra, en premier lieu, d'éclairer la toile de fond sur laquelle le présent pourvoi se doit d'être analysé. Tout en précisant les principes sous-jacents à la norme de contrôle applicable à la décision de la CALP, ce rappel éclairera les enjeux véritables posés, en l'espèce, par l'intervention de la Cour d'appel.

1993 CanLII 106 (SCC)

A. *Applicable Standard of Review*

Although the Court of Appeal recognized that, strictly speaking, the interpretation of s. 60 was within the CALP's jurisdiction, a functional analysis of the Act, however brief, seems desirable if not essential to decipher the legislative intent (see *Dayco (Canada) Ltd. v. CAW-Canada*, [1993] 2 S.C.R. 230, at p. 258 (*per* La Forest J.); *Canada (Attorney General) v. Public Service Alliance of Canada*, [1993] 1 S.C.R. 941 ("*PSAC No. 2*"), at pp. 965 (*per* Cory J.) and 977 (*per* L'Heureux-Dubé J.); *Université du Québec à Trois-Rivières v. Larocque*, [1993] 1 S.C.R. 471, at pp. 485-86 (*per* Lamer C.J.); *Canada (Attorney General) v. Public Service Alliance of Canada*, [1991] 1 S.C.R. 614 ("*PSAC No. 1*"), at pp. 628 (*per* Sopinka J.) and 657 (*per* Cory J.); *CAIMAW v. Paccar of Canada Ltd.*, [1989] 2 S.C.R. 983, at p. 1002, and *U.E.S., Local 298 v. Bibeault*, [1988] 2 S.C.R. 1048, at p. 1088). Determining the legislative intent as to the standard of review applicable to the decision of an administrative tribunal involves recognizing that, within its area of expertise, its decision-making autonomy may be of prime importance. Conversely, failing to go through the process of rejecting the correctness standard may conceal the real meaning of judicial intervention that falls outside the limits of the jurisdiction of an administrative agency. An initial conclusion that, for purposes of judicial review, the legislature admits several possible and rational constructions of the same legislative provision thus becomes of primary importance. This conclusion, while constituting the necessary starting-point of a discussion of the powers of supervision and control of courts of law, is ultimately the guiding principle for analyzing the appropriateness of judicial review.

In *Bibeault*, Beetz J. summarized the principles governing judicial review of decisions of an administrative tribunal, emphasizing its area of jurisdiction (at p. 1086):

A. *La norme de contrôle applicable*

Quoique la Cour d'appel ait reconnu que l'interprétation de l'art. 60 relevait de la compétence *stricto sensu* de la CALP, une analyse fonctionnelle de la Loi, si brève soit-elle, m'apparaît souhaitable, sinon nécessaire pour dégager l'intention du législateur (voir *Dayco (Canada) Ltd. c. TCA-Canada*, [1993] 2 R.C.S. 230, à la p. 258 (le juge La Forest); *Canada (Procureur général) c. Alliance de la Fonction publique du Canada*, [1993] 1 R.C.S. 941 («*AFPC n° 2*»), aux pp. 965 (le juge Cory) et 977 (le juge L'Heureux-Dubé); *Université du Québec à Trois-Rivières c. Larocque*, [1993] 1 R.C.S. 471, aux pp. 485 et 486 (le juge en chef Lamer); *Canada (Procureur général) c. Alliance de la Fonction publique du Canada*, [1991] 1 R.C.S. 614 («*AFPC n° 1*»), aux pp. 628 (le juge Sopinka) et 657 (le juge Cory); *CAIMAW c. Paccar of Canada Ltd.*, [1989] 2 R.C.S. 983, à la p. 1002, et *U.E.S., local 298 c. Bibeault*, [1988] 2 R.C.S. 1048, à la p. 1088). Cerner l'intention du législateur quant à la norme de contrôle applicable à la décision d'un tribunal administratif, c'est reconnaître que son autonomie décisionnelle peut, dans le cadre de son expertise, se révéler primordiale. À l'inverse, éluder les modalités d'une mise à l'écart de la norme de contrôle axée sur la justesse d'une interprétation donnée risque de masquer la portée véritable d'une intervention judiciaire qui s'articule au-delà du paramètre du champ de compétence de l'organisme administratif. Une conclusion initiale à l'effet que le législateur admet, aux fins du contrôle judiciaire, plusieurs lectures possibles et rationnelles d'une même disposition législative devient, par là, capitale. Tout en constituant le point de départ nécessaire d'un débat portant sur le pouvoir de contrôle et de surveillance des cours de justice, ce constat représente le fil directeur à l'aide duquel l'opportunité d'un contrôle judiciaire doit, en définitive, être analysée.

Dans l'arrêt *Bibeault*, le juge Beetz a résumé les principes régissant le contrôle judiciaire de la décision d'un tribunal administratif en mettant l'accent sur son champ de compétence (à la p. 1086):

1993 CanLII 106 (SCC)

1. if the question of law at issue is within the tribunal's jurisdiction, it will only exceed its jurisdiction if it errs in a patently unreasonable manner; a tribunal which is competent to answer a question may make errors in so doing without being subject to judicial review;

2. if however the question at issue concerns a legislative provision limiting the tribunal's powers, a mere error will cause it to lose jurisdiction and subject the tribunal to judicial review.

The initial step advocated by this Court must therefore focus primarily on the concept of jurisdiction. This step must, however, take into account both the desirability of curial deference and the ease with which a question can be incorrectly characterized as one of jurisdiction (see *Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp.*, [1979] 2 S.C.R. 227, at p. 233, and *Canada Labour Relations Board v. Halifax Longshoremen's Association, Local 269*, [1983] 1 S.C.R. 245, at p. 256). *Bibeault* explained the meaning of the concept of jurisdiction in the context of judicial review as follows (at p. 1090):

> Jurisdiction *stricto sensu* is defined as the power to decide. The importance of a grant of jurisdiction relates not to the tribunal's capacity or duty to decide a question but to the determining effect of its decision. As S. A. de Smith points out, the tribunal's decision on a question within its jurisdiction is binding on the parties to the dispute. . . . The true problem of judicial review is to discover whether the legislator intended the tribunal's decision on these matters to be binding on the parties to the dispute, subject to the right of appeal if any. [Emphasis added.]

This amounts to asking "Who should answer this question, the administrative tribunal or a court of law?" It thus involves determining who is in the best position to rule on the impugned decision. According to Beetz J., at p. 1088, in order to deal adequately with the question "Did the legislator intend the question to be within the jurisdiction conferred on the tribunal?", a court of law

1. Si la question de droit en cause relève de la compétence du tribunal, le tribunal n'excède sa compétence que s'il erre d'une façon manifestement déraisonnable. Le tribunal qui est compétent pour trancher une question peut, ce faisant, commettre des erreurs sans donner ouverture à la révision judiciaire.

2. Si, par contre, la question en cause porte sur une disposition législative qui limite les pouvoirs du tribunal, une simple erreur fait perdre compétence et donne ouverture à la révision judiciaire.

La démarche initiale préconisée par notre Cour exige donc, avant tout, de mettre l'accent sur la notion de compétence. Cette démarche doit, cependant, tenir compte à la fois de la valeur que représente la retenue judiciaire et de la facilité avec laquelle une question peut être incorrectement qualifiée de question de compétence (voir *Syndicat canadien de la Fonction publique, section locale 963 c. Société des alcools du Nouveau-Brunswick*, [1979] 2 R.C.S. 227, à la p. 233, et *Conseil canadien des relations du travail c. Association des débardeurs d'Halifax, section locale 269*, [1983] 1 R.C.S. 245, à la p. 256.) L'arrêt *Bibeault* est venu, ainsi, préciser le sens de la notion de compétence dans le cadre du contrôle judiciaire (à la p. 1090):

> La compétence, *stricto sensu*, se définit comme le pouvoir de décider une question. L'importance d'un octroi de compétence se rattache non pas à la faculté ou à l'obligation du tribunal de traiter d'une question, mais au caractère déterminant de sa décision. Comme S. A. de Smith le souligne, la décision du tribunal sur une question qui relève de sa compétence lie les parties au litige. [. . .] Le véritable problème du contrôle judiciaire est de savoir si le législateur veut que la décision du tribunal sur ces questions lie les parties au litige, sous réserve du droit d'appel, s'il en est. [Je souligne.]

Ce problème se résume à se demander «Qui doit répondre à cette question, le tribunal administratif ou une cour de justice?» Il met donc en jeu la question de savoir qui est le mieux placé pour se prononcer sur la décision contestée. Selon le juge Beetz, à la p. 1088, afin d'aborder adéquatement la question «Le législateur a-t-il voulu qu'une telle matière relève de la compétence conférée au tribunal?», une cour de justice

1993 CanLII 106 (SCC)

examines not only the wording of the enactment conferring jurisdiction on the administrative tribunal, but the purpose of the statute creating the tribunal, the reason for its existence, the area of expertise of its members and the nature of the problem before the tribunal.

The legislature's intention to give the CALP the power to make a final ruling on the meaning and scope of s. 60 *A.I.A.O.D.* is not open to question. As an appellate administrative tribunal, the CALP hears and disposes exclusively of appeals brought under ss. 37.3 and 193 of the *Act respecting Occupational Health and Safety* and the *A.I.A.O.D.* (s. 397). It has exclusive jurisdiction to "confirm the decision or the order brought before it; it may also quash the decision or the order and shall in that case render the decision or make the order that should have been given initially" (s. 400). Its members are subject to specific obligations set out in ss. 373 *et seq. A.I.A.O.D.*, they have all the powers necessary for the exercise of their jurisdiction and may rule on any questions of law or of fact (s. 407). In addition to these significant powers, the CALP has an obligation to publish its own decisions (s. 391), the authority to make recommendations to the Minister (s. 396) as well as the authority to review or revoke its own decisions for cause (s. 406).

Several provisions are designed to ensure that CALP decisions are effective. The decisions are final and without appeal and every person contemplated in the decision must comply with them without delay (s. 405). They may be filed in the office of the prothonotary of the Superior Court of the district in which the appeal was brought and such filing makes them executory as if they were final judgments of the Superior Court without appeal, and with all the effects thereof (s. 429). CALP decisions are also protected by a full privative clause, which I reproduce here for the sake of convenience:

examine non seulement le libellé de la disposition législative qui confère la compétence au tribunal administratif, mais également l'objet de la loi qui crée le tribunal, la raison d'être de ce tribunal, le domaine d'expertise de ses membres, et la nature du problème soumis au tribunal.

L'intention du législateur de confier à la CALP le pouvoir de se prononcer de manière définitive sur le sens et la portée de l'art. 60 *L.A.T.M.P.* ne souffre aucune ambiguïté. À titre de tribunal administratif d'appel, la CALP connaît et dispose, exclusivement à tout autre tribunal, des appels interjetés en vertu des art. 37.3 et 193 de la *Loi sur la santé et la sécurité du travail* et de la *L.A.T.M.P.* (art. 397). Elle possède une compétence exclusive pour «confirmer la décision, l'ordre ou l'ordonnance porté devant elle; elle peut aussi l'infirmer et doit alors rendre la décision, l'ordre ou l'ordonnance qui, selon elle, aurait dû être rendu en premier lieu» (art. 400). Ses membres sont soumis à des obligations spécifiques prévues aux art. 373 et suiv. *L.A.T.M.P.*, ils possèdent tous les pouvoirs nécessaires à l'exercice de leur compétence et peuvent décider de toute question de droit et de fait (art. 407). À ces pouvoirs significatifs s'ajoute l'obligation de la CALP de publier ses propres décisions (art. 391), le pouvoir de formuler des recommandations auprès du ministre (art. 396) ainsi que celui de réviser ou révoquer, pour cause, ses propres décisions (art. 406).

Plusieurs dispositions ont pour objet d'assurer l'efficacité des décisions de la CALP. Celles-ci sont finales et sans appel et toute personne visée doit s'y conformer sans délai (art. 405). Elles peuvent être déposées au bureau du protonotaire de la Cour supérieure du district où l'appel a été formé et ce dépôt la rend exécutoire comme un jugement final et sans appel de la Cour supérieure et en a tous les effets (art. 429). Les décisions de la CALP sont, de surcroît, protégées par une clause privative complète, que je rappelle ici pour fins de commodité:

1993 CanLII 106 (SCC)

409. Except on a question of jurisdiction, no proceedings under article 33 of the Code of Civil Procedure (chapter C-25) nor any extraordinary recourse within the meaning of the said Code may be taken, nor any provisional remedy be ordered against the board of appeal or one of its commissioners acting in his official capacity.

A judge of the Court of Appeal may annul summarily, upon a motion, any action granted, any writ, order or injunction issued or granted contrary to this section.

Finally, the nature of the problem presented here raises questions on which the CALP is eminently qualified. Section 60 *A.I.A.O.D.* is not only one of the legislative provisions on which the CALP has the express power to rule, it employs concepts which are at the core of its area of expertise, namely disability, employment injury and the complex system of compensation set up by the Quebec legislature. The interpretation of s. 60 by the CALP is, thus, a function directly relating to the objective sought by the legislature: to permit an administrative tribunal to issue a final ruling on decisions of first instance by giving a final interpretation of its enabling statute.

Since the interpretation of s. 60 *A.I.A.O.D.* is, strictly speaking, within the jurisdiction of the CALP, the standard of review applicable here is whether the decision is patently unreasonable. In *Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp., supra,* Dickson J. formulated the question which courts of law must constantly keep in mind in such circumstances (at p. 237):

> Did the Board here so misinterpret the provisions of the Act as to embark on an inquiry or answer a question not remitted to it? Put another way, was the Board's interpretation so patently unreasonable that its construction cannot be rationally supported by the relevant legislation and demands intervention by the court upon review? [Emphasis added.]

The patently unreasonable error test is the pivot on which judicial deference rests. As it relates to matters within the specialized jurisdiction of an

409. Sauf sur une question de compétence, une action en vertu de l'article 33 du Code de procédure civile (chapitre C-25) ou un recours extraordinaire au sens de ce code ne peut être exercé, et une mesure provisionnelle ne peut être ordonnée contre la Commission d'appel ou l'un de ses commissaires agissant en sa qualité officielle.

Un juge de la Cour d'appel peut, sur requête, annuler sommairement une action accueillie, un bref ou une ordonnance délivré ou une injonction accordée à l'encontre du présent article.

Enfin, la nature du problème ici posé soulève des questions sur lesquelles la CALP est éminemment qualifiée. Tout en comptant parmi les dispositions législatives sur lesquelles la CALP a le pouvoir explicite de se prononcer, l'art. 60 *L.A.T.M.P.* fait appel a des notions qui sont au cœur de son domaine d'expertise, soit l'incapacité, la lésion professionnelle et le régime d'indemnisation complexe instauré par le législateur québécois. L'interprétation de l'art. 60 par la CALP constitue donc une fonction qui participe directement à l'objectif poursuivi par le législateur: permettre à un tribunal administratif de disposer, en dernier ressort, des décisions des instances inférieures en interprétant sa loi constitutive de façon finale.

Puisque l'interprétation de l'art. 60 *L.A.T.M.P.* relève de la compétence *stricto sensu* de la CALP, la norme de contrôle ici applicable est le caractère manifestement déraisonnable de sa décision. Dans l'arrêt *Syndicat canadien de la Fonction publique, section locale 963 c. Société des alcools du Nouveau-Brunswick*, précité, le juge Dickson a formulé la question que les cours de justice devaient, dans ces conditions, constamment garder à l'esprit (à la p. 237):

> La Commission a-t-elle interprété erronément les dispositions législatives de façon à entreprendre une enquête ou à répondre à une question dont elle n'était pas saisie? Autrement dit, l'interprétation de la Commission est-elle déraisonnable au point de ne pouvoir rationnellement s'appuyer sur la législation pertinente et d'exiger une intervention judiciaire? [Je souligne.]

Le critère de l'erreur manifestement déraisonnable constitue le pivot sur lequel repose la retenue des cours de justice. Dans le cadre des questions

1993 CanLII 106 (SCC)

administrative body protected by a privative clause, this standard of review has a specific purpose: ensuring that review of the correctness of an administrative interpretation does not serve, as it has in the past, as a screen for intervention based on the merits of a given decision. The process by which this standard of review has progressively been accepted by courts of law cannot be separated from the contemporary principle of curial deference, which is, in turn, closely linked with the development of extensive administrative justice (see Cory J.'s reasons in *PSAC No. 1* and *PSAC No. 2*, *supra*, and *National Corn Growers Assn. v. Canada (Import Tribunal)*, [1990] 2 S.C.R. 1324 (*per* Wilson J.)). Substituting one's opinion for that of an administrative tribunal in order to develop one's own interpretation of a legislative provision eliminates its decision-making autonomy and special expertise. Since such intervention occurs in circumstances where the legislature has determined that the administrative tribunal is the one in the best position to rule on the disputed decision, it risks, at the same time, thwarting the original intention of the legislature. For the purposes of judicial review, statutory interpretation has ceased to be a necessarily "exact" science and this Court has, again recently, confirmed the rule of curial deference set forth for the first time in *Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp.*; *United Brotherhood of Carpenters and Joiners of America, Local 579 v. Bradco Construction Ltd.*, [1993] 2 S.C.R. 316; *PSAC No. 2*, *supra*; *Lester (W.W.) (1978) Ltd. v. United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry, Local 740*, [1990] 3 S.C.R. 644; *Bell Canada v. Canada (Canadian Radio-television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722; *National Corn Growers Assn. v. Canada (Import Tribunal)*, *supra*, and *CAIMAW v. Paccar of Canada Ltd.*, *supra*. In the recent decision *PSAC No. 2*, Cory J. noted that this was a strict test (at p. 964):

It is not enough that the decision of the Board is wrong in the eyes of the court; it must, in order to be

relevant de la compétence spécialisée d'un organisme administratif protégé par une clause privative, cette norme de contrôle a une finalité précise: éviter qu'un contrôle de la justesse de l'interprétation administrative ne serve de paravent, comme ce fut le cas dans le passé, à un interventionnisme axé sur le bien-fondé d'une décision donnée. Le processus par lequel cette norme de contrôle a progressivement trouvé droit de cité chez les cours de justice est indissociable du principe contemporain de la retenue judiciaire, étroitement lié, à son tour, au développement d'une justice administrative à grande échelle (voir les motifs du juge Cory dans *AFPC nº 1* et *AFPC nº 2*, précités; *National Corn Growers Assn. c. Canada (Tribunal des importations)*, [1990] 2 R.C.S. 1324 (le juge Wilson)). Substituer son opinion à celle du tribunal administratif afin de dégager sa propre interprétation d'une disposition législative, c'est réduire à néant son autonomie décisionnelle et l'expertise qui lui est propre. Puisqu'une telle intervention surgit dans un contexte où le législateur a déterminé que le tribunal administratif est celui qui est le mieux placé pour se prononcer sur la décision contestée, elle risque de contrecarrer, par la même occasion, son intention première. L'interprétation des lois a cessé, aux fins du contrôle judiciaire, d'être une science nécessairement «exacte» et notre Cour a confirmé, encore récemment, la règle de la retenue judiciaire énoncée pour la première fois dans l'arrêt *Syndicat canadien de la Fonction publique, section locale 963 c. Société des alcools du Nouveau-Brunswick*; *Fraternité unie des charpentiers et menuisiers d'Amérique, section locale 579 c. Bradco Construction Ltd.*, [1993] 2 R.C.S. 316; *AFPC nº 2*, précité; *Lester (W.W.) (1978) Ltd. c. Association unie des compagnons et apprentis de l'industrie de la plomberie et de la tuyauterie, section locale 740*, [1990] 3 R.C.S. 644; *Bell Canada c. Canada (Conseil de la radiodiffusion et des télécommunications canadiennes)*, [1989] 1 R.C.S. 1722; *National Corn Growers Assn. c. Canada (Tribunal des importations)*, précité, et *CAIMAW c. Paccar of Canada Ltd.*, précité. Dans le récent arrêt *AFPC nº 2*, le juge Cory a rappelé qu'il s'agissait là d'une norme sévère (à la p. 964):

Il ne suffit pas que la décision de la Commission soit erronée aux yeux de la cour de justice; pour qu'elle soit

1993 CanLII 106 (SCC)

patently unreasonable, be found by the court to be clearly irrational.

B. *Is the CALP's Interpretation Patently Unreasonable?*

While agreeing with the interpretation adopted by the Court of Appeal, Domtar argues that the court should have concluded that the CALP's decision in the case at bar was patently unreasonable. The CALP interpreted s. 60 *A.I.A.O.D.*, which I reproduced earlier, as follows (at p. 118):

> [TRANSLATION] That section imposes on the employer with whom the worker is employed when he suffers an employment injury an obligation to pay him, as an income replacement indemnity on account of his employment injury, 90% of his net salary or wages for each day or part of a day the worker would normally have worked had he not been unable to carry on his employment by reason of his injury, for the first 14 days following the beginning of his disability.
>
> The Commission d'appel concluded in this regard that the words "would normally have worked" used in s. 60 should not be separated from the words "had he not been disabled" which immediately follow them, so that no account should be taken of factors or circumstances extrinsic to the worker's inability to work by reason of his employment injury in determining what period he would have worked, in the usual way and had he not been disabled, during the first 14 days following the beginning of his disability.
>
> The Commission d'appel accordingly concluded that under s. 60 of the *Act respecting Industrial Accidents and Occupational Diseases*, the employer must pay the worker 90% of his net salary or wages for each day or part of a day on which he would normally have worked had he not been disabled by reason of his injury, regardless of any extrinsic cause, such as plant closure, which had no connection with the worker's inability to carry on his employment by reason of his employment injury. [Emphasis added.]

The CALP, therefore, concluded that the respondent had to pay the appellant 90 percent of his net salary or wages for each day or part of a day on which he would normally have worked according to his usual work schedule, regardless of the plant closure.

manifestement déraisonnable, cette cour doit la juger clairement irrationnelle.

B. *L'interprétation de la CALP est-elle manifestement déraisonnable?*

Tout en étant d'accord avec l'interprétation retenue par la Cour d'appel, Domtar soutient que celle-ci aurait dû conclure que la décision de la CALP était, en l'espèce, manifestement déraisonnable. La CALP a interprété l'art. 60 *L.A.T.M.P.*, que j'ai déjà reproduit ci-avant, de la façon suivante (à la p. 118):

> Cet article impose à l'employeur, au service duquel se trouve le travailleur lorsqu'il est victime d'une lésion professionnelle, l'obligation de lui verser, à titre d'indemnité de remplacement du revenu en raison de sa lésion professionnelle, 90 % de son salaire net pour chaque jour ou partie de jour où ce travailleur aurait normalement travaillé n'eût été de son incapacité d'exercer son emploi en raison de sa lésion, pendant les 14 premiers jours suivant le début de son incapacité.
>
> La Commission d'appel considère à cet égard que les termes «aurait normalement travaillé», utilisés à l'article 60, ne doivent pas être dissociés des termes «n'eût été de son incapacité» qui les suivent immédiatement, de sorte qu'on ne doit pas tenir compte de facteurs ni de circonstances extrinsèques à l'incapacité du travailleur de travailler en raison de sa lésion professionnelle pour déterminer à quelle période il aurait travaillé, de façon habituelle et n'eût été de son incapacité, durant les 14 premiers jours suivant le début de son incapacité.
>
> La Commission d'appel considère donc qu'aux termes de l'article 60 de la *Loi sur les accidents du travail et les maladies professionnelles* l'employeur doit verser au travailleur 90 % de son salaire net pour chaque jour ou partie de jour où il aurait habituellement travaillé n'eût été de son incapacité en raison de sa lésion, sans égard à quelque cause extrinsèque, une fermeture d'usine, à titre d'exemple, n'ayant aucune relation avec l'incapacité du travailleur d'exercer son emploi en raison de sa lésion professionnelle. [Je souligne.]

La CALP a donc conclu que l'intimée devait verser à l'appelant 90 p. 100 de son salaire net pour chaque jour ou partie de jour où il aurait normalement travaillé selon son horaire habituel de travail et ce, sans égard à la fermeture de l'usine.

1993 CanLII 106 (SCC)

In my opinion, this decision cannot be said to be patently unreasonable. This is also the conclusion reached by the Superior Court and the Court of Appeal. It is one thing to argue, as Domtar does, that the CALP's interpretation unduly favours workers who suffer occupational injuries over employees who receive no salary or wages during a strike, lockout or layoff; it is quite another to conclude that this decision is clearly irrational. In order to show that the CALP's interpretation is unreasonable, Domtar in its factum emphasized the difficulty of determining the frequency of the services provided by the worker prior to an injury for purposes of the phrase "would normally have worked":

[TRANSLATION] Thus, what does this "habit" signify for a worker who suffers an employment injury after working for the same employer for 10 years? Is the habit to be assessed on the basis of the entire period or only part of it? Should we only take into account the last year, the last month or the last week? If a collective agreement was signed on the day a worker suffers an employment injury and that collective agreement increases a worker's work week from four to five days a week, what happens according to the interpretation proposed by the C.A.L.P.? And if a worker suffers an employment injury on the day he is hired, can the employer successfully contend that he owes the worker no income replacement indemnity under s. 60 of the A.I.A.O.D.?

Without ruling on the merits of these hypotheses, I am of the view that, even if these problems arose in connection with the compensation system created by the Act, it would be for the CALP, and not a court of law, to dispose of them in a final fashion under its jurisdiction *stricto sensu* for the purposes of the *A.I.A.O.D*. This jurisdiction necessarily includes some room to manoeuvre, avoiding the need to anticipate all the legal consequences that may result from a given decision. In the case at bar the CALP did not go beyond the limits laid down by the legislature. The purpose of the *A.I.A.O.D.* is summarized in s. 1, which reads as follows:

Cette décision ne saurait, à mon avis, être qualifiée de manifestement déraisonnable. C'est la conclusion, d'ailleurs, à laquelle sont parvenues et la Cour supérieure et la Cour d'appel. En effet, c'est une chose que de soutenir, comme le fait Domtar, que l'interprétation de la CALP favorise indûment les travailleurs victimes de lésions professionnelles par rapport aux employés qui ne reçoivent pas de salaire à l'occasion d'une grève, d'un lock-out, ou d'une mise à pied, c'en est une autre que de conclure que cette décision est clairement irrationnelle. Pour démontrer le caractère déraisonnable de l'interprétation de la CALP, Domtar a insisté, dans son mémoire, sur la difficulté de circonscrire la fréquence de la prestation de travail fournie par le travailleur avant une lésion aux fins de l'expression «aurait normalement travaillé»:

Ainsi, à quoi rattache-t-on cette «habitude» pour un travailleur victime d'une lésion professionnelle qui travaille pour un même employeur depuis 10 ans? Évaluera-t-on l'habitude en tenant compte de toute cette période ou d'une partie de celle-ci? Devrions-nous ne tenir compte que de la dernière année, du dernier mois ou de la dernière semaine? Si une convention collective a été signée le jour où un travailleur subit une lésion professionnelle et que cette convention collective augmente la semaine de travail d'un travailleur de 4 à 5 jours par semaine: que fera-t-on suivant l'interprétation proposée par la C.A.L.P.? Et si un travailleur subit une lésion professionnelle le jour de son embauche, l'employeur pourra-t-il prétendre avec succès qu'il ne lui doit aucune indemnité de remplacement du revenu en vertu de l'article 60 de la L.A.T.M.P.?

Sans me prononcer sur le bien-fondé de ces hypothèses, je suis d'avis que, même si ces difficultés venaient à surgir dans le cadre du régime d'indemnisation prévu par la Loi, il appartiendrait à la CALP, et non à une cour de justice, d'en disposer en vertu de sa compétence *stricto sensu* aux fins de la *L.A.T.M.P.* et ce, de façon finale. Cette compétence comprend, nécessairement, une marge de manœuvre qui permet de ne pas entrevoir toutes les conséquences juridiques qui sont susceptibles de découler d'une décision donnée. En l'espèce, la CALP ne s'est pas écartée des jalons posés par le législateur. L'objet de la *L.A.T.M.P.* est résumé à l'art. 1, qui se lit ainsi:

1993 CanLII 106 (SCC)

1. The object of this Act is to provide compensation for employment injuries and the consequences they entail for beneficiaries.

The process of compensation for employment injuries includes provision of the necessary care for the consolidation of an injury, the physical, social and vocational rehabilitation of a worker who has suffered an injury, the payment of income replacement indemnities, compensation for bodily injury and, as the case may be, death benefits.

This Act, within the limits laid down in Chapter VII, also entitles a worker who has suffered an employment injury to return to work.

The entitlement of a worker who has suffered an employment injury to an income replacement indemnity is further dealt with in s. 44. This provision reads as follows:

44. A worker who suffers an employment injury is entitled to an income replacement indemnity if he becomes unable to carry on his employment by reason of the injury.

A worker who is no longer employed when his employment injury appears is entitled to the income replacement indemnity if he becomes unable to carry on the employment he usually held.

In concluding that the effect of the application of s. 60 was not to deprive the worker who suffers an employment injury of the right conferred on him by s. 44, the CALP did not render a patently unreasonable decision. The argument put forward by Domtar that the CALP's conclusion overlooks several important aspects which are peculiar to the general system of compensation may well be correct. This is not, however, a basis for judicial intervention as, in my view, this would simply be an error of law within jurisdiction. Since the evidence that the appellant suffered an employment injury on the relevant dates has never been disputed, the CALP's decision can be rationally defended both on the facts and on the law.

In principle, this conclusion should suffice to dispose of this appeal. This was not a case in which the CALP was deciding a general point of

1. La présente loi a pour objet la réparation des lésions professionnelles et des conséquences qu'elles entraînent pour les bénéficiaires.

Le processus de réparation des lésions professionnelles comprend la fourniture des soins nécessaires à la consolidation d'une lésion, la réadaptation physique, sociale et professionnelle du travailleur victime d'une lésion, le paiement d'indemnités de remplacement du revenu, d'indemnités pour dommages corporels et, le cas échéant, d'indemnité de décès.

La présente loi confère en outre, dans les limites prévues au chapitre VII, le droit au retour au travail du travailleur victime d'une lésion professionnelle.

Par ailleurs, le droit du travailleur victime d'une lésion professionnelle à l'indemnité de remplacement de revenu est prévu à l'art. 44. Cette disposition est à l'effet suivant:

44. Le travailleur victime d'une lésion professionnelle a droit à une indemnité de remplacement du revenu s'il devient incapable d'exercer son emploi en raison de cette lésion.

Le travailleur qui n'a plus d'emploi lorsque se manifeste sa lésion professionnelle a droit à cette indemnité s'il devient incapable d'exercer l'emploi qu'il occupait habituellement.

En concluant que l'application de l'art. 60 n'avait pas pour effet de retirer au travailleur victime d'une lésion professionnelle le droit que lui confère l'art. 44, la CALP n'a pas rendu une décision manifestement déraisonnable. L'argument avancé par Domtar à l'effet que la conclusion de la CALP omet plusieurs nuances importantes qui sont propres au régime global d'indemnisation est, peut-être, fondé. Cela ne constitue pas, pour autant, un motif d'intervention judiciaire car, à mes yeux, il ne s'agirait là que d'une simple erreur de droit commise dans le cadre de sa compétence. La preuve que l'appelant fut victime d'une lésion professionnelle aux dates pertinentes n'ayant jamais été contestée, la décision de la CALP est rationnellement défendable tant sous l'angle des faits que du droit.

Cette conclusion devrait suffire, en principe, pour disposer du présent pourvoi. Il ne s'agissait pas, en effet, pour la CALP de décider d'une ques-

1993 CanLII 106 (SCC)

law, to which, in the absence of a privative clause, this Court has held that there is no reason to show deference (*University of British Columbia v. Berg*, [1993] 2 S.C.R. 353; *United Brotherhood of Carpenters and Joiners of America, Local 579 v. Bradco Construction Ltd.*, *supra*; *Dayco (Canada) Ltd. v. CAW-Canada*, *supra*; *Canada (Attorney General) v. Mossop*, [1993] 1 S.C.R. 554). Similarly, since the interpretation of s. 60 *A.I.A.O.D.* does not raise constitutional questions here, the rule of curial deference clearly cannot be excluded on this ground (*Douglas/Kwantlen Faculty Assn. v. Douglas College*, [1990] 3 S.C.R. 570; *Cuddy Chicks Ltd. v. Ontario (Labour Relations Board)*, [1991] 2 S.C.R. 5, and *Tétreault-Gadoury v. Canada (Employment and Immigration Commission)*, [1991] 2 S.C.R. 22). Finally, as I pointed out earlier, the intention of the legislature to confer on the CALP the power to make a final ruling on the meaning and scope of s. 60 *A.I.A.O.D.* is not open to question. As the interpretation of this provision is at the core of its specialized jurisdiction, the rule of curial deference should in principle apply.

C. *Court of Appeal's Intervention*

Against this background, the intervention of the Court of Appeal may now be considered. Though it properly concluded that the CALP's decision was not patently unreasonable, the court was of the view that to apply this standard of review would not satisfactorily resolve the issue. According to Mailhot J.A. (at p. 2443):

> [TRANSLATION] In fact, it is clear that if this Court dismissed the appeal based on a finding that the C.A.L.P.'s interpretation was not unreasonable, the difficulties would not be resolved. This is well illustrated by a recent judgment of the Labour Court filed by the appellant. In *Commission de la santé et de la sécurité du travail du Québec v. BG Chéco International ltée*, *supra*, the C.S.S.T. brought penal proceedings against an employer which refused to pay a worker 90% of his net salary or wages for seven days, and the employer gave as its defence the fact that four days before suffering an employment injury the worker had been given a layoff notice for a temporary lack of work, a layoff which took

tion générale de droit ne relevant pas de son expertise où, en l'absence de clause privative, notre Cour a jugé qu'il n'y avait pas lieu de faire preuve de retenue (*Université de la Colombie-Britannique c. Berg*, [1993] 2 R.C.S. 353; *Fraternité unie des charpentiers et menuisiers d'Amérique, section locale 579 c. Bradco Construction Ltd.*, précité; *Dayco (Canada) Ltd. c. TCA-Canada*, précité; *Canada (Procureur général) c. Mossop*, [1993] 1 R.C.S. 554). De même, puisque l'interprétation de l'art. 60 *L.A.T.M.P.* ne soulève pas, en l'espèce, de questions constitutionnelles, la règle de la retenue judiciaire ne saurait être écartée pour ce motif (*Douglas/Kwantlen Faculty Assn. c. Douglas College*, [1990] 3 R.C.S. 570; *Cuddy Chicks Ltd. c. Ontario (Commission des relations de travail)*, [1991] 2 R.C.S. 5, et *Tétreault-Gadoury c. Canada (Commission de l'emploi et de l'immigration)*, [1991] 2 R.C.S. 22). Enfin, comme je l'ai souligné précédemment, l'intention du législateur de confier à la CALP le pouvoir de se prononcer de manière définitive sur le sens et la portée de l'art. 60 *L.A.T.M.P.* ne souffre aucune ambiguïté. L'interprétation de cette disposition étant au cœur de sa compétence spécialisée, la règle de la retenue judiciaire doit, en principe, trouver application.

C. *L'intervention de la Cour d'appel*

Ces jalons posés, il convient maintenant de se pencher sur l'intervention de la Cour d'appel. Bien qu'elle ait, à bon droit, conclu que la décision de la CALP n'était pas manifestement déraisonnable, la cour a estimé que l'application de cette norme de contrôle ne réglerait pas le litige de manière satisfaisante. Selon le juge Mailhot (à la p. 2443):

> De fait, l'on sait que, si notre Cour rejetait l'appel à la suite d'une conclusion que l'interprétation de la C.A.L.P. n'était pas déraisonnable, les difficultés ne seraient pas réglées. En effet, l'appelante a déposé un jugement récent du Tribunal du travail qui illustre bien cet énoncé. Dans l'affaire *Commission de la santé et de la sécurité du travail du Québec c. B.G. Chéco International ltée*, précitée, la C.S.S.T. a intenté une poursuite de nature pénale contre un employeur qui refusait de verser à un travailleur 90 % de son salaire net pendant sept jours, l'employeur invoquant pour sa défense que le travailleur avait reçu, quatre jours avant qu'il ne soit victime d'une lésion professionnelle, un avis de mise à

1993 CanLII 106 (SCC)

effect three days after the injury. After a carefully reasoned analysis, the Labour Court judge acquitted the employer. [Emphasis added.]

In the case referred to above by the Court of Appeal, the Labour Court was of the view (at p. 411) that:

> [TRANSLATION] Though we are dealing here with remedial legislation the aim and purpose of which are to compensate workers who suffer industrial accidents and occupational diseases, the Court must necessarily ask itself whether, despite recourse to this rule of interpretation, there is nevertheless a reasonable doubt as to the meaning or scope of the text, in which case it must acquit the defendant.

After undertaking its own analysis of several provisions of the *A.I.A.O.D.*, the Labour Court held that s. 60 raised [TRANSLATION] "a reasonable, significant and insurmountable doubt" as to the obligation on an employer in the event of a layoff occurring during the 14-day period mentioned in that provision (p. 412). The Labour Court therefore concluded that, in such circumstances, the employer should be acquitted (at p. 412):

> [TRANSLATION] In such a case, the Court has no choice but to give the defendant the benefit of the statutory interpretation most favourable to it, as in the circumstances such an interpretation is at least equally justifiable. As pointed out in Maxwell [*Maxwell on the Interpretation of Statutes* (12th ed. 1969), at p. 239]:
>
> > "If there is a reasonable interpretation which will avoid the penalty in any particular case", said Lord Esher M.R., "we must adopt that construction. If there are two reasonable constructions we must give the more lenient one. That is the settled rule for the construction of penal sections".

Citing its precedent in *Produits Pétro-Canada Inc. v. Moalli, supra*, the Court of Appeal held that it was in the interest of justice to resolve the conflict at once, abandoning the curial deference which would otherwise be required here. Mailhot J.A. concluded that she was faced with [TRANSLATION] "two . . . possibilities that could be rationally defended" and summed up the situation

pied pour manque temporaire de travail, mise à pied qui a pris effet trois jours après la lésion. Le juge du Tribunal du travail, après une analyse serrée, acquitte l'employeur. [Je souligne.]

Dans l'affaire à laquelle la Cour d'appel réfère, le Tribunal du travail a estimé que (à la p. 411):

> Même si nous sommes ici en présence d'une loi remédiatrice dont le but et l'objet visent l'indemnisation des travailleurs victimes d'accidents du travail et de maladies professionnelles, le Tribunal doit cependant nécessairement se demander si, malgré le recours à cette règle d'interprétation, il subsiste malgré tout un doute raisonnable quant au sens ou à la portée du texte, auquel cas il devra acquitter la défenderesse.

Après avoir procédé à sa propre analyse de plusieurs dispositions de la *L.A.T.M.P.*, le Tribunal du travail a jugé que l'art. 60 laissait subsister «un doute raisonnable, sérieux et insurmontable» quant à l'obligation d'un employeur dans le cas d'une mise à pied survenant pendant la période de 14 jours prévue à cette disposition (p. 412). Le Tribunal du travail a donc conclu, en l'espèce, à l'acquittement de l'employeur (à la p. 412):

> Dans un tel cas, le Tribunal n'a pas d'autre choix que de faire bénéficier la défenderesse de l'interprétation de la loi qui lui est la plus favorable, une telle interprétation étant dans les circonstances au moins tout aussi justifiable. Comme l'affirme Maxwell [*Maxwell on the Interpretation of Statutes* (12e éd. 1969), à la p. 239]:
>
> > [TRADUCTION] «S'il existe une interprétation raisonnable qui permet de pas infliger de peine dans un cas particulier» dit le maître des rôles lord Esher «c'est l'interprétation qu'il faut adopter. S'il existe deux interprétations raisonnables, nous devons choisir la plus indulgente des deux. C'est la règle d'interprétation établie en matière pénale».

Citant son précédent dans l'affaire *Produits Pétro-Canada Inc. c. Moalli*, précitée, la Cour d'appel a jugé qu'il était dans l'intérêt de la justice de trancher immédiatement le conflit, laissant de côté la réserve judiciaire qui autrement s'imposait ici. Estimant qu'elle était en présence de «deux thèses rationnellement défendables» le juge Mailhot a résumé la situation créée par l'interprétation

1993 CanLII 106 (SCC)

created by the interpretation of the CALP, on the one hand, and that of the Labour Court, on the other (at p. 2444):

> [TRANSLATION] It is true that in the instant case the fate of the parties does not depend on the identity of a member of the administrative tribunal. However, the uncertainty will remain and the outcome of the proceedings will not be satisfactorily resolved since the C.S.S.T., which has adopted the interpretation of s. 60 imposed by the C.A.L.P., is obliged to take action against employers who refuse to accept the C.A.L.P.'s interpretation and who, ultimately, benefit from acquittals as a result of the (probably justified) application of the theory of reasonable doubt "in view of two conflicting possibilities that could be rationally defended", whether in an administrative proceeding or a penal proceeding. The interpretation adopted by the C.A.L.P. thus leads to a dead end. The ideal of justice, which promotes the rule of law, is not really served. It is certainly desirable that the intention of the legislature should prevail. What therefore is that intent? Despite the fact that the wording used may be open to two not unreasonable interpretations, can it be determined?

To rectify this situation, the Court of Appeal decided to intervene to impose its own interpretation of s. 60. Again according to Mailhot J.A. (at p. 2445):

> [TRANSLATION] With respect for the contrary view, I am of the view that the intention of the legislature in this matter was not to treat injured workers differently from other workers as regards the first 14 days mentioned in s. 60. In my opinion, if the legislature intended that the entire first 14 days following the beginning of the disability be paid for by the employer, it would not have added the words "*for each day or part of a day the worker would normally have worked*". These words are intended to ensure that the injured person is treated like other workers, in other words that he is entitled to a salary or wages as he would be if the employer had work to give him and could do so, if these days were part of his regular schedule or if his contract was still in effect, and so on—in short, if he had worked as usual, had he not been disabled.

This interpretation is fairer to everyone and consistent with the other provisions of the A.I.A.O.D. Even if it is accepted that the statute is remedial and seeks to compensate the victim of an employment injury, it is still general legislation and is not intended, in my opinion, to

de la CALP d'une part, et celle du Tribunal du travail, de l'autre (à la p. 2444):

> Il est vrai que, dans le cas présent, le sort des plaideurs ne dépend pas de l'identité du membre du tribunal administratif. Mais l'incertitude demeurera, et le sort des poursuites ne sera pas réglé de façon satisfaisante puisque la C.S.S.T., qui s'est rangée à l'interprétation de l'article 60 imposée par la C.A.L.P., se voit obligée de poursuivre des employeurs qui refusent d'accepter l'interprétation de la C.A.L.P. et qui, en fin de compte, bénéficient d'acquittements suite à l'application (probablement à juste titre) de la théorie du doute raisonnable «devant deux thèses rationnellement défendables qui s'affrontent» que ce soit à l'occasion du recours administratif ou du recours pénal. Ainsi, l'interprétation soutenue par la C.A.L.P. aboutit à un cul-de-sac. L'idéal de justice qui veut que triomphe la règle de droit n'y trouve pas vraiment son compte. Il est certainement souhaitable que ce soit l'intention du législateur qui l'emporte. Quelle est donc celle-ci? En dépit du fait que les termes utilisés puissent prêter à deux interprétations non déraisonnables, peut-on la préciser.

Afin de remédier à cette situation, la Cour d'appel a décidé d'intervenir pour imposer sa propre interprétation de l'art. 60. Toujours selon le juge Mailhot (à la p. 2445):

> Avec égards pour l'avis contraire, je suis d'avis que l'intention du législateur en cette matière n'est pas de traiter les travailleurs accidentés de façon différente des autres travailleurs en ce qui concerne les 14 premiers jours visés par l'article 60. À mon avis, si le législateur voulait que tous les 14 premiers jours qui suivent le début de l'incapacité soient payés par l'employeur, il n'avait pas à ajouter les mots «*pour chaque jour ou partie de jour où ce travailleur aurait normalement travaillé*». Ces mots visent à assurer que la personne accidentée soit traitée comme les autres personnes qui travaillent, c'est-à-dire qu'elle ait droit à un salaire comme elle y aurait droit si l'employeur avait du travail à confier et pouvait le faire ou si ces journées faisaient partie de son horaire habituel, ou si son contrat était toujours en vigueur, etc.—en somme, si elle avait normalement travaillé, n'eût été de son incapacité.

Cette interprétation est plus équitable pour tous et s'harmonise avec les autres dispositions de la L.A.T.M.P. Car, même si l'on accepte que cette loi est remédiatrice et cherche à indemniser une personne victime d'une lésion professionnelle, elle demeure une loi

1993 CanLII 106 (SCC)

make more favourable provision for such a victim compared with other employees, who may be subject to the ups and downs of the labour market, including the choice to go on strike or the obligation to be subject to a lockout. [Emphasis in original.]

She came to the following conclusion, concurred in by her colleagues (at p. 2446):

> [TRANSLATION] I therefore conclude that when in s. 60 the legislature requires the employer to pay a victim of an employment injury 90% of his net salary or wages, it means payment of the salary or wages to which the victim would logically have been entitled if he had worked as usual. As generally there is no obligation to pay a salary or wages when there is a plant closure, strike, lockout, layoff, unpaid leave and so on, there can be no obligation to pay 90% of the net salary or wages during these periods.
>
> I therefore propose that the appeal be allowed with costs, the application for evocation be granted with costs, the C.A.L.P.'s decision be quashed and the court declare that the appellant has paid Mr. Roland Lapointe the indemnity to which he was entitled under s. 60 of the *Act respecting Industrial Accidents and Occupational Diseases*.

There are thus two aspects to the Court of Appeal's intervention. First, it concluded that there was a jurisprudential conflict between two administrative jurisdictions as to the same legislative provision. Second, the Court of Appeal relied on an independent ground for judicial review, namely that where there is a conflict of this kind, curial deference should yield to review based on the correctness of the administrative interpretation. I shall examine the two aspects of this intervention in turn.

1. The Conflict

The Court of Appeal relied on a single judgment of the Labour Court in a penal matter, *Commission de la santé et de la sécurité du travail v. BG Chéco International Ltée*, *supra*, in concluding that there were conflicting decisions. This conclusion calls for two observations.

d'application générale et elle ne vise pas, à mon avis, à créer un régime plus favorable pour celle-ci par rapport aux autres employés, lesquels peuvent être soumis aux aléas du marché du travail, incluant le choix de faire la grève ou l'obligation de subir un lock-out. [En italique dans l'original.]

Elle arrive à la conclusion suivante, à laquelle ses collègues concourent (à la p. 2446):

> Je conclus donc que, lorsque le législateur, à l'article 60, oblige l'employeur à verser à une victime d'une lésion professionnelle 90 % de son salaire net, il vise le paiement du salaire auquel elle aurait logiquement eu droit si elle avait travaillé normalement. Comme, généralement, il n'y a pas d'obligation de payer un salaire lorsqu'il y a fermeture d'établissement, grève, lock-out, mise à pied, congé non rémunéré etc., il ne peut en découler d'obligation de payer 90 % du salaire net pendant ces périodes.
>
> Je propose en conséquence d'accueillir le pourvoi avec dépens, de faire droit à la demande d'évocation avec dépens, de casser la décision de la C.A.L.P. et de déclarer que l'appelante a payé à M. Roland Lapointe l'indemnité à laquelle il avait droit en vertu de l'article 60 de la *Loi sur les accidents du travail et les maladies professionnelles*.

Ainsi, l'intervention de la Cour d'appel comporte deux volets. En premier lieu, elle a conclu à l'existence d'un conflit jurisprudentiel entre deux instances administratives au regard d'un même texte législatif. En second lieu, la Cour d'appel s'est appuyée sur un motif autonome de contrôle judiciaire, soit qu'en présence d'un conflit de cette nature, la retenue judiciaire doit céder le pas à un contrôle fondé sur la justesse de l'interprétation administrative. J'examinerai, tour à tour, les deux volets de cette intervention.

1. Le conflit

La Cour d'appel s'est autorisée d'une seule décision du Tribunal du travail en matière pénale, soit l'affaire *Commission de la santé et de la sécurité du travail c. BG Chéco International Ltée*, précitée, pour conclure à l'existence d'un conflit jurisprudentiel. Cette conclusion appelle deux remarques.

1993 CanLII 106 (SCC)

First, as counsel for the appellant pointed out, this conclusion fails to take into account the large number of decisions rendered by the CALP since the *A.I.A.O.D.* came into force on August 19, 1985. With reference to s. 60, that tribunal has always adopted the same interpretation (see, *inter alia*, *Tousignant et Hawker Siddeley Canada Inc.*, *supra*; *Desmeules et Entreprises B.L.H. Inc.*, [1986] C.A.L.P. 66; *Béland et Mines Wabush*, C.A.L.P., No. 00138-09-8604, November 27, 1986; *Collins & Aikman Inc. et Dansereau*, [1986] C.A.L.P. 134; *Lambert et Vic Métal Corp.*, [1986] C.A.L.P. 147, and *Létourneau et Électricité Kingston Inc.*, [1986] C.A.L.P. 241). The Labour Court, for its part, had apparently never had occasion to rule on the scope of s. 60 before *BG Chéco*. As I see it, the situation created by an isolated decision at variance with a consistent line of authority cannot a priori be characterized as a true "jurisprudential conflict". Moreover, counsel for the CSST noted that the Court of Appeal had taken the *Domtar* case under advisement on February 14, 1991. The decision of the Labour Court in *BG Chéco* was not rendered until March 18, 1991. Besides being doubtful in strictly quantitative terms, the "controversy" at issue here therefore also seems to be premature.

Furthermore, apart from this quantitative and temporal aspect, the Court of Appeal was concerned here with two bodies interpreting the same legislative provision, but in the particular context of each one's jurisdiction, in the one case a penal one and, in the other, an administrative one. Before concluding that a jurisprudential conflict existed, some consideration should, therefore, have been given to the distinction between the duty of a tribunal sitting in a penal proceeding to give an accused the benefit of a reasonable doubt and that of an appellate administrative tribunal responsible for making a final ruling on its enabling legislation so as to give effect to that legislation. Can it be said that these two jurisdictions, in deciding on matters where the ground rules are completely different, have created a conflict in the jurisprudence? I am far from sharing the categorical assertion of the Court of Appeal on this point. It should be

D'une part, comme l'a souligné le procureur de l'appelant, ce constat omet de tenir compte du nombre considérable de décisions rendues par la CALP depuis l'entrée en vigueur, le 19 août 1985, de la *L.A.T.M.P.* Dans le cadre de l'art. 60, celle-ci a toujours adopté la même interprétation (voir, entre autres, *Tousignant et Hawker Siddeley Canada Inc.*, précité; *Desmeules et Entreprises B.L.H. Inc.*, [1986] C.A.L.P. 66; *Béland et Mines Wabush*, C.A.L.P., nº 00138-09-8604, le 27 novembre 1986; *Collins & Aikman Inc. et Dansereau*, [1986] C.A.L.P. 134; *Lambert et Vic Métal Corp.*, [1986] C.A.L.P. 147, et *Létourneau et Électricité Kingston Inc.*, [1986] C.A.L.P. 241). Le Tribunal du travail n'avait, pour sa part, apparemment jamais eu l'occasion de se prononcer sur la portée de l'art. 60 avant l'affaire *BG Chéco*. À mes yeux, la situation créée par une décision isolée à l'encontre d'une jurisprudence constante ne saurait, à priori, être qualifiée de véritable «conflit jurisprudentiel». Par ailleurs, le procureur de la CSST a souligné que la Cour d'appel avait pris en délibéré l'affaire *Domtar* le 14 février 1991. Or, la décision du Tribunal du travail dans l'affaire *BG Chéco* n'a été rendue que le 18 mars 1991. Tout en étant douteuse sous l'angle strictement quantitatif, la «controverse» dont il est ici question semble donc, au surplus, prématurée.

D'autre part, au-delà de cet aspect quantitatif et temporel, la Cour d'appel était ici devant deux organismes interprétant un même texte législatif, mais dans le contexte particulier de la compétence de chacun, l'un en matière pénale, l'autre en matière administrative. Avant de conclure à l'existence d'un conflit jurisprudentiel, il y avait donc lieu de s'interroger sur la distinction entre le devoir d'un tribunal siégeant en matière pénale de faire bénéficier un inculpé du doute raisonnable, et celui d'un tribunal administratif d'appel chargé d'interpréter sa loi constitutive de façon finale et ce, dans le but qu'il produise ses effets. Statuant dans des matières dont les règles de base sont totalement différentes, peut-on affirmer que ces deux instances se retrouvent en situation de conflit jurisprudentiel? Je suis loin de partager l'avis catégorique de la Cour d'appel à ce sujet. Il convient de noter, à cet égard, que les décisions de la CALP

1993 CanLII 106 (SCC)

noted, in this connection, that the CALP decisions can be filed in the office of the prothonotary of the Superior Court for the district in which the appeal was brought, in order to make them executory as if they were final civil judgments of the Superior Court not subject to appeal (s. 429 *A.I.A.O.D.*). The Court of Appeal's conclusion that the CALP's interpretation leads to a "dead end" does not take into account the existence of this civil remedy, parallel to the penal remedy, which is in keeping with the twofold nature of the *A.I.A.O.D.* Furthermore, the fact that the Labour Court's judgment, unlike decisions of the CALP, can be appealed to the Superior Court under the *Code of Penal Procedure* further mitigates the allegedly irreconcilable "conflict" between these two tribunals.

For discussion purposes, however, I am prepared to assume, without deciding the point, that the interpretation of s. 60 *A.I.A.O.D.* by the CALP on the one hand and the Labour Court on the other creates a conflict in the jurisprudence. This leads me to discuss the standard of judicial review applicable to such a situation.

2. Consistency of Precedent and Judicial Review

The ground of judicial review referred to by the Court of Appeal should be seen in its proper academic and judicial context. This background will clarify the issues and indicate the relevance of the guiding principles outlined earlier.

While the analysis of the standard of review applicable in the case at bar has made clear the significance of the decision-making autonomy of an administrative tribunal, the requirement of consistency is also an important objective. As our legal system abhors whatever is arbitrary, it must be based on a degree of consistency, equality and predictability in the application of the law. Professor MacLauchlan notes that administrative law is no exception to the rule in this regard:

Consistency is a desirable feature in administrative decision-making. It enables regulated parties to plan their

peuvent être déposées au bureau du protonotaire de la Cour supérieure du district où l'appel a été formé et ce, afin de les rendre exécutoires comme n'importe quel jugement civil final et sans appel de la Cour supérieure (art. 429 *L.A.T.M.P.*). La conclusion de la Cour d'appel voulant que l'interprétation de la CALP conduise à un «cul-de-sac» ne tient pas compte de l'existence de ce recours civil qui, parallèle au recours pénal, s'inscrit dans une dualité propre à la *L.A.T.M.P.* De surcroît, le fait que le jugement du Tribunal du travail soit, contrairement aux décisions de la CALP, appelable devant la Cour supérieure en vertu du *Code de procédure pénale* vient tempérer davantage le caractère prétendument irréductible du «conflit» entre ces deux tribunaux.

Pour les fins de la discussion, toutefois, je suis prête à assumer, sans pour autant en décider, que l'interprétation de l'art. 60 *L.A.T.M.P.* par la CALP d'une part, et le Tribunal du travail de l'autre, crée un conflit jurisprudentiel. Ceci m'amène à discuter du contrôle judiciaire applicable à une telle situation.

2. La cohérence décisionnelle et le contrôle judiciaire

Il convient de replacer le motif de contrôle judiciaire auquel s'est référée la Cour d'appel dans le contexte doctrinal et jurisprudentiel qui lui est propre. Ce recul éclairera les enjeux ici en cause ainsi que la pertinence des principes directeurs exposés précédemment.

Si l'analyse de la norme de contrôle applicable en l'espèce a permis de mettre en lumière la valeur que représente l'autonomie décisionnelle d'un tribunal administratif, l'impératif de cohérence constitue, également, une finalité importante. Notre système juridique se voulant aux antipodes de l'arbitraire, il se doit de reposer sur une certaine cohérence, égalité et prévisibilité dans l'application de la loi. Le professeur MacLauchlan note que le droit administratif ne saurait, à cet égard, faire exception à la règle:

[TRADUCTION] La cohérence est un aspect souhaitable de la prise de décision en matière administrative. Elle per-

1993 CanLII 106 (SCC)

affairs in an atmosphere of stability and predictability. It impresses upon officials the importance of objectivity and acts to prevent arbitrary or irrational decisions. It fosters public confidence in the integrity of the regulatory process. It exemplifies "common sense and good administration".

(H. Wade MacLauchlan, "Some Problems with Judicial Review of Administrative Inconsistency" (1984), 8 *Dalhousie L.J.* 435, at p. 446.)

In the same vein Professor Comtois writes:

> [TRANSLATION] . . . [consistency] helps to build public confidence in the integrity of the administrative justice system and leaves an impression of common sense and good administration. It might be added, as regards administrative tribunals exercising quasi-judicial functions, that the specialized nature of their jurisdiction makes inconsistencies more apparent and tends to harm their credibility.

(Suzanne Comtois, "Le contrôle de la cohérence décisionnelle au sein des tribunaux administratifs" (1990), 21 *R.D.U.S.* 77, at pp. 77-78.)

This consistency requirement has led some writers to defend the idea of judicial review of administrative inconsistency. Thus, Dean Morissette has dealt with the problem of jurisprudential conflicts within administrative jurisdictions as they affect curial deference: "Le contrôle de la compétence d'attribution: thèse, antithèse et synthèse" (1986), 16 *R.D.U.S.* 591. At page 631, he asks the following question:

> [TRANSLATION] But is an irrational or unreasonable interpretation the only possible form of excess of jurisdiction after *C.U.P.E. v. N.B.L.C.*?

After giving the example of an administrative tribunal that rules on a constitutional question or misinterprets a provision conferring jurisdiction, Dean Morissette adds (at pp. 632-33):

> [TRANSLATION] Finally, the theory of reasonable interpretation leaves room for intervention by the superior courts when several well-reasoned and apparently rational interpretations are given by the same administrative jurisdiction and their consequences are inconsis-

met aux administrés de planifier leurs affaires dans un climat de stabilité et de prévisibilité. Elle fait comprendre aux responsables l'importance de l'objectivité et empêche la prise de décisions arbitraires ou irrationnelles. Elle favorise la confiance du public dans l'intégrité du processus de réglementation. Elle laisse une impression «de bon sens et de bonne administration».

(H. Wade MacLauchlan, «Some Problems with Judicial Review of Administrative Inconsistency» (1984), 8 *Dalhousie L.J.* 435, à la p. 446.)

Dans le même esprit, le professeur Comtois écrit:

> . . . [la cohérence] contribue à bâtir la confiance du public dans l'intégrité du système de justice administrative et laisse une impression de bon sens et de bonne administration. L'on pourrait ajouter, en ce qui concerne les tribunaux administratifs exerçant des fonctions quasi-judiciaires, que le caractère spécialisé de leur juridiction rend les incohérences plus visibles et a tendance à nuire à leur crédibilité.

(Suzanne Comtois, «Le contrôle de la cohérence décisionnelle au sein des tribunaux administratifs» (1990), 21 *R.D.U.S.* 77, aux pp. 77 et 78.)

Cet impératif de cohérence a conduit certains auteurs à défendre l'idée d'un contrôle judiciaire de l'incohérence administrative. Ainsi, le doyen Morissette s'est penché sur le problème des conflits jurisprudentiels au sein de juridictions administratives face à la retenue judiciaire: «Le contrôle de la compétence d'attribution: thèse, antithèse et synthèse» (1986), 16 *R.D.U.S.* 591. À la p. 631, il pose la question suivante:

> Mais l'interprétation irrationnelle ou déraisonnable est-elle la seule forme possible d'excès de juridiction après l'arrêt *S.C.F.P. c. S.A.N.B.*?

Après avoir fourni l'exemple du tribunal administratif qui tranche une question constitutionnelle ou qui interprète erronément une disposition attributive de compétence, le doyen Morissette poursuit (aux pp. 632 et 633):

> Enfin, la théorie de l'interprétation raisonnable laisse place à l'intervention des tribunaux supérieurs lorsque plusieurs interprétations motivées et en apparence rationnelles proviennent d'une même juridiction administrative et sont incompatibles dans leurs effets. On

1993 CanLII 106 (SCC)

tent. The matter can be illustrated by the example of an arbitrator sitting pursuant to s. 124 of the *Act respecting Labour Standards*. Two arbitrators sitting in different cases may well decide the same legal problem arising on similar facts in opposite ways, which are nevertheless rational and well-reasoned. The fate of the complainant, when discrepancies of this type occur, depends on the identity of the arbitrator hearing the complaint. This result is difficult to reconcile with the notion of equality before the law, which is one of the main corollaries of the rule of law, and perhaps also the most intelligible one. Where discrepancies of this type exist, whether within the same administrative jurisdiction, between different jurisdictions on the same level or between different levels of jurisdiction in the same specialized field, the superior courts will intervene to standardize the law even though each of the diverse interpretations seems to be reasonable. [Emphasis added.]

Dean Morissette considers that these objectives of equality, security and uniformity in implementing the law are consistent with the ultimate purpose of judicial review (at p. 634):

[TRANSLATION] On reflection, however, this is undoubtedly a basic form of rationality. As the primary purpose of judicial review is to prevent arbitrariness, what objection can there be to a principle which requires the superior courts to intervene, not in the name of meticulous legalism but in the interests of rationality? Imposing an interpretation one believes to be "correct" because, owing to its consequences or for some similar reason, one does not share some other otherwise rational interpretation is difficult to justify in terms of judicial review, unless of course one assumes that appeals and judicial review are one and the same thing. Imposing the interpretation one believes to be "correct" (or "the most rational") when one is confronted with contradictory but rational interpretations on the same point is fully justified in light of the rule of law, as this is the very kind of arbitrariness that principle is designed to prevent. [Emphasis added.]

In an article published in 1982 Professor Mullan also defends the idea of some form of judicial review of inconsistent decision-making (David J. Mullan, "Natural Justice and Fairness — Substantive as well as Procedural Standards for the Review of Administrative Decision-Making?" (1982), 27 *McGill L.J.* 250). Rather than concentrating on the situation created by inconsistency

peut illustrer la chose en utilisant l'exemple d'un arbitre siègeant en vertu de l'article 124 de la *Loi sur les normes du travail*. Deux arbitres siègeant dans des affaires différentes peuvent fort bien trancher de façon contradictoire, mais néanmoins rationnelle et motivée, une même difficulté juridique soulevée par des faits semblables. Le sort du plaignant, lorsque des divergences de ce type perdurent, dépend de l'identité de l'arbitre qui entend sa plainte. Ce résultat est difficile à concilier avec la notion d'égalité devant la loi, l'un des principaux corollaires de la primauté du droit, et peut-être aussi le plus intelligible. En présence de divergences de ce type, que ce soit au sein de la même juridiction administrative, entre juridictions différentes de même degré ou entre juridictions de degrés différents dans un même domaine d'attribution, les tribunaux supérieurs interviendront pour uniformiser le droit, même si chacune des diverses interprétations paraît raisonnable. [Je souligne.]

Le doyen Morissette estime que ces objectifs d'égalité, de sécurité et d'uniformité dans l'application de la loi sont compatibles avec la finalité même du contrôle judiciaire (à la p. 634):

Mais à bien y penser, il s'agit là, sans doute, d'une forme fondamentale de rationalité. Le contrôle judiciaire servant avant tout à combattre l'arbitraire, qu'y a-t-il à redire d'une doctrine qui commande aux tribunaux supérieurs d'intervenir, non plus au nom d'un légalisme minutieux, mais par souci de rationalité? Imposer l'interprétation qu'on croit être «correcte» parce qu'on ne partage pas, à cause de son effet ou pour quelque raison semblable, une autre interprétation par ailleurs rationnelle, ne se justifie que difficilement dans le cadre du contrôle judiciaire, à moins bien sûr de postuler que l'appel et le contrôle judiciaire sont une seule et même chose. Imposer l'interprétation qu'on croit être «correcte» (ou «la plus rationnelle») lorsqu'on est en présence d'interprétations contradictoires mais rationnelles sur une même question se justifie pleinement en regard de la primauté du droit, car c'est bien là le genre d'arbitraire que vise à empêcher ce principe. [Je souligne.]

Dans un article paru en 1982, le professeur Mullan a également défendu l'idée d'une certaine forme de contrôle judiciaire de l'incohérence décisionnelle (David J. Mullan, «Natural Justice and Fairness—Substantive as well as Procedural Standards for the Review of Administrative Decision-Making?» (1982), 27 *R.D. McGill* 250). Plutôt que de se concentrer sur la situation créée par

1993 CanLII 106 (SCC)

between two well-reasoned and rational interpretations, Professor Mullan emphasizes the principle that similar cases should be given similar treatment. In the interests of justice, fairness and equality in the application of the law, administrative inconsistency would thus require intervention by the courts (at pp. 285-86):

> Given the prevalence of this principle of consistency of treatment in the development of most legal systems as well as within the various substrata of legal systems, there is a strong case for branding as reviewable those cases where statutory authorities inexplicably fail to act consistently. To do so without reason or without thinking would seem to be the height of arbitrary behaviour. It is also worth remembering that judicial review of administrative action has from its earliest days been concerned with the appearance of the proper administration of justice. If the law is prepared to countenance a rule to the effect that a reasonable apprehension of bias will affect the validity of a decision in order to safeguard the reputation of the law, there is also clearly room for condemning unexplained or inexplicable inconsistencies in the administration of statutory discretions from which the law's reputation will suffer as much. [Emphasis added.]

Finally, Professor Comtois, *supra*, at p. 88, discusses the same constraints as the preceding writers, emphasizing the emergence of a "flexible" rule of consistency in administrative law:

> [TRANSLATION] A flexible rule, in the sense that it should not be interpreted as an obligation to follow precedents or amount to a strict application of the *stare decisis* rule, but one which may nevertheless receive judicial sanction when the court finds that fairness or respect for the rule of law requires its intervention to put an end to the uncertainty created by contradictory decisions rendered by different tribunals on the same point. [Emphasis added.]

The requirement of consistency in the application of the law is unquestionably a valid objective and so a persuasive argument. For litigants to receive diametrically opposite answers to the same question, depending on the identity of the members of administrative tribunals, may seem unacceptable to some and even difficult to reconcile with several objectives, including the rule of law. Yet, as the courts have held, consistency in decision-

l'incompatibilité entre deux interprétations motivées et rationnelles, le professeur Mullan a insisté sur le principe voulant que des causes similaires soient traitées de façon analogue. Par souci de justice, d'équité et d'égalité dans l'application de la loi, l'incohérence administrative exigerait, ainsi, l'intervention des cours de justice (aux pp. 285 et 286):

> [TRADUCTION] Puisque ce principe de la cohérence dans le traitement joue un rôle de premier plan dans l'élaboration de la plupart des systèmes juridiques et à l'intérieur des divers substrats des systèmes juridiques, on devrait considérer comme révisables les décisions prises par des autorités légales qui omettent inexplicablement d'agir avec cohérence. Agir ainsi sans raison ou réflexion semble constituer l'apogée du comportement arbitraire. Il importe aussi de se rappeler que le contrôle judiciaire des décisions administratives a toujours visé l'apparence de bonne administration de la justice. Si la loi permet, pour garantir sa réputation, d'admettre une règle établissant qu'une crainte raisonnable de partialité influera sur la validité d'une décision, il est de toute évidence possible de décrier les incohérences inexpliquées ou inexplicables dans l'administration des pouvoirs discrétionnaires légaux qui porteront atteinte à la réputation de la loi.

Enfin, le professeur Comtois, *loc. cit.*, à la p. 88, fait état des mêmes impératifs que les auteurs précédents en insistant sur l'émergence d'un principe «flexible» de cohérence en droit administratif:

> Un principe flexible dans le sens où il ne doit pas être interprété comme une obligation de suivre les précédents, ou équivaloir à une application stricte de la règle du *stare decisis*, mais un principe qui peut néanmoins être sanctionné judiciairement lorsque la cour juge que l'équité ou le respect de la primauté du droit requièrent qu'elle intervienne pour mettre fin à l'incertitude créée par les décisions contradictoires rendues par des bancs différents sur une même question. [Je souligne.]

L'impératif de cohérence dans l'application de la loi constitue, indéniablement, un objectif valable, donc un argument de poids. Que des justiciables reçoivent, relativement à la même question, des réponses diamétralement opposées selon l'identité des membres de tribunaux administratifs peut apparaître inacceptable à certains et même difficilement compatible avec plusieurs objectifs, parmi lesquels la primauté du droit. Or, comme

1993 CanLII 106 (SCC)

making and the rule of law cannot be absolute in nature regardless of the context. So far as judicial review is concerned, the problem of inconsistency in decision-making by administrative tribunals cannot be separated from the decision-making autonomy, expertise and effectiveness of those tribunals.

Courts have had the opportunity to consider the advisability of intervening to resolve conflicting decisions by administrative tribunals. In *Re Service Employees International Union, Local 204 and Broadway Manor Nursing Home* (1984), 48 O.R. (2d) 225 (C.A.), faced with two inconsistent interpretations of s. 13(*b*) of the *Inflation Restraint Act, 1982*, S.O. 1982, c. 55, by the Labour Relations Board on the one hand and the Education Relations Commission on the other, the Ontario Court of Appeal (at pp. 237-38) adopted the comments of Galligan J. of the Divisional Court (now of the Court of Appeal):

I cannot for one moment suggest that either's interpretation of the Act was patently unreasonable. The decisions of the two tribunals are careful, thoughtful, well-reasoned and persuasive. One of my many problems with this case is that as I read each decision I am persuaded by it. The extension of curial deference to each of them would lead to unacceptable results.

It seems to me that the curial deference demanded by authority ought only be extended to a tribunal when it is interpreting its Constitution or home statute. By that I mean curial deference need only be granted to the Labour Relations Board when it interprets the *Labour Relations Act*, and to the Education Relations Commission when it interprets the Boards and Teachers Negotiations Act. The Act is a statute that applies not only to workers and employers who are governed by the *Labour Relations Act* and the Boards and Teachers Negotiations Act but to many others. While it is legislation that applies only to what can loosely be called the public sector of Ontario, and not to the population of Ontario at large, I think the Act is more akin to a "general public enactment" as that term was used by Laskin C.J.C. in *McLeod et al. v. Egan et al.*, [1975] 1 S.C.R. 517 ...

l'indique la jurisprudence, la cohérence décisionnelle et la primauté du droit ne sauraient avoir un caractère absolu, dénué de tout contexte. Dans le cadre du contrôle judiciaire, le problème de l'incohérence décisionnelle au sein d'instances administratives est indissociable de l'autonomie décisionnelle, l'expertise et l'efficacité de ces mêmes tribunaux.

Les cours de justice ont eu, en effet, l'occasion de se pencher sur l'opportunité d'intervenir afin de régler un conflit jurisprudentiel entre des instances administratives. Dans l'affaire *Re Service Employees International Union, Local 204 and Broadway Manor Nursing Home* (1984), 48 O.R. (2d) 225 (C.A.), confrontée à deux interprétations incompatibles de l'al. 13*b*) de l'*Inflation Restraint Act, 1982*, S.O. 1982, ch. 55, par la Commission des relations de travail d'une part, et la Commission des relations de travail en éducation de l'autre, la Cour d'appel de l'Ontario a repris à son compte aux pp. 237 et 238 les propos du juge Galligan de la Cour divisionnaire (maintenant de la Cour d'appel):

[TRADUCTION] Je ne peux supposer pour un instant que l'une des deux interprétations était manifestement déraisonnable. Les décisions des deux tribunaux sont rédigées en termes soignés, réfléchis, raisonnés et convaincants. Un des nombreux problèmes que me pose la présente affaire est que chacune des décisions me convainc. Faire preuve de retenue judiciaire à l'égard de chacune d'elles donnerait lieu à des résultats inacceptables.

Il me semble qu'il y a lieu, selon la jurisprudence, de faire preuve de retenue judiciaire à l'égard d'un tribunal seulement lorsque celui-ci interprète sa loi constitutive ou sa loi interne. Ainsi, il n' y a lieu de faire preuve de retenue judiciaire à l'égard de la Commission des relations de travail que lorsqu'elle interprète la *Loi sur les relations de travail*, et à l'égard de la Commission des relations de travail en éducation, que lorsqu'elle interprète la Boards and Teachers Negotiations Act. La Loi est un texte qui s'applique non seulement aux travailleurs et aux employeurs régis par la *Loi sur les relations de travail* et la Boards and Teachers Negotiations Act, mais à bien d'autres. Bien qu'il s'agisse d'une loi qui vise seulement ce qui correspond vaguement au secteur public de l'Ontario et non l'ensemble de la population de l'Ontario, je crois que cette loi ressemble davantage à

1993 CanLII 106 (SCC)

than it is to the specialized and particular *Labour Relations Act* and Boards and Teachers Negotiations Act. [Emphasis added.]

It concluded (at p. 239):

> We agree with the decision of Galligan J. in this regard. The theory underlining the concept of curial deference has no application here. The Act is, in every sense, a general public enactment. It is not one with which either the Ontario Labour Relations Board or the Education Relations Commission was integrally or closely involved nor over which they could be said to profess any particular expertise. [Emphasis added.]

Domtar referred to *Broadway Manor Nursing Home* in support of its position. That case cannot be interpreted as adopting the existence of conflicting decisions as an independent basis for judicial review. The Ontario Court of Appeal was actually concerned with the nature of the statute which was the subject of the conflict in question. By characterizing the *Inflation Restraint Act, 1982* as a general public enactment which neither the Labour Relations Board nor the Education Relations Commission had the function of interpreting as part of their particular expertise, it simply held that, owing to this lack of expertise, the principle of curial deference did not apply. Since the Act, the interpretation of which was at issue, was not at the core of the specialized jurisdiction of either of the administrative tribunals, any error of law was immediately subject to strict judicial review and not to the patently unreasonable interpretation test.

This reading of *Broadway Manor Nursing Home* seems to be confirmed by a later judgment, *United Steelworkers of America, Local 14097 v. Franks* (1990), 75 O.R. (2d) 382. In that case, the Ontario Divisional Court was confronted with two inconsistent interpretations of s. 40a of the *Employment Standards Act*, R.S.O. 1980, c. 137. Reid J. first

«un texte législatif général d'intérêt public», au sens donné à cette expression par le juge en chef Laskin dans l'arrêt *McLeod et al. c. Egan et al.*, [1975] 1 R.C.S. 517, [. . .] qu'au texte spécialisé et particulier de la *Loi sur les relations de travail* et de la Boards and Teachers Negotiations Act. [Je souligne.]

Pour conclure (à la p. 239):

> [TRADUCTION] Nous sommes d'accord avec la décision du juge Galligan sur ce point. La théorie sous-jacente au concept de retenue judiciaire n'est pas applicable en l'espèce. La Loi est, à tous points de vue, un texte législatif général d'intérêt public. Il ne s'agit pas d'une loi que la Commission des relations de travail de l'Ontario ou la Commission des relations de travail en éducation a pour mission d'interpréter intégralement ou étroitement ni d'une loi relativement à laquelle elles possèdent une compétence particulière. [Je souligne.]

Domtar s'est référée à l'arrêt *Broadway Manor Nursing Home* pour appuyer sa position. Or, ce dernier ne saurait s'interpréter comme adoptant l'existence d'un conflit jurisprudentiel comme motif autonome de contrôle judiciaire. La Cour d'appel de l'Ontario s'est plutôt penchée sur la nature de la loi faisant l'objet du conflit en question. En qualifiant l'*Inflation Restraint Act, 1982* de loi d'intérêt public que ni la Commission des relations de travail et ni la Commission des relations de travail en éducation n'avaient pour mission d'interpréter dans le cadre de leur compétence particulière, elle a simplement jugé qu'en raison de cette absence d'expertise, le principe de la retenue judiciaire n'avait pas d'application. Puisque la loi dont l'interprétation était en jeu n'était au cœur de la compétence spécialisée ni de l'une ni de l'autre des instances administratives, toute erreur de droit était, dès le départ, sujette au contrôle judiciaire strict et non au test de l'interprétation manifestement déraisonnable.

Cette lecture de l'arrêt *Broadway Manor Nursing Home* semble confirmée par un arrêt subséquent, *United Steelworkers of America, Local 14097 c. Franks* (1990), 75 O.R. (2d) 382. Dans cette affaire, la Cour divisionnaire de l'Ontario était confrontée à deux interprétations incompatibles de l'art. 40a de la *Loi sur les normes d'em-*

1993 CanLII 106 (SCC)

noted the crucial importance of determining the applicable standard of review (at pp. 385-86):

> We have two reasonable, but conflicting, interpretations. (I use the term "reasonable" as a more convenient expression than the traditional but awkward phrase "not patently unreasonable".) It follows that, if the standard of review on this application is reasonableness, the application should be dismissed. If, on the other hand, the standard is correctness, only one may stand and we must choose between them. Two conflicting interpretations of the same statutory provision might be reasonable, but they cannot both be correct. This issue of standard of review is thus critical. [Emphasis added.]

Reid J. distinguished *Broadway Manor Nursing Home*, noting that, in that case, the administrative tribunal was not interpreting its enabling Act, unlike in the case before him (p. 386). After underlining the existence of a privative clause, he concluded as follows (at pp. 387-88):

> The dismissal of this application will leave in place two conflicting interpretations of equal legal stature of a statutory provision. We are informed that it has since been amended, but even if that were not so there does not appear to be any basis on which the court may intervene to resolve the conflict. The doctrine of *stare decisis* which prevails in the courts tends to the avoidance of conflict in their decisions and such conflict as does occur may be resolved by the mechanism of appeal. But the doctrine of *stare decisis* does not apply to referees, or arbitrators, or, for that matter, to administrative tribunals generally, nor are referees, or arbitrators, or administrative tribunals generally (there are exceptions) subject to appeal. These are characteristics of tribunals which legislators have created to provide what they believe to be for certain purposes more appropriate forums for decision-making than the courts. The references I have made above confirm that the courts' supervisory role on judicial review is very limited. There is no authority for extending that supervision in the way proposed nor any rationale for doing so. [Emphasis added.]

The Quebec Court of Appeal in turn considered conflicting decisions in *Produits Pétro-Canada*

ploi, L.R.O. 1980, ch. 137. Le juge Reid a d'abord noté l'importance primordiale de déterminer la norme de contrôle applicable (aux pp. 385 et 386):

> [TRADUCTION] Nous avons deux interprétations raisonnables, mais contradictoires. (J'utilise le terme «raisonnable» que j'estime plus utile que l'expression traditionnelle mais maladroite «non manifestement déraisonnable».) Il s'ensuit que, si la norme de contrôle qui s'y applique est le caractère raisonnable, la demande devrait être rejetée. Par contre, si la norme est la justesse de la décision, une seule peut être retenue et il nous faut faire un choix entre les deux. Deux interprétations contradictoires de la même disposition législative peuvent être raisonnables, mais elles ne peuvent être toutes deux correctes. La question de la norme de contrôle est donc critique. [Je souligne.]

Or, le juge Reid a distingué l'affaire *Broadway Manor Nursing Home* pour noter que là, le tribunal administratif n'interprétait pas sa loi constitutive, ce qui n'était pas le cas dans l'affaire dont il était saisi (p. 386). Après avoir souligné l'existence d'une clause privative, il a conclu dans les termes suivants (aux pp. 387 et 388):

> [TRADUCTION] Le rejet de la demande aura pour effet de maintenir, relativement à une même disposition législative, deux interprétations contradictoires de même importance juridique. On nous a informés que cette disposition a depuis été modifiée; toutefois, même si ce n'était pas le cas, il ne paraît pas exister de fondement qui justifierait l'intervention de la cour en vue de régler le conflit. La règle du *stare decisis* qui existe devant les tribunaux vise à éviter les contradictions entre leurs décisions, et les contradictions qui existent peuvent être réglées par voie d'appel. Toutefois, la règle du *stare decisis* ne s'applique pas aux arbitres, ni d'ailleurs aux tribunaux administratifs en général, et la décision d'un arbitre ou d'un tribunal administratif en général ne peut faire l'objet d'un appel (il existe des exceptions). Ce sont les caractéristiques des tribunaux que les législateurs ont créés afin d'offrir ce qu'ils considèrent, à certaines fins, comme des mécanismes décisionnels plus appropriés que les cours de justice. Les arrêts cités ci-dessus confirment que le rôle de supervision des cours de justice en matière de contrôle judiciaire est fort limité. Il n'y a pas de jurisprudence permettant d'élargir cette supervision de la façon proposée ni aucune raison de le faire. [Je souligne.]

La Cour d'appel du Québec s'est penchée, à son tour, sur un conflit jurisprudentiel dans l'affaire

1993 CanLII 106 (SCC)

Inc. v. Moalli, supra. Noting that there was a serious and unquestionable conflict in interpreting ss. 97 and 124 of the *Act respecting Labour Standards*, R.S.Q., c. N-1.1, it observed that this resulted in an unacceptable situation (at p. 267):

[TRANSLATION] For many years the fate of litigants has depended largely on the identity of the arbitrator hearing the dismissal complaint. Positions have hardened. Two separate and inconsistent rules of law are definitely being applied. Does this situation justify intervention by the Superior Court?

The court considered that [TRANSLATION] "in view of the seriousness of the conflict of interpretation that has resulted, however, this is a case in which sooner or later the superior courts will have to intervene" (p. 268). Accordingly (at p. 268):

[TRANSLATION] The instant appeal clearly raises this problem of interpretation, as to which there are "diametrically opposed" opinions. Its importance for legal practice in this area of labour relations cannot be denied. At this point, it appears that *we are confronted with one of those exceptional situations in which, contrary to the general rule of curial deference, the superior courts must intervene to arrive at an interpretation of the law and avoid having litigants subject to two different legal rules, and possibly even the unpredictable appointment of arbitrators* ... [Emphasis in original.]

The Court of Appeal thus pointed to the existence of an extremely serious case law conflict which had not been [TRANSLATION] "solved since the *Act respecting Labour Standards* came into force" (p. 267), and went on to develop its own interpretation of the provisions in question. Since the Court of Appeal and Domtar both referred to *Moalli* in arguing in favour of an independent basis for judicial review of decision-making inconsistency by administrative tribunals, it becomes necessary to consider the scope of that decision.

To begin with, it appears that, from the outset, the standard of review applicable in that case was the correctness of the arbitrator's interpretation, not whether his decision was patently unreasonable. The Court of Appeal held that the question of

Produits Pétro-Canada Inc. c. Moalli, précitée. Ayant constaté un conflit grave et incontestable d'interprétation des art. 97 et 124 de la *Loi sur les normes du travail*, L.R.Q., c. N-1.1, elle a noté que ce conflit donnait lieu à une situation inacceptable (à la p. 267):

Le sort des plaideurs, depuis plusieurs années, dépend largement de l'identité de l'arbitre saisi de la plainte de congédiement. Les positions se sont cristallisées. En définitive, l'on applique deux règles de droit distinctes et incompatibles. Cette situation justifierait-elle l'intervention de la Cour supérieure?

La cour a considéré qu'«[e]n tenant compte cependant de la gravité du conflit d'interprétation qui est survenu, il s'agit d'un cas où tôt ou tard, les tribunaux supérieurs doivent intervenir» (p. 268). Ainsi (à la p. 268):

Le présent appel pose clairement ce problème d'interprétation, au sujet duquel s'affrontent des opinions «diamétralement opposées». L'on ne saurait nier son importance pour la pratique juridique de ce secteur des relations de travail. À ce moment, il apparaît que *nous nous trouvons devant une de ces situations exceptionnelles où, par dérogation à la règle générale d'abstention judiciaire, il faut que les tribunaux supérieurs interviennent pour dégager une interprétation de la loi et éviter que les intéressés ne soient soumis à deux règles de droit différentes, sinon aux simples aléas de la désignation des arbitres* ... [En italique dans l'original.]

La Cour d'appel a donc invoqué l'existence d'un conflit jurisprudentiel extrêmement sérieux, n'ayant pas connu «de solution depuis l'entrée en vigueur de la *Loi sur les normes du travail*» (p. 267), avant de dégager sa propre interprétation des dispositions en cause. Puisque la Cour d'appel et Domtar se sont toutes deux référées à l'arrêt *Moalli* afin de justifier l'existence d'un motif autonome de contrôle judiciaire de l'incohérence décisionnelle au sein d'instances administratives, il convient de s'interroger sur la portée de cette décision.

En premier lieu, il semble que la norme de contrôle applicable dans cette affaire était, dès le départ, la justesse de l'interprétation de l'arbitre et non le caractère manifestement déraisonnable de sa décision. La Cour d'appel a, en effet, jugé que la

1993 CanLII 106 (SCC)

the applicability of s. 97 of the *Act respecting Labour Standards* to s. 124 of that Act was a question of jurisdiction. Thus, in the view of LeBel J.A. (at p. 266):

> [TRANSLATION] Section 124 requires that certain conditions be met for the arbitrator to hear the dismissal proceeding. One of these is continuous service for the same employer for five years. From this standpoint, the application and interpretation of s. 97 raise a jurisdictional question properly speaking, within the meaning given to that term by Beetz J. in *Syndicat des employés de production du Québec et de l'Acadie v. Canada Labour Relations Board*. The arbitrator would certainly have the right and even an obligation to deal with this question. However, his error, even a reasonable error, would be subject to judicial review. [Emphasis added.]

In her comment on *Moalli* Ms. Ouimet expands on this initial description:

> [TRANSLATION] In any case, we have to admit that by characterizing this question as within jurisdiction, the *Pétro-Canada* decision would have been completely different and LeBel J.A. would only have had to rule on the reasonability of the two schools of thought without at the same time settling the matter. Accordingly, it may be thought that he "chose" to characterize this question as jurisdictional in order to rule on the correctness of the interpretation of the arbitrator Moalli, rather than on his reasonableness, in which case we are back at square one.

(Hélène Ouimet, "Commentaires sur l'affaire Produits Pétro-Canada c. Moalli" (1987), 47 *R. du B.* 852, at p. 858.)

Another writer is of the view that this characterization did not disappear in favour of an independent ground of judicial review:

> [TRANSLATION] . . . in the view of LeBel J.A., who wrote the reasons, the question before the arbitrator in that case was "properly jurisdictional". Specifically, the applicability of s. 97 of the *Act respecting Labour Standards* to s. 124 of that Act, which requires continuous service for the same employer for five years for there to be a complaint of dismissal, was a jurisdictional question on which the arbitrator could not err. In other words, the question was from the outset, and always has been, a question of jurisdiction in the strict sense, not a

question de l'applicabilité de l'art. 97 de la *Loi sur les normes du travail* à l'art. 124 de la même loi était juridictionnelle. Ainsi, selon le juge LeBel (à la p. 266):

> L'article 124 exige la réalisation de certaines conditions pour que l'arbitre puisse se saisir du congédiement. L'une de celles-ci est la continuité du service pendant cinq ans pour le même employeur. Dans cette optique, l'application et l'interprétation de l'article 97 poseraient alors une question proprement juridictionnelle au sens donné à ce terme par monsieur le juge Beetz, dans l'arrêt *Syndicat des employés de production du Québec et de l'Acadie c. Conseil canadien des relations du travail*. L'arbitre aurait certes le droit et même l'obligation de statuer à son sujet. Cependant, son erreur, même raisonnable, serait sujette à révision judiciaire. [Je souligne.]

Dans son commentaire de l'arrêt *Moalli*, M[e] Ouimet élabore sur cette qualification initiale:

> En tout état de cause, force nous est d'admettre cependant qu'en qualifiant d'intra-juridictionnelle cette question, la décision *Pétro-Canada* aurait été tout autre et le juge LeBel n'aurait eu qu'à conclure à la raisonnabilité des deux écoles de pensée sans pour autant régler le litige. Dès lors, il est possible de croire qu'il ait «choisi» de qualifier cette question de juridictionnelle, de façon à statuer sur l'exactitude de l'interprétation de l'arbitre Moalli plutôt que sur sa raisonnabilité, auquel cas nous retournions à la case départ.

(Hélène Ouimet, «Commentaires sur l'affaire Produits Pétro-Canada c. Moalli» (1987), 47 *R. du B.* 852, à la p. 858.)

Par ailleurs, un autre auteur est d'avis que cette qualification ne s'est pas effacée au profit d'un motif autonome de contrôle judiciaire:

> . . . de l'avis du juge LeBel qui a rédigé les motifs, la question soumise à l'arbitre était, dans ce cas-là, «proprement juridictionnelle». Plus précisément, l'applicabilité de l'article 97 de la *Loi sur les normes du travail* à l'article 124 de la même loi, qui exige la continuité du service pendant cinq ans chez un même employeur pour donner lieu à une plainte de congédiement, était une question attributive de compétence sur laquelle l'arbitre ne pouvait se tromper. Autrement dit, la question était dès le départ et a toujours été une question de compé-

1993 CanLII 106 (SCC)

question within jurisdiction which lost that characterization because of a dispute. [Emphasis added.]

(Jean-François Jobin, "Le contrôle judiciaire des erreurs de compétence ou dites proprement juridictionnelles: où en sommes-nous?" (1990), 50 *R. du B.* 731, at pp. 748-49.)

Similarly, in *Moalli* the Court of Appeal referred to *Broadway Manor Nursing Home*, *supra*. After citing the reasons of Galligan J. which I reproduced above, LeBel J.A. continued (at pp. 267-68):

> [TRANSLATION] I would hesitate to apply this aspect of the reasoning without qualification in the case at bar . . . In some cases the interpretation of the wording of general legislation is a necessary function of the arbitrator or lower court. It is part of what they do and is protected by the usual attitude of curial deference. In any case, the problem does not seem to arise here on account of the jurisdictional characterization which I apply to the problem of interpreting and applying ss. 124 and 97 A.L.S. [Emphasis added.]

In the present case, on the contrary, there could be no question that the CALP was acting within its jurisdiction. The Court of Appeal does not seem to have made this distinction in referring to *Moalli*.

Furthermore, since *Moalli*, apart from the case at bar, the Quebec Court of Appeal has not to my knowledge thought it proper to intervene on the ground that there were conflicting decisions between administrative tribunals: *Hydro-Québec v. Conseil des services essentiels* (1991), 41 Q.A.C. 292; *Syndicat canadien de la Fonction publique v. Commission des écoles catholiques de Québec*, C.A. Québec, No. 200-09-000463-866, December 20, 1989, J.E. 90-176, and *Syndicat des communications graphiques, local 509M v. Auclair*, [1990] R.J.Q. 334. In this last case, Tourigny J.A. further clarified the meaning of *Moalli* as follows (at p. 340):

> [TRANSLATION] It might be argued that *Produits Pétro-Canada Inc. v. Moalli* created an exception to the generally accepted rule that courts intervene only where there are patently unreasonable errors. In that case, LeBel J.A. came to the conclusion that the Superior

tence au sens strict; et non pas une question intrajuridictionnelle qui aurait perdu ce qualificatif à cause d'une controverse. [Je souligne.]

(Jean-François Jobin, «Le contrôle judiciaire des erreurs de compétence ou dites proprement juridictionnelles: où en sommes-nous?» (1990), 50 *R. du B.* 731, aux pp. 748 et 749.)

De même, la Cour d'appel s'est référée, dans l'arrêt *Moalli*, à l'affaire *Broadway Manor Nursing Home*, précitée. Or, après avoir cité les motifs du juge Galligan que j'ai reproduits ci-avant, le juge LeBel a poursuivi (aux pp. 267-68):

> J'hésiterais à appliquer intégralement cet aspect de la motivation dans la présente espèce. [. . .] En certains cas, l'interprétation des textes des lois générales est une fonction nécessaire de l'arbitre ou du tribunal inférieur. Elle constitue une part de leur activité que protège l'attitude normale de réserve judiciaire. Quoi qu'il en soit, le problème ne se poserait pas ici, en raison de la qualification juridictionnelle que je retiens à l'égard du problème d'interprétation et d'application des articles 124 et 97 L.N.T. [Je souligne.]

Ici, au contraire, il ne saurait être mis en doute que la CALP agissait à l'intérieur de sa compétence. La Cour d'appel ne semble pas avoir fait cette distinction en se référant à l'arrêt *Moalli*.

D'autre part, depuis l'arrêt *Moalli* et exception faite de la présente affaire, la Cour d'appel du Québec n'a pas jugé opportun, à ma connaissance, d'intervenir au motif qu'il existait un conflit jurisprudentiel au sein d'instances administratives: *Hydro-Québec c. Conseil des services essentiels* (1991), 41 Q.A.C. 292; *Syndicat canadien de la Fonction publique c. Commission des écoles catholiques de Québec*, C.A. Québec, nº 200-09-000463-866, le 20 décembre 1989, J.E. 90-176, et *Syndicat des communications graphiques, local 509M c. Auclair*, [1990] R.J.Q. 334. Dans ce dernier arrêt, le juge Tourigny nuançait la portée de l'affaire *Moalli* dans les termes suivants (à la p. 340):

> On pourrait soutenir que *Produits Pétro-Canada Inc. c. Moalli* a créé une exception à la règle généralement acceptée à l'effet que les cours n'interviennent que dans les cas d'erreurs manifestement déraisonnables. Dans cette affaire, le juge LeBel en venait à la conclusion que

1993 CanLII 106 (SCC)

Court could have been justified in intervening in cases where, despite the reasonableness of the error of law, it was in the public interest to put an end to divergent opinions among lower tribunals. However, the wording used in that case should be examined more closely. LeBel J.A. speaks of "... the reality and seriousness of a case law conflict which has not been solved since the Act ... came into force" and of "... two separate and inconsistent rules of law". This language suggests that review in such circumstances should be reserved for cases in which there are significant conflicts in the decisions of the lower tribunals.

That is not the case here.

In *Syndicat canadien de la Fonction publique v. Commission des écoles catholiques de Québec*, Dussault J.A. rejected as follows the argument that the existence of two diverging lines of arbitral decisions justified intervention by the courts (at pp. 12-13):

[TRANSLATION] In my view, the judgment of this Court in *Produits Pétro Canada Inc. v. Moalli* ... must be considered with the greatest circumspection. It was rendered in response to the entirely exceptional circumstances of that case, when the differing interpretations related to the Act itself. It seems to me to be misguided if not dangerous to apply the rule of intervention by the courts every time one arbitrator takes a different approach from the others in interpreting a provision of a collective agreement and so to provide an automatic right of appeal disguised in the form of evocation.

In short, although, strictly speaking, *Moalli* can be interpreted as saying that the existence of a significant conflict in decisions is an independent basis for judicial review, it must be noted that its impact is both ambiguous and limited. While its scope has been qualified by subsequent decisions of the Quebec Court of Appeal, this restrictive interpretation does not of itself resolve the questions that remain regarding judicial review. The problem presented by the standard of review applicable to an arbitrator's decision seems to me to be unavoidable. If the question before the arbitrator in *Moalli* was jurisdictional in nature, he could not err without being subject to judicial review. If, on the other hand, the question was within jurisdiction, only a patently unreasonable interpretation

la Cour supérieure pouvait être justifiée d'intervenir dans des cas où, malgré le caractère raisonnable de l'erreur de droit, il était dans l'intérêt public de mettre fin à des opinions divergentes au sein des tribunaux inférieurs. On doit cependant regarder de plus près les termes utilisés dans cette affaire. Le juge LeBel parle de «(...) la réalité et la gravité d'un conflit jurisprudentiel qui ne connaît pas de solution depuis l'entrée en vigueur de la Loi (...)» et de «(...) deux règles de droit distinctes et incompatibles». Ces termes suggèrent que la révision en pareilles circonstances doit être réservée aux cas où il y a, dans la jurisprudence des tribunaux inférieurs, des conflits sérieux.

Ce n'est pas le cas ici.

Dans l'affaire *Syndicat canadien de la Fonction publique c. Commission des écoles catholiques de Québec*, le juge Dussault a rejeté, comme suit, l'argument voulant que l'existence de deux courants de jurisprudence arbitrale justifie l'intervention des cours de justice (aux pp. 12 et 13):

À mon avis, le jugement de notre Cour dans *Produits Pétro Canada Inc. c. Moalli* [...] doit être considéré avec la plus grande circonspection. Il a été prononcé en raison des circonstances tout à fait exceptionnelles de l'espèce et alors que les divergences d'interprétation visaient la loi elle-même. Il me paraîtrait abusif sinon dangereux de consacrer le principe de l'intervention des tribunaux à chaque fois qu'un arbitre n'aurait pas le même pas que les autres dans l'interprétation d'une disposition d'une convention collective et d'accorder ainsi, déguisé sous la forme de l'évocation, un droit d'appel automatique.

En résumé, même si l'arrêt *Moalli* peut, à la rigueur, s'interpréter comme s'autorisant de l'existence d'un conflit jurisprudentiel sérieux comme motif autonome de contrôle judiciaire, force est de constater que sa portée est à la fois ambiguë et limitée. Quoique les arrêts subséquents de la Cour d'appel du Québec aient nuancé sa portée, cette interprétation restrictive ne résout pas, pour autant, les interrogations qui subsistent en matière de contrôle judiciaire. Le problème posé par la norme de contrôle applicable à la décision de l'arbitre m'apparaît, à cet égard, incontournable. Si la question dont était saisi l'arbitre dans *Moalli* en était une de nature juridictionnelle, il ne pouvait commettre d'erreur sans s'exposer au contrôle judiciaire. Si, par ailleurs, la question était intrajuridictionnelle,

1993 CanLII 106 (SCC)

would call for judicial review. The fact that, in that case, the Court of Appeal held that it was departing from the rule of curial deference does not, strictly speaking, in any way alter the following observation: an initial conclusion that, for judicial review purposes, the legislature itself admits several possible and rational constructions of the same legislative provision is the guiding principle without which, in theory, there can be no judicial review in the event of conflicting decisions.

This guiding principle was well delineated by Reid J. in *Franks*, *supra*: like the standard of review applicable to the impugned decision, the context in which several contending values conflict, here as there, is crucial. The issue is between the expertise and effectiveness of administrative tribunals and curial deference, on the one hand, and consistency and predictability in the application of the law, on the other. The advisability of judicial intervention in the event of conflicting decisions among administrative tribunals, even when serious and unquestionable, cannot, in these circumstances, be determined solely by the "triumph" of the rule of law. Where decisions made within jurisdiction are not patently unreasonable, the issue instead turns on whether the principles underlying curial deference should give way to other imperatives. In my opinion, the answer is no.

First, dealing with a case of administrative inconsistency and solving it means altering the already delicate institutional relationship between administrative tribunals and courts with reference to the impugned decision. As Professor MacLauchlan notes, *supra*, at p. 441:

> It is a matter of applying rules, or principles, to facts. The essence of the matter is not to determine in some scientific fashion whether a decision is consistent with a claimed precedent but to determine *who should decide*. [Emphasis in original.]

At page 445, the author adds: "[r]eview for inconsistency, so far from being neutral or disengaged, invites full judicial reconsideration of the

seule une interprétation manifestement déraisonnable appelait le contrôle judiciaire. Le fait que la Cour d'appel ait jugé, dans cette affaire, qu'elle dérogeait au principe de la retenue judiciaire ne change strictement rien au constat suivant: une conclusion initiale à l'effet que le législateur admet lui-même, aux fins du contrôle judiciaire, plusieurs lectures possibles et rationnelles d'une même disposition législative constitue le fil directeur sans lequel l'opportunité d'un contrôle judiciaire en cas de conflit jurisprudentiel ne saurait, en principe, se poser.

Le juge Reid a bien cerné ce fil directeur dans l'affaire *Franks*, précitée: tout comme la norme de contrôle applicable à la décision contestée, le contexte dans lequel s'affrontaient, là comme ici, plusieurs valeurs, est déterminant. Il s'agit de l'expertise et de l'efficacité des tribunaux administratifs et la retenue judiciaire d'une part, contre la cohérence et la prévisibilité dans l'application de la loi, de l'autre. L'opportunité d'une intervention judiciaire en cas de conflit jurisprudentiel au sein de tribunaux administratifs, même grave et incontestable, ne saurait, dans ces conditions, s'inspirer uniquement du «triomphe» de la primauté du droit. Dans le cas de décisions intrajuridictionnelles non manifestement déraisonnables, le débat se résume, plutôt, à se demander si les principes sous-jacents à la retenue judiciaire doivent céder le pas à d'autres impératifs. À mon avis, la réponse est non.

En premier lieu, se pencher sur un cas d'incohérence administrative et le solutionner, c'est modifier le rapport institutionnel, déjà délicat, entre les tribunaux administratifs et les cours de justice sous l'angle de la décision contestée. Comme le souligne le professeur MacLauchlan, *loc. cit.*, à la p. 441:

> [TRADUCTION] Il s'agit d'appliquer les règles ou les principes aux faits. Le fond de la question n'est pas de déterminer d'une manière scientifique si une décision est cohérente par rapport à un précédent invoqué mais bien de déterminer *qui doit décider*. [En italique dans l'original.]

À la p. 445, l'auteur ajoute: [TRADUCTION] «L'examen de l'incohérence, loin d'être neutre ou libre, donne lieu à une révision judiciaire complète

1993 CanLII 106 (SCC)

administrative decision". A jurisprudential conflict must necessarily be found. In order to solve it, courts must proceed to examine the merits of the decisions in question. As Professor Mullan himself points out, *supra*, at p. 282:

> The determination of whether there has been inconsistency will seldom, if ever, come down to a case of different treatment of two persons in precisely the same situation. Rather, it will generally involve the court in making judgments as to whether A's situation was sufficiently dissimilar to B's to make their differential treatment justifiable. "Is refusing induction qualitatively the same as the situations previously dealt with by the Commission?" As soon as the determination of such questions becomes the court's function, the judge will be involved in substantially the same assessment task as the statute has confided to the Commission. [Emphasis added.]

In my opinion, there is a real risk that superior courts, by exercising review for inconsistency, may be transformed into genuine appellate jurisdictions. Far from being neutral, the concept of consistency is an elusive parameter which, varying depending on the objective sought, may distort the very nature of judicial review. The arbitrariness which the judicial sanction is designed to remedy may, thus, become the result. In *Bibeault*, *supra*, Beetz J. commented as follows on the use of the theory of preliminary or collateral questions as a means of arriving at judicial review (at p. 1087):

> The concept of the preliminary or collateral question diverts the courts from the real problem of judicial review: it substitutes the question "Is this a preliminary or collateral question to the exercise of the tribunal's power?" for the only question which should be asked, "Did the legislator intend the question to be within the jurisdiction conferred on the tribunal?" [Emphasis added.]

In my opinion, questions as to the advisability of resolving a jurisprudential conflict avoid the main issue, namely, who is in the best position to rule on the impugned decision. Substituting one's opinion for that of an administrative tribunal in order to develop one's own interpretation of a legislative provision eliminates its decision-making autonomy

de la décision administrative». Un conflit jurisprudentiel doit, nécessairement, être constaté. Afin de le solutionner, les cours de justice doivent procéder à un examen du bien-fondé des décisions concernées. Comme le souligne le professeur Mullan lui-même, *loc. cit.*, à la p. 282:

> [TRADUCTION] L'examen de la question de savoir s'il y a eu incohérence aboutira rarement, sinon jamais, à un cas où deux personnes exactement dans la même situation auront été traitées différemment. La cour de justice devra généralement décider plutôt si la situation de A diffère suffisamment de celle de B pour justifier un traitement différent. «Le refus d'enrôlement correspond-il qualitativement aux situations déjà examinées par la Commission?» Dès que la cour de justice doit trancher ce genre de questions, le juge jouera substantiellement le même rôle d'évaluation que celui que la loi a conféré à la Commission. [Je souligne.]

Le risque que les tribunaux supérieurs se transforment, par le biais d'un contrôle de l'incohérence, en de véritables juridictions d'appel est, à mes yeux, véritable. Loin d'être neutre, la notion de cohérence constitue un paramètre fuyant qui, malléable en fonction de la finalité recherchée, peut dénaturer l'essence même du contrôle judiciaire. L'arbitraire dont la sanction judiciaire se voudrait le remède peut, ainsi, en devenir la conséquence. Dans l'arrêt *Bibeault*, précité, le juge Beetz a critiqué, comme suit, l'utilisation de la théorie des conditions préalables comme moyen d'aborder le contrôle judiciaire (à la p. 1087):

> La notion de condition préalable détourne les tribunaux du véritable problème du contrôle judiciaire: elle substitue la question «S'agit-il d'une condition préalable à l'exercice du pouvoir du tribunal?» à la seule question qu'il faut se poser, «Le législateur a-t-il voulu qu'une telle matière relève de la compétence conférée au tribunal?» [Je souligne.]

À mes yeux, s'interroger sur l'opportunité de trancher un conflit jurisprudentiel, c'est se détourner, de même, de la question première, soit celle de savoir qui est le mieux placé pour se prononcer sur la décision contestée. Substituer son opinion à celle d'un tribunal administratif afin de dégager sa propre interprétation d'une disposition législative,

1993 CanLII 106 (SCC)

and special expertise. Since such intervention occurs in circumstances where the legislature has determined that the administrative tribunal is the one in the best position to rule on the disputed decision, it risks, at the same time, thwarting the original intention of the legislature. Any inquiry into decision-making inconsistency where there is no patently unreasonable error thus diverts courts of law from the fundamental question which the legislature has in any case already answered.

Moreover, limiting this type of review to serious and unquestionable jurisprudential conflicts would not, by itself, remove all difficulty. There are undoubtedly clear cases of inconsistency where the dictates of equality and consistency in the application of the law will have full effect. I am far from certain, however, that only those cases will come before the courts. The case at bar is a striking demonstration of this: is the fact that two bodies interpret the same legislative provision differently, but in the particular context of the jurisdiction of each, one in a penal and the other in an administrative matter, a "conflict in decisions"? What about an isolated decision conflicting with a consistent line of authority? Must a jurisprudential conflict "continue" before being brought to the attention of the courts? If so, how is the quantitative and temporal threshold to be determined? Professor Ouellette has voiced these concerns:

> [TRANSLATION] Now we know at least that the concept of "serious or significant conflict of decisions" must be strictly interpreted, but it remains a source of confusion and difficult to apply. How many differing opinions or persons affected, assuming that they can be quantified, must there be to justify review on evocation of a decision not otherwise patently unreasonable?

(Yves Ouellette, "Le contrôle judiciaire des conflits jurisprudentiels au sein des organismes administratifs: une jurisprudence inconstante" (1990), 50 *R. du B.* 753, at p. 757.)

c'est réduire à néant son autonomie décisionnelle et l'expertise qui lui est propre. Puisqu'une telle intervention surgit dans un contexte où le législateur a déterminé que le tribunal administratif est celui qui est le mieux placé pour se prononcer sur la décision contestée, elle risque de contrecarrer, par la même occasion, son intention première. Toute enquête sur l'incohérence décisionnelle en l'absence d'erreur manifestement déraisonnable détourne donc les cours de justice de l'interrogation fondamentale à laquelle le législateur a, au surplus, déjà répondu.

D'autre part, le fait de limiter cette forme de contrôle aux cas de conflits jurisprudentiels graves et incontestables n'évacuerait pas, en soi, les difficultés. Il existe, certes, des cas d'incohérence clairs où les impératifs d'égalité et de cohérence dans l'application de la loi prennent tout leur sens. Cependant, je suis loin d'être certaine que seuls ces cas seront portés à l'attention des cours de justice. La présente affaire en constitue l'éclatante démonstration: le fait que deux organismes interprètent différemment un même texte législatif, mais dans le contexte particulier de la compétence de chacun, l'un en matière pénale, l'autre en matière administrative, constitue-t-il un «conflit jurisprudentiel»? Qu'en-est-il d'une décision isolée à l'encontre d'une jurisprudence constante? Un conflit jurisprudentiel doit-il «perdurer» avant qu'il ne soit porté à l'attention des cours de justice? Dans l'affirmative, comment en fixer le seuil quantitatif et temporel? Le professeur Ouellette s'est fait l'écho de ces interrogations:

> On sait au moins maintenant que le concept de «conflit jurisprudentiel grave ou sérieux» doit s'interpréter restrictivement, mais il demeure source de confusion et difficile d'application. Combien faut-il d'opinions divergentes ou combien faut-il de personnes affectées, à supposer que l'on puisse les quantifier, pour justifier la révision sur évocation d'une décision par ailleurs non manifestement déraisonnable?

(Yves Ouellette, «Le contrôle judiciaire des conflits jurisprudentiels au sein des organismes administratifs: une jurisprudence inconstante?» (1990), 50 *R. du B.* 753, à la p. 757.)

1993 CanLII 106 (SCC)

The principle that decisions of administrative tribunals remain effective is accordingly decisive. While answers diametrically opposed according to the identity of the members of an administrative tribunal certainly would seem to be unacceptable, what is the position of the litigant in whose favour the same administrative tribunal has ruled but who sees this decision challenged (with all the costs, delays and so on involved), perhaps needlessly, on the ground of an alleged inconsistency? The first situation is relatively rare and can be resolved outside the judicial arena. The legislature is in that category. Similarly, the administrative body can play a role of primary importance. As Professor MacLauchlan noted, *supra*, at p. 437:

> The proper response to administrative action which is ostensibly inconsistent but which falls short of traditional jurisdictional grounds of review is not judicial oversight, but the exertion of pressure in the political dynamic, of which the administrative decision-maker forms a vital element.

Similarly, it is important to note the internal mechanisms developed by administrative tribunals to ensure the consistency of their own decisions: *IWA v. Consolidated-Bathurst Packaging Ltd.*, [1990] 1 S.C.R. 282, and *Tremblay v. Quebec (Commission des affaires sociales)*, [1992] 1 S.C.R. 952. In *Tremblay*, Gonthier J. noted that "the objective of consistency responds to litigants' need for stability but also to the dictates of justice" (p. 968). In *Consolidated-Bathurst*, Gonthier J. spoke of the importance for an administrative tribunal to maintain a high level of quality and consistency in its decisions (at pp. 327-28):

> It is obvious that coherence in administrative decision making must be fostered. The outcome of disputes should not depend on the identity of the persons sitting on the panel for this result would be [TRANSLATION] "difficult to reconcile with the notion of equality before the law, which is one of the main corollaries of the rule of law, and perhaps also the most intelligible one": Morissette, *Le contrôle de la compétence d'attribution: thèse, antithèse et synthèse* (1986), 16 *R.D.U.S.* 591, at p. 632. Given the large number of decisions rendered in

Le principe voulant que les décisions des tribunaux administratifs demeurent efficaces est, dès lors, déterminant. Si des réponses diamétralement opposées selon l'identité des membres d'un tribunal administratif paraît, certes, inacceptable, qu'en est-il du justiciable à qui le même tribunal administratif a donné raison, mais qui voit cette décision contestée (avec tous les frais, délais, etc. que cela comporte), de façon peut-être futile, au motif d'une incohérence présumée? La première situation est relativement rare et peut se régler à l'extérieur de l'arène judiciaire. Le législateur est de ceux-là. De même, l'organisme administratif peut jouer un rôle de tout premier ordre. Comme l'a noté le professeur MacLauchlan, *loc. cit.*, à la p. 437:

> [TRADUCTION] La façon de réagir à une décision administrative manifestement incohérente, mais qui ne soulève pas de motifs traditionnels d'examen de la compétence n'est pas l'inaction judiciaire, mais plutôt l'exercice de pressions dans la sphère politique, dont le décideur administratif est un élément essentiel.

Dans le même esprit, il convient de souligner l'importance des mécanismes internes mis en œuvre par les tribunaux administratifs afin d'assurer la cohérence de leur propre jurisprudence: *SITBA c. Consolidated-Bathurst Packaging Ltd.*, [1990] 1 R.C.S. 282, et *Tremblay c. Québec (Commission des affaires sociales)*, [1992] 1 R.C.S. 952. Dans l'affaire *Tremblay*, le juge Gonthier a ainsi souligné que «[l']objectif de cohérence répond à un besoin de sécurité des justiciables, mais également à un impératif de justice» (p. 968). Dans l'arrêt *Consolidated Bathurst*, le juge Gonthier a fait état de l'importance, pour un tribunal administratif, de maintenir un niveau élevé de qualité et de cohérence dans le cadre de ses décisions (aux pp. 327 et 328):

> Il est évident qu'il faut favoriser la cohérence des décisions rendues en matière administrative. L'issue des litiges ne devrait pas dépendre de l'identité des personnes qui composent le banc puisque ce résultat serait «difficile à concilier avec la notion d'égalité devant la loi, l'un des principaux corollaires de la primauté du droit, et peut-être aussi le plus intelligible»: Morissette, *Le contrôle de la compétence d'attribution: thèse, antithèse et synthèse* (1986), 16 *R.D.U.S.* 591, à la p. 632. Vu le grand nombre de décisions rendues en matière de

1993 CanLII 106 (SCC)

the field of labour law, the Board is justified in taking appropriate measures to ensure that conflicting results are not inadvertently reached in similar cases. [Emphasis added.]

This Court has also recognized that the search for consistency is not an absolute one. Thus, in the foregoing case it was held that the members of an administrative tribunal were not bound by any *stare decisis* rule (p. 333). Similarly, as Gonthier J. pointed out in *Tremblay*, the consistency objective must be pursued in keeping with the decision-making autonomy and independence of members of the administrative body (at p. 971):

> We have seen that the justification for institutionalizing decisions lies primarily in the need to ensure consistency in decisions rendered by administrative tribunals. Whether the latter make decisions with a high policy component or not, those decisions must be consistent with the requirements of justice. A consultation process by plenary meeting designed to promote adjudicative coherence may thus prove acceptable and even desirable for a body like the Commission, provided this process does not involve an interference with the freedom of decision makers to decide according to their consciences and opinions. [Emphasis added.]

Finally, in the same case, the Court noted that administrative tribunals could render contradictory decisions (at p. 974):

> Ordinarily, precedent is developed by the actual decision makers over a series of decisions. The tribunal hearing a new question may thus render a number of contradictory judgments before a consensus naturally emerges. This of course is a longer process; but there is no indication that the legislature intended it to be otherwise. Bearing this in mind, I consider it is particularly important for the persons responsible for hearing a case to be the ones to decide it. [Emphasis added.]

Though they were part of a discussion centering on the rules of natural justice, these remarks indicate that certainty of the law and decision-making consistency are chiefly notable for their relativity. Like the rules of natural justice, these objectives cannot be absolute in nature regardless of the context. The value represented by the decision-making

droit du travail, la Commission est justifiée de prendre les mesures nécessaires pour éviter d'arriver, par inadvertance, à des solutions différentes dans des affaires semblables. [Je souligne.]

Notre Cour a également reconnu que la recherche de la cohérence n'avait pas un caractère absolu. Ainsi, dans l'arrêt précité, on a décidé que les membres d'un tribunal administratif n'étaient liés par aucune règle de *stare decisis* (p. 333). De même, comme l'a souligné le juge Gonthier dans l'arrêt *Tremblay*, l'objectif de cohérence doit se poursuivre dans le respect de l'autonomie et l'indépendance décisionnelle des membres de l'organisme administratif (à la p. 971):

> Nous avons vu que la justification de l'institutionnalisation des décisions réside principalement dans l'impératif de cohérence des décisions rendues par les tribunaux administratifs. Que ceux-ci rendent des décisions à haut coefficient politique ou non, ces décisions doivent être compatibles par souci de justice. Le processus de consultation par réunion plénière visant à favoriser la cohérence de la jurisprudence pourrait donc s'avérer acceptable et même désirable pour un organisme comme la Commission, à condition que ce processus ne constitue pas une entrave à la liberté des décideurs de trancher selon leurs conscience et opinions. [Je souligne.]

Enfin, dans le même arrêt, la Cour a précisé que les tribunaux administratifs pouvaient rendre des décisions contradictoires (à la p. 974):

> Normalement, l'élaboration d'un courant jurisprudentiel se fait par les décideurs effectifs suite à un ensemble de décisions. Le tribunal saisi d'une question nouvelle peut ainsi rendre un certain nombre de jugements contradictoires avant qu'un consensus ne se dégage naturellement. Il s'agit évidemment d'un processus plus long; rien n'indique cependant que le législateur ait voulu qu'il en soit ici autrement. Dans cette optique, je suis d'avis qu'il est particulièrement important que les personnes saisies d'une affaire soient celles qui décident. [Je souligne.]

Bien qu'elles s'inscrivent dans le cadre d'un débat axé sur les principes de justice naturelle, ces remarques démontrent que la sécurité juridique et la cohérence décisionnelle se démarquent, avant tout, par leur relativité. Tout comme les principes de justice naturelle, ces objectifs ne sauraient avoir un caractère absolu, dénué de tout contexte. La

1993 CanLII 106 (SCC)

independence and autonomy of the members of administrative tribunals goes hand in hand here with the principle that their decisions should be effective. In light of these considerations we must conclude that, for purposes of judicial review, the principle of the rule of law must be qualified. This is consistent with the continuing evolution of administrative law itself. The process by which curial deference has progressively become established in courts of law was analyzed by Wilson J. in *National Corn Growers Assn. v. Canada (Import Tribunal), supra* (at p. 1336):

> Canadian courts have struggled over time to move away from the picture that Dicey painted toward a more sophisticated understanding of the role of administrative tribunals in the modern Canadian state. Part of this process has involved a growing recognition on the part of courts that they may simply not be as well equipped as administrative tribunals or agencies to deal with issues which Parliament has chosen to regulate through bodies exercising delegated power, e.g., labour relations, telecommunications, financial markets and international economic relations. Careful management of these sectors often requires the use of experts who have accumulated years of experience and a specialized understanding of the activities they supervise.
>
> Courts have also come to accept that they may not be as well qualified as a given agency to provide interpretations of that agency's constitutive statute that make sense given the broad policy context within which that agency must work. [Emphasis added.]

This process has led to the development of the patently unreasonable error test. If Canadian administrative law has been able to evolve to the point of recognizing that administrative tribunals have the authority to err within their area of expertise, I think that, by the same token, a lack of unanimity is the price to pay for the decision-making freedom and independence given to the members of these tribunals. Recognizing the existence of a conflict in decisions as an independent basis for judicial review would, in my opinion, constitute a

valeur que représente l'indépendance et l'autonomie décisionnelle des membres des tribunaux administratifs se conjugue, ici, au principe de l'efficacité de leurs décisions. Soupeser ces considérations, c'est constater que le principe de la primauté du droit doit, aux fins du contrôle judiciaire, être nuancé. Ceci participe à la dimension évolutive du droit administratif lui-même. Le processus par lequel la retenue judiciaire a progressivement trouvé droit de cité chez les cours de justice a été analysé par le juge Wilson dans l'arrêt *National Corn Growers Assn. c. Canada (Tribunal des importations)*, précité, à la p. 1336:

> Les tribunaux judiciaires canadiens se sont efforcés au fil des ans de se détacher du point de vue de Dicey pour en arriver à une compréhension plus subtile du rôle des tribunaux administratifs dans l'État canadien moderne. C'est là un processus qui s'est traduit notamment par une reconnaissance accrue de la part des cours de justice qu'il se peut qu'elles soient simplement moins en mesure que les tribunaux ou organismes administratifs de statuer dans des domaines que le Parlement a choisi de réglementer par l'intermédiaire d'organismes exerçant un pouvoir délégué, comme, par exemple, les relations de travail, les télécommunications, les marchés financiers et les relations économiques internationales. Une gestion prudente de ces secteurs nécessite souvent le recours à des experts ayant à leur actif des années d'expérience et une connaissance spécialisée des activités qu'ils sont chargés de surveiller.
>
> Les cours de justice ont également fini par se faire à l'idée qu'elles ne sont peut-être pas aussi bien qualifiées qu'un organisme administratif déterminé pour donner à la loi constitutive de cet organisme des interprétations qui ont du sens compte tenu du contexte des politiques générales dans lequel doit fonctionner cet organisme. [Je souligne.]

Ce processus a conduit à l'élaboration du critère de l'erreur manifestement déraisonnable. Si le droit administratif canadien a pu évoluer au point de reconnaître que les tribunaux administratifs ont la compétence de se tromper dans le cadre de leur expertise, je crois que l'absence d'unanimité est, de même, le prix à payer pour la liberté et l'indépendance décisionnelle accordées aux membres de ces mêmes tribunaux. Reconnaître l'existence d'un conflit jurisprudentiel comme motif autonome de contrôle judiciaire constituerait, à mes yeux, une

1993 CanLII 106 (SCC)

serious undermining of those principles. This appears to me to be especially true as the administrative tribunals, like the legislature, have the power to resolve such conflicts themselves. The solution required by conflicting decisions among administrative tribunals thus remains a policy choice which, in the final analysis, should not be made by the courts.

VI—Conclusion

For all these reasons, I would allow the appeal and dismiss the motion in evocation, the whole with costs throughout.

Appeal allowed with costs.

Solicitors for the appellant: Trudel, Nadeau, Lesage, Clearly, Larivière & Associés, Montréal.

Solicitors for the respondent: Desjardins, Ducharme, Stein, Monast, Québec.

Solicitors for the mis en cause CALP: Levasseur, Delisle, Morel, Québec.

Solicitors for the mis en cause CSST: Chayer, Panneton, Lessard, Québec.

grave entorse à ces principes. Ceci m'apparaît d'autant plus vrai que les tribunaux administratifs, tout comme le législateur, ont le pouvoir de régler eux-mêmes ces conflits. La solution qu'appellent les conflits jurisprudentiels au sein de tribunaux administratifs demeure donc un choix politique qui ne saurait, en dernière analyse, être l'apanage des cours de justice.

VI—Conclusion

Pour toutes ces raisons, je suis d'avis d'accueillir le pourvoi et de rejeter la requête en évocation, le tout avec dépens dans toutes les cours.

Pourvoi accueilli avec dépens.

Procureurs de l'appelant: Trudel, Nadeau, Lesage, Clearly, Larivière & Associés, Montréal.

Procureurs de l'intimée: Desjardins, Ducharme, Stein, Monast, Québec.

Procureurs de la mise en cause CALP: Levasseur, Delisle, Morel, Québec.

Procureurs de la mise en cause CSST: Chayer, Panneton, Lessard, Québec.

1993 CanLII 106 (SCC)

Consolidated-Bathurst Packaging Ltd. *Appellant*

v.

International Woodworkers of America, Local 2-69 *Respondent*

and

The Ontario Labour Relations Board *Respondent*

INDEXED AS: IWA *v.* CONSOLIDATED-BATHURST PACKAGING LTD.

File No.: 20114.

1989: April 26; 1990: March 15.

Present: Lamer, Wilson, La Forest, L'Heureux-Dubé, Sopinka, Gonthier and McLachlin JJ.

ON APPEAL FROM THE COURT OF APPEAL FOR ONTARIO

Administrative law — Natural justice — Audi alteram partem rule — Right to know case to be made — Three-person panel hearing case and ultimately making decision — Case involving important and wider policy implications — Full Board meeting called to discuss policy implications of a draft decision — Facts accepted as stated in draft decision — No vote or consensus taken — No minutes kept — Attendance not recorded — Whether or not breach of rules of natural justice occurred — Labour Relations Act, R.S.O. 1980, c. 228, ss. 14, 102(9), (13), 106, 108, 114.

The Ontario Labour Relations Board ordinarily sits in panels of three when hearing applications under the *Labour Relations Act*. A three-member panel decided that the appellant had failed to bargain in good faith by not disclosing during negotiations for a collective agreement that it planned to close a plant. In the course of deliberating over this decision, a meeting of the full Board was held to discuss a draft of the reasons. No express statutory authority exists for this practice.

The record did not indicate how many of the Board's 48 members attended the meeting in question and

Consolidated-Bathurst Packaging Ltd. *Appelante*

c.

Syndicat international des travailleurs du bois d'Amérique, section locale 2-69 *Intimé*

et

La Commission des relations de travail de l'Ontario *Intimée*

RÉPERTORIÉ: SITBA *c.* CONSOLIDATED-BATHURST PACKAGING LTD.

N° du greffe: 20114.

1989: 26 avril; 1990: 15 mars.

Présents: Les juges Lamer, Wilson, La Forest, L'Heureux-Dubé, Sopinka, Gonthier et McLachlin.

EN APPEL DE LA COUR D'APPEL DE L'ONTARIO

Droit administratif — Justice naturelle — Règle audi alteram partem — Droit de connaître la preuve invoquée contre soi — Audition d'une affaire et décision ultime par un banc de trois personnes — Affaire comportant des conséquences importantes et plus générales en matière de politique — Convocation d'une réunion plénière de la Commission pour discuter des conséquences en matière de politique d'un avant-projet de décision — Faits énoncés dans l'avant-projet de décision tenus pour avérés — Aucun vote ni aucune vérification du consensus — Aucune rédaction de procès-verbal des délibérations — Aucune prise des présences — Y a-t-il eu violation des règles de justice naturelle? — Loi sur les relations de travail, L.R.O. 1980, ch. 228, art. 14, 102(9), (13), 106, 108, 114.

La Commission des relations de travail de l'Ontario siège ordinairement en bancs de trois membres quand elle entend les demandes présentées en vertu de la *Loi sur les relations de travail*. Un banc de trois commissaires a statué que l'appelante avait refusé de négocier de bonne foi en ne divulguant pas, au cours des négociations visant la signature d'une convention collective, qu'elle projetait de fermer une usine. Pendant les délibérations relatives à cette décision, la Commission a tenu une réunion plénière pour débattre un avant-projet de motifs. Aucune disposition législative n'autorise expressément cette pratique.

Le dossier ne précise pas combien des 48 membres de la Commission ont assisté à la réunion en cause ni s'il y

1990 CanLII 132 (SCC)

whether labour and management were equally represented as contemplated by s. 102(9) of the Act. The members of the panel who heard the case, however, appear to have been present. The meeting was conducted in accordance with the Board's longstanding and usual practice. This practice required that discussion be limited to the policy implications of a draft decision, that the facts be accepted as contained in the decision, that no vote or consensus be taken, that no minutes be kept, and that no attendance be recorded.

Appellant applied for judicial review of the Board's decision on the ground that the rules of natural justice had been breached. The application was granted by the Divisional Court but was disallowed on appeal. At issue here was whether the two rules of natural justice had been breached: (a) that the adjudicator be independent and unbiased, that he who decides must hear, and (b) the *audi alteram partem* rule, the right to know the case to be met.

Held (Lamer and Sopinka JJ. dissenting): The appeal should be dismissed.

Per Wilson, La Forest, L'Heureux-Dubé, Gonthier and McLachlin JJ.: Full board meetings are a practical means of calling upon the accumulated experience of board members when making an important policy decision and obviate the possibility of different panels inadvertently deciding similar issues in a different way. The rules of natural justice should reconcile the characteristics and exigencies of decision making by specialized tribunals with the procedural rights of the parties.

The members of a panel who actually participate in the decision must have heard both the evidence and the arguments presented by the parties. The presence of other Board members at the full board meeting does not, however, amount to "participation" in the final decision. Discussion with a person who has not heard the evidence does not necessarily vitiate the resulting decision because this discussion might "influence" the decision maker.

Decision makers cannot be forced or induced to adopt positions they do not agree with by means of some formalized consultation process. A discussion does not prevent a decision maker from adjudicating in accordance with his own conscience and does not constitute an obstacle to this freedom. The ultimate decision, whatever discussion may take place, is that of the decision

avait représentation égale des employés et de l'employeur comme le prescrit le par. 102(9) de la Loi. Les membres du banc qui avaient entendu l'affaire semblent cependant avoir été présents. La réunion s'est déroulée conformément à la pratique habituelle que la Commission suit depuis longtemps. Cette pratique consiste à restreindre les débats aux conséquences en matière de politique d'un avant-projet de décision, à considérer les faits mentionnés dans la décision comme avérés, à ne pas prendre de vote ni vérifier s'il y a consensus, à ne pas rédiger de procès-verbal des délibérations et à ne pas prendre les présences.

L'appelante a demandé le contrôle judiciaire de la décision de la Commission pour le motif qu'il y avait eu violation des règles de justice naturelle. Cette demande a été accueillie par la Cour divisionnaire, mais rejetée en appel. Il s'agit en l'espèce de déterminer si les deux règles suivantes de justice naturelle ont été violées: a) celle portant que le décideur doit être indépendant et impartial, que celui qui tranche une affaire doit l'avoir entendue, et b) la règle *audi alteram partem*, le droit de connaître la preuve invoquée contre soi.

Arrêt (les juges Lamer et Sopinka sont dissidents): Le pourvoi est rejeté.

Les juges Wilson, La Forest, L'Heureux-Dubé, Gonthier et McLachlin: Les réunions plénières de la Commission sont un moyen pratique de faire appel à l'expérience acquise par les commissaires lorsqu'il s'agit de rendre une décision importante de politique et d'éviter que des bancs différents rendent des décisions divergentes sur des questions semblables. Les règles de justice naturelle devraient concilier les caractéristiques et les exigences du processus décisionnel des tribunaux spécialisés avec les droits des parties en matière de procédure.

Les membres du banc qui participent effectivement à une décision doivent avoir entendu la totalité de la preuve et des plaidoiries soumises par les parties. La présence d'autres commissaires à la réunion plénière de la Commission n'équivaut cependant pas à une «participation» à la décision finale. La discussion avec une personne qui n'a pas entendu la preuve n'entache pas forcément de nullité la décision qui s'ensuit parce que cette discussion est susceptible d'«influencer» le décideur.

On ne peut recourir à aucun mécanisme formel de consultation pour forcer ou inciter un décideur à adopter un point de vue qu'il ne partage pas. Une discussion n'empêche pas un décideur de juger selon sa propre conscience pas plus qu'elle ne constitue une entrave à sa liberté. Quelles que soient les discussions qui peuvent avoir lieu, la décision ultime appartient au décideur et il

1990 CanLII 132 (SCC)

maker and he or she must assume full responsibility for that decision. Board members are not empowered by the Act to impose one member's opinion on another and procedures which may in effect compel or induce a panel member to decide against his or her own conscience or opinion cannot be used to thwart this *de jure* situation.

The criteria for independence is not absence of influence but rather the freedom to decide according to one's own conscience and opinions. The full board meeting was an important element of a legitimate consultation process and not a participation in the decision of persons who had not heard the parties. As practised by the Board, the holding of full board meetings does not impinge on the ability of panel members to decide according to their opinions so as to give rise to a reasonable apprehension of bias or lack of independence.

For the purpose of the application of the *audi alteram partem* rule, a distinction must be drawn between discussions on factual matters and discussions on legal or policy issues.

Evidence cannot always be assessed in a final manner until the appropriate legal test has been chosen by the panel and until all the members of the panel have evaluated the credibility of each witness. It is, however, possible to discuss the policy issues arising from the body of evidence filed before the panel even though this evidence may give rise to a wide variety of factual conclusions. These discussions can be segregated from the factual decisions which will determine the outcome of the case once a test is adopted by the panel. The purpose of the policy discussions is not to determine which of the parties will eventually win the case but rather to outline the various legal standards which may be adopted by the Board and discuss their relative value.

Policy issues must be approached in a different manner because they have, by definition, an impact which goes beyond the resolution of the dispute between the parties. While they are adopted in a factual context, they are an expression of principle or standards akin to law. Since these issues involve the consideration of statutes, past decisions and perceived social needs, the impact of a policy decision by the Board is, to a certain extent, independent from the immediate interests of the parties even though it has an effect on the outcome of the complaint.

On factual matters the parties must be given a fair opportunity for correcting or contradicting any relevant

en assume la responsabilité entière. La Loi n'habilite pas les membres de la Commission à imposer leur avis à un autre commissaire et on ne saurait recourir à des procédures qui peuvent avoir pour effet de forcer ou d'inciter un membre d'un banc à statuer à l'encontre de ses propres conscience ou opinions pour contrecarrer cette situation de droit.

Le critère de l'indépendance est non pas l'absence d'influence, mais plutôt la liberté de décider selon ses propres conscience et opinions. La réunion plénière de la Commission a constitué un élément important du processus légitime de consultation, mais non une participation à la décision par des personnes qui n'avaient pas entendu les parties. La pratique de la Commission consistant à tenir des réunions plénières n'entrave pas la capacité des membres d'un banc de statuer selon leurs opinions, de manière à susciter une crainte raisonnable de partialité ou d'un manque d'indépendance.

Aux fins de l'application de la règle *audi alteram partem*, il faut distinguer les discussions portant sur des questions de fait et celles portant sur des questions de droit ou de politique.

Il n'est pas toujours impossible d'évaluer la preuve de façon définitive avant que le banc n'ait choisi le critère juridique approprié et avant que tous les membres du banc n'aient évalué la crédibilité de chaque témoin. Cependant, il est possible de débattre des questions de politique que soulève la preuve soumise au banc même si cette preuve peut entraîner une grande variété de conclusions sur les faits. Il est possible de dissocier ces discussions des décisions sur les faits qui déterminent l'issue du litige après que le banc a adopté un critère. Les discussions sur les politiques n'ont pas pour objet de décider quelle partie aura finalement gain de cause, mais elles ont pour objet d'exposer les différents critères juridiques que la Commission peut adopter et de débattre leur valeur relative.

Il faut aborder les questions de politique de manière différente parce qu'elles ont, par définition, des conséquences qui vont au-delà du règlement du litige particulier entre les parties. Bien qu'elles découlent de faits précis, elles constituent l'expression d'un principe ou de normes apparentées au droit. Puisque ces questions font appel à l'analyse des lois, des décisions antérieures et des besoins sociaux qui sont perçus, les conséquences d'une décision de politique prise par la Commission ne dépendent pas, dans une certaine mesure, de l'intérêt immédiat des parties, même si elles peuvent avoir un effet sur l'issue de la plainte.

Relativement aux questions de fait, les parties doivent obtenir une possibilité raisonnable de corriger ou de

1990 CanLII 132 (SCC)

statement prejudicial to their view. The rule with respect to legal or policy arguments not raising issues of fact is, however, somewhat more lenient because the parties only have the right to state their case adequately and to answer contrary arguments. This right does not encompass the right to repeat arguments every time the panel convenes to discuss the case.

The safeguards attached by the Board to this consultation process are sufficient to allay any fear of violations of the rules of natural justice provided the parties are advised of any new evidence or grounds and are given an opportunity to respond. The balance so achieved between the rights of the parties and the institutional pressures the Board faces are consistent with the nature and purpose of the rules of natural justice. In the instant case, the policy decided upon was the very subject of the hearing when the parties had full opportunity to deal with the matter and present diverging proposals which they did.

Per Lamer and Sopinka JJ. (dissenting): The introduction of policy considerations in the decision-making process by members of the Board who were not present at the hearing and their application by members who were present but who heard no submissions from the parties in that respect violates the rationale underlying the principles of natural justice.

The final decision was formally that of the three-member panel. The inference that the full Board meeting might have affected the outcome, however, exists and is fed by two difficulties. Firstly, uniformity can only be achieved if some decisions of the individual panels are brought into line with others by the uniform application of policy. Secondly, in matters affecting the integrity of the decision-making process, an appearance of injustice is sufficient to taint the decision.

The Board is required by statute to hold a hearing and to give the parties a full opportunity to present evidence and submissions. It is also entitled to apply policy. The role of policy in the decision-making function of boards must be reappraised in light of the evolution of the law relating to the classification of tribunals and the application of the rules of natural justice and fairness to those boards. The content of the rules of natural justice is no longer dictated by classification as judicial, quasi-judicial or executive, but by reference to the circumstances of the case, the governing statutory provisions and the nature of the matters to be determined. It is no longer appropriate to conclude that failure to disclose policy to

contredire tout énoncé pertinent qui nuit à leur point de vue. Cependant, la règle relative aux arguments juridiques ou de politique qui ne soulèvent pas des questions de fait est un peu moins sévère puisque les parties n'ont que le droit de présenter leur cause et de répondre aux arguments qui leur sont défavorables. Ce droit n'inclut pas celui de reprendre les plaidoiries chaque fois que le banc se réunit pour débattre l'affaire.

Les garanties dont la Commission assortit ce processus de consultation sont suffisantes pour dissiper toute crainte de violation des règles de justice naturelle pourvu également que les parties soient informées de tout nouvel élément de preuve ou de tout nouveau moyen et qu'elles aient la possibilité d'y répondre. L'équilibre ainsi réalisé entre les droits des parties et les pressions institutionnelles qui s'exercent sur la Commission sont compatibles avec la nature et l'objet des règles de justice naturelle. En l'espèce, la politique visée par la décision était l'objet même de l'audition à laquelle les parties avaient l'entière possibilité de traiter de la question et de présenter des propositions divergentes, et c'est ce qu'elles ont fait.

Les juges Lamer et Sopinka (dissidents): L'introduction de considérations de politique dans le processus décisionnel par des commissaires qui n'ont pas assisté à l'audition et leur application par des commissaires qui étaient présents mais qui n'ont pas entendu de plaidoiries des parties au sujet de ces considérations, est contraire à la raison d'être des principes de justice naturelle.

La décision finale est bel et bien celle du banc de trois commissaires. La conclusion que la réunion plénière de la Commission peut avoir influé sur l'issue de l'affaire existe toutefois et découle de deux difficultés. Premièrement, l'uniformité ne peut se réaliser que si on fait concorder certaines décisions de bancs particuliers par l'application constante d'une politique. Deuxièmement, en matière d'atteinte à l'intégrité du processus décisionnel, il suffit qu'il y ait apparence d'injustice pour vicier la décision.

La Loi oblige la Commission à tenir une audition et à donner aux parties toute possibilité de présenter des éléments de preuve et des arguments. Elle a aussi le pouvoir d'appliquer des politiques. Il y a lieu de réévaluer le rôle des politiques dans le processus décisionnel des commissions en fonction de l'évolution du droit relatif à la classification des tribunaux et à l'application des règles de justice naturelle et d'équité à leur endroit. Le contenu des règles de justice naturelle ne dépend plus de leur classification en règles judiciaires, quasi judiciaires ou administratives, mais il est déterminé par les circonstances de l'affaire, les dispositions législatives applicables et la nature des litiges à décider. Il ne

1990 CanLII 132 (SCC)

be applied by a tribunal is not a denial of natural justice without examining all the circumstances under which the tribunal operates.

The full board hearing deprived the appellant of a full opportunity to present evidence and submissions and accordingly constituted a denial of natural justice. It could not be determined with certainty from the record that a policy which was developed at the full Board hearing and was not disclosed to the parties was a factor in the decision. That this might very well have happened, however, was fatal to the Board's decision.

The goal of uniformity in the decisions of individual boards, while laudable, cannot be achieved at the expense of the rules of natural justice. The legislature, if it so chooses, can authorize the full board procedure.

The conclusion that no substantial wrong occurred could not be made. Prejudice arising because of a technical breach of the rules of natural justice must be established by the party making the allegation. The appellant, however, could hardly be expected to establish prejudice when it was not privy to the discussion before the full Board and when there is no evidence as to what in fact was discussed. The gravity of the breach of natural justice could not be assessed in the absence of such evidence.

The full board procedure was not saved by s. 102(13) of the *Labour Relations Act* which granted the Board the power to determine its own practice and procedure subject to the qualification that full opportunity be granted the parties to any proceedings to present their evidence and to make their submissions. The appellant was not given a full opportunity to present evidence and make submissions. The Board's practice must give way when at a variance with the rules of natural justice.

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By Gonthier J.

Considered: *United Electrical, Radio & Machine Workers of America, Local 504 v. Westinghouse Canada Ltd.*, [1980] OLRB Rep. 577; *Doyle v. Restrictive Trade Practices Commission*, [1985] 1 F.C. 362; **referred to**: *Kane v. Board of Governors of the University of British Columbia*, [1980] 1 S.C.R. 1105; *Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp.*, [1979] 2 S.C.R. 227; *Mehr v.*

convient plus de conclure que l'omission de divulguer les politiques que le tribunal va appliquer ne constitue pas un déni de justice naturelle sans examiner toutes les circonstances dans lesquelles le tribunal fonctionne.

La réunion plénière de la Commission a privé l'appelante de la pleine possibilité de présenter des éléments de preuve et de faire valoir des arguments et a constitué un déni de justice naturelle. Le dossier ne permet pas de déterminer avec certitude si la formulation, lors de la réunion plénière, d'une politique qui n'a pas été divulguée aux parties a eu un effet sur la décision. Le fait que la chose ait très bien pu se produire est cependant fatal à la décision de la Commission.

Même si l'uniformisation des décisions de tribunaux particuliers est souhaitable, elle ne peut se faire aux dépens des règles de justice naturelle. Si le législateur veut permettre la poursuite de cet objectif, il est libre d'autoriser la procédure de réunion plénière de la Commission.

Il est impossible de conclure qu'il n'y a pas eu de préjudice grave. Le préjudice causé par une violation technique des règles de justice naturelle doit être prouvé par la partie qui l'invoque. On ne saurait cependant demander à l'appelante de prouver l'existence d'un préjudice alors qu'elle n'a pas eu connaissance de ce qui a été discuté à la réunion plénière de la Commission et qu'il n'y a pas de preuve quant à ce qui y a été réellement discuté. En l'absence de cette preuve, il est impossible de déterminer la gravité de la violation des règles de justice naturelle.

La procédure de réunion plénière de la Commission n'est pas sauvegardée par le par. 102(13) de la *Loi sur les relations de travail* qui confère à la Commission le pouvoir de régir sa propre pratique et procédure sous réserve d'accorder aux parties toute possibilité de présenter leur preuve et de faire valoir leurs arguments. L'appelante n'a pas eu toute possibilité de présenter sa preuve et de soumettre ses arguments. Quand les règles de justice naturelle entrent en conflit avec une pratique de la Commission, cette dernière doit céder le pas.

Jurisprudence

Citée par le juge Gonthier

Arrêts examinés: *United Electrical, Radio & Machine Workers of America, Local 504 v. Westinghouse Canada Ltd.*, [1980] OLRB Rep. 577; *Doyle c. Commission sur les pratiques restrictives du commerce*, [1985] 1 C.F. 362; **arrêts mentionnés**: *Kane c. Conseil d'administration de l'Université de la Colombie-Britannique*, [1980] 1 R.C.S. 1105; *Syndicat canadien de la Fonction publique, section locale 963 c. Société des*

1990 CanLII 132 (SCC)

Law Society of Upper Canada, [1955] S.C.R. 344; *The King v. Huntingdon Confirming Authority*, [1929] 1 K.B. 698; *Re Rosenfeld and College of Physicians and Surgeons* (1969), 11 D.L.R. (3d) 148; *Regina v. Broker-Dealers' Association of Ontario* (1970), 15 D.L.R. (3d) 385; *Re Ramm* (1957), 7 D.L.R. (2d) 378; *Regina v. Committee on Works of Halifax City Council* (1962), 34 D.L.R. (2d) 45; *Grillas v. Minister of Manpower and Immigration*, [1972] S.C.R. 577; *Re Rogers* (1978), 20 Nfld. & P.E.I.R. 484; *Underwater Gas Developers Ltd. v. Ontario Labour Relations Board* (1960), 24 D.L.R. (2d) 673; *Re Toronto and Hamilton Highway Commission and Crabb* (1916), 37 O.L.R. 656; *Beauregard v. Canada*, [1986] 2 S.C.R. 56; *Valente v. The Queen*, [1985] 2 S.C.R. 673; *Rex v. Sussex Justices*, [1924] 1 K.B. 256; *Committee for Justice and Liberty v. National Energy Board*, [1978] 1 S.C.R. 369; *Board of Education v. Rice*, [1911] A.C. 179; *Local Government Board v. Arlidge*, [1915] A.C. 120.

By Sopinka J. (dissenting)

United Electrical, Radio & Machine Workers of America, Local 504 v. Westinghouse Canada Ltd., [1980] OLRB Rep. 577; *Re Ramm* (1957), 7 D.L.R. (2d) 378; *Mehr v. Law Society of Upper Canada*, [1955] S.C.R. 344; *Walker v. Frobisher* (1801), 6 Ves. Jun. 70, 31 E.R. 943; *Szilard v. Szasz*, [1955] S.C.R. 3; *Rex v. Huntingdon Confirming Authority*, [1929] 1 K.B. 698; *Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp.*, [1979] 2 S.C.R. 227; *B. Johnson & Co. (Builders), Ltd. v. Minister of Health*, [1947] 2 All E.R. 395; *Re Cloverdale Shopping Centre and the Township of Etobicoke* (1966), 2 O.R. 439; *Nicholson v. Haldimand-Norfolk Regional Board of Commissioners of Police*, [1979] 1 S.C.R. 311; *Martineau v. Matsqui Institution Disciplinary Board*, [1980] 1 S.C.R. 602; *Syndicat des employés de production du Québec et de l'Acadie v. Canada (Canadian Human Rights Commission)*, [1989] 2 S.C.R. 879; *Innisfil (Corporation of the Township) v. Corporation of Township of Vespra*, [1981] 2 S.C.R. 145; *City of Kamloops v. Nielsen*, [1984] 2 S.C.R. 2; *Capital Cities Communications Inc. v. Canadian Radio-Television Commission*, [1978] 2 S.C.R. 141; *R. v. Criminal Injuries Compensation Board*, [1973] 1 W.L.R. 1334; *Toshiba Corp. v. Anti-Dumping Tribunal* (1984), 8 Admin. L.R. 173; *Komo Construction Inc. v. Commission des Relations de Travail du Québec*, [1968] S.C.R. 172.

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Citée par le juge Sopinka (dissident)

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1990 CanLII 132 (SCC)

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William R. Herridge, Q.C., for the appellant.

Paul Cavalluzzo and *David Bloom*, for the respondent International Woodworkers of America, Local 2-69.

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POURVOI contre un arrêt de la Cour d'appel de l'Ontario (1986), 56 O.R. (2d) 513, qui a accueilli l'appel d'une décision de la Cour divisionnaire (1985), 51 O.R. (2d) 481, 20 D.L.R. (4th) 84, 85 CLLC 14,031, qui avait accueilli une demande d'annulation d'une décision de la Commission des relations de travail de l'Ontario, [1983] OLRB Rep. December 1995, 5 CRBR (NS) 79, rendue relativement à une demande de réexamen de sa décision initiale, [1983] OLRB Rep. September 1411, 4 CLRBR (NS) 178. Pourvoi rejeté, les juges Lamer et Sopinka sont dissidents.

William R. Herridge, c.r., pour l'appelante.

Paul Cavalluzzo et *David Bloom*, pour l'intimé le Syndicat international des travailleurs du bois d'Amérique, section locale 2-69.

1990 CanLII 132 (SCC)

Gordon F. Henderson, *Q.C.*, and *R. Ross Wells*, for the respondent the Ontario Labour Relations Board.

The reasons of Lamer and Sopinka JJ. were delivered by

SOPINKA J. (dissenting)—The issue in this case is the propriety of a practice of the Ontario Labour Relations Board pursuant to which a full Board session is held to discuss a draft decision of a three-person panel.

Facts

The Ontario Labour Relations Board (hereinafter the "Board") derives its statutory authority under the *Labour Relations Act*, R.S.O. 1980, c. 228 (hereinafter the "Act"). The Board ordinarily sits in panels of three in hearing applications under the Act. This is authorized by s. 102(9) of the Act which provides:

> **102.** . . .
>
> (9) The chairman or a vice-chairman, one member representative of employers and one member representative of employees constitute a quorum and are sufficient for the exercise of all the jurisdiction and powers of the Board.

The original decision of a panel of three members of the Board ([1983] OLRB Rep. September 1411) from which this litigation arises was that the appellant had failed to bargain in good faith by not disclosing during negotiations for a collective agreement that it planned to close its Hamilton plant. In the course of deliberating over this decision, a meeting was held of the full Board to discuss a draft of the reasons. No express statutory authority exists for this practice.

Although we are told that the full Board consists of 48 members, it does not appear from the record how many attended the meeting in question and whether labour and management were equally represented as contemplated by s. 102(9) of the Act. The affidavit of Mr. Michael Gordon, filed on behalf of the appellant, identifies thirteen of the

Gordon F. Henderson, *c.r.*, et *R. Ross Wells*, pour l'intimée la Commission des relations de travail de l'Ontario.

Version française des motifs des juges Lamer et Sopinka rendus par

LE JUGE SOPINKA (dissident)—Le présent pourvoi soulève la question du bien-fondé d'une pratique suivie par la Commission des relations de travail de l'Ontario en vertu de laquelle celle-ci tient une réunion plénière pour débattre l'avant-projet de la décision que doit rendre un banc de trois commissaires.

Les faits

La Commission des relations de travail de l'Ontario (ci-après la «Commission») tient son existence de la *Loi sur les relations de travail*, L.R.O. 1980, ch. 228 (ci-après la «Loi»). La Commission siège ordinairement en bancs de trois membres quand elle entend les demandes présentées en vertu de la Loi. Le paragraphe 102(9) de la Loi, qui permet cette façon de procéder, est ainsi conçu:

> **102** . . .
>
> (9) Le président ou un vice-président, un membre représentant les employeurs et un membre représentant les employés constituent le quorum et peuvent exercer les attributions de la Commission.

La décision initiale du banc de trois commissaires ([1983] OLRB Rep. September 1411) qui est à l'origine du présent litige portait que l'appelante avait refusé de négocier de bonne foi en ne divulguant pas, au cours des négociations visant la signature d'une convention collective, qu'elle projetait de fermer son usine de Hamilton. Pendant les délibérations relatives à cette décision, la Commission a tenu une réunion plénière pour débattre un avant-projet de motifs. Aucune disposition législative n'autorise expressément cette pratique.

Bien qu'on nous dise que la Commission au complet se compose de 48 membres, le dossier ne mentionne pas combien de membres ont assisté à la réunion en cause, ni s'il y avait représentation égale des employés et de l'employeur comme le prescrit le par. 102(9) de la Loi. L'affidavit de M. Michael Gordon, produit pour le compte de l'appe-

1990 CanLII 132 (SCC)

people present, among them an alternate chairman, several vice-chairmen, a number of Board members, solicitors and senior employees of the Board. Of those specifically identified, only Board member Wightman was a member of the panel which heard the case. Nevertheless it appears from the Board's reasons on reconsideration that the other members of the panel of three were also present.

While it is not contested that no evidence was introduced at this full board meeting, it is not clear from the record what was discussed. The meeting took several hours but no minutes were kept. The reasons of the Board on reconsideration describe the practice of the Board in relation to full board hearings but provide no details as to what was discussed. It may be assumed that the matters discussed were in accordance with the Board's practice in this regard. This practice is described in the decision of the Board on Consolidated-Bathurst's application to reconsider the original decision, [1983] OLRB Rep. December 1995, which reads, in part, at paragraph 8:

8. After deliberating over a draft decision, any panel of the Board contemplating a major policy issue may, through the Chairman, cause a meeting of all Board members and vice-chairmen to be held to acquaint them with this issue and the decision the panel is inclined to make. These "Full Board" meetings have been institutionalized to facilitate a maximum understanding and appreciation throughout the Board of policy developments and to evaluate fully the practical consequences of proposed policy initiatives on labour relations and the economy in the Province.

There is no evidence that the procedure at the meeting in question departed from the Board's usual practice, whereby discussion is limited to the policy implications of a draft decision, the facts contained in the decision are taken as given, no vote or consensus is taken, no minutes are kept, and no attendance is recorded. The practice is not a recent innovation. It goes back at least as far as

lante, fournit les noms de treize des personnes présentes, dont un président suppléant, quelques vice-présidents, un certain nombre de commissaires, des avocats et des cadres de la Commission. *a* Parmi les personnes expressément nommées, seul le commissaire Wightman faisait partie du banc qui avait entendu l'affaire. Néanmoins, il ressort des motifs rendus par la Commission au sujet de la demande de réexamen que les autres membres du *b* banc de trois commissaires étaient eux aussi présents.

Bien qu'il ne soit pas contesté qu'aucun élément de preuve n'a été soumis pour la première fois à la *c* réunion plénière de la Commission, le dossier n'indique pas clairement le sujet des délibérations. La réunion a duré plusieurs heures, mais personne n'a rédigé de procès-verbal. Les motifs rendus par la *d* Commission sur la demande de réexamen décrivent la pratique de la Commission de tenir des réunions plénières, sans toutefois préciser ce sur quoi les débats ont porté. On peut supposer que les sujets discutés étaient conformes à la pratique de *e* la Commission à cet égard. Cette pratique est décrite dans la décision rendue par la Commission au sujet de la demande de réexamen de la décision initiale, présentée par Consolidated-Bathurst, [1983] OLRB Rep. December 1995, dont le par. 8 *f* est ainsi conçu:

[TRADUCTION] 8. Après avoir délibéré sur un avant-projet de décision, un banc qui envisage de trancher une question importante de politique peut faire convoquer, *g* par l'intermédiaire du président, une réunion plénière des membres et des vice-présidents pour leur faire part de la question soulevée et de la décision que le banc favorise. Ces réunions plénières ont été institutionnalisées pour mieux faire comprendre et apprécier par l'ensemble des commissaires l'évolution des politiques et *h* pour examiner à fond les conséquences pratiques que les politiques envisagées pourraient avoir sur les relations de travail et sur l'économie de la province.

Il n'y a aucune preuve que la procédure suivie lors *i* de la réunion en cause a été différente de la pratique habituelle de la Commission qui consiste à restreindre les débats aux conséquences en matière de politique d'un avant-projet de décision, *j* à considérer les faits mentionnés dans la décision comme avérés, à ne pas prendre de vote ni vérifier s'il y a consensus, à ne pas rédiger de procès-verbal

1990 CanLII 132 (SCC)

1971 when it was referred to, disapprovingly, in Chief Justice McRuer's report in the *Royal Commission Inquiry into Civil Rights*, February 22, 1971, pp. 2004-6.

The appellant learned of the full board meeting by chance and requested a reconsideration by the Board of its decision. This request was denied. In the course of its reasons the Board, as mentioned above, described its practice in detail and defended it as promoting consistency in the Board's decisions and as an institutionalization of the informal practice of conferral among colleagues. The Board considered its practice not a breach of natural justice but rather a procedure well suited to the Board's size, composition, and statutory mandate. Subsequent to the Board's refusal to reconsider its decision, the appellant applied to the Divisional Court for judicial review.

Divisional Court (1985), 51 O.R. (2d) 481

The majority of the Divisional Court, with Osler J. dissenting, granted the application, quashed the Board's decision, and ordered the Board to reconsider the matter in light of the Court's reasons for judgment. The reasons of the majority of the Divisional Court, delivered by Rosenberg J., were to the effect that because the parties had no knowledge as to what had been said in the discussions and no opportunity to respond, there was a violation of the principle that he who hears must decide. It could not be said with certainty that the three-member panel was not influenced in its decision by the full Board, because of the lack of evidence as to what transpired at the meeting. Thus the Court quashed the Board's decision. Osler J., on the other hand, was of the view that the common law contained no prohibition of consultation among decision makers and their colleagues, so long as those who have not heard the evidence and submissions do not participate in the decision. While the parties must be given the

des délibérations et à ne pas prendre les présences. Cette pratique n'est pas récente. Elle remonte au moins aussi loin qu'en 1971, puisque le juge en chef McRuer la mentionne, pour la condamner, dans le rapport de la *Royal Commission Inquiry into Civil Rights*, le 22 février 1971, aux pp. 2004 à 2006.

L'appelante a appris par hasard la tenue de la réunion plénière de la Commission et elle a demandé à la Commission de réexaminer sa décision. Cette demande a été rejetée. Dans ses motifs, la Commission a, comme je l'ai déjà mentionné, décrit sa pratique en détail et l'a justifiée par la cohérence que cette pratique favorise dans les décisions de la Commission, affirmant qu'il s'agit de l'institutionnalisation de la coutume officieuse qu'ont les commissaires de se consulter entre eux. La Commission a estimé que cette pratique ne constituait pas un déni de justice naturelle, mais qu'elle constituait plutôt une procédure bien adaptée à la taille de la Commission, à sa composition et au mandat que lui confère la Loi. Suite au refus de la Commission de réexaminer sa décision, l'appelante a demandé à la Cour divisionnaire de procéder au contrôle judiciaire de la décision.

La Cour divisionnaire (1985), 51 O.R. (2d) 481

La Cour divisionnaire à la majorité, le juge Osler étant dissident, a fait droit à la demande, annulé la décision de la Commission et lui a ordonné de réexaminer l'affaire en fonction des motifs de jugement de la cour. Les motifs de la majorité des juges de la Cour divisionnaire, rédigés par le juge Rosenberg, portent que parce que les parties ne savaient pas ce qui s'était dit au cours des délibérations et n'ont pas eu la possibilité de répliquer, il y a eu violation du principe voulant qu'il appartient à celui qui entend une cause de la trancher. Il était impossible d'affirmer avec certitude que la réunion plénière de la Commission n'avait pas influencé la décision du banc de trois commissaires à cause de l'absence de preuve au sujet de ce qui s'était passé à la réunion. La cour a donc annulé la décision de la Commission. Le juge Osler, quant à lui, a estimé que la common law n'interdit nullement à celui qui doit rendre une décision de consulter des collègues pour autant que ceux qui n'ont pas entendu la preuve et les plaidoi-

1990 CanLII 132 (SCC)

opportunity to respond to new ideas or evidence, this case provided no evidence that the full board meeting had yielded any such ideas or evidence.

Court of Appeal (1986), 56 O.R. (2d) 513

The decision of the Divisional Court was reversed on appeal to the Court of Appeal. Cory J.A., as he then was, in the Court of Appeal, concluded that pursuant to s. 102(13) of the *Labour Relations Act* the Labour Relations Board had exclusive jurisdiction to determine its own practice and procedure subject only to the obligation to give a full opportunity to the parties to the proceedings to present evidence and make submissions. He further concluded that there was no denial of natural justice in this case and that the meeting was an exercise of common sense whereby the significance and effect of a decision was discussed with other experts in the field. He emphasized, however, that the full board procedure was limited in that the parties must be recalled if new evidence is considered in the full Board's discussion, and that while the panel can receive advice from the full Board there can be no participation by the other Board members in the decision.

Issues

The issue in this appeal is whether the following rules of natural justice have been violated:

(a) he who decides must hear;

(b) the right to know the case to be met.

The Effect of the Full Board Procedure

The first step in deciding whether the rules of natural justice have been breached is to assess what role, if any, the full board procedure played in the decision-making process. The appellant submits that the outcome of its case may have been influenced by a formalized meeting of the full Board. The respondent Union counters by submit-

ries ne prennent pas part à la décision. Quoique les parties doivent avoir la possibilité de répliquer aux énoncés ou aux éléments de preuve nouveaux, rien n'indique en l'espèce que la réunion plénière de la Commission a donné lieu à de tels énoncés ou éléments de preuve.

La Cour d'appel (1986), 56 O.R. (2d) 513

La Cour d'appel a infirmé la décision de la Cour divisionnaire. Le juge Cory (alors juge de la Cour d'appel) a conclu qu'en vertu du par. 102(13) de la *Loi sur les relations de travail*, la Commission des relations de travail avait compétence exclusive pour déterminer sa propre pratique et procédure sous réserve seulement de l'obligation d'accorder aux parties toute possibilité de présenter leur preuve et de faire valoir leurs arguments. Il a conclu de plus qu'il n'y avait pas eu déni de justice naturelle en l'espèce et que la réunion était conforme au bon sens en ce qu'elle permettait à des experts d'un domaine de se consulter sur l'importance et la portée d'une décision. Il a cependant souligné que la procédure de réunion plénière de la Commission était limitée étant donné qu'il fallait réentendre les parties si les délibérations de la Commission au complet portaient sur de nouveaux éléments de preuve. Il a aussi souligné que si le banc pouvait obtenir l'avis de la Commission au complet, les autres membres de la Commission ne pouvaient participer à la décision.

Les questions en litige

Il s'agit de déterminer en l'espèce s'il y a eu violation des règles suivantes de justice naturelle:

a) celui qui tranche une affaire doit l'avoir entendue;

b) le droit de connaître la preuve invoquée contre soi.

Les conséquences de la procédure de réunion plénière de la Commission

Pour déterminer s'il y a eu violation des règles de justice naturelle, il faut commencer par évaluer le rôle qu'a pu jouer la procédure de réunion plénière de la Commission dans le processus décisionnel. L'appelante soutient que la réunion plénière officielle de la Commission a pu influer sur l'issue de son affaire. Le syndicat intimé réplique

1990 CanLII 132 (SCC)

ting that the appellant must establish a breach of the rules of natural justice but can point to no new evidence or arguments in the decision of the Board that were obtained as a result of the full board procedure. The purport of the Board's reasons on the application for reconsideration is that the ultimate decision was left to the panel and therefore presumably that the discussion of policy implications did not influence the final decision.

In the Board's reasons on reconsideration, it is stated at p. 2002 that the object of the full Board hearings is as follows:

These "Full Board" meetings have been institutionalized to facilitate a maximum understanding and appreciation throughout the Board of policy developments and to evaluate fully the practical consequences of proposed policy initiatives on labour relations and the economy in the Province.

The Board further states, at pp. 2002-3, that:

9. "Full Board" meetings are as important to fashioning informed and practical decisions which will withstand the scrutiny of subsequent panels as is the research and reflection undertaken by the vice-chairmen in preparing their draft decisions .... The "Full Board" meeting merely institutionalizes these discussions and better emphasizes the broad ranging policy implications of individual decisions.

The learned authors of Sack and Mitchell, *Ontario Labour Relations Board Law and Practice*, at p. 7, summarized the practice in the following terms:

When such a matter is referred in this way, the full Board does not consider the evidence or the facts of the case, but individual members may express their views on questions of law or policy. No vote is taken. The panel which heard the case then confers in private session and reaches a decision. In this way, some uniformity in Board decisions on matters of policy and procedure has been achieved in spite of the fact that differently constituted panels sit every day.

que l'appelante doit faire la preuve d'une violation des règles de justice naturelle, mais qu'elle ne peut signaler, dans la décision de la Commission, la présence d'aucun nouvel élément de preuve ni
a d'aucun nouvel argument qui soit apparu en raison de la procédure de réunion plénière de la Commission. Les motifs rendus par la Commission au sujet de la demande de réexamen tendent à montrer que la décision ultime a été laissée au banc et qu'il faut
b donc présumer que le débat sur les conséquences de la politique n'a pas influé sur la décision finale.

Dans les motifs donnés par la Commission relativement à la demande de réexamen, on affirme, à
c la p. 2002, que les réunions plénières de la Commission visent les objets suivants:

[TRADUCTION] Ces réunions plénières de la Commission ont été institutionnalisées pour mieux faire com-
d prendre et apprécier par l'ensemble des commissaires l'évolution des politiques et pour examiner à fond les conséquences pratiques que les politiques envisagées pourraient avoir sur les relations de travail et sur l'économie de la province.

e

La Commission ajoute, aux pp. 2002 et 2003:

[TRADUCTION] 9. Les réunions plénières de la Commission sont tout aussi importantes pour concevoir des décisions éclairées et pratiques qui résisteront à l'exa-
f men de bancs saisis ultérieurement que le sont les recherches et la réflexion des vice-présidents quand ceux-ci préparent leurs avant-projets de décision. [. . .] La réunion plénière de la Commission ne fait qu'institutionnaliser ces débats et souligne mieux la portée consi-
g dérable des conséquences de décisions particulières en matière de politique.

Sack et Mitchell, les auteurs de l'ouvrage inti-
h tulé *Ontario Labour Relations Board Law and Practice*, décrivent brièvement cette pratique, à la p. 7:

[TRADUCTION] Quand une question lui est ainsi soumise, la Commission au complet ne s'arrête pas aux faits
i de l'espèce ou à la preuve soumise, mais un commissaire peut exprimer son avis sur des questions de droit ou de politique. Il n'y a pas de vote. Le banc qui a entendu l'affaire délibère ensuite privément et arrête sa décision. De cette manière, il est possible d'arriver à une certaine
j uniformité dans les décisions de la Commission sur des questions de politique et de procédure même si la composition des bancs change tous les jours.

1990 CanLII 132 (SCC)

The issue before the Board was whether unsolicited disclosure of a proposed plant closing which was alleged to be at least under serious consideration was an aspect of the duty to bargain in good faith. In this regard the Board was being asked by the respondent Union to extend its decision in *United Electrical, Radio & Machine Workers of America, Local 504 v. Westinghouse Canada Ltd.*, [1980] OLRB Rep. 577, or at least to give it a broad interpretation. That case had decided that, as part of the employer's obligation to negotiate in good faith, an employer had a duty to disclose a *de facto* decision to close a plant. Resolution of this issue required the panel to choose between competing policies. The important role of policy is depicted in the following passages in the Board's original reasons at pp. 1430-31, 1436 and 1443:

> In cases of this kind there are, of course, significant conflicting values at stake. There is the desirability of stability in collective bargaining relationships as evidenced by the statutory policy requiring a collective agreement for a minimum term of one year and the twin statutory requirements of "no strike and no lockout". All differences during the term of an agreement are to be funnelled through grievance arbitration. It is also widely understood that management must have the ability to take initiatives in responding to the new demands posed by changing circumstances. The market place seldom awaits labour and management consensus. On the other hand, unilateral management initiatives can adversely affect significant interests of employees and unions who, in the absence of change, may have built up certain expectations and attitudes concerning the status quo.
>
> . . .
>
> The Board must also be sensitive to the statutory purpose of the bargaining duty, the language describing that duty, and the industrial relations implications of one approach over another.
>
> . . .
>
> What policy justification then supports greater unsolicited disclosure and merits the Board's intervention in the face of these potential difficulties?

La Commission devait décider si l'obligation de négocier de bonne foi exigeait la divulgation spontanée d'un projet de fermer une usine qui, selon les allégations, était tout au moins sérieusement à l'étude. À cet égard, le syndicat intimé demandait à la Commission d'appliquer à l'espèce la décision qu'elle avait rendue dans l'affaire *United Electrical, Radio & Machine Workers of America, Local 504 v. Westinghouse Canada Ltd.*, [1980] OLRB Rep. 577, ou, tout au moins, de lui donner une interprétation libérale. Dans cette affaire, la Commission avait statué qu'en vertu de l'obligation qui lui incombe de négocier de bonne foi, l'employeur est tenu de divulguer la décision *de facto* de fermer une usine. La solution de cette question exigeait du banc saisi qu'il choisisse entre deux politiques opposées. Les motifs de la décision initiale de la Commission font état de l'importance du rôle des politiques dans les passages suivants aux pp. 1430, 1431, 1436 et 1443:

> [TRADUCTION] Les affaires de ce genre font intervenir des valeurs opposées importantes. Il y a, d'une part, l'avantage de la stabilité dans les relations de négociation collective que favorisent la règle de droit prescrivant que la convention collective ait une durée minimale d'une année et la double règle qui interdit le recours à la grève et au lock-out. Tous les différends qui surviennent pendant la durée d'une convention collective doivent être résolus par l'arbitrage des griefs. Il est aussi généralement reconnu que la direction doit avoir la possibilité de prendre les mesures que les changements du marché exigent. Les conditions économiques attendent rarement l'unanimité de la direction et des syndicats pour évoluer. D'autre part, les actions unilatérales de la direction peuvent nuire à des droits importants des travailleurs et des syndicats chez qui, faute de changement, il peut s'être développé certaines attentes et attitudes à l'égard du *statu quo*.
>
> . . .
>
> La Commission doit aussi tenir compte de l'objet de l'obligation de négocier, de la formulation de cette obligation et des conséquences du choix d'une orientation par rapport à une autre sur les relations industrielles.
>
> . . .
>
> Quelles sont les raisons de principe qui justifieraient une divulgation spontanée plus étendue et qui motiveraient l'intervention de la Commission face à la possibilité de telles difficultés?

1990 CanLII 132 (SCC)

In the result the Board chose to broaden the application of *Westinghouse* by extending the meaning of a *de facto* decision to the facts of this case. At paragraph 53, p. 1447 of its decision, it stated:

53. In any event, we find that the matter of the impending closing was so concrete and highly probable in early January and dealt with by the board of directors in such a perfunctory manner (in that there was no documentation or apparent consideration of alternatives), the company had a minimum obligation to say that unless a certain percentage of the new business was retained or unless there was a dramatic turn in the operation a recommendation to close would be made within the next few weeks. Having regard to the Christmas letter to employees; the productive second half of 1982; and to the then state of dialogue between local labour and management on the future of the plant, the company's silence at the bargaining table was tantamount to a misrepresentation within the meaning of the *de facto* decision doctrine established in *Westinghouse*.

The following passage, at p. 2004, from the Board's reasons on reconsideration summarizes the participation of the full Board in the application of policy:

Unsolicited disclosure in collective bargaining—the issue involved in the case—is an area of great significance to effective and harmonious collective bargaining in this Province and it is fair to say that many of the labour and management Board members in attendance at the meeting gave their reaction to the principles and their application as set out in the draft decision. No vote, however, was held and no other mechanism for measuring consensus was employed.

Given the number of Board members present and the fact that included were an alternate Chairman, Vice-chairmen and solicitors, the views expressed were potentially very influential.

In view of the above I adopt the following from the reasons of the majority of the Divisional Court, at pp. 491-92, as a correct statement as to the effect of the full board meeting:

En définitive, la Commission a choisi d'élargir la portée de la décision *Westinghouse* en appliquant le sens de l'expression «décision *de facto*» aux faits de l'espèce. Au paragraphe 53 de sa décision, la Commission dit, à la p. 1447:

[TRADUCTION] 53. De toute façon, nous concluons que la fermeture prochaine était si réelle et probable au début de janvier et que le conseil de direction l'a traitée de manière si superficielle (parce qu'il n'y a eu ni documentation, ni apparemment aucune étude des autres solutions possibles), que la société avait au moins l'obligation de dire qu'à défaut de réaliser une augmentation réelle du chiffre d'affaires ou de connaître un revirement spectaculaire dans l'exploitation de l'entreprise, la société recommanderait la fermeture dans les semaines suivantes. Compte tenu de la lettre envoyée aux employés à l'occasion de Noël, d'un bon deuxième semestre en 1982 et de l'état des pourparlers engagés entre le syndicat local et la direction sur l'avenir de l'usine, le silence de la société à la table des négociations équivalait à une déclaration mensongère au sens de la théorie de la décision *de facto* énoncée dans l'affaire *Westinghouse*.

L'extrait suivant des motifs rendus par la Commission relativement à la demande de réexamen résume la participation de la Commission au complet à l'application d'une politique (à la p. 2004):

[TRADUCTION] La divulgation spontanée à l'occasion de négociations collectives, l'objet du litige en l'espèce, a une grande importance pour ce qui est d'assurer l'efficacité et l'harmonie des négociations collectives dans la province. Aussi, il est juste de dire que de nombreux commissaires représentant les employés ou les employeurs présents à la réunion ont exprimé leur avis sur les principes énoncés dans l'avant-projet de décision et sur leur application. Cependant, il n'y a pas eu de vote, ni de recours à quelque autre moyen de vérifier s'il y avait consensus.

En raison du nombre de commissaires présents et parce que, parmi les personnes présentes, il y avait un président suppléant, des vice-présidents et des avocats, les avis qui y ont été exprimés étaient susceptibles d'avoir une très grande influence sur la décision.

Compte tenu de ce qui précède, j'estime que l'extrait suivant des motifs des juges formant la majorité de la Cour divisionnaire énonce correctement, aux pp. 491 et 492, les répercussions de la réunion plénière de la Commission:

1990 CanLII 132 (SCC)

Chairman Shaw [*sic*] states in his reasons that the final decision was made by the three members who heard evidence and argument. He cannot be heard to state that he and his fellow members were not influenced by the discussion at the full board meeting. The format of the full board meeting made it clear that it was important to have input from other members of the board who had not heard the evidence or argument before the final decision was made. The tabling of the draft decision to all of the members of the board plus all of the support staff involved a substantial risk that opinions would be advanced by others and arguments presented. It is probable that some of the people involved in the meeting would express points of view. The full board meeting was only called when important questions of policy were being considered. Surely, the discussion would involve policy reasons why s. 15 should be given either a broad or narrow interpretation. Members or support staff might relate matters from their own practical experience which might be tantamount to giving evidence. The parties to the dispute would have no way of knowing what was being said in these discussions and no opportunity to respond.

[TRADUCTION] Le président Shaw [*sic*] affirme dans ses motifs que la décision définitive a été arrêtée par les trois commissaires qui avaient entendu la preuve et les plaidoiries. Il ne peut valablement affirmer que lui-même et ses collègues membres du tribunal n'ont pas été influencés par le débat survenu lors de la réunion plénière de la Commission. La façon dont s'est déroulée la réunion plénière de la Commission laisse voir qu'il était important d'avoir l'avis des autres commissaires qui n'avaient entendu ni la preuve ni les plaidoiries avant de prendre une décision finale. La présentation de l'avant-projet de décision à tous les commissaires et à tout le personnel de soutien comportait un risque sérieux que d'autres personnes soumettent leur avis et fassent valoir des arguments. Il est probable que certaines des personnes présentes à la réunion ont exprimé leur avis. Il n'y avait convocation d'une réunion plénière de la Commission que s'il y avait des questions de politique importantes à débattre. La discussion a certainement porté sur les raisons de principe de donner à l'art. 15 une interprétation libérale ou une interprétation restreinte. Les commissaires ou le personnel de soutien ont pu faire part d'informations tirées de leur expérience pratique, ce qui pourrait équivaloir à présenter des éléments de preuve. Les parties au litige n'avaient aucun moyen de savoir ce qui se disait dans ce débat, ni aucune possibilité de répliquer.

I would conclude from the foregoing that the full board meeting might very well have affected the outcome. The Board in its reasons on reconsideration does not directly seek to refute this inference. It does affirm that the final decision was that of the panel. There are two difficulties which confront the Board in seeking to negate the inference. First, I find it difficult to understand how the full board practice can achieve its purpose of bringing about uniformity without affecting the decision of individual panels. Uniformity can only be achieved if some decisions are brought into line with others by the uniform application of policy. The second difficulty is that in matters affecting the integrity of the decision-making process, it is sufficient if there is an appearance of injustice. The tribunal will not be heard to deny what appears as a plausible objective conclusion. The principle was expressed by Mackay J. in *Re Ramm* (1957), 7 D.L.R. (2d) 378 (Ont. C.A.) Mackay J. wrote, at p. 382:

Je conclus de ce qui précède que la réunion plénière de la Commission a fort bien pu influer sur l'issue de l'affaire. Dans les motifs qu'elle a rendus au sujet de la demande de réexamen, la Commission ne tente pas directement de réfuter cette conclusion. Elle assure cependant que la décision finale est bel et bien celle du banc saisi. La Commission rencontre deux difficultés lorsqu'elle cherche à réfuter cette conclusion. Premièrement, il m'est difficile de comprendre comment la pratique de la Commission de tenir des réunions plénières peut permettre d'atteindre son objectif de réaliser l'uniformité sans influencer la décision des bancs particuliers. L'uniformité ne peut se réaliser que si on fait concorder certaines décisions par l'application constante d'une politique. La deuxième difficulté découle de ce qu'en matière d'atteinte à l'intégrité du processus décisionnel, il suffit qu'il y ait apparence d'injustice. On ne peut accepter que le tribunal nie ce qui paraît être une conclusion objective plausible. Ce principe a été formulé par le juge Mackay dans l'arrêt *Re Ramm* (1957), 7 D.L.R. (2d) 378 (C.A. Ont.), où il dit, à la p. 382:

1990 CanLII 132 (SCC)

With respect to the difference in the constitution of members of the Public Accountants Council on the first and second hearings, it may very well be that the two members of the Public Accountants Council who were not present at the earlier hearing, abstained from argument on the issues which fell for determination. It appears, however, that they did vote inasmuch as the decision to revoke the licence of the appellant Ramm was unanimous. It is well established that it is not merely of some importance but of fundamental importance, that "justice should not only be done but should manifestly and undoubtedly be seen to be done". In a word, it is not irrelevant to inquire whether two members of the Council who were not present at the earlier meeting took part in the proceeding in the Council's deliberation on the subsequent hearing. What is objectionable is their presence during the consultation when they were in a position which made it impossible for them to discuss in a judicial way, the evidence that had been given on oath days before and in their absence and on which a finding must be based. [Emphasis added.]

In *Mehr v. Law Society of Upper Canada*, [1955] S.C.R. 344, at p. 350, Cartwright J. cited with approval the following passage from the judgment of Lord Eldon L.C. in *Walker v. Frobisher* (1801), 6 Ves. Jun. 70, 31 E.R. 943, at pp. 72 and 944:

> ... but the arbitrator swears, it (hearing further persons) had no effect upon his award. I believe him. He is a most respectable man. But I cannot from respect for any man do that, which I cannot reconcile to general principles. A Judge must not take upon himself to say, whether evidence improperly admitted had or had not an effect upon his mind. The award may have done perfect justice, but upon general principles it cannot be supported.

This statement had been approved previously by this Court in *Szilard v. Szasz*, [1955] S.C.R. 3. Cartwright J. was also impressed by the statement of Romer J. in *Rex v. Huntingdon Confirming Authority*, [1929] 1 K.B. 698, at p. 717:

> Further, I would merely like to point this out: that at that meeting of May 16 there were present three justices who had never heard the evidence that had been given on oath on April 25. There was a division of opinion. The resolution in favour of confirmation was carried by eight to two, and it is at least possible that that majority was induced to vote in the way it did by the eloquence of

[TRADUCTION] Quand à la différence dans la composition du Public Accountants Council lors des première et seconde auditions, il se peut fort bien que les deux membres du Public Accountants Council absents lors de la première audition se soient abstenus de débattre des questions à décider. Il appert cependant qu'ils ont voté puisque la décision de révoquer la licence de l'appelant Ramm était unanime. Il est reconnu qu'il est non seulement important, mais essentiel que «non seulement justice soit rendue, mais qu'il y ait aussi apparence manifeste que justice est rendue». En un mot, il ne s'agit pas de se demander si deux membres du Conseil absents lors de la première audition ont participé aux délibérations du Conseil lors de l'audition subséquente. Ce qui est critiquable, c'est leur présence pendant la période de consultation, situation qui ne leur permettait pas d'examiner, d'une manière judiciaire, la preuve présentée sous serment plusieurs jours auparavant, en leur absence, sur laquelle une décision devait être fondée. [Je souligne.]

Dans l'arrêt *Mehr v. Law Society of Upper Canada*, [1955] R.C.S. 344, à la p. 350, le juge Cartwright cite, en l'approuvant, le passage suivant des motifs du lord chancelier Eldon dans l'arrêt *Walker v. Frobisher* (1801), 6 Ves. Jun. 70, 31 E.R. 943, aux pp. 72 et 944 respectivement:

> [TRADUCTION] ... mais l'arbitre jure que cela (le fait d'avoir entendu d'autres personnes) n'a pas influencé sa décision. Je le crois. C'est un homme très respectable. Je ne puis cependant, par déférence pour qui que ce soit, faire ce qui m'apparaît contraire aux principes généraux. Un juge ne peut prendre sur lui de dire si un élément de preuve irrégulièrement admis a influencé sa décision. La décision peut avoir rendu justice parfaitement, mais elle ne saurait être justifiée selon les principes généraux.

Notre Cour a déjà approuvé cette affirmation dans l'arrêt *Szilard v. Szasz*, [1955] R.C.S. 3. Le juge Cartwright a lui aussi été impressionné par l'énoncé du juge Romer dans l'arrêt *Rex v. Huntingdon Confirming Authority*, [1929] 1 K.B. 698, à la p. 717:

> [TRADUCTION] De plus, j'aimerais simplement souligner ceci: à cette réunion du 16 mai, il y avait trois juges qui n'avaient pas entendu la preuve présentée sous serment le 25 avril. Il y a eu partage d'opinions. La résolution en faveur de confirmer a été adoptée à huit voix contre deux et il est à tout le moins possible que la majorité ait été amenée à se prononcer comme elle l'a fait en raison

1990 CanLII 132 (SCC)

those members who had not been present on April 25, to whom the facts were entirely unknown.

I turn next to consider whether a discussion of policy matters at the full board meeting which may have affected the outcome constituted a breach of the rules of natural justice.

The Principles of Natural Justice

Section 102(13) of the Act provides that the Board shall give full opportunity to the parties to present their evidence and make their submissions. The Board is empowered to determine its own practice and procedure but rules governing its practice and procedure are subject to the approval of the Lieutenant Governor in Council. While not every practice of the Board would necessarily be subject to the approval of the Lieutenant Governor, the full board practice is one which might require such approval. No such approval has been given and indeed the practice does not appear to have been adopted formally as a rule of the Board. In view of the fact, however, that this point was not argued I do not propose to deal with it further.

The full board hearing in this case is said to violate the principles of natural justice in two respects: first, that members of the Board who did not preside at the hearing participated in the decision; and second, that the case is decided at least in part on the basis of materials which were not disclosed at the hearing and in respect of which there was no opportunity to make submissions.

Although these are distinct principles of natural justice, they have evolved out of the same concern: a party to an administrative proceeding entitled to a hearing is entitled to a meaningful hearing in the sense that the party must be given an opportunity to deal with the material that will influence the tribunal in coming to its decision, and to deal with it in the presence of those who make the decision. As stated by Crane in his case comment on the *Consolidated-Bathurst* decision (1988), 1 *C.J.A.L.P.* 215, at p. 217: "The two rules have the

de l'éloquence des membres qui avaient été absents le 25 avril et qui ignoraient absolument tout des faits.

Je vais maintenant examiner si le débat qui a été tenu sur des questions de politique lors de la réunion plénière de la Commission et qui a pu influer sur l'issue de l'affaire a constitué une violation des règles de justice naturelle.

Les principes de justice naturelle

Le paragraphe 102(13) de la Loi prévoit que la Commission doit accorder aux parties toute possibilité de présenter leur preuve et de faire valoir leurs arguments. La Commission a le pouvoir d'établir sa propre pratique et procédure, mais les règles qui régissent cette pratique et cette procédure sont soumises à l'approbation du lieutenant-gouverneur en conseil. Bien que ce ne soient pas toutes les pratiques de la Commission qui doivent être ainsi approuvées, la pratique des réunions plénières de la Commission en est une qui pourrait nécessiter cette approbation. Aucune approbation de cette nature n'a été donnée et la pratique ne paraît pas avoir été adoptée officiellement à titre de règle de la Commission. Mais puisque ce point n'a pas été débattu, je n'ai pas l'intention de m'y arrêter.

On a soutenu que la réunion plénière de la Commission en l'espèce viole les principes de justice naturelle de deux manières: premièrement, parce que des commissaires qui ne faisaient pas partie du banc qui a entendu l'affaire ont participé à la décision et, deuxièmement, parce que la décision a été, au moins en partie, prise en fonction d'éléments qui n'ont pas été divulgués à l'audition et à l'égard desquels il n'y a pas eu de possibilité de présenter des arguments.

Bien qu'il s'agisse de principes de justice naturelle distincts, ceux-ci découlent du même souci: faire en sorte qu'une partie à une procédure administrative qui a droit à une audition bénéficie d'une véritable audition, en ce sens qu'elle doit avoir la possibilité de répondre à tous les éléments qui influeront sur la décision du tribunal et d'y répondre en présence de ceux qui prennent cette décision. Crane le formule ainsi dans son commentaire sur la décision *Consolidated-Bathurst* (1988), 1 *C.J.A.L.P.* 215, à la p. 217: [TRADUCTION] «Les

1990 CanLII 132 (SCC)

same purpose: to preserve the integrity and fairness of the process." In the first case the party has had no opportunity to persuade some of the members at all, while in the second the party has not been afforded an opportunity to persuade the tribunal as to the impact of material obtained outside the hearing.

The concern for justice is aptly put by the pithy statement in the McRuer Report criticizing the full board procedure. At pages 2005-6, the former Chief Justice of the High Court of Ontario states:

> To take a matter before the full Board for a discussion and obtain the views of others who have not participated in the hearing and without the parties affected having an opportunity to present their views is a violation of the principle that he who decides must hear.
>
> . . .
>
> Notwithstanding that the ultimate decision is made by those who were present at the hearing, where a division of the Board considers that a matter should be discussed before the full Board or a larger division, the parties should be notified and given an opportunity to be heard.

Although I am satisfied that, at least formally, the decision here was made by the three-member panel, that does not determine the matter. The question, rather, is whether the introduction of policy considerations in the decision-making process by members of the Board who were not present at the hearing and their application by members who were present but who heard no submissions from the parties in respect thereto, violates the rationale underlying the above principles.

In answering this question, it is necessary to consider the role of policy in the decision-making processes of administrative tribunals. There is no question that the Labour Board is entitled to consider policy in arriving at its decisions. See Dickson J. (as he then was) in *Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp.*, [1979] 2 S.C.R. 227, at pp. 235-36:

deux règles ont le même objet, celui de préserver l'intégrité et l'équité du processus». Dans le premier cas, la partie n'a pas du tout eu la possibilité de convaincre certains des commissaires alors que, dans le second cas, la partie n'a pas eu la possibilité de convaincre le tribunal quant à l'incidence des éléments obtenus en dehors de l'audition.

L'énoncé lapidaire du rapport McRuer qui critique la procédure de réunion plénière de la Commission formule bien ce souci de justice. Aux pages 2005 et 2006, l'ancien juge en chef de la Haute Cour de l'Ontario dit ceci:

> [TRADUCTION] Le fait de porter une affaire à la connaissance de toute la Commission pour en débattre et obtenir l'avis de personnes qui n'ont pas participé à l'audition sans que les parties touchées aient la possibilité d'exprimer leur avis constitue une violation du principe selon lequel celui qui tranche une affaire doit l'avoir entendue.
>
> . . .
>
> Malgré que la décision ultime soit prise par ceux qui ont assisté à l'audition, quand une section de la Commission juge nécessaire qu'une affaire soit débattue devant l'ensemble de la Commission ou une section plus grande, il faudrait en prévenir les parties et leur donner la possibilité d'être entendues.

Quoique je sois convaincu qu'officiellement, à tout le moins, c'est le banc de trois commissaires qui a pris la décision, cette conclusion ne clôt pas le débat. La question en litige est plutôt de savoir si l'introduction de considérations de politique dans le processus décisionnel par des commissaires qui n'ont pas assisté à l'audition et leur application par des commissaires qui étaient présents mais qui n'ont pas entendu de plaidoiries des parties au sujet de ces considérations est contraire à la raison d'être des principes susmentionnés.

Pour répondre à cette question, il faut examiner le rôle des politiques dans le processus décisionnel des tribunaux administratifs. Il n'y a pas de doute que la Commission des relations de travail peut tenir compte de politiques pour rendre ses décisions. Voir le juge Dickson (maintenant Juge en chef) dans l'arrêt *Syndicat canadien de la Fonction publique, section locale 963 c. Société des alcools du Nouveau-Brunswick*, [1979] 2 R.C.S. 227, aux pp. 235 et 236:

1990 CanLII 132 (SCC)

The labour board is a specialized tribunal which administers a comprehensive statute regulating labour relations. In the administration of that regime, a board is called upon not only to find facts and decide questions of law, but also to exercise its understanding of the body of jurisprudence that has developed around the collective bargaining system, as understood in Canada, and its labour relations sense acquired from accumulated experience in the area.

The Board, then, is obliged by statute to hold a hearing and to give the parties a full opportunity to present evidence and submissions. It is also entitled to apply policy. At a time when the content of the rules of natural justice was determined by classifying tribunals as quasi-judicial or administrative, the Board would have been classified as exercising hybrid functions. A tribunal exercising hybrid functions did so in two stages. As a quasi-judicial tribunal it was required to comply with the rules of natural justice. In making its decision, however, it assumed its administrative phase and could overrule the conclusion which was indicated at the hearing by the application of administrative policy. Examples of this type of tribunal and the jurisprudence relating to its functions can be found in cases such as *B. Johnson & Co. (Builders), Ltd. v. Minister of Health*, [1947] 2 All E.R. 395, and *Re Cloverdale Shopping Centre and the Township of Etobicoke* (1966), 2 O.R. 439 (Ont. C.A.) In this state of the law there was no obligation on a tribunal during its administrative phase to comply with the rules of natural justice and hence to disclose policy which was being applied. Although tribunals exercising so-called administrative functions were subject to a general duty of fairness, disclosure of the policy to be applied by the tribunal was generally not a requirement. In the case of hybrid tribunals, therefore, such non-disclosure at the quasi-judicial stage would not have been considered a breach of the rules of natural justice. In this respect policy was treated on the same footing as the law. Both law and policy might be dealt with at the hearing but the tribunal was entitled to supplement it by its own researches without disclosure to the parties.

La commission est un tribunal spécialisé chargé d'appliquer une loi régissant l'ensemble des relations de travail. Aux fins de l'administration de ce régime, une commission n'est pas seulement appelée à constater des faits et à trancher des questions de droit, mais également à recourir à sa compréhension du corps jurisprudentiel qui s'est développé à partir du système de négociation collective, tel qu'il est envisagé au Canada, et à sa perception des relations de travail acquise par une longue expérience dans ce domaine.

La Loi oblige donc la Commission à tenir une audition et à donner aux parties toute possibilité de présenter des éléments de preuve et des arguments. Elle a aussi le pouvoir d'appliquer des politiques. À l'époque où la classification des tribunaux en tribunaux quasi judiciaires ou administratifs déterminait le contenu des règles de justice naturelle, la Commission aurait été classée dans la catégorie des tribunaux qui exerçaient des fonctions hybrides. Un tribunal qui exerçait des fonctions hybrides le faisait en deux étapes. À titre de tribunal quasi judiciaire, il était tenu de se conformer aux règles de justice naturelle. Au moment de rendre sa décision, il entrait dans la phase administrative de ses fonctions et pouvait, par l'application d'une politique administrative, écarter la conclusion indiquée à l'audience. On trouve des exemples de ce type de tribunal et de la jurisprudence qui traite de ses fonctions dans les arrêts *B. Johnson & Co. (Builders), Ltd. v. Minister of Health*, [1947] 2 All E.R. 395, et *Re Cloverdale Shopping Centre and the Township of Etobicoke* (1966), 2 O.R. 439 (C.A. Ont.) Selon cet état du droit, un tribunal n'était pas tenu, dans la phase administrative de ses fonctions, d'observer les règles de justice naturelle et par conséquent de divulguer la politique qu'il appliquait. Bien que les tribunaux qui remplissaient ces fonctions dites administratives étaient assujettis à une obligation générale d'agir avec équité, ils n'étaient pas tenus, en règle générale, de divulguer la politique qu'ils allaient appliquer. Par conséquent, dans le cas des tribunaux hybrides, la non-divulgation de cette politique pendant la phase quasi judiciaire n'aurait pas été considérée contraire aux règles de justice naturelle. À cet égard, les politiques étaient placées sur le même pied que le droit. Il était possible de traiter les politiques et le droit à l'audition, mais le tribunal pouvait la compléter par ses propres recherches sans en informer les parties.

1990 CanLII 132 (SCC)

This view of the role of policy must be reappraised in light of the evolution of the law relating to the classification of tribunals and the application to them of the rules of natural justice and fairness. The content of these rules is no longer dictated by classification as judicial, quasi-judicial or executive, but by reference to the circumstances of the case, the governing statutory provisions and the nature of the matters to be determined. See *Nicholson v. Haldimand-Norfolk Regional Board of Commissioners of Police*, [1979] 1 S.C.R. 311; *Martineau v. Matsqui Institution Disciplinary Board*, [1980] 1 S.C.R. 602, and *Syndicat des employés de production du Québec et de l'Acadie v. Canada (Canadian Human Rights Commission)*, [1989] 2 S.C.R. 879.

It is no longer appropriate, therefore, to conclude that failure to disclose policy to be applied by a tribunal is not a denial of natural justice without examining all the circumstances under which the tribunal operates.

The proceedings which are the subject of this appeal involve the exercise of extraordinary powers by the Board. In this case the Board was asked to order reopening of the Hamilton plant although it had operated at a loss. Although the Board declined to make that order, it apparently considered that it had jurisdiction to do so. In lieu thereof the employer was ordered to pay damages. These are civil consequences that affect the rights of employers to a greater degree than many civil actions in the courts in which a litigant enjoys the whole panoply of protection afforded by the rules of practice, procedure and the rules of evidence. The Act, here, provides for a full opportunity to the parties to present evidence and to make submissions. Is this opportunity denied when the tribunal considers and applies policy without giving the parties an opportunity to deal with it at the hearing? Is it a breach of the standard of fairness which underlies the rules of natural justice?

The answers to these questions lie in the nature of policy and whether it is correct to treat it on the

Il y a lieu de réévaluer cette conception du rôle des politiques en fonction de l'évolution du droit relatif à la classification des tribunaux et à l'application des règles de justice naturelle et d'équité à leur endroit. Le contenu de ces règles ne dépend plus de leur classification en règles judiciaires, quasi judiciaires ou administratives, mais il est déterminé par les circonstances de l'affaire, les dispositions législatives applicables et la nature des litiges à décider. Voir *Nicholson c. Haldimand-Norfolk Regional Board of Commissioners of Police*, [1979] 1 R.C.S. 311, *Martineau c. Comité de discipline de l'Institution de Matsqui*, [1980] 1 R.C.S. 602, et *Syndicat des employés de production du Québec et de l'Acadie c. Canada (Commission canadienne des droits de la personne)*, [1989] 2 R.C.S. 879.

Il ne convient donc plus de conclure que l'omission de divulguer les politiques que le tribunal va appliquer ne constitue pas un déni de justice naturelle sans examiner toutes les circonstances dans lesquelles le tribunal fonctionne.

Les procédures visées par le présent pourvoi portent sur l'exercice de pouvoirs exceptionnels de la part de la Commission. En l'espèce, on demandait à la Commission d'ordonner la réouverture de l'usine de Hamilton, même si son exploitation avait été déficitaire. Même si la Commission a refusé de rendre cette ordonnance, elle semble avoir estimé qu'elle avait compétence pour la rendre. L'employeur a plutôt été condamné à payer des dommages-intérêts. Ce sont là des conséquences civiles qui touchent plus les droits des employeurs que ne le font de nombreuses actions civiles devant des tribunaux où le justiciable bénéficie de toute la protection offerte par les diverses règles de pratique, de procédure et de preuve. En l'espèce, la Loi prescrit d'accorder toute possibilité aux parties de présenter leur preuve et de faire valoir leurs arguments. Cette possibilité est-elle refusée quand le tribunal examine et applique une politique sans donner aux parties la possibilité d'en traiter à l'audition? Est-ce là une violation de la norme d'équité qui sous-tend les règles de justice naturelle?

La réponse à ces questions dépend de la nature des politiques et de ce qu'il est ou non correct de

1990 CanLII 132 (SCC)

same footing as the law. In *Innisfil (Corporation of the Township) v. Corporation of Township of Vespra*, [1981] 2 S.C.R. 145, this Court was called upon to deal with the question whether a party to a proceeding before the Ontario Municipal Board was entitled to challenge policy by leading evidence and by cross-examination—the traditional methods for contesting fact. The Court of Appeal of Ontario had held that government policy introduced at the hearing was not binding but could be met by other evidence. Cross-examination was, however, denied. In this Court, the right to challenge policy by evidence was affirmed. In addition, the appellants were accorded the right to cross-examine and the Court of Appeal was reversed in this respect. Estey J., who delivered the judgment of the Court, stated, at p. 167:

> On the other hand, where the rights of the citizen are involved and the statute affords him the right to a full hearing, including a hearing of his demonstration of his rights, one would expect to find the clearest statutory curtailment of the citizen's right to meet the case made against him by cross-examination.

If a party has the right to attack policy in the same fashion as fact, it follows that to deprive the party of that right is a denial of a full opportunity to present evidence and is unfair. Policy in this respect is not like the law which cannot be the subject of evidence or cross-examination. Policy often has a factual component which the law does not. Furthermore, under our system of justice it is crucial that the law be correctly applied. The court or tribunal is not bound to rely solely on the law as presented by the parties. Accordingly, a tribunal can rely on its own research and if that differs from what has been presented at the hearing, it is bound to apply the law as found. Ordinarily there is no obligation to disclose to the parties the fruits of the tribunal's research as to the law, although it is a salutary practice to obtain their views in respect of an authority which has come to the tribunal's attention and which may have an important influence on the case. For an example of the application of this practice in this Court, see *City of Kamloops v. Nielsen*, [1984] 2 S.C.R. 2, at p.

les mettre sur le même pied que le droit. Dans l'arrêt *Innisfil (Municipalité du canton) c. Municipalité du canton de Vespra*, [1981] 2 R.C.S. 145, notre Cour devait décider si une partie à une procédure tenue devant la Commission municipale de l'Ontario avait le droit de contester une politique en présentant des éléments de preuve et en procédant à des contre-interrogatoires, qui sont les méthodes traditionnelles de contester les faits. La Cour d'appel de l'Ontario avait statué que la politique du gouvernement présentée à l'audition n'avait pas force obligatoire, mais qu'elle était susceptible de contestation sous forme de preuve contradictoire. On a cependant refusé le droit de contre-interroger. Notre Cour a confirmé le droit de contester une politique au moyen d'une preuve. De plus, l'appelante s'est vu accorder le droit de contre-interroger, ce qui infirmait la décision de la Cour d'appel à cet égard. Le juge Estey, qui a rendu l'arrêt de la Cour, dit ceci, à la p. 167:

> D'autre part, quand les droits d'une personne sont en jeu et que la loi lui accorde le droit à une audition complète, dont celle de la démonstration de ses droits, on s'attendrait à trouver dans la loi la négation catégorique du droit de cette personne de réfuter, par contre-interrogatoire, la preuve apportée contre elle.

Si une partie a le droit de contester une politique de la même manière qu'elle peut contester un fait, il s'ensuit que priver une partie de ce droit constitue un refus d'accorder à cette partie toute possibilité de présenter sa preuve et est injuste. Sous ce rapport, une politique diffère du droit qui ne peut faire l'objet d'une preuve ou d'un contre-interrogatoire. Une politique a souvent une composante factuelle que le droit n'a pas. De plus, selon notre système de justice, il est essentiel que le droit soit correctement appliqué. Un tribunal judiciaire ou administratif n'est pas astreint à s'en remettre aux seules règles de droit que les parties lui ont soumis. En conséquence, un tribunal administratif peut se fonder sur ses propres recherches et, en cas de divergence avec ce qui a été soumis à l'audition, il est tenu d'appliquer le droit déterminé par le résultat de ses recherches. Ordinairement, il n'y a pas d'obligation de révéler aux parties le fruit des recherches du tribunal quant au droit, bien qu'il soit recommandable d'obtenir leur avis quant à un précédent qui est porté à l'attention du tribunal et

1990 CanLII 132 (SCC)

36. We do not have the same attitude to policy. There is not necessarily one policy that is the right policy. Often there are competing policies, selection of the better policy being dependent on being subjected to the type of scrutiny which was ordered in *Innisfil*, *supra*.

Ample support can be found in the cases and writings for the proposition that generally policy is to be treated more like fact than law. In *Capital Cities Communications Inc. v. Canadian Radio-Television Commission*, [1978] 2 S.C.R. 141, Laskin C.J., in holding that the Commission was entitled to rely on policy, stated at p. 171:

> ... it was eminently proper that it lay down guidelines from time to time as it did in respect of cable television. The guidelines on this matter were arrived at after extensive hearings at which interested parties were present and made submissions. An overall policy is demanded in the interests of prospective licensees and of the public under such a regulatory regime as is set up by the *Broadcasting Act*. Although one could mature as a result of a succession of applications, there is merit in having it known in advance.

In *de Smith's Judicial Review of Administrative Action* (4th ed. 1980), at p. 223, the learned author states:

> ... an opportunity to be heard, both on the application and the merits of the policy, may be required in order to prevent a fettering of discretion.

In support, the learned author cites *R. v. Criminal Injuries Compensation Board*, [1973] 1 W.L.R. 1334, at p. 1345, *per* Megaw L.J.:

> As to the question of the board's minutes, I think that justice and paragraph 22 of the Scheme alike require that if the board in any particular case are minded to be guided by any principle laid down in any pre-existing minute of the board, the applicant must be informed of the existence and terms of that minute, so that he can, if he wishes, make his submissions with regard thereto: that is, submissions on the questions whether the principle is right or wrong in relation to the terms of the

qui peut avoir une influence considérable sur sa décision. Pour un exemple de l'application de cette pratique en notre Cour, on peut consulter l'arrêt *Ville de Kamloops c. Nielsen*, [1984] 2 R.C.S. 2, à la p. 36. Nous n'avons pas la même attitude envers les politiques. Il n'y a pas nécessairement une politique qui soit la bonne à suivre. Il arrive souvent que les politiques s'opposent et que le choix de la meilleure dépende d'un examen comme celui ordonné dans l'arrêt *Innisfil*, précité.

La jurisprudence et la doctrine appuient abondamment la proposition qu'en général il y a lieu de traiter une politique davantage comme un fait que comme du droit. Dans l'arrêt *Capital Cities Communications Inc. c. Conseil de la Radio-Télévision canadienne*, [1978] 2 R.C.S. 141, le juge en chef Laskin, statuant que la Commission avait le droit de se fonder sur une politique, dit à la p. 171:

> ... il était tout à fait approprié d'énoncer des principes directeurs comme le Conseil l'a fait à l'égard de la télévision par câble. Les principes en cause ont été établis après de longues auditions auxquelles les parties intéressées étaient présentes et ont pu faire des observations. Sous le régime de réglementation établi par la *Loi sur la radiodiffusion*, il est dans l'intérêt des titulaires éventuels de licences et du public d'avoir une politique d'ensemble. Même si une telle politique peut ressortir d'une succession de demandes, il est plus judicieux de la faire connaître à l'avance.

Dans son ouvrage intitulé *de Smith's Judicial Review of Administrative Action* (4ᵉ éd. 1980), de Smith affirme, à la p. 223:

> [TRADUCTION] ... la possibilité d'être entendu tant sur l'application que sur le bien-fondé d'une politique peut être nécessaire afin d'éviter une diminution de pouvoir discrétionnaire.

Pour étayer son avis, l'auteur cite les motifs du lord juge Megaw dans l'arrêt *R. v. Criminal Injuries Compensation Board*, [1973] 1 W.L.R. 1334, à la p. 1345:

> [TRADUCTION] Quand aux procès-verbaux de la commission, je crois que la justice de même que le régime du paragraphe 22 exigent que si, dans un cas particulier, la commission veut s'inspirer de quelque principe formulé dans un procès-verbal préexistant, le requérant soit avisé de l'existence et des termes de ce procès-verbal, de sorte qu'il puisse, s'il le désire, présenter des arguments à son égard, c'est-à-dire des arguments relatifs aux questions de savoir si le principe est bon ou mauvais par rapport

1990 CanLII 132 (SCC)

Scheme and whether the principle, if right, is applicable or inapplicable to the facts of the particular case.

Another comment from de Smith is found in the section on the right to a hearing, at p. 182, note 92:

Whilst it would be going too far to assert that in all circumstances there is an implied right to be apprised of and to argue against policy proposals, there are some indications pointing in this direction: see for example, *British Oxygen Co. Ltd.* v. *Board of Trade* [1971] A.C. 610, 625, 631 (desirable that notice be given to applicants for industrial grants of any rule or policy generally followed by the Department, and an opportunity for the applicants to make representations on the soundness or applicability of the policy or rule: this would make applications more effective and prevent the Department from fettering its statutory discretion) . . . .

In Professor Garant's *Droit administratif* (2nd ed. 1985), he states, at pp. 792-93:

[TRANSLATION] It seems to be well established that a policy or guidelines previously adopted by a tribunal do not give rise to a reasonable apprehension of bias, if the tribunal respects the *audi alteram partem* rule, even if the decision to intervene is in accordance with the policy or guidelines.

See also Dussault and Borgeat, *Administrative Law: A Treatise* (2nd ed. 1985), at p. 423, and Pépin and Ouellette, *Principes de contentieux administratif* (2nd ed. 1982), at p. 269.

In the discussion of "The Duty of Disclosure" Aronson and Franklin in *Review of Administrative Action* write, at p. 183:

The extent to which policy, expertise and independent inquiry are integral to the decision-making process will inevitably vary according to the subject matter for decision or investigation. But even in a trial-type hearing, the adjudicator is not bound exclusively by the parties' proofs and arguments, and will need to accommodate public and institutional interests. The more "polycentric", policy-oriented or technical a problem, the greater is the pressure on decision-makers to seek out solutions, to confer separately with interested persons, and to use their experience to find a settlement. The ability of administrators to inform themselves, and to apply their expertise and accumulated experience, and the expecta-

aux conditions du régime et si, à supposer qu'il soit bon, ce principe est applicable ou non aux faits de l'espèce.

On trouve cet autre commentaire de de Smith dans la section portant sur le droit à une audition, à la p. 182, note 92:

[TRADUCTION] Quoique ce serait aller trop loin que de soutenir qu'il existe, en toutes circonstances, un droit implicite d'être informé de toute proposition de politique et de la contester, il y a des indications en ce sens: voir, par exemple, *British Oxygen Co. Ltd.* v. *Board of Trade*, [1971] A.C. 610, aux pp. 625 et 631 (il est à souhaiter que les demandeurs de subventions industrielles soient informés de l'existence de toute règle ou politique généralement appliquée par le Ministère, et qu'ils aient la possibilité de présenter des arguments sur le bien-fondé ou l'applicabilité de la politique ou de la règle: cette pratique rendrait les demandes plus efficaces et empêcherait le Ministère de restreindre son pouvoir discrétionnaire) . . .

Dans son ouvrage intitulé *Droit administratif* (2e éd. 1985), le professeur Garant affirme, aux pp. 792 et 793:

La jurisprudence nous semble bien à l'effet qu'un énoncé de politique ou des directives prises préalablement par un tribunal ne donnent pas lieu à crainte raisonnable de préjugé, si le tribunal respecte la règle *audi alteram partem*, même si la décision à intervenir est conforme à l'énoncé de politique ou aux directives.

Voir également Dussault et Borgeat, *Traité de droit administratif* (2e éd. 1984), à la p. 423, et Pépin et Ouellette, *Principes de contentieux administratif* (2e éd. 1982), à la p. 269.

Au sujet de [TRADUCTION] «L'obligation de divulguer», Aronson et Franklin écrivent dans leur ouvrage intitulé *Review of Administrative Action*, à la p. 183:

[TRADUCTION] La mesure dans laquelle les politiques, l'expérience et la recherche personnelle font partie intégrante du processus décisionnel varie forcément selon le sujet de la décision ou de la recherche. Même dans une audition apparentée à un procès, le décideur n'est pas restreint à la preuve et aux arguments soumis par les parties, mais il doit tenir compte de l'intérêt du public et des institutions. Plus un problème est «polycentrique», technique ou axé sur une politique, plus le décideur sera poussé à chercher des solutions, à conférer séparément avec les personnes intéressées et à faire appel à leur expérience pour arriver à un règlement. La capacité des juges de tribunaux administratifs de se renseigner, de

1990 CanLII 132 (SCC)

tion that they will do so, makes the duty of disclosure sometimes difficult to define, and to observe. At the same time, however, it enhances the importance of the duty. Disclosure can act as an important safeguard against the use of inaccurate material or untested theories. It can also contribute to the efficiency of the hearing by directing argument and information to the relevant issues and materials. [Emphasis added.]

Wade, *Administrative Law* (4th ed. 1977) states, at p. 470:

> Policy is of course the basis of administrative discretion in a great many cases, but this is no reason why the discretion should not be exercised fairly *vis-a-vis* any person who will be adversely affected. The decision will require the weighing of any such person's interests against the claims of policy; and this cannot fairly be done without giving that person an opportunity to be heard.

In my opinion, therefore, the full board hearing deprived the appellant of a full opportunity to present evidence and submissions and constituted a denial of natural justice. While it cannot be determined with certainty from the record that a policy developed at the full board hearing and not disclosed to the parties was a factor in the decision, it is fatal to the decision of the Board that this is what might very well have happened.

While achieving uniformity in the decisions of individual boards is a laudable purpose, it cannot be done at the expense of the rules of natural justice. If it is the desire of the legislature that this purpose be pursued it is free to authorize the full board procedure. It is worthy of note that Parliament has given first reading to Bill C-40, a revised *Broadcasting Act* which authorizes individual panels to consult with the Commission and officers of the Commission in order to achieve uniformity in the application of policy (s. 19(4)). Provision is made, however, for the timely issue of guidelines and statements with respect to matters within the jurisdiction of the Commission.

mettre à profit leurs compétences et expérience et les attentes qu'ils le feront, rend parfois difficile de définir et de respecter l'obligation de divulguer. Mais, en même temps, cette capacité accroît l'importance de cette obligation. La divulgation peut constituer une protection importante contre l'utilisation d'éléments inexacts ou de théories non éprouvées. Elle peut aussi favoriser l'efficacité de l'audition en concentrant les renseignements et l'argumentation sur les sujets et les éléments de preuve pertinents. [Je souligne.]

Wade affirme, à la p. 470 de son ouvrage intitulé *Administrative Law* (4^{e} éd. 1977):

> [TRADUCTION] Il va sans dire que les politiques constituent le fondement de la discrétion administrative dans de nombreuses affaires, mais ceci ne justifie pas de ne pas exercer ce pouvoir discrétionnaire avec équité envers toute personne qui sera défavorisée par une décision. La décision exige qu'on soupèse les intérêts de ces personnes en fonction de ce qu'exige une politique; on ne peut le faire sans donner à cette personne la possibilité d'être entendue.

À mon avis, la réunion plénière de la Commission a donc privé l'appelante de la pleine possibilité de présenter des éléments de preuve et de faire valoir des arguments et a constitué un déni de justice naturelle. Quoique le dossier ne permette pas de déterminer avec certitude si la formulation, lors de la réunion plénière, d'une politique qui n'a pas été divulguée aux parties a eu un effet sur la décision, le fait que la chose ait très bien pu se produire est fatal à la décision de la Commission.

Même si l'uniformisation des décisions de tribunaux particuliers est souhaitable, elle ne peut se faire aux dépens des règles de justice naturelle. Si le législateur veut permettre la poursuite de cet objectif, il est libre d'autoriser la procédure de réunion plénière de la Commission. Il convient de souligner que le Parlement a adopté en première lecture le projet de loi C-40, une refonte de la *Loi sur la radiodiffusion*, lequel permet à des bancs particuliers de consulter le Conseil et ses cadres afin de réaliser une application uniforme des politiques (par. 19(4)). On prévoit cependant la promulgation régulière de directives et d'énoncés de politique relativement aux matières relevant de la compétence du Conseil.

1990 CanLII 132 (SCC)

Section 114

The respondents do not contend that if a breach of natural justice has occurred, the privative clause in s. 108 of the Act would apply. They have, however, submitted that if there was a breach of natural justice, it was technical only and hence no remedy should be available. The respondents cite s. 114 of the Act as well as *Toshiba Corp. v. Anti-Dumping Tribunal* (1984), 8 Admin. L.R. 173 (F.C.A.) Section 114 reads:

> **114.** No proceedings under this Act are invalid by reason of any defect of form or any technical irregularity and no such proceedings shall be quashed or set aside if no substantial wrong or miscarriage of justice has occurred.

Toshiba concerned a preliminary staff report prepared for the Anti-Dumping Tribunal which was not revealed to the parties and which the Court described as "a dangerous practice." Nonetheless, the Court of Appeal was satisfied that the report contained only matters of general knowledge or was based upon facts and sources which were brought out at the hearing in such a manner that the parties had the opportunity to test them. Thus any breach of natural justice was minor and inconsequential and the application for judicial review was dismissed.

The submission that there is no prejudice as a result of a technical breach of rules of natural justice requires that the party making the allegation establish this fact. To do so in this case it would be necessary for the respondents to satisfy the court that the matters discussed were all matters that had been brought out at the hearing. This has not occurred; unlike *Toshiba* there is no report or minutes of the full board meeting against which the hearing proceedings can be compared. The appellant can hardly be expected to establish prejudice when it was not privy to the discussion before the full Board and there is no evidence as to what in fact was discussed. In the absence of such evidence the gravity of the breach of natural jus-

L'article 114

Les intimés ne soutiennent pas que s'il y a eu violation des règles de justice naturelle, la clause privative de l'art. 108 de la Loi s'applique. Ils ont toutefois soutenu que s'il y a eu violation des règles de justice naturelle, elle a été purement formelle et qu'il n'y a pas lieu d'accorder quelque réparation que ce soit. Les intimés invoquent l'art. 114 de la Loi et l'arrêt *Toshiba Corp. c. Tribunal antidumping* (1984), 8 Admin. L.R. 173 (C.A.F.) L'article 114 est ainsi conçu:

> **114** Les instances introduites en application de la présente loi ne sont pas nulles en raison d'un vice de forme ou d'une irrégularité technique. Elles ne sont pas rejetées ni annulées, à moins qu'il n'en résulte un préjudice grave ou une erreur judiciaire fondamentale.

L'arrêt *Toshiba* porte sur un rapport préliminaire du personnel préparé pour le Tribunal antidumping qui n'avait pas été divulgué aux parties, ce que la cour a qualifié de «pratique dangereuse». Néanmoins, la Cour d'appel s'est dite convaincue que tout ce qui était contenu dans le rapport était de notoriété publique ou était fondé sur des faits et des sources soulevés à l'audience d'une manière telle que les parties avaient eu la possibilité de les examiner. Donc, s'il y avait eu violation des règles de justice naturelle, elle était mineure et sans importance de sorte que la demande de contrôle judiciaire a été rejetée.

L'argument selon lequel il n'y a pas eu de préjudice causé par une violation technique des règles de justice naturelle exige de la partie qui l'invoque qu'elle établisse cette absence. Pour faire cette preuve en l'espèce, il faudrait que les intimés convainquent la cour que les sujets discutés avaient tous été abordés à l'audition. Ce n'est pas ce qui s'est produit; à la différence de l'affaire *Toshiba*, il n'y a pas de compte rendu ou de procès-verbal de la réunion plénière de la Commission qui permettraient de faire la comparaison avec les procédures d'audition. On ne saurait demander à l'appelante de prouver l'existence d'un préjudice alors qu'elle n'a pas eu connaissance de ce qui a été discuté à la réunion plénière de la Commission et qu'il n'y a pas de preuve quant à ce qui y a été réellement discuté. En l'absence de cette preuve, il est impossible de déterminer la gravité de la violation des

1990 CanLII 132 (SCC)

tice cannot be assessed, and I cannot conclude that no substantial wrong has occurred.

Section 102(13)

Nor can I conclude that the full board procedure is saved by virtue of s. 102(13) of the *Labour Relations Act*. Section 102(13) reads:

> **102.** . . .
>
> (13) The Board shall determine its own practice and procedure but shall give full opportunity to the parties to any proceedings to present their evidence and to make their submissions, and the Board may, subject to the approval of the Lieutenant Governor in Council, make rules governing its practice and procedure and the exercise of its powers and prescribing such forms as are considered advisable. [Emphasis added.]

I recognize the importance of deference to a board's choice of procedures expressed by this Court in *Komo Construction Inc. v. Commission des Relations de Travail du Québec*, [1968] S.C.R. 172, at p. 176 [reported in English translation at (1967), 1 D.L.R. (3d) 125, at p. 127], *per* Pigeon J.:

> While upholding the rule that the fundamental principles of justice must be respected, it is important to refrain from imposing a code of procedure upon an entity which the law has sought to make master of its own procedure.

However, in this case the appellant was not given a full opportunity to present evidence and make submissions, which is an explicit limit placed by statute on the Board's control of its procedure. Furthermore, when the rules of natural justice collide with a practice of the Board, the latter must give way.

Disposition

In the result, the appeal is allowed, the judgment of the Court of Appeal is set aside and the order of the Divisional Court restored with costs to the appellant against the respondents both here and in the Court of Appeal.

règles de justice naturelle et je ne puis conclure qu'il n'y a pas eu de préjudice grave.

Le paragraphe 102(13)

Je ne puis non plus conclure que la procédure de réunion plénière de la Commission est sauvegardée en vertu du par. 102(13) de la *Loi sur les relations de travail*. Le paragraphe 102(13) est ainsi conçu:

> **102** . . .
>
> (13) La Commission régit sa propre pratique et procédure, sous réserve toutefois d'accorder aux parties toute possibilité de présenter leur preuve et de faire valoir leurs arguments. La Commission peut, sous réserve de l'approbation du lieutenant-gouverneur en conseil, établir des règles de pratique et de procédure, réglementer l'exercice de ses attributions et prescrire les formules qu'elle estime opportunes. [Je souligne.]

Je reconnais l'importance de la déférence à l'égard du choix fait par une commission de sa procédure, dont parle le juge Pigeon de notre Cour dans l'arrêt *Komo Construction Inc. v. Commission des Relations de Travail du Québec*, [1968] R.C.S. 172, à la p. 176:

> Tout en maintenant le principe que les règles fondamentales de justice doivent être respectées, il faut se garder d'imposer un code de procédure à un organisme que la loi a voulu rendre maître de sa procédure.

Cependant, en l'espèce, l'appelante n'a pas eu toute possibilité de présenter sa preuve et de faire valoir ses arguments, alors que cette possibilité constitue une limite expresse que la Loi impose au contrôle de la Commission sur sa procédure. De plus, quand les règles de justice naturelle entrent en conflit avec une pratique de la Commission, cette dernière doit céder le pas.

Dispositif

En conséquence, le pourvoi est accueilli, l'arrêt de la Cour d'appel est infirmé et l'ordonnance de la Cour divisionnaire est rétablie avec dépens en faveur de l'appelante contre les intimés en notre Cour et en Cour d'appel.

1990 CanLII 132 (SCC)

The judgment of Wilson, La Forest, L'Heureux-Dubé, Gonthier and McLachlin JJ. was delivered by

GONTHIER J.—I have had the opportunity to read the reasons of my colleague, Sopinka J., and I must respectfully disagree with his conclusions in this case. While I do not generally disagree with the summary of the facts, decisions and issues, I consider it useful to refer to them in somewhat more detail.

The appeal is from a decision of the Court of Appeal of Ontario dismissing an application for judicial review of two decisions of the Ontario Labour Relations Board (the "Board"). In the first decision, a tripartite panel composed of G. W. Adams, Q.C., Chairman of the Board, W. H. Wightman and B. F. Lee representing the management and labour sides respectively, decided, Mr. Wightman dissenting, that the appellant had failed to bargain in good faith with the respondent union because it did not disclose during the negotiations its impending decision to close the plant covered by the collective agreement. Counsel for the appellant then learned that a full board meeting had been called to discuss the policy implications of its decision when it was still in the draft stage. The parties were neither notified of nor invited to participate in this meeting. The appellant applied for a reconsideration of this decision under s. 106 of the *Labour Relations Act*, R.S.O. 1980, c. 228, on the ground that the full board meeting had vitiated the Board's decision and on the ground that the evidence adduced at the first hearing had been improperly considered. The same panel rejected both these arguments in the second decision (the "reconsideration decision").

The Board's decisions were challenged in the Divisional Court on the basis: (1) that the original decision was manifestly unreasonable in fact and in law, and (2) that the full board meeting called by the Board prior to the panel's decision constituted a violation of the rules of natural justice. The Divisional Court rejected the first ground and the appellant did not raise this argument in the

Version française du jugement des juges Wilson, La Forest, L'Heureux-Dubé, Gonthier et McLachlin rendu par

LE JUGE GONTHIER—J'ai eu l'avantage de lire les motifs de mon collègue le juge Sopinka et, en toute déférence, je ne puis partager ses conclusions en l'espèce. Bien que, dans l'ensemble, je ne sois pas en désaccord avec le résumé des faits, des décisions et des questions en litige, je crois utile de les exposer un peu plus en détail.

Le pourvoi est formé contre un arrêt de la Cour d'appel de l'Ontario qui a rejeté une demande de contrôle judiciaire de deux décisions de la Commission des relations de travail de l'Ontario (la «Commission»). Dans la première décision, un banc tripartite composé du président de la Commission G. W. Adams, c.r., et de W. H. Wightman et B. F. Lee qui représentaient l'employeur et les employés respectivement, a statué, avec dissidence de la part de M. Wightman, que l'appelante n'avait pas négocié de bonne foi avec le syndicat intimé en ne divulguant pas, pendant les négociations, sa décision imminente de fermer l'usine visée par la convention collective. L'avocat de l'appelante a alors appris qu'une réunion plénière de la Commission avait été convoquée dans le but d'analyser les conséquences en matière de politique de sa décision alors que celle-ci était encore au stade d'avant-projet. Les parties n'ont été ni avisées de cette réunion, ni invitées à y participer. L'appelante a demandé le réexamen de cette décision en vertu de l'art. 106 de la *Loi sur les relations de travail*, L.R.O. 1980, ch. 228, pour le motif que la réunion plénière de la Commission a entaché de nullité sa décision et que les éléments de preuve soumis à la première audition n'avaient pas été examinés correctement. Le même banc a rejeté ces deux arguments dans la seconde décision (la «décision relative à la demande de réexamen»).

Les décisions de la Commission ont été contestées devant la Cour divisionnaire pour les motifs suivants: (1) la décision initiale était manifestement déraisonnable en fait et en droit et (2) la réunion plénière convoquée par la Commission avant que le banc ne rende sa décision violait les règles de justice naturelle. La Cour divisionnaire a rejeté le premier motif invoqué et l'appelante ne l'a

1990 CanLII 132 (SCC)

Court of Appeal nor in this Court. Thus, the only issue before this Court is whether the impugned meeting vitiated the first decision rendered by the Board on the ground that the case was there discussed with panel members by persons who did not hear the evidence nor the arguments.

In order to determine whether the principles of natural justice have been breached in this case, it is necessary to examine in some detail the facts which led to the initial complaint made by the respondent union. It will also be necessary to examine the evidence as to the purpose and the context of the full board meeting so as to understand the policy matters in issue at that meeting.

I—The Facts

(a) *Plant Closure and Collective Agreement Negotiations*

The appellant operated a corrugated container plant in Hamilton (the "Hamilton plant") and decided to close it on April 26, 1983. This decision was approved by the Board of Directors on February 25, 1983 and announced on March 1, 1983. The respondent union was the bargaining agent for the employees of the Hamilton plant and negotiated a new collective agreement with the appellant from November 2, 1982 to January 13, 1983, the date at which a memorandum of settlement was concluded. The collective agreement was signed on April 22, 1983. It is obvious from the evidence heard by the Board that the decision to close the Hamilton plant and the labour negotiations concerning this plant took parallel courses. It is also obvious that the respondent union was never informed of the possibility of an impending plant closure. Although its demands did initially include a modification of art. 18.26 of the existing collective agreement concerning plant closure and severance pay, the respondent union unilaterally dropped this demand during the negotiations and art. 18.26 was simply renewed. At no other point during the negotiations did the subject of plant closure arise.

soulevé ni en cour d'appel, ni en notre Cour. La seule question en litige devant notre Cour est donc celle de savoir si la réunion contestée a entaché de nullité la première décision de la Commission pour le motif que les membres du banc qui ont entendu l'affaire en ont alors discuté avec d'autres personnes qui n'avaient pas entendu la preuve ni les plaidoiries.

Pour décider s'il y a eu manquement aux principes de justice naturelle en l'espèce, il est nécessaire d'analyser plus en détail les faits à l'origine de la première plainte du syndicat intimé. Il sera aussi nécessaire d'examiner la preuve relative à l'objet et aux circonstances de la réunion plénière de la Commission afin de comprendre les questions de politique qui étaient en cause lors de cette réunion.

I—Les faits

a) *La fermeture de l'usine et les négociations visant la signature d'une convention collective*

L'appelante exploitait une usine de fabrication de boîtes de carton ondulé à Hamilton («l'usine de Hamilton») qu'elle a décidé de fermer le 26 avril 1983. Cette décision, qui avait été approuvée par le conseil d'administration le 25 février 1983, a été annoncée le 1er mars 1983. Le syndicat intimé était l'agent négociateur des employés de l'usine de Hamilton et du 2 novembre 1982 au 13 janvier 1983 avait négocié une nouvelle convention collective avec l'appelante, date à laquelle un mémoire d'entente avait été signé. La convention collective a été signée le 22 avril 1983. Il ressort clairement de la preuve entendue par la Commission que les événements menant à la décision de fermer l'usine de Hamilton se sont déroulés parallèlement aux négociations collectives relatives à cette usine. Il est aussi évident que le syndicat intimé n'a jamais été avisé de la possibilité d'une fermeture imminente de l'usine. Quoique les demandes du syndicat aient compris au départ la modification de l'art. 18.26 de la convention collective existante qui traitait de la fermeture d'usine et des indemnités de départ, le syndicat intimé a abandonné cette demande de sa propre initiative pendant les négociations et l'art. 18.26 a été simplement reconduit. Le sujet de la fermeture de l'usine n'a plus jamais été soulevé au cours des négociations.

1990 CanLII 132 (SCC)

According to the testimonies of the representatives of the appellant, the Hamilton plant was so unprofitable that it would have been closed in 1982 if an industry-wide strike had not taken place from June to December of that year. The Hamilton plant remained open during that period and the appellant hoped that some goodwill would be generated through the new contracts entered into as a result of the industry-wide strike. As early as 1981, following the negotiation of the 1980-82 collective agreement, the appellant and the respondent union met to discuss concerns over the possibility of a plant closure given the severe losses anticipated for that year. The appellant had decided to turn the plant around and sought the respondent union's collaboration adding that there were no plans to close the Hamilton plant at that time. In October of 1981, the employees of the bargaining unit did commit themselves to the improvement of productivity at the plant. After registering a loss of $1.3 million for the year 1981, the appellant continued to invest in the Hamilton plant but warned that it would not continue to "throw 'good money after bad'" and that the plant would have to become profitable in the short term. In May of 1982, immediately before the industry-wide strike, 25 employees had to be laid off and the plant was operating only two shifts a day on a four-day work week.

In this context, the industry-wide strike was a godsend for the Hamilton plant. New clients had to award contracts to the Hamilton plant for the duration of this strike and the plant was operating at capacity, three shifts a day, seven days a week. Unfortunately, the anticipated goodwill from new customers did not materialize and Mr. Ted Haiplik, Vice-President and General Manager of the Container Division, reported to his superiors that in his opinion the Hamilton plant should be closed. Mr. Souccar, to whom Mr. Haiplik reports, testified that this recommendation was made to him in the "first or second week of February during one of their regular meetings". The matter was brought to the attention of the Board of Directors during their meeting of February 25, 1983 and they decided that the plant would close on April

D'après les dépositions des représentants de l'appelante, l'usine de Hamilton entraînait des pertes si considérables qu'elle aurait fermé ses portes en 1982 s'il n'y avait pas eu une grève à l'échelle de cette industrie de juin à décembre de la même année. L'usine de Hamilton est restée ouverte pendant cette période et l'appelante espérait qu'une certaine clientèle serait générée grâce aux nouveaux contrats signés par suite de la grève à l'échelle de l'industrie. Dès 1981, après la négociation de la convention collective visant les années 1980 à 1982, l'appelante et le syndicat intimé avaient discuté de la crainte que l'usine ferme ses portes à cause des pertes considérables prévues au cours de cette année. L'appelante avait décidé de rentabiliser l'usine et elle a demandé la collaboration du syndicat intimé, ajoutant qu'elle n'avait pas l'intention de fermer l'usine de Hamilton à ce moment-là. En octobre 1981, les employés de l'unité de négociation se sont engagés à améliorer la productivité à cette usine. Après avoir essuyé des pertes de 1,3 million de dollars en 1981, l'appelante a continué d'investir de l'argent dans l'usine de Hamilton, tout en prévenant qu'elle ne continuerait pas de [TRADUCTION] «jeter de l'argent par les fenêtres» et que l'usine devrait devenir rentable à court terme. En mai 1982, immédiatement avant la grève à l'échelle de l'industrie, 25 employés avaient dû être mis à pied et l'usine ne fonctionnait plus qu'à deux quarts par jour, quatre jours par semaine.

Dans ces circonstances, la grève à l'échelle de l'industrie fut un don du ciel pour l'usine de Hamilton. De nouveaux clients durent attribuer des contrats à l'usine de Hamilton pour la durée de la grève et l'usine fonctionnait à plein rendement, à trois quarts par jour, sept jours par semaine. Malheureusement, il n'y eut pas autant de nouveaux clients que prévu et M. Ted Haiplik, vice-président et directeur général de la division des emballages a fait rapport à ses supérieurs qu'à son avis il fallait fermer l'usine de Hamilton. Monsieur Souccar, le supérieur immédiat de M. Haiplik, a témoigné avoir reçu cette recommandation pendant [TRADUCTION] «la première ou la deuxième semaine de février, à l'occasion d'une de leurs réunions régulières». La question a été portée à l'attention du conseil d'administration lors de sa

1990 CanLII 133 (SCC)

26, 1983. Mr. Souccar insisted that it took four to five weeks following the end of the industry-wide strike to determine the amount of market share retained by the appellant and assess its viability under normal circumstances. Thus, according to Mr. Souccar, no decision concerning the closure of the Hamilton plant could be made before February of 1983.

Throughout this period, no mention was made of the possibility of plant closure during the negotiations except to point out that customers were monitoring these negotiations closely to see whether there was any possibility of a strike after the deadline set for January 8, 1983 by the respondent union. Moreover, Mr. Gruber, labour negotiator for the appellant, testified that he was not aware of any plans to close the plant during the negotiations. It is in this context that the Board was asked to determine whether the appellant had breached its obligation to bargain in good faith and, more particularly, whether it had the obligation to disclose its plans to close the Hamilton plant.

The obligation to disclose, without being asked, information relevant to any particular labour negotiation was held by the Board to be part and parcel of the obligation to bargain in good faith in *United Electrical, Radio & Machine Workers of America, Local 504 v. Westinghouse Canada Ltd.*, [1980] OLRB Rep. 577, (*Westinghouse*), where this information relates to plans "which, if implemented during the term of the collective agreement, would have a significant impact on the economic lives of bargaining unit employees" (at p. 598). In order to understand the policy issues which were the subject of discussion at the full board meeting held by the Board, it is necessary to analyse the *Westinghouse* decision and its implications in this case.

(b) *The Westinghouse Decision and the Arguments Raised by the Parties before the Board*

In *Westinghouse*, management had decided to relocate its Switchgear and Control Division from Hamilton to several other locations two months

réunion du 25 février 1983; le conseil a alors décidé que l'usine fermerait ses portes le 26 avril 1983. Monsieur Souccar a souligné qu'il fallait de quatre à cinq semaines, après une grève à l'échelle de l'industrie, pour connaître la part de marché retenue par l'appelante et vérifier sa viabilité dans des circonstances normales. Donc, d'après M. Souccar, aucune décision de fermer l'usine de Hamilton ne pouvait être prise avant février 1983.

Pendant toute cette période, personne n'a jamais parlé de la possibilité de fermer l'usine au cours des négociations, sauf qu'on a mentionné que les clients suivaient ces négociations de près pour vérifier s'il y aurait possibilité de grève après la date cible du 8 janvier 1983 fixée par le syndicat intimé. De plus, M. Gruber, qui agissait à titre de négociateur pour l'appelante a témoigné qu'il n'avait été au courant d'aucun projet de fermer l'usine pendant les négociations. C'est dans ce contexte qu'on a demandé à la Commission de décider si l'appelante avait manqué à l'obligation qu'elle avait de négocier de bonne foi et, plus précisément, si elle avait l'obligation de divulguer son projet de fermer l'usine de Hamilton.

La Commission a statué, dans la décision *United Electrical, Radio & Machine Workers of America, Local 504 v. Westinghouse Canada Ltd.*, [1980] OLRB Rep. 577 (la décision *Westinghouse*), que l'obligation de divulguer spontanément tout renseignement utile aux fins des négociations collectives fait partie intégrante de l'obligation de négocier de bonne foi si ces renseignements ont trait à des projets [TRADUCTION] «qui, s'ils sont mis à exécution pendant la durée de la convention collective, auront des conséquences importantes sur la situation économique des employés de l'unité de négociation» (à la p. 598). Pour comprendre les questions de politique qui ont été débattues lors de la réunion plénière de la Commission, il faut analyser la décision *Westinghouse* et ses répercussions sur l'espèce.

b) *La décision Westinghouse et les arguments invoqués par les parties devant la Commission*

Dans l'affaire *Westinghouse*, la direction avait décidé de déménager de Hamilton à divers autres endroits la division des appareils de commutation

1990 CanLII 132 (SCC)

after the conclusion of negotiations for a collective agreement. In this decision, the Board ruled that the obligation to bargain in good faith set out in s. 14 of the *Labour Relations Act*, now s. 15, comprised the obligation to reveal during the course of negotiations decisions which may seriously affect members of the bargaining unit. However, the Board found it difficult to define the point at which a planned decision becomes sufficiently certain to warrant disclosure during the negotiations without creating unnecessarily threatening perceptions in the bargaining process. The Board described as follows the perils of forced disclosure of plans which may be discarded in the future and held that an employer does not have the obligation to disclose plans until they have become at least *de facto* decisions, at pp. 598-99:

> 41. The competitive nature of our economy and the ongoing requirement of competent management to be responsive to the forces at play in the marketplace result in ongoing management consideration of a spectrum of initiatives which may impact on the bargaining unit. More often than not, however, these considerations do not manifest themselves in hard decisions. For one reason or another, plans are often discarded in the conceptual stage or are later abandoned because of changing environmental factors. The company's initiation of an open-ended discussion of such imprecise matters at the bargaining table could have serious industrial relations consequences. The employer would be required to decide in every bargaining situation at what point in his planning process he must make an announcement to the trade union in order to comply with section 14. Because the announcement would be employer initiated and because plans are often not transformed into decisions, the possibility of the union viewing the employer's announcement as a threat (with attendant litigation) would be created. If not seen as a threat the possibility of employee overreaction to a company initiated announcement would exist. A company initiated announcement, as distinct from a company response to a union inquiry may carry with it an unjustified perception of certainty. The collective bargaining process thrusts the parties into a delicate and often difficult interface. Given the requirement upon the company to respond honestly at the bargaining table to union inquiries with respect to company plans which may have a

et de contrôle deux mois après la fin des négociations visant la signature d'une convention collective. Dans cette décision, la Commission a statué que l'obligation de négocier de bonne foi, énoncée à l'art. 14 de la *Loi sur les relations de travail*, devenu depuis l'art. 15, comportait l'obligation de divulguer, pendant les négociations, les décisions susceptibles de toucher sérieusement les membres de l'unité de négociation. Cependant, la Commission a trouvé difficile de déterminer à quel moment une décision projetée devient suffisamment certaine pour justifier sa divulgation pendant les négociations sans qu'il en résulte inutilement des perceptions de menaces au cours du processus de négociation. La Commission a défini de la manière suivante les dangers de la divulgation forcée de projets qui seront peut-être délaissés plus tard et elle a statué que l'employeur n'est pas tenu de divulguer des projets avant qu'ils n'aient atteint au moins le stade de décisions *de facto*, aux pp. 598 et 599:

> [TRADUCTION] 41. La nature concurrentielle de notre économie et l'obligation, pour une administration compétente, de s'adapter aux forces du marché exigent des administrateurs qu'ils envisagent constamment de nouvelles mesures susceptibles d'avoir des répercussions sur l'unité de négociation. Mais plus souvent qu'autrement, il n'en résulte pas de décision concrète. Pour une raison ou une autre, les projets sont souvent rejetés à l'étape de leur conception ou abandonnés plus tard en raison de changements des circonstances externes. L'amorce par la société de discussions libres portant sur des sujets aussi vagues à la table de négociation pourrait avoir de graves conséquences sur les relations de travail. L'employeur devrait décider à chaque fois qu'il y a négociation à quel moment, dans l'évolution de son projet, il doit en faire part au syndicat pour se conformer à l'art. 14. Parce que cette annonce viendrait de l'employeur et que les projets n'ont souvent aucune suite, il y aurait possibilité que le syndicat perçoive l'annonce faite par l'employeur comme une menace (et qu'elle entraîne des contestations). Si l'annonce n'était pas perçue comme une menace, il y aurait quand même possibilité de réaction exagérée des employés à l'annonce de la société. Une mesure annoncée par la société, par opposition à une réponse de la société à une demande syndicale de renseignements, peut donner prise à un sentiment de certitude qui n'est pas justifié dans les faits. Les négociations collectives lancent les parties dans des pourparlers délicats et souvent périlleux. Compte tenu de l'obligation déjà imposée à la société de répondre

1990 CanLII 132 (SCC)

significant impact on the bargaining unit, the effect of requiring the employer to initiate discussion on matters which are not yet decided within his organization would be of marginal benefit to the trade union and could serve to distort the bargaining process and create the potential for additional litigation between the parties. The section 14 duty, therefore, does not require an employer to reveal on his onw [*sic*] initiative plans which have not become at least de facto decisions. [Emphasis added.]

The Board then decided that management "... had not made a hard decision to relocate during the course of bargaining as would have required it to reveal its decision to the trade union" (at p. 599). [Emphasis added.]

The facts in this case are substantially similar to those in the *Westinghouse* case in that a decision which would substantially affect the bargaining unit was taken by management either during or immediately after collective agreement negotiations thereby raising the issue of whether plans to close the Hamilton plant had gone sufficiently far through management's decision-making process to justify their disclosure to union representatives during the course of the negotiations. Before the Board, the appellant and the respondent union both argued, *inter alia*, that the test established in the *Westinghouse* decision ought to be modified. In his reasons, [1983] OLRB Rep. September 1411, Chairman Adams stated the respondent union's position as follows, at p. 1428:

26. The complainant's second major alternative argument requested this Board to reconsider its holding in *Westinghouse* that an employer does not have to reveal on his own initiative plans which have not become at least *de facto* decisions. The complainant asserted that the test ought to be disclosure where an employer is "seriously considering an action which if carried out will have a serious impact on employees".

Chairman Adams later summarized the appellant's arguments as follows, at p. 1429:

29. On behalf of the respondent company it was submitted that the extent of its bargaining duty was to disclose any decisions the company had made about the closing

franchement, à la table des négociations, aux demandes de renseignements du syndicat au sujet des projets de l'employeur susceptibles d'avoir des conséquences importantes sur l'unité de négociation, exiger de l'employeur qu'il engage le débat sur des sujets qui n'ont pas encore fait l'objet d'une décision de sa part comporterait peu d'avantages pour le syndicat et risquerait de fausser le processus de négociation et d'engendrer plus de litiges entre les parties. L'obligation définie à l'art. 14 n'impose pas à l'employeur le devoir de divulguer, de sa propre initiative, les projets qui n'ont pas encore atteint au moins le stade de décisions *de facto*. [Je souligne.]

La Commission a donc statué que la direction [TRADUCTION] « ... n'avait pas pris de décision ferme de déménager, pendant les négociations collectives, qui l'aurait obligée à divulguer sa décision au syndicat» (à la p. 599). [Je souligne.]

Les faits de l'espèce ressemblent beaucoup à ceux de l'affaire *Westinghouse* puisque la direction avait pris, pendant ou immédiatement après la négociation de la convention collective, une décision susceptible d'influencer profondément l'unité de négociation et qu'il fallait alors décider si le projet de fermer l'usine de Hamilton était rendu suffisamment loin dans le processus décisionnel de la direction pour justifier sa divulgation aux représentants du syndicat au cours des négociations. Devant la Commission, la société appelante et le syndicat intimé ont soutenu notamment qu'il fallait modifier le critère établi dans la décision *Westinghouse*. Dans ses motifs, [1983] OLRB Rep. September 1411, le président Adams formule ainsi la position du syndicat intimé, à la p. 1428:

[TRADUCTION] 26. Dans son deuxième argument important soulevé à titre subsidiaire, le plaignant demande à la Commission de réexaminer la décision qu'elle a rendue dans l'affaire *Westinghouse* et en vertu de laquelle un employeur n'est pas tenu de divulguer, de sa propre initiative, des projets qui n'ont pas encore atteint au moins le stade de décisions *de facto*. Le plaignant soutient que la norme devrait imposer la divulgation quand un employeur «envisage sérieusement de prendre une mesure dont la réalisation aura des conséquences profondes sur les employés».

Le président Adams a résumé plus loin l'argumentation de l'appelante en ces termes, à la p. 1429:

[TRADUCTION] 29. On a soutenu, au nom de la société intimée, qu'elle était tenue de divulguer lors des négociations collectives toute décision de fermer l'usine qu'elle

1990 CanLII 132 (SCC)

of the plant during the course of negotiations. Counsel submitted that on the evidence before the board one could only conclude that a definitive decision had not been made and that the respondent was not obligated to engage in speculation about a possible plant closing during bargaining.

Thus, although other legal and factual arguments were put forward by the parties, the main issue before the Board was whether the *Westinghouse* decision had to be reconsidered and the test it adopted replaced by either one of the tests proposed by the parties. This issue was a policy issue which had important implications from the point of view of labour law principles as well as of the effectiveness of collective bargaining in Ontario. The Board's desire to discuss it in a full board meeting was therefore understandable.

The Board panel decided in this case, Mr. Wightman dissenting on this issue, that the test set out in the *Westinghouse* case should be confirmed and that in this case, the appellant had made a *de facto* decision to close the Hamilton plant during the course of the negotiations. Thus, the appellant had the obligation to disclose this decision to the respondent union even if no questions were asked on this subject. The Board also found in the alternative that the decision to close the plant was so highly probable that the appellant should have informed the respondent union that if the Hamilton plant's financial situation did not improve in the short term, a recommendation to close the plant would shortly be made to the Board of Directors.

(c) *The Full Board Meeting*

On September 23, 1983, Mr. Michael Gordon, counsel for the appellant, became aware that a full board meeting concerning the Hamilton plant closure was taking place at the Board's offices. Mr. Gordon was aware that full board meetings have been part of the Board's practice for some time but had never been aware that any of the cases in which he had been involved was the subject of such a meeting. The appellant then filed an application for a reconsideration of the initial decision on the

avait prise au cours des négociations. L'avocat de l'intimée soutient que d'après la preuve soumise à la Commission, on ne peut que conclure qu'aucune décision définitive n'avait été arrêtée et que l'intimée n'était pas tenue de spéculer, pendant les négociations, sur la possibilité de fermer l'usine.

Donc, même si les parties ont invoqué d'autres arguments de droit et de fait, la principale question en litige devant la Commission était de savoir s'il y avait lieu de réexaminer la décision *Westinghouse* et de remplacer le critère adopté dans cette décision par l'un de ceux proposés par les parties. La question en était une de politique qui avait des conséquences importantes du point de vue des principes du droit du travail et de l'efficacité des négociations collectives en Ontario. La volonté de la Commission de débattre cette question en réunion plénière était donc compréhensible.

Le banc de la Commission chargé de l'audition a décidé en l'espèce, avec dissidence de la part de M. Wightman sur ce point, qu'il y avait lieu de confirmer le critère établi dans la décision *Westinghouse* et que, dans la présente affaire, l'appelante avait pris la décision *de facto* de fermer l'usine de Hamilton pendant le déroulement des négociations. Ainsi, l'appelante avait l'obligation de divulguer sa décision au syndicat intimé même si on ne lui avait pas posé de question à ce propos. La Commission a conclu, à titre subsidiaire, que la décision de fermer l'usine était si probable que l'appelante aurait dû informer le syndicat intimé que si la situation financière de l'usine de Hamilton ne s'améliorait pas rapidement, la recommandation de fermer l'usine serait soumise au conseil d'administration.

c) *La réunion plénière de la Commission*

Le 23 septembre 1983, Me Michael Gordon, l'avocat de l'appelante, a appris qu'une réunion plénière se déroulait aux bureaux de la Commission à propos de la fermeture de l'usine de Hamilton. Me Gordon savait que la Commission avait depuis un certain temps l'habitude de tenir des réunions plénières, mais il n'avait jamais eu connaissance que l'un des dossiers auxquels il avait participé faisait l'objet d'une telle réunion. L'appelante a présenté une demande de réexamen de la

1990 CanLII 132 (SCC)

basis, *inter alia*, that the practice of holding full board meetings is illegal.

In this reconsideration decision, Chairman Adams described in detail the purpose of these meetings and the way in which they are held. Not surprisingly, Chairman Adams emphasized the necessity to foster coherence and maintain a high level of quality in the decisions of the Board, at p. 2001:

> 6. In considering this question, it is to be noted that the Act confers many areas of broad discretion on the Board in determining how the statute should be interpreted or applied to an infinite variety of factual situations. Within these areas of discretion, decision-making has to turn on policy considerations. At this level of "administrative law", law and policy are to a large degree inseparable. In effect, law and policy come to be promulgated through the form of case by case decisions rendered by panels. It is in this context that the Board is sometimes criticized for not creating enough certainty in "Board law" to facilitate the planning of the parties regulated by the statute. This criticism, however, ignores the fact that there is a huge corpus of Board law much of which is almost as old as the legislation itself and as settled and stable as law can be. Board decision-making has recognized the need for uniformity and stability in the application of the statute and the discretions contained therein. Indeed, it is because there is so much settled law and policy that upwards to 80% of unfair labour practice charges are withdrawn, dismissed, settled or adjusted without the issuance of a decision and that a high percentage of other matters are either settled or withdrawn without the need for a hearing .... Thus, there is great incentive for the Board to articulate its policies clearly and, once articulated, to maintain and apply them. Nevertheless, there remains, even in applying an established policy, an inevitable area of discretion in applying the statute to each fact situation. Moreover, the Board reserves the right to change its policies as required and new amendments to the Act create additional requirements for ongoing policy analysis. To perform its job effectively, the Board needs all the insight it can muster to evaluate the practical consequences of its decisions, for it lacks the capacity to ascertain by research and investigation just what impact its decisions have on labour relations and the economy generally. In this context therefore, and accepting that no one panel of the Board can bind another panel by any decision rendered, what institutional procedures has the Board developed to foster greater insightfulness in the exercise

décision initiale pour le motif notamment que la pratique de tenir des réunions plénières de la Commission est illégale.

Dans la décision relative à la demande de réexamen, le président Adams décrit en détail l'objet de ces réunions et la façon dont elles sont tenues. Naturellement, le président Adams insiste sur la nécessité de promouvoir la cohérence des décisions de la Commission et d'y maintenir un niveau élevé de qualité, à la p. 2001:

> [TRADUCTION] 6. En examinant cette question, il faut souligner que la Loi confère à la Commission des pouvoirs discrétionnaires étendus sur plusieurs sujets quant à la façon d'interpréter et d'appliquer la Loi à toutes sortes de situations concrètes. À l'intérieur de ces pouvoirs discrétionnaires, la prise des décisions doit s'appuyer sur des considérations de politique. À ce niveau de «droit administratif», le droit et les politiques sont dans une large mesure inséparables. En effet, le droit et les politiques en viennent à être établis sous la forme de décisions rendues par différents bancs dans des affaires particulières. C'est dans ce contexte que l'on blâme parfois la Commission de ne pas créer suffisamment de certitude dans sa jurisprudence de manière à faciliter la planification par les parties régies par la Loi. Cette critique ne tient cependant pas compte du fait qu'il existe une jurisprudence abondante de la Commission depuis presque aussi longtemps que la Loi elle-même existe et qu'elle est aussi stable et incontestable que le droit peut l'être. La Commission a reconnu dans ses décisions qu'il est nécessaire d'avoir une uniformité et une stabilité dans l'application de la Loi et des pouvoirs discrétionnaires que celle-ci comporte. En réalité, c'est parce qu'il y a tant de droit et de politiques bien établis que jusqu'à 80 pour 100 des plaintes de pratiques déloyales en matière de travail sont retirées, rejetées, réglées ou arrangées sans délivrance d'une décision et qu'une grande proportion des autres affaires sont soit réglées soit retirées sans qu'il soit nécessaire de tenir une audience. [...] Donc, il y a de grands avantages pour la Commission à ce que celle-ci établisse clairement ses politiques et qu'après les avoir établies, elle les maintienne et les applique. Néanmoins, même quand la Commission applique une politique établie, il reste une marge inévitable de pouvoir discrétionnaire dans l'application de la Loi à chaque situation concrète. De plus, la Commission conserve le droit de changer ses politiques au besoin et les nouvelles modifications apportées à la Loi créent d'autres obligations de procéder à une analyse permanente des politiques. Pour s'acquitter efficacement de ses tâches, la Commission a besoin de toutes

1990 CanLII 132 (SCC)

of the Board's powers by particular panels? What internal mechanisms has the Board developed to establish a level of thoughtfulness in the creation of policies which will meet the labour relations community's needs and stand the test of time? What internal procedures has the Board developed to ensure the greatest possible understanding of these policies by all Board members in order to facilitate a more or less uniform application of such policies? The meeting impugned by the respondent must be seen as only part of the internal administrative arrangements of the Board which have evolved to achieve a maximum regulatory effectiveness in a labour relations setting. [Emphasis added.]

les lumières qu'elle peut rassembler dans le but d'évaluer les conséquences pratiques de ses décisions, parce qu'elle n'a pas les moyens de vérifier par des recherches et des enquêtes quelles seront au juste les conséquences de ses décisions sur les relations de travail et sur l'ensemble de l'économie. Dans ces circonstances, et si on accepte qu'aucun banc de la Commission ne peut en lier un autre par sa décision, quelles procédures institutionnelles la Commission a-t-elle mises au point pour conférer plus de perspicacité dans l'exercice par les bancs particuliers des pouvoirs conférés à la Commission? Quels mécanismes internes la Commission a-t-elle établis pour fixer un niveau de réflexion dans la formulation de politiques qui répondent aux besoins de la collectivité en matière de relations de travail et qui de plus résisteront à l'épreuve du temps? Quelles procédures internes la Commission a-t-elle établies pour assurer la meilleure compréhension possible de ces politiques par tous les commissaires de manière à faciliter une application plus ou moins uniforme de ces politiques? La réunion contestée par l'intimé doit être perçue seulement comme une partie des arrangements administratifs internes que la Commission a pris pour réaliser le maximum d'efficacité de la réglementation dans un contexte de relations de travail. [Je souligne.]

It will be noted that Chairman Adams does not claim that the purpose of full board meetings is to achieve absolute uniformity in decisions made by different panels in factually similar situations. Chairman Adams accepts that "no one panel of the Board can bind another panel by any decision rendered" (at p. 2001). The methods used at those meetings to discuss policy issues reflect the need to maintain an atmosphere wherein each attending Board member retains the freedom to make up his mind on any given issue and to preserve the panel members' ultimate responsibility for the outcome of the final decision. Thus, Chairman Adams states that discussions at full board meetings are limited to policy issues, that the facts of each case must be taken as presented and that no votes are taken nor any attendance recorded, at p. 2002:

On remarquera que le président Adams ne soutient pas que l'objet des réunions plénières de la Commission est de réaliser l'uniformité absolue des décisions prises par les différents bancs dans des situations de fait semblables. Le président Adams reconnaît qu' [TRADUCTION] «aucun banc de la Commission ne peut en lier un autre par sa décision» (à la p. 2001). Les méthodes utilisées à ces réunions pour débattre des questions de politique traduisent la nécessité de préserver une ambiance où chaque commissaire présent garde la liberté de se former une opinion sur une question précise et de sauvegarder la responsabilité ultime des membres de chaque banc à l'égard de la décision finale. Ainsi, le président Adams affirme, à la p. 2002, qu'aux réunions plénières de la Commission les discussions se limitent aux questions de politique, que les faits de chaque cas sont tenus pour avérés et qu'on ne prend pas de vote, ni de présence:

8. After deliberating over a draft decision, any panel of the Board contemplating a major policy issue may, through the Chairman, cause a meeting of all Board members and vice-chairmen to be held to acquaint them with this issue and the decision the panel is inclined to

[TRADUCTION] 8. Après avoir délibéré sur un avant-projet de décision, un banc qui envisage de trancher une question importante de politique peut faire convoquer, par l'intermédiaire du président, une réunion plénière des membres et des vice-présidents pour leur faire part

1990 CanLII 132 (SCC)

make. These "Full Board" meetings have been institutionalized to facilitate a maximum understanding and appreciation throughout the Board of policy developments and to evaluate fully the practical consequences of proposed policy initiatives on labour relations and the economy in the Province. But this institutional purpose is subject to the clear understanding that it is for the panel hearing the case to make the ultimate decision and that discussion at a "Full Board" meeting is limited to the policy implications of a draft decision. The draft decision of a panel is placed before those attending the meeting by the panel and is explained by the panel members. The facts set out in the draft are taken as given and do not become the subject of discussion. No vote is taken at these meetings nor is any other procedure employed to identify a consensus. The meetings invariably conclude with the Chairman thanking the members of the panel for outlining their problem to the entire Board and indicating that all Board members look forward to that panel's final decision whatever it might be. No minutes are kept of such meetings nor is actual attendance recorded. [Emphasis added.]

de la question soulevée et de la décision que le banc favorise. Ces réunions plénières ont été institutionnalisées pour mieux faire comprendre et apprécier par l'ensemble des commissaires l'évolution des politiques et pour examiner à fond les conséquences pratiques que les politiques envisagées pourraient avoir sur les relations de travail et sur l'économie de la province. Cependant, cet objet institutionnel est assujetti au principe accepté de tous qu'il appartient au banc qui entend l'affaire de prendre la décision ultime et que les débats à la réunion plénière de la Commission se limitent aux conséquences en matière de politique d'un avant-projet de décision. L'avant-projet de décision d'un banc est soumis à la réunion par le banc lui-même et expliqué par les commissaires qui le composent. Les faits mentionnés dans l'avant-projet de décision sont tenus pour avérés et ne font pas l'objet de discussions. Aucun vote n'est pris lors de ces réunions et aucune autre procédure n'est utilisée pour vérifier s'il y a consensus. Le président clôt toujours ces réunions en remerciant les commissaires composant le banc d'avoir exposé leur problème à toute la Commission et en disant que tous les commissaires attendront avec impatience la décision du banc quelle qu'elle puisse être. Il n'y a pas de procès-verbal de ces réunions ni de prise de présences. [Je souligne.]

At page 2004 of his reasons, Chairman Adams confirmed that the impugned meeting was held in accordance with the above-mentioned rules.

À la page 2004 de ses motifs, le président Adams confirme que la réunion contestée a été tenue selon les règles ci-dessus mentionnées.

Finally, Chairman Adams rejected the idea that full board meetings could have an overbearing effect on the panel members' capacity to decide the issues at hand in accordance with their opinion, at p. 2003:

10. The respondent's submission is really attempting to probe the mental processes of the panel which rendered the decision in question and in so doing ignores the inherent nature of judicial decision-making and administrative law making .... In general, the deliberations of this panel were not unlike those engaged in by a judge sitting in court. The "Full Board" meeting, to the extent there is no judicial analogy, distinguishes an administrative agency from somewhat more individual common law judging. But, as an extra-record event, "Full Board" meetings are in substance no different than the post-hearing consultation of a judge with his law clerks or the informal discussions that inevitably occur between brother judges. Such meetings, we also suggest, have no greater or lesser effect than a judge's post-hearing read-

Enfin, le président Adams rejette l'idée que les réunions plénières de la Commission puissent avoir une influence impérieuse sur la capacité des membres du banc de trancher selon leur opinion les questions soulevées. Il dit, à la p. 2003:

[TRADUCTION] 10. L'argument de l'intimé cherche réellement à déterminer le cheminement mental du banc qui a rendu la décision visée et, ce faisant, il ne tient pas compte de la nature propre du processus décisionnel judiciaire et des décisions de droit administratif. [...] De manière générale, les délibérations de ce banc n'ont pas différé de celles d'un juge appelé à rendre une décision judiciaire. La réunion plénière de la Commission, dans la mesure où il n'y a pas d'équivalent en matière judiciaire, différencie un organisme administratif du processus quelque peu plus individualiste de jugement en common law. Cependant, à titre d'événement officieux, les réunions plénières de la Commission ne diffèrent pas substantiellement des consultations que mène un juge après l'audience, avec ses recherchistes ou des discussions informelles qui surviennent inévitablement entre collègues juges. Ces réunions, à notre avis, n'ont ni plus, ni moins d'influence que la consultation

1990 CanLII 132 (SCC)

ing of reports and periodicals which may not have been cited or relied on by the advocates.

It follows that the full board meetings held by the Board are designed to promote discussion on important policy issues and to provide an opportunity for members to share their personal experiences in the regulation of labour relations. There is no evidence that the particular meeting impugned in this case was used to impose any given opinion upon the members of the panel or that the spirit of discussion and exchange sought through those meetings was not present during those deliberations. Moreover, three sets of reasons were issued by the members of the panel, one member dissenting in part while another dissented on the principal substantive issue at stake in this case. If this meeting had been held for the purpose of imposing policy directives on the members of the panel, it certainly did not meet its objective.

Incidentally, the record does not disclose the identity of all the persons who attended the impugned meeting. In his affidavit, Mr. Gordon, counsel for the appellant before the Board, describes the events which led him to conclude that a full board meeting was taking place; he also lists the persons whom he saw entering or leaving the room where the meeting took place. This affidavit does disclose that Mr. Wightman was seen leaving the room in which the meeting was held but there is no evidence that the other members of the panel did attend the meeting. However, the Board's decision on the motion for reconsideration indicates that all members of the panel attended the meeting.

II—Decisions of the Courts Below

Of the two decisions rendered by the Board in this case, only the reconsideration decision is relevant since it alone deals with the issue of the legality of the practice of holding full board meetings on important policy issues. The Board decided that the practice of holding full board meetings on policy issues does not breach principles of natural justice because of its tripartite nature, the manner in which they are conducted and because of the institutional requirements which they serve.

que le juge fait après l'audition de jurisprudence ou de doctrine que les avocats n'ont ni invoquée, ni citée.

Il s'ensuit que les réunions plénières que tient la Commission sont conçues pour favoriser la discussion d'importantes questions de politique et donner aux commissaires l'occasion de mettre en commun leur expérience en matière de relations de travail. Il n'y a rien qui indique que la réunion visée en l'espèce ait servi à imposer une opinion quelconque aux membres du banc ou que l'esprit de discussion et d'échange que ces réunions cherchent à favoriser n'ait pas prévalu au cours de ces délibérations. De plus, chacun des trois commissaires qui composaient le banc a rédigé des motifs, l'un d'eux étant dissident en partie alors qu'un autre était dissident sur la principale question de fond à trancher en l'espèce. Si cette réunion avait été tenue pour imposer aux membres du banc des directives en matière de politique, elle n'a certes pas atteint son objectif.

Soit dit en passant, le dossier n'identifie pas tous ceux qui ont assisté à la réunion contestée. Dans son affidavit, M[e] Gordon, l'avocat de l'appelante à l'audience devant la Commission, relate les événements qui l'ont amené à conclure qu'une réunion plénière avait lieu; il fournit aussi les noms des personnes qu'il a vu entrer et sortir de la pièce où se déroulait la réunion. Cet affidavit mentionne qu'on a vu M. Wightman sortir de la pièce où la réunion se déroulait, mais il n'y a aucune preuve que les autres membres du banc ont assisté à la réunion. Cependant, la décision de la Commission sur la demande de réexamen indique que tous les membres du banc ont assisté à la réunion.

II—Les décisions des tribunaux d'instance inférieure

Des deux décisions rendues par la Commission en l'espèce, seule la décision relative à la demande de réexamen est pertinente puisqu'elle seule porte sur la légalité de la pratique de la Commission de tenir des réunions plénières sur des questions de politique importantes. La Commission a statué que sa pratique de tenir des réunions plénières sur des questions de politique ne viole pas les principes de justice naturelle à cause de sa nature tripartite, de la manière dont les réunions sont tenues et à cause

1990 CanLII 132 (SCC)

According to Chairman Adams, with whom Messrs. Lee and Wightman concurred, ss. 102 and 103 of the *Labour Relations Act* create a procedural framework based on panels composed of three members and the high number of cases handled by the Board creates the necessity to have a large number of full-time and part-time members and, therefore, a wide variety of panels. Such institutional constraints create the necessity to provide a mechanism which would promote a maximum amount of coherence in Board decisions. In essence, the Board decided that full board meetings are a necessary component of decision making within the procedural framework of the *Labour Relations Act* and that they do not breach the principles of natural justice.

In the Divisional Court (1985), 51 O.R. (2d) 481, Rosenberg J., with whom J. Holland J. concurred, allowed the appellant's application for judicial review on the basis that the impugned full board meeting allowed persons who did not hear the evidence to "participate" in the decision even though they did not vote. Rosenberg J. adopted the recommendations of the McRuer Report entitled *Royal Commission Inquiry into Civil Rights*, vol. 5, Report No. 3, 1971, which dealt specifically with the Board and recommended that the parties be notified and given an opportunity to be heard whenever important policy issues must be dealt with by the entire Board, at pp. 2205-06:

> In Report Number 1 we pointed out that no person should participate in a decision of a judicial tribunal who was not present at the hearing and heard and considered the evidence and that all persons who had heard and considered the evidence should participate in the decision.
>
> The practice we have outlined violates that principle. To take a matter before the full Board for a discussion and obtain the views of others who have not participated in the hearing and without the parties affected having an opportunity to present their views is a violation of the principle that he who decides must hear.
>
> . . .

des exigences institutionnelles auxquelles elles répondent. Selon le président Adams, aux motifs duquel les commissaires Lee et Wightman ont souscrit, les art. 102 et 103 de la *Loi sur les relations de travail* établissent un système de procédure fondé sur des bancs de trois commissaires et le grand nombre d'affaires traitées par la Commission est à l'origine de la nécessité d'avoir un grand nombre de commissaires à temps plein et à temps partiel et, en conséquence, d'avoir un grand nombre de bancs. Ces contraintes institutionnelles sont à l'origine de la nécessité de fournir un mécanisme qui favorise la plus grande cohérence possible des décisions de la Commission. Essentiellement, la Commission a jugé que ses réunions plénières sont une composante nécessaire de son processus décisionnel à l'intérieur du système de procédure établi par la *Loi sur les relations de travail* et qu'elles ne violent pas les principes de justice naturelle.

En Cour divisionnaire (1985), 51 O.R. (2d) 481, le juge Rosenberg, aux motifs duquel le juge J. Holland a souscrit, a accueilli la demande de contrôle judiciaire de l'appelante pour le motif que la réunion plénière contestée de la Commission a permis à des personnes qui n'avaient pas entendu la preuve de «participer» à la décision même s'ils n'avaient pas voté. Le juge Rosenberg a suivi les recommandations du rapport McRuer de la *Royal Commission Inquiry into Civil Rights*, vol. 5, rapport n° 3, 1971, qui visait précisément la Commission et qui portait qu'il y a lieu d'aviser les parties et de leur donner la possibilité d'être entendues chaque fois que la Commission au complet doit débattre d'importantes questions de politique, aux pp. 2205 et 2206:

> [TRADUCTION] Dans le rapport numéro 1, nous avons souligné que nul ne devrait participer à la décision d'un tribunal judiciaire s'il n'a pas été présent à l'audition et s'il n'a pas entendu et examiné la preuve et que toutes les personnes qui ont entendu et examiné la preuve devraient participer à la décision.
>
> La pratique que nous avons exposée viole ce principe. Le fait de porter une affaire à la connaissance de toute la Commission pour en débattre et obtenir l'avis de personnes qui n'ont pas participé à l'audition sans que les parties touchées aient la possibilité d'exprimer leur avis constitue une violation du principe selon lequel celui qui tranche une affaire doit l'avoir entendue.
>
> . . .

1990 CanLII 132 (SCC)

Notwithstanding that the ultimate decision is made by those who were present at the hearing, where a division of the Board considers that a matter should be discussed before the full Board or a larger division, the parties should be notified and given an opportunity to be heard.

The majority stated, at pp. 491-92, that the practice of holding full board meetings creates situations where members who did not hear the evidence can have an influence over the result as well as situations where arguments are proposed by persons attending the meeting without giving the parties the opportunity to respond:

> Chairman Shaw [*sic*] states in his reasons that the final decision was made by the three members who heard evidence and argument. He cannot be heard to state that he and his fellow members were not influenced by the discussion at the full board meeting. The format of the full board meeting made it clear that it was important to have input from other members of the board who had not heard the evidence or argument before the final decision was made. The tabling of the draft decision to all of the members of the board plus all of the support staff involved a substantial risk that opinions would be advanced by others and arguments presented. It is probable that some of the people involved in the meeting would express points of view. The full board meeting was only called when important questions of policy were being considered. Surely, the discussion would involve policy reasons why s. 15 should be given either a broad or narrow interpretation. Members or support staff might relate matters from their own practical experience which might be tantamount to giving evidence. The parties to the dispute would have no way of knowing what was being said in these discussions and no opportunity to respond. [Emphasis added.]

Rosenberg J. then added at p. 492 that factual issues are necessarily built into policy issues since it is impossible, in his opinion, to decide factual issues without a prior determination of the legal standards applicable to them.

Malgré que la décision ultime soit prise par ceux qui ont assisté à l'audition, quand une section de la Commission juge nécessaire qu'une affaire soit débattue devant l'ensemble de la Commission ou une section plus grande, il faudrait en prévenir les parties et leur donner la possibilité d'être entendues.

La majorité a affirmé, aux pp. 491 et 492, que la pratique de la Commission de tenir des réunions plénières crée des situations où des commissaires qui n'ont pas entendu la preuve peuvent influencer la décision, de même que des situations où des personnes présentes à la réunion soumettent des arguments sans que les parties aient la possibilité d'y répondre:

> [TRADUCTION] Le président Shaw [*sic*] affirme dans ses motifs que la décision définitive a été arrêtée par les trois commissaires qui avaient entendu la preuve et les plaidoiries. Il ne peut valablement affirmer que lui-même et ses collègues membres du tribunal n'ont pas été influencés par le débat survenu lors de la réunion plénière de la Commission. La façon dont s'est déroulée la réunion plénière de la Commission laisse voir qu'il était important d'avoir l'avis des autres commissaires qui n'avaient entendu ni la preuve ni les plaidoiries avant de prendre une décision finale. La présentation de l'avant-projet de décision à tous les commissaires et à tout le personnel de soutien comportait un risque sérieux que d'autres personnes soumettent leur avis et fassent valoir des arguments. Il est probable que certaines des personnes présentes à la réunion ont exprimé leur avis. Il n'y avait convocation d'une réunion plénière de la Commission que s'il y avait des questions de politique importantes à débattre. La discussion a certainement porté sur les raisons de principe de donner à l'art. 15 une interprétation libérale ou une interprétation restreinte. Les commissaires ou le personnel de soutien ont pu faire part d'informations tirées de leur expérience pratique, ce qui pourrait équivaloir à présenter des éléments de preuve. Les parties au litige n'avaient aucun moyen de savoir ce qui se disait dans ce débat, ni aucune possibilité de répliquer. [Je souligne.]

Le juge Rosenberg a alors ajouté, à la p. 492, que les questions de fait sont nécessairement imbriquées dans les questions de politique puisqu'il est impossible, à son avis, de statuer sur des questions de fait sans d'abord déterminer les normes juridiques qui leur sont applicables.

1990 CanLII 132 (SCC)

Osler J. dissented on the basis that there is no authority prohibiting decision makers acting in a judicial capacity to engage in either formal or informal discussions with their colleagues concerning policy issues at stake in a case standing for judgment. Full board meetings are merely a formalized method of seeking the opinion of colleagues on policy issues. In fact, this practice is desirable given the importance of achieving a high degree of coherence in Board decisions. Osler J. also noted that the tripartite procedural framework imposed by the *Labour Relations Act* made it necessary to resort to full board meetings as a means of achieving such coherence. Finally, Osler J. held that the record in this case does not indicate that either new evidence was heard during the impugned meeting or that new ideas requiring a reply from the parties were discussed during this meeting. The policy alternatives had all been proposed by the parties during argument and Chairman Adams' decision as well as Mr. Wightman's dissent simply adopted one of the alternatives.

The Court of Appeal (1986), 56 O.R. (2d) 513, unanimously allowed the appeal for the reasons set out in Osler J.'s dissent. Cory J.A. (as he then was) added that the following limitations on the practice of holding full board meetings on policy issues must be observed by the Board, at p. 517:

> It must be stressed, however, and indeed it was conceded by the appellants, that if new evidence was considered by the entire Board during its discussion, then both parties would have to be recalled, advised of the new evidence and given full opportunity to respond to it in whatever manner they deemed appropriate. In the absence of the introduction of fresh material, the evidence must be taken as found in the draft reasons for the purposes of the full Board discussions.

As in any judicial or *quasi*-judicial proceeding, the panel should not decide the matter upon a ground not raised at the hearing without giving the parties an opportunity for argument. It is also an inflexible rule that while the panel may receive advice there can be no participation by other members of the Board in the final decision.

Le juge Osler a exprimé une dissidence en faisant valoir qu'il n'y a aucun précédent qui interdise aux décideurs qui agissent à titre judiciaire de mener des discussions officielles ou officieuses avec leurs collègues au sujet des questions de politique soulevées par une affaire en instance. Les réunions plénières de la Commission constituent simplement un moyen formel de demander l'avis de collègues sur des questions de politique. En réalité, cette pratique est souhaitable à cause de l'importance d'avoir des décisions de la Commission très cohérentes. Le juge Osler a aussi fait remarquer que le système de procédure tripartite qu'impose la *Loi sur les relations de travail* rend nécessaire le recours aux réunions plénières de la Commission comme moyen de réaliser cette cohérence. Enfin, le juge Osler a statué que le dossier en l'espèce n'indique pas que, pendant la réunion contestée, on a présenté de nouveaux éléments de preuve ou fait valoir de nouvelles idées exigeant une réplique des parties. Les choix de politique possibles avaient tous été proposés par les parties pendant leurs plaidoiries et le président Adams dans sa décision et le commissaire Wightman dans sa dissidence n'avaient fait qu'adopter un de ces choix.

La Cour d'appel (1986), 56 O.R. (2d) 513, a accueilli à l'unanimité l'appel pour les motifs énoncés par le juge Osler dans sa dissidence. Le juge Cory (alors juge de la Cour d'appel) a ajouté que la Commission devrait respecter les conditions suivantes quand elle tient des réunions plénières au sujet de questions de politique, à la p. 517:

> [TRADUCTION] Il faut souligner cependant, ce que les appelants ont reconnu, que si, pendant sa réunion plénière, la Commission examine de nouveaux éléments de preuve, il faut rappeler les deux parties, leur faire part des nouveaux éléments de preuve et leur donner entière possibilité de répliquer de la manière qu'elles jugent appropriée. En l'absence de tout nouvel élément de preuve, la preuve exposée dans l'avant-projet de décision doit être tenue pour avérée pour les fins de discussion à la réunion plénière de la Commission.

Comme dans toute procédure judiciaire ou quasi judiciaire, le banc ne doit pas fonder sa décision sur un moyen non soulevé à l'audience sans donner aux parties la possibilité de présenter leurs arguments. Il existe également une règle stricte selon laquelle, bien que le banc puisse recevoir des avis, aucun autre membre de la Commission ne peut participer à la décision finale.

1990 CanLII 132 (SCC)

It was therefore the view of the Court of Appeal that, while some precautions are necessary in the use of any formalized consultation process, the full board meeting procedure described by Chairman Adams does not violate any principle of natural justice.

III—Analysis

(a) *Introduction*

It is useful to begin with a summary of the arguments submitted by the parties. The appellant argues that the practice of holding full board meetings on policy issues constitutes a breach of a rule of natural justice appropriately referred to as "he who decides must hear". According to the appellant's version of this rule, a decision maker must not be placed in a situation where he can be "influenced" by persons who have not heard the evidence or the arguments. Thus, the appellant's position is that panel members must be totally shielded from any discussion which may cause them to change their minds even if this change of opinion is honest, because the possibility of undue pressure by other Board members is too ominous to be compatible with principles of natural justice. The appellant also claims that full board meetings do not provide the parties with an adequate opportunity to answer arguments which may be voiced by Board members who have not heard the case.

It is important to note at the outset that the appellant's arguments raise issues with respect to two important and distinct rules of natural justice. It has often been said that these rules can be separated in two categories, namely "that an adjudicator be disinterested and unbiased (*nemo judex in causa sua*) and that the parties be given adequate notice and opportunity to be heard (*audi alteram partem*)": Evans, *de Smith's Judicial Review of Administrative Action* (4th ed. 1980), at p. 156; see also Pépin and Ouellette, *Principes de contentieux administratif* (2nd ed. 1982), at pp. 148-49. While the appellant does not claim that the panel was biased, it does claim that full board meetings may prevent a panel member from deciding the topic of discussion freely and independently

La Cour d'appel a donc été d'avis que, bien que certaines précautions s'imposent lorsqu'on a recours à un processus formel de consultation, la procédure de réunion plénière de la Commission décrite par le président Adams ne porte atteinte à aucun principe de justice naturelle.

III—Analyse

a) *Introduction*

Il convient de commencer par résumer les arguments des parties. L'appelante soutient que la pratique de la Commission de tenir des réunions plénières sur des questions de politique viole la règle de justice naturelle dite «celui qui tranche une affaire doit l'avoir entendue». D'après l'interprétation que l'appelante donne à cette règle, un décideur ne doit pas se trouver dans une situation où il peut être «influencé» par des personnes qui n'ont pas entendu la preuve ni les plaidoiries. Donc, l'appelante soutient que les commissaires qui composent un banc doivent être totalement à l'abri de toute discussion qui pourrait les amener à changer d'avis, même si ce changement d'avis est sincère, parce que le risque de pression indue de la part des autres commissaires est trop grand pour être compatible avec les principes de justice naturelle. L'appelante soutient encore que les réunions plénières de la Commission ne fournissent pas aux parties une possibilité suffisante de répondre aux arguments que des commissaires qui n'ont pas entendu la preuve peuvent y faire valoir.

Il importe de souligner dès le début que les arguments de l'appelante soulèvent des questions relativement à deux règles importantes, mais distinctes, de justice naturelle. On a souvent dit que ces règles peuvent se répartir en deux catégories, savoir [TRADUCTION] «que le décideur doit être désintéressé et impartial (*nemo judex in causa sua*) et que les parties doivent recevoir un préavis suffisant et avoir la possibilité d'être entendues (*audi alteram partem*)»: Evans, *de Smith's Judicial Review of Administrative Action* (4e éd. 1980), à la p. 156; voir également Pépin et Ouellette, *Principes de contentieux administratif* (2e éd. 1982), aux pp. 148 et 149. Bien que l'appelante ne soutienne pas que le banc a été partial, elle soutient que les réunions plénières de la Commis-

1990 CanLII 132 (SCC)

from the opinions voiced at the meeting. Independence is an essential ingredient of the capacity to act fairly and judicially and any procedure or practice which unduly reduces this capacity must surely be contrary to the rules of natural justice.

The respondent union argues that the practice of holding full board meetings on important policy issues is one which is justified for the reasons set forth by Chairman Adams in the reconsideration decision quoted previously.

Before embarking on an analysis of these arguments, one should keep in mind the difference between a full board meeting and a full board hearing: a full board hearing is simply a normal hearing where representations are made by both parties in front of an enlarged panel comprised of all the members of the Board in the manner prescribed by s. 102 of the *Labour Relations Act*; on the other hand, a full board meeting does not entail representations by the parties since they are not invited to or even notified of the meeting. The procedure recommended by the McRuer Report is somewhat different in that it entails the presence of the parties at an informal meeting where they would have the right to answer the arguments raised by members of the Board. In this case, the parties have not made any arguments on the relative virtues of these procedures and have restricted their arguments to the legality of the full board meeting procedure in relation to the rules of natural justice.

I agree with the respondent union that the rules of natural justice must take into account the institutional constraints faced by an administrative tribunal. These tribunals are created to increase the efficiency of the administration of justice and are often called upon to handle heavy caseloads. It is unrealistic to expect an administrative tribunal such as the Board to abide strictly by the rules applicable to courts of law. In fact, it has long been recognized that the rules of natural justice do

sion peuvent empêcher un membre du banc de se prononcer sur le sujet des discussions de façon libre et indépendante des opinions exprimées lors de la réunion. L'indépendance est un élément essentiel de la capacité d'agir avec équité et de façon judiciaire et toute procédure ou pratique qui mine indûment cette capacité doit certainement être contraire aux règles de justice naturelle.

Le syndicat intimé soutient que la pratique de la Commission de tenir des réunions plénières sur des questions de politique importantes est justifiée pour les motifs énoncés par le président Adams dans la décision relative à la demande de réexamen déjà citée.

Avant d'entreprendre l'analyse de ces arguments, il faut se rappeler la différence qui existe entre une réunion plénière de la Commission et une audience plénière de la Commission: une audience plénière de la Commission est tout simplement une audience normale au cours de laquelle les deux parties plaident devant un banc élargi composé de tous les membres de la Commission, de la manière prescrite par l'art. 102 de la *Loi sur les relations de travail*; par contre, une réunion plénière ne comporte pas de plaidoiries par les parties puisque celles-ci ne sont pas invitées à participer à la réunion, ni même avisées de sa tenue. La procédure que recommande le rapport McRuer est quelque peu différente parce qu'elle comporte la présence des parties à une réunion officieuse à laquelle celles-ci auraient le droit de répondre aux arguments soulevés par les commissaires. En l'espèce, les parties n'ont pas abordé le mérite relatif de ces procédures et ont limité leurs plaidoiries à la légalité de la procédure de réunions plénières de la Commission eu égard aux règles de justice naturelle.

Je suis d'accord avec le syndicat intimé que les règles de justice naturelle doivent tenir compte des contraintes institutionnelles auxquelles les tribunaux administratifs sont soumis. Ces tribunaux sont constitués pour favoriser l'efficacité de l'administration de la justice et doivent souvent s'occuper d'un grand nombre d'affaires. Il est irréaliste de s'attendre à ce qu'un tribunal administratif comme la Commission observe strictement toutes les règles applicables aux tribunaux judiciaires. De

1990 CanLII 132 (SCC)

not have a fixed content irrespective of the nature of the tribunal and of the institutional constraints it faces. This principle was reiterated by Dickson J. (as he then was) in *Kane v. Board of Governors of the University of British Columbia*, [1980] 1 S.C.R. 1105, at p. 1113:

> 2. As a constituent of the autonomy it enjoys, the tribunal must observe natural justice which, as Harman L.J. said, [*Ridge v. Baldwin*, at p. 850] is only "fair play in action". In any particular case, the requirements of natural justice will depend on "the circumstances of the case, the nature of the inquiry, the rules under which the tribunal is acting, the subject-matter which is being dealt with, and so forth": per Tucker L.J. in *Russell v. Duke of Norfolk*, at p. 118. To abrogate the rules of natural justice, express language or necessary implication must be found in the statutory instrument. [Emphasis added.]

The main issue is whether, given the importance of the policy issue at stake in this case and the necessity of maintaining a high degree of quality and coherence in Board decisions, the rules of natural justice allow a full board meeting to take place subject to the conditions outlined by the Court of Appeal and, if not, whether a procedure which allows the parties to be present, such as a full board hearing, is the only acceptable alternative. The advantages of the practice of holding full board meetings must be weighed against the disadvantages involved in holding discussions in the absence of the parties.

(b) *The Consequences of the Institutional Constraints Faced by the Board*

The *Labour Relations Act* has entrusted the Board with the responsibility of fostering harmonious labour relations through collective bargaining, as appears clearly in the preamble of the Act:

> WHEREAS it is in the public interest of the Province of Ontario to further harmonious relations between employers and employees by encouraging the practice and procedure of collective bargaining between employers and trade unions as the freely designated representatives of employees.

fait, il est admis depuis longtemps que les règles de justice naturelle n'ont pas un contenu fixe sans égard à la nature du tribunal et aux contraintes institutionnelles auxquelles il est soumis. Le juge Dickson (maintenant Juge en chef) a réitéré ce principe dans l'arrêt *Kane c. Conseil d'administration de l'Université de la Colombie-Britannique*, [1980] 1 R.C.S. 1105, à la p. 1113:

> 2. En tant qu'élément constitutif de l'autonomie dont il jouit, le tribunal doit respecter la justice naturelle qui, comme l'a dit le lord juge Harman [dans] *Ridge v. Baldwin*, à la p. 850, équivaut simplement [TRADUCTION] «à jouer franc jeu». Dans chaque cas, les exigences de la justice naturelle varient selon [TRADUCTION] «les circonstances de l'affaire, la nature de l'enquête, les règles qui régissent le tribunal, la question traitée, etc.»: le lord juge Tucker dans *Russell v. Duke of Norfolk*, à la p. 118. Les règles de justice naturelle ne peuvent être abrogées que par un texte de loi exprès ou nettement implicite en ce sens. [Je souligne.]

La question principale est de savoir si, vu l'importance de la question de politique en cause en l'espèce et la nécessité de maintenir un niveau élevé de qualité et de cohérence dans les décisions de la Commission, les règles de justice naturelle permettent la tenue d'une réunion plénière de la Commission sous réserve des conditions exposées par la Cour d'appel et, dans la négative, si une procédure qui permet aux parties d'être présentes, telle une audience plénière de la Commission, est la seule autre solution acceptable. Il faut soupeser les avantages de la pratique de la Commission de tenir des réunions plénières en regard des inconvénients que comporte la tenue de débats en l'absence des parties.

b) *Les conséquences des contraintes institutionnelles auxquelles la Commission est soumise*

La *Loi sur les relations de travail* confie à la Commission la responsabilité de faciliter les bonnes relations de travail par la négociation collective, comme le stipule expressément le préambule de la Loi:

> ATTENDU qu'il est dans l'intérêt public de la province de l'Ontario de faciliter les bonnes relations entre employeurs et employés en favorisant le recours à la négociation collective entre les employeurs et les syndicats à titre de représentants librement choisis des employés.

1990 CanLII 132 (SCC)

The Board has been granted the powers thought necessary to achieve this task, not the least of which is the power to decide in a final and conclusive manner all matters which fall within its jurisdiction: s. 106(1) of the *Labour Relations Act*. As was stated by Chairman Adams in his reconsideration decision, the Board has also been given very broad discretionary powers as is the case with the power to determine what constitutes "bargaining in good faith" (s. 15).

The immensity of the task entrusted to the Board should not be underestimated. As Chairman Adams wrote in the reconsideration decision, the Board had a caseload of 3189 cases to handle in 1982-83 and employed 12 full-time chairman and vice-chairmen, 4 part-time vice-chairmen, 10 full-time Board members representing labour and management as well as another 22 part-time Board members to hear and decide those cases. The Board's full-time chairman and vice-chairmen have an average caseload of 266 cases per year. Moreover, the tripartite nature of the Board makes it necessary to have an equal representation from management and labour unions on each panel as appears clearly from s. 102 of the *Labour Relations Act*:

102.—(1) The Ontario Labour Relations Board is continued.

(2) The Board shall be composed of a chairman, one or more vice-chairmen and as many members equal in number representative of employers and employees respectively as the Lieutenant Governor in Council considers proper, all of whom shall be appointed by the Lieutenant Governor in Council.

. . .

(9) The chairman or a vice-chairman, one member representative of employers and one member representative of employees constitute a quorum and are sufficient for the exercise of all the jurisdiction and powers of the Board.

. . .

(11) The decision of the majority of the members of the Board present and constituting a quorum is the

La Commission a reçu, en vertu du par. 106(1) de la *Loi sur les relations de travail*, les pouvoirs jugés nécessaires pour accomplir cette tâche dont celui, qui n'est pas le moindre, de rendre, au sujet de toute question qui relève de sa compétence, des décisions finales et définitives. Comme l'affirme le président Adams dans sa décision sur la demande de réexamen, la Commission a aussi reçu des pouvoirs discrétionnaires très étendus, notamment celui de déterminer ce que comporte une «négociation de bonne foi» (art. 15).

Il ne faut pas sous-estimer l'ampleur de la tâche assignée à la Commission. Comme le président Adams l'a écrit dans la décision relative à la demande de réexamen, la Commission a eu 3 189 affaires à traiter durant l'exercice 1982-1983 et elle comptait, outre le président, 11 vice-présidents à plein temps, 4 vice-présidents à temps partiel, 10 commissaires permanents représentant les employés et les employeurs ainsi que 22 autres commissaires à temps partiel pour entendre et trancher ces affaires. Le président et les vice-présidents à plein temps ont en moyenne 266 affaires par année à entendre. De plus, la nature tripartite de la Commission fait en sorte qu'elle doit compter un nombre égal de représentants des employeurs et des syndicats sur chaque banc, comme le stipule clairement l'art. 102 de la *Loi sur les relations de travail*:

102 (1) La Commission des relations de travail de l'Ontario demeure en fonction.

(2) La Commission se compose d'un président, d'un ou plusieurs vice-présidents et des autres membres répartis en un nombre égal de représentants des employeurs et de représentants des employés que le lieutenant-gouverneur en conseil juge nécessaires. Ces personnes sont nommées par le lieutenant-gouverneur en conseil.

. . .

(9) Le président ou un vice-président, un membre représentant les employeurs et un membre représentant les employés constituent le quorum et peuvent exercer les attributions de la Commission.

. . .

(11) La décision de la majorité des membres de la Commission présents qui constitue le quorum est la

1990 CanLII 132 (SCC)

decision of the Board, but, if there is no majority, the decision of the chairman or vice-chairman governs.

The rules governing the quorum of any panel of the Board are especially suited for panels of three although they do not appear to prevent the formation of a larger panel. However, even if the *Labour Relations Act* allows full board hearings, such a procedure would not necessarily be practical every time an important policy issue is at stake.

Indeed, it is apparent from the size of the Board's caseload and from the number of persons which would sit on such an enlarged panel that holding full board hearings is a highly impractical way of solving important policy issues. Furthermore, the difficulties involved in setting up a panel comprised of an equal number of management and labour representatives and in scheduling such a meeting are also obvious when one takes into consideration the large number of Board members who would have to be present. In fact, one wonders whether it is really possible to call a full board hearing every time an important policy issue arises. The solution proposed in the McRuer Report, i.e., allowing the parties to be present and to answer the arguments made at the meeting, would entail similar difficulties since their presence would necessitate some formal procedure and involve organizational difficulties as well.

The first rationale behind the need to hold full board meetings on important policy issues is the importance of benefiting from the acquired experience of all the members, chairman and vice-chairmen of the Board. Moreover, the tripartite nature of the Board makes it even more imperative to promote exchanges of opinions between management and union representatives. As was pointed out clearly by Dickson J. (as he then was) in *Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp.*, [1979] 2 S.C.R. 227, the primary purpose of the creation of

décision de la Commission. Si aucune majorité ne se dégage, le président ou le vice-président a voix prépondérante.

Les règles régissant le quorum d'un banc de la Commission conviennent particulièrement bien à des bancs de trois personnes même si elles ne paraissent pas interdire la constitution de bancs composés d'un plus grand nombre de commissaires. Cependant, même si la *Loi sur les relations de travail* autorise les audiences plénières de la Commission, une telle procédure ne serait pas forcément pratique dans tous les cas où il se présente une question de politique importante.

En réalité, il ressort manifestement du nombre d'affaires soumises à la Commission et du nombre de personnes qui participeraient à ces bancs élargis que la tenue d'audiences plénières de la Commission constitue une façon très peu pratique de résoudre des questions de politique importantes. De plus, les difficultés que présenteraient la constitution d'un banc composé d'un nombre égal de représentants des employeurs et des employés et la fixation de la date de cette réunion ressortent clairement si on considère le grand nombre de commissaires qui devraient être présents. En fait, on se demande même s'il est vraiment possible de convoquer une audience plénière de la Commission chaque fois qu'il y a une importante question de politique à débattre. La solution préconisée dans le rapport McRuer, c'est-à-dire celle d'autoriser les parties à assister à la réunion et à répliquer aux arguments qui y sont avancés, comporterait des difficultés semblables puisque la présence des parties exigerait une procédure formelle quelconque et susciterait aussi des difficultés d'organisation.

La première raison pour laquelle il est nécessaire de tenir des réunions plénières de la Commission au sujet des questions de politique majeures tient à l'importance de bénéficier de l'expérience acquise de tous les commissaires, y compris le président et les vice-présidents de la Commission. De plus, la nature tripartite de la Commission rend encore plus impérieux de favoriser les échanges d'avis entre les représentants des employeurs et ceux des syndicats. Comme le souligne clairement le juge Dickson (maintenant Juge en chef) dans l'arrêt *Syndicat canadien de la Fonction publique,*

1990 CanLII 132 (SCC)

administrative bodies such as the Ontario Labour Relations Board is to confer a wide jurisdiction to solve labour disputes on those who are best able, in light of their experience, to provide satisfactory solutions to these disputes, at pp. 235-36:

> Section 101 constitutes a clear statutory direction on the part of the Legislature that public sector labour matters be promptly and finally decided by the Board. Privative clauses of this type are typically found in labour relations legislation. The rationale for protection of a labour board's decisions within jurisdiction is straightforward and compelling. The labour board is a specialized tribunal which administers a comprehensive statute regulating labour relations. In the administration of that regime, a board is called upon not only to find facts and decide questions of law, but also to exercise its understanding of the body of jurisprudence that has developed around the collective bargaining system, as understood in Canada, and its labour relations sense acquired from accumulated experience in the area.

The rules of natural justice should not discourage administrative bodies from taking advantage of the accumulated experience of its members. On the contrary, the rules of natural justice should in their application reconcile the characteristics and exigencies of decision making by specialized tribunals with the procedural rights of the parties.

The second rationale for the practice of holding full board meetings is the fact that the large number of persons who participate in Board decisions creates the possibility that different panels will decide similar issues in a different manner. It is obvious that coherence in administrative decision making must be fostered. The outcome of disputes should not depend on the identity of the persons sitting on the panel for this result would be [TRANSLATION] "difficult to reconcile with the notion of equality before the law, which is one of the main corollaries of the rule of law, and perhaps also the most intelligible one": Morissette, *Le contrôle de la compétence d'attribution: thèse, antithèse et synthèse* (1986), 16 *R.D.U.S.* 591, at p.

section locale 963 c. Société des alcools du Nouveau-Brunswick, [1979] 2 R.C.S. 227, aux pp. 235 et 236, le but premier de la constitution des organismes administratifs comme la Commission
a des relations de travail de l'Ontario est d'attribuer une compétence générale pour régler les différends du travail à ceux qui sont le plus en mesure, à cause de leur expérience, de trouver des solutions satisfaisantes à ces différends:

> b L'article 101 révèle clairement la volonté du législateur que les différends du travail dans le secteur public soient réglés promptement et en dernier ressort par la Commission. Des clauses privatives de ce genre sont typiques dans les lois sur les relations de travail. On veut protéger
> c les décisions d'une commission des relations de travail, lorsqu'elles relèvent de sa compétence, pour des raisons simples et impérieuses. La commission est un tribunal spécialisé chargé d'appliquer une loi régissant l'ensemble des relations de travail. Aux fins de l'administration de
> d ce régime, une commission n'est pas seulement appelée à constater des faits et à trancher des questions de droit, mais également à recourir à sa compréhension du corps jurisprudentiel qui s'est développé à partir du système de négociation collective, tel qu'il est envisagé au Canada,
> e et à sa perception des relations de travail acquise par une longue expérience dans ce domaine.

Les règles de justice naturelle ne devraient pas dissuader les organismes administratifs de tirer
f profit de l'expérience acquise par leurs membres. Au contraire, les règles de justice naturelle devraient, par leur application, concilier les caractéristiques et les exigences du processus décisionnel des tribunaux spécialisés avec les droits des parties
g en matière de procédure.

La seconde raison d'être de la pratique de tenir des réunions plénières de la Commission tient au fait que le grand nombre de personnes qui partici-
h pent aux décisions de la Commission crée un risque que des bancs différents rendent des décisions divergentes sur des questions semblables. Il est évident qu'il faut favoriser la cohérence des décisions rendues en matière administrative. L'is-
i sue des litiges ne devrait pas dépendre de l'identité des personnes qui composent le banc puisque ce résultat serait «difficile à concilier avec la notion d'égalité devant la loi, l'un des principaux corollai-
j res de la primauté du droit, et peut-être aussi le plus intelligible»: Morissette, *Le contrôle de la compétence d'attribution: thèse, antithèse et syn-*

1990 CanLII 132 (SCC)

632. Given the large number of decisions rendered in the field of labour law, the Board is justified in taking appropriate measures to ensure that conflicting results are not inadvertently reached in similar cases. The fact that the Board's decisions are protected by a privative clause (s. 108) makes it even more imperative to take measures such as full board meetings in order to avoid such conflicting results. At the same time, the decision of one panel cannot bind another panel and the measures taken by the Board to foster coherence in its decision making must not compromise any panel member's capacity to decide in accordance with his conscience and opinions.

A full board meeting is a forum for discussion which, in Cory J.A.'s words (as he then was) is "no more than an amplification of the research of the hearing panel carried out before they delivered their decision" (at p. 517). Like many other judicial practices, however, full board meetings entail some imperfections, especially with respect to the opportunity to be heard and the judicial independence of the decision maker, as is correctly pointed out by Professors Blache and Comtois in "La décision institutionnelle" (1986), 16 *R.D.U.S.* 645, at pp. 707-8:

> [TRANSLATION] There are advantages and disadvantages to institutionalizing the decision-making process. The main advantages with which it is credited are increasing the efficiency of the organization as well as the quality and consistency of decisions. It is felt that institutional decisions tend to promote the equal treatment of individuals in similar circumstances, increase the likelihood of better quality decisions and lead to a better allocation of resources. Against this it is feared that institutionalization creates a danger of the introduction, without the parties' knowledge, of evidence and ideas obtained extraneously and reduces the decision maker's personal responsibility for the decision to be made.

The question before this Court is whether the disadvantages involved in this practice are sufficiently important to warrant a holding that it

thèse (1986), 16 *R.D.U.S.* 591, à la p. 632. Vu le grand nombre de décisions rendues en matière de droit du travail, la Commission est justifiée de prendre les mesures nécessaires pour éviter d'arriver, par inadvertance, à des solutions différentes dans des affaires semblables. Puisque les décisions de la Commission sont protégées par une clause privative (l'art. 108), il est encore plus impérieux de recourir à des mesures comme les réunions plénières de la Commission pour éviter ces solutions incompatibles. En même temps, la décision d'un banc ne saurait lier un autre banc et les mesures prises par la Commission pour favoriser la cohérence de ses décisions ne doivent pas entraver la capacité de chacun des membres d'un banc de décider selon sa conscience et ses opinions.

Une réunion plénière de la Commission est un lieu de discussion qui, selon l'expression du juge Cory (alors juge de la Cour d'appel,) ne constitue [TRADUCTION] «rien de plus qu'un approfondissement de la recherche à laquelle procède le banc qui entend une affaire avant de rendre sa décision» (à la p. 517). Cependant, comme bien d'autres pratiques judiciaires, les réunions plénières de la Commission comportent certaines imperfections, notamment en ce qui concerne la possibilité pour les parties d'être entendues et l'indépendance du décideur, comme le soulignent avec justesse les professeurs Blache et Comtois dans «La décision institutionnelle» (1986), 16 *R.D.U.S.* 645, aux pp. 707 et 708:

> L'institutionnalisation du processus décisionnel présente des avantages et des inconvénients. Les principaux avantages qui lui sont imputés sont d'accroître l'efficacité de l'organisme ainsi que la cohérence et la qualité des décisions. La décision institutionnelle est, croit-on, susceptible de favoriser l'égalité de traitement d'individus se trouvant dans des situation similaires, de maximiser la possibilité de rendre des décisions d'une qualité supérieure, et de favoriser une meilleure affectation des ressources. On craint par contre que l'institutionnalisation ne risque d'encourager l'introduction, à l'insu des parties, de preuve et d'idées obtenues hors instance et d'entraîner la diminution de la responsabilité personnelle du décideur face à la décision à rendre.

La question dont est saisie notre Cour est de savoir si les inconvénients que cette pratique comporte sont assez importants pour conclure qu'elle consti-

1990 CanLII 132 (SCC)

constitutes a breach of the rules of natural justice or whether full board meetings are consistent with these rules provided that certain safeguards be observed.

(c) *The Judicial Independence of Panel Members in the Context of a Full Board Meeting*

The appellant argues that persons who did not hear the evidence or the submissions of the parties should not be in a position to "influence" those who will ultimately participate in the decision, i.e., vote for one side or the other. The appellant cites the following authorities in support of its argument: *Mehr v. Law Society of Upper Canada*, [1955] S.C.R. 344, at p. 351; *The King v. Huntingdon Confirming Authority*, [1929] 1 K.B. 698, at pp. 715 and 717; *Re Rosenfeld and College of Physicians and Surgeons* (1969), 11 D.L.R. (3d) 148 (Ont. H.C.), at pp. 161-64; *Regina v. Broker-Dealers' Association of Ontario* (1970), 15 D.L.R. (3d) 385 (Ont. H.C.), at pp. 394-95; *Re Ramm* (1957), 7 D.L.R. (2d) 378 (Ont. C.A.), at pp. 382-83; *Regina v. Committee on Works of Halifax City Council* (1962), 34 D.L.R. (2d) 45 (N.S.S.C.), at pp. 53-55; *Grillas v. Minister of Manpower and Immigration*, [1972] S.C.R. 577, at p. 594; *Re Rogers* (1978), 20 Nfld. & P.E.I.R. 484 (P.E.I.S.C.), at p. 499; *Doyle v. Restrictive Trade Practices Commission*, [1985] 1 F.C. 362 (C.A.), at p. 371; *Royal Commission Inquiry into Civil Rights*, vol. 5, Report No. 3, c. 124, at pp. 2004-5. In all those decisions with the exception of *Re Rogers*, some of the members of the panel which rendered the impugned decision had not heard all the evidence or all the representations of the parties; their vote was cast even though some of the members of these panels did not have the benefit of assessing the credibility of the witnesses or the validity of the factual and legal arguments. I agree that, as a general rule, the members of a panel who actually participate in the decision must have heard all the evidence as well as all the arguments presented by the parties and in this respect I adopt Pratte J.'s words in *Doyle v. Restrictive Trade Practices Commission*, *supra*, at pp. 368-69:

tue une violation des règles de justice naturelle ou si les réunions plénières de la Commission sont conformes à ces règles pourvu que certaines garanties soient respectées.

c) *L'indépendance judiciaire des membres d'un banc dans le contexte d'une réunion plénière de la Commission*

L'appelante soutient que les personnes qui n'ont pas entendu la preuve ou les plaidoiries des parties ne doivent pas être en mesure d'«influencer» celles qui, en fin de compte, participeront à la décision, c'est-à-dire de se prononcer en faveur d'un côté ou de l'autre. L'appelante cite les décisions suivantes pour étayer son argumentation: *Mehr v. Law Society of Upper Canada*, [1955] R.C.S. 344, à la p. 351; *The King v. Huntingdon Confirming Authority*, [1929] 1 K.B. 698, aux pp. 715 et 717; *Re Rosenfeld and College of Physicians and Surgeons* (1969), 11 D.L.R. (3d) 148 (H.C. Ont.), aux pp. 161 à 164; *Regina v. Broker-Dealers' Association of Ontario* (1970), 15 D.L.R. (3d) 385 (H.C. Ont.), aux pp. 394 et 395; *Re Ramm* (1957), 7 D.L.R. (2d) 378 (C.A. Ont.), aux pp. 382 et 383; *Regina v. Committee on Works of Halifax City Council* (1962), 34 D.L.R. (2d) 45 (C.S.N.-É.), aux pp. 53 à 55; *Grillas c. Ministre de la Main-d'Oeuvre et de l'Immigration*, [1972] R.C.S. 577, à la p. 594; *Re Rogers* (1978), 20 Nfld. & P.E.I.R. 489 (C.S.Î.-P.-É.) à la p. 499; *Doyle c. Commission sur les pratiques restrictives du commerce*, [1985] 1 C.F. 362 (C.A.), à la p. 371; *Royal Commission Inquiry into Civil Rights*, vol. 5, rapport n° 3, ch. 124, aux pp. 2004 et 2005. Dans toutes ces décisions, sauf *Re Rogers*, certains des membres du banc qui avait rendu la décision contestée n'avaient pas entendu la totalité de la preuve ou des plaidoiries des parties; ils avaient participé au vote même s'ils n'avaient pas été en mesure d'évaluer la crédibilité des témoins ou les arguments factuels et juridiques. Je reconnais qu'en règle générale les membres d'un banc qui participent effectivement à une décision doivent avoir entendu la totalité de la preuve et des plaidoiries soumises par les parties et, à cet égard, je fais miens les propos tenus par le juge Pratte dans l'arrêt *Doyle c. Commission sur les pratiques restrictives du commerce*, précité, aux pp. 368 et 369:

1990 CanLII 132 (SCC)

The important issue is whether the maxim "he who decides must hear" invoked by the applicant should be applied here.

This maxim expresses a well-known rule according to which, where a tribunal is responsible for hearing and deciding a case, only those members of the tribunal who heard the case may take part in the decision. It has sometimes been said that this rule is a corollary of the *audi alteram partem* rule. This is true to the extent a litigant is not truly "heard" unless he is heard by the person who will be deciding his case .... This having been said, it must be realized that the rule "he who decides must hear", important though it may be, is based on the legislator's supposed intentions. It therefore does not apply where this is expressly stated to be the case; nor does it apply where a review of all the provisions governing the activities of a tribunal leads to the conclusion that the legislator could not have intended them to apply. Where the rule does apply to a tribunal, finally, it requires that all members of the tribunal who take part in a decision must have heard the evidence and the representations of the parties in the manner in which the law requires that they be heard.

In that case, one of the issues was whether it was sufficient for the members of the panel who had not heard the evidence to read the transcripts and this question was answered in the negative in light of the relevant statutory provisions. In this case, however, the members of the panel who participated in the impugned decision, i.e., Chairman Adams and Messrs. Wightman and Lee, heard all the evidence and all the arguments. It follows that the cases cited by the appellant cannot support its argument, nor can the presence of other Board members at the full board meeting amount to "participation" in the final decision even though their contribution to the discussions which took place at that meeting can be seen as a "participation" in the decision-making process in the widest sense of that expression.

However, the appellant claims that the following extract from the reasons of Romer J. in *The King v. Huntingdon Confirming Authority*, *supra*, constitutes the basis of a rule whereby decision makers who have heard all the evidence and representations should not be influenced by persons who have not, at p. 717:

Ce qui importe, c'est de savoir s'il y a lieu d'appliquer ici la maxime «*he who decides must hear*» qu'invoque le requérant.

Cette maxime exprime une règle bien connue suivant laquelle, lorsque la loi charge un tribunal d'entendre et décider une affaire, seuls les membres du tribunal qui ont entendu l'affaire peuvent participer à la décision. On a parfois dit que cette règle exprimait une conséquence de la règle *audi alteram partem*. Cela est vrai dans la mesure où un justiciable n'est vraiment «entendu» que s'il est entendu par celui qui décidera sa cause. [...] Ceci dit, il faut voir que la règle «*he who decides must hear*», si importante qu'elle soit, est fondée sur la volonté présumée du législateur. Elle ne s'applique donc pas lorsque le législateur en a expressément écarté l'application; elle ne s'applique pas non plus lorsque l'étude de l'ensemble des dispositions régissant l'activité d'un tribunal conduit à croire que le législateur n'a pas dû vouloir qu'elle s'y applique. Enfin, lorsque la règle s'applique à un tribunal, elle exige que tous les membres de ce tribunal qui participent à une décision aient entendu la preuve et les représentations des parties de la façon que la loi veut qu'elles soient entendues.

Dans cette affaire, l'une des questions à trancher était de savoir s'il suffisait que les membres du banc qui n'avaient pas entendu la preuve lisent la transcription sténographique des audiences, ce à quoi on a répondu par la négative en raison des dispositions législatives applicables. En l'espèce cependant, les membres du banc qui ont participé à la décision contestée, c'est-à-dire le président Adams et les commissaires Wightman et Lee, ont entendu toute la preuve et toutes les plaidoiries. Il s'ensuit que les décisions citées par l'appelante ne peuvent étayer son argumentation et la présence d'autres commissaires à la réunion plénière de la Commission ne peut pas non plus équivaloir à une «participation» à la décision finale, même si l'on peut considérer leur apport aux discussions qui s'y sont déroulées comme une «participation» au processus décisionnel au sens le plus large du terme.

Cependant, l'appelante soutient que le passage suivant des motifs du juge Romer dans l'arrêt *The King v. Huntingdon Confirming Authority*, précité, à la p. 717, constitue le fondement de la règle en vertu de laquelle le décideur qui a entendu la totalité de la preuve et des plaidoiries ne doit pas être influencé par des personnes qui ne l'ont pas fait:

1990 CanLII 132 (SCC)

Further, I would merely like to point this out: that at that meeting of May 16 there were present three justices who had never heard the evidence that had been given on oath on April 25. There was a division of opinion. The resolution in favour of confirmation was carried by eight to two, and it is at least possible that that majority was induced to vote in the way it did by the eloquence of those members who had not been present on April 25, to whom the facts were entirely unknown. [Emphasis added.]

Thus, Romer J. was of the opinion that the influence of those who did not hear the evidence could go beyond their vote and that this influence constituted a denial of natural justice. Following that reasoning, it was held in *Re Rogers* that the presence of a person who heard neither the evidence nor the representations at one of the meetings where a quorum of the Prince Edward Island Land Use Commission was deliberating invalidated the decision of the Commission even though that person did not vote on the matter. The opposite result was reached in *Underwater Gas Developers Ltd. v. Ontario Labour Relations Board* (1960), 24 D.L.R. (2d) 673 (Ont. C.A.), where it was held that the presence of Board members who neither heard the evidence nor voted on the matter did not invalidate the Board's decision, at p. 675.

I am unable to agree with the proposition that any discussion with a person who has not heard the evidence necessarily vitiates the resulting decision because this discussion might "influence" the decision maker. In this respect, I adopt Meredith C.J.C.P.'s words in *Re Toronto and Hamilton Highway Commission and Crabb* (1916), 37 O.L.R. 656 (C.A.), at p. 659:

The Board is composed of persons occupying positions analogous to those of judges rather than of arbitrators merely; and it is not suggested that they heard any evidence behind the back of either party; the most that can be said is that they—that is, those members of the Board who heard the evidence and made the award—allowed another member of the Board, who had not heard the evidence, or taken part in the inquiry before, to read the evidence and to express some of his views regarding the case to them . . . . [B]ut it is only fair to add that if every Judge's judgment were vitiated because

[TRADUCTION] De plus, j'aimerais simplement souligner ceci: à cette réunion du 16 mai, il y avait trois juges qui n'avaient pas entendu la preuve présentée sous serment le 25 avril. Il y a eu partage d'opinions. La résolution en faveur de confirmer a été adoptée à huit voix contre deux et il est à tout le moins possible que la majorité ait été amenée à se prononcer comme elle l'a fait en raison de l'éloquence des membres qui avaient été absents le 25 avril et qui ignoraient absolument tout des faits. [Je souligne.]

Le juge Romer a donc été d'avis que l'influence de ceux qui n'avaient pas entendu la preuve pouvait aller au-delà de leur vote et que cette influence a constitué un déni de justice naturelle. On a jugé, en suivant ce raisonnement dans l'arrêt *Re Rogers*, que la présence d'une personne qui n'a entendu ni la preuve ni les plaidoiries à l'une des réunions de délibérations de la Land Use Commission de l'Île-du-Prince-Édouard où il y avait quorum avait pour effet d'invalider la décision de la Commission même si cette personne n'avait pas voté sur la question. On est arrivé au résultat contraire dans l'arrêt *Underwater Gas Developers Ltd. v. Ontario Labour Relations Board* (1960), 24 D.L.R. (2d) 673 (C.A. Ont.), où on statue, à la p. 675, que la présence de commissaires qui n'ont ni entendu la preuve ni voté sur la question n'a pas pour effet d'invalider la décision de la Commission.

Je ne puis souscrire à l'affirmation portant que toute discussion avec une personne qui n'a pas entendu la preuve entache forcément de nullité la décision qui s'ensuit parce que la discussion est susceptible d'«influencer» le décideur. À cet égard, je fais miens les propos du juge en chef Meredith dans l'arrêt *Re Toronto and Hamilton Highway Commission and Crabb* (1916), 37 O.L.R. 656 (C.A.), à la p. 659:

[TRADUCTION] La Commission se compose de personnes qui occupent des postes qui ressemblent à un poste de juge plutôt qu'à un poste de simple arbitre; personne ne prétend qu'ils ont entendu quelque élément de preuve à l'insu de l'une ou l'autre des parties; tout ce qu'on peut dire c'est qu'ils, à savoir les commissaires qui ont entendu la preuve et rendu la décision, ont permis à un autre commissaire qui n'avait pas entendu la preuve ni participé à l'enquête auparavant, d'en lire la transcription et de leur exprimer certaines de ses vues sur la cause [. . .] [M]ais, il convient d'ajouter que si toutes les

1990 CanLII 132 (SCC)

he discussed the case with some other Judge a good many judgments existing as valid and unimpeachable ought to fall; and that if such discussions were prohibited many more judgments might fall in an appellate Court because of a defect which must have been detected if the subject had been so discussed. [Emphasis added.]

The appellant's main argument against the practice of holding full board meetings is that these meetings can be used to fetter the independence of the panel members. Judicial independence is a long standing principle of our constitutional law which is also part of the rules of natural justice even in the absence of constitutional protection. It is useful to define this concept before discussing the effect of full board meetings on panel members. In *Beauregard v. Canada*, [1986] 2 S.C.R. 56, Dickson C.J. described the "accepted core of the principle of judicial independence" as a complete liberty to decide a given case in accordance with one's conscience and opinions without interference from other persons, including judges, at p. 69:

> Historically, the generally accepted core of the principle of judicial independence has been the complete liberty of individual judges to hear and decide the cases that come before them: no outsider—be it government, pressure group, individual or even another judge—should interfere in fact, or attempt to interfere, with the way in which a judge conducts his or her case and makes his or her decision. This core continues to be central to the principle of judicial independence.

See also *Valente v. The Queen*, [1985] 2 S.C.R. 673, at pp. 686-87, and Benyekhlef, *Les garanties constitutionnelles relatives à l'indépendance du pouvoir judiciaire au Canada*, at p. 48.

It is obvious that no outside interference may be used to compel or pressure a decision maker to participate in discussions on policy issues raised by a case on which he must render a decision. It also goes without saying that a formalized consultation process could not be used to force or induce decision makers to adopt positions with which they do

décisions d'un juge étaient entachées de nullité parce qu'il a discuté de l'affaire avec un autre juge, il faudrait invalider un grand nombre de jugements considérés comme valides et inattaquables, et que si ces discussions étaient prohibées, encore plus de jugements pourraient être infirmés en Cour d'appel à cause du vice qu'il faudrait constater si le sujet avait été ainsi discuté. [Je souligne.]

Dans son principal argument à l'encontre de la pratique de la Commission de tenir des réunions plénières, l'appelante soutient que ces réunions peuvent servir à diminuer l'indépendance des membres du banc. L'indépendance des juges est un principe reconnu depuis longtemps dans notre droit constitutionnel; elle fait également partie des règles de justice naturelle même en l'absence de protection constitutionnelle. Il est utile de définir cette notion avant d'aborder l'effet des réunions plénières de la Commission sur les membres d'un banc. Dans l'arrêt *Beauregard c. Canada*, [1986] 2 R.C.S. 56, le juge en chef Dickson définit «ce qui a ... été accepté comme l'essentiel du principe de l'indépendance judiciaire», comme la liberté complète de juger une affaire donnée selon sa conscience et ses opinions, sans l'intervention d'autres personnes, y compris de juges, à la p. 69:

> Historiquement, ce qui a généralement été accepté comme l'essentiel du principe de l'indépendance judiciaire a été la liberté complète des juges pris individuellement d'instruire et de juger les affaires qui leur sont soumises: personne de l'extérieur—que ce soit un gouvernement, un groupe de pression, un particulier ou même un autre juge—ne doit intervenir en fait, ou tenter d'intervenir, dans la façon dont un juge mène l'affaire et rend sa décision. Cet élément essentiel continue d'être au centre du principe de l'indépendance judiciaire.

Voir également *Valente c. La Reine*, [1985] 2 R.C.S. 673, aux pp. 686 et 687, et Benyekhlef, *Les garanties constitutionnelles relatives à l'indépendance du pouvoir judiciaire au Canada*, à la p. 48.

Il est évident qu'aucune ingérence extérieure ne peut être pratiquée pour forcer ou contraindre un décideur à participer à des discussions au sujet de questions de politique soulevées par une affaire sur laquelle il doit statuer. Il va de soi aussi qu'on ne peut recourir à aucun mécanisme formel de consultation pour forcer ou inciter un décideur à

1990 CanLII 132 (SCC)

not agree. Nevertheless, discussions with colleagues do not constitute, in and of themselves, infringements on the panel members' capacity to decide the issues at stake independently. A discussion does not prevent a decision maker from adjudicating in accordance with his own conscience and opinions nor does it constitute an obstacle to this freedom. Whatever discussion may take place, the ultimate decision will be that of the decision maker for which he assumes full responsibility.

The essential difference between full board meetings and informal discussions with colleagues is the possibility that moral suasion may be felt by the members of the panel if their opinions are not shared by other Board members, the chairman or vice-chairmen. However, decision makers are entitled to change their minds whether this change of mind is the result of discussions with colleagues or the result of their own reflection on the matter. A decision maker may also be swayed by the opinion of the majority of his colleagues in the interest of adjudicative coherence since this is a relevant criterion to be taken into consideration even when the decision maker is not bound by any *stare decisis* rule.

It follows that the relevant issue in this case is not whether the practice of holding full board meetings can cause panel members to change their minds but whether this practice impinges on the ability of panel members to decide according to their opinions. There is nothing in the *Labour Relations Act* which gives either the chairman, the vice-chairmen or other Board members the power to impose his opinion on any other Board member. However, this *de jure* situation must not be thwarted by procedures which may effectively compel or induce panel members to decide against their own conscience and opinions.

It is pointed out that "justice should not only be done, but should manifestly and undoubtedly be seen to be done": see *Rex v. Sussex Justices*, [1924] 1 K.B. 256, at p. 259. This maxim applies whenever the circumstances create the danger of an injustice, for example when there is a reason-

adopter un point de vue qu'il ne partage pas. Cependant, les discussions avec des collègues ne constituent pas en soi une atteinte à la capacité des membres d'un banc de trancher les questions en litige de manière indépendante. Une discussion n'empêche pas un décideur de juger selon ses propres conscience et opinions, pas plus qu'elle ne constitue une entrave à sa liberté. Quelles que soient les discussions qui peuvent avoir lieu, la décision ultime appartient au décideur et il en assume la responsabilité entière.

La différence fondamentale entre les réunions plénières de la Commission et les discussions informelles entre collègues tient à la pression morale que les membres du banc peuvent ressentir si les autres commissaires, le président ou les vice-présidents ne partagent pas leur avis. Cependant, les décideurs ont le droit de changer d'avis, peu importe que ce soit à la suite de discussions avec des collègues ou de leur propre réflexion sur le sujet. L'opinion de la majorité de ses collègues peut également amener un décideur à changer d'avis par souci de cohérence de la jurisprudence puisqu'il s'agit d'un critère légitime qui doit être pris en considération, même si le décideur n'est lié par aucune règle de *stare decisis*.

Il s'ensuit que la question qu'il faut se poser en l'espèce est non pas de savoir si la pratique des réunions plénières de la Commission peut amener les membres d'un banc à changer d'avis, mais plutôt de savoir si cette pratique entrave la capacité des membres de ce banc de statuer selon leurs opinions. Il n'y a rien dans la *Loi sur les relations de travail* qui autorise le président, les vice-présidents ou les autres commissaires à imposer leur avis à quelque autre commissaire. Cependant, cette situation de droit ne doit pas être contrecarrée par des procédures qui peuvent avoir pour effet de forcer ou d'inciter des membres d'un banc à statuer à l'encontre de leurs propres conscience et opinions.

On souligne qu'il est essentiel [TRADUCTION] «que non seulement justice soit rendue, mais que justice paraisse manifestement et indubitablement être rendue»: voir *Rex v. Sussex Justices*, [1924] 1 K.B. 256, à la p. 259. Cette maxime s'applique chaque fois que les circonstances créent un risque

1990 CanLII 132 (SCC)

able apprehension of bias, even if the decision maker has completely disregarded these circumstances. However, in my opinion and for the reasons which follow, the danger that full board meetings may fetter the judicial independence of panel members is not sufficiently present to give rise to a reasonable apprehension of bias or lack of independence within the meaning of the test stated by this Court in *Committee for Justice and Liberty v. National Energy Board*, [1978] 1 S.C.R. 369, at p. 394, reaffirmed and applied as the criteria for judicial independence in *Valente v. The Queen*, *supra*, at p. 684:

> ... the apprehension of bias must be a reasonable one, held by reasonable and right minded persons, applying themselves to the question and obtaining thereon the required information. In the words of the Court of Appeal, that test is "what would an informed person, viewing the matter realistically and practically—and having thought the matter through—concluded ...."

See also p. 689.

A full board meeting set up in accordance with the procedure described by Chairman Adams is not imposed: it is called at the request of the hearing panel or any of its members. It is carefully designed to foster discussion without trying to verify whether a consensus has been reached: no minutes are kept, no votes are taken, attendance is voluntary and presence at the full board meeting is not recorded. The decision is left entirely to the hearing panel. It cannot be said that this practice is meant to convey to panel members the message that the opinion of the majority of the Board members present has to be followed. On the other hand, it is true that a consensus can be measured without a vote and that this institutionalization of the consultation process carries with it a potential for greater influence on the panel members. However, the criteria for independence is not absence of influence but rather the freedom to decide according to one's own conscience and opinions. In fact, the record shows that each panel member held to his own opinion since Mr. Wightman dissented and Mr. Lee only concurred in part with Chairman Adams. It is my opinion, in agreement with the Court of Appeal, that the full board

d'injustice, par exemple, quand il existe une crainte raisonnable de partialité, même si le décideur n'a pas du tout tenu compte de ces circonstances. Cependant, pour les motifs ci-après, je suis d'avis que le risque que les réunions plénières de la Commission diminuent l'indépendance judiciaire des membres du banc n'est pas suffisant pour susciter une crainte raisonnable de partialité ou d'un manque d'indépendance au sens du critère formulé par notre Cour dans l'arrêt *Committee for Justice and Liberty c. Office national de l'énergie*, [1978] 1 R.C.S. 369, à la p. 394, lequel a été confirmé et appliqué à titre de critère d'indépendance judiciaire dans l'arrêt *Valente c. La Reine*, précité, à la p. 684:

> ... la crainte de partialité doit être raisonnable et le fait d'une personne sensée et raisonnable qui se poserait elle-même la question et prendrait les renseignements nécessaires à ce sujet. Selon les termes de la Cour d'appel, ce critère consiste à se demander «à quelle conclusion en arriverait une personne bien renseignée qui étudierait la question en profondeur, de façon réaliste et pratique . . .»

Voir aussi à la p. 689.

La réunion plénière de la Commission tenue conformément à la procédure décrite par le président Adams n'est pas imposée, elle est convoquée à la demande du banc qui a entendu l'affaire ou par l'un de ses membres. Elle est soigneusement organisée pour favoriser la discussion sans qu'il y ait tentative de vérifier s'il y a consensus; il n'est pas dressé de procès-verbal, le vote n'y est pas pris, la présence à la réunion est facultative et les présences n'y sont pas prises. La décision revient entièrement au banc qui a entendu l'affaire. On ne saurait dire que cette pratique vise à signaler aux membres du banc qu'il faut se conformer à l'avis de la majorité des commissaires présents. Par ailleurs, il est vrai qu'il est possible de vérifier s'il y a consensus sans recourir à un vote et que cette institutionnalisation du processus de consultation comporte un risque d'influence plus prononcée sur les membres du banc. Cependant, le critère de l'indépendance est non pas l'absence d'influence, mais plutôt la liberté de décider selon ses propres conscience et opinions. En fait, le dossier démontre que chacun des membres du banc s'en est tenu à son opinion puisque M. Wightman a été dissident et que M. Lee n'a souscrit qu'en partie à l'avis du

1990 CanLII 132 (SCC)

meeting was an important element of a legitimate consultation process and not a participation in the decision of persons who had not heard the parties. The Board's practice of holding full board meetings or the full board meeting held on September 23, 1983 would not be perceived by an informed person viewing the matter realistically and practically—and having thought the matter through—as having breached his right to a decision reached by an independent tribunal thereby infringing this principle of natural justice.

(d) *Full Board Meetings and the Audi Alteram Partem Rule*

Full board meetings held on an *ex parte* basis do entail some disadvantages from the point of view of the *audi alteram partem* rule because the parties are not aware of what is said at those meetings and do not have an opportunity to reply to new arguments made by the persons present at the meeting. In addition, there is always the danger that the persons present at the meeting may discuss the evidence.

For the purpose of the application of the *audi alteram partem* rule, a distinction must be drawn between discussions on factual matters and discussions on legal or policy issues. In every decision, panel members must determine what the facts are, what legal standards apply to those facts and, finally, they must assess the evidence in accordance with these legal standards. In this case, for example, the Board had to determine which events led to the decision to close the Hamilton plant and, in turn, decide whether the appellant had failed to bargain in good faith by not informing of an impending plant closing either on the basis that a "*de facto* decision" had been taken or on some other basis. The determination and assessment of facts are delicate tasks which turn on the credibility of the witnesses and an overall evaluation of the relevancy of all the information presented as evidence. As a general rule, these tasks cannot be properly performed by persons who have not heard all the evidence and the rules of natural justice do not allow such persons to vote on the result. Their

président Adams. J'estime, à l'instar de la Cour d'appel, que la réunion plénière de la Commission a constitué un élément important du processus légitime de consultation, mais non une participation à la décision par des personnes qui n'avaient pas entendu les parties. Une personne bien renseignée qui étudierait la question en profondeur, de façon réaliste et pratique, ne percevrait pas la pratique de la Commission de tenir des réunions plénières ou la réunion plénière de la Commission tenue le 23 septembre 1983 comme une atteinte à son droit d'obtenir une décision d'un tribunal indépendant et ainsi comme une violation de ce principe de justice naturelle.

d) *Les réunions plénières de la Commission et la règle audi alteram partem*

Les réunions plénières de la Commission tenues *ex parte* comportent certains inconvénients sur le plan de la règle *audi alteram partem* parce que les parties ne savent pas ce qui a été dit à ces réunions et n'ont pas la possibilité de répliquer aux nouveaux arguments soumis par les personnes qui y ont assisté. De plus, il y a toujours le risque que les personnes présentes à la réunion discutent de la preuve.

Aux fins de l'application de la règle *audi alteram partem*, il faut distinguer les discussions portant sur des questions de fait et celles portant sur des questions de droit ou de politique. Dans toute décision, les membres du banc doivent établir les faits, les normes juridiques à appliquer à ces faits et, enfin, il doivent évaluer la preuve conformément à ces normes juridiques. En l'espèce, par exemple, la Commission devait déterminer quels événements avaient donné lieu à la décision de fermer l'usine de Hamilton, pour ensuite décider si l'appelante avait omis de négocier de bonne foi en n'informant pas de la fermeture prochaine de l'usine, pour le motif qu'«une décision *de facto*» avait été prise en ce sens ou pour un autre motif. La détermination et l'évaluation des faits sont des tâches délicates qui dépendent de la crédibilité des témoins et de l'évaluation globale de la pertinence de tous les renseignements présentés en preuve. En général, les personnes qui n'ont pas entendu toute la preuve ne sont pas à même de bien remplir cette tâche et les règles de justice naturelle ne permet-

1990 CanLII 132 (SCC)

participation in discussions dealing with such factual issues is less problematic when there is no participation in the final decision. However, I am of the view that generally such discussions constitute a breach of the rules of natural justice because they allow persons other than the parties to make representations on factual issues when they have not heard the evidence.

It is already recognized that no new evidence may be presented to panel members in the absence of the parties: *Kane v. Board of Governors of the University of British Columbia*, *supra*, at pp. 1113-14. The appellant does not claim that new evidence was adduced at the meeting and the record does not disclose any such breach of the *audi alteram partem* rule. The defined practice of the Board at full board meetings is to discuss policy issues on the basis of the facts as they were determined by the panel. The benefits to be derived from the proper use of this consultation process must not be denied because of the mere concern that this established practice might be disregarded, in the absence of any evidence that this has occurred. In this case, the record contains no evidence that factual issues were discussed by the Board at the September 23, 1983 meeting.

In his reasons for judgment, Rosenberg J. has raised the issue of whether discussions on policy issues can be completely divorced from the factual findings, at p. 492:

> In this case there was a minority report. Although the chairman states that the facts in the draft decision were taken as given there is no evidence before us to indicate whether the facts referred to those in the majority report or the minority report or both. Also, without in any way doubting the sincerity and integrity of the chairman in making such a statement, it is not practical to have all of the facts decided except against a background of determination of the principles of law involved. For example, a finding that Consolidated-Bathurst was seriously considering closing the Hamilton plant is of no significance if the requirement is that the failure to bargain in good faith must be a *de facto* decision to close. Accordingly,

tent pas à ces personnes de voter sur l'issue du litige. Leur participation aux discussions portant sur ces questions de fait pose moins de problèmes quand elles ne participent pas à la décision finale. Cependant, j'estime que ces discussions violent généralement les règles de justice naturelle parce qu'elles permettent à des personnes qui ne sont pas parties au litige de faire des observations sur des questions de fait alors qu'elles n'ont pas entendu la preuve.

Il est déjà admis que les membres d'un banc ne peuvent être saisis de nouveaux éléments de preuve en l'absence des parties: *Kane c. Conseil d'administration de l'Université de la Colombie-Britannique*, précité, aux pp. 1113 et 1114. L'appelante ne soutient pas que de nouveaux éléments de preuve ont été soumis à la réunion et le dossier ne révèle aucune violation de la règle *audi alteram partem* pour ce motif. La pratique définie par la Commission lors de ces réunions plénières consiste précisément à discuter des questions de politique en tenant pour avérés les faits établis par le banc. Il ne faut pas refuser les avantages que l'utilisation valable de ce processus de consultation peut procurer, uniquement à cause de la simple crainte que cette pratique établie ne soit pas respectée, en l'absence de toute preuve que la chose s'est produite. En l'espèce, le dossier ne contient aucune preuve que des questions de fait ont été discutées par la Commission lors de la réunion du 23 septembre 1983.

Dans ses motifs de jugement, le juge Rosenberg soulève la question de savoir si les discussions de questions de politique peuvent être totalement séparées des constatations de fait, à la p. 492:

> [TRADUCTION] En l'espèce, il y a eu des motifs minoritaires. Bien que le président affirme que les faits mentionnés dans l'avant-projet de décision ont été tenus pour avérés, rien dans la preuve qui nous est soumise n'indique si les faits se rapportaient à ceux des motifs de la majorité, de la minorité ou des deux à la fois. De plus, même si je ne doute nullement de la bonne foi et de l'intégrité du président au moment où il affirme cela, il n'est pas pratique de déterminer tous les faits si ce n'est en fonction de la détermination des principes de droit applicables. Par exemple, la constatation que Consolidated-Bathurst envisageait sérieusement de fermer l'usine de Hamilton n'a pas d'importance s'il est nécessaire que

1990 CanLII 132 (SCC)

until the board decides what the test is the findings of fact cannot be finalized.

With respect, I must disagree with Rosenberg J. if he suggests that it is not practical to discuss policy issues against the factual background provided by the panel.

It is true that the evidence cannot always be assessed in a final manner until the appropriate legal test has been chosen by the panel and until all the members of the panel have evaluated the credibility of each witness. However, it is possible to discuss the policy issues arising from the body of evidence filed before the panel even though this evidence may give rise to a wide variety of factual conclusions. In this case, Mr. Wightman seemed to disagree with Chairman Adams with respect to the credibility of the testimonies of some of the appellant's witnesses. While this might be relevant to Mr. Wightman's conclusions, it was nevertheless possible to outline the policy issues at stake in this case from the summary of the facts prepared by Chairman Adams. In turn, it was possible to outline the various tests which could be adopted by the panel and to discuss their appropriateness from a policy point of view. These discussions can be segregated from the factual decisions which will determine the outcome of the case once a test is adopted by the panel. The purpose of the policy discussions is not to determine which of the parties will eventually win the case but rather to outline the various legal standards which may be adopted by the Board and discuss their relative value.

Policy issues must be approached in a different manner because they have, by definition, an impact which goes beyond the resolution of the dispute between the parties. While they are adopted in a factual context, they are an expression of principle or standards akin to law. Since these issues involve the consideration of statutes, past decisions and perceived social needs, the impact of a policy decision by the Board is, to a certain extent, independent from the immediate interests

l'omission de négocier de bonne foi découle d'une décision *de facto* de fermer l'usine. En conséquence, la constatation des faits ne peut être parachevée avant que la Commission ne décide du critère applicable.

En toute déférence, je ne puis souscrire à l'avis du juge Rosenberg s'il veut dire qu'il n'est pas pratique de discuter des questions de politique en fonction de la base factuelle fournie par le banc.

Il est vrai qu'il n'est pas toujours possible d'évaluer la preuve de façon définitive avant que le banc n'ait choisi le critère juridique approprié et avant que tous les membres du banc n'aient évalué la crédibilité de chaque témoin. Cependant, il est possible de débattre des questions de politique que soulève la preuve soumise au banc même si cette preuve peut entraîner une grande variété de conclusions sur les faits. En l'espèce, M. Wightman semble avoir différé d'opinion avec le président Adams sur la crédibilité des dépositions de certains témoins de l'appelante. Bien que cela puisse être pertinent relativement aux conclusions de M. Wightman, il était néanmoins possible d'énoncer les questions de politique en cause dans cette affaire à partir du résumé des faits préparé par le président Adams. Puis, il était possible d'exposer les différents critères que le banc pouvait adopter et de discuter de leur pertinence sur le plan des politiques. Il est possible de dissocier ces discussions des décisions sur les faits qui déterminent l'issue du litige après que le banc a adopté un critère. Les discussions sur les politiques n'ont pas pour objet de décider quelle partie aura finalement gain de cause, mais elles ont pour objet d'exposer les différents critères juridiques que la Commission peut adopter et de débattre leur valeur relative.

Il faut aborder les questions de politique de manière différente parce qu'elles ont, par définition, des conséquences qui vont au-delà du règlement du litige particulier entre les parties. Bien qu'elles découlent de faits précis, elles constituent l'expression d'un principe ou de normes apparentées au droit. Puisque ces questions font appel à l'analyse des lois, des décisions antérieures et des besoins sociaux qui sont perçus, les conséquences d'une décision de politique prise par la Commis-

1990 CanLII 132 (SCC)

of the parties even though it has an effect on the outcome of the complaint.

I have already outlined the reasons which justify discussions between panel members and other members of the Board. It is now necessary to consider the conditions under which full board meetings must be held in order to abide by the *audi alteram partem* rule. In this respect, the only possible breach of this rule arises where a new policy or a new argument is proposed at a full board meeting and a decision is rendered on the basis of this policy or argument without giving the parties an opportunity to respond.

I agree with Cory J.A. (as he then was) that the parties must be informed of any new ground on which they have not made any representations. In such a case, the parties must be given a reasonable opportunity to respond and the calling of a supplementary hearing may be appropriate. The decision to call such a hearing is left to the Board as master of its own procedure: s. 102(13) of the *Labour Relations Act*. However, this is not a case where a new policy undisclosed or unknown to the parties was introduced or applied. The extent of the obligation of an employer engaged in collective bargaining to disclose information regarding the possibility of a plant closing was at the very heart of the debate from the outset and had been the subject of a policy decision previously in the *Westinghouse* case. The parties had every opportunity to deal with the matter at the hearing and indeed presented diverging proposals for modifying the policy. There is no evidence that any new grounds were put forward at the meeting and each of the reasons rendered by Chairman Adams and Messrs. Wightman and Lee simply adopts one of the arguments presented by the parties and summarized at pp. 1427-30 of Chairman Adams' decision. Though the reasons are expressed in great detail, the appellant does not identify any of them as being new nor does it contend that it did not have an opportunity to be heard or to deal with them.

sion ne dépendent pas, dans une certaine mesure, de l'intérêt immédiat des parties, même si elles peuvent avoir un effet sur l'issue de la plainte.

J'ai déjà exposé les motifs qui justifient les membres d'un banc d'avoir des discussions avec les autres commissaires. Il faut maintenant examiner les conditions dans lesquelles les réunions plénières de la Commission doivent être tenues afin de respecter la règle *audi alteram partem*. À cet égard, la seule violation possible de la règle a lieu quand on propose une nouvelle politique ou un nouvel argument à une réunion plénière de la Commission et qu'une décision fondée sur cette politique ou cet argument est rendue sans qu'on accorde aux parties la possibilité de répliquer.

Je souscris à l'avis du juge Cory (alors juge de la Cour d'appel) qu'il faut aviser les parties de tout nouveau moyen à propos duquel elles n'ont pas soumis de plaidoiries. Dans un tel cas, il faut accorder aux parties une possibilité raisonnable de répliquer et la convocation d'une audience supplémentaire peut se révéler appropriée. La décision de convoquer une telle audience revient à la Commission en tant que maîtresse de sa propre procédure: par. 102(3) de la *Loi sur les relations de travail*. Cependant, en l'espèce, il n'y a eu ni présentation ni application d'une nouvelle politique qui n'avait pas été divulguée aux parties ou que celles-ci ne connaissaient pas. La portée de l'obligation d'un employeur qui négocie collectivement de divulguer les renseignements relatifs à la fermeture possible d'une usine était au cœur même du débat depuis le début et avait déjà fait l'objet d'une décision de politique dans l'affaire *Westinghouse*. Les parties avaient eu toutes les chances possibles de traiter ce sujet à l'audience et avaient même soumis des propositions contradictoires de modification de la politique. Il n'y a aucune preuve que de nouveaux moyens ont été présentés lors de la réunion et les motifs de chacun des trois commissaires, le président Adams et MM. Wightman et Lee, ne font qu'adopter l'un des arguments soumis par les parties que le président Adams résume aux pp. 1427 à 1430 de sa décision. Bien que les motifs soient très élaborés, l'appelante n'en désigne aucune partie comme nouvelle, ni ne soutient qu'elle n'a pas eu la possibilité de se faire entendre ou d'en traiter.

1990 CanLII 132 (SCC)

Since its earliest development, the essence of the *audi alteram partem* rule has been to give the parties a "fair opportunity of answering the case against [them]": Evans, *de Smith's Judicial Review of Administrative Action, supra,* at p. 158. It is true that on factual matters the parties must be given a "fair opportunity ... for correcting or contradicting any relevant statement prejudicial to their view": *Board of Education v. Rice*, [1911] A.C. 179, at p. 182; see also *Local Government Board v. Arlidge*, [1915] A.C. 120, at pp. 133 and 141, and *Kane v. Board of Governors of the University of British Columbia*, *supra*, at p. 1113. However, the rule with respect to legal or policy arguments not raising issues of fact is somewhat more lenient because the parties only have the right to state their case adequately and to answer contrary arguments. This right does not encompass the right to repeat arguments every time the panel convenes to discuss the case. For obvious practical reasons, superior courts, in particular courts of appeal, do not have to call back the parties every time an argument is discredited by a member of the panel and it would be anomalous to require more of administrative tribunals through the rules of natural justice. Indeed, a reason for their very existence is the specialized knowledge and expertise which they are expected to apply.

I therefore conclude that the consultation process described by Chairman Adams in his reconsideration decision does not violate the *audi alteram partem* rule provided that factual issues are not discussed at a full board meeting and that the parties are given a reasonable opportunity to respond to any new ground arising from such a meeting. In this case, an important policy issue, namely the validity of the test adopted in the *Westinghouse* case, was at stake and the Board was entitled to call a full board meeting to discuss it. There is no evidence that any other issues were discussed or indeed that any other arguments were raised at that meeting and it follows that the appellant has failed to prove that it has been the

Depuis sa première formulation, la règle *audi alteram partem* vise essentiellement à donner aux parties une [TRADUCTION] «possibilité raisonnable de répliquer à la preuve présentée contre [elles]»: Evans, *de Smith's Judicial Review of Administrative Action*, précité, à la p. 158. Il est vrai que relativement aux questions de fait, les parties doivent obtenir une [TRADUCTION] «possibilité raisonnable [...] de corriger ou de contredire tout énoncé pertinent qui nuit à leur point de vue»: *Board of Education v. Rice*, [1911] A.C. 179, à la p. 182; voir également *Local Government Board v. Arlidge*, [1915] A.C. 120, aux pp. 133 et 141, et *Kane c. Conseil d'administration de l'Université de la Colombie-Britannique*, précité, à la p. 1113. Cependant, la règle relative aux arguments juridiques ou de politique qui ne soulèvent pas des questions de fait est un peu moins sévère puisque les parties n'ont que le droit de présenter leur cause adéquatement et de répondre aux arguments qui leur sont défavorables. Ce droit n'inclut pas celui de reprendre les plaidoiries chaque fois que le banc se réunit pour débattre l'affaire. Pour des raisons pratiques manifestes, les cours supérieures, et en particulier les cours d'appel, ne sont pas tenues de convoquer de nouveau les parties chaque fois qu'un membre du banc infirme un argument et il serait anormal d'être plus exigeant envers les tribunaux administratifs en raison des règles de justice naturelle. En réalité, une de leurs raisons d'être est justement leurs connaissances et compétences spécialisées qu'on souhaite les voir appliquer.

Je conclus donc que le processus de consultation décrit par le président Adams dans sa décision relative à la demande de réexamen ne viole pas la règle *audi alteram partem* pourvu que les questions de fait ne soient pas discutées à la réunion plénière de la Commission et que les parties aient une possibilité raisonnable de répliquer à tout nouveau moyen soulevé à cette réunion. En l'espèce, une importante question de politique était en jeu, savoir la validité du critère adopté dans la décision *Westinghouse* et la Commission avait le droit de convoquer une réunion plénière pour en débattre. Il n'y a aucune preuve qu'on ait discuté d'autres sujets ou même qu'on ait soulevé quelque autre argument lors de cette réunion. Il s'ensuit que

1990 CanLII 132 (SCC)

victim of any violation of the *audi alteram partem* rule. Indeed, the decision itself indicates that it rests on considerations known to the parties upon which they had full opportunity to be heard.

IV—Conclusion

The institutionalization of the consultation process adopted by the Board provides a framework within which the experience of the chairman, vice-chairmen and members of the Board can be shared to improve the overall quality of its decisions. Although respect for the judicial independence of Board members will impede total coherence in decision making, the Board through this consultation process seeks to avoid inadvertent contradictory results and to achieve the highest degree of coherence possible under these circumstances. An institutionalized consultation process will not necessarily lead Board members to reach a consensus but it provides a forum where such a consensus can be reached freely as a result of thoughtful discussion on the issues at hand.

The advantages of an institutionalized consultation process are obvious and I cannot agree with the proposition that this practice necessarily conflicts with the rules of natural justice. The rules of natural justice must have the flexibility required to take into account the institutional pressures faced by modern administrative tribunals as well as the risks inherent in such a practice. In this respect, I adopt the words of Professors Blache and Comtois in "La décision institutionnelle", *supra*, at p. 708:

> [TRANSLATION] The institutionalizing of decisions exists in our law and appears to be there to stay. The problem is thus not whether institutional decisions should be sanctioned, but to organize the process in such a way as to limit its dangers. There is nothing revolutionary in this approach: it falls naturally into the tradition of English and Canadian jurisprudence that the rules of natural justice should be flexibly interpreted.

l'appelante n'a pas prouvé qu'elle ait été victime d'une violation quelconque de la règle *audi alteram partem*. En réalité, la décision elle-même montre qu'elle repose sur des considérations connues des parties et au sujet desquelles elles avaient eu tout le loisir de se faire entendre.

IV—Conclusion

L'institutionnalisation du processus de consultation adopté par la Commission fournit un cadre qui permet au président, aux vice-présidents et aux commissaires de mettre leur expérience en commun et d'améliorer la qualité globale de leurs décisions. Quoique le respect de l'indépendance judiciaire des commissaires empêche d'obtenir la cohérence parfaite des décisions de la Commission, celle-ci cherche, par ce processus de consultation à éviter les décisions contradictoires rendues par inadvertance et à atteindre le niveau de cohérence le plus élevé possible dans les circonstances. Un processus institutionnalisé de consultation ne permet pas nécessairement aux commissaires de parvenir à un consensus, mais il fournit une tribune où il est possible de parvenir librement à ce consensus suite à une discussion réfléchie des questions soulevées.

Les avantages d'un processus institutionnalisé de consultation sont manifestes et je ne puis souscrire à la proposition que cette pratique contrevient forcément aux règles de justice naturelle. Les règles de justice naturelle doivent avoir la souplesse nécessaire pour tenir compte à la fois des pressions institutionnelles qui s'exercent sur les tribunaux administratifs modernes et des risques inhérents à cette pratique. À cet égard, je fais miens les propos tenus par les professeurs Blache et Comtois dans «La décision institutionnelle» précité, à la p. 708:

> Le phénomène d'institutionnalisation de la décision existe dans notre droit et il semble qu'il y soit pour rester. Le problème qui se pose n'est donc pas de savoir si la décision institutionnelle devrait ou non être autorisée, mais d'articuler des modalités de mise en œuvre qui permettent d'en limiter les risques. Il s'agit là d'une approche qui n'a rien de révolutionnaire et s'inscrit dans la tradition jurisprudentielle anglaise et canadienne selon laquelle il faut interpréter avec flexibilité les règles de justice naturelle.

1990 CanLII 132 (SCC)

The consultation process adopted by the Board formally recognizes the disadvantages inherent in full board meetings, namely that the judicial independence of the panel members may be fettered by such a practice and that the parties do not have the opportunity to respond to all the arguments raised at the meeting. The safeguards attached to this consultation process are, in my opinion, sufficient to allay any fear of violations of the rules of natural justice provided as well that the parties be advised of any new evidence or grounds and given an opportunity to respond. The balance so achieved between the rights of the parties and the institutional pressures the Board faces are consistent with the nature and purpose of the rules of natural justice.

For these reasons, I would dismiss the appeal with costs.

Appeal dismissed with costs, LAMER *and* SOPINKA JJ. *dissenting.*

Solicitors for the appellant: Beard, Winter, Toronto.

Solicitors for the respondent the International Woodworkers of America, Local 2-69: Cavalluzzo, Hayes & Lennon, Toronto.

Solicitors for the respondent Ontario Labour Relations Board: Gowling & Henderson, Ottawa.

Le processus de consultation adopté par la Commission reconnaît formellement les inconvénients inhérents aux réunions plénières de la Commission, savoir que l'indépendance judiciaire des membres d'un banc peut être diminuée par une telle pratique et que les parties n'ont pas la possibilité de répliquer à tous les arguments soulevés au cours de ces réunions. Les garanties dont est assorti ce processus de consultation sont, à mon avis, suffisantes pour dissiper toute crainte de violation des règles de justice naturelle pourvu également que les parties soient informées de tout nouvel élément de preuve ou de tout nouveau moyen et qu'elles aient la possibilité d'y répondre. L'équilibre ainsi réalisé entre les droits des parties et les pressions institutionnelles qui s'exercent sur la Commission sont compatibles avec la nature et l'objet des règles de justice naturelle.

Pour ces motifs, je suis d'avis de rejeter le pourvoi avec dépens.

Pourvoi rejeté avec dépens, les juges LAMER *et* SOPINKA *sont dissidents.*

Procureurs de l'appelante: Beard, Winter, Toronto.

Procureurs de l'intimé le Syndicat international des travailleurs du bois d'Amérique, section locale 2-69: Cavalluzzo, Hayes & Lennon, Toronto.

Procureurs de l'intimée la Commission des relations de travail de l'Ontario: Gowling & Henderson, Ottawa.

1990 CanLII 132 (SCC)

DECISION

IN THE MATTER OF an application by New Brunswick Power Corporation pursuant to the *Electricity Act*, S.N.B. 2013, c.7, for the approval of a Class Cost Allocation Study methodology.

(Matter No. 271)

May 13, 2016

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

IN THE MATTER OF an application by New Brunswick Power Corporation pursuant to the *Electricity Act*, S.N.B. 2013, c.7, for the approval of a Class Cost Allocation Study methodology. (Matter No. 271)

NEW BRUNSWICK ENERGY AND UTILITIES BOARD:

Chairman:	Raymond Gorman, Q.C.
Vice-Chairperson:	François Beaulieu
Members:	Michael Costello
	Patrick Ervin
	John Patrick Herron
Counsel:	Ellen Desmond, Q.C.
Chief Clerk:	Kathleen Mitchell

APPLICANT:

New Brunswick Power Corporation:	John Furey

INTERVENERS:

Enbridge Gas New Brunswick Inc.:	Paul Volpé
J. D. Irving, Limited:	Christopher Stewart
New Clear Free Solutions:	Chris Rouse
Public Intervener:	Heather Black
Utilities Municipal:	Scott Stoll

A. Introduction

1. Background

[1] New Brunswick Power Corporation (NB Power) filed an application with the New Brunswick Energy and Utilities Board (Board) on October 17, 2014 (Application), seeking approval of a Class Cost Allocation Study (CCAS) methodology. The Application represents the first occasion, since 1992, that a CCAS methodology has been considered for approval in relation to NB Power as an integrated utility.

[2] In the Application NB Power indicated that, until the Board has approved a CCAS methodology, any proposed rate increase would be uniform across all rate classes.

[3] The hearing of the Application had been initially scheduled for April 20, 2015. On March 4, the Board received a letter from counsel for Utilities Municipal (UM letter), which indicated that there was a need for more evidence from NB Power.

[4] In response to the UM letter, a procedural conference was convened. At that time, the Board was informed that there was a consensus that further and better evidence was required in order for the cost allocation issues to be fully considered.

[5] Following the procedural conference, NB Power filed a Notice of Motion, requesting that the Board adjourn the CCAS hearing in order to prepare additional evidence. The Board granted the requested adjournment, pending receipt of further studies. The Board issued an Order setting out conditions for the adjournment (Adjournment Order).

[6] The Adjournment Order required NB Power to carry out seven additional studies, five of which were to be filed in evidence for this Application. The remaining two studies are to be filed as part of NB Power's general rate application for 2017/18.

[7] All five studies were filed by the end of October 2015. NB Power filed a newly proposed 2015/16 CCAS model with supporting evidence prepared by Mr. Todd of Elenchus Research Associates, Inc. (Elenchus Report). The hearing commenced on February 1, 2016.

2. The Purpose and Nature of a Class Cost Allocation Study

[8] The *Electricity Act* (Act) requires the Board to approve or fix just and reasonable rates that NB Power charges for its services. In making this determination, there are a number of considerations that the Board takes into account. Some are prescribed by the Act, while others

are based on the Board's consideration of the public interest. There are also a number of generally accepted regulatory principles that assist the Board in this task.

[9] A widely accepted regulatory principle is that a utility's costs should generally be shared between customer classes on the basis of cost causation. A CCAS is a method by which a utility's revenue requirement is apportioned between rate classes. On a system-wide basis, the revenues to be obtained through approved rates from all customer classes should be equal to the sum of the cost apportionments for each customer class. To state this another way, the system revenue to cost ratio should equal 1.0 (or unity).

[10] In theory, a revenue to cost ratio of 1.0 should apply for each class. There may be valid reasons, however, why rates will produce projected revenues higher than allocated costs for some classes, offset by rates for other classes that will produce revenues lower than allocated costs. In the decision of December 21, 2005, the New Brunswick Board of Commissioners of Public Utilities (PUB) indicated that "… a long term target range of .95 to 1.05 for the revenue to cost ratio for each class is reasonable." This continues to be the view of the Board.

[11] In addition to allocating costs, a CCAS is essential in the establishment of just and reasonable rates. By identifying the sources or nature of costs allocated to customer classes, rates can be set to provide effective price signals to the customer, which can shape consumption patterns to promote economically efficient use of electricity.

[12] A CCAS generally follows a three-step process. First, costs are functionalized according to the broad investment and operational areas of the utility. In the case of electric utilities, the main functional areas are production (also referred to as generation), transmission, and distribution.

[13] Second, the functionalized costs are classified according to how those costs are incurred. The three principal classifications are (a) demand costs, which vary with the megawatt demand imposed on the system by the customer; (b) energy costs, which vary with the amount of energy, or megawatt hours (MWh) provided to the customer in any period; and (c) customer costs, which are related to the number of customers served.

[14] Third, the costs are allocated to the customer classes. This step is intended to fairly allocate costs to customers, based on the principle of cost causation.

B. Issues

[15] This decision will address the following issues:

1. What is the appropriate methodology for allocating fixed production costs given the circumstances of NB Power's system and loads?

2. Should the allocation of the demand related portion of fixed production costs be based on a modified peak and average methodology, using the average class contributions to three monthly system peaks, rather than a single system peak demand?

3. Should natural gas purchased power agreement costs be classified as 100% energy, or should they be classified in the same way as other fixed generation costs?

4. Should purchase power agreement costs related to wind power be classified as 100% energy, or should a portion of wind costs be classified as demand?

5. Should combustion turbine fixed production costs be allocated in the same way as other NB Power production assets, or should they be sub-functionalized and classified as 100% demand?

6. Should transmission costs continue to be classified as 100% demand, or should such costs be allocated in the same manner as fixed production costs? Secondly, should the costs of sole use transmission facilities be directly allocated to the rate class of customers served by such facilities?

7. Should the Board consider introducing seasonality, based solely on the allocation of energy related costs, and should production costs be seasonally allocated in the absence of seasonal rates?

8. Should energy and demand loss factors, associated with distribution, be incorporated into the CCAS methodology?

C. Analysis

1. Methodology for Allocation of Fixed Production Costs

[16] NB Power's historic method of allocating fixed production costs has been to classify such costs as 40% demand and 60% energy, as deemed by the PUB. Although this allocation approximates the outcome of the "Peaker Credit" methodology, the PUB made it clear in 2005 that it did not endorse that method.

[17] NB Power had originally proposed retaining the 40/60 split to classify and allocate fixed production costs. Changes in the generation mix would have resulted in a 25/75 demand/energy

split, if the Peaker Credit method was applied. NB Power proposed retaining the 40/60 split to avoid a large shift in allocation, while seeking an alternative method.

[18] In accordance with the Adjournment Order, NB Power filed a second report from Concentric Energy Advisors, Inc. (Concentric) dated May 13, 2015, which considered several generation cost classification and allocation methods (Study #1). It recommended against the continued use of the Peaker Credit method, citing "…potential problems with its continued use as the system's generation/power supply mix continues to evolve".

[19] Instead, Concentric advocated using the Average and Excess method. This uses a "load structure approach", which relies on energy load data to determine which loads are serving energy requirements and which are serving demand. The Concentric report acknowledged that NB Power would be undertaking a comprehensive review, however, and that this could result in alternative recommendations.

[20] In preparation for the February hearing, NB Power examined further alternative methodologies. In response to paragraph 7 of the Adjournment Order, NB Power conducted a study (Study #5) which considered capital costs versus fuel costs with respect to generation cost classification (break-even analysis). The break-even analysis is also referred to as a Base and Peak method. The study, as detailed in the Elenchus Report, did not recommend the Base and Peak method since it is based on a generation fleet concept that is not similar to the NB Power fleet and does not reflect the way in which the fleet is used to minimize production costs. None of the parties advocated for this methodology.

[21] NB Power now proposes to adopt the Peak and Average method, as recommended in the Elenchus Report, for the allocation of fixed production costs. This method is similar to the Average and Excess method, in its reliance on load data. The proposed model uses multiple coincident peaks as opposed to a single coincident peak, an issue which is considered later in this decision.

[22] The Elenchus Report outlines the reasons for recommending the Peak and Average method. It acknowledges that, while the Average and Excess method is an acceptable method, the Peak and Average method (as modified by the use of multiple peaks) "…would be more appropriate in light of the comprehensive review" conducted by Elenchus.

[23] A key difference between the two methods is that Peak and Average uses coincident peak to determine peak demand. Average and Excess uses non-coincident peak to arrive at the excess demand over the average and thus recognizes class peak demands at times other than system peak. As demand-related fixed production costs are caused primarily by system peak, it is

Elenchus' view that Peak and Average is more appropriate, particularly with its modification of multiple coincident peaks.

[24] The use of the Peak and Average method was generally supported by all parties. Mr. Drazen, who appeared as the expert witness for J. D. Irving, Limited (JDI), stated in his opening statement that the Peak and Average method is acceptable, subject to the use of a single peak.

[25] Utilities Municipal indicated that it had no preference between the Average and Excess method or the Peak and Average method, and that both are acceptable.

[26] Mr. Whalen, of Multeese Consulting Incorporated, who was engaged as an expert by Board staff, supported the Multiple Coincident Peak and Average method, with the caveat that combustion turbines and wind generation should be treated differently. These issues are reviewed later in this decision.

[27] Mr. Athas, the expert witness engaged by the Public Intervener, testified that he prefers the Peaker Credit method. He believes that the primary reason for NB Power's rejection of Peaker Credit was the resulting shift in the demand/energy mix from 40/60 to 25/75. He states that while the Peak and Average method is simple to compute and reflects changes in system load shape, it does not directly reflect cost causation. Mr. Athas testified that Peaker Credit reflects cost causation and should be continued, but recommends against shifting the 40/60 generation cost allocation at this time.

[28] The Public Intervener submitted that the Peaker Credit method provides valuable information about the effect of NB Power's generation investment decisions, pointing to the significant demand/energy shift when that method was updated in 2014. It was acknowledged, however, that there were valid arguments against the use of Peaker Credit. The Public Intervener ultimately recommended that the Multiple Coincident Peak and Average method, as proposed by NB Power, be adopted for this proceeding.

[29] There are various acceptable methods for allocating fixed production costs. The issue is to determine which method is the most appropriate, given NB Power's system and recognizing the evolving nature of NB Power's generation supply mix. Having considered all of the evidence, the Board finds that a methodology that relies on load-based data, such as the Peak and Average method or the Average and Excess method is the most appropriate.

[30] The Board is also of the view that the allocation of energy costs versus demand costs is best resolved by reference to class coincident peaks, used in the Peak and Average method, rather than non-coincident peaks used in the Average and Excess method.

[31] For these reasons, the Board concludes that the Peak and Average method, as modified below, is the most appropriate method to allocate fixed production costs.

2. Modified Peak and Average Methodology

[32] NB Power proposes a modified version of the Peak and Average method, using multiple coincident peaks, rather than a single coincident peak. This modified version of the Peak and Average method is detailed in Appendix #3 of the Elenchus Report, which was prepared in compliance with the Adjournment Order.

[33] The issue considered here is whether the allocation of the demand related portion of production fixed costs should be based on class contributions to a single system peak demand or, as Elenchus recommends, on the average class contributions to three monthly system peaks, being December, January and February.

[34] Elenchus explains its recommendation to use three coincident peaks. First, it submits that a single coincident peak is based on an over-simplification of the design factors that contributed to the current generation fleet and its utilization. According to the Elenchus Report, NB Power's load duration curves "…make it clear that … there is essentially no distinction between plants required for base load operations and plants required only for peaking."

[35] A second rationale is that an average of several peak hours may be more stable, and better represents class responsibilities for demand related costs. This is because class contributions to the system peak may vary from time to time.

[36] The Elenchus Report also states that the need to rely on estimates of class responsibility for demand requires that these estimates be averaged across multiple peak hours. This, according to Elenchus, may reduce the risk that relying on a single estimation of peak responsibility would result in an inequitable class allocation. The use of multiple peaks would "…reduce the risk the allocation [sic] of costs will reflect extreme circumstances that may occur in the single system peak hour of the year."

[37] The recommended multiple peak demand method uses estimates of class coincident peaks for the month of January (the 1CP demand) plus the class coincident peaks for the months of December and February. The December and February forecast peak demands are within 10% of the January forecast peak demand.

[38] The use of a three coincident peak (3CP) allocator was opposed by JDI. The pre-filed report of Mr. Drazen, dated December 11, 2015, questions the Elenchus rationale for using a 3CP allocator. The report points to NB Power's statements made in its *Load Forecast 2015-2025*, its

Strategic Plan 2011-2040, and its *Integrated Resource Plan 2014*, which emphasize the need for NB Power to plan to meet the maximum energy requirement in a one-hour period of the year, including a reserve capacity.

[39] Mr. Drazen testified that neither extreme risks, nor the actual peak month, is relevant for NB Power's planning purposes, but rather, the magnitude of the peak. He stated that NB Power's peak forecasting and class contributions to the peak are based on a normalized weather temperature of minus 24 Celsius. Thus, the allocator should be based on the forecast system peak demand, regardless of the month.

[40] In its final argument, JDI submitted that the estimates of the coincident peaks for the distribution classes (Residential, General Service I & II and Small Industrial) are only estimates, and that by using three estimates instead of one, "…does more harm than good." In its submission, the purpose of NB Power's use of a 3CP allocator is a "rate smoothing mechanism," and not as a means of allocation on the basis of cost causation.

[41] Utilities Municipal supported the use of multiple coincident peaks. It made the distinction between the use of peak for system planning purposes, and its use for cost allocation purposes. For system planning, the ability to meet the single system peak is the key objective. For allocation purposes, however, determining the magnitude of the system peak is not as important as knowing the relative contributions of the classes to the total under peak conditions. In its submission, an average of several peak hours may be more stable and more representative for determining class responsibilities for demand related costs.

[42] Utilities Municipal also pointed out that using multiple coincident peaks mitigates the impact of anomalies that may exist during any particular system peak. For example, the time of day of a peak may determine whether or not the system load includes street lights. Similarly, the day of the week of a peak may determine whether certain general service or industrial customers are contributing to the demand.

[43] The Board agrees that, for planning purposes, the ability of the system to meet the single hour of system peak load is critical. As Mr. Drazen points out, NB Power emphasizes that need in several of its planning documents.

[44] In terms of class allocations of demand-based fixed production costs however, there are additional considerations. Relative class load responsibilities fluctuate month by month, day by day, and hour by hour. The choice of an appropriate peak demand method must therefore distinguish between what is relevant for system planning purposes, and what is the most appropriate for allocation purposes.

[45] Estimations of coincident peaks for the distribution classes are, by their nature, imperfect proxies for accurate hourly load data. Class load estimations based on a single hour may not be representative of typical class contributions during a system peak. The use of estimations based on the month of January and the two adjacent months with peak demands within 10% of January's peak is, in the Board's view, likely to provide a more reliable result. This approach to using a multiple coincident peak allocator, where the demand peaks are within 10% of the single coincident peak, is a recognized approach in the National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual*.

[46] The Board therefore accepts the use of multiple coincident peaks in conjunction with the Peak and Average method, as proposed by NB Power.

3. Natural Gas Purchased Power Costs

[47] The proposed CCAS classifies all power supplied under purchased power agreements (PPAs) as 100% energy. There are several PPAs, two of which are related to natural gas.

[48] Mr. Whalen, in his December 2015 report, states that the classification of those natural gas PPA costs as 100% energy is inappropriate. Mr. Whalen recommends that they be classified in the same way as other fixed generation costs, using the Multiple Coincident Peak and Average method. This would allocate a portion of such costs as demand.

[49] Mr. Todd responded to this issue during cross-examination. In his analysis, if the natural gas PPA plants were owned and operated by NB Power, the fixed costs would be allocated using the Multiple Peak and Average method, as proposed, and fuel costs would be treated as 100% energy. Mr. Todd acknowledged that the "purest approach" would be to look through the natural gas PPAs and classify the underlying costs accordingly.

[50] NB Power confirmed that the natural gas PPAs are structured in such a way that it is possible to separate fixed capital and OM&A costs from fuel costs, the latter being significantly larger than the former.

[51] NB Power proposed to undertake a detailed review of the natural gas PPAs, to identify the charges that reflect the fixed costs of the facilities, and allocate those costs using the Multiple Coincident Peak and Average method. The fuel charges would continue to be classified as energy. This would treat the PPAs in the same manner as NB Power's own generation. NB Power proposed to implement this change for the cost allocation model for 2016/17 and subsequent years. This proposal, to address Mr. Whalen's recommendation, is the most appropriate approach to this issue.

[52] Accordingly, the Board directs NB Power to review its natural gas PPAs, with a view to identifying the charges that reflect the fixed costs of the facilities, and to allocate those costs using the Multiple Coincident Peak and Average method. The fuel charges components of those agreements will continue to be classified as energy. The CCAS will be revised by NB Power accordingly.

4. Wind Purchased Power Costs

[53] Wind power, which is supplied to NB Power under PPAs, is classified as 100% energy. For planning purposes, NB Power assumes that wind generates an average of 30% of the nameplate capacity.

[54] Mr. Whalen's report recommends that a portion of wind purchase power costs should be classified as demand because there is a high probability that some portion of capacity will be available during times of system peak. He recommends that the demand portion be equal to the 30% nameplate capacity, which is considered as firm for planning purposes. Any generation in excess of such percentage would be classified as energy.

[55] Mr. Drazen agreed with this approach. Utilities Municipal also supported this recommendation.

[56] In his testimony, Mr. Todd emphasized that wind energy is unreliable and non-dispatchable. In his view, wind power does not assist NB Power in meeting capacity requirements, but is simply a source of energy. NB Power argued that, although wind contracts are on a take or pay basis, the supply is not on a firm basis, but rather, only available when conditions permit. NB Power submits that it must supply back-up capacity to wind generation to meet reliability requirements.

[57] Finally, NB Power states that when wind energy is available, it reduces the need for out of province purchases or the need to incur fuel costs, both of which are energy cost savings. Conversely, when wind is not available, energy-related costs are incurred to replace it.

[58] Wind energy is not relied upon to fulfill NB Power's capacity to meet peak loads. Further, the level of its contribution to in-province energy needs during any period will either reduce other energy-related costs or require other energy related costs to be incurred.

[59] The Board determines that wind PPA costs are properly classified as 100% energy related.

5. Combustion Turbine Costs

[60] In NB Power's proposed CCAS, there is no sub-functionalization of its production assets. All fixed costs of production are classified and allocated in accordance with the Multiple Coincident Peak and Average method.

[61] In his report, Mr. Whalen agrees with this approach, except in relation to NB Power's combustion turbine costs. In his view, those fixed costs should be classified as 100% demand related.

[62] In his testimony, Mr. Todd recommended that all of NB Power's generation assets should be treated as one integrated package, for the purposes of applying a methodology to generation costs. In his view, if combustion turbines were to be treated differently, then to be consistent, the allocators for all other forms of generation, or perhaps every plant, should be likewise assessed. In his view, this would be a complex exercise, with little benefit.

[63] NB Power submitted that carving out combustion turbine costs for different treatment would not result in a more equitable allocation of costs or an allocation that is more consistent with cost causality.

[64] Utilities Municipal submitted that Mr. Whalen's recommendation "lacks internal consistency", and that approval of the Multiple Coincident Peak and Average method should be applied to all of the plants forming NB Power's generation fleet.

[65] The Board agrees that the application of the Multiple Coincident Peak and Average method should be consistently applied to all fixed NB Power generation costs. That methodology focuses on load characteristics, and not on the nature or intended use of generation plants. The Board accordingly approves the application of the Multiple Coincident Peak and Average method in relation to all of NB Power's production assets, as proposed.

6. Transmission Costs

[66] The proposed CCAS methodology classifies transmission costs as 100% demand, using a 3CP allocator. Two issues were raised in connection with the proposed method.

[67] First, Mr. Whalen recommends classifying transmission in the same manner as production; that is, both demand and energy, using the Multiple Coincident Peak and Average method. Mr. Whalen submits that NB Power's interconnections are for the purpose of importing and exporting energy. He also cites examples of other Canadian jurisdictions which classify a portion of transmission as energy.

[68] Mr. Larlee, Director of Strategic Planning for NB Power, testified that NB Power's transmission system is designed to meet the peak demand. Reliability was described as a key reason for interconnections with external grids, and that transmission interconnections are not built solely to serve the export market.

[69] Mr. Todd testified that he is not aware of any jurisdiction in which all transmission assets are treated, for allocation purposes, in the same manner as generation plant. He recommends maintaining the current classification of transmission as 100% demand.

[70] In the Board's view, while generation may employ a mix of assets designed and built to meet base loads or peak loads, transmission assets are designed and built to meet peak loads. Although generation plant may have energy constraints, the same is not true of transmission assets, for which capacity is the only constraint. The Board also accepts that reliability is a key reason for interconnections with external grids, and that transmission interconnections are not built solely to serve the export market.

[71] The Board finds that transmission costs should be allocated as 100% demand. The existing method of treating transmission as wholly demand based is more reflective of cost causality than the approach recommended by Mr. Whalen.

[72] The second issue relating to transmission costs was raised by Utilities Municipal. It requested that the Board directly allocate sole use transmission facilities to the rate class of customers served by those facilities.

[73] A total of 1,253 km of transmission lines solely serve wholesale, industrial and distribution customers. Directly allocating the costs associated with those assets would reduce the allocation of transmission costs to the Wholesale rate class by 0.4% ($518,000), which is offset by increased allocations to other classes. It would have no impact on the rounded revenue to cost ratio of any class.

[74] The Board finds that direct allocation is more accurate and better reflects cost causality. NB Power is ordered to directly allocate the costs of sole use transmission assets in the implementation of an approved CCAS methodology.

7. Seasonal Allocation of Costs

[75] Pursuant to the Adjournment Order, Elenchus conducted a study (Study #2), considering the seasonal allocation of production costs to rate classes. Elenchus does not recommend introducing seasonality into the CCAS model at this time. It suggested that seasonal allocation could be considered in the CCAS model for 2017/18 or later, in the event that NB Power considers using

seasonal rates. Accordingly, NB Power does not propose seasonal allocation in the current CCAS application.

[76] Production costs are classified as either demand or energy. In relation to demand costs, Elenchus states that, while monthly coincident peak demands can be estimated by customer class, NB Power does not currently have monthly or seasonal load profiles for all classes.

[77] Energy costs, however, deal with energy consumption, and not peak demand. As a result, Elenchus states that allocating fuel and purchased power on a seasonal basis could be estimated with “reasonable accuracy.” It illustrated a seasonal allocation of such costs, based only on the estimated energy consumption for each class.

[78] Many of the arguments that were advanced during the hearing were with respect to introducing seasonality, based solely on the allocation of energy costs, without considering demand costs. Other arguments were centered on whether seasonal allocation should take place in the absence of corresponding seasonal rates.

[79] The issues are therefore: (a) should the Board consider introducing seasonality, based solely on the allocation of energy costs, and (b) should production costs be seasonally allocated in the absence of seasonal rates.

[80] Dealing with the first issue, NB Power states that the allocation of fuel and purchased power costs on a seasonal basis should not be considered until its impact on all customer classes is known. NB Power suggests that classes that might benefit from seasonal allocation could see that benefit offset, if other time-of-use cost variances were considered. It also suggests that there is a risk that, in implementing the seasonal allocation of energy costs, certain classes whose revenue to cost ratios are currently outside of the range of reasonableness may move further away from that range.

[81] JDI submits that energy costs should be allocated on a seasonal basis now, because they are easily identifiable. JDI relies on the evidence of Mr. Drazen, who recommends the allocation of fuel and purchased power costs on a monthly basis, because of large monthly variations in those costs per MWh. In his opinion, fuel and purchased power costs are much higher in winter (December to March), because of out-of-province purchases and higher cost generation from Coleson Cove and Bayside. Although his recommendation is for monthly allocation, Mr. Drazen stated in his opening statement: “On the issue of monthly versus seasonal allocation, both produce similar results. Both are preferable to the annual method. As between the two, the monthly allocation approach is more accurate. The allocated costs can then be combined into seasonal rates if desired.”

[82] The evidence of Mr. Athas had recommended that the Board adopt the Peaker Credit methodology of cost allocation. He concluded that, using that methodology, costs can be allocated seasonally without seasonal rates. He testified, however, that a seasonal energy cost allocation should not be adopted in the 2016/17 rates if the Board approved the Multiple Coincident Peak and Average method. He stated that "…the step away from cost causation to the 3CP and average methodology would not necessarily warrant the precision of seasonal allocation."

[83] In closing argument the Public Intervener submitted that seasonal allocation of costs should not be implemented as a result of this proceeding, pending NB Power obtaining and reviewing better hourly load data.

[84] The seasonal allocation of costs, including energy costs, is a generally accepted approach. To the extent that seasonal costs are attributed to the appropriate class of customers and the allocation adds precision, there is value in considering this methodology.

[85] The overall impact of seasonal allocation, however, can only be estimated at this time. Seasonal allocation of energy costs is just one dimension of other time-of-use cost drivers. Costs also vary between high and low demands of a typical day and intra-week. There may be other allocations and impacts that should be considered.

[86] The Board accepts in principle that allocation on the basis of seasonality is valid and the allocation of energy costs is possible at this time. More information relating to demand allocation is required, however, prior to making this allocation.

[87] The second issue is whether energy costs should be allocated on a seasonal basis in the absence of seasonal rates.

[88] Elenchus states that the primary purpose of allocating costs on a seasonal basis is to develop seasonal rates, which would serve as a price signal to customers. Elenchus also states that, unless seasonal or time of use rates are contemplated, it does not recommend seasonal allocation of any production costs in the proposed CCAS model. Elenchus suggests that it may be appropriate to revisit the issue of seasonality, in the event that NB Power's program to reduce and shift demand (RASD) leads to a consideration of seasonal rates.

[89] Mr. Larlee testified that, without seasonal rates to reflect seasonal allocation of costs, certain customers within a customer class could be disadvantaged. He referred to the difference between residential customers who are not electrically heated, and those who heat with electricity. With a flat rate structure, the former customers would receive the seasonal cost allocation without any

means to reduce their bill. Residential class customers that do not heat with electricity form 37% of that class.

[90] In contrast, JDI emphasized the need to segregate allocation issues from rate design issues. It submits that the rate impact of allocations on particular customer classes should not inhibit an appropriate allocation that is reflective of cost causation. It submits the allocation can proceed, without the need for seasonal rates and that rate design can be addressed separately.

[91] Utilities Municipal submitted that it is not requesting implementation of seasonal allocation at this time. In its view, seasonal or monthly allocations should not be made without a strategy to "carry costs all the way to the customer level" and a strategy to provide support to customers in responding to the price signal. It also pointed to the impact of seasonality on customer classes that are not homogeneous in terms of the seasonality of their use. Seasonal allocation without a corresponding rate will result, in its submission, in a subsidy by intra-class customers who use less winter energy than the average for that class.

[92] The Board finds that energy related costs should not be allocated at this time, without a corresponding rate design. First, allocating costs without a seasonal rate design that appropriately reflects the allocation, would deny rate classes the price signal that would encourage changes in consumption patterns. This relates to a timing gap between the allocation of fuel and purchased power costs, on one hand, and the implementation of appropriate rates on the other.

[93] Second, the fact that certain rate classes are not homogeneous in their seasonal patterns raises the potential of intra-class unfairness, in the absence of appropriate rate design. This is a matter properly considered in the context of a hearing in which rate design and rates are under consideration.

[94] The Board is of the view that the seasonal allocation of energy related fuel and purchased power costs should be implemented with a corresponding approved rate design. It is preferable that rates are designed in a way that will allow the utility to recover its revenue requirement from each customer class in accordance with its share of allocated costs, and provide customers with appropriate price signals.

[95] NB Power is directed to prepare a proposed strategy for the timely introduction of seasonal allocation of energy and demand production costs together with a corresponding rate design strategy. The proposed strategy is to be filed with the Board by June 1, 2017.

8. Energy and Demand Loss Factors

[96] The Adjournment Order required NB Power to conduct a study, updating the energy and demand loss factors associated with distribution components, and to include a recommendation as to whether and how such an update could be incorporated in a CCAS methodology. This study (Study #4) was filed in this matter as part of the Elenchus Report.

[97] Elenchus recommends annual updates of the energy and demand loss factors for the primary distribution circuits, distribution transformers and the secondary distribution circuits, and that the updated loss factors be implemented for the 2016/17 and 2017/18 CCAS models. None of the parties disagreed with this recommendation.

[98] The Board directs that NB Power prepare an update of the energy and demand loss factors for the primary distribution circuits, distribution transformers and the secondary distribution circuits, to be incorporated as part of the CCAS methodology. The Board further directs NB Power to prepare annual updates of such loss factors, to be incorporated in each subsequent general rate application.

D. Conclusion

[99] The Board approves the CCAS model as proposed by NB Power, subject to those elements modified by the Board in this decision, namely:

a) The fixed cost portions of NB Power’s natural gas PPAs will be allocated using the approved Multiple Coincident Peak and Average method. The fuel charges components of those contracts would continue to be classified as energy.

b) NB Power will directly allocate the costs of sole use transmission assets.

c) Updated energy and demand loss factors for the primary distribution circuits, distribution transformers and the secondary distribution circuits, will be incorporated as part of the CCAS methodology.

[100] NB Power is directed to file a revised CCAS model, incorporating the changes arising from this decision in its 2017/18 general rate application.

Dated in Saint John, New Brunswick, this 13th day of May, 2016.

Raymond Gorman, Q.C.
Chairman

François Beaulieu
Vice-Chairperson

Michael Costello
Member

Patrick Ervin
Member

John Patrick Herron
Member

Newfoundland & Labrador

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF A

GENERAL RATE APPLICATION

FILED BY

NEWFOUNDLAND POWER INC.

DECISION AND ORDER OF THE BOARD

ORDER NO. P.U. 13(2013)

BEFORE:

Andy Wells
Chair and Chief Executive Officer

Dwanda Newman, LL.B.
Commissioner

James Oxford
Commissioner

NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

AN ORDER OF THE BOARD
NO. P.U. 13(2013)

IN THE MATTER OF the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 and the *Public Utilities Act,* RSNL 1990, Chapter P-47 as amended, and subordinate regulations;

AND IN THE MATTER OF a general rate application by Newfoundland Power Inc. for approval of, *inter alia*, rates to be charged its customers.

BEFORE:

Andrew Wells
Chair and Chief Executive Officer

Dwanda Newman, LL.B.
Commissioner

James Oxford
Commissioner

TABLE OF CONTENTS

PART ONE. APPLICATION AND PROCEEDING

I. THE APPLICATION

Newfoundland Power Inc. ("Newfoundland Power") filed a general rate application (the "Application") with the Board of Commissioners of Public Utilities (the "Board") on September 14, 2012 for an Order of the Board approving, among other things, an overall average increase in current electricity rates of 6.0% as of March 1, 2013 for the supply of power and energy to its customers. In the Application Newfoundland Power proposes that the Board approve:

1. rates, tolls and charges with effect from March 1, 2013 which result in an overall average increase in current customer rates of 6.0% and average increases in proposed customer rates by class as follows:

Rate Class	Average Increase
Domestic	7.2%
General Service 0-100 kW (110 kVA)	0.6%
General Service 110-1000 kVA	6.0%
General Service 1000 kVA and Over	6.0%
Street and Area Lighting	6.0%

2. certain rate structure changes to all rate classes, with effect from March 1, 2013, including the merger of Rates 2.1 and 2.2 into a single rate class, and changes to the demand and energy charges, the energy block, the early payment discount and the basic customer charge across several rate classes;

3. an increase in the current rate of return on average rate base from 8.14% to 8.64% for 2013 and 8.58% for 2014;

4. a forecast average rate base for 2013 of $917,891,000 and for 2014 of $954,123,000;

5. the approval of an increase in rates based on the forecast revenue requirements from customer rates for 2013 of $601,551,000 and for 2014 of $618,846,000;

6. the discontinuation of using the automatic adjustment formula for setting the allowed rate of return on average rate base for Newfoundland Power;

7. certain amendments to the Rate Stabilization Clause in the rules and regulations governing Newfoundland Power's provision of electrical service to its customers; and

8. several changes in relation to accounting treatments, policies and procedures, including:

(a) the calculation of the depreciation expense with effect from January 1, 2013 by using the depreciation rates recommended in the Depreciation Study filed with the Application and the amortization of the accumulated reserve variance of approximately $2.6 million over the remaining life of the assets;

(b) the calculation of the defined benefit pension expense for regulatory purposes in accordance with United States Generally Accepted Accounting Principles and the amortization over 15 years of the forecast defined benefit pension expense regulatory asset of approximately $12.4 million;

(c) the deferral and amortization with effect from January 1, 2013 of annual customer energy conservation program costs over a seven-year period;

(d) the annual disposition of prior year balances in the Weather Normalization Reserve through the Rate Stabilization Account, with effect from January 1, 2013; and

(e) the recovery over a three-year period, from 2013 through 2015, of:

(i) certain cost recovery deferrals approved in 2011 and 2012;

(ii) an estimated $1.25 million in Board and Consumer Advocate costs related to the Application;

(iii) the outstanding year-end balance for 2011 in the Weather Normalization Reserve of approximately $5.0 million due to customers; and

(iv) a forecast 2013 revenue shortfall of an estimated $980,000.

II. NOTICE AND INTERVENORS

Notice of the Application and pre-hearing conference was published in newspapers throughout the Province beginning on September 29, 2012. The pre-hearing conference was held on October 11, 2012. Order No. P.U. 32(2012) identified intervenors, established procedural rules and set the schedule for the proceeding.

Newfoundland Power was represented by Mr. Ian Kelly, QC, Mr. Gerard Hayes and Mr. Liam O'Brien. Registered intervenors for the proceeding were the Government appointed Consumer Advocate, Mr. Thomas Johnson, assisted by Mr. Greg Kirby, and Newfoundland and Labrador Hydro, represented by Mr. Geoff Young. Newfoundland and Labrador Hydro advised in its Intervenor Submission that it proposed to participate in the proceeding in a limited fashion. It was copied with all the documents throughout the proceeding but did not otherwise participate.

The Board was assisted by Ms. Jacqueline Glynn, Legal Counsel, Ms. Maureen Greene, QC, Board Hearing Counsel, and Ms. Cheryl Blundon, Board Secretary.

On December 14, 2012 notice of the hearing was published inviting participation in the hearing which was scheduled to begin on January 10, 2013.

III. PRE-FILED EVIDENCE

Newfoundland Power filed comprehensive supporting material with the Application including the written evidence of company and expert witnesses and other reports and exhibits.

On November 9, 2012 the Board's financial consultants, Grant Thornton LLP ("Grant Thornton"), completed its review of the Application and filed a report. On November 28, 2012 the Board's cost of capital expert, Mr. Troy MacDonald of Grant Thornton, filed a report.

On November 28, 2012 evidence was filed on behalf of the Consumer Advocate by:

(i) Dr. Laurence Booth of the Rotman School of Management, University of Toronto, in relation to cost of capital; and

(ii) Mr. Jacob Pous of Diversified Utility Consultants Inc., in relation to depreciation.

On December 14, 2012 Newfoundland Power filed Rebuttal Evidence of Mr. John W. Wiedmayer, Jr. of Gannett Fleming Inc. in relation to depreciation.

On January 18, 2013 the Consumer Advocate filed Surrebuttal Evidence of Mr. Jacob Pous.

A total of 955 Requests for Information were filed and answered in the proceeding.

IV. NEGOTIATION AND SETTLEMENT PROCESS

The schedule for the proceeding included a number of negotiation days to enable and/or facilitate discussion between Newfoundland Power and the intervenors to determine what, if any, agreement may be reached. The Board set aside December 17 to December 19, 2012 for negotiations and Board Hearing Counsel facilitated the discussions. Newfoundland and Labrador Hydro advised that it would not participate.

On December 21, 2012 a settlement agreement between Newfoundland Power and the Consumer Advocate was filed with the Board (the "Settlement Agreement"). The Settlement Agreement addressed a range of issues, including forecasting, certain amortizations, accounting changes and rate design issues.

V. THE HEARING

The hearing began as scheduled and testimony was heard on January 10, 14, 15, 16, 17, 18, 23, 24, 25 and 31, 2013. During the hearing the following witnesses testified:

<u>On behalf of Newfoundland Power:</u>

Mr. Earl Ludlow	President and Chief Executive Officer
Ms. Jocelyn Perry	Vice-President, Finance and Chief Financial Officer
Mr. Gary Smith	Vice-President, Engineering and Operations

Ms. Kathleen McShane	President, Foster Associates, Inc.
Dr. James Vander Weide	Research Professor, Finance and Economics Fuqua School of Business, Duke University
Mr. John Wiedmayer, Jr.	Project Manager, Depreciation Studies Valuation and Rate Division Gannett Fleming Inc.

On behalf of the Consumer Advocate:

Dr. Laurence Booth	Professor of Finance Rotman School of Management University of Toronto
Mr. Jacob Pous	Principal, Diversified Utility Consultants Inc.

On behalf of the Board:

Mr. Troy MacDonald	Partner, Advisory Service Grant Thornton LLP

On January 31, 2013 the Board heard a presentation from Mr. Winston Adams. The Board also received six written letters of comment. The Board expresses its appreciation to everyone who took the time to participate in the proceeding, especially Mr. Adams who attended the hearing and made a very comprehensive and informative presentation to the Board.

On February 5, 2013 written submissions were filed by Newfoundland Power and the Consumer Advocate.

On February 8, 2013 oral submissions were presented by Newfoundland Power and the Consumer Advocate.

PART TWO. BOARD DECISIONS

I. SETTLEMENT AGREEMENT

The Settlement Agreement was filed with the Board on December 21, 2012. Newfoundland Power, the Consumer Advocate and Board Hearing Counsel executed the Settlement Agreement. In considering the Settlement Agreement the Board must be satisfied that the proposals are reasonable and consistent with the existing regulatory framework and legislation, with particular reference to the power policy of the Province as set out in section 3 of the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1.

The Settlement Agreement sets out the following consensus issues:

- 2013 and 2014 Customer, Energy and Demand Forecast;
- accounting treatment of the defined benefit pension expense for regulatory purposes;
- amortization of Conservation Program Costs and an amendment to the definition of the Conservation and Demand Management Cost Deferral Account;
- amendments to the Weather Normalization Reserve account;
- amortization of regulatory deferrals and reserves;
- forecast average rate base;
- rate design and rate structure; and
- changes to the Rate Stabilization Clause.

1. 2013 and 2014 Customer, Energy and Demand Forecast

The parties to the Settlement Agreement agree that the Board may accept and rely upon the 2013 and 2014 Customer, Energy and Demand Forecast, dated August 2012, which was filed with the Application.

Newfoundland Power explains that the number of customers is forecast to increase by approximately 1.3% annually in both 2013 and 2014. Energy sales are forecast to increase by approximately 1.2% annually in both 2013 and 2014. Demand is forecast to increase by approximately 1.6% in 2013 and 1.3% in 2014 and demand purchases from Hydro are forecast to increase by 1.8% in 2013 and 1.4% in 2014.

Grant Thornton explains that the Customer, Energy and Demand Forecast forms the foundation of Newfoundland Power's planning process and is a key input in developing estimates of capital expenditures and revenue from electrical sales and expenditures on purchased power. Grant Thornton confirmed that Newfoundland Power's methodologies for forecasting as described in the Customer, Energy and Demand Forecast are consistent with those used in the last general rate application.

The Board accepts the agreement in relation to the Customer, Energy and Demand Forecast and accepts the 2013 and 2014 Customer, Energy and Demand Forecast, dated August 2012, to be used in calculating the 2013 and 2014 forecasts of revenue requirement, rate base and rate of return on rate base for the purpose of determining customer rates.

2. Defined Benefit Pension Expense

The parties to the Settlement Agreement agree that the Board should approve, with effect from January 1, 2013, Newfoundland Power's proposal to calculate defined benefit pension expense for regulatory purposes in accordance with United States Generally Accepted Accounting Principles, and to amortize over 15 years the forecast defined benefit pension expense regulatory asset of approximately $12.4 million.

In Order No. P.U. 27(2011) the Board approved Newfoundland Power's adoption of United States Generally Accepted Accounting Principles for regulatory purposes. This Order gave Newfoundland Power the authority to calculate its annual defined benefit pension expense for regulatory purposes in accordance with United States Generally Accepted Accounting Principles. In Order No. P.U. 11(2012) the Board approved the creation of a regulatory asset to reflect the 2012 difference in the annual defined benefit pension expense calculated under United States Generally Accepted Accounting Principles and Canadian Generally Accepted Accounting Principles.

Newfoundland Power proposes, effective January 1, 2013, to: (i) calculate annual defined benefit pension expense for regulatory purposes in accordance with United States Generally Accepted Accounting Principles; and (ii) amortize the recovery of the forecast regulatory asset of approximately $12.4 million over 15 years. Newfoundland Power states that the proposal will reduce its revenue requirement since the proposed annual defined benefit pension expense under United States Generally Accepted Accounting Principles, including the amortization of the regulatory asset, is forecast to be lower than it would be under Canadian Generally Accepted Accounting Principles by approximately $0.5 to $0.7 million through 2017. Newfoundland Power explains that the single remaining difference between financial reporting and regulatory reporting which arose with the adoption of United States Generally Accepted Accounting Principles will also be eliminated.

Grant Thornton concurs that the proposed treatment will reduce the revenue requirement for 2013 and 2014 and further that eliminating differences between financial and regulatory reporting will enhance transparency. Grant Thornton advises that it agreed the defined benefit pension expense under both the current and proposed methods to the supporting documentation.

The Board accepts the agreement in relation to defined benefit pension expense and effective January 1, 2013 will approve: i) Newfoundland Power's proposed calculation of this expense; and ii) the amortization over 15 years of the forecast defined benefit pension expense regulatory asset of approximately $12.4 million.

3. Conservation Program Costs

The parties to the Settlement Agreement agree with Newfoundland Power's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2013, over seven years, as well as the proposed change in the definition of the Conservation and Demand Management Cost Deferral Account.

Conservation program costs are forecast to increase by approximately $2.4 million each year. Newfoundland Power currently expenses customer energy conservation program costs in the year in which they are incurred and is proposing to instead defer and amortize these costs over a seven-year period commencing in 2013 with recovery through the Rate Stabilization Account. Newfoundland Power states that this is reasonably consistent with public utility practice in relation to conservation cost recovery.

Newfoundland Power is also proposing a change in the definition for the Conservation and Demand Management Cost Deferral Account. Newfoundland Power and Newfoundland and Labrador Hydro recently completed an assessment of the portfolio of conservation programs and the jointly prepared report, *Five-Year Energy Conservation Plan: 2012-2016*, was filed with the Application. The principal changes to the conservation programs relate to: (i) the discontinuation of certain residential incentives for new construction; (ii) the introduction of new residential customer programs; and (iii) expansion of commercial customer programs.

Grant Thornton explains that annually recurring general conservation costs relating to providing general customer information, community outreach and planning will continue to be expensed in the year in which costs are incurred. Grant Thornton advises that nothing arose in its review to indicate that regulatory deferrals and amortizations are unreasonable or not in accordance with Board Orders, though Grant Thornton notes that the amortization period is longer than has been used in the past for recovery of costs of this nature.

The Board accepts the agreement in relation to conservation program costs and will approve, effective January 1, 2013,: i) the proposed change in the definition of the Conservation and Demand Management Cost Deferral Account, and ii) the amortization of annual customer energy conservation program costs over seven years with recovery through the Rate Stabilization Account.

4. Weather Normalization Reserve

The parties to the Settlement Agreement agree that the Board should approve Newfoundland Power's proposals that, with effect from January 1, 2013: i) annual balances in the Weather Normalization Reserve be recovered from, or credited to, customers as part of the annual Rate Stabilization Account adjustment to customer rates; and ii) the outstanding year-end balance in 2011 in the Weather Normalization Reserve of approximately $5.0 million due to customers be amortized over three years commencing in 2013.

The Weather Normalization Reserve normalizes the effects of weather and hydrology on Newfoundland Power's sales and power supply costs. The purpose of the reserve is to ensure that Newfoundland Power does not experience an earnings windfall or shortfall as a result of weather conditions. Currently, balances reflecting annual transfers to and from the Weather Normalization Reserve are considered annually by the Board and potential disposition of accrued balances in the reserve have typically been reviewed by the Board during general rate applications.

Newfoundland Power is proposing that annual balances in the reserve be recovered from, or credited to, customers as part of the annual Rate Stabilization Account adjustment on July 1 of each year. Newfoundland Power is also proposing that the outstanding year-end balance in 2011 of approximately $5.0 million after tax due to customers be amortized over three years, commencing in 2013. Newfoundland Power states that the Weather Normalization Reserve is the only regulatory mechanism which does not provide for timely recovery or credit of balances.

Grant Thornton notes that the proposal to include the amortization of the Weather Normalization Reserve in the annual Rate Stabilization Account adjustment would be consistent with the regulatory treatment of Newfoundland Power's other supply cost mechanisms and, according to Newfoundland Power, is consistent with current regulatory practice in Canada.

The Board accepts the agreement in relation to the Weather Normalization Reserve and will approve, with effect from January 1, 2013: i) that annual balances in the Weather Normalization Reserve Account be recovered from or credited to customers through the Rate Stabilization Account; and ii) the amortization over three years of the outstanding 2011 year-end balance due to customers in the Weather Normalization Reserve of approximately $5.0 million.

5. Cost Recovery Deferrals

The parties to the Settlement Agreement agree with Newfoundland Power's proposal that the Board should approve, with effect from January 1, 2013, Newfoundland Power's proposal to amortize and recover over a three-year period, commencing in 2013, the deferrals that were ordered by the Board in Order Nos. P.U. 30(2010), P.U. 22(2011) and P.U. 17(2012).

In Order Nos. P.U. 30(2010) and P.U. 22(2011) the Board approved the deferred recovery of approximately $2.4 million in each of 2011 and 2012, which is the difference between actual regulatory deferrals and the amount that was included in the 2010 test year revenue requirement. In Order No. P.U. 17(2012) the Board approved the deferred recovery of the amount of the difference in revenue for 2012 relating to the determination of Newfoundland Power's 2012 cost of capital estimated to be approximately $2.5 million. Newfoundland Power is proposing to amortize these deferrals using the straight-line method over a three-year period beginning in 2013.

The Board accepts the agreement in relation to previously ordered deferrals, and will approve the amortization over three years, commencing in 2013, of: i) the deferrals approved in Order Nos. P.U. 30(2010) and P.U. 22(2011) in the amount of $4,726,000; and ii) the deferral approved in Order No. P.U. 17(2012) of approximately $2.5 million.

6. Hearing Costs

The parties to the Settlement Agreement agree with Newfoundland Power's proposal that an estimated $1.25 million in Board and Consumer Advocate hearing costs be recovered in customer rates evenly over a three-year period from 2013 to 2015.

Newfoundland Power estimates that it will be billed approximately $1.25 million for Board and Consumer Advocate costs related to the Application.

Grant Thornton notes that the proposal is consistent with previous Board Orders and that it will have a forecast annual revenue requirement impact of approximately $417,000.

The Board accepts the agreement in relation to hearing costs and will approve the amortization over three years, commencing in 2013, of costs billed to Newfoundland Power for Board and Consumer Advocate hearing costs related to the Application, estimated to be $1.25 million.

7. 2013 Revenue Shortfall

The parties to the Settlement Agreement agree with Newfoundland Power's proposed amortization from the effective date of the new rates to December 31, 2015 to provide for recovery in customer rates of any 2013 revenue shortfall.

Newfoundland Power explains that, based upon a March 1, 2013 implementation, customer rates designed to recover the 2013 revenue requirement would result in an estimated $980,000 shortfall in recovering the 2013 revenue requirement. Newfoundland Power is proposing a revenue amortization to recover this shortfall.

The parties agree with the proposed amortization and further that the amount of the 2013 revenue shortfall will be affected with a later implementation date than March 1, 2013 and that the amortization should provide for recovery of any 2013 revenue shortfall.

The Board accepts the agreement in relation to the 2013 revenue shortfall and will approve the amortization over three years, commencing in 2013, of the 2013 revenue shortfall resulting from the implementation of rates after January 1, 2013.

8. Forecast Average Rate Base

The parties to the Settlement Agreement agree that Newfoundland Power's forecast 2013 and 2014 average rate base, as set out in the Application, should be used for ratemaking purposes, subject to adjustment by the Board in relation to issues not addressed in the Settlement Agreement.

The parties also agree that Newfoundland Power's forecast 2013 and 2014 rate base, as set out in the Application, is calculated in accordance with Board Orders and regulatory practice.

Grant Thornton concludes that the forecast average rate base is in accordance with established practice and accurately reflects Newfoundland Power's proposals with respect to the updated depreciation study, pension costs under United States Generally Accepted Accounting Principles, customer energy conservation programs, regulatory deferral accounts and the updated calculations related to the rate base allowances.

The Board accepts the agreement in relation to forecast average rate base and will approve the proposed forecast average rate base for 2013 and 2014 to be used for ratemaking purposes, incorporating the determinations of the Board in this Order.

9. Rate Design and Rate Structure

The parties to the Settlement Agreement agree that the Board should approve Newfoundland Power's proposed changes to rate design and rate structure as set out in the Application.

Newfoundland Power proposes to vary the rate increase by customer rate class so cost recovery for each class is within the target revenue to cost ratio range of 90% to 110%. Newfoundland Power uses an embedded cost of service study to assess the fairness of its rates by comparing the revenue collected from each class with the cost to serve that class. Newfoundland Power states that maintaining revenue to cost ratios for each class within a range of 90% to 110% has been an accepted approach to avoiding undue cross-subsidization among the various classes.

Newfoundland Power also proposes to implement changes in customer rate design in accordance with a review of the retail rates undertaken following Newfoundland Power's 2007 general rate application. The Retail Rate Review involved a comprehensive review of the rates with the participation of Newfoundland Power, the Consumer Advocate and Newfoundland and Labrador Hydro. A detailed report was filed in 2009 and in 2010 it was agreed that consideration of overall rate structure changes would be deferred until Newfoundland Power's next general rate application.

Newfoundland Power now proposes to implement the recommendations arising from the Retail Rate Review, including changes in relation to the basic customer charge, the merger of Rates 2.1 and 2.2, modifications to demand and energy charges to better reflect marginal costs, changes to the energy block sizes in Rates 2.3 and 2.4 and changes to the Maximum Monthly Charge and the Early Payment Discount.

The Board accepts the agreement in relation to rate design and rate structure and will approve rates based on Newfoundland Power's proposal to: i) vary the rate increase by customer class so cost recovery for each class is within the target revenue to cost ratio range of 90% to 110%; and ii) implement the proposed changes to rate design and structure as follows:

- **(i) merge existing Rates 2.1 and 2.2 into a single General Service Rate for all customers with demand of less than 100kW;**
- **(ii) modify demand and energy charges to better reflect marginal costs;**
- **(iii) change energy block sizes in Rates 2.3 and 2.4;**
- **(iv) make changes to the basic customer charge;**
- **(v) apply the average rate increase to the Maximum Monthly Charge;**
- **(vi) maintain the Curtailable Service Option with the current credit;**
- **(vii) modify the Early Payment Discount;**
- **(viii) maintain the Optional Seasonal Rate Revenue and Cost Recovery Account until the next general rate application;**

(ix) **increase the Optional Seasonal Rate consistent with the Rate 1.1 increase; and**

(x) **increase the Time of Day Rates in accordance with the increase in the applicable rate class.**

10. Rate Stabilization Clause Amendments

The parties to the Settlement Agreement agree that the amendments to the Rate Stabilization Clause proposed by Newfoundland Power should be approved.

Three proposed amendments to the Rate Stabilization Clause give effect to the Settlement Agreement with respect to conservation program costs, the Weather Normalization Reserve and the Maximum Monthly Charge. In addition Newfoundland Power proposes to amend the Rate Stabilization Clause to reflect the most recent energy consumption information for street and area lighting fixtures.

The Board accepts the agreement in relation to amendments to the Rate Stabilization Clause and will approve, effective January 1, 2013, the proposed amendments to:

(i) **reflect annual changes in the Rate Stabilization Account adjustment factors between test years for customers that benefit from the Maximum Monthly Charge provided for in proposed Rate 2.1 and existing Rates 2.3 and 2.4;**

(ii) **reflect the most recent energy consumption information for street and area lighting fixtures;**

(iii) **permit recovery through the Rate Stabilization Account of customer energy conservation program costs; and**

(iv) **permit the ongoing disposition through the Rate Stabilization Account of annual transfers to the Weather Normalization Reserve.**

II. CONTESTED ISSUES

The parties acknowledge and list the following issues that have not been resolved in the Settlement Agreement and remain outstanding:

(i) 2013 Forecast Revenue Requirements from rates of $601,551,000 and 2014 Forecast Revenue Requirements from rates of $618,846,000;

(ii) 2013 and 2014 Test Year Operating Costs;

(iii) approval, with effect from January 1, 2013, of the calculation of depreciation expense by:

  (a) use of the depreciation rates as recommended in the Depreciation Study filed with the Application; and

  (b) adjustment of depreciation expense to amortize over the remaining life of the assets an accumulated reserve variance of approximately $2.6 million identified in the Depreciation Study filed with the Application;

(iv) approval of an appropriate capital structure for ratemaking purposes;

(v) approval of a return on average rate base for 2013 of 8.64% within a range of 8.46% to 8.82% and a return on average rate base for 2014 of 8.58% in a range of 8.40% to 8.76%; and

(vi) discontinuance of the use of the automatic adjustment formula to determine Newfoundland Power's allowed rate of return on rate base.

1. Cost of Capital

Determining a fair return for Newfoundland Power is a central issue in this proceeding. Mr. Ludlow, President and Chief Executive Officer of Newfoundland Power, stated:

> "*The Public Utilities Act provides that Newfoundland Power is entitled to the opportunity to earn a just and reasonable return each year in addition to its reasonable costs. This entitlement reflects the essential balance between the competing interests of utility investors and customers.*" (Transcript, January 10, 2013, page 37/15-21)

In determining a fair return the Board is required to observe the power policy of the Province as set out in the *Electrical Power Control Act, 1994, SNL 1994*, c. E-5.1. Paragraph 3(a)(iii) states that the rates for the supply of power within the Province should provide sufficient revenue to enable a utility to earn a just and reasonable return so that it is able to achieve and maintain a sound credit rating in the financial markets of the world. In Order No. P.U. 43(2009) the Board stated at page 11:

> "*To be considered fair the return must be commensurate with the return on investments of similar risk and sufficient to assure financial integrity and to attract necessary capital.*"

i) Market Conditions

The Consumer Advocate submits that a fair return on equity cannot be determined independent of the state of the capital markets. He believes that capital market conditions have dramatically improved since the evidence was prepared for Newfoundland Power's last general rate application in 2009.

Dr. Booth explains that it is clear that capital market conditions today are much easier than in 2009 and that there is nothing in current capital market conditions to indicate that Newfoundland Power needs any sort of cushion to improve its capital market access so that it can obtain funds on fair and reasonable terms. He states:

> "*Overall the Canadian economy is good shape. As the Bank of Canada noted the remaining spare capacity will be used up in 2013/4 and the financial system is firing on all cylinders. The stock market is valuing utilities very favourably, credit is easy and utilities are issuing 40 and 50 year debt at very low rates. The only "problem" is that as one of the few AAA rated issuers the Government of Canada is borrowing on extremely low interest rates; significantly lower than US government. However, this does not indicate any "heightened risk aversion in the credit markets." Overall market conditions are remarkably benign.*" (Dr. Laurence Booth, Written Evidence, page 40)

Dr. Booth believes that the markets are in a long drawn out recovery.

Newfoundland Power on the other hand submits that the evidence supports a finding that current financial market conditions continue to be challenging.

Ms. McShane concludes that, by the end of July 2012:

(i) the systemic risks to the global financial system, as assessed by the Bank of Canada, were no lower than they were at the end of 2009;
(ii) long-term Government of Canada bond yields were much lower but this was not indicative of the trend in the market cost of equity;
(iii) changes in spreads on high grade corporate bonds indicate that the credit risk was not perceived to have declined; and
(iv) investor confidence was lower, equity market volatility was similar and the indicated market cost of equity was higher than it was in late 2009.

Mr. MacDonald states that the Canadian economy continues to be challenged by an uncertain global economic environment and risk remains relatively high. He explains that long-term Canadian bond yields were significantly lower in October 2012 than January 2010 which was partly influenced by the Bank of Canada's monetary policy encouraging low interest rates in challenging economic conditions.

ii) Risk and Capital Structure

Newfoundland Power argues that it continues to be an average risk Canadian utility and that its 45% common equity ratio should be maintained for ratemaking purposes.

The Consumer Advocate submits that Newfoundland Power is, at most, of average business risk and lower financial risk compared to other Canadian utilities. Based on this, the Consumer Advocate believes that Newfoundland Power should either have a lower allowed return on equity than a benchmark Canadian utility or its common equity ratio should be reduced. The Consumer Advocate notes that Newfoundland Power has a higher common equity percentage than its parent, Fortis Inc., and any other Fortis utility in Canada. He submits that there is no objective evidence that Newfoundland Power requires a common equity ratio of 45% and recommends that it be reduced to 40% for ratemaking purposes.

Dr. Booth believes that Newfoundland Power has average business risk and lower financial risk and states that it is a logical conclusion that Newfoundland Power should have either a lower allowed return on equity than a benchmark Canadian utility or its common equity ratio should be reduced. Dr. Booth states that he can see no reason why Newfoundland Power should have a 45% common equity ratio. He recommends that it be reduced to 40% with the issuance of preferred shares. In his analysis this would reduce the revenue requirement by about $3 million and would not affect Newfoundland Power's credit rating.

Newfoundland Power submits that the evidence is consistent that its overall risk profile has not changed materially since the last general rate application and that it remains an average risk Canadian utility. Mr. Ludlow states:

> *"I believe Newfoundland Power's risk profile is substantially the same as it was in 2009. We face some unique challenges. We are a small utility. We operate in an isolated system in a harsh weather environment and the demographics of our service territory are changing. Our operational challenges may be greater than that of many other Canadian utilities. As this Board has observed in the past, these challenges are offset by our strong capital structure. We also have a generally supportive regulatory environment similar to other utilities in Canada. So, on balance, we still consider our self an average risk utility."* (Transcript, January 10, 2013, page 29/4-18)

Newfoundland Power explains that its target 45% common equity component has been confirmed by Order of the Board since 1990 and has been recognized favorably by both the Dominion Bond Rating Service and Moody's Investors Service. Newfoundland Power states:

> *"It is clear from the evidence that Newfoundland Power's longstanding 45% common equity ratio is a key component of the Company's current creditworthiness. The witnesses, Ms. McShane, Dr. Vander Weide, Mr. MacDonald and Ms. Perry all support the maintenance of Newfoundland Power's 45% common equity ratio."* (Newfoundland Power, Written Submission, page D-5)

Newfoundland Power's Vice-President of Finance, Ms. Perry, believes that changing the capital structure could lead to a re-evaluation of the regulatory support perceived by credit rating agencies. Ms. Perry explains that Newfoundland Power is a small issuer in financial markets and she questions whether Dr. Booth's suggestion in relation to retractable preferred shares is possible. Further, she states that it would be costly and, from a credit rating perspective, retractable preferred shares would effectively be the same as issuing additional debt. Ms. Perry notes that Newfoundland Power's 45% common equity ratio has consistently been singled out by credit rating agencies as a financial strength and the maintenance of this ratio is a prominent feature of the Board's regulatory support of Newfoundland Power's financial integrity.

The Dominion Bond Rating Service states in its February 14, 2013 report that it expects Newfoundland Power to maintain its approved capital structure and further lists a strong balance sheet as one of Newfoundland Power's strengths. Moody's Investors Service also notes Newfoundland Power's strong balance sheet, concluding:

> *"NPI's allowed ROE was increased for 2012 to 8.80% from 8.38% in 2011 and while it remains one of the lowest in Canada, it is mitigated by one of the highest deemed equity levels in Canada at 45%."* (JP#4: Moody's Investors Service, Credit Opinion: Newfoundland Power Inc., January 18, 2013)

Ms. McShane concludes that Newfoundland Power continues to be an average risk Canadian utility. She offers examples of Canadian utilities that may be riskier than Newfoundland Power, including Nova Scotia Power and Pacific Northern Gas, but could not provide an example of a Canadian utility with lower risk on an overall basis, noting the trade-off between capital structure and business risk. Ms. McShane concludes:

> "*The Company's capital structure is reasonable in light of its business risks, the importance of maintaining the existing credit ratings, the upward trend in the common equity ratios of Newfoundland Power's Canadian peers, the necessity of ensuring financial strength in uncertain capital markets and the need to be positioned to compete for capital on reasonable terms and conditions.*" (Ms. Kathleen McShane, Written Evidence, page 2)

Ms. McShane explains that the proposed reduction in common equity would in all likelihood cause Moody's Investors Service to re-evaluate its conclusion that Newfoundland Power operates in a supportive regulatory environment. She believes if this rating or any other regulatory risk factors are changed there is a very high likelihood that Newfoundland Power would be downgraded. Ms. McShane also explains that, in her opinion, if the common equity percentage was reduced by five percent the fair return would increase by about 50 basis points.

Dr. Vander Weide assessed Newfoundland Power's common equity ratio by comparing it to the average approved equity ratio for United States electric and gas utilities and concludes that the 45% common equity ratio is reasonable. He agrees that there is a relationship between the cost of equity and the percentage of debt in the capital structure.

Mr. MacDonald concludes that Newfoundland Power is an average risk Canadian utility and a forecast common equity ratio of 45% for 2013 and 2014 is reasonable. He explains that the basis for his conclusion is that there have been no material changes in Newfoundland Power's business, regulatory or financial risk since the last general rate application, the allowed equity ratios of its peers have remained constant since 2010, and if the ratio is lowered it could weaken credit metrics and negatively impact the debt ratings agencies' perception of the regulatory environment. He states:

> "*Why I advocate ongoing review of the appropriateness of the common equity level and making adjustments as required, I am mindful of the sovereign debt issues that continue to create broad economic uncertainty. These factors provide further rationale for maintaining the common equity component at its current levels.*" (Transcript, January 18, 2013, page 183/12-19)

The Consumer Advocate urges caution with respect to Ms. McShane's recommendation that the fair return would increase by about 50 basis points if the common equity component was lowered by five percent. He submits:

> "*In our respectful submission, the Board would only adjust the ROE if the Board found that Newfoundland Power is an average risk utility and their capital structure is more aggressive than the average. That is to say that if the average common equity for a firm like Newfoundland Power was 40 percent, and the Board gave Newfoundland Power 35 percent like Fortis uses, then you would adjust the ROE. However, in this case, we are simply moving an average risk utility to the average common equity ratio and recommending an average ROE.*" (Transcript, February 8, 2013, page 80/6-18)

Board Findings – Risk and Capital Structure

In Order No. P.U. 43(2009) the Board stated at page 13:

> *"While there is some evidence that Newfoundland Power may be considered low risk even vis a vis its Canadian counterparts, in the absence of better evidence and given the current financial circumstances, the Board continues to believe that it is appropriate to consider Newfoundland Power's overall risk to be average in relation to Canadian utilities."*

The Board finds that the evidence does not demonstrate that Newfoundland Power's financial risk or overall risk has changed since the last general rate application when the Board determined that it was an average risk Canadian utility.

In Order No. P.U. 16(1998-99) Newfoundland Power's capital structure was comprehensively reviewed. The Board determined that it would deem a common equity ratio of 45% stating that the Board's objective in establishing capital structure for ratemaking purposes is to reflect the mix of capital that would result in the least cost of capital overall and maintain credit worthiness. In Order No. P.U. 19(2003) the Board stated at page 45:

> *"The Board also notes that NP retained an "A" credit rating in its October 2002 bond issue with an actual capital structure of 44% equity despite having an ROE characterized by NP as the lowest in Canada. Based on this recent experience and the Board's findings relating to NP's risk profile, the Board is not convinced at this time to change what has proven a sound and successful capital structure for NP. The Board is not satisfied that the common equity component could be notably reduced without significantly compromising interest coverage. Dr. Kalymon's proposal to substitute preferred shares for equity is not seen as an acceptable solution in the judgement of the Board. The Board notes this same proposal by Dr. Kalymon was rejected in Order No. P.U.16(1998-99). In reaching this decision of a maximum 45% common equity component, the Board recognizes NP will continue to retain one of the most favourable capital structures among Canadian utilities of comparable risk. The Board acknowledges the sensitivity in the relationship between capital structure and ROE and the importance of maintaining an appropriate balance to ensure both efficient access to the capital markets by NP and least cost electricity for consumers."*

In Newfoundland Power's last two general rate applications the Board accepted the settlement of the parties recommending a 45% common equity ratio for ratemaking purposes.

The Board acknowledges that it is not bound by its earlier decisions but it will have reference to these decisions with a view to ensuring consistent and predictable decision making. The Board also acknowledges that the evidence demonstrates that Newfoundland Power's common equity ratio is generally higher than the common equity ratios of other Canadian utilities. Dr. Booth states that there is no reason for Newfoundland Power to have a 45% common equity ratio. Dr. Booth estimates a potential reduction in revenue requirement of about $3 million if the common equity ratio was reduced to 40% and believes that this would not result in significant changes in Newfoundland Power's credit metrics. Ms. Perry, Ms. McShane and Mr. MacDonald all suggest that a reduction in the common equity ratio may lead to a downgrade by credit rating agencies.

Further, Ms. Perry also questions whether Dr. Booth's suggestion in relation to preference shares is practical. It is Ms. McShane's opinion that a reduction in the common equity ratio may be associated with an increase in the fair return of about 50 basis points. Mr. MacDonald expresses concern in relation to a reduction in Newfoundland Power's common equity ratio given the current economic uncertainty. The Board finds that the evidence raises significant issues in relation to the suggested change to Newfoundland Power's capital structure.

Newfoundland Power has had a deemed common equity ratio of approximately 45% for the last twenty-five years and the evidence is clear that the rating agencies place importance on its strong common equity position. There is no evidence of a change in circumstances which would justify a change in the ratio and there is little substantive evidence demonstrating that the appropriate common equity ratio for Newfoundland Power is 40%. The Board therefore finds that a change in the common equity ratio has not been justified in the circumstances. The Board notes that it has been some time since Newfoundland Power's capital structure has been comprehensively reviewed and that it may be appropriate for this issue to be addressed in Newfoundland Power's next general rate application. Newfoundland Power will be directed to file a comprehensive report in relation to its capital structure with its next general rate application.

The Board finds that Newfoundland Power continues to be an average risk Canadian utility. The Board will accept a common equity component of no greater than 45% for ratemaking purposes for Newfoundland Power. The Board will require Newfoundland Power to file a report in relation to its capital structure with its next general rate application.

iii) Methodologies for Determining Fair Return

A variety of methodologies for the determination of a fair return for Newfoundland Power were considered by the four cost of capital experts in this proceeding. Mr. MacDonald explains in relation to the fair return determination:

> "*Despite the relatively long history of the fair return concept there is as of yet, no single universally accepted method to determine a fair return on equity for an investor-owned utility. All methodologies are imperfect and cost of capital estimation is much more of an art than a science. Each methodology is more or less reliable depending on the prevailing economic and capital market conditions and each has its own strengths and weaknesses. In our view it is best to estimate the cost of capital using more than one methodology, as the return determined by any model or test will not perfectly capture all of the variables that might be considered in determining a fair return.*" (Mr. Troy MacDonald, Written Evidence, page 26)

Mr. MacDonald states that the capital asset pricing model is one of the most widely used methods for determining the rate of return for an asset held as part of a diversified portfolio and one of the most common models used by Canadian regulators. However, he explains that in the current circumstances the abnormally low risk-free rate can cause distortions in the results of methods such as the capital asset pricing model. Mr. MacDonald explains that he utilized multiple methodologies to ensure a broad view as the different methodologies provide multiple points of insight including historical market returns, forward looking market data, significant

Canadian based data and carefully selected United States data. He utilizes the capital asset pricing model, the equity risk premium model and the discounted cash flow model. He does not use the comparable earnings test because it has not been widely accepted in the Canadian regulatory environment in recent years. He explains that he used his professional judgement to develop a weighting for each of the three methodologies to address further considerations including the impact of the unusually low risk-free rates, the potential differences between United States and Canadian utilities, and the potential fluctuations over time.

Dr. Booth states that the capital asset pricing model is overwhelmingly the most important model used by a company in estimating cost of equity. However, he believes that the Canadian bond market is not normal right now and he judges a simple application of the capital asset pricing model under current market conditions as giving an unrealistic low estimate of the fair return. He states:

> "*I'd say this more - more than ever at this particular point in time, given the focus in Canada traditionally on risk premium models and the role of - the central role of the long Canada bond yield, judgement is involved and more important at the current point in time than ever before.*" (Transcript, January 18, 2013, page 131/10-16)

Dr. Booth explains that the recent very low long-term Canada bond yields forced him to re-evaluate his approach to the capital asset pricing model and the discounted cash flow model. He states that, while in theory the two methodologies should give the exact same answers, there have been extensive periods when there have been substantial divergences between the discounted cash flow and the risk premium estimates. He now uses the discounted cash flow model when estimating a reasonable return on the market. He states that his final analysis looks like a capital asset pricing model but that he is putting greater emphasis on the discounted cash flow now than he did three years ago.

Dr. Vander Weide explains that he references three generally accepted models to determine cost of equity: the discounted cash flow, the risk premium and the capital asset pricing model. He has not used the comparable earnings test for a number of years. He explains that the capital asset pricing model results are highly sensitive to the estimate of the risk-free rate and he did not assign it any weight in this case, concluding that it does not work for Canadian utilities.

Ms. McShane details a number of challenges in relation to the capital asset pricing model and concludes that it is not inherently superior to other approaches, particularly in light of the adjustments necessary to apply it to the utility industry. Ms. McShane concludes:

> "*Under current market conditions the application of the capital asset pricing model becomes particularly problematic. The model itself provides no guidance as to how to reconcile the abnormally low level of long term Canada Bond yields, which is the proxy for the risk-free rate with estimates of the market risk premium which have typically been expressed in the nature of a long term average level. As a result, much more judgement is required under current market conditions in the application of that model, and I think less confidence can be placed in the accuracy of the results. In those conditions it is particularly important to look to tests such as the discounted cash flow test, which are not benchmarked or anchored to the long term Canada Bond yield. I would also note in respect to the discounted cash flow test that we have in the last*

couple of years, I think, seen other regulators in Canada tend to give more weight to discounted cash flow than they had in earlier proceedings." (Transcript, January 14, 2013, pages 10/6-25 to 11/1-5)

Ms. McShane uses multiple tests to determine a fair rate of return and notes that the Ontario Energy Board has said that the use of multiple tests to determine the market risk premium is a superior approach to relying on a single methodology. She explains:

"*Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of ensuring that all three requirements of the fair return standard are met; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return. Changes to the inputs to individual tests may have different implications depending on the prevailing economic and capital market conditions. These considerations emphasize the importance of reliance on multiple tests.*" (Ms. Kathleen McShane, Written Evidence, page 50)

Unlike the other experts in this proceeding Ms. McShane also uses the comparable earnings test. She believes that this methodology is entitled to significant weight but acknowledges that regulators have afforded it a small amount or no weight in recent years and as such she presents this methodology in the alternative.

Newfoundland Power submits that all the experts' cost of equity recommendations in this proceeding, except those of Dr. Booth, are based on multiple tests and the Board should give greater weight to recommendations arrived at by use of multiple methodologies. Newfoundland Power states that the days of sole reliance on the capital asset pricing model are over, and specifically:

"*Mr. Chairman, that evidence tells us that there have been two important shifts in regulatory thinking since we were here in 2009. The first is with respect to the use of the CAP-M methodology. With the collapse of long Canada bond yields, which are driven by government monetary policy instead of market forces, there's no longer any clear and predictable relationship between long Canada bond yields on the one hand and a utility's cost of equity on the other. That's why regulators such as the British Columbia Utilities Commission, the Ontario Energy Board, the Alberta Utilities Commission, have moved away from sole or predominant reliance on the CAP-M methodology. They increasingly rely on other methodologies, in particular, the discounted cash flow or DCF methodology.*" (Transcript, February 8, 2013, pages 18/16-25 to 19/1-9)

The Consumer Advocate clarifies that Dr. Booth does use the discounted cash flow method to estimate the fair return for the capital market as a whole and it is an important element in his risk premium estimates.

Board Findings – Methodologies for Determining Fair Return

All the cost of capital experts in this proceeding reference multiple methodologies. Mr. MacDonald and Ms. McShane give weight to the capital asset pricing model, the other equity risk premium models and the discounted cash flow model. Dr. Vander Weide gives weight to the equity risk premium models and the discounted cash flow model and rejects the capital asset pricing model in the circumstances. Dr. Booth completes a discounted cash flow analysis which he uses to inform his judgement when determining a fair rate of return within the context of the capital asset pricing model. Only Ms. McShane uses the comparable earnings test.

The Board accepts the evidence of the experts that there are challenges with each of the methodologies which can be exacerbated in certain financial and economic conditions. The Board has in the past preferred the equity risk premium methodology in determining a fair return referencing the stability of the bond market and consistent and predictable decision making (Order No. P.U. 19(2003), page 48). In Order No. P.U. 43(2009), the Board stated at page 18:

> *"Consistent with past practice of this Board and other Canadian regulators, and considering the evidence respecting the issues in relation to the comparable earnings and the discounted cash flow tests, especially in relation to the reliance on U.S. data without making adjustments, the Board will continue to rely principally on the equity risk premium test to estimate a fair return on regulated common equity for Newfoundland Power for ratemaking purposes."*

In Newfoundland Power's last general rate application the Board relied primarily on the capital asset pricing model. However, in this proceeding, the experts agree that given the abnormally low long-term Canada bond yields a simple application of the capital asset pricing model will not produce a fair return for Newfoundland Power. Both Mr. MacDonald and Dr. Booth make adjustments in relation to the capital asset pricing model estimates and Dr. Vander Weide rejects the capital asset pricing model results. The Board notes that other regulators are moving away from sole reliance on the capital asset pricing model.

The Board concludes that given the current financial and economic conditions a simple application of the capital asset pricing model cannot be relied on to produce a fair return for Newfoundland Power. In the circumstances it is necessary to take a broader view and look to other available information in relation to fair return. The Board will continue to give primary weighting to the capital asset pricing model; however, it will also look to the other evidence in relation to the fair return for Newfoundland Power and in particular the results of other models. Given the evidence that the comparable earnings test is not a widely accepted method of estimating a fair return the Board will not consider the results of this test. The Board will not adopt an assigned weighting for each methodology but rather will have regard to all of the circumstances to inform its judgement as to the fair return.

The Board will continue to give primary weighting to the capital asset pricing model but in the circumstances will look to the results of other accepted models and other relevant evidence when determining a fair return for Newfoundland Power.

iv) Financing Flexibility

All the experts in this proceeding include an allowance for financing flexibility in the fair return. Mr. MacDonald, Dr. Booth and Dr. Vander Weide include an allowance of 50 basis points and Ms. McShane includes either 50 or 100 basis points, depending on whether the comparable earnings test is used in determining a fair return. Mr. MacDonald explains that the concept of an allowance for financing flexibility is supported by financial theory and regulatory practice. Dr. Vander Weide explains that there are two justifications for the allowance: first, to compensate for flotation costs which is generally around 20-25 basis points; and, secondly, to reflect differences in market values and book values of debt and equity. Dr. Booth states that a 50 basis points allowance has been a non-contentious issue in most jurisdictions, except in Quebec where 35 basis points is used. Dr. Booth says the adjustment is meant to cover the costs of raising equity that are not recovered directly in the revenue requirement. Ms. McShane explains that the financing flexibility allowance is a required element of the concept of fair return. In relation to her recommended 100 basis points allowance, Ms. McShane explains:

> "*The higher allowance for financing flexibility is intended to recognize that the Board has in previous decisions decided that it will not give weight to the comparable earnings test, but only to tests derived from equity capital market data. In that case there needs, in my view, to be an explicit recognition that the market data in which these market-based tests, the equity risk premium, and discounted cash flow test, are based, reflect market value capital structures.*" (Transcript, January 14, 2013, page 8/1-12)

Newfoundland Power states that the higher financing flexibility allowance proposed by Ms. McShane recognizes that the equity risk premium and discounted cash flow tests are based on market values and the return on equity approved by the Board is applied to book value.

The Consumer Advocate notes that Ms. McShane has doubled her financing allowance while Ms. Perry indicated that she has no knowledge of these costs doubling.

<u>Board Findings – Financing Flexibility</u>

The Board accepts the evidence of Mr. MacDonald, Dr. Booth and Dr. Vander Weide that an allowance of 50 basis points for financing flexibility is appropriate. In Newfoundland Power's last general rate application the Board included a 50 basis point allowance for financing flexibility and the Board finds that there is no evidence that financing costs have increased. Ms. McShane's suggestion that a 50 basis point allowance is inadequate if the comparable earnings test is not used is not supported by the recommendations of the other experts or by Canadian regulatory practice.

The Board accepts that a 50 basis point allowance for financing flexibility should be included in the estimate of the fair return for Newfoundland Power.

v) Risk-Free Rate

Mr. MacDonald estimates the risk-free rate to be 3.04% for 2013 and 2014. This determination is based on the October 2012 forecasts for the 10-year long-term Canada bond yields and the observed average daily difference between the 10-year and 30-year long-term Canada bond yields. Mr. MacDonald does not make any adjustments to the forecast yields but states that he makes an adjustment to his capital asset pricing model result, increasing it by 206 basis points, to address concerns regarding the impact of the abnormally low risk-free rate.

Dr. Booth also forecasts the long-term Canada bond yield to be about 3.0% but determines a base adjusted long-term Canada bond yield of 3.8%. He believes that the forecast long-term Canada bond yield is well below any equilibrium yield since it is only 1.0% above the forecast inflation rate and that it would result in a negative real yield for a typical taxable investor. Dr. Booth states that he regards any long-term Government of Canada bond yield below 3.8% as indicating abnormal capital market conditions and not reflective of a risk verses return trade off by ordinary investors. He explains that the forecast low long-term bond yield reflects the actions of global policy makers and central banks and should not directly influence the fair rate of return for Newfoundland Power. Dr. Booth adjusts the long-term Canada bond yield upward by 80 basis points which he estimates is the approximate impact of the United States Operation Twist on the Canadian bond market.

Dr. Vander Weide estimates the risk-free rate to be 2.73% based on the June 2012 Consensus Economics forecast interest rate on long-term Canada bonds for 2013. Dr. Vander Weide did not use a blended 2013 and 2014 forecast. Dr. Vander Weide states that the forecast 2.73% yield on long-term Canada bonds is significantly less than the historical 7.3% average yield. He explains that the forecast yield is unusually low and reflects policy decisions of Canadian and United States governments, the Bank of Canada, and the United States Federal Reserve Bank.

Ms. McShane estimates the long-term Canada bond yield to be approximately 3.5% based on a forecast yield of 3.0% for 2013 and 4.0% for 2014. She uses the April 2012 Consensus Economics forecast for 2014 but uses other available forecasts for 2013. She comments that the yield is expected to rise from this historically and abnormally low rate over the next three years but that it is anticipated to average well below long-term levels of approximately 5.0%. Ms. McShane explains that the long-term government bond yield can be problematic as an estimate of the true risk-free rate as it reflects the impact of monetary and fiscal policy and may reflect a scarcity premium demonstrating an imbalance between supply and demand.

<u>Board Findings – Risk-Free Rate</u>

It is regulatory practice in Canada to use the forecast yield for the long-term Canada bond as a proxy for the risk-free rate in equity risk premium models. While the experts continue to look to the long-term Canada bond yield when determining the risk-free rate, they agree that bond market conditions are unusual right now and that the yield for 30-year Government of Canada bonds is abnormally low.

The range of recommended risk-free rates is 2.73% - 3.80%. Dr. Vander Weide adopts a rate of 2.73% but does not reflect the 2014 forecast and does not use the most recent forecast for 2013. Ms. McShane uses 3.50% but does not consider the most recent forecast and does not use the Consensus Economics forecast for 2013. Mr. MacDonald and Dr. Booth agree that the forecast long-term Canada bond yield for 2013 and 2014 is approximately 3.00%. Dr. Booth makes an adjustment to the forecast yield to reflect the impact of the actions of global policy makers. Dr. Booth applies an 80 basis point adjustment and determines a risk-free rate of 3.80%. Mr. MacDonald does not adjust the risk-free rate specifically but ultimately increases his capital asset pricing model result to address concerns regarding the impact of the abnormally low risk-free rate.

The Board accepts that the forecast long-term Canada bond yield is approximately 3.0%. The Board also accepts that this forecast is abnormally low and reflects the actions of global policy makers. Because the forecast may not accurately reflect the risk verses return trade-off by ordinary investors, the Board finds that an unadjusted forecast long-term Canada bond yield may not be a good proxy for the risk-free rate at this time. The Board accepts Dr. Booth's 80 basis point adjustment to the long-term Canada bond yield to reflect these unusual conditions.

The Board will accept a risk-free rate of 3.8%.

vi) Capital Asset Pricing Model

The capital asset pricing model requires a determination of both the risk premium for the equity market and the relative risk factor for the utility, or beta.

Risk Premium of the Market

Mr. MacDonald explains that the market risk premium is the premium that the market demands over and above the risk-free rate to hold an asset. He supports a market risk premium of 5.5% for use in the capital asset pricing model, placing particular emphasis on the empirical evidence gathered from over a century of Canadian investment returns. Mr. MacDonald refers to the Fernandez study, *Market Risk Premium Used in 82 Countries In 2012: a Survey With 7,192 Answers,* where the mean and median returns in both Canada and the United States were approximately 5.5%. Mr. MacDonald also refers to Professor Aswath Damondaran who, in June 2012, estimated a risk premium of 6% for Canada and stated that, according to the Credit Suisse Global Investment Returns Sourcebook 2012, the historical arithmetic mean Canadian Equity Risk Premium from 1900-2011 is 5.0%-5.5%. While Mr. MacDonald does not make adjustments to his risk premium, as noted earlier, he makes an adjustment to his capital asset pricing model result, increasing it by 206 basis points to address concerns regarding the impact of the abnormally low risk-free rate.

Dr. Booth concludes that, while his own direct estimate of the experienced market risk premium is less than 5.0%, he judges the current market risk premium to be in a range of 5.0%-6.0%. He notes that there is variability in the risk premium from year to year and says that the determination is based on historic evidence constrained by the facts. He explains that his estimate reflects the Fernandez survey results and gives weight to the evidence from the United

States. Dr. Booth makes an upward adjustment to his market risk premium to reflect the unusual market conditions. He believes that abnormal market conditions have affected the Canadian bond market and have had an impact on the equity market. Dr. Booth notes that other regulators have added a financial crisis risk premium based on conditions in the credit market. He explains:

> "*In empirical applications we use several methods of estimating the MRP: a) long run historical values which are about 5.0% for Canada, b) historic values from other markets such as the US which are tops about 6.0% c) survey results which are in the range of 5.0-6.0% and d) direct estimates of the expected return on the market from DCF and other estimates minus the current long Canada yield. Most of these methods do not take into account current capital market conditions, whereas the use of credit spreads does.*" (PUB-CA-16)

He calculates that the A spreads are about 80 basis points more than normal and adjusts his capital asset pricing model results to reflect this difference.

Ms. McShane selects 8.0% for her market risk premium explaining that the market risk premium can be expected to be higher with a lower risk-free rate. Ms. McShane sets out the equity returns and risk premiums for various bond income returns and concludes that historically lower bond income returns have been associated with higher achieved risk premiums. Ms. McShane calculates that a reasonable estimate of the expected value of the nominal equity market return is approximately 11.5% based on Canadian equity market returns and supported by U.S. equity market returns. She concludes that the analysis of Canadian equity risk premiums in conjunction with bond income returns supports a market equity risk premium of no less than 8.0% at the 30-year Government of Canada bond yield forecast of 3.5%.

Beta

Mr. MacDonald explains that the volatility of an asset in relation to the market as a whole is measured with the beta. For Newfoundland Power Mr. MacDonald determines a beta of 0.60. He suggests that the calculated average beta of 0.40 is below historical norms, explaining that this number is a spot estimate based on a particular period of observations and may not be indicative of the average beta. He acknowledges that, although he used the Blume adjustment, some experts believe that utility betas converge towards the average beta for their group and not towards 1.0 as assumed with the Blume adjustment.

Dr. Booth explains that he believes that the relative risk of Canadian utilities will return to the historic range of 0.45-0.55 from the levels recently seen of about 0.30-0.35. He explains that, when determining the beta, actual or historic returns are used, making the data very sensitive to what happened during the estimation period. It is Dr. Booth's judgement that betas tend to revert to their long run average levels of 0.45-0.55, not the long run average of the market of 1.0 as is assumed in the Blume adjustment.

Ms. McShane concludes that the relative risk adjustment for an average risk Canadian utility is in the approximate range of 0.65-0.70. She uses an adjusted beta based on several sources: Total Market Risk; Relative Historic Returns and Betas: Canadian Utilities; Recent Bloomberg

Adjusted Beta: Canadian Utilities; Long-term Adjusted Betas: Canadian Utilities Index; and Value Line Betas: United States Utility Sample.

Board Findings – Capital Asset Pricing Model

The experts recommend a range of market risk premiums of 5.5% to 8.0% for the capital asset pricing model. Mr. MacDonald concludes that the market risk premium is 5.5% but makes a 206 basis points adjustment to his final capital asset pricing model results. Dr. Booth agrees that the market risk premium is approximately 5.5% but adds a credit spread premium of 80 basis points for an effective market risk premium of 6.3%. Ms. McShane estimates a market risk premium of 8.0%, considerably higher than the risk premium she recommended in 2009. In Newfoundland Power's last general rate application the long-term Canada bond yield was 4.5% and the Board accepted a market risk premium of 6%. The forecasted long-term Canada bond yield is now 3.0% and the Board has accepted an adjusted long Canada bond yield of 3.8%. Based on the range of recommendations of the experts, the relationship of the market risk premium to the long-term Canada bond yield, and changes in market conditions since the last general rate application the Board will accept a market risk premium of 6.5% for use in the capital asset pricing model.

In relation to the beta to be applied to the market risk premium the range recommended by the experts is 0.45-0.70. Mr. MacDonald determines a beta of 0.60. Dr. Booth recommends a beta of 0.45-0.55. Ms. McShane recommends a beta of 0.65-0.70. The Board notes that it accepted a beta of 0.60 for Newfoundland Power in the last general rate application. The Board finds that the evidence continues to support a beta of 0.60 for Newfoundland Power.

The Board will accept a market risk premium of 6.5% and a beta of 0.60 resulting in a risk premium of 3.90% for use in the capital asset pricing model. When combined with a risk-free rate of 3.80% and an allowance for financing flexibility of 0.5% the estimated return on equity using the capital asset pricing model is 8.2%.

vii) Other Equity Risk Premium Models

Like the capital asset pricing model the historic and forward-looking equity risk premium models estimate the risk premium to be applied to the risk-free rate. The difference is that these models determine the risk premium for the utility based on utility specific data rather than overall market data.

Historic Equity Risk Premium Model

Mr. MacDonald conducts a historic equity risk premium analysis and calculates the return to be 10.26%. He explains that this approach captures the difference between equity and debt returns over a period of time but does not reflect the expected changes in the economy or industry or for the company in question. His equity risk premium test suggests a utility market risk premium of 6.72% using stock return data from two Canadian indices. Mr. MacDonald averages the 4.66% risk premium calculated on the S&P/TSX Utilities 1956-2011 and the 8.77% risk premium calculated on the BMO Capital Markets Utilities 1983-2011. Mr. MacDonald does not make an express adjustment to this risk premium but reduces the overall result produced with this model by 135 basis points considering the potential fluctuations over time in this model, particularly as it relates to the companies that are included and the events in time.

Dr. Vander Weide calculates the historic or ex post premium return to be 9.9%. Like Mr. MacDonald he estimates that the risk premium is 6.7% based on the S&P/TSX Utilities 1956-2011 and the BMO Capital Markets Utilities 1983-2011. He cannot explain why the risk premium using the S&P/TSX Utilities index is so much lower than the risk premium using the BMO Utilities index. He states that his analysis shows that the required equity risk premium increases when interest rates decline and since the expected 2.73% yield on long-term Canada bonds is significantly less than the average yield on long Canada bonds of 7.3%, the current required equity risk premium should be significantly higher than the average 6.7% equity risk premium.

Ms. McShane conducts a historic utility equity risk premium test which indicates a return of 10.75%, assuming an allowance for financing flexibility of 50 basis points. She also calculates a utility equity risk premium of approximately 6.75%. Her analysis reflects three data sources: S&P/TSX Utilities 1956-2011; United States electric utility; and United States gas utility. She adjusts the long-term historic average data to recognize the inverse relationship between utility equity risk premiums and bond yields. Ms McShane acknowledges that in 2011 the Alberta Utilities Commission rejected her historic equity risk premium analysis and that her approach is much like that of Dr. Vander Weide.

The Consumer Advocate submits that there is no reasonable basis for the Board to conclude that the historic equity risk premium method puts forward reliable evidence with respect to the return investors expect on a utility like Newfoundland Power. He notes that in 2011 the Alberta Commission found that the evidence on historic returns was inconclusive with respect to the return investors expect on comparable investments.

Forward-Looking Equity Risk Premium

Dr. Vander Weide conducts a forward-looking or ex ante risk premium analysis suggesting a return of 11.1%. He concludes that the ex ante risk premium is 7.7% for his electric utility comparable group and 8.1% for his natural gas comparable group. This is based on studies of the discounted cash flow expected return on comparable groups of United States utilities in each month of his study period since 1998 using the constant growth model. He explains that the difficulty with using Canadian utilities is that there are very few, if any, analysts' growth forecasts available for each Canadian utility.

Ms. McShane calculates a forward-looking discounted cash flow based equity risk premium analysis with an indicated return of 10.0%, assuming an allowance for financing flexibility of 50 basis points. Her calculated utility equity risk premium of 6.0% is based on the difference between the discounted cash flow cost of equity and yields on long-term government bonds for a sample of United States utilities. She looked to the monthly published long-term earnings growth rate forecast for each of the sample utilities from Thomson Reuters. She explains that she constructed a constant growth and a three-stage growth discounted cash flow based equity risk premium test. Ms. McShane concludes, based on the discounted cash flow based regression analysis of the United States utilities from 1998-2012 with a forecast Government bond yield of 3.5%, that the indicated utility cost of equity is in the range of approximately 9.3% to 9.7% and therefore the equity risk premium is approximately 6%.

Board Findings – Other Equity Risk Premium Models

Mr. MacDonald, Dr. Vander Weide and Ms. McShane estimate the utility market risk premium to be approximately 6.75% using the historic equity risk premium test. The Board has several concerns in relation to the historic equity risk premium test, the most significant of which is the large unexplained discrepancy in the available Canadian data. The S&P/TSX Utilities 1956-2011 suggests a utility risk premium of 4.66%, which is approximately half the premium suggested by the BMO Capital Markets Utilities 1983-2011 of 8.77%. The Board notes Exhibit 15 of Dr. Vander Weide's evidence which sets out the average risk premium for the S&P/TSX Utilities over the same period as the BMO Capital Markets Utilities 1983-2011 to be 7.88%. The Board also has concerns in relation to Ms. McShane's use of unadjusted United States data. The Board notes that Ms. McShane's approach to the historic equity risk premium was not accepted by the Alberta Utilities Commission.

The forward-looking equity risk premium analysis completed by both Dr. Vander Weide and Ms McShane is based on analysts' forecasts for United States utilities. Ms. McShane's market risk premium is 6.0% while Dr. Vander Weide's result is 7.7% for electric utilities and 8.1% for gas utilities. The Board has concerns in relation to these results as they are based on unadjusted United States data. In addition, the Board, like other Canadian regulators, has concerns in relation to the use of analysts' growth forecasts, particularly when used in the constant growth model.

The Board does not believe that much weight should be given to the experts' recommendations in relation to either the historic or forward-looking equity risk premium models as these are based largely on inadequate Canadian data, unadjusted United States data and analysts' growth forecasts using the constant growth model. The Board estimates that, using the long period Canadian data, adjusted United States data and the multi-stage model, the risk premium would be approximately 5.0%. With a risk-free rate of 3.8% and an allowance for financing flexibility of 0.5% the indicated cost of equity would be 9.3%. However, the Board acknowledges that this approach restricts the extent of the information considered and will therefore assign little weight to these results.

The Board will place little weight on the results of the historic and forward looking equity risk premium models.

viii) Discounted Cash Flow

The discounted cash flow test is based on the theory that the current market price of a utility's stock is equal to the present value of all future expected cash flows from the investment, discounted at a rate that reflects the riskiness of the cash flows.

According to Mr. MacDonald the discounted cash flow model is the most widely used method to determine the allowed return on equity for regulated utilities in the United States as there is a large universe of comparable public companies that are widely followed by investment analysts. This provides readily available estimates of growth rates for utility proxy groups. He explains that in the Canadian context the discounted cash flow model is problematic given the small number of utility proxies and lack of reliable estimates of growth rates. While there is some disagreement as to whether Canadian and United States utilities are comparable, Mr. MacDonald believes that United States comparisons are informative. He concludes that, given the strong degree of economic and financial market integration, it is possible to construct a United States proxy group which is similar in total risk to Newfoundland Power. However, he also believes that the clear differences in the United States and Canadian marketplaces for utilities and in the markets overall require that an adjustment be made to the results to recognize these differences. In relation to the growth rate in the discounted cash flow model, Mr. MacDonald comments that it becomes more difficult to estimate further out in time and that over time a firm's growth rate will trend towards overall economic growth.

Mr. MacDonald's discounted cash flow analysis suggests a fair return of 9.63%. This is the average of the constant growth approach, with a return of 9.71%, and the two-stage model, with a return of 9.55%, for a group of seven United States utilities that meet his six established criteria. He explains that each of the seven utilities has an identical credit rating to Newfoundland Power and a majority of assets which are regulated. In relation to the growth rate, he explains that he uses Value Line dividend growth estimates for the first three years and thereafter the growth rate is based on the Consensus Forecasts long-term average real GDP and inflation forecast for 2018-2022. Mr. MacDonald states that he makes a 72 basis point adjustment to address concerns regarding differences between United States and Canadian companies. He notes this is consistent with the statement of the British Columbia Utilities Commission that a 50 to 100 basis point adjustment should be applied for comparable United States utilities.

Dr. Booth explains that conceptually the discounted cash flow and risk premium models are equally valid ways of estimating the fair rate of return but the data in relation to the discounted cash flow model may not be adequate for reasonable estimates. Dr. Booth explains that he has been reluctant to look at United States data, noting that it is a foreign country with different laws, procedures, and cultural factors. At this time he believes that a difference in the fair return between Canadian and United States utilities of 100 basis point is reasonable. He explains:

> "*So before the BCUC in 2009, I said you can use US evidence, ... and at that time I said US estimates need to be downward adjusted by 90 to 100 basis points. ... the BCUC downwardly adjusts Ms. McShane's DCF estimates by 50 to 100 basis points and the basis of the downward adjustment was the fact that I felt that long term bond yields were higher in the US, the market risk premium was higher in the US and probably the relative risk of utilities is higher in the US. .... In my judgement the US is a riskier capital market, they're more competitive than we are and I don't regard that as a bad thing.*" (Transcript, January 17, 2013, page 199/1-20)

In relation to the use of analysts' growth forecasts, Dr. Booth states that he is extremely skeptical of results based on analysts' forecasts as they are generally optimistic and, further, that realistically these should be used with a two-stage growth model. Dr. Booth's discounted cash flow analysis suggests a fair return of 9.23% for United States utilities.

Dr. Vander Weide explains that regulatory commissions in the United States give greater weight to the discounted cash flow model than other models. He does not use data in relation to Canadian utilities noting that there are very few, if any, analysts' growth forecasts for Canadian utilities and also the number of publicly traded Canadian utilities is significantly less. Dr. Vander Weide believes that, in the past, United States utilities were more risky than Canadian utilities, but today they are comparable in risk. For this reason he does not believe adjustments are necessary. Dr. Vander Weide explains that he relies on analysts' projections of future earnings per share growth because he has found that analysts' growth forecasts are the best proxy for investor growth expectations.

Dr. Vander Weide's discounted cash flow analysis produces a result of 10.3% for his larger group of utilities and 10.1% for his smaller group. He explains that his larger group includes publicly-traded United States electric and natural gas utilities that meet five criteria and the smaller group is restricted further to utilities that have at least 80 percent of total assets devoted to regulated utility operations as well as an S&P bond rating of BBB or higher. He uses a constant growth method based on analysts' estimates of future earnings per share growth as reported by I/B/E/S Thomson Reuters. He explains that these estimates represent five-year forecasts of earnings per share growth and are used by investors as a consensus estimate of future firm performance.

Ms. McShane explains that the United States utility equity market is a much broader and deeper universe of companies from which to select a sample of comparable risk companies. To address concerns in relation to United States comparables she has, since the last general rate application, tightened her selection criteria in relation to credit ratings and put a cap on the amount of unregulated operations. She also provides an in-depth review and assessment of the different characteristics and regulatory risk characteristics of each of the companies. She believes that it is not necessary to make adjustments to the data since the cost of equity for the sample of companies is a reasonable proxy for the cost of equity for Newfoundland Power at its capital structure. Ms. McShane acknowledges that there is an ongoing debate around the accuracy of investment analysts' forecasts as the measure of investor expectations of growth. She states that the use of forecast GDP growth in a multi-stage model as the proxy for the rate of growth over the longer term is a widely utilized approach.

Ms. McShane's discounted cash flow results indicate a cost of equity of approximately 9.9%, using both Canadian and United States data and assuming an allowance for financing flexibility of 50 basis points. She estimates the cost of equity using five major publicly-traded Canadian utilities, using analysts' forecasts in both the three-stage model and the constant growth model. She believes that, in the case of the Canadian utilities, it is important to look at both the constant and multi-stage growth results because the constant growth model likely overstates the expected return and the three-stage model likely understates it. For the United States utilities she uses sustainable growth, three-stage growth and constant growth. For the constant growth model she relies on the earnings forecasts of four global providers of real time financial data with periods of between three and five years, which are intended to represent the normalized rate of earnings growth over a business cycle. She also provides growth estimates based on sustainable growth rates derived from Value Line forecasts of returns on equity, earnings retention rates and earnings growth from external financing. For the three-stage growth model she employs investors' forecasts for the first five years, an average for the next five years, and thereafter the long-run expected nominal rate of growth in GDP.

Newfoundland Power notes that the National Energy Board expressly recognized in 2009 that the integration of Canadian and United States financial markets makes comparisons informative for determining a fair return and further that the British Columbia, Ontario and Alberta Commissions now all consider United States based discounted cash flow results in informing their views of appropriate returns. Newfoundland Power submits:

> *"Now the second change... is with respect to US comparisons in determining the fair return. That's driven in part by increased reliance on the DCF methodology because it's not possible to construct a proxy group of Canadian utilities to apply the DCF model. There are only two publicly traded Canadian companies that you could use. It is possible, however, to construct a sample of US utilities, having comparable overall investment risk to Newfoundland Power. Each cost of capital witness did that, including Dr. Booth himself."* (Transcript, February 8, 2013, pages 20/15-25 to 21/1-3)

The Consumer Advocate notes that Dr. Booth has started to look at discounted cash flow estimates for both the United States and Canadian markets and that Dr. Booth indicated before the British Columbia Utilities Commission that the United States estimates need to be reduced by 90 to 100 basis points. The Consumer Advocate states:

> *"We believe that the evidence is very clear that you must make adjustments. As Dr. Booth notes, undeniably, long term bond yields are higher in the United States, at least 50 basis points higher than in Canada. He then says you look at the market risk premiums, historic evidence of the market risk premiums are of being higher in the United States, and you look at the Canadian utilities versus the US utilities. You can look at US evidence, but you have to make adjustments. Mr. MacDonald said the same thing."* (Transcript, February 8, 2013, page 69/2-13)

In relation to the analysts' growth estimates, the Consumer Advocate notes that the suggested return on equity decreases when you change from using analysts' growth estimates in the constant growth model to the multi-stage model to the sustainable growth model. The Consumer Advocate concludes:

> *"This is a clear indication that not only are the short run analyst's growth estimates unreasonable methods for long run growth, but that using the long run GDP growth rate also overestimates a reasonable long run growth rate. ... there is no evidence on the record to substantiate that either the Canadian or the US utilities were in fact able to achieve the GDP growth rate historically."* (Transcript, February 8, 2013, pages 61/15-25 to 62/1-7)

<u>Board Findings – Discounted Cash Flow Model</u>

The Board finds that the evidence demonstrates that Canadian utility data is inadequate to complete a discounted cash flow analysis and that, in the particular circumstances, it may be informative to look to data from the United States. As to how this data is to be used the Board accepts the evidence of both Dr. Booth and Mr. MacDonald that there are differences in the United States and Canadian experience that justify an adjustment to the discounted cash flow results. Dr. Booth suggests an adjustment of 100 basis points. Mr. MacDonald makes a 72 basis point adjustment. The British Columbia Utilities Commission has found that the United States data should be adjusted by between 50 and 100 basis points. The Board finds that an adjustment of 50 to 100 basis points is appropriate at this time.

In addition, the Board shares the concern expressed by the Consumer Advocate in relation to the use of analysts' forecasts which are intended to reflect expected growth over a three to five-year period to determine long-run growth expectations. The Board notes the results are significantly higher when analysts' forecasts are used in the constant growth method. The Board observes that Dr. Booth is skeptical as to the use of these forecasts and suggests that these forecasts should be used in two-stage models. The Board also notes the evidence of Mr. MacDonald that, over the long run, growth likely reverts to market average. The Board believes that a multi-stage model best reflects the available information and how it was intended to be used. The sustainable model used by Ms. McShane may also be informative.

The Board notes that, when the allowance for financing flexibility is included, Ms. McShane's discounted cash flow model suggests a return of 9.9%. This result reflects unadjusted United States data and the use of analysts' forecasts in the constant growth model. Mr. MacDonald's multi-stage United States indication is 9.55%. Dr. Booth's result for United States utilities is 9.23%. As the Board believes that adjustments must be made to the United States data and does not accept the use of analysts' forecasts using the constant growth model the Board would estimate an indicated return of 9.0% using the discounted cash flow model.

The Board will place less weight on the results of the discounted cash flow model and accepts that the estimated return on equity using the discounted cash flow is 9.0%.

ix) Fair Return on Equity

Newfoundland Power argues that its allowed returns on equity for 2010 through 2012 were amongst the lowest in Canada for investor-owned electric utilities, though the returns were sufficient to preserve its financial integrity. Newfoundland Power states:

> *"In setting the return, the Board should be mindful that Newfoundland Power's allowed ROE's since the last GRA have been below par. That was especially true in 2011, but it was also true in 2010 and 2012. So the allowed returns for those years are not the appropriate benchmarks for the return that you should set today.*
>
> *Now my friend Mr. Johnson, the Consumer Advocate, will say that the cost of equity has come down and I'm sure he will say to you Ms. McShane said so. But it hasn't come down from nine percent. It's come down from what the real cost of capital was in 2010.*

> *If you look at allowed utility returns in Canada, the average was 9.29 percent in 2010. It was 9.08 percent in 2012 and you'll find that information in the response to the PUB staff question PUB-CA-023 and find it in Ms. McShane's Schedule 3, page two of two. And the evidence of the cost of capital witnesses was that the financial market conditions in 2013, 2014 will be no different than in 2012. You'll find Dr. Booth's answer saying that at PUB-CA-015.*" (Transcript, February 8, 2013, pages 17/12-25 to 18/1-11)

The Consumer Advocate submits that the evidence establishes that Newfoundland Power overstates the return on equity required to maintain credit worthiness and to ensure it is able to issue further debt. He notes that Newfoundland Power has had financial integrity since the last general rate application and that the Board's financial consultant's report shows that, even if Newfoundland Power received no rate relief in either 2013 and 2014, it would still be meeting its credit metrics. The Consumer Advocate submits:

> "*It is one thing for company witnesses to come before the Board with a multitude of tests and methods, but the fundamental question is whether the results are reasonable. It is necessary to pause and consider that we are dealing with the fair ROE determination for a low risk utility. TD Economics, Royal Bank of Canada and Mercers have all been cited in Dr. Booth's evidence. These institutions are independent.*" (Consumer Advocate, Written Submission, page 27)

Dr. Booth states that cost of capital is not as complicated as experts make it and that the members of the panel should look at what independent economists such as TD Economics, the Royal Bank of Canada and Mercers are saying. He reports that on October 19, 2012 TD Economics projected long-run returns on equities in Canada of 7.0% which convert to an arithmetic return of 9.0%. Dr. Booth explains that three years ago Mercers estimated that the long-run return on the equity market was 8.5%. He states that there is no question that the estimates put forward by independent people looking at what we can expect in the equity market have come down significantly over the last three years. Dr. Booth also suggests that the Board look to the changes in the recommendations of the experts compared to the last general rate application and concludes:

> "*They're all unanimous that it goes down. Then I think that is where all of the experts are in unanimous agreement that the recommended ROE has gone down by 50-60 basis points. And if they think nine percent was fair in 2009, that means a level of 8.4 or 8.5 percent.*" (Transcript, January 18, 2013, page 145/5-11)

Dr. Booth states that since the collapse in interest rates, market to book ratios have gone well above one indicating that investors are very happy with the allowed returns. Dr. Booth notes that the 9.08% average cost of capital in 2012 in Canada, as set out in Schedule 3 of Ms. McShane's evidence, includes the return for some demonstrably more risky utilities than Newfoundland Power. Dr. Booth recommends a return for Newfoundland Power for 2013 of 7.5%. In the alternative, he recommends the Board fix the return on equity for a five-year period at 8.25%.

Dr. Vander Weide believes the cost of equity has declined recently, but not by nearly as much as the interest rate, and that it is still higher than the allowed returns in Canada. He recommends a cost of equity of 10.4%.

Ms. McShane explains that the cost of equity for a utility is probably 50 basis points lower than it was in 2009 and recommends a return on equity of 10.5%.

The Dominion Bond Rating Service states in its report dated February 14, 2013 that Newfoundland Power's financial profile has been reasonable for the rating category, supported by stable earnings and cash flow, as well as reasonable leverage. It expects Newfoundland Power's earnings to be relatively stable for 2013 as the majority of the earnings are derived from regulated operations. Moody's Investors Service, Credit Opinion: Newfoundland Power Inc., dated January 18, 2013, states that a downgrade revision of Newfoundland Power's rating is unlikely in the near term with a downgrade possible if there is a meaningful reduction in the level of regulatory support combined with a sustained deterioration in financial metrics such as CFO Pre-W/C to interest coverage of less than 2.6x, CFO Pre-WC to debt in the low teens and RCF to debt below 9.0%. Moody's Investors Service states:

> "*Despite the fact that NPI has one of the lowest allowed ROEs in Canada (8.80% for 2012), we continue to view the PUB as one of the more supportive regulators in Canada. Regulatory decisions tend to be timely and balanced and NPI's 45% deemed equity is one of the highest in Canada.*" (Exhibit JP-4, Moody's Investors Service, Credit Opinion: Newfoundland Power Inc., January 18, 2013)

<u>Board Findings – Fair Return on Equity</u>

The cost of capital recommendations of the experts can be summarized as follows:

Cost of Capital Summary of Expert Evidence				
Expert Witness	**Ms. McShane**[1]	**Dr. Vander Weide**	**Dr. Booth**	**Mr. MacDonald**
Capital Asset Pricing Model	**9.4%**[2]	**N/A**	**7.5%**	**6.84%**
Historic Equity Risk Premium	**10.75%**[2]	**9.9%**	**N/A**	**10.26%**
Forward-Looking Equity Risk Premium	**10.00%**[2]	**11.10%**	**N/A**	**N/A**
Discounted Cash Flow	**9.90%**[2]	**10.2%**	**N/A**	**9.63%**
Recommended Return on Equity	**10.50%**[2]	**10.40%**	**7.50%** **8.25%**[3]	**8.91%**

[1] Ms. McShane's recommendation in relation to the comparable earnings test is not shown.
[2] Ms. McShane's results reflect the accepted allowance for financing flexibility of 50 basis.
[3] Recommended in the alternative for a five-year period.

Taking Ms. McShane and Dr. Vander Weide as effectively supporting one recommendation on behalf of Newfoundland Power the range of fair returns recommended by the experts for Newfoundland Power is 7.5% to 10.5% with an average of 8.95% and a midpoint of 9.0%. The Board notes that Dr. Booth also recommended as an alternative that the Board could fix the return on equity for a five-year period at 8.25%.

The Board, after reviewing the evidence, finds that there are significant issues in relation to each of the methodologies used. The Board has in the past given preference to the capital asset pricing model but concludes that the current state of the bond market requires that more judgement be exercised in considering the results of this model. The Board finds that the estimated return indicated by the capital asset pricing model is 8.2%. The Board estimates that the historic and forward-looking equity risk premium models suggest a return of 9.3% but concludes that little weight should be given to these models. The Board notes significant issues with the discounted cash flow model and, in light of considerations around the use of United States data and analysts' growth forecasts, it will give less weight to the estimated return using the discounted cash flow test of 9.0%. The Board finds that the range of returns suggested by the methodologies is 8.2% to 9.3% with an average of 8.8%. If the historic and forward-looking equity risk premium results are excluded the average is 8.6%.

The evidence of the experts is clear that the cost of equity has declined since the last general rate application by approximately 50 basis points. The return established by the Board for Newfoundland Power for 2010 was 9.0%. In June of 2012 the Consumer Advocate and Newfoundland Power settled on a cost of capital for Newfoundland Power for 2012 of 8.8% which was accepted by the Board. The evidence in this proceeding does not suggest a significant change in forecasts for 2013 and 2014.

The evidence in relation to credit metrics is informative in relation to the issue of Newfoundland Power's credit rating and financial integrity. According to Exhibit 5 of the Application an allowed return on equity of 8.75% would result in an estimated cash flow interest coverage of 3.25 times and a cash flow to debt of 15.2%. This would keep Newfoundland Power well within acceptable financial metrics according to the Moody's Investors Service downgrade threshold as set out in the table below.

MOODY'S INVESTORS SERVICE DOWNGRADE THRESHOLD			
	2007	**2009**	**2013/14**
CFO Pre-W/C to interest coverage	3.0x	2.5x	2.6x
CFO Pre-W/C to debt	15%	low teens	low teens
RCF to debt			9.0%

(Source: Application Exhibit JP-4, Order P.U. 43(2009))

Considering the recommendations of the experts, the Board's analysis of the range of returns suggested by the accepted methodologies, the evidence in relation to changes and trends in market conditions and expected returns, and the evidence in relation to credit metrics, the Board believes that a fair rate of return on equity for Newfoundland Power for 2013 and 2014 is 8.80%.

The Board accepts that for the 2013 and 2014 test years a ratemaking return on common equity of 8.8%, with a deemed common equity component of 45%, will provide Newfoundland Power the opportunity to earn a just and reasonable return on rate base that is consistent with the fair return principle and the provision of least cost reliable power.

2. Automatic Adjustment Formula

Newfoundland Power submits that the Board should discontinue the use of the automatic adjustment formula, arguing that the formula has not provided a reasonable opportunity to earn a fair return each year. Newfoundland Power further argues that the divergent formulas proposed in this proceeding do not provide a basis for ensuring a reasonable opportunity to earn a fair return following the test years. Newfoundland Power submits that since 2009 there has been no broad consensus amongst Canadian utility regulators with regard to using an automatic adjustment formula with only the Ontario Energy Board and the Régie de l'Energie du Quebec maintaining a formula. Newfoundland Power states:

> "*The lack of consensus over automatic adjustment formulas arises because there's no longer any clear and predictable relationship between long Canada bond yields and a utility's cost of equity. The attempts in this hearing to create a formula proxy for a utility's cost of equity have resulted in proposals which are complicated and uncertain. The proposed formulas not only incorporate utility bond credit spreads, but they've also added floors and dead bands and automatic triggers. There's no principal basis for us to conclude that such mechanisms will correctly establish the cost of equity for Newfoundland Power.*" (Transcript, February 8, 2013, pages 24/23-25 to 25/1-12)

Ms. Perry testifies that Newfoundland Power does not propose a formula given the lack of consensus on the relationship between long-term Canada Bond yields and the utility's cost of capital. She states:

> "*I believe the proposed formulas demonstrate that lack of consensus. The 1.2 percent increase in long Canada bond yields in Mr. MacDonald's proposed formula would almost certainly increase Newfoundland Power's forecasted cost of equity. However, a 1.2 percent increase in Dr. Booth's proposed formula would either leave Newfoundland Power's forecast cost of equity unchanged or could potentially reduce it.*" (Transcript, January 10, 2013, page 162/12-21)

Ms. McShane explains:

> "*In light of the persistently unsettled capital markets and the unstable relationship between the utility cost of equity and Government bond yields, it would be, in my view, difficult to construct an automatic adjustment mechanism for return on equity at this time that would successfully capture prospective changes in the utility cost of equity. In particular, an automatic adjustment formula tied to changes in government bond yields has the potential to unfairly suppress the allowed ROE.*" (Ms. Kathleen McShane, Written Evidence, page 48)

Newfoundland Power submits that it is clear that there will be a continuing period of low long-term Canada bond yields for at least the next three years and that the best approach at this time is to discontinue the use of the formula and set a reasonable rate of return for Newfoundland Power with a cost of capital review if market conditions change. Newfoundland Power explains that the certainty of a known return which is fair and reasonable is preferable to the uncertainty of what a formula may or may not do in a world of uncertain financial markets which are driven by government monetary policy rather than normal market forces.

The Consumer Advocate supports the continued use of an automatic adjustment formula. He states that both Mr. MacDonald and Dr. Booth recommend a formula and he supports Dr. Booth's recommended formula. The Consumer Advocate states:

> "*This Board has a long history of using the formula and we regard Dr. Booth's recommendation as regards adjustment to changes in long Canada bond yields as reasonable, and in line with the Board's historical adjustment mechanism.*" (Transcript, February 8, 2013 page 84/18-23)

Dr. Booth explains that he recommends a formula because he was asked to but a formula is not the only option. He explains that he thinks it would also be reasonable to fix a return of 8.25% for five years and if Newfoundland Power feels it is unfair in two or three years it can apply to the Board for a finding that it is unfair at the time. The Consumer Advocate does not support Dr. Booth's suggestion that the return could be set for a period of five years or until a general rate application.

Mr. MacDonald explains that he believes a formula is appropriate because it creates regulatory certainty so that all the parties around the table understand what will happen in 2015 if there is no rate hearing. However, he confirms that he agrees with Dr. Booth that one of the alternatives that the Board should consider is simply setting a rate of return, and either party can come back and apply to change it as needed.

Board Findings – Automatic Adjustment Formula

The automatic adjustment formula was initially established for Newfoundland Power in Order Nos. P.U. 16(1998-99) and P.U. 36(1998-99). At the time the Board stated that there may be circumstances which would render the use of an automatic adjustment formula inappropriate for Newfoundland Power, including changes in financial market conditions which would suggest that the formula is not accurately reflecting the appropriate return on equity. In 2009, during its last general rate application, Newfoundland Power sought the discontinuation of the automatic adjustment formula. The Board rejected Newfoundland Power's request and ordered the continued use of the formula stating that it is fundamental to the multi-year regime in place in this Province and that it contributes to regulatory predictability and certainty. The formula was used to set Newfoundland Power's return in 2011 but, upon application from Newfoundland Power, the Board suspended the operation of the formula for 2012 and the return on equity was established by the Board after considering the negotiated settlement of the parties.

While the Board continues to see the value of an automatic adjustment formula, the evidence is clear that the formula as it is currently structured may not result in a fair return for Newfoundland Power in the current circumstances. Long-term Canada bond yields are abnormally low which is particularly problematic in the operation of the automatic adjustment formula. In the absence of a clear relationship between the long-term Canada bond yield and the cost of equity it is difficult to see that the established return can be appropriately adjusted for 2015 without the exercise of further judgement. Dr. Booth and Mr. MacDonald offered opinions as to changes that could be made to the formula to account for the unusual financial conditions. Ms. McShane and Ms. Perry doubted whether the current financial conditions could be effectively addressed in the formula. The Board accepts that in the circumstances it would be difficult to conclude that any formula could be relied on to establish a fair rate of return after the test years.

Newfoundland Power has applied for rates to be established based on two test years, 2013 and 2014. Newfoundland Power states that a three-year interval between general rate applications appears reasonable, and given this timeframe its next general rate application would be filed in June 2015 for a 2016 test year. The Board agrees with Newfoundland Power that a three-year period between general rate applications is generally consistent with sound utility regulation. Newfoundland Power states that it prefers the certainty of setting a rate of return for a period of time. The Board notes that the experts forecast a period of relative stability in the bond markets with continued low long-term Canada bond yields and a gradual return to normal levels over the next several years. Dr. Booth suggests that the Board could set a rate of return for five years, though this suggestion was rejected by the Consumer Advocate.

Given the Board's reservations in relation to the use of the formula in the circumstances the Board finds that, in the interests of regulatory efficiency and certainty, it is appropriate to continue Newfoundland Power's rate of return on common equity at 8.8% for 2015. The Board will monitor economic conditions throughout the period and, in accordance with normal process, if there is a dramatic change in circumstances which suggest that the established rate of return is unfair an application can be filed by Newfoundland Power or directed by the Board. To be clear the Board is not discontinuing the use of the automatic adjustment formula and, in the absence of a further Order of the Board, it will be used to establish a fair return for Newfoundland Power following its next general rate application.

The Board will not order the use of the formula to establish the rate of return after the 2013 and 2014 test years. The Board accepts that a ratemaking return on common equity of 8.8% in 2015, with a deemed common equity component of 45%, will provide Newfoundland Power the opportunity to earn a just and reasonable return on rate base that is consistent with the fair return principle and the provision of least cost reliable power.

The Board will require Newfoundland Power to file a general rate application with a 2016 test year on or before June 1, 2015.

3. Depreciation

Newfoundland Power does not propose to change its existing depreciation system and proposes to update depreciation rates and amortize an accumulated reserve variance of $2.6 million over the remaining life of the assets. These proposals would result in depreciation estimates for 2013 and 2014 of $46.6 million and $48.3 million, respectively, increasing the amount to be recovered in customer rates by approximately $0.7 million per year. These estimates are based on the depreciation study prepared by Gannett Fleming for plant in service at December 31, 2010.

The Consumer Advocate argues, based on the expert evidence of Mr. Jacob Pous, that the following adjustments should be made to Newfoundland Power's proposals:

(i) a change from the equal life group procedure to the average life group procedure;
(ii) changes to proposed mass property life analysis for seven accounts; and
(iii) a change to the proposed mass property net salvage analysis for one account.

The combined impact of these recommendations would be an annual reduction of approximately $10.5 million in depreciation expense beginning in 2013.

i) Equal Life Group Procedure

Newfoundland Power has used the equal life group procedure for many years and proposes the continued use of this procedure. The Board first accepted the use of the equal life group procedure for Newfoundland Power for new plant in 1978 with full adoption for all plant in 1982. The equal life group procedure mathematically estimates the life for each unit, subdivides property into groups having equal lives and then calculates depreciation for each equal life group based on the straight line method. Under the average life group procedure, each asset in the account is depreciated over the average life of the account.

Gannett Fleming has been performing depreciation studies for Newfoundland Power since 1995 and has used the equal life group procedure in each of these studies. Mr. Wiedmayer recommends that the equal life group procedure continue to be used by Newfoundland Power and explains:

> *"First of all, both the equal life group and the average life group procedures are accepted depreciation procedures in utility rate making. I have conducted numerous studies for utility companies using both procedures. Equal life group procedure has been used in Newfoundland by Newfoundland Power for over 30 years. Equal life group procedure is used by a majority of Canadian electric and gas studies based upon my knowledge of what other utilities are using, and we've provided a list of approximately 34 Canadian utilities in the exhibits that we filed and a slight majority use the equal life group procedure in Canada. I believe the equal life group procedure provides a more accurate estimate of the actual consumption of the service value of the property. The major advantage of equal life group procedure is that it more closely matches the depreciation charge with the service rendered during the life of the property than does the average life group procedure."* (Transcript, January 23, 2013, pages 45/5-25 to 46/1-2)

The Consumer Advocate acknowledges that the equal life group procedure may represent the best mathematical depreciation procedure in theory but submits that there is a valid basis to question whether, as applied in the real world of utility operation and ratemaking, it is the procedure that results in the best matching of the consumption and service value of the assets.

Mr. Pous states that the average life group procedure is the industry standard calculation and estimates that using this procedure would result in a total reduction of overall depreciation expense of approximately $7.0 million. He explains his concerns in relation to the equal life group procedure:

> *"While proponents of ELG claim that it is the most precise calculation procedure, they fail to note that that situation only exists in a theoretical world. In the reality of utility*

ratemaking or the real world, ELG is one of the least precise forms of depreciation and results in greater levels of true-up to correct for prior differences between estimates and actual retirement patterns." (Mr. Jacob Pous, Written Evidence, page 5)

Mr. Pous raises several concerns in relation to Newfoundland Power's use of the equal life group procedure, specifically:

(i) the equal life group procedure is not precise and will require a greater degree of true-up to correct for differences between forecasts and actuals;
(ii) the equal life group procedure is more time sensitive than the average life group procedure and is already outdated by the time it is presented in a depreciation study; and
(iii) Newfoundland Power's net salvage estimates and depreciation reserve are not calculated on an equal life basis.

Mr. Pous raises issues in relation to matching and intergenerational inequity and states:

"The reality is that for the past three decades customers have overpaid due to the implementation of ELG-based depreciation rates. Current customers and future customers will continue to receive this subsidy if the ELG calculation procedure is adopted. Alternatively, adoption of the ALG calculation procedure will result in a transition period of at least 11 to 15 years where customers during this period will receive lower levels of subsidies until they reach a level where they are back to paying the level of capital recovery they should have been paying all along, taking into account depreciation, return, and taxes." (Mr. Jacob Pous, Surrebuttal Evidence, January 18, 2013, page 14)

Mr. Wiedmayer argues that the equal life group procedure better matches capital recovery with the actual lives forecast by the estimated survivor curve, stating:

"As a result, the ELG procedure allocates cost in a manner that approximates the result of each asset being depreciated over its actual life. Conversely, the ALG procedure depreciates every unit of property within an account over the same life, that is, the average life. As Figure 2 shows, this average life will be incorrect the majority of the time-in this example, the average life will be the wrong life for 98.18% of the assets." (Mr. John Wiedmayer, Rebuttal Evidence, December 2012, page 8)

Mr. Wiedmayer explains that the benefits to customers of switching to the average life group procedure are time limited as the resulting higher rate base would eventually lead to a higher revenue requirement. Mr. Wiedmayer addresses the three issues raised by Mr. Pous as summarized below.

(i) The concern in relation to the precision of the equal life group procedure is overstated and is applicable to any calculation procedure, including average life group. Further, it is wrong to suggest that the equal life group procedure magnifies the degree of error to be corrected between depreciation studies.

(ii) The argument that the equal life group procedure is time sensitive is without substance and in reality Mr. Pous' proposal is as time sensitive as the continued use of the equal life group procedure.

(iii) The suggested inconsistency in relation to net salvage is overstated given that the net salvage estimates in depreciation studies tend to be conservative estimates of future net salvage. Further Newfoundland Power does not maintain its depreciation reserve on either an equal life group or average life group procedure basis and that since the equal life group procedure has been used for decades the cumulative depreciation accruals in the depreciation reserve are primarily based on equal life group depreciation accruals.

Newfoundland Power states that its revenue requirement is lower today as a result of the historic use of the equal life group procedure. Newfoundland Power concludes:

> *"ELG is a recognized sound public utility practice in Canada. It best matches the expense with the life of the utility assets. It also ensures the fulfilment of the power policy requirement of least cost power consistent with reliability over the long term. Customer rates today are 3.7 million dollars less annually because of the Board's decision to adopt ELG."* (Transcript, February 8, 2013, page 31/11-20)

The Consumer Advocate concludes:

> *"We advocate ALG as the method by which the vast majority of customers in North America have their depreciation expenses determined, and a method that does not result in a situation where depreciation accruals are higher in earlier periods and lower in later periods, and a method, in our respectful submission, that is more aligned with the reality of how depreciation actually gets implemented in the utility industry, and in rate cases."* (Transcript, February 8, 2013, page 101/6-16)

<u>Board Findings – Equal Life Group Procedure</u>

Depreciation is defined by the American Institute of Certified Public Accountants as follows:

> *"Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is a portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences."* (Mr. Jacob Pous, Written Evidence, page 7)

The *Public Utilities Act*, RSNL 1990, c. P-47, states:

> *68 (1) A public utility shall make provision for proper and adequate annual depreciation of its property and assets used and useful in providing or supplying each kind of service, and shall keep proper accounts.*

> *(2) The annual depreciation shall be calculated by the straight line method or by another method that the board may prescribe.*
> *(3) A public utility shall report to the board the annual rates of depreciation applied to the several classes of property of the public utility.*
> *(4) The board may ascertain and determine what are proper and adequate rates of depreciation of the several classes of property of a public utility, and the public utility shall conform its depreciation account to the rates so ascertained and determined.*
> *(5) The board may revise the rates of depreciation as it considers necessary or expedient.*

The Board finds that both the equal life group procedure and the average life group procedure are accepted depreciation procedures which are widely used by Canadian electric utilities and approved by Canadian regulators. The evidence does not demonstrate that the equal life group procedure results in improper or inadequate rates of depreciation or intergenerational inequity. The Board accepts that both procedures can be considered straight-line with the equal life group procedure grouping by asset life and the average life group procedure grouping by class of asset. The Board finds that the evidence does not demonstrate that the equal life group procedure is less precise or causes larger true-ups in the depreciation study updates. The Board accepts that the equal life group procedure is an industry standard approach for the determination of proper and adequate depreciation rates.

Newfoundland Power has been using the equal life group procedure for all of its assets since 1982. The Board is not persuaded to direct Newfoundland Power to abandon the equal life group procedure which has been approved and used by Newfoundland Power for decades. The evidence is clear that moving to the average life group procedure now would result in significant fluctuations in depreciation expense with rates dropping for several years to adjust for prior depreciation rates and thereafter increasing to levels which are higher than existing rates. Having found that equal life group is an accepted and reasonable procedure the Board will maintain a consistent approach and accept the continued use of the equal life group procedure.

The Board will accept Newfoundland Power's proposal to continue to use the equal life group procedure.

ii) Service Lives

Newfoundland Power has 57 mass property accounts. Gannett Fleming recommends an increase in the services lives for 27 accounts, a reduction of service life for 5 accounts and no change for 25 accounts. The Consumer Advocate has no objection to the recommended service lives for 50 of these accounts but, based on the recommendations of Mr. Pous, submits that Newfoundland Power's proposed life extension for seven accounts be further extended. The proposed estimated service lives are set out in the table below.

Estimated Service Lives
Current and Proposed

Account	Description	Currently Approved	Newfoundland Power Proposal	Consumer Advocate Proposal
355.1	Transmission Poles	44	47	51
355.2	Transmission Poles and Fixtures	44	47	51
361.12	Distribution Bare Aluminum	50	55	61
361.2	Distribution Underground Cables	40	45	57
362.1	Distribution Poles (Under 35')	45	48	57
362.2	Distribution Poles (35' and Over)	45	48	57
365.1	Services Overhead	39	44	51

(Source: Newfoundland Power, Written Submission, Table F-1)

Mr. Pous explains that he reviewed the major accounts of Newfoundland Power and for the seven accounts for which he is recommending adjustments he reviewed all actuarial analyses, Gannett Fleming notes in relation to input from Newfoundland Power personnel, industry information and responses to Requests for Information. He explains that based on this information and his extensive experience and knowledge, having performed hundreds of depreciation analyses throughout Canada and the United States, he is recommending adjustments to seven accounts. He calculates a reduction in depreciation expense of $2.8 million dollars if these adjustments are made.

The Consumer Advocate states:

> *"We submit, first of all, that the Board shouldn't give Newfoundland Power's depreciation expert an automatic pass on the accounts because of his relationship with Newfoundland Power and the fact that he's met with the company personnel. We would urge you to look at the evidence on each of the accounts and to see if it stands up to scrutiny."* (Transcript, February 8, 2013, page 102/2-10)

Newfoundland Power states that the essential issue in relation to service lives is the degree of life extension and explains that Mr. Pous proposes an average extension of approximately 25% beyond the existing service life for the seven accounts while Gannett Fleming proposes a 10% life extension. Mr. Wiedmayer believes that the extensions recommended by Mr. Pous are dramatic and should be supported by overwhelming evidence. Mr. Wiedmayer states:

> *"I think it's unreasonable to expect for mass property assets such as poles, overhead conductor, underground conductor services, to change as significantly as what the consumer advocate is proposed for these types of assets in one study over a five year period of time. I believe there's some risk that his – are maybe overstating the lives and in one study, I typically don't see that magnitude of change when I do studies for other utilities."* (Transcript, January 23, 2013, page 63/12-21)

Mr. Wiedmayer explains that the service life recommendations in the depreciation study are based on a number of factors including analysis of data, discussions with Newfoundland Power operating staff and management, prior life estimates and a general knowledge of the property. He believes that the recommendations of Mr. Pous are based on different interpretations of data accompanied by general, and often incorrect, assumptions about the property. Newfoundland Power submits that:

> "*There is no reasonable evidence on the record supporting changes of this magnitude. More significantly, there is no evidence whatsoever on the record of this Application indicating that the service lives recommended in the Depreciation Study are not reasonable.*" (Newfoundland Power, Written Submission, page F-11)

The specific accounts identified by Mr. Pous for adjustment are discussed below.

a.) Accounts 355.1 and 355.2 – Transmission Poles and Fixtures

The approved service life for these accounts is 44 years. Gannett Fleming recommends an increase to 47 years and Mr. Pous recommends an increase to 51 years.

Mr. Pous believes the service lives for the assets in these accounts can be extended beyond that recommended by Gannett Fleming based on the historical data and the inspection program. Mr. Pous states:

> "*As noted by Gannett Fleming in its 2010 Study, there have been many improvements over the past 5 years to the Company's Transmission system and generally in the industry for the past several decades. Those recent improvements obviously have not been in place long enough to be adequately or realistically reflected in the historical actuarial analysis. This fact is significant given that approximately 25% of the current investment has been added in just the past 5 years and approximately 40% of the investment has been added in the last decade*" (Mr. Jacob Pous, Written Evidence, pages 26-27)

In relation to the inspection program Mr. Pous states:

> "*This is the first utility that I am aware of that claims no life related benefits relating to inspection programs. Indeed, even Mr. Wiedmayer noted in response to CA-NP-084 that the new testing programs allow the Company to better target replacements and <u>maintenance</u>. In other situations, utilities are able to extend service lives for poles due to better maintenance practices. In addition, while inspection programs normally do result in an initial wave of retirements because they identify poles that will have a higher probability of failure in the future and proactive steps are taken to replace those most at risk, they also result in longer life expectancy for the remaining poles that, absent the inspection, would eventually fail earlier than they would otherwise.*" (Mr. Jacob Pous, Surrebuttal Evidence, January 18, 2013, page 34)

Mr. Wiedmayer states that Mr. Pous' estimates ignore significant data points and are not based on any additional information other than that provided in the depreciation study. Mr. Wiedmayer believes that the reliability program will lead to more retirements in the future since certain poles that would have been retired upon failure will be replaced earlier. He also notes that pole treatments over the years have become more environmentally friendly but less effective in preventing decay.

Mr. Smith, Newfoundland Power's Vice-President of Engineering and Operations, spoke to the impact inspection programs can have on the service life of assets, explaining:

> *"Inspection practices have impacts on the service lives of the company's assets. For certain assets such as substation equipment, inspections will tend to increase service lives. For other assets, such as poles and wires, inspections tend to decrease service lives."* (Transcript, January 25, 2013, page 13/3-9)

b.) Account 361.12 – Bare Aluminum Cables

The approved service life for this account is 50 years. Gannett Fleming recommends an increase to 55 years and Mr. Pous recommends an increase to 61 years.

Mr. Pous explains that his recommendation is based primarily on the actuarial data. He states that Mr. Wiedmayer's reference to data from the period 2000-2009 reflects a period too short to provide statistically credible results. He explains that a longer life expectancy for a conductor is anticipated given the industry practice of more inspection programs and better design criteria and concludes that the more recent experience provides additional insights to trends. He rejects the assertion that inspection programs result in shorter lives and believes that inspection programs should result in better maintenance on a more timely basis and ultimately yields a longer life expectancy for associate assets.

Mr. Wiedmayer points out that Mr. Pous relies on a 1990-2009 experience band to support a longer service life, when a more detailed analysis of more recent activity shows that the trend is actually to increasing levels of retirements. He notes that retirements declined in the 1990s, during the downturn in the economy, and increased significantly starting in 2000 and, further, that this upward trend is expected to continue. Mr. Wiedmayer comments on the impact of the reliability program as follows:

> *"Further, the impact the reliability program will have on poles will – if anything - also tend to shorten the lives of overhead cables. Since due to the reliability program the poles in service will generally have less decay and will be stronger structurally, the impact of the elements (such as storms and wind) will have less of an effect on poles. Instead, the elements will have a greater effect on conductors. In other words, wind that would damage decaying poles will not knock down stronger, newer poles, but will instead be more likely to damage the cable on the poles (which is less strong than the poles).*
>
> *Thus, contrary to Mr. Pous' implication in his testimony, the effect of the Company's reliability program will not be to extend the lives of the aluminum conductor."* (Mr. John Wiedmayer, Rebuttal Evidence, December 14, 2012, Appendix B, page 9)

c.) Account 361.2 – Underground Cables

The approved service life for this account is 40 years. Gannett Fleming recommends an increase to 45 years and Mr. Pous recommends an increase to 57 years.

Mr. Pous believes that the service life for this account can be extended given that over the past forty years there have been improvements in underground cable. Mr. Pous states that life expectancy for new cable is significantly longer than the life expectancy for cable placed in service over twenty years ago. In looking to industry experience he explains:

> "*It was not uncommon to see one group of utilities reporting life expectancies in the mid-30 to 40-year age range when relying on older type of cables in actuarial analyses and other utilities reporting 50-plus year life expectancy for cable when the newer and improved types of cable are mainly reflected in the historical actuarial analyses.*" (Mr. Jacob Pous, Written Evidence, page 33)

Mr. Pous states that his recommendation represents the most realistic expectation for the newer type of investment reflected in this account, especially given that approximately 50% of the investment in this account was made after 1990.

Mr. Wiedmayer states that an increase in average service life is warranted given the few retirements in recent years but that, as a result of the small number of retirements, care should be taken not to increase the service life too much in one study. He explains that a comparison with the experience of other utilities provides evidence that Newfoundland Power's level of retirements cannot continue. Mr. Wiedmayer states that the estimated life proposed by Mr. Pous is outside the typical experience for most companies. Mr. Wiedmayer also explains that there are a number of reasons that Newfoundland Power may experience a shorter life for this account than others in the industry. He explains that, unlike many companies, approximately 80% of Newfoundland Power's cable is not installed in conduit and also Newfoundland experiences harsher freeze and thaw cycles. Mr. Wiedmayer states that it is more reasonable to increase the average service life consistent with others in the industry rather than the dramatic increase proposed by Mr. Pous.

d.) Accounts 362.1 and 362.2 – Wood Poles and Fixtures

The approved service life for these accounts is 45 years. Gannett Fleming recommends an increase to 48 years and Mr. Pous recommends an increase to 57 years.

Mr. Pous explains that, in consideration of the results of the actuarial analysis and recognizing that the vast majority of investment is associated with treated poles, and that a pole inspection and maintenance program has been implemented, an extension to 57 years for these accounts is a conservative estimate. He states:

> "*Moreover, it is illogical and unsupported that capital expenditures to strengthen the aging infrastructure and to provide better maintenance practices will not result in a longer life expectancy than what might occur absent such efforts. Indeed, the Company has not been able to show that its changing data capture practices has in fact shortened the life expectancy for the investment in these accounts rather than lengthening them.*" (Mr. Jacob Pous, Surrebuttal Evidence, January 18, 2013, page 47)

Mr. Wiedmayer recommends an extension for these accounts based on historical information and discussions with Newfoundland Power and believes that historical data and improvements in treatments and inspection programs do not justify the dramatic increase in service life of 12 years or 27% proposed by Mr. Pous. Mr. Wiedmayer states that Mr. Pous placed too much reliance on the retirement pattern of 2004 – 2010, which differed from prior years due to a change in data collection and maintenance, and that Mr. Pous is also mistaken in his interpretation that improved wood pole treatment and inspection programs support longer service lives. Mr. Smith spoke to the impact of inspection programs on poles explaining:

> "*For many distribution assets, such as poles and wires, the impact of inspection practices may be different. For the most part, poles and wires are inspected to determine if they need to be replaced. There's very little in the way of maintenance which can be done to extend the lives of these assets.* (Transcript, January 25, 2013, page 12/10-17)

e.) Account 365.1 – Overhead Services

The approved service life for this account is 39 years. Gannett Fleming recommends an increase to 44 years and Mr. Pous recommends an increase to 51 years.

Mr. Pous explains that his analysis includes data from 1967 through 2009. He notes that all of the remaining investment in this account was placed in service after 1967 and therefore reliance on the older actuarial data fails to correspond with the current investment in the system and fails to recognize the trend to longer service lives for current investment. He states:

> "*In other words, Gannett Fleming's presentation depicts retirement patterns over the past approximately 60 years. During this time frame, the industry has experienced changes in design, installation, and materials. Indeed, proper analysis dictates review of additional and more current placement and experience bands in order to determine whether there are changes in life characteristics.*" (Mr. Jacob Pous, Written Evidence, page 39)

Mr. Wiedmayer notes that Mr. Pous recommends an increase in the service life of 12 years or 31%. Mr. Wiedmayer believes that the best representation of service lives can be obtained by using the longest experience band available. He states:

> *"Over a long period of time, it is common for utilities to experience increases and decreases in the level of retirements and capital spending, due to a number of factors including capital budget cycles and economic conditions (such as those arising from the cod moratorium). As a result, there are a number of cyclical trends that can be misinterpreted as permanent trends if experience bands that are too short are used."* (Mr. John Wiedmayer, Rebuttal Evidence, December 14, 2012, Appendix B, pages 25-26)

Mr. Wiedmayer also states that, contrary to Mr. Pous' position, there have not been any significant changes in the industry that would impact service lives and that Mr. Pous' analysis places too much emphasis on the unusually low level of capital spending during the 1990s.

Board Findings - Service Lives

The Consumer Advocate submits that the life extension recommended by Gannett Fleming should be further extended for seven accounts. The average life extension recommended by Mr. Pous is approximately 25% as compared to the approximate 10% increase recommended by Gannett Fleming. The Board sees merit in the more conservative approach to life extension supported by Mr. Wiedmayer. The Board also acknowledges that a new depreciation study is completed regularly and trends can be further adjusted as appropriate in the next study. The Board finds that Newfoundland Power's proposals are fully supported by the evidence. While Mr. Pous provides an alternate approach which may also be considered to be reasonable, Mr. Wiedmayer responded to each of the issues raised and provided a satisfactory explanation in each case.

The Board will accept Newfoundland Power's proposals in relation to the service lives of its 57 mass property accounts.

iii) Net Salvage

The Consumer Advocate has proposed a change in the net salvage value for one account – Overhead Services. Net salvage is the salvage value of an asset less the cost of removal. Gannett Fleming has recommended a negative 60% net salvage value for Overhead Services, which is unchanged from the 2005 depreciation study. Mr. Pous recommends the use of a negative 40% salvage value for this account which he estimates would result in an $0.6 million reduction in annual depreciation expense.

Mr. Pous believes that Newfoundland Power's proposal is excessively negative and notes that the level of net salvage experienced by Newfoundland Power over the last ten years has ranged from negative 107% to negative 29%. He states that variances of this magnitude could be attributable to a variety of factors including the number of services retired per year or economies of scale. Mr. Pous believes that the past ten years of historical data affirms the concept of economies of scale, which is not adequately reflected in a simple arithmetic average over extended periods of time. Mr. Pous also questions Newfoundland Power's allocation of costs in the estimate of net salvage and states that he is not aware of any other utility that allocates 50% of the labor charges to the cost of removal. He states:

> *"Indeed, in my opinion, it would be difficult to present a scenario under which an equal sharing of labor costs is appropriate for the removal of a service compared to the installation of a service."* (Mr. Jacob Pous, Written Evidence, page 43)

Mr. Pous notes that the industry reports a rather wide range of values but that his recommendations are within the range of values reported.

Mr. Wiedmayer states that the recommended net salvage estimates are based on historical data, information provided by Newfoundland Power personnel and experience in the industry. Mr. Wiedmayer believes that the historical indications are relevant since Newfoundland Power personnel indicated there were no intended changes. Mr. Wiedmayer says that net salvage has trended more negative in recent years and this trend continued in 2010. Mr. Wiedmayer states:

"His (Mr. Pous) argument appears to be that higher quantities of services will be retired in the future, and therefore the costs will be lower. However, as detailed in Appendix C, he offers no evidence to support his claim. Instead, a more thorough analysis of trends in the Company's data and additional information specific to Newfoundland Power shows both that economies of scale will have a muted impact on net salvage for this account, and other factors that result in increasing cost of removal will offset any efficiency gains from economies of scale." (Mr. John Wiedmayer, Rebuttal Evidence, December 14, 2012 pages 27-28)

Mr. Wiedmayer believes that Newfoundland Power's allocation of replacement cost is reasonable and explains:

"In Newfoundland Power's experience, when performing a replacement of the service, the crew doing the work does on average spend a similar amount of time on each activity (removing the old service and installing the new service). For this reason alone the 50% allocation rate is reasonable. (Mr. John Wiedmayer, Rebuttal Evidence, December 14, 2012, pages 28-29)

Newfoundland Power provides a detailed breakdown of the activities associated with Overhead Service Replacement and on average a similar amount of time is required for removing the old service and installing the new service. Mr. Wiedmayer concludes that this is reasonable and further that negative 60% for Overhead Services is quite typical.

Board Finding - Net Salvage

The Board finds that the net salvage for Overhead Services has been fully justified based on Newfoundland Power's historical experience, detailed work description and Mr. Wiedmayer's evidence. Mr. Pous notes that the historical data demonstrates a wide range in the level of net salvage for Overhead Services and he believes that economies of scale may reduce the level in the future. Should the circumstances contemplated by Mr. Pous develop, the impact on net salvage for Overhead Services will be reflected in the next depreciation study.

The Board will accept Newfoundland Power's proposed net salvage for the Overhead Services account.

iv) Depreciation Rates

Newfoundland Power proposes to adjust the depreciation expense to amortize the accumulated reserve variance of $2.6 million over the account's composite remaining life. No representations were made in this proceeding in relation to this proposal.

Grant Thornton reviewed the depreciation expense and concludes that the results and recommendations of the 2010 depreciation study have been incorporated into the depreciation estimates for 2013 and 2014. Grant Thornton notes that the proposal to amortize the reserve variance over the account's composite remaining life differs from past practice but will decrease the revenue requirement.

The Board is satisfied that Newfoundland Power's proposed depreciation rates are proper and adequate.

The Board will approve Newfoundland Power's proposal to adjust the depreciation expense to amortize the accumulated reserve variance of approximately $2.6 million over the account's composite remaining life. The Board will approve the depreciation rates proposed by Newfoundland Power.

v) Depreciation Study

The evidence supports the filing of a new depreciation study every three to five years. No representations were made in this proceeding as to the specific timing of Newfoundland Power's next depreciation study. The Board has ordered Newfoundland Power to file its next general rate application on June 1, 2015. To ensure that the 2016 test year revenue requirement reflects the most up-to-date depreciation information the Board will require Newfoundland Power to file its next full depreciation study relating to plant in service as of December 31, 2014 with its next general rate application.

Newfoundland Power will be required to file its next depreciation study relating to plant in service as of December 31, 2014 with its next general rate application.

4. Operating Costs

i) Other Post Employment Benefits

Newfoundland Power maintains an Other Post Employment Benefits Plan ("OPEBs") for its employees which provides benefits to retired employees including drug coverage. Newfoundland Power proposes to include the OPEBs expense determined by its actuarial consultants, Mercer (Canada) Ltd., of approximately $10.4 million in the 2013 and 2014 test years' revenue requirement.

The Consumer Advocate submits that the OPEBs expense proposed to be included in the 2013 and 2014 test years should be reduced to reflect provincial drug policy and regulations implemented in April 2012 limiting the price of generic drugs. The Consumer Advocate states that the estimates provided by Mercer (Canada) Ltd. for OPEBs expense do not reflect the introduction of this legislation. The Consumer Advocate states:

> "*The Mercer approach is accepted and standard for purposes of financial reporting. However, this actuarial methodology was not designed to be a forecast that would meet the generally accepted standards for determining the forecast costs for a test year that should be recovered in rates set by a regulator. Any forecast of costs that are to be included in rates should reflect all known cost drivers that will result in higher or lower rates than are derived by simply extrapolating past costs. This extrapolation approach would never be accepted for forecasting energy demand, labour costs, or any other expense included in the company's revenue requirement. It is not acceptable for forecasting OPEBs costs either.*" (Consumer Advocate, Written Submission, page 38)

The Consumer Advocate submits that, in forecasting any cost to be recovered in rates, the best available estimate of the impact of any known cost driver should be used, rather than assuming a known cost driver will have no impact. He argues that Newfoundland Power ratepayers are entitled to enjoy the benefit of the legislated savings on a timely basis. He acknowledges that the information on the record may not enable a precise forecast of the impact of the reduced drug costs on the OPEBs expense but, based on the testimony of Ms. Perry, he estimates that it would be reasonable to assume a 6% reduction in OPEBs expense. He submits that it is more reasonable to assume this reduction than no impact. He also submits that the Board need not be concerned that such an adjustment may not be accurate as the OPEBs Cost Variance Deferral Account will ensure actual costs are passed on to the ratepayer.

Newfoundland Power explains the regulation was not reflected in the OPEBs expense for 2013 and 2014 and states:

> "*The impact of the Regulations on Newfoundland Power's long-term health care cost, trend which is used in calculating the Company's OPEBs expense and valuation, however, is currently uncertain. The health care cost trend assumption is based on historic claims experience; expectations related to aging and drug consumption; and long- term expectations for future drug cost increases. The impact of the Regulations on Newfoundland Power's OPEBs Plan is unpractical to quantify at this time, however, to the extent that the implementation of the Regulations does impact the Company's long-term health care cost trend, it will be fully reflected in future OPEBs valuations.*" (CA-NP-683)

Ms. Perry testified that she had discussions with Mercer (Canada) Ltd. and Blue Cross and was advised that it was not practical to forecast the impact of the new regulation on the health care trend rate in relation to the plan. She explains that the results will be monitored and any reduction in cost will be reflected in the OPEBs expense and reflected through the deferral account. Newfoundland Power explained:

> "*And succinctly summarized, Ms. Perry made the following observations: Newfoundland Power followed the usual process of forecasting drug costs based upon the health care trend numbers provided by Mercers. Mercers said the effect of the new drug regulation was impractical to quantify at this point in time. Overall drug costs depend not only on price but also drug usage. Further, Newfoundland Power already has pricing agreements with pharmacies through Blue Cross which provide better prices than current on drugs. And the forecast drug costs are based upon the best information currently available.*
>
> *The Consumer Advocate's assertion that a six percent cost reduction will occur is unfounded speculation without any evidentiary basis. It is no basis for this Board to conclude that the forecast expense is unreasonable and imprudent.*" (Transcript, February 8, 2013, pages 34/8-25 to 35/1-2)

Board Finding - OPEBs

The amount of the proposed OPEBs expense is based on the recommendations of Newfoundland Power's actuaries, determined in accordance with usual practice. The Board accepts

Newfoundland Power's explanation that there are numerous factors that will influence the impact of the regulations and that it is not practical to forecast the impact on the plan at this time. The Consumer Advocate submits that the benefits of the regulation changes should be flowed to ratepayers in a timely fashion. Using the limited information available he estimates the impact of the regulation changes on OPEBs expense to be a 6% reduction. He argues that the estimated reduction is preferable to no adjustment and that the difference from actual can be flowed through the deferral account. The Board does not believe that it is reasonable to make adjustments to the proposed expense which has been forecast using industry standard approaches, unless there is convincing evidence that the expense should be adjusted and the amount of the adjustment can be reasonably determined. The Board notes that, to the extent that the actual OPEBs expense varies from the forecast amount, it will be flowed through to ratepayers through the operation of the deferral account in the July 1 rate adjustment in the following year.

The Board accepts the forecast OPEBs expense for the 2013 and 2014 test years.

ii) Retirement Allowance

Newfoundland Power's compensation package for its employees includes a retirement allowance for both unionized and non-unionized employees with ten or more years of service. The retirement allowance is calculated by multiplying the basic weekly salary by the years of continuous employment to a maximum of twenty-four weeks. Newfoundland Power forecasts that total retirement allowance payments for unionized and non-unionized employees will be $631,000 in 2013 and $889,000 in 2014.

The Consumer Advocate submits that the revenue requirement for 2013 and 2014 should not include any recognition of future retirement benefit costs in the form of retirement allowances for non-unionized employees who commence employment with Newfoundland Power during the test years 2013 and 2014 or beyond. The Consumer Advocate acknowledges that payment of the retirement allowance to unionized employees is a term of Newfoundland Power's collective agreement but submits that there is no contractual obligation to provide a retirement allowance to new non-unionized employees. The Consumer Advocate submits that:

(i) there is no evidence that this benefit is needed in order to attract and retain employees;
(ii) there is a growing trend away from the payment of retirement allowances;
(iii) workforce demographics indicate that the present time is an ideal time to address the practice; and
(iv) the transition from a defined benefit pension plan to a defined contribution pension plan did not negatively impact Newfoundland Power's ability to attract qualified employees.

Newfoundland Power explains that retirement allowances are paid in recognition of an employee's long service and have been included in Newfoundland Power's collective agreement with its employees for in excess of twenty years. Mr. Smith explains that there is more pressure than ever to make sure that Newfoundland Power has a good package to ensure that it gets the best employees. Newfoundland Power notes that the retirement allowance developments in New Brunswick and the Federal civil service cited by the Consumer Advocate were not introduced in evidence and do not represent any evidence of changes in retirement allowances in Newfoundland and Labrador. Newfoundland Power submits:

> *"But keep in mind retiring allowances are one part of a total compensation package. Changing any one component necessarily requires adjustment to other components to ensure that the total compensation package remains competitive and you must be competitive, especially in today's environment. So there is simply no basis to conclude that the test year estimate of costs for labour overall is unreasonable or imprudent."* (Transcript, February 8, 2013, pages 35/25 to 36/1-10)

Board Findings - Retirement Allowances

The Board believes that the design of Newfoundland Power's overall compensation package goes to the core of the discretion of management to attract and retain its workforce. The Board will defer to the determinations of management in this regard unless the evidence demonstrates that unreasonable or imprudent costs may be passed on to ratepayers. Newfoundland Power provided evidence that the retirement allowance is a part of the package which has been in place for a number of years to reward long service employees and attract new employees. There is no evidence that the overall compensation package is unreasonable or that labor costs are imprudent. The evidence does not establish that retirement allowances are uncommon in compensation packages in Newfoundland and Labrador. In the absence of evidence demonstrating that Newfoundland Power's retirement allowance is unreasonable, the Board defers to the management of Newfoundland Power as to the compensation package which is appropriate to attract and retain its workforce.

The Board will not exclude expenses associated with Newfoundland Power's retirement allowance for new non-unionized employees from the revenue requirement in the 2013 and 2014 test years.

iii) Short Term Incentive Plan

The Consumer Advocate submits that the revenue requirement for 2013 and 2014 should not include expenses in relation to the portion of the Short Term Incentive Plan for executives and managers that relates to achieving earnings targets. He argues that the achievement of these targets is for the primary benefit of shareholders and not ratepayers. In support of his position the Consumer Advocate provides regulatory precedent from the Public Utilities Board of the Northwest Territories, the Alberta Energy Utilities Board and the Ontario Energy Board. He submits that Newfoundland Power's earnings based compensation targets are not truly distinguishable from these regulatory precedents and urges the Board to not allow the inclusion of expenses in relation to this portion of the Short Term Incentive plan in revenue requirement for the test years.

Newfoundland Power explains that earnings have been a component of its Short Term Incentive Plan since 1997 and that the Board has found this to be reasonable. Newfoundland Power states:

> *"Sound financial management, including earning the return allowed by the Board, remains a critical component of Newfoundland Power's least-cost service delivery to its customers. Recognition of this in an STI plan has accordingly been consistently included by the Board in Newfoundland Power's cost of service."* (CA-NP-452)

Newfoundland Power explains that the regulated utility cost of service in British Columbia, Alberta and Prince Edward Island includes executive compensation with a financial performance factor.

Ms. Perry explains that the earnings target in the Short Term Incentive plan exists to incent senior management to achieve the return on equity approved by the Board for ratemaking purposes. She explains that in Newfoundland Power's last general rate application Karl Aboud of Hay Group indicated that Newfoundland Power's total compensation, including the Short Term Incentive plan, is benchmarked to the 50th percentile of the Canadian commercial industrial group. She notes that ratepayers do not fund the total compensation paid to Newfoundland Power executives. Any amounts paid in excess of 100% of the Short Term Incentive targets are effectively funded by the shareholder as are Newfoundland Power's long term incentives which in 2011 totalled $309,000 for Mr. Ludlow, Ms. Perry, Mr. Smith and Mr. Alteen. Newfoundland Power states that the non-regulated Short Term Incentive payouts were approximately $170,000 in 2011. Mr. Ludlow explains that he does not agree that shareholders are the primary beneficiary of earnings related targets in the Short Term Incentive Plan, stating that a balance has to be struck in relation to earnings and financial integrity.

Newfoundland Power notes that Dr. Booth acknowledges that incompetent management can lead to unstable earnings and ultimately a higher rate of return. Newfoundland Power explains that earnings are important for both investors and customers:

> *"As I discussed earlier, management has an obligation both to its shareholders and to its customers to work hard to earn comparable returns. Unless the utility actually earns a fair return, credit metrics deteriorate, bond ratings are jeopardized, borrowing costs potentially increase and customers suffer. The Electrical Power Control Act makes it clear that maintaining a sound credit rating is an important objective."* (Transcript, February 8, 2013, pages 36/19-25 to 37/1-4)

Board Findings - Short Term Incentive Plan

The Board notes that there have been some changes in Newfoundland Power's Short Term Incentive Plan since the last general rate application, but there is no evidence that these changes are unreasonable and the Consumer Advocate makes no submissions in this regard. Total compensation including the Short Term Incentive payouts is in the 50th percentile of Canadian comparables. Shareholders pay the cost of the Short Term Incentives that exceed 100% of target as well as the entire cost of the long term incentives. Newfoundland Power's overall methodology for setting executive and management compensation has been comprehensively reviewed on numerous occasions over the last number of years and in Order Nos. P.U. 36(1998-99) and P.U. 19(2003) the Board accepted the level of executive compensation. No new evidence was presented in this proceeding demonstrating that it is now unreasonable.

The Consumer Advocate argues that the earnings provision in the performance based incentive is for the primary benefit of shareholders and not ratepayers. The Board notes that Mr. Ludlow and Dr. Booth both explain that shareholders also benefit when Newfoundland Power's earnings are consistently within the allowed range. The Board finds that the evidence shows that a stable well managed company that consistently earns its allowed return will, keeping everything else equal, be considered less risky and will therefore require a lower return and have easier access to financing for its operations and capital program. The Board accepts that ratepayers benefit if earnings are consistently within the allowed range. The Board finds that there is insufficient evidence to deny the recovery of the costs of the Short Term Incentive Plan related to financial performance.

The Board will not exclude expenses associated with the financial performance factor in Newfoundland Power's Short Term Incentive Plan from the revenue requirement for the 2013 and 2014 test years.

5. Conservation Program

Over the years Newfoundland Power and Newfoundland and Labrador Hydro have worked together to implement a portfolio of customer energy conservation programs. To be responsive to customers' desire to lower their electricity bills, Newfoundland Power introduced a broader customer energy conservation portfolio in 2009. Newfoundland Power and Newfoundland and Labrador Hydro recently reassessed the programs and developed a new plan as set out in a report, *Five-Year Energy Conservation Plan: 2012-2016*, which Newfoundland Power filed with the Application. The principal changes to the programs are as follows:

(i) discontinuation of certain residential incentives for minimum building code compliance for new construction as a result of changes to the National Building Code of Canada;

(ii) introduction of new residential customer programs such as an incentive for the installation of heat recovery ventilators; and

(iii) expansion of commercial customer programs such as the commercial lighting program.

The total conservation costs for 2013 and 2014 are forecast to be approximately $4.8 million each year, increased from approximately $3 million per year. It was agreed in the Settlement Agreement that conservation program costs would be amortized over a seven-year period. Newfoundland Power states that the increase in the total customer energy conservation costs reflects the expansion of customer energy conservation program offerings, as well as additional market research and customer education and support activities. Newfoundland Power estimates that this program will result in lower customer electricity bills and additional avoided Holyrood production costs of approximately $9.4 million annually by the end of 2014. Newfoundland Power explains that the breakeven point on the 2013 and 2014 conservation costs will be about two and a half years and energy savings will continue for years into the future.

Mr. Smith summarizes Newfoundland Power's conservation programs:

> "*Our customers are indicating they want to conserve energy and lower their electricity bills. We're responding to this with energy conservation programs. There have been over 17,000 participants since the program began in 2009. Based on our experience, Newfoundland Power and Hydro recently reassessed the portfolio of programs. The results are reflected in the five year energy conservation plan, which is provided in Volume II of the Application. The primary change in the five year plan is to improve program accessibility. The new plan is intended to reach a broader scope of customers, not just those with electric heat. The biggest area of expansion is the small technologies program for residential customers, and a new program for commercial customers. Participation in the expanded plan will help customers lower their electricity bills.*" (Transcript, January 25, 2013, pages 6/12-25 to 7/1-6)

The Consumer Advocate states:

> "*The Consumer Advocate is encouraged with the greater emphasis being placed on conservation and acknowledges that each utility reports growing customer participation in their programs.*" (Consumer Advocate, Written Submission, page 49)

However, the Consumer Advocate raises an issue relating to the discontinuation of the residential Insulation Program.

> "*There is concern however that in circumstances where 96% of electricity customers indicated the primary motivation for trying to cut back on electricity use is to save money by lowering their electricity bill (Plan, p. 11., footnote 21) that the 2012 Plan reflects that spending will decrease over the 2012-2016 period in relation to the residential Insulation Program (Schedule "A", p. 2 of 2; Schedule "C', p. 2 of 3). This is a concern because the Insulation Program has resulted in the highest amount of energy savings of all programs in the portfolio. While the need to incentivize insulation in new housing stock has been lessened due to changes to building standards, the existing housing stock in the province still remains and given that insulation produces energy cost savings at the household level which are noticeable to customers in their monthly bills, it should be enhanced.*" (Consumer Advocate, Written Submission, page 49)

During the hearing, Mr. Winston Adams made a detailed presentation relating to Newfoundland Power's conservation program. Mr. Adams concludes after completing a comprehensive analysis that the program is lacking not only in funding but in scope and opportunity. He raises the potential of mini-split heat pumps and explains that he is concerned that Newfoundland Power is not targeting the insulation program for older stock houses. He states:

> "*In conclusion, the conservation plan as proposed is inappropriate in funding and in measures selected, and has no meaningful beneficial impact for the rate payer. It does little to reduce system peak loads, the high cost of which is put on the rate payer. The utilities, both Newfoundland Power and Newfoundland Hydro, should be replaced by others with this mandate. In addition, rates that give discounts for more power use should be changed, as it discourages conservation, and 400 amp residential services also discourages efficient heating systems, adding to utility asset costs.*" (Transcript, January 31, 2013, page 49/9-22)

The Consumer Advocate recommends a review process explaining:

> *"The Consumer Advocate submits the merits, shortfalls, criticisms, recommendations and areas of improvement that arise from the 2008 Plan and the recently filed 2012 Plan requires a process involving both utilities in a framework which allows for the proper examination of the various issues. The Consumer Advocate would recommend that the Board therefore initiate a process in consultation with the utilities and the Consumer Advocate that would allow an appropriate review of the Plans involving interested parties and providing an opportunity for input."* (Consumer Advocate, Written Submission, page 51)

Newfoundland Power explains that the mini-split heat pumps referenced by Mr. Adams are being evaluated by the utilities but a proper cost benefit analysis requires information on energy supply costs and the potential savings which is not currently available. Newfoundland Power states:

> *"However, Newfoundland Power and Newfoundland Hydro will be assessing this technology and its potential costs and system benefits as part of its continuing evaluation of conservation opportunities."* (Transcript, February 8, 2013, page 40/16-20)

Newfoundland Power explains that the plan provides for ongoing evaluation and consultation with industry and market participants and no new or additional process is required.

<u>Board Findings – Conservation Program</u>

Newfoundland Power and Newfoundland and Labrador Hydro have worked cooperatively to design and implement conservation programs that are appropriate for Newfoundland and Labrador. The Consumer Advocate acknowledges the greater emphasis being placed on conservation and suggests that the Board initiate a process to review the conservation programs with the involvement and input of interested persons.

It is apparent that conservation is an issue of increasing interest and importance for ratepayers and the Board agrees that there may be value in the process suggested by the Consumer Advocate. The Board will require Newfoundland Power to file a report by April 1, 2014 which provides an update on the conservation programs, an evaluation of the referenced heat pumps and recommendations in relation to the appropriate process to be followed for review of the conservation programs. The process for the review of the conservation programs can be assessed thereafter with the input of Newfoundland and Labrador Hydro and the Consumer Advocate.

Newfoundland Power will be required to file a report in relation to its conservation program and the review process on or before April 1, 2014.

III. REVISED APPLICATION

1. Forecast Rate Base, Return on Rate Base and Range of Return

The Settlement Agreement in relation to the proposed forecast average rate base for 2013 and 2014 has been accepted for ratemaking purposes. As a result of the determinations of the Board in this Order, revisions to the calculation of the forecast average rate base for 2013 and 2014 may be required.

The forecast 2013 and 2014 rate of return on rate base will change as a result of the determinations of the Board in this Order and should be revised by Newfoundland Power to reflect these changes.

No submissions were made in this proceeding in relation to Newfoundland Power's established range of return on rate base of 36 basis points which will be maintained. The Board notes that the current definition of the Excess Earnings Account sets out the established annual rate of return on rate base which requires that a new definition be approved with each change in rate of return on rate base. Newfoundland Power will be required to file an application to revise the definition to avoid this requirement and to set out the range of 36 basis points in the definition.

The Board has accepted a return on equity for ratemaking purposes for 2015 of 8.8%. Newfoundland Power will be required to file, on or before November 17, 2014, an application for approval of a 2015 forecast average rate base and rate of return on rate base and may file for approval of a revised Schedule of Rates, Tolls and Charges to reflect these revisions.

Newfoundland Power will be required to file an application for approval of a revised calculation of the forecast average rate base and rate of return on rate base for the 2013 and 2014 test years to reflect the determinations of the Board in this Order.

Newfoundland Power's allowed range of return on rate base of 36 basis points will be continued for 2013, 2014 and 2015.

Newfoundland Power will be required to file an application for approval of a revised definition of the Excess Earnings Account.

Newfoundland Power will be required to file on or before November 17, 2014 an application for approval of the forecast average rate base and rate of return on rate base for 2015 maintaining a return on equity of 8.8% and a common equity ratio of 45%.

2. Forecast Revenue Requirement

The Board notes that the forecast 2013 and 2014 revenue requirement will change as a result of the determinations of the Board in this Order.

Newfoundland Power will be required to file a revised forecast 2013 and 2014 revenue requirement to reflect the determinations of the Board in this Order.

3. Rates

Newfoundland Power is required to file an application for approval of a Schedule of Rates, Tolls and Charges to implement the proposals in the Application, incorporating the determinations of the Board in the Order. As a part of the normal regulatory process, Newfoundland Power is also required to make application for new rates effective July 1, 2013 as a result of the annual Rate Stabilization Account adjustment. To ensure the orderly implementation of the rate changes associated with the Application and the rate changes associated with the annual July 1st Rate Stabilization Account adjustment, the Board will require Newfoundland Power to use a July 1, 2013 effective date for the rate changes flowing from this Order.

Newfoundland Power will be required to file an application for approval of a revised Schedule of Rates, Tolls and Charges effective for service provided on and after July 1, 2013.

4. Rules and Regulations and Accounts

Newfoundland Power's Rules and Regulations will change as a result of the proposals in the Application and the determinations of the Board in this Order.

Newfoundland Power will be required to file revised Rules and Regulations to be effective July 1, 2013.

IV COSTS

Newfoundland Power shall pay the costs and expenses of the Board arising from this Application, including the expenses of the Consumer Advocate incurred by the Board, pursuant to the *Public Utilities Act*, RSNL 1990, *c. P-47*.

PART THREE. BOARD ORDER

IT IS THEREFORE ORDERED THAT:

RATE BASE, RETURN ON RATE BASE AND RANGE OF RETURN

1. Newfoundland Power shall file an application for approval of a revised forecast average rate base and rate of return on rate base for 2013 and 2014 based on the proposals in the Application, incorporating the determinations of the Board in this Order, including:
   i) a common equity component in the capital structure not to exceed 45% for ratemaking purposes; and
   ii) a ratemaking rate of return on common equity of 8.8%.

2. The allowed range of rate of return on rate base shall be 36 basis points for 2013, 2014 and 2015.

3. Newfoundland Power shall file an application for approval of a revised definition of the Excess Earnings Account.

4. Newfoundland Power shall file an application on or before November 17, 2014 for approval of the 2015 forecast average rate base and rate of return on rate base maintaining the ratemaking common equity ratio and return on common equity established in this Order.

5. Newfoundland Power shall, unless otherwise directed by the Board, file its next general rate application with a 2016 test year on or before June 1, 2015.

REVENUE REQUIREMENT

6. Newfoundland Power shall calculate and file a revised forecast revenue requirement for the 2013 and 2014 test years based on the proposals in the Application, incorporating the determinations of the Board in this Order.

DEPRECIATION

7. Newfoundland Power's proposal to adjust the depreciation expense to amortize the accumulated reserve variance of approximately $2.6 million over the account's composite remaining life is approved.

8. Newfoundland Power's proposal to use the depreciation rates recommended in the 2010 Depreciation Study is approved.

9. Newfoundland Power shall file its next depreciation study relating to plant in service as of December 31, 2014 with its next general rate application.

OTHER REGULATORY MATTERS

10. The proposed calculation of the defined benefit pension expense for regulatory purposes in accordance with United States Generally Accepted Accounting Principles is approved.

11. The amortization over 15 years, commencing in 2013, of the forecast defined benefit pension expense regulatory asset approved in Order No. P.U. 11(2012) of approximately $12.4 million is approved.

12. The amortization over seven years, commencing in 2013, of annual customer energy conservation program costs through the annual Rate Stabilization Account adjustment is approved.

13. The proposed change in the definition of the Conservation and Demand Management Cost Deferral Account is approved as set out in Schedule A to this Order.

14. The proposed disposition of the annual balance in the Weather Normalization Reserve Account through the annual Rate Stabilization Account adjustment is approved.

15. The amortization over three years, commencing in 2013, of the 2011 year-end balance in the Weather Normalization Reserve Account of approximately $5.0 million is approved.

16. The amortization over three years, commencing in 2013, of the amount of $4,726,000 relating to previously approved deferrals is approved.

17. The amortization over three years, commencing in 2013, of the amount of the revenue shortfall for 2012 resulting from the determination of Newfoundland Power's 2012 cost of capital in Order No. P.U. 17(2012) is approved.

18. The amortization over three years, commencing in 2013, of costs billed to Newfoundland Power for Board and Consumer Advocate hearing costs relating to the Application, estimated to be $1.25 million, is approved.

19. The proposed amortization over three years, commencing in 2013, of the 2013 revenue shortfall resulting from the implementation of new rates after January 1, 2013 is approved.

20. Newfoundland Power shall file with the Board, no later than April 1, 2014, a report in relation to its conservation program and the process for the review of this program.

21. Newfoundland Power shall file, as part of its next general rate application, a report on its capital structure.

RATES, RULES AND REGULATIONS

22. The proposed changes to the rate design and structure are approved as follows:

- **(i) merge existing Rates 2.1 and 2.2 into a single General Service Rate for all customers with demands of less than 100kW;**
- **(ii) modify demand and energy charges to better reflect marginal costs;**
- **(iii) change energy block sizes in Rates 2.3 and 2.4;**
- **(iv) make changes to the basic customer charge;**
- **(v) apply the average rate increase to the Maximum Monthly Charge;**
- **(vi) maintain the Curtailable Service Option with the current credit;**
- **(vii) modify the Early Payment Discount;**
- **(viii) maintain the Optional Seasonal Rate Revenue and Cost Recovery Account until the next general rate application;**
- **(ix) increase the Optional Seasonal Rate consistent with the Rate 1.1 increase; and**
- **(x) increase the Time of Day Rates in accordance with the increase in the applicable rate class.**

23. The proposed changes to the Rate Stabilization Clause are approved as set out in Schedule B to this Order.

24. Newfoundland Power shall file an application for approval of a revised Schedule of Rates, Tolls and Charges effective for service provided on and after July 1, 2013, based on the proposals in the Application, incorporating the determinations of the Board in this Order.

25. Newfoundland Power shall file revised Rules and Regulations to be effective July 1, 2013.

HEARING COSTS

26. Newfoundland Power shall pay the costs and expenses of the Board arising from the Application, including the expenses of the Consumer Advocate incurred by the Board.

DATED at St. John's, Newfoundland and Labrador this 17th day of April 2013.

Andy Wells
Chair & Chief Executive Officer

Dwanda Newman, LL.B.
Commissioner

James Oxford
Commissioner

Cheryl Blundon
Board Secretary

Schedule A

ORDER NO. P.U. 13(2013)

Conservation and Demand Management Cost Deferral Account

NEWFOUNDLAND POWER INC.
CONSERVATION AND DEMAND MANAGEMENT COST DEFERRAL ACCOUNT

CDM Cost Deferral Account 188xx

This account shall be charged with the costs incurred in implementing the CDM Program Portfolio.

These costs include the CDM Program Portfolio costs incurred by Newfoundland Power for: detailed program development, promotional materials, advertising, pre and post customer installation checks, incentives, processing applications and incentives, training of employees and trade allies, and program evaluation costs.

This account shall also be charged the costs of major CDM studies such as comprehensive customer end use surveys and CDM potential studies that cost greater than $100,000.

Transfers to, and from, the proposed account will be tax-effected.

This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred.

Recovery of annual amortizations of costs in this account shall be through the Company's Rate Stabilization Account or as otherwise ordered by the Board.

Schedule B

ORDER NO. P.U. 13(2013)

Rate Stabilization Clause Amendments

NEWFOUNDLAND POWER INC.
RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA")

3. The annual kilowatt-hours used in calculating the Rate Stabilization Adjustment to the monthly streetlighting rates are as follows:

	Fixture Size (watts)				
	100	150	175	250	400
Mercury Vapour	-	-	840	1,189	1,869
High Pressure Sodium	454	714	-	1,260	1,953

II. RATE STABILIZATION ACCOUNT ("RSA")

7. On March 31st of each year, beginning in 2014, the Rate Stabilization Account shall be increased on a before tax basis, by the CDM Cost Recovery Transfer.

   The CDM Cost Recovery Transfer, expressed in dollars, will be calculated to provide for the recovery of costs charged annually to the Conservation and Demand Management Cost Deferral Account (the "CDM Cost Deferral") over a seven-year period, commencing in the year following the year in which the CDM Cost Deferral is charged to the Conservation and Demand Management Cost Deferral Account.

   The CDM Cost Deferral Account will identify the year in which each CDM Cost Deferral was incurred.

   The CDM Cost Recovery Transfer for each year will be the sum of individual amounts representing 1/7th of each CDM Cost Deferral, which individual amounts shall be included in the CDM Cost Recovery Transfer for seven years following the year in which the CDM Cost Deferral was recorded.

II. RATE STABILIZATION ACCOUNT ("RSA")

8. On March 31st of each year, beginning in 2013, the Rate Stabilization Account shall be increased (reduced), on a before tax basis, by the balance in the Weather Normalization Reserve as of the end of the previous year.

III. RATE CHANGES

The energy charges in each rate classification shall be adjusted as required to reflect the changes in the Rate Stabilization Adjustment. The new energy charges shall be determined by subtracting the previous Rate Stabilization Adjustment from the previous energy charges and adding the new Rate Stabilization Adjustment. The new energy charges shall apply to all bills based on consumption on and after the effective date of the adjustment.

Newfoundland & Labrador
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
120 TORBAY ROAD, ST. JOHN'S, NL

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DECISION **2014 NSUARB 53**
M05473

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **NOVA SCOTIA POWER INCORPORATED** and a Hearing for Approval of the 2013 Cost of Service Study

2014 NSUARB 53 (CanLII)

BEFORE:	Peter W. Gurnham, Q.C., Chair Roland A. Deveau, Q.C., Vice-Chair Kulvinder S. Dhillon, P. Eng., Member
APPLICANT:	**NOVA SCOTIA POWER INCORPORATED** David Landrigan, LL.B. Nicole Godbout, LL.B.
INTERVENORS:	**CONSUMER ADVOCATE** William A. Mahody, LL.B.
	SMALL BUSINESS ADVOCATE E.A. Nelson Blackburn, Q.C.
	HERITAGE GAS Michael Johnston
	INDUSTRIAL GROUP Nancy G. Rubin, Q.C. Maggie Stewart, LL.B.
	MUNICIPAL ELECTRIC UTILITIES OF NOVA SCOTIA CO-OPERATIVE Albert Dominie Donald Regan

PORT HAWKESBURY PAPER LP
David MacDougall, LL.B.
James MacDuff

BOARD COUNSEL: S. Bruce Outhouse, Q.C.

HEARING DATE(S): December 10, 11 and 12, 2013

FINAL SUBMISSIONS: January 29, 2014

DECISION DATE: **March 11, 2014**

DECISION: **Cost of Service Study approved, as amended. See summary at paragraph [177].**

2014 NSUARB 53 (CanLII)

TABLE OF CONTENTS

2014 NSUARB 53 (CanLII)

1.0 INTRODUCTION

[1] Nova Scotia Power Incorporated ("NSPI") made application dated June 28, 2013, to the Nova Scotia Utility and Review Board ("Board") for approval of its 2013 Cost of Service Study ("COSS") ("Application"). This study reviews and, where appropriate, recalibrates how the costs of the electricity system are apportioned among customer classes. This process neither increases nor decreases the costs of making electricity; rather it determines the equitable share each customer class should pay for the component parts of the system: generation, wires, poles, line repair, administration, etc. Cost of service alone does not determine rates as rates are set and approved by the Board during a general rate application ("GRA").

[2] Notice of a public hearing was duly advertised in accordance with sections 64 and 86 of the *Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended ("*Act*").

[3] The Small Business Advocate ("SBA"); the Consumer Advocate ("CA"); Heritage Gas ("Heritage"); the Industrial Group, whose counsel represented 12 Intervenors ("Industrial Group"); the Lower Power Rates Alliance of Nova Scotia ("LPRA"); the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC"); the Nova Scotia Department of Energy ("Province"); the Nova Scotia Liberal Caucus ("Liberal Caucus"); and Port Hawkesbury Paper LP ("PHP"), all intervened in the hearing.

2.0 BACKGROUND

[4] In a decision of the Board dated November 29, 2011, concerning the 2012 GRA, the Board ordered NSPI to undertake a cost of service hearing and provide a schedule for convening the hearing. Although the schedule was amended several times, the final schedule provided for the filing of the Application in June of 2013.

2014 NSUARB 53 (CanLII)

[5] In regulating NSPI the Board uses a cost of service framework. It is intended to provide a fair allocation of utility costs among customer classes based on cost causation and asset utilization.

[6] In some instances costs are directly assigned to rate classes. Costs not directly assigned are allocated to rate classes following a three step process:

1. Costs are functionalized as generation, transmission, distribution and retail;
2. Costs by function are classified as energy, demand or customer related; and
3. The energy, demand and customer categories are allocated to various classes of service on the basis of their respective demands, energy use, customer number or other established allocators.

The COSS governs how these issues are determined.

[7] A unique feature of the current cost of service process was the degree of stakeholder engagement. NSPI described the stakeholder engagement as follows:

> Beginning with the initial project scoping exercise in July 2012, through development of the project Terms of Reference, issuance of responses to stakeholder data requests, technical conferences and issuance of the two COS Strawman documents, NS Power has sought to provide complete and accurate information regarding the Company's COS practices, and practices that are commonly applied in the industry. As well, NS Power has attempted to clearly communicate its perspective on COS issues and understand and incorporate stakeholder and expert opinion on these matters to its position documents. To this end, the Company has:
>
> - Engaged electricity industry Cost of Service expert consultant, Christensen Associates Energy Consulting, to review the Company's Cost of Service framework and practices, provide comment with respect to the consistency of these with accepted utility practice, and provide recommendations for improvement;
> - Held three technical conferences on this matter;
> - Developed Terms of Reference to establish the objective of this process, approach, scope and decision-making criteria;
> - Developed an FTP site and populated this with information relevant to the NS Power COS model;

2014 NSUARB 53 (CanLII)

- Issued responses to 128 data requests received from stakeholders, including 47 sensitivity analyses identifying the effect on customer class costs of alternative COS approaches;
- Issued Strawman Report Version 1, which provided:
  - Background to the Company's COS methodology;
  - The report of the Company's COS consultant, Christensen Associates Energy Consulting, concerning NS Power's COS framework and processes;
  - Results of COS surveys conducted by various consulting companies and NS Power;
  - The Company's position on recommendations presented by CAEC;
- Issued Strawman Report Version 2, which provided:
  - Feedback of stakeholders on Strawman Report Version 1;
  - Amended positions of the Company with respect to CAEC recommendations and other issues raised by stakeholders;
  - Identified areas where consensus had been developed, where consensus had not, and those areas requiring further analysis;
- Held numerous teleconferences with Board staff and stakeholder consultants.

As a result of this work, a shared understanding of the Company's Cost of Service processes and related issues and their materiality to customer rates has emerged. …

[Exhibit N-1, pp. 18-19]

[8] All parties were complimentary of the stakeholder engagement process undertaken by NSPI which the Board views as a template for future proceedings.

[9] As a consequence, the hearing itself was able to proceed very efficiently.

[10] There were a significant number of issues where the parties reached consensus and the Board, as noted later in this Decision, accepts that consensus.

[11] There were a number of matters to be worked on in future which are described later in this Decision.

[12] Not surprisingly, on an issue as complex as cost of service, there were issues where consensus could not be reached and the Board is asked to make a determination. The Board does so in this Decision.

2014 NSUARB 53 (CanLII)

[13] The Board, however, does appreciate the efforts of NSPI and the parties to reach consensus on a number of these issues.

3.0 ANALYSIS AND FINDINGS

3.1 Classification and Allocation of Base Load Plant

2014 NSUARB 53 (CanLII)

[14] Since the Board's 1995 cost of service decision NSPI has used the system load factor ("SLF") methodology for classification and a 3CP (coincident peak) method for allocation of base load generation.

[15] The SLF method takes into account that the investment made in generation is made to provide lower base cost energy relative to more expensive per kilowatt hour peaking units to meet demand.

[16] The SLF classifies as energy the portion of the generation fixed costs equivalent to the SLF in any given year. The remainder is classified to demand.

[17] Once classified NSPI allocates the demand cost among customer classes according to the average of the three highest months of energy use (coincident peaks – the 3CP). While various methods were reviewed with respect to the classification of base load generation, by the end of the hearing the Board was essentially faced with two choices: NSPI, supported by the SBA and CA, recommended continuation of the existing SLF 3CP methodology; while the Industrial Group and PHP recommended a modified break-even/SLF methodology which will, for simplicity, be called the base peak ("BP").

[18] The methodology recommended by Mr. Drazen, on behalf of the Industrial Group, employs SLF for classification between demand and energy and then the BP method is used to allocate the energy related portion of fixed generation costs. The BP method recognizes what is described as the break-even point in the base load versus

peaker investment decision. Based on that break-even point further energy usage, according to Mr. Drazen, does not affect the initial investment decision.

[19] Mr. Whalen, Board Counsel's consultant, supported NSPI's position as does the SBA. At the conclusion of the hearing, Mr. Chernick, the CA's consultant, supported NSPI's position although his preference, before the hearing, was to use a 12CP allocation (i.e., 100% to the three months December, January and February and 50% to all other months). His position, at the conclusion of the hearing, was that he could accept the 3CP allocation as a placeholder pending results of the upcoming Integrated Resource Plan ("IRP").

2014 NSUARB 53 (CanLII)

[20] In support of the continuation of the SLF 3CP methodology NSPI stated:

> NS Power confirmed in its Strawman reports that it supports maintenance of the SLF approach, as long as no superior alternative is found. In the Company's assessment, there were no convincing arguments put forward to confirm an alternative method would be superior.
>
> The application of the EPM and BP methods to classification of base load generation were examined in the 1993 COS proceeding and were rejected in favor of the current SLF-based method. Though the operational landscape of NS Power has changed since that time, the characteristics of the EPM and BP methods have not.
>
> …
>
> As far as allocation of demand-related costs of generation is concerned, NS Power does not find evidence in support of a departure from the current three coincident peak (3CP) approach. As provided in response to CA DR-42, 43 and 44, NS Power remains a winter peaking utility and combustion turbine (CT) usage during non-winter months is not a significant factor with respect to generation investment decisions.
>
> [Exhibit N-1, pp. 35-36]

[21] Mr. Whalen noted that NSPI tested a number of alternatives and he supported NSPI's recommendation of continuing with the SLF 3CP approach. Mr. Whalen, in his evidence, explained his concerns over the use of time differentiated methods such as BP:

These approaches suffer all of the same weakness of the Equivalent Peaker methods. In addition:

> a) These methods require a breakeven point which is a function not only of capital cost differences, but also of differences between base generation and peaker fuel costs. The difference between these may be very volatile from year to year.
>
> b) The underlying philosophy of this method is that the need for peaking units is largely driven by classes with lower load factors. This does not take into account the need for reserves to cover forced outages and planned maintenance outages of base load units.
>
> c) Utility generation planning and resulting generation additions are based on long term forecasts of peak demands, energy requirements, public policy, available technologies and their characteristics (capital and operating costs, heat rates, forced outage rates, etc.), fuel forecasts and a variety of other factors. The choice and timing of generation additions reflect consideration of how various viable options will serve the system over multiple years, rather than on a single year's breakeven points among options.
>
> d) NSPI uses its hydro generation (particularly Wreck Cove) to serve load during peak periods. This affects NSPI's generation choice between a base load unit and a CT but is not reflected in the breakeven calculation.
>
> e) As noted in the discussion of this method in the NARUC Cost Allocation Manual, "The logic of this approach is that the extra capital costs would be incurred once the system was expected to run for a certain minimum number of hours; i.e., once the break-even point in unit run time between a peaker and baseload (or intermediate) unit was reached. However, system planners generally recognize no difference between on-peak hours and off-peak energy loads on the decision to build a baseload power plant, instead, the belief is that system planners consider the total annual energy loads that determine the type of plant to build. To allocate energy-related production plant costs on the basis of only on-peak energy use implies a differential impact of on-peak KWH as compared to off-peak KWH that may or may not exist".
>
> f) If the BP or BIP fixed classification methods were to be adopted, it could also have implications on the apportionment of fuel costs among rate classes. If, for example, the BP logic were applied to fuel costs, class responsibility for fuel costs would not be based on annual class usage but on relative shares of energy being supplied by plant type. This would significantly complicate the FAM process, as discussed in NSPI (AVON) DR-16.

[Exhibit N-10, pp. 24-25]

[22] The SBA's position is summarized in its final submission:

… The problem with the Base Peak methodology is that it is data intensive, complex and relies on a large number of assumptions, unlike the SLF methodology which is relatively simple. Furthermore, the Base Peak methodology while theoretically an acceptable alternative, has no history of implementation in other utilities, particularly in Canada. In other words, we have no track record or experience to rely upon with utilities using this methodology. The SBA submits that there is little evidence that supports replacing the SLF methodology with Base Peak methodology; or that the SLF ·methodology is inferior to the Base Peak methodology. As we have said in our opening statement, "If it ain't broke, why fix it". The SBA supports continuation of the SLF classification with the

2014 NSUARB 53 (CanLII)

> allocation of demand related plant on the basis of 3 CP, reflecting how the Company plans its generation system.
>
> [SBA Final Submission, pp. 5-6]

[23] Mr. Drazen noted that he did not disagree with the concept of classifying only part of base load fixed costs as demand related. However, in his view, allocating the energy portion on the basis of total energy usage does not accurately reflect cost causation. He went on to state:

> The problem is that the portion of the investment that is not "demand-related" is not really "energy-related" either, at least not in the same sense as fuel is energy-related. It is better described (and allocated) as *peak*-energy-related. The decision to build a base load plant versus a peaker is not determined by *total* energy output, but, rather, on output up to a certain duration or "breakeven" point. …
>
> [Exhibit N-11, p. 14]

[24] He argued that since energy production beyond the threshold point does not affect the investment decision, it is not relevant to cost causation.

> …
>
> Q IN WHAT WAY IS NSPI'S CURRENT METHOD OF USING ALL ENERGY TO ALLOCATE THE "NON-DEMAND" PORTION COUNTER PRODUCTIVE?
>
> A It is counterproductive to encouraging customers to improve the system load factor because it penalizes customers who do so. For greater system efficiency, it is desirable for customers to reduce peak demand and increase use of energy off-peak–that is, to improve the system load factor. The demand charges in the General Service and Industrial rates provide motivation to do so. But, if customers respond to that, the higher system load factor will increase the portion of fixed costs classified as energy and increase the portion of generation fixed cost allocated to them. The breakeven energy method of allocation avoids this effect, because off-peak energy is not considered in the allocation of the non-demand base load fixed costs.
>
> [Exhibit N-11, p. 17]

[25] In argument the Industrial Group stressed that the BP method (albeit the traditional BP method, not the hybrid one suggested by Mr. Drazen) scored very well in the cost causation category in rankings of six criteria undertaken by NSPI. PHP argued in support of the position taken by Mr. Drazen, on behalf of the Industrial Group.

2014 NSUARB 53 (CanLII)

[26] In its Reply Brief, NSPI argued that the hybrid approach, suggested by Mr. Drazen, was not considered as part of NSPI's assessment. It argued that the hybrid method proposes to use five year forecasts for capital and fuel to determine the base split between demand and energy. In NSPI's view, this method would actually rank lower on the comparative cost causation criteria.

2014 NSUARB 53 (CanLII)

[27] The CA, in argument, stated that the hybrid BP approach "has no resemblance to actual utility planning and operation" citing several factors including:

- Energy use in all hours contributes to emission control costs and renewable energy requirements;
- Using 2014 forecast fuel prices, even though the decisions to build each coal plant was made at very different fuel prices, would have suggested very different breakeven hours;
- Excluding the environmental and fuel switching plant costs, variable O&M, income taxes, grants in lieu, and decommissioning costs from the break-even computation.

3.1.1 Findings

[28] It appears to the Board that the SLF 3CP method is working well and has worked reasonably well since 1995 to classify and allocate base load plant.

[29] The Board recognizes that more costs are classified as energy under this method than under the BP method and under methods used in other jurisdictions.

[30] The Board has several concerns about the BP method.

[31] While it appears it is an acceptable method under the National Association of Regulatory Utility Commissioners' ("NARUC") guidelines, it also appears it is not

widely used. Indeed, no witness could point to a jurisdiction in Canada that uses the BP method.

[32] Secondly, and more importantly, the approach would require the use of five year fuel forecasts and capital forecasts in order to calculate the BP method break-even point. NSPI's fuel forecasts have been notoriously wrong as evidenced by the current under-recovery in the fuel adjustment mechanism. It appears to the Board there will be a significant risk of volatility with respect to the setting of the break-even point which could lead to volatility in cost of service.

[33] Mr. Whalen noted that one of the redeeming features of the SLF is that it does not do that:

> MS. RUBIN: Okay. Would you acknowledge that these other factors aren't reflected in the current System Load Factor method or, for example, in the equivalent peaker method, and that all of these methodologies reflect a simplification of the planning approach?
>
> MR. WHALEN: Yes, that's true to some extent. I think the advantage the System Load Factor has is that it's essentially saying what's happening on average and determining an energy piece from that perspective. And then what happens above the average loads is deemed to be the demand portion and is allocated with respect to demands.
>
> So the fact that, on the System Load Factor, you're averaging or working up average loads, it tends to capture some of these pluses or minuses more than a breakeven analysis would.
>
> [Transcript, p. 497]

[34] In part, based on this risk of volatility, the Board is not prepared to accept the BP methodology. The Board also notes the other concerns raised by Mr. Whalen as detailed in paragraph [21] of this Decision.

[35] Accordingly, the Board accepts the evidence of NSPI, Mr. Whalen and the submissions of the SBA and the CA, that the SLF 3CP methodology should continue.

2014 NSUARB 53 (CanLII)

[36] The Board sees no particular reason, as recommended by Mr. Chernick, to adopt the 3CP allocation as a temporary placeholder. However, it would obviously be subject to future review when cost of service is re-examined at a future date.

2014 NSUARB 53 (CanLII)

3.2 NSPI Wind

[37] NSPI proposed to change the cost of service treatment of NSPI owned wind facilities to align with system planning and to eliminate the distinction between renewable electricity standard (“RES”) investments and non-RES investments.

[38] Currently NSPI treats all wind facilities installed after 2009 as energy only because they are intended to contribute to the RES targets. Older wind projects are treated based on their capacity factor such that the assets are classified as 30% to demand and 70% to energy.

[39] NSPI proposed to eliminate the distinction between RES and non-RES wind energy and bring the cost of service treatment of wind costs into alignment with its capacity planning.

[40] NSPI initially proposed that wind projects connected by a network resource interconnection service (“NRIS”) should be classified as 80% to energy and 20% to demand, because these projects contribute to capacity. Projects connected to energy resource interconnection service (“ERIS”) were proposed to be classified as 100% to energy. NSPI owned wind generation units and Independent Power Producers would be treated the same for cost of service purposes.

[41] Mr. Whalen provided evidence that the actual history of wind curtailments indicates that ERIS curtailment and system peaks may not be coincident and that ERIS projects may be able to contribute to firm capacity. Mr. Drazen also recommended that

ERIS connected wind projects be treated as providing capacity although discounted from NRIS projects.

[42] In its Reply Evidence, NSPI changed its recommendation to request that the classification should align with planning assumptions in effect at the time of the next GRA, rather than seek to fix specific classification factors now. NSPI noted that it would update the classification factors for a general rate application, if this is required, to align with planning assumptions in effect at the time of future GRAs. The SBA and the Industrial Group supported NSPI's recommendation on this issue.

2014 NSUARB 53 (CanLII)

3.2.1 Findings

[43] The Board accepts NSPI's revised position and directs that the necessary work be undertaken. The classification NSPI proposes, after the necessary research, is to be submitted to the Board for approval. The Board observes that it does appear, based on the evidence in this proceeding, that ERIS projects are able to contribute firm capacity.

[44] The CA does not appear to question NSPI's recommendation in this regard, but disagrees with the manner in which NSPI classifies wind energy.

[45] Mr. Chernick, on behalf of the CA, argued that NSPI has a two-step process for classifying non-peaking base load generation between energy and capacity. The first step classifies the environmental and fuel switching costs to energy, while the second step applies a SLF to the remainder and classifies that portion as energy related as well. He argued that NSPI has consistently not applied both steps to wind. He stated that the wind plants were never planned or justified based on their contribution to meeting peak demands and should be classified entirely energy related until the capacity is used and useful. No other party criticized NSPI's process in this regard.

[46] NSPI indicated that the result of the CA's suggestion would see a change in classification results from the current 90/10 split between energy and demand to a 95/5 split.

[47] NSPI correctly points out that the classification of wind generation was not the subject of the 1995 cost of service decision as there was no wind generation at the time. It argued that the 1995 decision was specific in applying SLF classification to only base load generation.

[48] The Board notes that the current approach classifies wind generation as 90% to energy, which recognizes a significant energy cost causation content of wind generation. The Board is not persuaded that the change recommended by Mr. Chernick needs to be made (noting that no other party advocated for this change) and agrees that NSPI should continue the current process.

3.3 Classification and allocation of Purchased Power Costs

[49] The issue to be addressed for purchased power costs is their classification between energy and demand components, segregated between wind and non-wind generation, for in-province purchases. Purchased power also includes imports.

[50] In its Reply Evidence, NSPI summarized its current methodology:

> Currently, NS Power classifies non-wind power purchases as 45% fixed and 55% variable. As with the base load units, a portion of the fixed component is then classified as energy-related based on the system load factor. Wind purchases are split as 30% fixed and 70% variable. There is then a second step which classifies the fixed component as 70% energy and 30% demand. The 70/30 ratios are based on estimated capacity factors of wind generation. The effect of this two-step process is that the current overall demand/energy classification of wind purchases is 9% demand and 91% energy.
>
> [Exhibit N-30, p. 17]

[51] NSPI proposes to treat the classification of in-province purchased power so as to align it with that applied to its own generation. Initially, it proposed as follows:

2014 NSUARB 53 (CanLII)

> …for those wind purchases interconnected by the non-firm Energy Resource Interconnection Service [ERIS], no capacity value (i.e. demand) classification is made. These costs are considered 100% energy. For wind purchases interconnected by the firm transmission Network Resource Interconnection Service [NRIS], the Company proposes for the COS proceeding, to classify 20% of these costs to demand and 80% to energy.
>
> For non-wind, in-province purchases the Company proposes to treat this the same way as Company owned, non-wind base load generation fixed costs (classified to demand and energy based on the system load factor). The treatment of these assets from a planning perspective is the same. It follows that the treatment for COS purposes should also be aligned.
>
> [Exhibit N-30, p. 18]

2014 NSUARB 53 (CanLII)

[52] With respect to imports, NSPI proposed to classify them as 100% energy since they are typically non-firm.

[53] In his Pre-Filed Evidence, Mr. Whalen supported this approach with respect to all three sources of purchased power, noting that the in-province "wind" and "non-wind" resources are similar to NSPI owned wind and NSPI owned base load generation, respectively, from both system planning and system operating perspectives.

[54] After referring to the discussion canvassed earlier in this Decision about NSPI owned wind generation, as it relates to in-province wind purchases, Mr. Whalen stated as follows in relation to non-wind in-province purchases and imports:

> …non-wind in-province purchases displace NSPI's generation, they are made under long term contracts and from NSPI's perspective are fixed costs. Classifying them as NSPI classifies the fixed costs of its own base load generation is appropriate.
>
> …imports are usually non-firm purchases which occur whenever it is possible to take advantage of any marginal cost differentials between NSPI and New Brunswick. Their primary purpose is to reduce fuel costs, so their classification as energy is appropriate.
>
> [Exhibit N-10, p. 13]

[55] However, during the course of this proceeding, NSPI changed its position with respect to the treatment of NSPI owned renewable resources. As noted earlier in this Decision with respect to NSPI owned wind generation, NSPI undertook to review and update the classification factors related to its wind generation and to provide the

relevant support for the classification as part of future GRA or cost of service proceedings. In section 3.2 above, the Board accepted this approach.

2014 NSUARB 53 (CanLII)

[56] The only party opposing NSPI's proposal for purchased power costs is the CA. Mr. Chernick noted that the cost of wind generation was incurred by NSPI to meet environmental and RES requirements. As noted earlier in this Decision, he opposed the classification of a portion of the renewables cost as demand. The CA requested that NSPI apply the full two-step SLF method to wind, subject to updating of the wind capacity credit.

[57] With respect to non-wind purchased power, the CA submitted:

> NSPI has proposed that purchases of non-wind firm power (mostly biomass) be classified in the same manner as similar NSPI-owned resources. …The CA agrees with this approach.
>
> However, NSPI has failed to match the classification of purchase costs to the classification of the total cost (including fuel and variable O&M) of comparable NSPI-owned generation. This is not an issue for the wind purchases, …
>
> For the non-wind purchases, NSPI simply applies the system load factor to the total purchase costs. Most of these purchases are from biomass plants, and NSPI projects increasing biomass purchases from Minas Basin and COMFIT projects. The purchase price covers both the fixed costs of the IPP and its fuel costs. For Port Hawkesbury itself, NSPI properly classifies the fuel and variable O&M costs as energy-related, but NSPI fails to classify a similar portion of the purchased-power costs as energy-related and effectively classifies 44% of the IPP fuel costs as related to peak demand. The Consumer Advocate requests that Board direct NSPI to address this unfair approach.
>
> The Consumer Advocate requests that the Board instruct NSPI to classify the costs of biomass purchases in proportion to the classification of total Port Hawkesbury costs.
>
> [CA Final Submission, pp. 6-7]

[58] In its Rebuttal Submission, NSPI refuted the CA's assertion that NSPI follows a two-step process in the treatment of NSPI owned wind and biomass. NSPI submitted that its current generation planning already recognizes the capacity value of RES-based wind generation. NSPI stated:

> …The SLF-approach was designed for the classification of dispatchable base-load generation, investments which had been made for economic reasons. The wind generation, since it has been accounted for as a separate item in the COS in the 2005

> GRA, has been recognized as a distinct non-dispatchable generation category. NS Power's proposal to continue to exclude classification of wind from the SLF-based approach remains consistent with the current treatment.
>
> [Exhibit N-30, p. 20]

2014 NSUARB 53 (CanLII)

3.3.1 Findings

[59] No party opposed the treatment of imports as 100% energy. The Board accepts this treatment.

[60] Further, non-wind in-province purchased power displaces NSPI's generation. As noted by NSPI and Mr. Whalen, such purchases are made under long term contracts and they are treated as fixed costs. Thus, the Board considers it reasonable and appropriate that such purchased power costs be classified in like fashion to NSPI's base load generation.

[61] With respect to the purchased power costs from biomass, the Board accepts the CA's submission that NSPI should classify the cost of biomass purchases in proportion to the classification of total costs for the Port Hawkesbury biomass plant. NSPI is so directed.

[62] The Board also considers that the treatment of in-province wind purchases should be consistent with the treatment of NSPI owned wind generation. NSPI has undertaken to review and update the classification factors related to its wind generation and to provide the support for its classification as part of future GRA or cost of service proceedings. The Board finds it appropriate that these findings should be consistently applied to in-province purchased wind power.

3.4 Transmission

[63] As is the case with generation, currently NSPI classifies its transmission capacity between energy and demand using SLF and allocates demand using 3CP.

NSPI says that the current approach is atypical of the North American electricity industry where transmission costs are primarily demand driven and classified to demand and, therefore, is proposing to classify transmission 100% to demand. However, NSPI then goes on to ameliorate or undo the demand weighting by allocating transmission on the basis of 12CP in order to recognize that the energy weighting needs to be maintained.

2014 NSUARB 53 (CanLII)

[64] NSPI explained their compromise as follows:

> NS Power is proposing that transmission be classified to demand only and allocated on 12CP. This treatment will align with the cost treatment under OATT. Although, this represents a departure from the 3CP approach used currently in allocation of demand related transmission costs, NS Power believes it is a good compromise between views of the parties to this proceeding and aligns with CAEC's recommendations.
>
> [Exhibit N-1, p. 47]

[65] During the hearing the Board expressed a concern that classifying transmission as demand and then allocating on a 12CP had no theoretical basis:

> THE CHAIR: Can I ask you a question here, sorry? How does allocating it to 12CP create an energy recognition?
>
> MR. FERGUSON: It's really relative to the option of 3CP. So by using 12CP, you recognize utilization of the asset over the entire year versus the three months where the heaviest loading is. So it moderates the effect of the pure 3CP methodology which focuses on the three heaviest years of -- three heaviest months of utilization.
>
> THE CHAIR: I understand the effect; I just don't understand the theory as to why you would do it.
>
> MR. FERGUSON: The theory is the desire -- and it's really founded in the Board's decision in 1995 that transmission should be classified on the same basis as generation, recognizing that there's a large energy component.
>
> THE CHAIR: But you've departed from that; your theory has changed. So has allocating on 12CP consistent with your theory? That's what I'm struggling with.
>
> MR. FERGUSON: Well, the shift to 12CP is a shift in our thinking as well. So originally in our Application and our thinking proposal when we worked with stakeholders was classify and demand and allocate on 3CP which would have a -- predominantly a demand focus for the transmission system.
>
> Discussions with customers and the intervenors and review of -- in my case, review of the Board's original decision reinforced that it was recognized from the outset that that transmission -- there was a large element of energy cost causation in the transmission

> system. So the 100 percent demand classification with the 3CP allocation seemed overly severe and seemed to underplay the role of electricity -- excuse me, the energy role in contributing to the cost of the transmission system. We sought to address that.
>
> THE CHAIR: So is it overly severe from an impact standpoint, or overly severe from a classification standpoint?
>
> MR. FERGUSON: I think the latter, overly severe from a classification and allocation standpoint. It doesn't fairly recognize, in my perspective, in my view, that transmission costs in our province have been driven in part by the desire to produce lower cost energy.
>
> THE CHAIR: Then why depart from the system [load] factor?
>
> MR. FERGUSON: Because there is, in our view, a stronger demand component in the transmission system than base load generation assets.
>
> MR. CHAPMAN: Might I add something?
>
> THE CHAIR: You're trying to kind of keep a foot in both camps, aren't you?
>
> MR. FERGUSON: I don't think of it that way. I think of it more in terms of the primary -- the initial plan is to recognize that transmission demand is a driver of transmission. So it's a shift.
>
> Yeah, I guess it is a feet in both camps. We are recognizing that there remains an energy component, but we think there is -- the demand component is more substantive on the transmission system than it is on the generation base load.
>
> [Transcript, pp. 114-117]

[66] The CA supported continuation of the SLF 3CP method on the basis that the change proposed by NSPI is not justified by cost causation. In its Final Brief, the CA stated:

> There is universal acceptance that a large portion of the transmission investment was undertaken to connect the remote coal and hydro plants to the load centres, to provide customers lower fuel costs from these units that could not be located near load. (Ex. N-1 at 44-46 and Appendix I at 5, 15)
>
> There is also nearly universal acceptance that much of the recent construction of transmission in Nova Scotia is due to the construction of wind and other renewables, driven by energy-related mandates (Ex. N-1 at 46 and Appendix J at 111; Ex. N-16 at 48).
>
> [CA Final Submission, pp. 8-9]

[67] The SBA, PHP and Industrial Group support a 100% classification to demand and a 3CP allocator. The SBA argued that the evidence regarding NSPI's monthly peak supports the use of a 3CP allocator.

2014 NSUARB 53 (CanLII)

[68] The Industrial Group stated as follows:

> 122. With respect to COS treatment of transmission, it is NSPI's position that only a small portion of the transmission assets have an energy component arising from connecting remote generation to the grid. As noted above, it is not unusual for generation to be located at some distance from the load centre; indeed, all transmission exists to connect generation with load but the industry standard is nonetheless to classify as demand and allocate based on the appropriate coincident peaks. It is submitted that both the SLF classification and the 12 CP allocation overstate the energy component. The demand patterns of the NSPI system strongly indicate that it is appropriate to use demand classification and a 3CP allocator.
>
> 123. Alternatively if the Board wishes to reflect an energy component, Mr. Drazen, Mr. Mikkelsen and Ms. Smith all agree that a different COS treatment for some portion of the transmission assets could be an appropriate solution rather than retreating from the recommended Demand Classification and 3CP allocation. The Industrial Group could support functionalizing a limited amount of radial transmission (those which are truly atypical) to generation as described by Mr. Mikkelsen. This could be the subject of further study by NSPI and report.
>
> [Industrial Group Final Submission, pp. 28-29]

[69] PHP argued that there is no evidence that NSPI is "markedly different" from the wide range of jurisdictions in North America that classify utility transmission costs on the basis of 100% demand.

[70] Mr. Whalen's preference was to continue with the existing SLF 3CP methodology. He noted that 100% demand 12CP adds energy to the methodology such that while it is not the exact piece of energy you would get if you applied the SLF, it is close. He conceded that he accepted NSPI's position because he understood it was a compromise of views.

[71] While NSPI may have thought they had a compromise or agreement, it is clear they did not.

3.4.1 Findings

[72] NSPI, in its Direct Evidence, set the context for this discussion by quoting from the Board's 1995 Decision:

> The concept was reflected in Board's analysis of the 199[5] proceeding

2014 NSUARB 53 (CanLII)

> One of the major differences of opinion at the hearing was the classification of generation and transmission rate-base assets. This results in a need to determine what portion of fixed costs should be classified as energy and the appropriate allocation of demand related costs to each customer class. For example, a transmission line to a remote base-load plant built to provide least-cost energy to the load centre has an energy related intent. The actual cost incurred, however, is a function of the physical size of the conductor, which relates to its demand capability. [Emphasis added by NSPI]
>
> and further
>
> It is the Board's opinion that there is an element of energy related cost causation in past generation planning that is present in the NSPI system today. Ms. Chown acknowledges the need for energy recognition in cases such as hydro or nuclear plants, where large capital investments have been made to minimize energy costs. The Board considers that the same rationale applies to the siting of coal fired plants in Cape Breton, as the site was chosen for a combination of reasons which culminated in the least cost solution at that time. [Emphasis added by NSPI]
>
> [Exhibit N-1, p. 45]

[73] NSPI went on to argue that the factors considered by the Board in 1995 regarding investment in transmission as opposed to generation are significantly different today.

[74] The Board fails to understand why. The system, with regard to base load generation, is largely configured in the way it was in 1995, albeit there is less use of the coal plants and more use of the gas fired plant at Tufts Cove. However, the Board observes that the most significant change on the system is the addition of renewable generation which required transmission to be built to service multiple renewable generation sites (principally wind). NSPI's consultant, Christensen Associates Energy Consulting ("CAEC"), argued that renewable generation is justification for moving to a 12CP allocator in order to recognize the energy component to accommodate the new reality of the renewable generation. However, it seems to the Board that this fact argues implicitly and explicitly in favour of the existing methodology.

2014 NSUARB 53 (CanLII)

[75] The Board is not persuaded that the case has been made to change from the existing methodology and, accordingly, with respect to classification and allocation of transmission costs, the SLF 3CP methodology is to continue.

2014 NSUARB 53 (CanLII)

3.5 Customer Weighting Factors

[76] NSPI is requesting Board approval to change its weighting factors to 85% number of customers and 15% revenues for each customer class. The Intervenors and Board Counsel consultant, with the exception of the CA, agree with NSPI's request.

[77] NSPI uses weighting factors to allocate customer related or customer care expenses such as billing, meter reading, collection costs, customer enquiries and responses, and customer accounting. NSPI stated that:

> … These services are labour intensive and the costs associated with their delivery can vary with factors other than customer counts, such as customer type, size and complexity of the rates under which these customers are billed. In order to reflect more accurately the cost causation behind these services, there is a need to weigh customer counts by these other cost factors. Although it is desirable to base customer weighting factors on empirical cost data, in practicality this is difficult to accomplish, as there is often no readily available accounting data to support such an approach.
>
> [Exhibit N-1, pp. 65-66]

[78] NSPI currently has seven allocators and three use weightings:

- Allocator C-1 is an "Average Customer" allocator. It allocates costs to all classes on the basis of number of customers, with no weighting applied to any of the customer numbers. It is not used in the COSS, but is identical to C-5, which is used.
- Allocator C-2 is a "Weighted Secondary Customer" allocator. It allocates costs only to classes served at a secondary distribution voltage level. It is based on the number of customers in each class with customer weightings of 5.0 for customers in the General and Small Industrial classes. It is used in Exhibit 3A to allocate the rate base associated with customer "Services" (i.e. from the pole to the customers' premises).
- Allocator C-3 is a "Weighted Average Customer" allocator. It is similar to C-1 except that a weighting of 0.82 is applied to the Unmetered class, a weighting of 5.0 is applied to the General and Small Industrial classes, a weighting of 25.0 is applied to the Medium Industrial class, and a weighting of 100 is applied to the Large General, Large Industrial and Municipal classes. It is used in Exhibit 6 to allocate operating costs associated with the Call Center and Billing Services.
- Allocator C-4 is a non-weighted allocator. It is used in Exhibit 3D to allocate the secondary customer portion of pole rate base and in Exhibit 3F to allocate the secondary customer portion of wire rate base.

- Allocator C-5 is identical to allocator C-1. It is used in Exhibit 3D to allocate the primary customer portion of pole rate base and in Exhibit 3F to allocate the primary customer portion of wire rate base.
- Allocator C-6 is similar to allocator C-3 except that the Unmetered class is excluded. It is used in Exhibit 6B to allocate operating costs associated with meter reading.
- Allocator C-7 is similar to allocator C-1 except that seasonal customers are excluded from the Residential class. It is used in Exhibit 6 to allocate the operating costs associated with Customer Service – H/O, Electrical Wiring Inspection – H/O, Payment Services, and Cost of Goods Sold (Net of Sales), and in Exhibit 6B to allocate the operating costs associated with Wiring Inspections.

[Exhibit N-10, pp. 6-7]

2014 NSUARB 53 (CanLII)

[79] NSPI initially proposed assigning a weighting of 90% to the number of bills in each customer class and 10% to class revenues to calculate the weighting factors. The proposed weighting factors also align with Canadian electric industry experience. For the unmetered class, NSPI proposed to abandon a 2006 negotiated solution and use the weightings as proposed.

[80] However, NSPI, in its Reply Evidence, having considered the evidence of Mr. Whalen, MEUNSC, and the CA, revised its proposal to calculate weighting factors based on 85% number of customers and 15% revenues in each customer class.

[81] NSPI disagreed with the CA's proposal to defer this issue to a future date. NSPI also disagreed with the CA's suggested use of empirical data and methods for weighting. NSPI stated that it is not practical to use an empirical approach to determine weighting factors because of the lack of data. Mr. Grus, on behalf of NSPI, explained:

> You know, we have to remember that we are talking about $50 million in customer-related costs, which represents four percent of total revenue requirement.
>
> Only some of these categories might be subject to weighted -- to allocation through weighted customer counts. And when you look at the fact of applying these weighted factors, you're looking at redistribution effect of the fraction of this four percent.
>
> Cost of service sources warn against over-analyzing and over-reliance on empirical data. Empirical research, empirical data is data intensive, it's time consuming and often fall into a state of disrepair, disuse. Our surveys of other jurisdictions provided to as an indication on this.

> So caution should be exercised before committing to empirical research-based development of customer weighting factors.
>
> [Transcript, pp. 76-77]

[82] The Intervenors disagreed with the weighting factors as originally proposed by NSPI. The CA had suggested that since judgment is used, the weighting for total class revenues should be higher than 10%. The MEUNSC opined that 90% weighting for number of bills is "too heavy" and other cost causation factors including regulatory costs, unmetered costs and non-billing activity should be considered.

[83] Mr. Chernick disagreed with NSPI's proposed weighting factors and recommended that the weighting should be calculated based on the cost or effort required per customer for each customer class.

[84] In its Post-Hearing Submission, the CA also questioned the proposed change of allocating service drops from 100% to 90% based on number of customers and 10% on revenues in each customer class. He suggested that any change to the current method should be based on real data. In addition, he recommended that the current weighting factors should be updated to reflect the current cost.

[85] NSPI, in its Closing Submission, did not support the deferral of the service drop issue because it does not have operational data to make changes suggested by the CA.

[86] Mr. Whalen, in his Pre-Filed Evidence, stated that the proposed "weights are based on some analysis of the resources used", but also require "substantial judgement". The approach used by NSPI is based on BC Hydro's approach and Mr. Whalen supported NSPI's proposal for the following reasons:

a) The proposed change applies only to weighted customer-based allocators (i.e. three of the current seven customer-based allocators).

2014 NSUARB 53 (CanLII)

b) The data necessary to calculate the proposed allocators is readily available so the allocators can easily be determined and updated for each COSS.

c) The new allocators will still reflect only the customer classes that use a service.

d) The proposed approach requires judgment with respect to only the two weighting factors to be applied to the number of bills and the class revenue, as opposed to the many judgments that have to be applied if empirical methods are pursued.

[Exhibit N-10, p. 8]

[87] He also noted that NSPI's changes would affect residential and general customer classes only. He recommended that the impact on these customer classes could be reduced with a weighting of 85% for number of customers and 15% for revenues in each customer class.

3.5.1 Findings

[88] NSPI's proposal to change the weighting to calculate allocators which assign common costs to various customer classes is supported by the Intervenors and Board Counsel consultant, with the exception of the CA.

[89] The CA recommended deferring this issue for additional data collection and consultation and noted that these weights should be based on empirical data. He also recommended that the current weighting factors should be updated to reflect current costs.

[90] The CA recommended that service drops not be part of the weighting as proposed by NSPI until more accurate information is available. NSPI disagreed due to lack of data on service drops.

[91] As discussed later in this Decision, NSPI proposed no changes to the poles and wires in the current COSS, but plans to do a further study and collect data. In addition, NSPI also agreed with the parties to do a streetlight use study as a part of poles and wires data collection.

2014 NSUARB 53 (CanLII)

[92] Based on this, the Board is of the view that data on service drops can be collected at the same time NSPI collects data on poles, wires and streetlights to improve the COSS.

[93] The Board approves NSPI's request with the exception of service drops. The current methodology relating to service drops will remain pending collection of additional information and consultation with stakeholders.

2014 NSUARB 53 (CanLII)

3.6 Depreciation Phase In

[94] The depreciation of distribution assets is currently classified as demand and customer related. NSPI stated that this classification method is based on the total net plant weighted average.

[95] NSPI is proposing to disaggregate distribution depreciation to include more details and a more accurate classification to better reflect allocation among customer classes.

[96] All Intervenors, including the Board Counsel consultant, support NSPI's proposed changes. The CA, in supporting the change, also recommended a phase-in to reduce the impact of this change.

[97] NSPI does not support the phase-in:

> … NS Power does not agree with a phase-in of this recommendation. NS Power depreciates its assets in accordance with UARB-approved depreciation approaches and rates. Further, the materiality of this issue does not warrant a phased-in approach. No class would see a higher increase in costs than 0.2 percent as a result of the change.
>
> [NSPI Closing Submission, p. 11]

3.6.1 Findings

[98] The Board notes that the proposed change has the support of all parties. NSPI, in its Reply Evidence, noted that the impact of this change on any customer class

is not more than 0.2%. Based on the degree of impact on customer classes, the Board approves this change without a phase-in.

3.7 Lingan

[99] Mr. Drazen, on behalf of the Industrial Group, indicated that NSPI plans to operate Lingan units 1 and 2 at very low capacity factors over the course of the next few years in advance of their retirement. In his view, they no longer operate as base load units. In his direct evidence he suggested that NSPI prepare cost of service runs with Lingan 1 and 2 functionalized as peaking units.

[100] The Industrial Group, in its Final Submission, requested the Board direct NSPI to report back to the Board on the recommended functionalization of Lingan 1 and 2 following the outcome of the IRP process. The Industrial Group argued that if the evidence demonstrates the units are more appropriately treated as peaking units rather than base load units that they should be treated as such in cost of service in the next GRA filing.

[101] NSPI's response with respect to the suggestion that Lingan 1 and 2 might be considered as peaking units was that it is premature to make that determination. NSPI committed, however, to review utilization during the IRP process and advised that this should inform future cost of service decisions. In the meantime, NSPI maintained that no changes to the classification of Lingan should be undertaken.

[102] Mr. Chernick recommended that Lingan plants continue to be treated as base load generation. He submitted that the costing treatment should reflect the original cost causation behind the investment in these plants, which was to produce lower cost energy.

2014 NSUARB 53 (CanLII)

3.7.1 Findings

[103] The Board agrees that it is premature to make a change to the treatment of Lingan 1 and 2 in this Decision. The Board agrees with NSPI and the Industrial Group that the utilization for Lingan 1 and 2 be considered as part of the IRP process and that may inform future cost of service decisions.

3.8 System Voltage

[104] NSPI is requesting the Board's approval to: add a bulk system level; eliminate differentiation between the High Voltage ("HV") and Extra High Voltage ("EHV") for transmission usage; manually adjust rate base between transmission and distribution [discussed in section 3.11]; allocate distribution costs to Municipal Utility customers and Large Industrial customers which are serviced from the distribution system; and eliminate the distinction between dedicated and non-dedicated substations.

[105] NSPI justified its initial request, which was included in the Application, as follows:

> (a) Distribution customers from the Large Industrial and Municipal classes are treated as transmission customers for cost allocation purposes, which is inconsistent with the COS design.
>
> (b) The COS does not recognize the extra high voltage transmission level at which some customers, within the Large Industrial Class, are served.
>
> (c) The COS supporting processes of load research sample design and line loss determination could be improved to increase accuracy in cost allocation.
>
> [Exhibit N-1, pp. 6-7]

[106] NSPI noted that this item has significant cost impact on certain customer classes. Certain Municipal Utility customers (3%) and certain Large Industrial customers (0.9%) have the largest increases with the proposed changes.

2014 NSUARB 53 (CanLII)

[107] Currently, the cost of service design divides the distribution system into primary and secondary categories and transmission system into EHV and HV categories. NSPI has identified two issues with the current cost allocation method:

> …currently not all class loads are classified in this manner. The coefficients used to apportion class distribution loads between primary and secondary voltages of the General, Small Industrial and Medium Industrial rate classes are dated, while loads of large customer classes are not correctly accounted for by distribution and transmission voltage levels.
>
> [Exhibit N-1, p. 48]

[108] NSPI stated that applying the voltage differentiation at the customer's point of receipt is practical and has been used to date:

> The concept of applying transmission voltage differentiated service at NS Power has a long tradition dating back to 1995 with the approval of the Large Industrial Expansion Rate.
>
> The challenges around data collection by EHV and HV transmission level will not go away with the adoption of a unitary approach to transmission, as this information is required for the purpose of ongoing calculation of 1P-RTP adders and the OATT. In the Company's view, the approaches under the COS and the OATT to this cost determination should be reconciled and the same cost assumptions should be used for the purposes of both calculations. The differential in these costs has been on record for some time now and it did not stand in the way of offering EHV treatment to customers billed under the COS-based ELI 2P-RTP rate since its creation in 2007. It would not be good ratemaking practice to treat a new subgroup of EHV customers differently.
>
> The concept of service differentiation by transmission voltage level has been firmly established in the ratemaking practice in our jurisdiction. For the purposes of 1P RTP adder calculations, NS Power has grouped all customers drawing power at an EHV level into a separate category. As is the case with distribution voltage service differentiation, the potential cost redistribution effect of implementation of the approach should not be a reason for its rejection.
>
> Recognition of EHV service at a point of customer receipt for all rate classes is a fair and implementable treatment in COS. It will create opportunities for the creation of price differentials to current and future EHV customers who typically are large industrial power consumers with the highest price elasticity of demand.
>
> [Exhibit N-1, pp. 53-54]

[109] NSPI also proposed that all five current customers which have service from the low voltage side of bulk power substations and which use no distribution system assets will continue to be treated as transmission customers. Mr. Whalen supports NSPI's proposal for these five customers.

2014 NSUARB 53 (CanLII)

[110] Currently MEUNSC's members are billed on HV level, but there are two municipal utilities which are serviced at the distribution level. The Large Industrial customers are billed on the HV level, but have some customers served at the distribution level. The Board understands that NSPI's proposal will impact those customers which are currently serviced from distribution, but not billed at distribution level.

[111] All parties agreed with the voltage service differentiation by primary and secondary at the distribution level. However, the MEUNSC would, as recommended by CAEC, like the issue of "low voltage cases" studied further. The purpose of this study would be to determine whether customers need low voltage or they happen to be on the low voltage distribution line (i.e., a geographic location issue).

[112] NSPI responded that CAEC did not propose a study but recommended that the allocation should vary depending upon whether this is a geographic issue or a service specifically sought by the customer.

[113] The MEUNSC, in its Final Submission, noted its concern with respect to two of its municipal electric utilities which receive service at distribution level (23,000 volts). The proposed change is expected to add $763,000 for these two utilities. It noted:

> We would submit that the appropriate process to be followed, is no "hurried changes". This is the only appropriate process until all facts are evidenced as to the reasons; actual asset book values; and potential NSP benefits associated with the service provisions to the 2 Municipal customers; are identified and known. Here again, as Mr. Whalen pointed out, "the voltage level at which customers are served is usually a <u>least cost decision by the Utility</u> rather than a customer choice". (direct evidence pg. 14, lines 2-3, emphasis added in original)
>
> [MEUNSC Final Submission, p. 1]

[114] NSPI, in its Reply to Closing Submissions, stated that:

2014 NSUARB 53 (CanLII)

> It does not appear that the MEUNSC disagrees with the principle that distribution service represents an incremental cost category to transmission that must be paid for by all distribution customers without exception. However, the MEUNSC argues that Undertaking U-4 should be read to support not proceeding with this recommendation. U-4 provides a net present value of the original investment. It does not reflect upgrades and refurbishments. Further, even if NS Power had a way, which it does not, to determine accurately the value of these assets, it would not be relevant to the COS treatment of service differentiation for the following reasons:
>
> (a) Regulatory ratemaking of shared assets, those that are not dedicated for use by individual customers, is based on the concept of cost generalization by level of service at a system level.
>
> (b) Service differentiation for COS purposes represents a balanced consideration of costing precision and practicality of cost determination.
>
> (c) The assets in question are shared by customers from various customer classes and therefore they cannot pass for dedicated asset treatment.
>
> [NSPI Reply to Closing Submissions, p. 11]

[115] Mr. Whalen, MEUNSC and the CA supported NSPI's request not to functionalize the transmission system into HV and EHV levels.

[116] The Industrial Group disagreed with NSPI's proposal to not functionalize the transmission system into HV and EHV levels. Mr. Drazen noted that, under the current system, customers on EHV level are billed at EHV rate and customers on HV level are billed at HV rate. By not recognizing this distinction on a go-forward basis, new customers who are serviced at EHV level and not billed at the EHV rate may consider the current proposal discriminatory.

[117] Currently, one-third of Large Industrial loads are serviced from the distribution level, but are billed as HV customers. Based on the proposed change, these customers would pay distribution level costs.

> 129 The Industrial Group supports the initial proposal, consistent with the CAEC recommendations. As explained by Mr. Drazen, while the distribution cost issue is basically rate design, it is relevant to the structure of the COS insofar as distribution costs allocated should be recovered only from those customers served at distribution level. This could be done by either by having a separate distribution service charge or by having a separate demand and energy charge for the different voltage levels. The COS study should show the costs for each class in a way that may be translated easily into rates.
>
> [Industrial Group, Closing Submission, p. 30]

2014 NSUARB 53 (CanLII)

[118] NSPI, in its Closing Submission, stated that :

> Drazen Consulting Group, Inc. also commented on this issue, providing support for a separate distribution service charge, which the consultant acknowledges is a rate design issue, but enabled through identification within the Cost of Service of the distribution cost of each class in a way that is easy to translate into different rates.
>
> [NSPI Closing Submission, p. 6]

3.8.1 Findings

[119] The MEUNSC supported NSPI's request except for the additional cost to two of its municipal units, which would be billed at the distribution rate and not the HV rate. It proposed a delay until the actual costs can be determined. NSPI stated that the cost impact is a ratemaking decision and should be dealt with at a GRA application. The Board agrees.

[120] The Industrial Group agreed that the distribution cost is a rate issue. However, it recommended that the cost of service should be designed so that the distribution cost of each customer class is clearly identified and can easily be translated into different rates.

[121] NSPI, in its Reply Submission, agreed with the Industrial Group's recommendation. The Board agrees as well.

[122] As noted earlier, the Industrial Group disagrees with NSPI's proposal to not functionalize the transmission system into EHV and HV levels. It argued that by not functionalizing the transmission system, new customers who are serviced from the EHV level may perceive this as discriminatory.

[123] The Board understands that currently no customer is impacted by not functionalizing the transmission system.

[124] The Board approves NSPI's request. The Intervenors may argue the cost implications of these changes at future GRAs.

2014 NSUARB 53 (CanLII)

[125] The Board expects NSPI to consider the Industrial Group's suggestion to collect additional data and show costs which can easily be converted to customer rates for customers who are serviced at the distribution level.

2014 NSUARB 53 (CanLII)

3.9 Revenue to Cost Ratios

[126] The ratio of revenue recovered from a customer class to costs assigned to that class through the cost of service is referred to as the class' Revenue to Cost ("R/C") ratio. In GRAs, the Board has determined that rates should be applied across NSPI's customer classes such that the R/C ratio for each class falls within a band of 0.95 to 1.05.

[127] At the request of the SBA, it was agreed by the parties to the 2012 GRA Settlement Agreement that the issue of R/C ratios would be canvassed as part of the cost of service proceeding. This was raised as a concern by the SBA because the Small General and General Classes have, over the course of several GRAs, been located near the upper limit of the R/C band (i.e., at or near 1.05). Conversely, the Large Industrial class has tended to fall below 1.0.

[128] In its Reply Evidence, NSPI acknowledged some of the impacts on customer classes resulting from the application of the R/C band:

> The current R/C band recognizes the imprecision inherent in any COS model and promotes rate stability across classes. Particularly at times of significant change (e.g. change in generation mix or change in methodology), the cost burden can shift measurably from one class or group to another. The R/C band provides the flexibility to move forward to R/C parity gradually, rather than abruptly, which would possibly result in significant rate increases or decreases. However, an unintended outcome of this rate-setting approach is that customer classes may be allowed to remain above or below the R/C ratio of 1.0 through several years and multiple rate proceedings.
>
> [Exhibit N-30, p. 31]

[129] While NSPI's consultant recommended that the R/C band should be expanded, NSPI concluded that the current R/C band is appropriate and should be maintained. It noted that the 0.95 to 1.05 band is commonly used in Canada.

[130] In his testimony Mr. Ferguson, on behalf of NSPI, considered that customer classes who pay within 5% of their cost of service allocation are paying the cost to serve them. He added that the current R/C band provides flexibility to the Board in GRAs with respect to the implementation of rates.

[131] The SBA, in his Final Submission, reiterated his view that this issue should be revisited:

> From the Small Business Advocate's perspective, there is no more pressing issue that impacts on the classes it represents - Small General, General, and Small Industrial - then the revenue to cost ratios, and the historic treatment of these classes in the assessment of costs to them.
>
> ...
>
> ... all of the small business classes have consistently been assessed in excess of 100% of their identified costs for the eighteen year period under review - with each class at times paying in excess of the range (105%) established by the Board. No other sector has been treated in this manner on a continuous basis over the time frame under review.
>
> ...
>
> The issues of the R/C ratios and the narrowing of the band are prime for re-consideration by the Board. The historical inequity of the Small Business classes paying more than their estimated cost of service, and, at times, above the high end of the band, needs to be rectified. It is submitted that all classes, including the Small Business classes, should pay their cost of service, but should not be expected, over time, to pay more than their cost of service. This leads to the inequity that the Small Business classes have faced over the past eighteen years, which inequity cannot be justified by any public policy or other rationale. We ask that the Board address this and insure that the Small Business classes pay no more than their cost of service in the future. We further suggest that the Board consider a reduction in the band, from its present 0.95 to 1.05 to 0.97 to 1.03. Such reduction will help to eliminate or minimize the likelihood of classes paying too less or paying too much in the future. A reduction in the band still will provide the Board with flexibility in applying rates, and should not create rate shock to any class. ...
>
> [SBA Final Submission, pp. 1-4]

[132] In her Pre-Filed Evidence, on behalf of the SBA, Lee Smith stated:

> In my experience, most regulatory commissions and frequently either state laws or regulatory rules support the idea that classes should pay the cost of serving them. It is unusual to accept significant deviations from cost of service as an appropriate end state,

2014 NSUARB 53 (CanLII)

> or to accept such deviations over a long period of time, particularly without any clear policy basis for the deviation between revenues and costs. …
>
> …
>
> I do not know of any such basis, and particularly I do not know of any Nova Scotia public policy that would support a long term policy of charging more, relative to the cost of service, to Small Business than to other customers.
>
> …
>
> I recommend that the Board express a policy that all classes should be moved to R/C ratios of 1.0, unless clear public policy reasons are expressed for deviation from these ratios, and that this movement toward the 1.0 ratio will be tempered by considerations of rate continuity. The R/C "range" should simply be guidance as to deviations from 1.0 that will be accepted until the 1.0 ratio is reached or where costs have shifted between classes. I recommend that the range should be narrowed to .97 to 1.03. This policy still leaves the Board free to make exceptions which it believes comport with public policy.
>
> [Exhibit N-12, pp. 15-16]

[133] Mr. Whalen concurred with NSPI's position that the current R/C band be maintained. Further, he considers R/C ratios as "playing a role in rate design, but I do not believe it to be a COSS issue" (Exhibit N-10, p. 27).

[134] In its Final Argument, PHP addressed the issue of the R/C ratios:

> PHP believes that a narrowing of the band that would potentially limit flexibility in rate design does not appear warranted at this time, particularly as this is one of the tools available to the Board in dealing with issues arising from changes to the COS.
>
> [PHP Final Argument, p. 17]

[135] In fact, PHP referred to Mr. Christensen, NSPI's consultant, who recommended in his report that NSPI consider applying to the Board to relax the requirement of close adherence to the 0.95 to 1.05 band, in order to enhance its pricing flexibility in the short term.

3.9.1 Findings

[136] Mr. Whalen correctly noted in his Pre-Filed Evidence that the topic of R/C ratios, and the application of an appropriate band, are more appropriately rate design issues, rather than cost of service issues. While the application of the cost of service analysis allocates the costs across the various customer classes, the application of an

2014 NSUARB 53 (CanLII)

R/C band is actually a rate design tool which is available to the Board in its ratemaking function. As noted by Ms. Smith, however, the two issues are undeniably related.

[137] The Board accepts the evidence of NSPI that the current 0.95 to 1.05 band is commonly applied in Canada. Further, it notes that either expanding or narrowing the band (both of which were referred to at times in this proceeding) could have negative consequences on some customer classes and/or would reduce the flexibility of the Board to apply rates in a reasonable and appropriate fashion across NSPI's various customer classes.

2014 NSUARB 53 (CanLII)

[138] The Board notes that in the past it has had occasion to address the concerns expressed by the SBA. In the 2012 GRA, the Board capped the R/C ratio for two of the SBA's customer groups to 1.03. However, in a number of recent GRA proceedings, rate level issues were dealt with by way of settlement agreement negotiated among the parties.

[139] While the Board is mindful of the SBA's concerns on this issue, it is satisfied that the current R/C band of 0.95 to 1.05 is appropriate and should be maintained. The application of the R/C band is a rate design tool held by the Board in the setting of rates. Where it is in the public interest to do so, the Board will use the R/C band, or apply other recognized ratemaking methods, to reduce the impact of rates on one or more customer classes.

3.10 Functionalization and Classification of Distribution Poles and Wires

[140] Board approval is requested to keep the current system of functionalization and classification of poles and wires.

[141] NSPI stated that these items in the COSS have not been updated since 1977. The distribution poles are split 65% as primary poles and 35% as secondary

poles; then 30% of primary poles are classified to demand and the remaining 70% are split equally between demand and customer service. The 35% secondary poles are split equally between demand and customer service. This results in an overall distribution poles split of 65% to demand and 35% to customer service.

[142] The distribution wires are split 70% to primary wires and 30% secondary wires. Similar to poles, the primary wires are further split 30% to demand and 70% to demand and customer service equally. The 30% secondary wires are equally split between demand and customer service.

[143] NSPI noted that it has complete data for primary poles and wires, but not for secondary poles and wires.

[144] NSPI discussed with Intervenors its initial proposal of a percentage split between primary and secondary distribution poles of 70/30 from 65/35 and no changes to the distribution wires because of the higher percentage of primary conductors (wires) in the system. Based on this, the percentage split between distribution poles and wires would have been the same: 70/30 between primary poles and wires and secondary poles and wires, respectively. No change was proposed in the current classification of these assets.

[145] NSPI, based on additional Intervenor feedback, now proposes no change to the current functionalization and classification of distribution poles and wires and to continue its effort to find a better solution supported by empirical data. This would involve carrying out an inventory of distribution secondary poles and wires at a minimum.

2014 NSUARB 53 (CanLII)

[146] NSPI, in its Reply Evidence, recommended that a study to examine poles and wires inventories be undertaken. The scope of the study would be as per Exhibit N-6, IR-13.

[147] In its Closing Submission, NSPI stated that all parties have agreed to defer the issue of functionalization until the inventory results are available. It also noted that there is no agreement on the classification of costs between demand and customer service, which is currently based on judgment.

[148] Mr. Chernick did not accept the 70/30 split between primary and secondary poles, as initially proposed by NSPI, based on his examination of the rural and urban areas of NSPI's system. He was of the opinion that rural populated areas have 20% of secondary poles and there are none in other parts of the system. He also estimated the cost of secondary poles to be lower than the primary poles. Based on this he believes that the secondary poles should not be more than 10% of the entire system.

[149] Mr. Chernick also argued that secondary poles do not add cost but lower the overall cost of the system by reducing the requirement for primary poles. Based on this and non-availability of supporting data from NSPI, he supported 100% allocation of secondary poles to demand.

[150] Mr. Chernick did not agree that the treatment of wires should be the same as poles and recommended a separate treatment for overhead and underground wires.

[151] He noted the issues which the Board may consider before proceeding with the data collection project:

- Are secondary poles complementary to primary poles, imposing no additional costs beyond the costs of poles to serve customers at primary, or are the costs of the secondary poles incremental to primary poles?

2014 NSUARB 53 (CanLII)

- What portion of joint poles, which carry both primary and secondary lines, should be sub-functionalized as secondary?
- Should poles that carry only streetlighting equipment (and a line to the streetlight) be functionalized as general-service poles or as streetlighting plant?

[Exhibit N-16, p. 69]

2014 NSUARB 53 (CanLII)

[152] Mr. Chernick concluded that only 10% of locations are at the end of the system and may require extensions to service additional customers. These extensions will also serve area demand in addition to serving new customers. He estimated that only 5% of primary and joint poles may be required for incremental customers.

[153] The SBA's consultant recommended that a zero intercept or a minimum size method be used to classify distribution poles and wires.

[154] Mr. Whalen agreed with NSPI's recommendation to keep the current method of functionalization and classification of distribution poles and wires. Specifically, the classification approach based on judgment is preferable to minimum size or zero intercept approaches.

[155] The CA, in its Post Hearing Submission, did not support the minimum size approach and recommended that the classification of poles issue be referred back to stakeholders for further consultation.

3.10.1 Findings

[156] The Board understands that all Intervenors have agreed to retain the current system of functionalizing poles and wires until the results of NSPI proposed studies are available. The Board agrees and approves this request.

[157] The Board also understands that during the hearing all parties, except the CA, agreed to retain the current method of classifying poles and wires.

[158] The CA, in its Post Hearing Submission, noted that it has a concern about the current system of classifying distribution poles to estimate customer related costs and requested that the issue be referred back for further consultation among the parties. The Board approves NSPI's request to keep the current classification of poles and refers the issue for further consultation among the parties.

[159] As for the classification of conductors, the CA, in its Post Hearing Submission, recommended that all conductor costs be demand related until additional information is available through the survey of distribution systems and a reasonable methodology is developed to allocate these costs to the customer category.

[160] The Board has considered the CA's recommendation and is of the opinion that no change should be made at this time. The Board's view is that it is premature to make a change now if, in the future, based on the data and consultation among the parties, the classification of wires may be changed.

[161] The Board approves the current system of classifying conductors as proposed by NSPI and refers the issue for further consultation among the parties once the additional data is available.

[162] The Board directs NSPI to collect appropriate data so the Board may consider the issues identified by Mr. Chernick.

[163] To summarize, the Board approves NSPI's proposal to retain the current method of functionalization and classification of distribution poles and wires. NSPI is to obtain additional necessary data and have further consultation with stakeholders as agreed among the parties.

2014 NSUARB 53 (CanLII)

3.11 Re-allocation of Transmission Rate Base to Distribution

[164] NSPI has requested approval to maintain the manual adjustment to redistribute a portion of the transmission rate base to distribution. Currently, NSPI recognizes there is an element of distribution in transmission capital projects and a manual adjustment to re-functionalize a small portion of the transmission substation rate base to distribution is made to account for this. It explains:

> …in its Application the Company had recommended discontinuation of a manual transfer of transmission costs to distribution costs to recognize the portion of transmission substation capital expenditures appropriately classified to distribution. Upon further review with the parties, it was determined that this adjustment continues to be required and the amount should be examined and updated if necessary.
>
> [Exhibit N-30, p. 27]

[165] Subsequent to the change in its recommendation there have been no comments from Intervenors objecting to this recommendation.

3.11.1 Findings

[166] The Board understands the change in position was agreed to during settlement conferences and resulted in consensus. The Board approves the continuation of the manual adjustment until a sustainable process to update the transmission and distribution adjustment has been agreed to. This is action item number 9, outlined in Undertaking U-6.

3.12 Agreed to Items - Approach and Future Studies

[167] CAEC found much of the current COSS to be in line with industry practice. For those items where no change has been requested, NSPI seeks Board confirmation that the existing methodology is appropriate and should be maintained.

[168] Numerous recommendations sought change, but were not argued before the Board as NSPI had achieved consensus prior to the Application. These include:

2014 NSUARB 53 (CanLII)

Item 1 (a) Elimination of dedicated substations

NS Power has recommended that the Board eliminate dedicated substations from Exhibit 3b in the current Cost of Service Study. In its Application, NS Power noted that it had reached consensus on this recommendation with participating parties' consultants. No party has filed evidence objecting to this recommendation and this issue was not a subject of examination during the hearing. NS Power respectfully requests that its recommendation that dedicated substations be removed from the Cost of Service be approved.

[NSPI Closing Submission, January 15, 2014, p.5]

Item 1 (b) Creation of a bulk power substation service level to facilitate allocation of distribution substation costs to the Large Industrial and Municipal Classes in recognition of their use of these assets

This recommendation came forward for the first time, on the record, by NS Power in its Reply Evidence, but was arrived at following settlement discussions with the parties in advance of this. As stated in its Reply Evidence, NS Power understands that this approach is supported by Mr. Whalen who stated in his Evidence:

> During the settlement conferences, stakeholders and NSPI agreed that NSPI would create a bulk power service level. This will allow the costs of serving these five customers to be more accurately determined.
>
> However, there are other Large Industrial and Municipal customers who are served using primary distribution assets. NSPI proposes to apply CAEC's recommendation to these customers.
>
> I concur with NSPI's proposal.

Drazen Consulting Group, Inc. also commented on this issue, providing support for a separate distribution service charge, which the consultant acknowledges is a rate design issue, but enabled through identification within the Cost of Service of the distribution cost of each class in a way that is easy to translate into different rates.

This issue was not discussed during the hearing. NS Power respectfully requests that its recommendation to create a bulk power substation service level be approved.

[NSPI Closing Submission, January 15, 2014, pp. 5-6]

Item 1 (e) Update meter costs

NS Power states in its Evidence that parties who had participated in the engagement process in advance of the filing of the Application were in agreement with NS Power's proposal on this matter. No party filed evidence objecting to this recommendation and this issue was not a subject of examination during the hearing. NS Power respectfully requests that its recommendation that meter costs be updated in the Cost of Service be approved.

[NSPI Closing Submission, January 15, 2014, p.10]

2014 NSUARB 53 (CanLII)

> **Item 1 (f) Correctly allocate interruptible supply credit among rate classes**
>
> NS Power states in its Evidence that consensus on this matter was reached in advance of filing the Application. No party has filed evidence objecting to this recommendation and this issue was not a subject of examination during the hearing. NS Power respectfully requests that its recommendation that the allocation of the cost of the interruptible supply credit be revised be approved.
>
> [NSPI Closing Submission, January 15, 2014, p.10]

[169] There were numerous items identified in the Application that relate to informing future change.

[170] In response to Undertaking U-6, NSPI provided a list of cost of service related items for which additional action was agreed to, as follows:

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2014 NSUARB 53 (CanLII)

App'n No.	U-6 No.	Item to be deferred	Description	Timeframe
15, 16	1	ERIS	NS Power will review if generation resources on ERIS can be considered to provide capacity for planning purposes and this should be recognized in the COS.	To be completed as part of the upcoming IRP.
15, 16	2	NRIS	NS Power will review the aggregate firm capacity equivalent of existing and committed wind resources to determine the capacity recognition for this generation for planning purposes and the appropriate COS treatment.	To be completed as part of the upcoming IRP.
42	3	Treatment of Lingan ½	The Company continues to include this generation as baseload and will address any changes to this treatment and provide its support for the proposed treatment as part of future GRAs.	The outlook for all generation units will be examined as part of the upcoming IRP.
21	4	Survey of Distribution System	NS Power will conduct a review of poles and wires, leading to recommendations regarding sub-functionalization of poles between primary and secondary, and sub- functionalization of conductors between primary and secondary.	This survey will take approximately 3 - 5 months to complete. The Company intends to provide results to stakeholders and the Board at the end of Q2.
37, 38	5	Class Load Data Collection and analysis	NS Power will undertake to complete a review of the Load Research sample to confirm its accuracy and make any appropriate adjustments. This undertaking will involve the engagement of a statistician, procurement and installation of meters, data collection for one full calendar year and implementation of data into the COS.	The class load data collection and analysis will take approximately 18 to 24 months to complete. Throughout this process, as refinements are identified, they will be incorporated within the Load Research sample.
7, 8, 9	6	Line Loss Determination model	NS Power will develop a methodology to confirm the load research design is appropriate and provides the required supporting data, gather one calendar year of load research data and implement this into the COS.	Development of a line loss determination model will happen concurrently with updating the load research sample. Implementation of this model will take 1 to 3 months following the collection of one calendar year of load research data from the redesigned sample.
30	7	Miscellaneous revenues	NS Power will review the origin of miscellaneous revenues by class and/or function and develop new allocators.	This undertaking will take approximately 3 months. NS Power intends to provide results to stakeholders and the Board in Q2.
29	8	Overhead costs, including technical and construction costs	NS Power will review the origin of overhead costs (including technical and construction costs) by class and/or function and develop new allocators.	This undertaking will take approximately 3 months. NS Power intends to provide results to stakeholders and the Board in Q2.
34	9	Manual Adjustment for Transmission rate base from Distribution	NS Power has withdrawn its original recommendation regarding the transmission/distribution rate base adjustment. The Company has agreed to determine the appropriate adjustment from transmission to distribution rate base.	This undertaking will take approximately 3 months. NS Power intends to provide results to stakeholders and the Board in Q2.
10	10	Review Transformer Loss Adjustment	The Company has undertaken to review the transformer loss adjustment (1.75%) that is in place on some of our rates. This adjustment has not been reviewed since the late 1980's and should be reexamined.	The review will take approximately 6 months to complete.

2014 NSUARB 53 (CanLII)

3.12.1 Findings

[171] The Board accepts the consensus reached on the above noted items 1(a), (b), (e), and (f).

[172] It appears the studies outlined in Undertaking U-6 were a condition of consensus in many cases and, therefore, appear to be required as opposed to merely recommended. The Board directs NSPI to complete the items as outlined in U-6 according to the proposed timeline. The Board also directs NSPI to report back to the Board the results and recommended revisions to the cost of service for each of the above items within 30 days of the respective timeframes outlined above.

[173] With respect to cost of service items that stakeholders agreed were either not to be reviewed in the scope of this study, or where consensus was reached to maintain the current methodology, the Board accepts the continuation of the existing methodology. Otherwise, if the Board has not commented on an issue, NSPI is directed to continue the status quo.

[174] With respect to the Maritime Link, the Industrial Group requested the Board direct NSPI to engage in a process to address the Maritime Link cost of service. NSPI argued that the cost of service treatment of the Maritime Link has not been determined and will require engagement of the parties. The Board agrees with NSPI that this was not the forum to review the future cost of service implications of the Maritime Link. However, the Board acknowledges the potential impact on future cost of service and directs NSPI to work with interested parties prior to any rate application associated with the Maritime Link to establish a process towards resolving related cost of service issues.

2014 NSUARB 53 (CanLII)

[175] A number of parties spoke to the need for more timely future reviews of the COSS. The Board notes that as a whole the results of this process confirm the existing cost of service was not significantly out of balance. The Board expects the agreed-to updates to the cost of service data anticipated through GRAs to alleviate the need for a scheduled full scale COSS. The Board is prepared to consider submissions on future cost of service changes and will continue to monitor accordingly.

2014 NSUARB 53 (CanLII)

4.0 COMPLIANCE FILING

[176] Given the complexity of implementing these changes in the next GRA the Board directs NSPI to provide a Compliance Filing on the approved cost of service items. The Board directs NSPI to restate, no later than July 31, 2014, the 2014 GRA Compliance Filing incorporating the above approved changes. The Compliance Filing shall list the items which remain unresolved and are subject to further study. This will provide parties an opportunity to understand the impact of changes related to the cost of service study separate from those of the next GRA.

5.0 SUMMARY OF BOARD FINDINGS

[177] NSPI made an application for approval of its 2013 Cost of Service Study ("COSS"). This study reviews and, where appropriate, recalibrates how the costs of the electricity system are apportioned among customer classes. This process neither increases nor decreases the costs of making electricity; rather it determines the equitable share each customer class should pay for the component parts of the system: generation, wires, poles, line repair, administration, etc. It is intended to provide a fair allocation of utility costs among customer classes based on cost causation and asset utilization.

[178] This was the first comprehensive COSS review since 1995. However, as a whole, the results of this process confirmed that the existing cost of service was not significantly out of balance.

[179] All parties were complimentary of the stakeholder engagement process undertaken by NSPI which the Board views as a template for future proceedings. There were a significant number of issues where the parties reached consensus and the Board accepted that consensus.

[180] In this Decision, the Board addressed the issues where there was no consensus among the parties. Its findings include:

- For Base Load Plant, the existing approach is retained, i.e., system load factor ("SLF") methodology for classification and a 3CP (coincident peak) method for allocation;
- For Wind, including Purchased Wind Power, the classification should align with planning assumptions in effect at the time of the next general rate application, rather than seek to fix specific classification factors now. NSPI is directed to carry out the necessary study;
- For other Purchased Power Costs, imports shall be treated as 100% energy; non-wind in-province purchased power shall be classified in like fashion to NSPI's base load generation; and for purchased power costs from biomass, NSPI is directed to classify the cost of biomass purchases in proportion to the classification of total costs for the Port Hawkesbury biomass plant;

2014 NSUARB 53 (CanLII)

- For the classification and allocation of transmission costs, the SLF 3CP methodology is to continue;
- The customer weighting factors are changed to 85% number of customers and 15% revenues for each customer class. However, the current methodology related to service drops will remain pending collection of additional information and consultation with stakeholders;
- The disaggregation of distribution depreciation is approved, without a phase-in;
- There shall be no change to the treatment of Lingan units 1 and 2. The utilization of Lingan will be considered as part of the IRP process;
- With respect to System Voltage, the transmission system shall not be functionalized into EHV and HV levels;
- The current R/C band of 0.95 to 1.05 is maintained;
- The existing method of functionalization and classification of distribution poles and wires is retained. NSPI is to obtain additional necessary data and have further consultation with stakeholders;
- The manual adjustment to redistribute a portion of the transmission rate base to distribution is maintained, subject to further review with the parties.

[181] There were a number of matters which the parties agreed should be worked on in the future, including those items listed in Undertaking U-6. The Board directs NSPI to report back to the Board the results and recommended revisions to the

2014 NSUARB 53 (CanLII)

cost of service for each of the items within 30 days of the respective timeframes outlined.

[182] With respect to cost of service items that stakeholders agreed were either not to be reviewed in the scope of this study, or where consensus was reached to maintain the current methodology, the Board accepts the continuation of the existing methodology. Otherwise, if the Board has not commented on an issue, NSPI is directed to continue the status quo.

[183] An Order will issue accordingly.

DATED at Halifax, Nova Scotia, this 11th day of March, 2014.

Peter W. Gurnham

Roland A. Deveau

Kulvinder S. Dhillon

2014 NSUARB 53 (CanLII)

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2013-0416/EB-2014-0247

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

FOR APPROVAL OF DISTRIBUTION RATES FOR 2015 TO 2019

DECISION

March 12, 2015

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EB-2013-0416/EB-2014-0247

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015, and each year thereafter to December 31, 2019.

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order approving an exemption from sections 7.5.1 and 7.5.2. of the Distribution System Code.

BEFORE: Ken Quesnelle
Presiding Member

Marika Hare
Member

Emad Elsayed
Member

DECISION

March 12, 2015

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TABLE OF CONTENTS

1.0 INTRODUCTION AND SUMMARY

This is a Decision of the Ontario Energy Board (OEB) in response to an application by Hydro One Networks Inc. (Hydro One) for permission to charge certain distribution rates to its customers.

Hydro One owns and operates the largest electricity transmission and distribution system in Ontario. The transmission system is made up of a high voltage network of transmission lines, steel towers and equipment. It conveys electricity long distances from electricity generation facilities to large power consumers, urban centres and to transformer stations. The distribution system consists of a lower voltage network of distribution lines, poles and equipment. It conveys electricity at lower voltages from the transformer stations to homes and businesses throughout the province.

Hydro One applies for transmission rates and distribution rates separately. This Decision deals with an application by Hydro One for the approval of distribution rates.

Hydro One's distribution system serves primarily the rural and remote areas of the province. Its 122,000 km distribution system serves about 1.3 million end-use customers and smaller electricity distributors.

The rates that the OEB has approved in this Decision are set based on the OEB's determination of the level of revenue that is required by Hydro One to cover the reasonably incurred costs of operating and maintaining the distribution system at a level of service that meets the needs of its customers.

A few years ago, the OEB reviewed its approach to setting distribution rates for regulated distribution companies in Ontario. The resulting policy was introduced in October of 2012 in a Report of the Board titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (RRFE). The RRFE policy provides options in the way a distributor can structure its rate-setting application. The array of options allows flexibility so that a distributor can choose a rate-setting structure that best matches its needs in terms of the amount and variability of its capital investment needs.

The RRFE policy, as the report title states, is a performance based approach to regulation that supports the cost-effective planning and operation of the electricity distribution network. The OEB intends that the policy provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

There are three main areas in which the OEB describes its expectations and desired outcomes in the policy report: rate-setting, planning, and measuring performance. The OEB has evaluated Hydro One's application against the policy objectives pertaining to these areas and the RRFE policy in general.

The Custom Incentive Rate-setting option (Custom IR) is one of the rate setting options contained in the RRFE policy. It is at minimum, a five-year plan and is described as being suitable for distributors with large or highly variable capital investment requirements. It was under this option that Hydro One applied for rates covering a five year period.

Hydro One asked the OEB to approve increases to distribution rates for each of the years 2015 through to 2019. The total annual increases requested represent growth in distribution revenues of 29%, from $1.25 billion in 2014 to $1.61 billion in 2019[1]. The OEB finds Hydro One's evidence in support of its proposed revenue requirement to be generally adequate. However, the OEB notes that, despite having applied under the Custom IR framework, Hydro One characterized its application as a "Custom Cost of Service" application. The company indicated that cost savings from productivity improvements were embedded in cost forecasts, and that the company would bear the risk of failing to achieve these savings. The OEB does not consider Hydro One's "Custom Cost of Service" application to be sufficiently aligned with the objectives of the RRFE policy to approve the application as presented. Also, the OEB does not consider it acceptable to postpone the potential commencement of an appropriately-structured **incentive based** rate setting framework until 2020 following the five year period proposed by Hydro One.

The OEB accordingly denies Hydro One's request for five year rate setting. However, the OEB will approve rates for 2015, 2016, and 2017 using a cost of service methodology, based on the evidence filed and tested in the hearing. This results in an increase in distribution revenues of about 19% from 2014 to 2017, compared to Hydro One's request of a 29% increase over a five year period as cited above.

[1] Exhibit J3.3, September 12, 2014

The OEB has determined that it is appropriate to approve cost-based rates for a three year period for the following reasons:

- The OEB is persuaded that Hydro One’s work plans in the short term are vital to maintain system reliability and that Hydro One requires more revenues than are currently being collected in order to perform this work. Complete denial of Hydro One's application is therefore not a reasonable option in this case.

- The OEB finds that sufficient evidence was provided to be able to set just and reasonable rates for the shorter period of 3 years.

- The OEB expects Hydro One to undertake a review of its approach to performance management and to reflect the objectives encompassed in the RRFE policy in its next application. The OEB considers two years – the anticipated time period before Hydro One applies for 2018 rates – to be an appropriate amount of time for Hydro One to undertake the types of initiatives that are necessary in advance of its next rates application.

The OEB has determined that Hydro One’s approach lacks the RRFE features designed to achieve a central policy objective of measuring performance and providing incentives for continuous improvement. Hydro One is directed in this Decision to initiate a number of activities and report the results as part of its next rate application. A discussion of specific shortcomings of Hydro One’s application follows in the body of this Decision.

The OEB has determined that Hydro One’s capital spending plan is justified over the three year period approved in this Decision. Hydro One’s proposed spending on compensation, vegetation management, and conservation and demand management has not been fully accepted, for the reasons provided in the body of this Decision. The OEB still expects Hydro One to execute and achieve its proposed work plans with the lesser amount of spending that has been accepted. This imposes a need for Hydro One to find efficiency gains for each of 2015, 2016 and 2017. The rates the OEB will set reflect the spending levels approved in this Decision.

This Decision determines the total amount of revenue Hydro One will be permitted to recover from its customers; and also the way the proportion of revenue to be recovered from each customer class (group of customers with common characteristics) is to be calculated. In response to this Decision, Hydro One will provide updated information that reflects the OEB's findings. The precise impact on customers' bills will be known after that information is received.

Hydro One has a customer class known as Seasonal. These customers receive electrical service at dwellings that are not their primary residence. Hydro One's application contained a proposal to make changes with respect to Seasonal Rates. Hydro One withdrew its proposal in light of the submissions received from the parties in this proceeding. The OEB has determined that the Seasonal customer classification is no longer justified and directs Hydro One to prepare a plan by August 4, 2015 for the elimination of the seasonal rate class commencing January 1, 2016.

The OEB has also approved the recovery of past investments in Smart Meters.

Hydro One applied for an exemption from a section of the Distribution System Code (DSC) as part of this rates application. The section of the DSC deals with a distributor's obligation to attempt to contact customers every time a service appointment will be missed. Hydro One submitted that it cannot meet the DSC requirement. The OEB established a separate file number for the exemption request because it affects Hydro One's licence, not its rates, but the OEB heard the evidence and arguments on the matter at the same time as matters dealing with Hydro One's rate application.

The OEB has denied Hydro One's request for an exemption. The OEB's analysis of the issues and reasons for its determination are included in this Decision.

2.0 ORGANIZATION OF THE DECISION

As summarized above, the OEB has determined that it will approve rates for 2015, 2016, and 2017, based on the evidence filed, using a cost of service methodology as opposed to the five year “Custom Cost of Service” format that Hydro One requested.

The OEB has organized this Decision into chapters, reflecting the issues that the OEB has considered in making its findings. Each chapter covers the OEB’s reasons for approving or denying certain aspects of the application in the form requested and its determinations on what level of spending is allowed in the calculation of Hydro One’s rates using a cost of service methodology.

The initial chapter provides a description of the RRFE policy and why Hydro One has not convinced the OEB that the objectives of the policy are likely to be achieved under Hydro One’s Custom Cost of Service plan.

Subsequent chapters deal with the proposed work plans of Hydro One in terms of operations and maintenance spending as well as its capital spending and how it developed its capital spending plan.

Matters dealing with the development of the rates themselves are covered in chapters dealing with revenue requirement (which incorporates the results of the budgets for capital and operations and maintenance, cost of capital, depreciation, etc.), load forecast, cost allocation and rate design.

Hydro One has applied to have previously spent money approved for inclusion in rates as well. This money is tracked in accounts known as deferral and variance accounts (DVAs) that were previously approved by the OEB for tracking purposes. They include an account for spending on Smart Meters. These issues are dealt with in a separate chapter.

The OEB’s determination on the DSC exemption request is also included in a stand-alone chapter.

An account of the proceeding containing a list of the participants and witnesses is attached as Appendix 1. This appendix also contains a list of the acronyms or short forms used in this Decision to identify intervenors. The transcription record of the decision on a motion by the City of Hamilton is attached as Appendix 2.

3.0 ALIGNMENT WITH THE RENEWED REGULATORY FRAMEWORK FOR ELECTRICITY

The Renewed Regulatory Framework for Electricity is a comprehensive, performance-based approach to regulation that focuses on the achievement of outcomes that ensure Ontario's electricity system provides value for money for customers. The OEB's RRFE Report (*Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, issued October 18, 2012) provides three rate-setting options under which a distributor may apply for rates to be set, depending on its capital requirements.

The Custom Incentive Rate-setting option (Custom IR) is described by the OEB as suitable for distributors with large or highly variable capital requirements. Hydro One applied for rates under this option, and asked the OEB to set rates for each of five years (2015 – 2019) based on its cost forecasts for those years. The company indicated that cost savings from productivity improvements were embedded in the cost forecasts, and that the company would bear the risk of failing to achieve these savings.

At page 13 of the RRFE Report, the OEB provides a table of the elements of each rate-setting method. Parties in the hearing criticized Hydro One's application as being non-compliant or inadequate with respect to some of these elements. The criticisms included:

- The form of the application: Custom Cost of Service rather than Custom IR
- Lack of a productivity factor
- Lack of a stretch factor
- Weak benchmarking evidence
- Lack of appropriate sharing of benefits between the utility and its customers (e.g. through an earnings sharing mechanism)
- Proposed annual adjustments, unforeseen events and off-ramps that differ from OEB policy

- Overall lack of consistency and comparability with incentive rate-setting particularly with regard to the specification and use of a custom index approach to rate-setting that includes explicit, externally imposed improvement incentives.

In its May 30, 2014 evidence update, Hydro One provided eight outcomes by which to measure its five year plan. The company agreed to report annually on these outcomes, including the results achieved and actual amounts spent on the programs. Many parties submitted that additional reporting, for example, on actual capital spending and the results of the smart grid program, was necessary.

Parties submitted that the inadequacies of the application should be addressed by the OEB through either denial of the five year application (i.e. set rates for only one or two years) or substantive adjustments to the five year plan such as using 2015 as a base year and setting rates for 2016 – 2019 through an index.

Findings

The OEB has concluded, for the reasons set out below, that Hydro One's application is insufficient as a Custom IR application under RRFE and has determined that it will deny approval of the proposed five-year plan. Instead the OEB will approve rates for a three-year period based on the evidence provided. This change from what was applied for by Hydro One is due to a number of shortcomings with Hydro One's proposed approach. The OEB is directing Hydro One to address those shortcomings, set out below, over the next three years in preparation for the next rates application.

3.1 Inconsistency with outcome-based regulation

Hydro One chose to interpret the OEB's Custom IR option, referred to in the RRFE Report as "custom index", to include "custom cost of service". The OEB does not accept this interpretation. All three rate-setting methods are described in the Report as incentive rate-setting, not cost of service.

Cost of service rate-setting has an important role in performance-based regulation regimes to periodically examine in detail the costs and activities underpinning rates. However, the OEB continues to believe that multi-year incentive rate-setting, with its emphasis on results, is the most effective way to incent behaviour similar to that seen in commercially-oriented, consumer market-driven companies. Incentive rate-setting differs from cost of service rate-setting in that it relies less on a utility's internal cost, output, and service quality to establish rates, and more on benchmarks of cost, output, and service quality that are external to the utility revealing superior performance and encouraging best practice. The decoupling of rates from the utility's own costs simulates a competitive market environment and is more compatible with an outcomes-based approach to regulation.

The OEB finds that Hydro One's proposed plan is deficient in this regard, as it includes limited prospects for continuous improvement, lacks any externally imposed improvement incentives, includes limited cost and productivity benchmarking support, and fails to demonstrate value to customers commensurate with the forecasted spending.

3.2 Lack of externally imposed incentives

The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.

The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company. Furthermore, the plan lacks measurement of increased efficiency year-over-year in a form illustrating trends in a transparent fashion.

It is not sufficient to embed savings in cost forecasts. As already noted, the OEB's Custom IR is an incentive rate-setting approach designed to drive efficiencies. Benefits from explicit, objectively determined productivity and efficiency adjustments such as stretch factors include mimicking competitive market conditions, sharing anticipated savings with ratepayers “up front”, and facilitating a more outcome-based approach to regulation.

As already noted, traditional cost of service review will continue to entail detailed input cost assessments. However, Custom IR proceedings are intended to be framed more like performance inquiries resulting in multi-year outcome commitments and measures that facilitate year-over-year performance assessment. The productivity and efficiency elements allow the OEB to move away from detailed input cost assessment and focus more on utility performance. These factors provide utilities with strong incentives to continually seek efficiencies and share expected savings with ratepayers “up front” avoiding “after the fact” regulatory scrutiny.

3.3 Weak benchmarking evidence

The RRFE policy articulates the importance the OEB places on benchmarking. Benchmarking evidence, whether it compares a utility’s performance to itself year-over-year, or to other utilities, is a critical input to the OEB’s assessment of utility performance.

Benchmarking, when used in combination with specific cost drivers and other sources of utility performance information, allows for an overall assessment of a utility’s cost and outcome performance.

A majority of parties were critical of the lack of benchmarking in Hydro One’s plan. Hydro One described eight benchmarking or similar studies it had undertaken. The OEB agrees with the submissions of OEB staff and the majority of the intervenors that the studies provided in this proceeding by Hydro One, lack:

1) a top-down perspective of what the appropriate level of costs should be; and

2) measures of Hydro One’s cost performance against other comparable utilities.

Parties also pointed out that no total factor productivity study, capital cost benchmarking study or an overall OM&A benchmarking study, were submitted.

Accordingly, the OEB does not find this evidence sufficient to provide a complete assessment of Hydro One's cost and outcome performance. The OEB disagrees with Hydro One's assertion that external benchmarking will not assist the OEB in determining whether costs at Hydro One are reasonable. As stated earlier, benchmarking information is used in combination with specific cost drivers and other sources of utility performance information. Benchmarking evidence is expected to include an explanation of any significant divergence from the optimal benchmark.

While the OEB considers Hydro One's benchmarking efforts for this proceeding to be inadequate, the weakness of the benchmarking evidence does not completely impede the OEB's ability to assess the reasonableness of the cost forecasts in this case. As described later in this Decision, the OEB will disallow some of the requested costs in certain areas, and direct Hydro One to address a number of shortcomings in its plan, including specific benchmarking evidence the OEB expects to be filed in Hydro One's next rates application.

The OEB acknowledges that Hydro One expressed concern over the OEB's approach to estimating total factor productivity and benchmarking of distributors' total costs as it applies to Hydro One. Despite Hydro One's perception of shortcomings of the approach, the OEB's studies do provide important information regarding Hydro One's performance. For example, according to the 2013 Benchmarking Update[2], Hydro One's average cost performance has improved by 10.4% over the 2012 benchmarking study.

In addition, as OEB staff pointed out in its submission, Hydro One's response to staff IR #60 showed that "…while Hydro One's productivity continues to be negative, it appears it may become less so." In other words, while Hydro One's productivity trend is negative, the evidence indicates that the trend may become less negative and may continue to improve over the next few years.

[2] Empirical Research in Support of Incentive Rate-Setting: 2013 Benchmarking Update prepared for the OEB by Pacific Economics Group Research, LCC, issued July 2014, Table 3.

The OEB sees value in Hydro One measuring its own total factor productivity over time to be able to demonstrate improvement in productivity to its customers and the OEB. The OEB requires Hydro One to conduct such a study. Given Hydro One's concerns, the OEB leaves it to Hydro One to determine its preferred total factor productivity study method. However, the period of the study should include years at least going back to 2002. The results of the study must be filed as part of Hydro One's next rates application.

3.4 Limited prospects for continuous improvement

The OEB is concerned that under Hydro One's proposed plan, lack of efficiency incentives lessens the probability of achieving continuous improvement.

Hydro One's forecasted annual savings built into its forecasted costs are summarized in the evidence[3]. Several parties noted, and Hydro One acknowledged, that most of the savings come from investments made in 2010 through to 2014. In its submission, OEB staff calculated Hydro One's new savings each year for 2015, 2016, 2017, 2018 and 2019 at $27.7 million, $8.1 million, $3.8 million, $1.0 million, and $0.2 million, respectively. In short, the savings are declining over time.

While Hydro One characterises its forecasted annual savings as ambitious, the OEB is concerned that the declining trend and relatively small savings do not show Hydro One to be a company with a strong orientation towards continuous improvement. Furthermore, Hydro One's proposed plan does not include any measure of continuous improvement. In response to questions from parties on how any savings beyond those forecasted will be measured and treated, Hydro One indicated that any such savings would be re-invested into the company's work plan. Hydro One explained that its customers would benefit from this re-investment though the additional work that Hydro One would be able to carry out.

Hydro One has stated that it is in the fourth quartile of North American utility performance with respect to system reliability and that it has no plan to improve on that

[3] Exhibit A Tab 19 Schedule 1, page 4, Table 2

score. It submits that to do so would not be cost effective and its customers would not want to pay the cost associated with the improvements. The OEB considers Hydro One's stance on its performance to be misplaced. Rather than argue that it would be too expensive to move up the ladder in comparison to those that are in the first, second and third quartile, Hydro One should be finding cost effective ways to improve its performance and provide evidence intended to convince the OEB that it has identified more appropriate benchmarks to which it can and will compare itself for continuous improvement tracking purposes.

The OEB expects distributors to embrace the principles of continuous improvement and to develop plans which provide benefits to customers. If the benefits are considered to be the ability to re-invest in additional work then the product of that additional work should be measurable desired outcomes.

3.5 Value to customers

The OEB agrees with the Canadian Manufacturers and Exporters' (CME's) characterization of RRFE as a shift in focus for rate regulation away from input cost assessment to utility performance, underscored by an understanding of value for customers.

It is the OEB's view that Hydro One's customer engagement in relation to its application appears to have been generally good, with the exception of the consultation regarding seasonal rates (which was criticized by a number of parties). Otherwise, the OEB accepts that Hydro One made a good attempt to understand what its customers want and link that to the priorities in its proposed plan.

Hydro One's responsiveness to feedback is evident in the way its proposed plan evolved over the course of the pre-hearing and hearing processes. The resultant set of eight outcome measures are a reasonable reflection of the areas where Hydro One is proposing to increase capital or operating expenditures over the next few years. Hydro One proposed targets for each measure. While varying views and some concerns were expressed by parties on certain details associated with Hydro One's proposed measures, the OEB supports Hydro One's overall approach to customer engagement. However, the OEB notes that some of Hydro One's chosen measures may not be effective measures of value to customers. In Hydro One's proposed plan, spending levels are clearly measured, but from a customer's standpoint, what will be gained from that spending is not always clear.

A number of Hydro One's measures are activity-based such as the number of substations refurbished, rather than being outcome-based whereby the number of outages avoided or length of outages reductions as a result of the substation refurbishment would be measured.

Furthermore, in some cases the trends in targets for the proposed measures do not show year-over-year improvement. Based on the evidence provided, it is unclear whether Hydro One's customers would understand the value proposition associated with Hydro One's plan.

The Association of Major Power Consumers (AMPCO) proposed revisions to a number of Hydro One's outcome measures for the Board's consideration:

- Vegetation management and pole replacement should be based on a cost per unit metric.

- The proposed measure "number of PCB oil replacements" does not equate with the RRFE expectations of continuous improvement and cost effectiveness. "Cost per pole-top transformer with PCB oil replaced" would be a more appropriate measure.

- The substation refurbishments metric could be revised to reflect unit costs instead of number of substations refurbished, with a cost per transformer refurbished or cost per transformer replaced as a more appropriate metric.

As previously noted, it is clear that the distribution system is in need of investment, and changes to system performance may not be immediately visible. Rather, system performance may erode without the investment. However, the OEB agrees with

AMPCO’s suggestion that in the absence of an outcome measure to demonstrate performance improvement value to customers, Hydro One could have brought forward unit cost metrics to demonstrate cost performance improvements (e.g., reduced cost per transformer replaced). This is another way to demonstrate value for customers.

4.0 OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Operations, maintenance and administration (OM&A) costs are the largest component of Hydro One's revenue requirement, in the order of $600 million per year during the plan term. Included in OM&A costs are employee compensation, corporate costs, customer services and operations costs. These operations costs capture day-to-day maintenance of the system, including vegetation management. Also included in OM&A are costs related to work requested by customers ("demand" work) such as restoring service interruptions, repairing failed equipment or responding to customer requests.

Arriving at an appropriate OM&A budget is critical in ensuring that Hydro One has sufficient funds to operate a safe and reliable system while at the same time considering the customer bill impacts so that any increase is fully justified and reasonable.

In reviewing the OM&A budget, the OEB also considers Hydro One's efforts in achieving efficiency gains (i.e. doing more work with fewer resources), implementing innovation and demonstrating continuous improvement in performance. One general criticism by parties to this proceeding was that Hydro One's evidence did not demonstrate operating efficiencies through benchmarking, cost control or continuous improvement. The importance of these elements has been addressed previously in this Decision within the discussion of conformance with the RRFE. In this section, the OEB will focus on the actual budget proposed in order to determine the OM&A amount to be included in the revenue requirement calculation.

Over the proposed plan term Hydro One's OM&A costs are relatively constant. The cost per customer declines slightly but the cost per kilometre of line increases.[4] Parties to the hearing generally accepted the proposed OM&A budget as being reasonably controlled over the life of the plan insofar as the proposed budget represents an increase less than would result if the last OEB-approved budget were adjusted by the rate of inflation.

[4] Cost per customer is down 1.3% from 2014 to 2019, while cost per km rises by 3.2%. Exhibit I/Tab 3.01/Staff 38

Despite general agreement by parties that the overall budget was reasonable, parties criticized employee compensation (including pensions and benefits), vegetation management costs and the conservation and demand management budget. Each of these areas is addressed below.

4.1 Compensation

In 2014, Hydro One's total compensation for all of its 5,400 regular employees[5] was approximately $617 million[6]. Compensation includes employee base salary, short and long term incentives, pensions and benefits. The total compensation for all employees, including temporary and casual, is $807 million in 2014. Along with the total number of employees Hydro One requires to complete its work programs, the proportional mix of those employees (regular, temporary and casual) directly affects the compensation cost total.

Many parties expressed concern with the richness of Hydro One's employees' compensation. The OEB has ruled on this issue in previous Hydro One rate applications. The last Hydro One distribution cost of service proceeding for 2010/2011 rates reviewed this issue and the OEB's findings included a reduction in the OM&A envelope to account for this high compensation cost relative to the industry. In Hydro One's transmission case (EB-2010-0002) the OEB also expressed concerns about compensation levels and the productivity being achieved.

The Mercer Study, commissioned by Hydro One and filed in this proceeding showed that compensation is about ten per cent higher than industry comparators at the market median.[7]

In this proceeding, many parties acknowledged that the evidence demonstrated that Hydro One is moving towards the market median for compensation. Hydro One has done so through a number of cost-cutting measures such as adjusting the staff mix to increase the use of temporary and casual staff, a strategic approach to contract

[5] This includes both Hydro One's Transmission and Distribution businesses.
[6] Exhibit C1-3-2 Attachment 1, p. 3 and Attachment 2
[7] Exhibit C1-3-2, Attachment 1: Mercer Compensation Cost Benchmarking Study, December 9, 2013

negotiations, and other hiring practices. However, parties argued that the ten per cent premium in compensation costs should not be recovered in full from ratepayers. The Mercer market median was suggested as a suitable level of recovery. Hydro One indicated that bringing the compensation to the market median level would result in a reduction of about $15.4 million per year in OM&A costs.[8]

This argument about reducing compensation was made with awareness of the legal context in which Hydro One operates, which requires the company to negotiate and abide by collective agreements with its unionized workers, who make up the majority (about 90%) of Hydro One's staff. Only the Power Workers' Union argued that Hydro One's compensation is reasonable and that Hydro One has behaved prudently and achieved reasonable results through collective bargaining.

Findings

The OEB recognises Hydro One's challenge in managing its compensation levels in a highly unionized environment. However, the OEB must determine a reasonable compensation amount to be included in the revenue requirement and thus borne by ratepayers.

A consideration of the appropriateness of compensation levels should be influenced by what a company can demonstrate is necessary to attract and retain employees with the skills and competencies it requires to accomplish its required outcomes. Hydro One's recent positive movement in getting closer to the market median has, in part, been a result of its compensation packages for new hires.

There has been a considerable focus on the market median of compensation levels over several years now. While Hydro One may focus on the market median as a benchmark, and target parity with it as a goal, it does not negate the OEB's need for evidence that illustrates the level of compensation required to allow Hydro One to attract and retain employees with the skills and competencies it requires.

[8] Undertaking J3.12

As is the case with any benchmark comparison, the need for cogent evidence to justify a level of spending or level of service quality is commensurate with its deviation from the level demonstrated by similar distributors. For instance, if a company spends more for a particular service or activity than most other comparable companies, it must provide more evidence for the level of proposed spending than if its level of spending was less than comparable companies. The OEB uses benchmarking as a tool to focus and prioritize its attention on certain costs. Benchmarking increases the efficiency of regulatory oversight. It does not replace the need for substantiating evidence in support of spending levels.

Hydro One did not provide sufficient evidence in support of its proposed compensation spending. The company did not demonstrate that the market requires the level of compensation proposed in order to attract and retain the necessary employees. In the absence of such evidence the OEB will use the market median as a reference point for the percentage of compensation costs that will be included in the rates paid by Hydro One's customers.

As previously stated, in arriving at an appropriate OM&A budget it is critical to ensure that Hydro One has sufficient funds to operate a safe and reliable system. The OEB must balance the ability of Hydro One to perform the work that is necessary to maintain the system and the fairness to its customers in paying for a level of compensation that has not been satisfactorily substantiated. In the absence of evidence indicating that higher levels of compensation are justified, the market median compensation level provides an indication that Hydro One customers are being asked to pay too much for the provision of the service they receive. As noted above, Hydro One indicated that if its compensation level were set at the market median level it would result in a reduction of about $15.4 million per year in OM&A costs.

While the OEB recognizes the progress that Hydro One has made over the last few years in getting closer to the market median, the OEB does not find that it is fair that ratepayers pay for a 10% premium over the market median. The OEB, however, will not disallow the entire 10% premium. Rather, the OEB will require efficiency from Hydro One by disallowing half of that amount from the revenue requirement, or $7.7 million per year, each year for 2015, 2016 and 2017. The OEB still expects Hydro One to accomplish the work programs as outlined. In addition, the OEB directs Hydro One, in its next rates application, to file a compensation study similar to the one filed in this proceeding so that the OEB can continue to benchmark Hydro One's compensation against that paid by comparable companies.

A few parties raised concerns regarding Hydro One's pension and benefits plan, including the plan's long-term sustainability, the level of contribution by employees, and the possible need to review the accounting for other post-employment benefits. Hydro One has reduced the employer pension contribution level such that the employer/employee ratio for 2015 is planned to be 72/28. Hydro One has indicated that it plans to move to a 65/35 ratio by 2019.[9] This progress must continue, and the OEB encourages Hydro One to continue to move toward a 50/50 ratio, the generally recognized norm in public sector defined benefit pension plans.

Submissions were made concerning the need for a generic review of pension and other post-employment benefits. The OEB agrees that this issue is more appropriately dealt with on a generic basis. A generic proceeding could enhance understanding of the different rate making options, establish policy and decide on how best to apply that policy to Hydro One and other Board-regulated entities. Any changes to pensions and other post-employment benefits for Hydro One, if required, could be addressed by the OEB in Hydro One's next cost of service proceeding, having been informed by the outcomes of a generic proceeding. The OEB will not adjust the pension costs or pension accounting methodology at this time, but expects that a generic review may result in some changes applicable to Hydro One's next rates application. No specific disallowance with respect to pension or other pension and benefits costs is made in this Decision.

4.2 Vegetation Management

Most parties objected to Hydro One's proposed increased vegetation management budget (which includes cost for tree and brush clearing). The OEB agrees with the concerns expressed and is concerned that overall, Hydro One's vegetation

[9] Exhibit I/Tab4.03/Schedule 1/Staff 68

management budget shows no achieved efficiencies or productivity. The evidence shows an increase in unit costs for vegetation management activities related to tree line clearing. This is a significant component of OM&A, accounting for about $100 million per year. On the other hand, brush control unit costs show improvement in 2015 over 2013 actuals, and are fairly steady during the plan period.

The OEB does not accept Hydro One's explanation that increased tree densities and work complexities contribute to unit cost increases as Hydro One moves towards an 8-year clearing cycle. The evidence in the last cost of service proceeding (EB-2009-0096) indicated that Hydro One was already on an 8 year cycle, and was seeking additional funds to move to a 7 year cycle. In this proceeding, Hydro One indicated it was on a 9½ year cycle, and that it would take until 2023 to achieve the goal of being on a sustainable 8 year vegetation management cycle.

The OEB notes that the 2011-2012 CN Utility Benchmarking analysis[10] showed that Hydro One had the highest vegetation management cost per customer relative to its peers. This benchmarking comparison emphasizes the need for Hydro One to provide detailed and thorough evidence substantiating its spending requirements and how it intends to continuously improve in this activity. Hydro One's solution to a reduced vegetation management budget appears to be to scale back on this necessary program.[11] While the OEB acknowledges Hydro One's submissions on dealing with remoteness and difficult terrain, the OEB still expects Hydro One to show continuous improvement in these areas. This may mean a change in the labour mix for this work or further innovation in undertaking the program. It is the OEB's view that Hydro One needs to manage this program more cost effectively.

The OEB finds that a reduction of $39 million to the total vegetation management costs over the 2015 to 2017 period is appropriate. This was arrived at by taking the average unit cost for line clearing from 2011 to 2013 ($7,588 per km) and applying it to the volume of work projected to be undertaken over the three-year period.

[10] Exhibit J3.10 p. 33
[11] Hydro One Reply Argument, October 27, 2014, page 52

The OEB also directs Hydro One to present in its next rates application a comprehensive trend analysis of its vegetation management program showing year-over-year comparisons in unit costs. Further, the OEB encourages Hydro One to explore best practices in vegetation management with other distributors and transmitters, similar to the CN Utility Study filed with the OEB in the EB-2009-0096 proceeding, and file any resulting study in its next rates application.

4.3 Conservation and Demand Management (CDM)

Hydro One has requested approval to recover approximately $3 million annually for work conducted by its utility staff to support CDM programs. This budget includes costs for labour, research and development, collaboration within the sector and maintaining a base level of CDM capability required to participate in industry activities, including testing of new technologies and delivery of pilot programs.

The OEB agrees with the submissions of the Sustainable Infrastructure Alliance (SIA) that the roles of distributors with respect to CDM have changed since Hydro One's last rates decision, and that CDM program development costs should not continue to be included in base distribution rates. The Independent Electricity System Operator (IESO), which merged with the Ontario Power Authority (OPA) at the beginning of 2015, is charged with developing CDM programs for Ontario, and utilities have been implementing the former OPA's programs with funding made available through the OPA. Hydro One should not be including a research and development budget to develop and test CDM programs in parallel with the efforts of the organization chiefly responsible for them.

While there are no filing requirements for CDM activities specific to Custom IR, the OEB's *Filing Requirements for Electricity Distribution Rate Applications* ("Filing Requirements") in Chapter 2 state the following:

> CDM activity is funded either through OPA-Contracted Province-Wide CDM Programs, or through Board-approved CDM programs. Both of these approaches fund the programs through the global

> adjustment mechanism, and therefore costs directly attributable to these CDM programs (e.g., staff labour dedicated to such programs) must not be included in distribution rates.[12]

The OEB finds that this policy applies in this case. The OEB will therefore not approve Hydro One's request for approval of approximately $1 million of annual rate funding to support CDM research and development.

The Minister of Energy issued separate Directives dated March 26, 2014 to the OEB and the OPA related to electricity conservation (the Conservation Directives). Both Directives state that distributors will be required to make CDM programs available to customers in their licenced service areas between January 1, 2015 and December 31, 2020. The Conservation Directive to the OEB requires the OEB to amend the licence of each licensed electricity distributor, among other things, to:

> Add a condition that specifies that the Distributor shall meet its CDM Requirement by:
> a) Making Province-Wide Distributor CDM Programs, **funded by the OPA**, available to customers in its licensed service area;
> b) Making Local Distributor CDM Programs, **funded by the OPA**, available to customers in its licensed service area; or,
> c) A combination of (a) and (b).[13] [Emphasis added]

The Conservation Directive to the OPA also states that:

> The OPA Conservation Fund provides financial support to new and innovative electricity conservation initiatives designed to enable Ontario's residents, businesses and institutions to cost-effectively reduce their demand for electricity.
>
> The OPA shall continue to provide, through its Conservation Fund, support and funding for new and innovative electricity conservation initiatives, including small scale distribution storage technologies, as a means to assist Distributors and others in their conservation efforts.[14]

It is clear from the Conservation Directives to the OEB and the OPA that funding for CDM program research and development between 2015 and 2020 will be provided by the OPA. This funding comes from the global adjustment mechanism and not from

[12] Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rates Applications, Chapter 2, Cost of Service, Section 2.7.6, Conservation and Demand Management.
[13] Directive from the Minister of Energy to the OEB, March 31, 2014, Page 1
[14] Directive from the Minister of Energy to the OPA, March 31, 2014, 2015-2020 Conservation First Framework, Section 8 – Support and Funding for Research and Innovation, Page 11

distribution rates. Hydro One should be receiving the necessary funding it requires to deliver CDM programs and meet its CDM Requirement from the OPA.

However, Hydro One has been one of the province's leaders in CDM, including co-ordination with other distributors, participating in energy sector education and collaboration. For example, Hydro One has been an active participant with the OPA in CDM program review, with the Ministry of Energy and in OEB consultations with respect to CDM. The OEB sees the need for this leadership role to continue, and therefore sees merit in including the requested labour costs associated with CDM in the OM&A budget.

In addition, the OEB notes that should Hydro One need additional funding to support CDM activities incremental to its CDM requirement which are not made available through the province-wide distributor CDM programs between 2015 and 2020, it may make a separate application to the OEB for approval of funding associated with a specific CDM program which is currently not offered by the OPA and for which Hydro One would seek OEB approval to pursue.

Overall Impact with Respect to OM&A

As a result of the findings, the approved OM&A budget is summarized in the table below.

Table 1
Operations, Maintenance and Administration Costs
Summary of Findings
2015 to 2017

	2015 ($ million)	**2016 ($ million)**	**2017 ($ million)**
Requested OM&A	564.3	610.2	614.0
Less, compensation reduction	7.7	7.7	7.7
Less, vegetation management reduction	13.0	13.0	13.0
Less CDM reduction	1.0	1.0	1.0
OEB approved OM&A	542.6	588.5	592.3
Percentage Reduction as a result of this Decision	4.0%	3.7%	3.7%

5.0 DEPRECIATION AND AMORTIZATION

Hydro One proposed depreciation and amortization expenses for each of the 5 test years as shown below:

Table 2
Depreciation and Amortization Expenses[15]
2015 to 2019

Year	Depreciation and Amortization
2015	$355.4 million
2016	$374.9 million
2017	$390.2 million
2018	$402.9 million
2019	$413.6 million

The OEB notes that Hydro One updates its depreciation methodology whenever it files a cost of service rate application, as it did in this application with an updated Foster and Associates study.[16] Depreciation expenses were not challenged in the proceeding by OEB staff or intervenors.

Findings

The Board approves the depreciation expenses as filed for rate setting purposes from 2015 to 2017 and expects Hydro One to file an updated depreciation study with its next rates application.

[15] Exhibit C1/Tab6/Schedule1
[16] Exhibit C1/Tab6/Schedule1/Attachment 1

6.0 LEAP FUNDING

In its application, Hydro One proposed that it would provide $1.2 million in funding to the Low-Income Energy Assistance Program (LEAP). In reply to an SIA interrogatory regarding this level of funding[17], Hydro One stated that “The $1.2 million was calculated based on the prescribed OEB formula of 0.12% of HONI’s Service Revenue Requirement.” In its submission, the SIA pointed out that the service revenue requirement for 2015 is forecast by Hydro One to be $1,414.9 million and that this amount, multiplied by 0.12% results in a LEAP amount of $1.7 million, not $1.2 million as stated in Hydro One’s evidence.

The OEB acknowledges the SIA submission and directs Hydro One to increase its LEAP funding amount for 2015 to $1.7 million for 2015 with the expectation that Hydro One will proportionally increase its annual contribution (as related to its service revenue requirement) over the 2015-2017 period.

[17] SIA Interrogatory Exhibit 3.1 - SIA 22

7.0 DISTRIBUTION SYSTEM PLAN, RATE BASE & CAPITAL EXPENDITURES

7.1 Distribution System Plan

The RRFE Report emphasizes the importance of planning as the foundation for rate-setting, and the filing requirements for distribution system plans (DSPs) are provided in Chapter 5 of the OEB's Filing Requirements. In support of its proposed capital investment programs, Hydro One filed a significant amount of evidence and provided a summary table which cross-referenced its evidence with the items required by the OEB to be included in a DSP[18].

Parties acknowledged Hydro One's efforts to continuously improve its asset management process and recognized that the new tools that Hydro One introduced would help it get more accurate and current information on its assets. However, some parties felt that Hydro One must still make further improvements to meet the intent of the Filing Requirements. The areas identified as being deficient included the following:

- The presentation of the various components of the DSP in different parts of Hydro One's application does not meet the intent of the OEB's requirement (Chapter 5) of having a "consolidated" plan.
- Investment levels do not yet appear to be properly aligned with the actual condition of the assets.
- The DSP does not clearly demonstrate the process by which Hydro One ensures the most effective use of capital and OM&A spending.
- Lack of third-party review or external benchmarking of Hydro One's processes and methodology to demonstrate that they are consistent with best practices.

OEB staff cited a number of examples in its submission where the linkage between the risk assessment results and the investment prioritization was not clear[19].

[18] Exhibit A, Tab 7, Schedule 1
[19] Board Staff submission, Section 4.2

Hydro One submitted that it has an industry-leading business planning process which is based on its business values and strategic objectives, and which considers a balance of its work programs and associated risks.

Findings

The OEB finds that Hydro One's evidence provides significant and useful details about its asset management and investment planning processes. The OEB also acknowledges that Hydro One continues to make improvements to these processes. However, the OEB agrees with the position of some parties that, while Hydro One's evidence contains the various key components of its processes, it does not provide a sufficiently consolidated plan as contemplated in Chapter 5 of the Filing Requirements.

As stated in Section 5.3 of the Filing Requirements, the information contained in the DSP "is to provide the OEB and stakeholders with an understanding of the distributor's asset management process, and direct links between the process and the expenditure decisions that comprise the distributor's capital investment plan". The OEB finds that such links are difficult to follow when the DSP components are not consolidated. Clear links would be crucial in demonstrating to the OEB that the resulting capital expenditure plans have been sufficiently optimized. In addition, this lack of consolidation of the DSP components could be confusing and may result in the use of inconsistent terminology for the different stages of the investment planning and optimization process.[20]

Hydro One's application provides an opportunity for the OEB to point out the advantage of having the consolidated DSP as a stand-alone document. The OEB directs Hydro One, in its next rates application, to provide a consolidated plan, preferably as a stand-alone document in a separate exhibit, with a direct and clear alignment of the various components, explicitly showing how the process steps lead to an optimized DSP and a corresponding capital investment program.

[20] Transcript Vol. 5, p. 21-23 and Board Staff submission, p. 42

The OEB also expects that Hydro One will consider the merits of having its DSP reviewed by an independent third party and, if done, to file that review in its next rates application. If not done, an explanation of that choice must be filed with the DSP.

7.2 Rate Base & Capital Expenditures

The following table shows Hydro One's forecast rate base for the 2015 to 2019 period. The rate base underlying each of the test years' revenue requirements includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance.

Hydro One's proposed capital expenditures during the five-year plan term are also shown in the following table as well as the corresponding in-service capital additions.

Table 3
Rate Base, Capital Expenditures and
In-Service Capital Additions
2015 to 2019

	2015	2016	2017	2018	2019
Rate Base ($million)[21]	6,533	6,864	7,191	7,541	7,870
Capital Expenditures ($million)[22]	648.9	654.7	661.4	655.1	669.1
In-Service Capital Additions ($million)[23]	656.6	621.8	696.0	681.4	660.9

The evidence indicates that the biggest drivers of the rate increase sought by Hydro One are the increase in 2015 rate base, and the planned annual increases in certain capital programs. The increase in rate base is a result of capital additions made during

[21] Hydro One's Reply Submission, p. 7
[22] Hydro One's Reply Submission, p. 6
[23] Hydro One's Reply Submission, p. 6

the IRM period and proposed additions during the test years, including additions from regulatory assets, as well as the associated increase in return and depreciation amounts since last approved by the Board. The last approved rate base amount was $4,986.6 million for the 2011 test year. Hydro One witnesses testified that the need for increased capital spending going forward was largely attributable to under-spending in prior years, which has led to a large number of assets needing repair or replacement.

The proposed 2015 rate base increase was primarily due to the in-service additions made during the IRM period preceding this application. In general, parties accepted the proposed rate base for 2015 and subsequent years.

The largest component in the proposed capital spending is in the “sustaining” category, which includes investments required to ensure that existing distribution system facilities function as originally designed; an example of sustainment investment is the replacement of worn-out poles. Spending in this area shows the greatest growth, up 33.9% from 2014 to 2019, growing steadily from $286.4 million to $383.5 million. The “development” category, which includes investments required to serve new load and generation customers and meet the growing needs of existing customers remains relatively stable. The third category, known as “corporate common costs and other capital” investment, includes sustainment and enhancement of existing equipment and infrastructure, including information technology, transport and work equipment and service equipment, and facilities and real estate. Spending in this category is forecast to fall by 25.1% over the 5 year period.

Many parties submitted that the level of capital spending on sustaining capital programs over the five year period, particularly pole replacement and station refurbishment, was not adequately justified, and proposed that the OEB reduce the budgets for these activities. Hydro One submitted that these programs were essential given the age and condition of the assets in these categories, and that any reductions in the programs would exacerbate asset deterioration and increase unplanned spending on repairs made in reaction to an actual asset failure.

Several parties noted the lack of tangible unit cost reductions for capital work, and suggested a dollar per unit metric for reporting on pole replacement and station refurbishment (and vegetation management, which is discussed in the OM&A section). In contrast, some parties submitted that Hydro One was continuing to underspend on its assets, given their age and condition.

As described in the DSP section, many parties submitted that the planning evidence was unclear and inadequate to provide the OEB with an understanding of Hydro One's planning and prioritization process. Although Hydro One has revised its planning process using new tools to assess risk and set priorities based on risk assessment, some parties found the risk scoring system difficult to understand and inconsistently applied to actual investment priorities and pacing.

In recognition of the perceived inadequacies of Hydro One's planning evidence, some parties proposed that in addition to reporting on the success of the capital program outcomes, the OEB should require Hydro One to report annually on asset condition. This would include establishment of a net cumulative asymmetrical variance account to track the impact on revenue requirement of any in-service capital additions shortfall compared to OEB approved amounts.

Findings

The OEB has determined that it will approve Hydro One's proposed rate base and corresponding capital expenditure plan for the 2015 to 2017 period as submitted. However, given the direction provided by the OEB in the previous section regarding the development of a more consolidated DSP, the OEB expects that the consolidated plan will provide a more cohesive and easily understood capital expenditure plan in Hydro One's next rates application.

In approving a 3-year capital plan, the OEB gave consideration to the following factors:

- Given some of the DSP shortcomings described earlier, a shorter approval period than 5 years is appropriate, consistent with the 3 year cost of service approach determined earlier in this Decision. The OEB expects that Hydro One will take the opportunity to make the necessary improvements to support a longer-term capital plan.

- While the evidence in this case supports the need for Hydro One to make investments in its assets in the short term, the OEB's level of confidence that capital spending has been optimized decreases in the longer term.
- The OEB accepts Hydro One's argument that significant reductions in the proposed 2015 to 2017 spending levels would likely create cost pressures in the longer term.
- Approval of capital spending for a shorter time period reduces the risk to ratepayers if in fact the capital program is unrealistic. Approval of a longer term plan at the time of Hydro One's next rates application will be contingent on the quality of the supporting evidence.

Since the OEB is approving a 3-year plan for Hydro One, the amounts proposed by Hydro One for 2015 to 2017 will form the basis of Hydro One's capital envelope and capital in-service additions. Given the shortened plan term, the OEB does not find it necessary for Hydro One to establish a variance account to track the impact of in-service additions shortfall on revenue requirement. At the time of Hydro One's next rates application, the OEB expects Hydro One to provide evidence of its capital in-service additions (actual vs. approved with explanations of any variances) on an annual basis, as required in the OEB Filing Requirements.

The OEB also directs Hydro One to conduct an external benchmarking study on the unit cost of its pole replacement and station refurbishment programs against other utilities as well as carry out an internal trend analysis to show the variability of these unit costs over time (year over year). Hydro One will report on the results of this work with the corresponding analysis as part of its next rates application.

The benchmarking and trend analysis of unit costs for these two programs is required because the company plans significant spending in these areas. However, as noted in the section of this Decision that discussed the RRFE, Hydro One should prepare supporting productivity evidence for its next rates filing for any areas of its business where recovery of significant planned spending is sought.

7.3 Working Capital

Hydro One proposed, as part of its 5 year rate plan, to adjust working capital annually. As only a 3 year plan is approved in this Decision, the Board will not require an adjustment to working capital in years 2 and 3. This approach is in keeping with the past practice in multiyear cost of service periods.

8.0 COST OF CAPITAL

Hydro One proposed an annual cost of capital adjustment (using the OEB's updated cost of capital parameters and an update of Hydro One's long term debt) before each new rate year, as per its past practice in implementing its multi-year rate setting decisions.

The OEB agrees that these updates should continue in this case for the 3 year period of this rate approval. No change to the debt/equity structure was proposed.

9.0 REVENUE REQUIREMENT AND RATE SMOOTHING

Hydro One applied for the OEB's approval of a revenue requirement for each of the five years of the rate plan. OEB staff noted that the company's revenue requirement grew by 19% between 2011 and 2015 (largely due to capital additions) and would grow by 17.8% from 2015 – 2019. Due to the large increase in revenue requirement in 2015, Hydro One proposed rate smoothing by way of rate riders over the five year period of the plan, resulting in an annual average distribution revenue increase of 6.3%. If the Hydro One application were accepted as filed, typical UR and R1 customers would experience a total bill impact of less than 2% (below the predicted rate of inflation) for each of the five years. Other classes would see an increase in some cases significantly above inflation.

The Vulnerable Energy Consumers' Coalition (VECC) and SIA opposed the rate smoothing proposal, arguing that it promotes intergenerational inequity, adds interest and carrying costs, masks the actual increase in any one year, and is unnecessary because the effect on the distribution component of the bill would be immaterial. VECC argued that the unsmoothed increases for 2015 and 2016 are acceptable, and that there is no evidence that customers want to pay additional costs to achieve rate smoothing.

Findings

The OEB's overall finding is that the revenue requirements and rates approved in this application will be in place for a three year period. The OEB will not approve the rate smoothing scheme as requested. The OEB considers that the rate smoothing would only have a minor effect on rates over the three year period. The OEB directs that rate mitigation be applied for customers in rate classes that experience undue rate impacts, that is, an increase from all causes greater than 10% on the total bill. The OEB will condition its rate approvals accordingly, when the Draft Rate Order is filed.

10.0 LOAD FORECAST

OEB staff and intervenors generally accepted Hydro One's load forecasts and the underlying economic forecasts. Hydro One's history of accurate load forecasting was noted by staff and several intervenors, but VECC, supported by Consumers Council of Canada (CCC), argued that there were major flaws in Hydro One's CDM forecast. For example, VECC submitted that the CDM report did not track actual CDM achieved or the difference between forecast and actual CDM effects. VECC urged the OEB to require Hydro One to undertake a proper evaluation of CDM results, and ensure that the definitions of forecast CDM are the same as the definitions used in tracking CDM results actually achieved. VECC also suggested that Hydro One's forecast CDM savings should be adjusted by using the OPA's draft target for the impact of future programs, prorated over the five year period. Hydro One responded that its CDM forecast is reasonable and supported by the evidence, and that the OPA forecast was too preliminary to be used to adjust Hydro One's forecast.

Findings

The OEB is persuaded by the historical accuracy of Hydro One's load forecasting and the support shown for the forecasts by many parties. The OEB acknowledges the arguments of some intervenors regarding the CDM portion of the load forecast; however the OEB is not persuaded that these perceived flaws have a significant impact on the overall forecast for the 2015 to 2017 period. The OEB finds that Hydro One's load forecasts are appropriate for the time period approved in the Decision.

11.0 COST ALLOCATION AND RATE DESIGN

Hydro One proposed a number of changes in the areas of cost allocation and rate design including the addition of a new unmetered scattered load class, changes to the definition of seasonal customer class, incorporation of the results of a rate class review, narrowing the revenue to cost ratio ranges for all classes and increasing the revenues collected from fixed charges.

Hydro One noted that some of the company's proposed changes in cost allocation and customer classification are significant, and may have a greater impact on some customers than the requested increase in revenue requirement. Although the company is neutral regarding cost allocation and rate design (because the full revenue requirement is recovered through the various rates and charges irrespective of the rate design and allocation of costs), Hydro One stated that in the interest of fairness to customers, the company's proposals are designed to align cost causality and cost recovery. Hydro One also considered bill impacts, and submitted a rate mitigation plan for some customers moving from one class to another as part of the rate class review. A summary of the company's proposals was presented in Exhibit G1/Tab 1/Schedule 1.

Lastly, the City of Hamilton raised a specific issue with respect to street lighting charges. The OEB addresses each of these proposals individually below.

11.1 Rate Class Review

Hydro One undertook a rate classification review using a Geographic Information System (GIS) tool to identify clusters of customers that may require reclassification, and to verify in general that customers were properly classified according to density. Hydro One proposed to implement the results of the study, which would reclassify 11% of its customers. This would, in turn, require a 3.4% increase in revenue collected from all other customer classes to make up for revenue lost due to reclassification to higher density classes. Hydro One proposed to repeat the reclassification review every five years, but use the GIS tool to monitor density changes that may prompt reclassification on an ongoing basis.

Intervenors generally supported the results of the review and the reassignment of customers between classes. However, VECC suggested that some mitigation of the resulting impacts may be required in 2016 if some of the impact in 2015 is shifted to the following year. The School Energy Coalition (SEC) noted that the absence of a medium density class for general service customers means that many schools are classified as rural, although they are situated in towns, and may be overpaying for their electricity service.

OEB staff (supported by CCC and VECC) suggested that Hydro One should perform another customer classification review in three years, and move to a five year cycle if the three-year review does not show the need for material levels of reclassification. In addition, staff recommended that Hydro One report to the OEB annually on complaints related to density and subsequent reclassifications, to determine if the GIS-based monitoring is lagging actual system characteristics. Hydro One submitted that both a shorter time frame for review and the tracking and reporting of complaints would consume considerable resources for little benefit, as the GIS tool will capture any data that would prompt reclassification.

Findings

The OEB accepts the results of the rate classification review for the purpose of setting Hydro One's rates for the next three years. The OEB agrees that a five year cycle of review and reclassification may be appropriate for the company in the future, but given that rates are set for three years in this Decision, the OEB will require Hydro One to report on an updated customer classification in its next rates application. The OEB finds that customer reclassification resulting from the rate classification review (as opposed to reclassification prompted by customer inquiries or complaints) can be implemented on a going forward basis as of the date of the implementation of rates resulting from this Decision. Retroactive reclassification from January 1, 2015 is not required where the reclassification is prompted by the rate classification review.

The OEB expects Hydro One to implement a rate impact mitigation plan. Hydro One proposed that mitigation take place for those customers who experienced a 15% or greater total bill impact as a result of movement to another rate class. However, the OEB does not accept this level of rate impact caused by reclassification alone. The OEB directs mitigation to be applied to those customers who experience a total bill impact greater than 10% in total as a result of the application of all elements of this Decision.

11.2 Revenue to Cost Ratios

Hydro One proposed to move all customer classes to a revenue to cost ratio range of 98% - 102% over the five year plan, submitting that improvements to its cost allocation process support this narrow range. The status quo revenue to cost ratios for the Hydro One customer classes ranged widely from 129% in the Residential Urban class to 72% for the Sub-Transmission class.[24]

However, the company acknowledged that the movement to this range has the largest impact by rate class in 2015 of any of its proposals, and that pacing of the change may be required to mitigate the rate impact.

OEB staff and several intervenors (e.g. CME, Energy Probe) submitted that Hydro One should aim for a wider range in the ratio, for example 95 – 105% for all classes, and phase in this less dramatic change over the five year plan. VECC (supported by CCC) argued for an even broader range of 90 – 110%, submitting that the degree of improvement in Hydro One's cost allocation methodology was insufficient to support a narrower range.

Findings

The OEB agrees with VECC, and is not persuaded that the improvement in cost allocation methodology is sufficient to support the narrow 98 – 102% range. The OEB directs Hydro One to move its ratios to 90% - 110% over the three year period for which rates are approved. At its next rates application, the company may choose to propose further narrowing of the range.

11.3 Increase in Fixed Charges

Hydro One's rates include a fixed charge component and a variable charge component. Hydro One proposed to increase the proportion of the revenue collected through the

[24] Exhibit G1/Tab 3/Schedule 1, p.16

fixed charge and decrease the proportion of the revenue collected through the variable charge for all classes, to be consistent with an updated minimum system study that recalculated the peak load carrying capacity adjustment using detailed feeder data. The proportion to be collected through the fixed charge rises from 40% to 42% across all classes, although some classes (such as distributed generation) see larger increases in the fixed charge. Hydro One indicated that the increase in the portion of revenues earned through the fixed charge is more consistent with cost causality, and is unlikely to have a significant effect on conservation as the change affects only 13% of the total bill. OEB staff and some intervenors supported the proposed change.

Several intervenors opposed the change as discouraging conservation. The Green Energy Coalition (GEC) filed evidence from Dr. W. Marcus, which supported the arguments that the increase would reduce conservation gains and have a disproportionate impact on low energy use customers, who tend to be lower income customers. GEC pointed out that such effects would be contrary to government policy. GEC proposed that any change to the fixed charges should await the conclusions of the OEB's generic rate design review (EB-2012-0410).

SEC and the Federation of Ontario Cottagers Associations (FOCA), among others, supported the idea of waiting for completion of the OEB's review. VECC argued that the basis for the calculation of the fixed charge was flawed, and the current fixed variable split should be retained for residential rate classes (except for the seasonal rate class).

Findings

The OEB approves Hydro One's proposal to increase the amount recovered through the fixed charge from 40% to 42% across all classes. The overall change is minimal. While the OEB recognizes that some classes will experience a much higher increase in the fixed charge than 2 percentage points, the OEB accepts Hydro One's argument that the change will better reflect the actual cost to serve those classes.

11.4 Seasonal Rate Class

Issues surrounding the seasonal rate class received considerable attention in the hearing. Hydro One proposed in its evidence that about 11,000 seasonal customers move to the R1 and R2 rate classes, because the consumption pattern of these higher-use seasonal customers was similar to customers in the residential classes. However, R2 customers presently receive a Rural and Remote Rate Protection (RRRP) subsidy. Eligibility for that subsidy is defined on the basis of residency under Ontario Regulation 442/01under the *Ontario Energy Board Act, 1998*. For practical reasons, Hydro One proposed to use monthly consumption patterns as a proxy for residency, and provide the subsidy to the new customers in the R2 rate class without a specific inquiry into their residency status. Intervenors who addressed this issue and OEB staff all argued that Hydro One could not avoid satisfying the residency criteria in the regulation, and that seasonal customers moving to the R2 class would have to satisfy those criteria or not receive RRRP.

VECC and CCC also did not support Hydro One's proposal, and argued that further study was needed before a solution to the inequities existing in the seasonal class could be reduced or eliminated. CCC suggested that density based sub-classes might help, while VECC submitted that a principled approach, taking account of load profiles as well as consumption patterns, could better reflect cost causality. VECC suggested using the proportion of revenues recovered through fixed and variable charges to address the cross-subsidy between high and low volume customers. Mr. Hurley recommended that seasonal customers pay for service only in those months when they are using electricity.

Hydro One supported the continuation of the seasonal rate class on the basis that seasonal customers do display different consumption patterns and load profiles than those of residential customers. However, the Balsam Lake Coalition (BLC) argued that the original justification for the creation of the seasonal class was obsolete, given the development of density-based rate classes. BLC submitted that the existing seasonal class is not based on factors directly relevant to cost, as customers with identical cost drivers and consumption patterns may be in different rate classes. Elimination of the seasonal class and distribution of its members to density-based residential classes would, in BLC's submission, more properly reflect density weightings for the members of the class and reduce within-class cross-subsidy caused by volumetric rate design. BLC acknowledged that the impact on low-volume seasonal customers would be high, but the impact could be phased in over a five year period. FOCA and OEB staff did not support the elimination of the class due to rate impacts on lower use customers.

In response to the almost unanimous rejection of its proposal by intervenors, Hydro One withdrew its request to change seasonal rates and submitted that no further review of seasonal rates would be helpful.

Findings

The OEB finds the arguments of BLC to be persuasive. Hydro One has developed the technical capability to implement and maintain density-based rates for its non-seasonal residential classes. These classes are defined by their geographic location in relation to the amount of distribution system assets that are required to serve each customer. The OEB considers the relative use of distribution assets to be a significant and predominant cost causality driver for the establishment of residential rate classes. The OEB agrees with BLC that the existence of density-based rate classes erodes justification for the retention of the seasonal class. The OEB finds that the seasonal class should be eliminated for rate setting purposes. Existing seasonal class customers shall be placed in a residential class according to their density.

The OEB considered the proposal of VECC and others that further work be conducted by Hydro One to compare the load profiles of customers within the seasonal class and residential classes, at various usage levels, to determine if they are sufficiently similar to combine into one or more classes. The OEB recognizes the practice of considering load profiles and consumption patterns in creating rate classes, but the OEB also recognizes that load profiles and consumption patterns will inevitably differ to some degree between customers within any rate class. Given the significance and predominance of the density cost causality characteristic the OEB is not convinced that the load characteristics of seasonal customers are sufficiently different from their neighbours in the residential classes to justify the continuation of the seasonal class.

The OEB agrees with the submissions of OEB staff and others that Hydro One cannot apply the RRRP subsidy to new entrants to the R2 class without determining their residency status in accordance with Regulation 442/01.

The OEB is aware that the elimination of the seasonal class will cause rate impacts, particularly for lower volume seasonal customers. At the same time, the OEB is mindful of BLC’s submission that this group of customers is not paying the full costs of the service they receive. That said, the OEB wishes to mitigate any large impacts to seasonal customers.

The OEB requires Hydro One to bring forward a plan for the elimination of the seasonal class. The plan should propose a phase-in period for those customers expected to experience a total bill impact of greater than 10% as a result of migrating to another class. The Board will conduct a hearing to examine the rate mitigation issues in the plan with the intent to implement the initial rate changes January 1st 2016. Hydro One should submit its plan to the OEB and the intervenors of record in this case by August 4, 2015. Hydro One should also propose what it considers to be an appropriate billing frequency for the customers that own secondary residences for consideration along with the hearing of the other matters.

11.5 Street Lighting Class Rates

The City of Hamilton, a street lighting customer of Hydro One, noted that the street lighting rates would increase by approximately 22% in 2015 under Hydro One's proposed rates schedules, and that the OEB had initiated a consultation related to cost allocation for street lighting customers. The City of Hamilton asked the OEB to include in its decision a provision for re-opening of Hydro One's application if there are changes to OEB policies that affect the costs and revenues allocated to the street lighting customer class. Hydro One objected to the idea of putting cost allocation for these customers on hold awaiting the completion of the OEB's consultation, and suggested that should the OEB's cost allocation model be modified, the rates for the street lighting class could be updated at the time of Hydro One's annual adjustments.

VECC submitted that traffic lights should not be included in the street lighting class, as traffic lights operate 24 hours a day, unlike street lights, which operate only during periods of darkness. Hydro One indicated that only about 1% of the lights in the street lighting class are traffic lights, and that to create and maintain two separate accounts for the two different types of lights would be inefficient.

Findings

The OEB agrees with Hydro One that finalization of the rates in this application should not await the completion of the consultation on street lighting. The OEB will not at this time create a specific provision for the re-opening of Hydro One's rates for adjustments related to cost allocation for street lighting.

As noted by the City of Hamilton, a consultation process has been initiated by the OEB under file number EB-2012-0383. When this consultation is complete, the OEB expects Hydro One to apply to adjust its street lighting rates at the earliest opportunity during which rate changes are being considered (i.e. during the review of the 2016 Seasonal Rate Class proposal, or the next complete rates filing if the consultation is not completed at the time of seasonal rate class review). The OEB may also provide generic direction on the basis of the outcome of the consultation.

With regard to traffic lights, the OEB agrees with Hydro One's argument, given the immateriality of traffic lights within this class.

11.6 Unmetered Scattered Load Class

Hydro One proposed the creation of a separate Unmetered Scattered Load (USL) rate class as a result of the direction of the OEB report *Review of Electricity Distribution Cost Allocation Policy* issued March 31, 2011. Previously, these customers were General Service energy (GSe) customers with a reduced monthly fixed charge to reflect that USL customers do not have any metering related costs.

Findings

No party opposed the creation of this new class in the hearing. In the OEB's view, the creation of this class should make it easier to consider cost allocation matters that are specific to the characteristics of the class. The OEB approves the creation of an unmetered scattered load class.

11.7 Line Loss Study

Hydro One engaged Navigant Consulting to track the variances between OEB-approved losses recovered in rates and actual line losses. The resulting study showed that actual losses tracked OEB-approved amounts reasonably well. Consistent with a study recommendation, Hydro One proposed new loss factors for its rate classes to reflect more accurately the losses that occur as a result of delivery of electricity to those classes.

The evidence in this proceeding indicates that there is a reasonable match between amounts recovered in rates for line losses and actual losses on Hydro One's system.

The Ontario Federation of Agriculture recommended that Hydro One increase its efforts to reduce line losses and urged the OEB to initiate a working group to study the issue. While the OEB appreciates that reduction of line losses is a desirable goal, the OEB will not initiate a working group to study the issue at this time. The OEB expects Hydro One to work continuously to lower line losses as it invests in its system.

11.8 Miscellaneous Service Charges

SIA raised a concern that Hydro One's charges for miscellaneous services significantly under-recover the true cost of the services. SIA suggested that the charges should be updated to more closely reflect actual costs, which would offset some revenue to be collected from rates. While Hydro One agreed that the charges under-recover costs, the company submitted that the charges are consistent with the OEB's rate handbook, and that a review of the charges should be undertaken on a generic basis. The OEB has indicated that it will initiate a review of service charges in the distribution sector. However, as Hydro One has unique service characteristics, the OEB directs Hydro One to file, as part of its next rates application, a study assessing whether its service charges reflect Hydro One's underlying costs and to propose changes accordingly. Hydro One's study is to be informed by any available OEB guidance that results from the generic review.

12.0 SMART METER COSTS

Hydro One is seeking recovery of $445.1 million in smart meter capital costs and $59.4 million in OM&A costs for the period 2009 to 2014. Hydro One's request for recovery of its historical smart meter costs (recorded in accounts 1555 and 1556) was opposed by OEB staff and several intervenors.

OEB staff noted that the average cost per installed smart meter for Hydro One was $568 (combined capital and OM&A over the 2006 to 2014 period), which is significantly higher than for other distributors. Staff provided examples of four other distributors that staff submitted face issues of low density and remoteness at levels similar to Hydro One. OEB staff submitted that Hydro One had not justified the recovery of the significantly higher costs per meter, and urged denial of full recovery of the costs. Staff suggested recovery of a per meter cost of $484, which would be 20% higher than the highest previously-approved cost for smart meters for these four distributors.

Some intervenors supported staff's proposed reduction, but others argued that the evidence on the record is insufficient to allow recovery, or to support a specific reduction. These intervenors proposed a separate proceeding be convened to fully review these costs.

In its reply argument, Hydro One resisted any reduction in recovery of the historical costs of its smart meter program. Hydro One argued that the costs of its smart meters have been audited and represent actual costs prudently incurred. The smart meter program was mandated by government policy and was not discretionary.

Hydro One indicated that the early installations (2006 to 2008) involved a large number of meters as they focused on high-density, easy to reach, mostly residential customers, while the 2009 to 2014 installations were for rural and low-density customers which involved significantly higher costs. Hydro One also submitted that the scope of work undertaken in the 2009 to 2014 period included communication reinforcement requirements for meters installed during the earlier period. This work was necessary to meet the minimum standards for billing and to improve meter reliability.

Hydro One emphasized that the fact that its costs are higher than those of other utilities does not mean that they are imprudent. Hydro One gave examples of the challenges it faced that are not faced by other distributors, and explained why the comparison to the utilities listed by OEB staff is not valid. Hydro One argued that staff's suggestion of a cap on costs of 20% above the highest cost for another utility is unreasonable and contrary to well-established rate making principles. Hydro One submitted that the OEB can only disallow actual costs already incurred if the costs are found to be imprudently incurred, and there is no evidence of imprudence in this case.

Hydro One also indicated that negative financial consequences would result if the recovery of regulatory assets that have been incurred is denied. Such a denial would affect Hydro One's risk profile and lead to a credit downgrade and an increase in borrowing costs, according to Hydro One. Hydro One submitted that this danger is particularly acute since the nature of the 2009 to 2014 smart meter costs is similar to the smart meter costs previously approved by the OEB for the 2006 to 2008 period.

Findings

The OEB recognizes that the smart meter program was mandated by government policy and was not discretionary. However, that does not mean that any level of cost incurred by a distributor to carry out the installation of smart meters is necessarily prudent. These costs are held in a variance account, and had not been considered by the OEB prior to this application. No utility is guaranteed recovery of amounts recorded in deferral and variance accounts. The onus is on the utility to demonstrate that the costs were reasonably incurred based on what was known or ought to have been known when it incurred the cost. As noted in section 2.8 of the OEB's Filing Requirements, the final determination of the prudence of costs recorded in an account will be made at the time of disposition of the account.

Hydro One's smart meter costs are significantly higher than other distributors. However, the OEB agrees with Hydro One that the fact that its costs are higher than those of other utilities does not necessarily mean that they are imprudent. Hydro One's service territory is low density and presents challenging terrain. The OEB recognizes that in the 2009 to 2013 period, Hydro One faced particular challenges in its service territory related to a need for investment in communications and accompanying infrastructure. The OEB does not consider the circumstances that Hydro One managed in the implementation of its smart meter program to be comparable to the examples of others distributors provided by OEB staff. The implementation of the smart meter program involved travel to every residential customer dwelling in the province. The OEB therefore considers the customer-to-service area ratio to be a very significant distinguishing cost driver for individual utilities. Hydro One's low density customers make up a much larger percentage of its total customer population than other distributors in the province. Many of Hydro One's seasonal customers are in hard to reach locations such as water access only properties, contributing to much higher implementation costs.

Given the significant difficulties of the implementation of Hydro One's smart meter program, the OEB does not consider the significantly higher average cost to be unreasonable. Therefore a separate proceeding to review the smart meter costs is not required. The program has been completed and the information presented in this application has sufficiently informed the OEB.

Considering all of these factors, the OEB will allow the recovery of these costs as submitted.

13.0 DEFERRAL AND VARIANCE ACCOUNTS

Hydro One proposed the discontinuance of eleven deferral and variance accounts[25], the recovery of the $33.2 million balance in 16 accounts over five years[26], and the continuance of several other accounts. These proposals were unopposed. Hydro One also proposed the creation of two accounts to deal with bill impact mitigation and rate smoothing. The issues of bill impact mitigation and rate smoothing are dealt with elsewhere in this Decision.

Findings

The OEB approves Hydro One's requests regarding the deferral and variance accounts described above with the exception of the creation of the rate smoothing account, as it will no longer be required. The OEB also approves the disposition of the $33.2 million and finds that the recovery period will be three years rather than five years. The OEB has considered the increased total bill impact of a three-year recovery as compared to the five-year disposition period on an average residential customer and considers it to be acceptable.

As indicated in its evidence,[27] Hydro One will apply to the OEB for disposal of its RSVA accounts when disposal thresholds are met.

13.1 Restatement of balances

OEB staff asked that the OEB require Hydro One to restate the balances in accounts related to renewable generation connection and smart grid using the method prescribed in the OEB's Accounting Procedures Handbook (APH), to ensure consistency across the industry. However, Hydro One submitted that its approach was more transparent than that in the APH, and therefore no restatement should be required.

[25] Exhibit F1/Tab1/Sch2 and Reply Argument, pages 71 and 72.
[26] Exhibit F1/Tab1/Sch1/p3 and Reply Argument, page 73
[27] Exhibit A/Tab 4/Schedule 2, p. 3

Hydro One also took the position that the OEB-issued model cannot accommodate its circumstances. Hydro One stated that its methodology takes into consideration the timing of the projects, the cost of capital, depreciation and tax impacts, whereas the APH does not. In addition, according to Hydro One, the APH does not distinguish between capital expenditures and in-service capital additions, which are different concepts.

Findings

The OEB finds that there are no compelling reasons to require Hydro One to restate its balances using the APH method at this time as it may not appropriately accommodate Hydro One's specific circumstances.

14.0 DISTRIBUTION SYSTEM CODE EXEMPTION (EB-2014-0247)

Hydro One requested an exemption from the Distribution System Code sections 7.5.1 and 7.5.2. Section 7.5.1 sets out the obligations on a distributor to attempt to contact customers if a service appointment is missed or is going to be missed, and to attempt to contact the customer to reschedule the appointment within one business day of the missed appointment. Section 7.5.2 indicates that the requirements in section 7.5.1 must be met 100% of the time.

Hydro One submitted that it cannot meet the 100% requirement due to the fact that the geography of its service territory includes areas with gaps in communications infrastructure. It also claims unforeseen re-deployment of staff to power outage calls, managing its employee's priorities in relation to customer communications and unexpected emergencies involving staff reduce the ability of the company to meet the 100% standard. Hydro One has requested that the company be permitted to meet the requirements in section 7.5.1 90% of the time. It indicated that its target is to meet the requirements 95% of the time.

The OEB granted an interim exemption to Hydro One on September 8, 2014, the opening day of the oral hearing.

Parties who made submissions on this issue held varying opinions on whether the permanent exemption should be granted. Hydro One and two intervenors noted that Hydro One is not the only distributor that fails to meet this metric, and that many distributors fail to report their lack of compliance, according to the OEB's 2013 Yearbook. SIA submitted that this metric should not be tracked, as it affects a very small fraction of customers. Several parties, including OEB staff, supported a generic review of the standard in section 7.5.2.

Findings

The OEB finds that Hydro One has failed to demonstrate, with the evidence provided in this proceeding, that a permanent exemption should be granted.

The intent of the 100% standard is to minimize, to the extent possible, the negative impact on a customer who is going to be inconvenienced by the distributor's failure to meet a scheduled appointment.

Based on historic records of the number of appointments in a year, approximately 2,500 Hydro One customers per year could be affected if the proposed 90% compliance level is accepted by the OEB. In other words, potentially 2,500 customers that have made arrangements to be available (possibly incurring monetary expense) may not be contacted when Hydro One personnel realize they can't meet the pre-arranged appointment.

A standard that provides an explicit allowance for even one customer to be exposed to this scenario could only be justified if no reasonable steps to avoid the situation were available. Hydro One provided evidence that there are several causes for its inability to meet the standard to date. Hydro One did not provide evidence attributing any specific frequency or percentage of the total incidents to any of these causes.

The 100% standard in section 7.5.2 requires that only an **attempt** be made to contact the customer prior to an appointment being missed and for rescheduling

The evidence that the geography of Hydro One's service territory includes areas that do not have full communication system coverage may be a valid reason for failing to meet the standard. The inability to communicate in the normal fashion with certain customers has a significant bearing on whether Hydro One could make a genuine attempt to contact customers in those areas.

However, no alternatives to traditional methods of communication were explored in the evidence, nor were any alternative performance protocols examined. The OEB does not know what percentage of the failures to meet the standard are the result of a genuine absence of communications infrastructure, nor what avenues have been explored to minimize these incidents.

The OEB does not consider Hydro One's other submitted causes for its inability to meet the expected standard to be of comparable merit. More rigid communication protocols and employee training to reinforce the importance of customer communication could reduce incidents of non-compliance not related to lack of communications infrastructure. It is understood that employees who have appointments with customers will, on rare occasions, become otherwise engaged on short notice. Given the importance of contacting the customer with this information, Hydro One should be able to devise appropriate communication protocols and safeguards to ensure an attempt is made to contact the customer whenever possible. The evidence in this proceeding did not demonstrate that this had yet been done. This performance metric has been in place for a number of years, and company protocols and employee behaviour must recognize its importance.

The interim exemption granted to Hydro One on September 8, 2014 will expire 60 days from the issuance of this Decision.

15.0 RECOVERY OF LOST REVENUES

On December 18, 2014, the OEB issued a Decision and Interim Rate Order declaring Hydro One Networks Inc.'s current Board-approved Tariff of Distribution Rates and Charges interim effective January 1, 2015.

The OEB has determined that the effective date for rates in this Decision is January 1, 2015, with an expected implementation date of May 1, 2015. Therefore, Hydro One is directed to calculate, as part of its draft Rate Order, the lost revenue for this period and to propose a rate rider to recover this amount over the remainder of this calendar year. The rate rider is to be a Monthly Fixed Charge.

16.0 SUMMARY OF DIRECTIONS FOR FILING

The following list is a summary of directions for filing contained in this Decision. Where any discrepancies exist between this list and the text of the Decision, the text in the Decision governs.

The OEB directs Hydro One to address shortcomings in its application as described in the Decision, including filing the following specific evidence as part of its next rates application:

- A total factor productivity study of Hydro One's own productivity, including data from 2002 and following years at a minimum.
- A compensation study similar to the study filed as part of this application to allow benchmarking to comparable companies.
- A comprehensive trend analysis of the vegetation management program showing year over year comparisons in unit costs.
- A best practices study, if undertaken, for vegetation management similar to the CN Utility study filed in EB-2009-0096.
- An updated depreciation study.
- A consolidated Distribution System Plan, with either an independent third party review of the Plan if conducted, or an explanation of the decision not to conduct such a review.
- Annual capital in-service additions, with explanations of any variance from approved levels (as required by the OEB Filing Requirements).
- An external benchmarking study on the unit cost of the pole replacement program.
- An internal trend analysis to show the variability of the unit costs of the pole replacement program year over year.
- An external benchmarking study on the unit cost of the station refurbishment program.
- An internal trend analysis to show the variability of the unit costs of the station refurbishment program year over year.
- A report on an updated customer classification review.
- A study on Hydro One's miscellaneous service charges, assessing whether the charges reflect underlying costs.

In addition, Hydro One is directed:

- To submit, by August 4, 2015, to the OEB and intervenors of record in this application, a plan for the elimination of the seasonal class, including recommendations for a phase-in period or other mitigation for customers expected to experience a bill impact greater than 10%, and a proposal for billing frequency.
- To apply to adjust its street lighting rates at the earliest opportunity during which rate changes are being considered.

17.0 IMPLEMENTATION AND ORDER

The OEB directs Hydro One to file a Draft Rate Order reflecting the OEBs findings in this Decision, complete with detailed supporting material, including:

- all relevant calculations showing the determination of the revenue requirements for 2015 to 2017;

- a schedule (or schedules) clearly showing the allocation of the revenue requirements from this Decision to the customer classes for 2015 to 2017,

- a schedule (or schedules) clearly showing the calculation of the rate rider that is to collect the lost revenue from January 1, 2015 to April 30, 2015.

- a schedule of final rates and all approved rate riders, including bill impacts (in a table similar to that filed at ExhibitG2/Tab4/Schedule1), and a calculation showing reconciliation of the total revenues by class to the revenue requirements.

- a detailed plan on how Hydro One will address rate mitigation that may be necessary when the approved rates are implemented.

- any other documentation that would assist Intevenors, OEB staff and the OEB in their consideration of the proposed Draft Rate Order.

The Ontario Energy Board Orders That:

1. Hydro One shall file with the OEB, and forward to all intervenors, a Draft Rate Order that includes all items listed above, including revised models in Microsoft Excel format as appropriate and a proposed Tariff of Rates and Charges reflecting the OEB’s findings no later than **March 25, 2015**.

2. Hydro One will present its Draft Rate Order and supporting materials to OEB staff and Intervenors at a Technical Conference to be held on **April 1, 2015** in the OEB's hearing room at the OEB Offices at 2300 Yonge Street, Toronto beginning at 9:30 am. Hydro One should endeavour to have staff available to address any questions or comments provided by Intervenors or OEB staff.

3. Board staff and intervenors shall file any comments on the Draft Rate Order with the OEB with Hydro One no later than **April 6, 2015**.

4. Hydro One shall file with the OEB, and forward to intervenors, responses to any comments on its Draft Rate Order no later than **April 10, 2015**.

5. Hydro One shall file with the OEB and forward to intervenors a revised Draft Rate Order no later than **April 16, 2015**.

All filings to the OEB must quote the file number, **EB-2013-0416**, be made through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/ ,and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

ADDRESS

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DATED at Toronto, March 12, 2015

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

18.0 APPENDICES

APPENDIX 1
THE PROCEEDING, PARTICIPANTS AND WITNESSES

THE PROCEEDING

On December 19, 2013, Hydro One filed an application with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, Schedule B for an order or orders approving distribution rates for a five year period, commencing January 1, 2015.

The OEB issued a Notice of Application on January 24, 2014. In response to the Notice, the OEB received 19 requests for intervenor status. The OEB approved 18 of these interventions.

The OEB also received 13 Letters of Comment from ratepayers across Ontario, the vast majority expressing concern with the high level of the proposed rate increases. In addition, the OEB received resolutions from 42 Ontario municipalities, expressing concern over electricity rate increases.

Hydro One updated its pre-filed evidence in this case on January 30, 2014 and provided a further update on May 30, 2014. At the applicant's suggestion, the OEB held a series of three transcribed technical conferences on April 1, 10 and 23 and also held a transcribed session on May 12, 2014 during which Hydro One senior management made a presentation on the application.

The OEB approved an issues list for this case on May 20, 2014. Following an interrogatory process, a further technical conference was held on July 21 and 22, 2014. A settlement conference was held on July 28, 2014 but no settlement was achieved.

Motion and Decision

On September 4, 2014, the City of Hamilton filed a motion requesting an order freezing the rates of Hydro One for the street lighting class at 2014 levels or setting these rates as interim in this proceeding. The OEB heard the motion on September 12, 2014 and on September 16, 2014 gave an oral decision denying the motion. A copy of this decision is attached as Appendix 2.

The oral hearing for this proceeding began on September 8, 2014. On that date the OEB granted an interim exemption from section 7.5.2 of the DSC. The evidentiary portion of the hearing concluded on September 18, 2014. Hydro One presented oral argument-in-chief on September 24, 2014. The OEB received submissions from OEB staff and fifteen intervenors. The record closed with receipt of reply argument from Hydro One on October 27, 2014.

Decision on Interim Rates

On December 18, 2014, the OEB acknowledged that the OEB's decision may not be issued until after the proposed effective date of January 1, 2015 and declared Hydro One's current approved distribution rates interim as of January 1, 2015 pending the Board's final decision on the application.

In the decision on interim rates, the OEB also granted Hydro One's request to discontinue collection of revenue through the Regulation 330/09 renewable connection funding adder from provincial ratepayers as of December 31, 2014.

PARTICIPANTS

A list of participants and their representatives who were active either at the oral hearing or at another stage of the proceeding is shown below. A complete list of intervenors is available at the OEB's offices.

OEB Counsel and Staff (OEB staff)	Jennifer Lea, Harold Thiessen, Lisa Brickenden, Leila Azaiez, Keith Ritchie, Stephen Cain
Hydro One Networks Inc. (Hydro One)	Don Rogers, Anita Varjacic
Society of Energy Professionals (SEP)	Bohdan Dumka, Vicki Power

Consumers Council of Canada (CCC)	Julie Girvan
Canadian Manufacturers and Exporters (CME)	Emma Blanchard, Vince DeRose
Association of Major Power Consumers of Ontario (AMPCO)	Shelley Grice
Energy Probe Research Foundation (EP)	Roger Higgin, Brady Yauch
School Energy Coalition (SEC)	Mark Rubenstein, Jay Shepherd
Green Energy Coalition GEC)	David Poch
Vulnerable Energy Consumers' Coalition (VECC)	Michael Janigan
Power Workers' Union (PWU)	Richard Stephenson
Ontario Federation of Agriculture (OFA)	Ted Cowan
Individual Intervenor	Patrick Hurley
Federation of Ontario Cottagers Associations (FOCA)	John McGee
Balsam Lake Coalition (BLC)	Nicholas Copes, Michael Buonaguro
Sustainable Infrastructure Alliance (SIA)	Dionisio Rivera

WITNESSES

Eleven witnesses testified at the oral hearing.

Witnesses called by Hydro One (all Hydro One employees):

Susan Frank, Vice-President and Chief Regulatory Officer

Michael Winters, Senior Vice-President - Engineering and Construction

Glenn Scott, Director - Business Planning and Financial Support
Sandy Struthers, Chief Administration Officer and Chief Financial Officer
Samir Chhelavda, Director – Corporate Accounting and Reporting
Sam Amodeo, Manager - Productivity, ISD Support & NEB

Tom Irvine, Director – Network Operating Division
Paul Brown, Director - Distribution Asset Management Planning
Kelly Kingsley, Manager – Customer Care

Stanley But, Manager - Economics and Load Forecasting
Henri Andre, Manager - Transmission & Distribution Pricing, Regulatory Affairs, Corporate & Regulatory Affairs

Witnesses called by intervenors:

For the Ontario Federation of Agriculture: Ted Cowan

The Green Energy Coalition filed evidence but witness William Marcus did not appear at the oral hearing.

APPENDIX 2
ORAL DECISION ON CITY OF HAMILTON MOTION, SEPTEMBER 16, 2014
TR Volume 6, September 16, 2014, p. 98

RULING:

MR. QUESNELLE: As I mentioned before the lunch break, the Board has made a determination on the motion by the city of Hamilton heard on Friday, September 12th, 2014.

The city of Hamilton brought the motion for an order freezing the rates of Hydro One Networks for the street lighting class at the 2014 levels, for a period to be determined by the Board, or in the alternative, an order requiring that the rates for street lighting class, as they may be determined in EB-2013-0416, be interim and be reconsidered and, if necessary, reset following the outcome of the Board's considerations in EB-2012-0383.

The grounds submitted for the motion included the following:

> "In its report of the Board entitled 'Review of the Board's cost allocation policy for unmetered loads', EB-2012-0383, dated December 19th, 2013, the Board stated that: 'The revenue to cost ratio range for the street lighting rate class should not be narrowed unless there was sufficient evidence as to the correct methodology for setting street lighting rates, and further investigation was necessary before making a determination as to the allocation of costs to daisy-chain configured systems.'

The city of Hamilton submitted that those stated requirements for sufficient evidence and further investigation before setting rates for the street lighting class have not been fulfilled. The city noted that the Board has, by letter dated August 21st, 2014, given notice of its intention to undertake a study of, among other things, the appropriateness for the application of existing methods of cost allocation to various street light system configurations, and to update the Board's cost allocation model with respect the cost allocation to various street lighting system configurations.

The city submitted that in light of the Board's statements in EB-2012-0383 and in light of the commencement of the study, it would be premature and unfair to the city of Hamilton to set HONI's rates for the street lighting class until the study has been completed.

No other party supported the motion. The motion is opposed by Hydro One, the Vulnerable Energy Consumer Coalition, School Energy Coalition, Canadian Manufacturers and Exporters, Consumers Council of Canada, and Board Staff.

In support of its motion, the city argued that the Board's report in EB-2012-0383 established that the Board's expectation that rates for street lighting services would remain unchanged until further investigation had been completed.

The Vulnerable Energy Consumers Coalition and some others submitted that the city's interpretation of the report is incorrect, and that the Board had simply determined that there was insufficient evidence to narrow the Board's revenue to cost ratio range for street lighting class for all distributors.

Those opposed to the motion also submitted that the Board routinely initiates policy considerations or policy reviews that have the potential to alter the rate-setting methodologies that are in place, and that the Board has not in the past set the current rates as interim or freeze rates in anticipation of a potential change to the rates. Those opposed to the motion submitted that to do so would be unworkable and result in ongoing uncertainty with respect to rates paid by customers of all rate classes.

The Board accepts the arguments of those opposed to the motion on both the interpretation of the Board's intent in the report of the Board, and the manner in which the Board should deal with current rates during reviews of rate-setting policies.

The Board's report clearly states that the revenue to cost range should not be allowed due to lack of evidence that would suggest otherwise. The Board's various revenue to cost ranges were originally set in 2007 and have been narrowed for different classes at different stages as the cost allocation policy of the Board has evolved over time. The Board has not refrained from setting final rates, even though the ranges have been known to be in a state of flux. The Board considers certainty of rates paid at the time of system use to be a very important attribute of a fair and reasonable ratemaking scheme.

The Board will hear and consider Hydro One's evidence with respect to rates for the street lighting class, and make its determination giving due regard to the fact that a review of the class allocation methodology for street lighting has been initiated.

The motion brought by the City of Hamilton is denied.

Ontario Energy Board | **Commission de l'Énergie de l'Ontario**

Ontario

EB-2011-0210

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

BEFORE: Marika Hare
Presiding Member

Karen Taylor
Board Member

DECISION AND RATE ORDER
January 17, 2013

Union Gas Limited ("Union") filed an application on November 10, 2011 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998* for an order of the Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2013 (the "Application"). The Board assigned file number EB-2011-0210 to the Application and issued a Notice of Application on December 1, 2011. This is the first cost-of-service application for setting rates since 2007. From 2008 to 2012 rates were set under an Incentive Regulation Mechanism ("IRM") which adjusted rates through a mechanistic formula.

The Board issued its Procedural Order No. 1 on January 11, 2012, which established the approved list of intervenors for this proceeding. The list included:

- Association of Power Producers of Ontario ("APPrO")
- Building Owners and Managers Association Toronto ("BOMA")
- Canadian Manufacturers and Exporters ("CME")
- City of Kitchener ("Kitchener")
- Consumers Council of Canada ("CCC")
- Enbridge Gas Distribution Inc. ("Enbridge")
- Energy Probe Research Foundation ("Energy Probe")
- Federation of Rental-housing Providers of Ontario ("FRPO")
- Industrial Gas Users Association ("IGUA")
- Jason F. Stacey
- Just Energy Ontario LP ("Just Energy")
- London Property Management Association ("LPMA")
- Ontario Association of Physical Plant Administrators ("OAPPA")
- Ontario Power Generation ("OPG")
- School Energy Coalition ("SEC")
- Six Nations Natural Gas Company Limited ("SNNG")
- Shell Energy North America (Canada) Inc. ("Shell Energy")
- TransAlta Generation Partnership ("TransAlta Generation")
- TransAlta Cogeneration LP ("TransAlta Cogeneration")
- TransCanada Pipelines Limited ("TCPL")
- TransCanada Energy Limited ("TCE")
- Vulnerable Energy Consumers Coalition ("VECC").

The Board also determined that APPrO, BOMA, CME, CCC, Energy Probe, FRPO, IGUA, LPMA, OAPPA, SEC, and VECC are eligible to apply for an award of costs under the Board's *Practice Direction on Cost Awards*.

Union filed its Application on the basis of US Generally Accepted Accounting Principles ("USGAAP"). At the same time, Union sought approval to move to USGAAP from Canadian GAAP as part of this Application. The Board decided to first deal with Union's request for the adoption of USGAAP for regulatory purposes (the "Preliminary Issue") prior to processing the Application in accordance with the Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment (the "Addendum Report").

In Procedural Order No. 1 the Board established a timeline for interrogatories, interrogatory responses, submissions, and reply submissions related to the Preliminary

Issue in advance of further procedural steps. In addition, the Board adopted the evidence related to the USGAAP issue from Union's 2012 IRM Proceeding EB-2011-0025 (the "Adopted Evidence").

Submissions were received from the LPMA, CCC, SEC, CME, APPrO and Board staff. LPMA, CCC, SEC and Board staff supported the request by Union for the adoption of USGAAP for regulatory purposes. CME and APPrO were also supportive of Union's request but provided some proposed conditions of approval.

The Board issued its Decision on the Preliminary Issue and Procedural Order No. 2 on March 1, 2012. The Board granted Union approval to use USGAAP for regulatory purposes. The Board also set out the timelines for the Issues Conference, Issues Day Hearing, filing of interrogatories and responses to interrogatories by Union in this Procedural Order.

Procedural Orders No. 3 and No. 4 set timelines for the next procedural steps, including setting dates for the Technical Conference and the Settlement Conference.

The Board revised some of the timelines for interrogatories and filing intervenor evidence in Procedural Order No. 5 after considering a letter filed by TCPL that requested revised dates to accommodate timelines related to the hearing of its application before the National Energy Board.

TCPL filed a Notice of Motion on May 17, 2012. The Motion requested the following:

1) An Order requiring Union to provide proper answers to the Interrogatories identified in Appendix "A" to the Notice of Motion, or such other information as the Board considers appropriate.

2) An Order requiring Union to file with the Board unredacted copies of pages in Interrogatory Responses that were filed in redacted form as part of Union's Interrogatory Responses to TCPL, so that the Board could assess the reasonableness of the claims for confidentiality and make such order as it considers appropriate in that regard.

The Board in Procedural Order No. 6, issued on May 18, 2012, decided that it would not hear the second request as part of the TCPL Motion as there were other exhibits, not mentioned in TCPL's Motion, which were filed under confidential cover. The Board in Procedural Order No. 6 established a separate process for reviewing Union's claims for confidentiality.

The Board heard the Motion filed by TCPL by way of written hearing. Procedural Order No. 6 made provision for all parties to the proceeding to file submissions on the merits of TCPL's Motion and for TCPL to file reply submissions. This process was completed on June 8, 2012.

TCPL, BOMA and Union filed submissions on TCPL's Motion. The interrogatory information sought by TCPL related primarily to Union's Parkway West project which purports to provide for loss of critical unit protection at Parkway.

With respect to the Parkway West project questions, TCPL's position was that the information that it was seeking was necessary for the Board to evaluate the reasonableness of Union's proposed capital expenditures. Union submitted that the information requested by TCPL was not relevant to Union's Application as the Parkway West project would not come into rate base until 2014 and did not impact 2013 rates. Union's position was that providing such further information could have no bearing on deciding the issues before the Board in this Application.

BOMA's submissions largely supported TCPL's request for Union to provide answers to the TCPL Parkway West interrogatories.

The Board in its Decision dated June 15, 2012, granted the Motion and required Union to provide responses to the interrogatories.

With respect to the relevance of the Parkway West interrogatories, the Board indicated that a review of the forecast capital spending plan was a conventional aspect of a cost of service rebasing process. The Board recognized that the specific projects that were the focus of the interrogatories at issue were not expected to close to rate base within the test year, and that the Board was not conducting a review of the projects for approval. However, the Board has commonly reviewed capital spending forecasts as part of a cost of service review, and determined that it would do so in this case.

The Board noted that the proposed projects may have important implications for Union's operations during the following year, in particular if Union is again entering into an incentive regulation regime for rate-setting. The Board indicated that it would be remiss in considering this cost-of-service application if it did not ensure that it had as clear a picture as possible of the significant developments likely to arise within the next regulatory rate-setting period.

On the issue of confidentiality, the Board determined that, except for the benchmarking studies, the information that Union proposed to redact was not confidential, and that the full and unredacted versions should form part of the public record. With respect to the benchmarking studies, the Board agreed with Union that the specific rankings of the studies' participants (other than Union) should not be on the public record, and therefore allowed the redactions. However, the Board required that the list of the participants to the studies be made public where it was included in the study. The Board noted that in assessing the relevance of a benchmarking study, it was important that the "comparators" be known.

As per Procedural Order No. 4, a Settlement Conference was held from June 6 to June 18, 2012 between Union and intervenors to settle some or all issues. In broad terms, the parties reached an agreement with respect to rate base and cost of service for the test year, being the issues under headings Exhibit B – Rate Base and Exhibit D – Cost of Service, respectively, with the exception of matters pertaining to Gas Supply Planning (Issue 3.14) and capital expenditures relating to Parkway West (Issue 1.1). The parties also reached agreement on several other issues, each of which were separately identified as settled in the Settlement Agreement. As a result of the Settlement Agreement, the updated revenue deficiency proposed by Union was reduced to $54.524 million from $71.4 million. The Board considered and accepted the Settlement Agreement as reasonable.

The Board issued a Decision and Order on the remaining issues in Union's 2013 rates proceeding on October 25, 2012. In the Decision, the Board ordered Union to file a Draft Rate Order within 42 days of the date of the Decision.

In Procedural Order No. 8 and Interim Rate Order ("Procedural Order No. 8") issued on November 26, 2012, the Board noted that Union filed a letter on November 21, 2012 requesting a one week extension to file the Draft Rate Order in order to incorporate changes related to the January 1, 2013 Quarterly Rate Adjustment Mechanism ("QRAM") application into its Draft Rate Order. The Board accepted Union's request and granted the requested extension. The Board also set out the revised timeline for the filing of comments on the Draft Rate Order by intervenors and Board staff.

In Procedural Order No. 8, the Board also ordered that Union's current rates be made interim until the Board issues a Rate Order determining 2013 rates.

Union filed the Draft Rate Order on December 13, 2012. The Board received comments on Union's Draft Rate Order from Board staff and intervenors in accordance with the timeline set in Procedural Order No. 8. The Board also received reply comments from Union.

Union filed an updated Draft Rate Order on January 10, 2013 reflecting some revisions proposed by Board staff and LPMA in their comments on the Draft Rate Order.

The Board is of the view that the Updated Draft Rate Order filed on January 10, 2013 accurately reflects the Board's findings in its October 25, 2012 Decision and Order and the revised Settlement Agreement filed on July 24, 2012 (and approved by the Board on July 25, 2012). As such, the Board approves Union's Updated Draft Rate Order.

Storage and Transportation ("S&T") Allocation Methodologies

In the EB-2011-0210 Decision and Order, the Board found that Union's use of S&T margin as a rate design tool to manage rate impacts, rate continuity and revenue-to-cost ratios is not appropriate, and that S&T margin should be allocated to rate classes on the basis of sound regulatory principles. The Board noted that there are three sub-categories for S&T margin: Long-Term Transportation-related S&T margin, Short-Term Transportation-related S&T margin and Storage and Other Balancing Services-related S&T margin, and directed Union to file allocation methodologies for the above noted sub-categories, which reflect regulatory principles.[1]

<u>Long-Term and Short-Term Transportation-related S&T Margin</u>

[1] Union Updated Draft Rate Order, January 10, 2013 at p. 2.

The long-term and short-term transportation-related S&T margin to be allocated to in-franchise ratepayers is $3.314 million and $6.291 million respectively, for a total of $9.605 million.

Union proposed to allocate long-term and short-term transportation-related S&T margin between Union North and Union South operating areas in proportion to forecasted 2013 distance weighted available capacity on the Dawn-Parkway and Ojibway/St. Clair transmission systems.

Union proposed to allocate the long-term and short-term transportation-related S&T margin to Union North rate classes in proportion to the 2013 Board-approved excess of peak day demand over average day demand (XSPK&AVG allocator). This approach is consistent with the allocation of 2013 Dawn-Trafalgar Easterly demand costs to Union North rate classes.

Union proposed to allocate the long-term and short-term transportation-related S&T margin to Union South rate classes in proportion to EB-2011-0210 design (peak) day demand.

Union noted that its proposal is consistent with the methodology approved by the Board in EB-2008-0034 (Union's 2007 Deferral Account disposition proceeding) to allocate the Transportation and Exchange Services deferral account (No. 179-69) to rate classes.[2]

Board staff submitted that it supports Union's proposed allocation methodologies for allocating the long-term and short-term transportation-related S&T margins as they reflect established regulatory principles.[3] No other parties commented on this issue.

Storage and Other Balancing Services-related S&T Margin

The storage and other balancing services-related S&T margin to be allocated to in-franchise ratepayers is $4.551 million.

Union proposed to allocate storage and other balancing services-related S&T margin between the Union North and Union South operating areas in proportion to the

[2] Ibid at p. 3.
[3] Board Staff Comments on Draft Rate Order, December 31, 2012 at p. 2.

allocation of storage space related costs per the 2013 Board-approved STORAGEXCESS allocator.

Union proposed to allocate the storage and other balancing services-related S&T margin to Union North rate classes in proportion to the 2013 Board-approved excess of peak day demand over average day demand (XSPK&AVG allocator). This approach is consistent with the allocation of 2013 storage demand costs to Union North rate classes.

Union proposed to allocate the storage and other balancing services-related S&T margin to Union South rate classes in proportion to EB-2011-0210 design (peak) day demand.

Union noted that its proposal is consistent with the methodology approved by the Board in EB-2011-0038 (Union's 2010 Deferral Account disposition proceeding) and proposed by Union in EB-2012-0087 (Union's 2011 Deferral Account disposition proceeding) to allocate the balance in the Short-Term Storage and Other Balancing Services deferral account (No. 179-70) to rate classes.[4]

Board staff submitted that it supports Union's proposed allocation methodologies for allocating the storage and other balancing services-related S&T margin as they reflect established regulatory principles.[5] No other parties commented on this issue.

Board Findings

The Board approves Union's proposed allocation methodologies for allocating the S&T margins (Long-Term & Short-Term Transportation-related S&T margins and Storage & Other Balancing Services-related S&T margins) as they reflect established regulatory principles.

Optimization Margin

In its EB-2011-0210 Decision, the Board ordered the establishment of a new gas supply variance account in which 90% of all optimization margin not otherwise reflected in the revenue requirement are to be captured for the benefit of the ratepayers and directed

[4] Union Updated Draft Rate Order, January 10, 2013 at pp. 3-4.
[5] Board Staff Comments on Draft Rate Order, December 31, 2012 at p. 3.

Union to file a proposal to allocate the balance of the new gas supply variance account to in-franchise customers, including direct purchase customers in the North.

Union proposed to allocate FT-RAM net revenues between Union North and Union South based on the upstream transportation contracts used to serve each delivery area. FT-RAM net revenues generated using upstream transportation long-haul contracts and STS contracts designed to serve Union North (with delivery points of SSMDA, WDA, NDA, NCDA and EDA) will be allocated to Union North. FT-RAM net revenues generated using upstream transportation long-haul contracts designed to serve Union South (the CDA delivery point) will be allocated to Union South. Specifically, with respect to capacity assignments, the revenue from each capacity assignment was attributed to either the Union North or Union South based on the delivery point.
With respect to FT-RAM optimization, the total revenue earned from all optimization will be allocated based on the quantity of transportation capacity optimized, either North or South.

Union proposed that the portion of optimization margin related to Union North be allocated to rate classes in proportion to the allocation of 2013 Board-approved TCPL FT transportation demand costs. This approach ensures that optimization margin is allocated to North rate classes consistent with the manner in which FT transportation demand costs are recovered in approved gas supply transportation rates (i.e. North sales service and bundled direct purchase customers).

Union noted that the portion of optimization margin related to Union South is applicable to sales service customers only. Accordingly, Union proposed to allocate the portion of the balance related to Union South to sales service customers based on sales service volumes. This approach is consistent with the manner in which Union allocates the Unabsorbed Demand Cost ("UDC") Variance Account balance applicable to Union South to sales service customers.

Union noted that this approach is consistent with the methodology proposed by Union in EB-2012-0087 (Union's 2011 Deferral Account disposition hearing).[6]

CME submitted that, in the DRO, Union has interpreted the findings in the Decision and Order (at pages 39 and 40) to require that revenues realized from optimizing assets, other than Union's upstream supply portfolio held to serve its in-franchise bundled

[6] Union Updated Draft Rate Order, January 10, 2013 at pp. 4-5.

customers, be classified as gas supply with 90% thereof to be held for the benefit of ratepayers as gas supply cost reductions. CME questioned whether Union's interpretation is the appropriate interpretation of the Board's findings.

CME stated that the evidence at the hearing indicated that Union engaged in optimization activities using assets outside of the ambit of its upstream supply portfolio held to serve in-franchise customers. Assets used to support such optimization activities included Union's integrated transmission, storage and distribution assets, with or without incremental upstream transportation that Union acquired outside of the ambit of its Gas Supply Plan to support such transactions. These optimization activities that take place outside of the ambit of the gas supply portfolio held by Union to serve its in-franchise customers include base exchanges.

CME noted that in the Board's findings at page 39 of its Decision and Order, the Board accepted Union's definition of gas supply portfolio optimization which is confined in scope to the optimization of the gas supply portfolio that Union holds to serve its in-franchise bundled customers. CME stated that the incremental upstream transportation that Union acquires to support base exchanges that in turn depend upon the existence of Union's other integrated assets is not part of the gas supply portfolio that Union holds to serve its in-franchise customers. The amounts that Union spends on incremental upstream transportation to support base exchanges are not charged to ratepayers through any Gas Supply Deferral Accounts. They are third party costs incurred to support optimization activities unrelated to the gas supply portfolio that Union holds to serve in-franchise customers. As such, CME submitted that base exchanges do not fall within the ambit of the definition of gas supply portfolio optimization that the Decision adopts.

Having regard to the foregoing, CME submitted that the Gas Supply Variance Account described in the Decision and Order at the bottom of page 39 is limited in scope to optimization activities in which Union engages using the upstream transportation it holds to serve its in-franchise customers.

CME submitted that other optimization activities, including the revenues from base exchanges net of all third-party costs, including incremental transportation acquired outside of the ambit of Union's Gas Supply Plan, are to be brought into revenue requirement and allocated to rate classes in the North and South on the basis of sound regulatory principles.

CME submitted that net revenues from the optimization of assets other than the upstream gas supply portfolio that Union holds to serve its in-franchise customers should be classified and allocated on the basis of sound regulatory principles. CME stated that it understands that these assets are paid for by all ratepayers through their delivery rates and, accordingly, the benefits of these optimization activities should flow to all ratepayers. CME submitted that Union's classification of the $9.1M of forecast base exchange revenues for 2013 as a gas supply-related amount to be allocated only to those rate classes who pay for the gas supply portfolio that Union holds for in-franchise customers is incompatible with the definition of gas supply portfolio optimization adopted in the Board's Decision and Order.

CME submitted that the $9.1M of forecast base exchange revenues should be treated differently than the gas supply portfolio optimization margins.[7]

Board staff supported Union's proposed allocation methodologies for allocating the optimization margin as they reflect established regulatory principles. Board staff submitted that Union's proposed allocation methodologies, discussed above, should be used to allocate the forecast optimization margin to rate classes for 2013 and should also be used to allocate the optimization margin that accrues in the new gas supply variance account to rate classes going forward. Board staff noted that if the Board agrees with Board staff's proposition that the same methodology should be used for allocating both the forecast 2013 margin and the margin that accrues in the variance account, then Directive #12[8] in Appendix F of the Draft Rate Order can be deleted.

Board staff also noted that it had an opportunity to briefly review CME's comments on the Draft Rate Order.

Board staff noted that on page 117 of its October 25, 2012 Decision, the Board stated:

> As ordered previously, the amount built into rates related to gas supply optimization is 90% of Union's 2013 forecast of base exchanges and 90% of half of Union's FT-RAM 2013 forecast.

Board staff submitted that the Board's intent, in its October 25, 2012 Decision, was that margins related to base exchanges and other upstream transportation optimization

[7] CME Comments on Draft Rate Order, December 31, 2012 at pp. 4-5.
[8] Directive #12 states: File a proposal to allocate the balance of the new gas supply variance account to in-franchise customers, at the time an application is filed with the Board to clear this account.

activities (i.e. FT-RAM activities) be treated in the same manner (i.e. as gas supply cost reductions). As such, Board staff submitted that Union has appropriately interpreted the Board's findings on this issue.[9]

In its reply comments on the Draft Rate Order, Union stated that the premise of CME's view is contrary to the Board's Decision and the evidence at the hearing that there is no distinction between base exchanges and FT-RAM related exchanges other than the use of the FT-RAM program in the latter case. Union noted that, at page 25 of the Board's Decision and Order, the Board indicated that "exchange revenue is comprised of activity using Union's upstream transportation capacity to provide exchange services to third parties. It also includes net revenue generated from pipe releases or revenue from [FT-RAM] program."

Union also noted that page 39 of the Decision provides:

> Consistent with the long-standing principle that a gas utility should not profit from the procurement of gas supply for its in-franchise customers, and to eliminate the creation of inappropriate incentives during the test year, the Board finds that the optimization activities, as defined below, are to be considered part of gas supply, not part of transactional services.
> The Board reiterates that gas supply costs refer to both the upstream gas cost, including fuel gas, and the cost (rate multiplied by contract volume) of upstream transportation that is required to deliver gas supply to Union's in-franchise customers in the North and South Delivery Areas.
>
> Consistent with the description provided by Union, the Board will define optimization as any market-based opportunity to extract value from the upstream supply portfolio held by Union to serve in-franchise bundled customers, including, but not limited to, all FT-RAM activities and exchanges.

Union submitted that exchange revenues are created by Union optimizing its upstream transportation contracts and its integrated assets. The upstream transportation contracts held by Union are to provide services to in-franchise customers, including all sales service customers and bundled direct purchase customers in Union North. As noted above in the Board's Decision, optimization revenue is defined as any opportunity or transaction that uses Union's in-franchise upstream portfolio. Union submitted that considering all upstream transportation contracts are held for in-franchise customers,

[9] Board Staff Comments on Draft Rate Order, December 31, 2012 at pp. 4-5.

the optimization revenues generated from those assets are to be included as part of the gas supply plan.

Union submitted that it is clear that the Board required Union to include all exchange revenues, both base exchange revenues and FT-RAM revenues as gas cost reductions.[10]

Board Findings

The Board approves Union's proposed allocation methodologies for allocating the optimization related margins as they reflect established regulatory principles. The Board directs Union to use the above noted allocation methodologies to allocate the forecast optimization margin to rate classes for 2013 and to allocate the optimization margin that accrues in the new gas supply variance account to rate classes going forward. The Board notes that Directive #12 included as part of the Draft Rate Order has been deleted as Union will use the same methodology to allocate the forecast optimization margin to rate classes for 2013 as it will use to allocate the optimization margin that accrues in the new gas supply variance account to rate classes going forward.

Transportation Tolls and Fuel – Northern and Eastern Operations Area Deferral Account (No. 179-100) and Unabsorbed Demand Cost ("UDC") Variance Account (No. 179-108)

In its Draft Rate Order, Union noted that it proposed, during the oral hearing, that some updates be made to certain accounting orders to be consistent with Union's actual accounting treatment for these accounts. Union noted that its Draft Rate Order includes revisions to the Transportation Tolls and Fuel – Northern and Eastern Operations Area Deferral Account (No. 179-100) and Unabsorbed Demand Cost ("UDC") Variance Account (No. 179-108).[11]

Board staff supported Union's updates to the above noted accounts as Union has stated that the revised accounting orders better reflects Union's actual accounting treatment. Board staff noted that the Board did not make findings on this issue in its October 25, 2012 Decision and Order. Board staff stated that the Board should make an explicit

[10] Union Reply Comments on Draft Rate Order, January 8, 2013 at pp. 8-9.
[11] Union Updated Draft Rate Order, January 10, 2013 at p. 2.

finding on this issue in its Decision on the Draft Rate Order.[12] No other parties commented on this issue.

Board Findings

The Board approves the updates proposed by Union to the accounting orders for the Transportation Tolls and Fuel – Northern and Eastern Operations Area Deferral Account (No. 179-100) and Unabsorbed Demand Cost ("UDC") Variance Account (No. 179-108). The Board finds that the updates better reflect Union's actual accounting treatment for these accounts.

Short-Term Storage and Other Balancing Services Deferral Account (No. 179-70)

In the Draft Rate Order, Union proposed the following description for the Short-Term Storage and Other Balancing Services Deferral Account (No. 179-70) ("Short-Term Storage Account"):

> To record, as a debit (credit) in Deferral Account No. 179-70 the utility portion of actual net revenues for Short-term Storage and Other Balancing Services, less the 10% shareholder incentive to provide these services and less the net revenue forecast for these services as approved by the Board for ratemaking purposes. The utility portion of actual revenues for Short-term Storage and Other Balancing Services is determined by allocating total margins received from the sale of these services based on the utility share of the total quantity of the services sold each calendar year.

> To record, as a credit in Deferral Account No. 179-70 the payment by Union Gas for the market value of utility space that was subject to encroachment.

Board staff submitted that the accounting order description adequately reflects the Board's findings as it relates to storage encroachment. However, Board staff submitted that the language regarding the "utility share" could be better defined.

Board staff noted that, in its October 25, 2012 Decision and Order, the Board stated:

> …all revenues generated through the use of the regulated utility storage space up to the 100 PJ cap, both planned and the excess over planned, should be recorded in the account for sharing with ratepayers.

[12] Board Staff Comments on Draft Rate Order, December 31, 2012 at pp. 5-6.

Board staff submitted that the following update should be made to Union's proposed description for the Short-Term Storage Account (updates are underlined):

> To record, as a debit (credit) in Deferral Account No. 179-70 the utility portion of actual net revenues for Short-term Storage and Other Balancing Services, less the 10% shareholder incentive to provide these services and less the net revenue forecast for these services as approved by the Board for ratemaking purposes. The utility portion of actual net revenues for Short-term Storage and Other Balancing Services is determined by allocating total margins received from the sale of these services based on the utility share of the total quantity of the services sold each calendar year. The utility share reflects the transactions supported by utility storage space (up to the 100 PJ cap – both planned and excess over planned).[13]

In its reply comments on the Draft Rate Order, Union accepted Board staff's proposed update to the description for the Short-Term Storage Account.[14] No other parties commented on this issue.

Board Findings

The Board approves the proposed language for the Short-Term Storage and Other Balancing Services Deferral Account (No. 179-70) as updated by Board staff and reflected in the revised accounting order filed as part of the Updated Draft Rate Order on January 10, 2013.

Upstream Transportation Optimization Deferral Account (No. 179-131)

In its Draft Rate Order, Union proposed the following descriptions (and entries) for the Upstream Transportation Optimization Deferral Account (No. 179-131) ("Optimization Account"):

[13] Board Staff Comments on Draft Rate Order, December 31, 2012 at pp. 6-7.
[14] Union Reply Comments on Draft Rate Order, January 8, 2013 at p. 2.

Debit	-	Account No. 179-131 Other Deferred Charges – Upstream Transportation Optimization
Credit	-	Account No. 626 Exchange Gas

To record as a debit in Deferral Account No. 179-131 a receivable from customers and a reduction in cost of gas for the unit rate of optimization revenues refunded to in-franchise customers multiplied by the actual distribution transportation volumes.

Debit	-	Account No. 579 Miscellaneous Operating Revenue
Credit	-	Account No. 179-131 Other Deferred Charges – Upstream Transportation Optimization

To record as a credit in Deferral Account No. 179-131 a payable to customers and a reduction in transportation revenue equal to the ratepayer portion (90%) of the actual net revenue from gas supply optimization activities.

Board staff requested that Union explain the entries in the Upstream Transportation Optimization Deferral Account as part of its reply comments on the Draft Rate Order.[15]

In its reply comments on the Draft Rate Order, Union stated that the first entry captures the amount of optimization revenue refunded to customers in approved rates. The second entry captures the actual optimization to be refunded to ratepayers. The resulting balance in the account will be the variance between the actual optimization revenue to be refunded and the actual amount refunded in approved rates.

Union stated that the two separate entries are required to ensure the effect of any volume-related variance is captured in the deferral account. If Union's sales service volumes are greater than forecast the amount refunded to customers will be higher than forecast, similarly, if sales service volumes are less than forecast the amount refunded to customers will be lower than forecast. Union noted that accounting for the actual volumes in the deferral account ensures there is no gain or loss resulting from the credit for upstream optimization included in rates.[16] No other parties commented on this issue.

Board Findings

The Board approves the accounting order for the Upstream Transportation Optimization Deferral Account (No. 179-131). The Board is of the view that the accounting order entries and descriptions adequately reflect the purpose and operation of the account.

[15] Board Staff Comments on Draft Rate Order, December 31, 2012 at pp. 7-.8.
[16] Union Reply Comments on Draft Rate Order, January 8, 2013 at p. 2.

Closure of Rate Class and Service Offerings

In its Draft Rate Order, Union noted that its rate design evidence included proposals to eliminate the wholesale transportation service Rate 77, the contract unbundled service offerings (U5, U7, and U9) and the unbundled storage service offerings on the Rate 20 and Rate 100 rate schedules in Union North effective January 1, 2013. Union proposed to eliminate the above noted rate class and service offerings as there are no customers forecast to utilize these services in 2013. Union noted that no concerns were raised during the interrogatory and hearing processes. As such, Union noted that its Draft Rate Order includes the elimination of the above noted rate class and service offerings.[17]

Board staff supported Union's proposal to eliminate the above noted rate class and services offerings as there are no customers forecast to make use of these services in 2013. Board staff noted that the Board did not make findings on this issue in its October 25, 2012 Decision and Order. Board staff stated that the Board should make an explicit finding on this issue in its Decision on the Draft Rate Order.[18] No other parties commented on this issue.

Board Findings

The Board approves the closure of above noted rate class and service offerings as there are no customers forecast to utilize these services in 2013.

Rate Mitigation

CME submitted that the Draft Rate Order filed by Union is based on a premise that no rate mitigation is necessary. CME questioned whether this premise is appropriate when there are many customers in several rate classes that will be facing increases in their delivery charges that are well in excess of 10%.

CME stated it accepts that for non-contract customers, total bill impact should be the primary guide for determining whether mitigation measures should be adopted. However, for contract customers, the situation is different because many of them only pay Union for delivery services. CME noted that for many customers, their costs of gas supply are the subject matter of a separate bill. CME stated that, in prior cases, the Board has considered the magnitude of delivery-related charge increases only in

[17] Union Updated Draft Rate Order, January 10, 2013 at p. 2.
[18] Board Staff Comments on Draft Rate Order, December 31, 2012 at pp. 8-9.

determining whether large percentage rate increases and off-setting decreases should be phased-in as a mitigation measure. Phase-in periods of up to five (5) years have been adopted in prior cases. CME urged the Board to consider whether a phase-in of the increases and decreases in contract rates over a period of two or more years is needed for non-contract customers, having regard to the range of delivery charge impacts disclosed in the Draft Rate Order Working Papers.[19]

The Atlantic Power Corporation submitted that the Board should direct Union to consider appropriate rate mitigation measures or potentially reconsider rates for customers in light of the large rate increases. [20]

Board staff noted that there are no rate classes where the bill impact is greater than 10% on the total bill. As such, Board staff submitted that no rate mitigation is required.[21] No other parties commented on this issue.

In its reply comments on the Draft Rate Order, Union noted that in the October 18, 2012 Report of the Board titled Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach Board's at Section 2.4:

> Rate mitigation has been a policy of the Board since 2000. At that time, the Board established a requirement that distributors *consider* mitigation where total bill increases for any customer class exceed 10%. Since only consideration and not implementation of mitigation is required, this percentage is referred to as a "soft" threshold. The most recent articulation of the Board's mitigation policy confirmed the continuation of the "soft" 10% threshold for the filing of mitigation plans and provides guidance to distributors on preparing those plans. In its mitigation plan a distributor may propose any, or no, mitigation mechanism as may be suitable in a particular circumstance.

Union noted that, as filed at Working Papers Schedule 17, no rate class has a delivery bill impact that is greater than 10% of total bill. As such, Union stated that no rate mitigation is necessary.[22]

Board Findings

[19] CME Comments on Draft Rate Order, December 31, 2012 at p. 6.
[20] Atlantic Power Corporation Comments on Draft Rate Order, January 3, 2013 at p. 1.
[21] Board Staff Comments on Draft Rate Order, December 31, 2012 at pp. 9.
[22] Union Reply Comments on Draft Rate Order, January 8, 2013 at pp. 9-10.

The Board is of the view that the 10% threshold on the total bill is an appropriate threshold to apply for the consideration of rate mitigation measures. As the bill impact is less than 10% on the total bill for Union's rate classes, the Board finds that no rate mitigation is required.

Customer Notices

CME noted that the Board has stated that one of its priorities is to assure that utility customers are better informed about their energy bills. In this context, CME urged the Board to carefully review the customer notices that Union asks it to approve. CME noted that as the rate impacts in this case vary widely from customer to customer and are the outcome of this rebasing proceeding that follows five (5) years of rate setting under the auspices of an IRM, the customer notices need to contain sufficient information to enable each customer to understand why the rates are changing to the degree that they are, particularly in those cases where the rates for customers are increasing significantly.

CME submitted that the text of the draft Notices that Union has prepared for its contract customers does little, if anything, to help them understand the causes for the rate changes that the Board has approved. CME submitted that the text of the customer notices should be strengthened in order to convey that information to all contract customers and particularly those whose rates are increasing significantly.[23] No other parties commented on this issue.

In its reply comments on the Draft Rate Order, Union noted that its current rate notices, both for general service and contract customers, were developed with Board staff's communications group in 2008. Union stated that the customer notices were developed to create a standardized notice that customers would recognize as a communication tool informing them that rates are changing.

Union submitted that it will address the need for more detailed explanations with customers as follows:

- For general service customers, Union will provide a bill insert that will explain the changes in distribution rates for 2013. This insert will be included with the first customer invoice for 2013 rates.

[23] CME Comments on Draft Rate Order, December 31, 2013 at p. 7.

- For contract rate customers, Union is not aware of customer concerns related to its past communication of rate changes. Union has communicated the 2013 rate case proposals at customer meetings throughout 2012. In addition, consistent with past practices, Union will explain Board-approved changes in rates via email to each contract rate customer. The e-mail communications will be more detailed than the customer notices, and will provide an explanation of the major drivers of change and rate impacts. Also, consistent with past practices, in response to customer requests, Union Account Managers will meet with large contract customers on a one-to-one basis to discuss Union's 2013 rates Decision and specific rate impacts.

Union submitted that the customer notices are intended to inform customers that rates are changing and the text should not be altered. The customer notices are clear and do not confuse the customer. Union stated that its other initiatives including the bill insert, emails and face-to-face meetings address CME's concern about a customer's lack of understanding.[24]

Board Findings

The Board notes that the customer notices were developed in association with the Board's communications group. The Board believes that the customer notices, as proposed by Union, adequately inform customers that rates are changing. The Board is of the view that Union's other initiatives for informing customers, as discussed above, will address the concerns raised by CME. As such, the Board approves Union's proposed customer notices.

Rate Implementation

In its Draft Rate Order, Union proposed to implement new rates on February 1, 2013, and to dispose of any rate adjustments for the period January 1 to January 31, 2013 to rate classes 01, 10, M1 and M2 through a temporary charge or credit in rates between February 1, 2013 and December 31, 2013. Union noted that all other rate classes will be billed effective January 1, 2013 and therefore no rate adjustment is required.[25]

[24] Union Reply Comments on Draft Rate Order, January 8, 2013 at pp. 10-11.
[25] Union Updated Draft Rate Order, January 10, 2013 at pp. 1-2.

Board staff supported Union's rate implementation proposal. Board staff submitted that the temporary rate riders and disposition period are appropriate.[26] No other parties commented on this issue.

Board Findings

The Board finds that Union's rate implementation proposal is appropriate. As such, the Board approves Union's proposal for rate implementation.

THE BOARD ORDERS THAT:

1. The rate changes set out in Appendix "A" and the rate schedules set out in Appendix "B" are approved effective January 1, 2013. Union shall implement these rates on the first billing cycle on or after February 1, 2013. With the exception of customer-supplied fuel under Rate T1, T2, T3, M12, M13, M16, and C1, variances between the rates charged to customers during the period January 1, 2013 to January 31, 2013 and the rates approved herein shall form part of the adjustment to be recovered from each rate class at the time that new rates are implemented.

   For General Service customers served under Rates 01, 10, M1 and M2, Union shall dispose of the adjustment amount in each of these rate classes through a temporary volumetric rate rider charge/(credit) in rates from February 1, 2013 to December 31, 2013 as set out in the temporary price adjustments identified at Appendix "H".

2. In accordance with the EB-2011-0210 Settlement Agreement (item 1.4 at p.5), as approved by the Board, 2013 distribution-related rate base shall be reduced by $12.0 million.

3. The cost of gas in delivery rates shall be updated to reflect the Board-approved January 1, 2013 Ontario Landed Reference Price of $5.566/GJ ($21.0506 cents/m^3).

4. In accordance with the EB-2011-0210 Decision and Order a 50:50 blended approach of the 20-year declining trend and the 30-year average methodology shall be used to derive total Heating Degree Days estimates for 2013.

[26] Board Staff Comments on Draft Rate Order, December 31, 2012 at pp. 9-10.

5. In accordance with the Board's EB-2011-0210 Decision and Order 2013 customer attachments shall be increased by 800 customers to reflect the customers forecasted to attach in Red Lake.

6. In accordance with the Board's EB-2011-0210 Decision and Order the 2013 contract customer demand forecast shall be increased by $2.74 million as follows:
   - Commodity revenue - $1.0 million;
   - Fuel commodity revenue - $0.14 million;
   - Power overrun revenue - $0.5 million;
   - Non-power market overrun revenue - $1.1 million.

7. In accordance with the Board's EB-2011-0210 Decision and Order, 90% of the net revenue forecast related to short-term storage and balancing shall be reflected in 2013 rates. Union receives 10% of the margin earned from short-term storage and balancing services.

8. In accordance with the Board's EB-2011-0210 Decision and Order, the 2013 revenue forecast shall be increased to reflect FT-RAM activity. The 2013 forecast will be increased to reflect 90% of $5.8 million related to FT-RAM forecast, or $5.22 million.

9. In accordance with the EB-2011-0210 Settlement Agreement (item 1.6 at p.7), as approved by the Board, $0.300 million related to system integrity costs for Union's non-utility storage space shall be excluded from the calculation of short-term storage margin available for sharing with ratepayers.

10. In accordance with the EB-2011-0210 Settlement Agreement (item 2.4 at p.9), as approved by the Board, the 2013 S&T forecast shall be increased by $2.0 million for St. Clair revenue.

11. In accordance with the EB-2011-0210 Settlement Agreement (item 3.1 at p.9), as approved by the Board, the 2013 O&M budget shall been reduced by $9.550 million to $381.417 million.

12. In accordance with the EB-2011-0210 Settlement Agreement (item 3.10 at p.13), as approved by the Board, the forecast of 2013 property tax shall be reduced by $0.750 million to $63.272 million.

13. In accordance with the "Report of the Board on the Cost of Capital for Ontario Regulated Utilities," dated December 11, 2009 (EB-2009-0084), the return on equity for 2013 shall be calculated using September 2012 actual and forecast bond yields. The updated ROE for 2013 is 8.93%.

14. In accordance with the Board's EB-2011-0210 Decision and Order, the costs for system integrity space related to filled space shall be allocated on the basis of storage space requirements. Empty system integrity space reserved for hysteresis shall be allocated based on revised storage space excluding non-utility third party storage space and system integrity space reserved for the Hagar LNG facility and storage hysteresis.

15. In accordance with the Board's EB-2011-0210 Decision and Order, Tecumseh Metering Assets shall be classified to the demand classification and allocated to rate classes based on the design day demand of Dawn compression.

16. In accordance with the Board's EB-2011-0210 Decision and Order, Oil Spring East Assets shall be functionalized to both storage and transmission.

17. In accordance with the Board's EB-2011-0210 Decision and Order the transmission classification of Dawn Trafalgar Easterly Transmission for Oil Spring East metering shall be eliminated.

18. In accordance with the Board's EB-2011-0210 Decision and Order, Union shall include the costs associated with C1 Dawn to Dawn-TCPL, C1 Dawn to Dawn-Vector firm transportation service and the M12 firm all day (F24-T) transportation service in the 2013 revenue requirement. The supplemental service charge for F24-T customers shall be calculated based on the costs associated with the five incremental nomination windows and updated demands as set out in Exhibit J.G-9-13-1.

19. In accordance with the Board's EB-2011-0210 Decision and Order, North Distribution Customer Station Plant costs shall be allocated on the basis of the average number of customers, excluding Rate 01 and the Rate 10 customers that do not meet the hourly consumption threshold of 320 m^3/hour.

20. In accordance with the Board's EB-2011-0210 Decision and Order, Union North and

Union South distribution maintenance costs for meter and regulator repair shall be allocated in proportion to the distribution meter and regulator gross plant cost allocation, excluding the M1 and Rate 01 rate classes.

21. In accordance with the Board's EB-2011-0210 Decision and Order, Equipment on customer premises distribution maintenance costs shall continue to be allocated to Union South based on service call time and Union North based on a historical allocator.

22. In accordance with the Board's EB-2011-0210 Decision and Order, purchase production general plant costs shall be classified to both the Purchase Production System and Purchase Production Other classifications in proportion to the components of Purchase Production System and Other O&M. These costs shall be allocated to rate classes in proportion to the components of Purchase Production System and Other O&M.

23. In accordance with the Board's EB-2011-0210 Decision and Order, Dawn-Trafalgar Easterly Costs shall be allocated based on distance-based commodity-kilometres.

24. In accordance with the Board's EB-2011-0210 Decision and Order, storage assets shall be allocated to the regulated storage business using the updated storage allocation factors provided in Exhibits J8.3, J8.4 and J8.5.

25. In accordance with the Board's EB-2011-0210 Decision and Order, revenue from optimization activities shall not be included in the S&T margin forecast and shall be allocated to sales service and North bundled customers that pay the costs of facilitating Union's gas supply plan.

26. In accordance with the EB-2011-0210 Decision and Order, effective January 1, 2013 the current Rate T1 rate class shall be split into new Rate T1 and Rate T2 rate classes. The new T1 rate class will be the mid-market service for commercial/industrial customers consuming a minimum annual volume of 2,500,000 m^3 with a daily firm contracted demand that does not exceed 140,870 m^3. The new T2 rate class will be the large market service for commercial/industrial customers with a minimum daily firm contracted demand of 140,870 m^3.

27. In accordance with the EB-2011-0210 Decision and Order, effective January 1,

2013, Union shall eliminate the supplemental service charge for Commercial and Industrial customers under group meters in Union South to harmonize treatment with Union North.

28. In accordance with the EB-2011-0210 Decision and Order, effective January 1, 2014, Union shall implement an interruptible service offering for Rate M4 customers with an interruptible daily contracted demand of a least 2,400 m^3 and minimum annual interruptible volume of 350,000 m^3.

29. In accordance with the EB-2011-0210 Decision and Rate Order, Rate 77 will be eliminated effective January 1, 2013.

30. In accordance with the EB-2011-0210 Decision and Rate Order, the contract unbundled service Rates U5, U7 and U9 shall be eliminated effective January 1, 2013.

31. In accordance with the EB-2011-0210 Decision and Rate Order, the contract unbundled service offerings on the Rate 20 and Rate 100 rate schedules shall be eliminated effective January 1, 2013.

32. In accordance with the EB-2011-0210 Decision and Order, effective January 1, 2014, the eligibility criteria for M4 and M5A shall be lowered to a minimum daily contract demand of 2,400 m^3, maximum daily contracted demand of 60,000 m^3, and minimum annual volume requirement of 350,000 m^3.

33. In accordance with the EB-2011-0210 Decision and Order, effective January 1, 2014, the eligibility criteria for Rate M7 in Union South shall be lowered to a maximum daily contracted demand of 60,000 m^3 and the minimum annual volume requirement shall be eliminated as a condition of qualifying for Rate M7.

34. In accordance with the EB-2011-0210 Decision and Order, effective January 1, 2013, the Distribution Consolidated Billing fee shall be lowered to $0.57 per month per customer.

35. Union shall close the following deferral accounts effective January 1, 2013:

179-113	Late Payment Penalty Litigation
179-124	Harmonized Sale Tax

36. Union shall maintain the following deferral accounts in accordance with Appendix "G".

179-70	Short-term Storage and Other Balancing Services
179-75	Lost Revenue Adjustment Mechanism
179-100	Transportation Tolls and Fuel – Northern and Eastern Operations Area
179-103	Unbundled Services Unauthorized Storage Overrun
179-105	North Purchase Gas Variance Account
179-106	South Purchase Gas Variance Account
179-107	Spot Gas Variance Account
179-108	Unabsorbed Demand Cost (UDC) Variance Account
179-109	Inventory Revaluation Account
179-111	Demand Side Management Variance Account
179-112	Gas Distribution Access Rule ("GDAR") Costs
179-115	Shared Savings Mechanism
179-117	Carbon Dioxide Offset Credits
179-118	Average Use Per Customer
179-120	CGAAP to IFRS Conversion Cost
179-123	Conservation Demand Management
179-126	Demand Side Management Incentive
179-127	Pension Charge on Transition to USGAAP

37. In accordance with the EB-2011-0210 Decision and Order, Union shall establish the Gas Supply Optimization deferral account (No. 179-131) to record 90% of optimization margins not reflected in the revenue requirement.

In accordance with the EB-2011-0210 Decision and Rate Order, Union shall allocate the optimization-related margin in the manner set out by Union in its Draft Rate Order.

38. In accordance with the EB-2011-0210 Decision and Rate Order, Union shall allocate the Long-term and Short-term transportation-related S&T margin in the manner set out by Union in its Draft Rate Order.

39. In accordance with the EB-2011-0210 Decision and Rate Order, Union shall allocate the Storage and other balancing services-related S&T margin in in the manner set out by Union in its Draft Rate Order.

40. In accordance with the EB-2011-0210 Decision and Order, Union shall establish the Gas Supply Plan Review deferral account (No. 179-128) to record the cost of hiring a consultant to undertake a review of the gas supply plan, gas supply planning process and gas supply planning methodology.

41. In accordance with the EB-2011-0210 Decision and Order, Union shall establish the Preparation of Audited Utility Financial Statements deferral account (No. 179-129) to record the costs of the annual preparation of audited utility financial statements.

42. In accordance with the EB-2011-0210 Decision and Order, the accounting order for Short-Term Storage and Other Balancing Services (No. 179-70) shall be amended to reflect the Board's finding that the account will capture all short-term storage transactions and revenues generated by utility storage assets. This accounting order shall be further amended to capture storage encroachment.

43. In accordance with the EB-2011-0210 Decision and Order, the accounting order for the Inventory Revaluation deferral account (No. 179-109) shall be amended to remove the transmission line pack gas from the deferral account.

44. In accordance with the EB-2011-0210 Decision and Order, the accounting order for the Average Use Per Customer deferral account (No. 179-118) shall be amended to reflect its continuation and use for 2013.

45. The rates pursuant to all contracts for interruptible service under Rates M5A, M7, T1, T2 and 25 shall be adjusted effective January 1, 2013 by the amounts set out in Appendix "C". Union shall implement 2013 changes in rates on the first billing cycle after February 1, 2013.

46. The customer notices in Appendix “D” shall be given to all customers with the first bill or invoice reflecting the new rate.

47. Union shall charge the fees as set out in Appendix “E” for non-energy charges.

48. Union shall comply with the Board directives set out in Appendix "F".

49. Union shall pay the balance of the intervenors' costs as authorized in the Board's EB-2011-0210 Decision and Order, forthwith upon receipt of the Board's Cost

Orders.

50. Union shall pay the Board's costs of, and incidental to, this proceeding immediately upon receipt of the Board's invoice.

DATED at Toronto, January 17, 2013

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Appendix A

Decision and Rate Order

Summary of Changes to Sales Rates

Board File No. EB-2011-0210

Dated: January 17, 2013

UNION GAS LIMITED
Northern & Eastern Operations Area
Summary of Changes to Sales Rates
Rate 01A - Small Volume General Firm Service

Line No.	Particulars (cents/m^3)	EB-2012-0437 Approved January 1, 2013 Rate (a)		Rate Change (b)	EB-2011-0210 Approved January 1, 2013 Rate (c)	
1	Monthly Charge - All Zones	$21.00			$21.00	
	Monthly Delivery Charge - All Zones					
2	First 100 m^3	7.5664		2.1682	9.7347	(8)
3	Next 200 m^3	7.0559		2.1542	9.2102	(8)
4	Next 200 m^3	6.6932		2.1442	8.8375	(8)
5	Next 500 m^3	6.3604		2.1350	8.4955	(8)
6	Over 1,000 m^3	6.0855		2.1274	8.2130	(8)
7	Delivery - Price Adjustment (All Volumes)	(0.0578)	(1)	0.5088	0.4510	(2)
	Gas Transportation Service					
8	Fort Frances	5.8897		(0.9510)	4.9387	
9	Western Zone	6.2981		(0.7580)	5.5401	
10	Northern Zone	7.6495		(0.0220)	7.6275	
11	Eastern Zone	8.7597		(0.2444)	8.5153	
12	Transportation - Price Adjustment (All Zones)	1.1131	(3)	(0.0608)	1.0523	(4)
	Storage Service					
13	Fort Frances	1.8724		0.2783	2.1507	
14	Western Zone	1.8700		0.5210	2.3910	
15	Northern Zone	2.2540		0.9712	3.2252	
16	Eastern Zone	2.5640		1.0159	3.5799	
17	Storage - Price Adjustment (All Zones)	-		0.2109	0.2109	(5)
	Commodity Cost of Gas and Fuel					
18	Fort Frances	12.7016		(0.1205)	12.5811	
19	Western Zone	12.7558		(0.1205)	12.6353	
20	Northern Zone	12.8230		(0.1205)	12.7025	
21	Eastern Zone	12.8825		(0.1205)	12.7620	
22	Commodity and Fuel - Price Adjustment (All Zones)	(2.1736)	(6)	(0.0286)	(2.2022)	(7)

Notes:
(1) Includes a temporary credit of (0.0578) cents/m^3 for the period October 1, 2012 to March 31, 2013.
(2) Includes a temporary credit of (0.0578) cents/m^3 for the period October 1, 2012 to March 31, 2013 and a temporary charge of 0.5088 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(3) Includes Prospective Recovery of 0.1719, 0.2735, 0.4323 and 0.2354 cents/m^3.
(4) Includes Prospective Recovery of 0.1719, 0.2735, 0.4323 and 0.2354 cents/m^3, and a temporary credit of (0.0608) cents/m^3 for the period February 1, 2013 to December 31, 2013.
(5) Includes a temporary charge of 0.2109 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(6) Includes Prospective Recovery of (0.7743), (0.6697), (0.8603) and 0.1307 cents/m^3.
(7) Includes Prospective Recovery of (0.7743), (0.6697), (0.8603) and 0.1307 cents/m^3, and a temporary credit of (0.0286) cents/m^3 for the period February 1, 2013 to December 31, 2013.
(8) EB-2011-0210, Rate Order, Working Papers, Schedule 24, Page 2, column (c).

UNION GAS LIMITED
Northern & Eastern Operations Area
Summary of Changes to Sales Rates
Rate 10 - Large Volume General Firm Service

Line No.	Particulars (cents/m^3)	EB-2012-0437 Approved January 1, 2013 Rate		Rate Change	EB-2011-0210 Approved January 1, 2013 Rate	
		(a)		(b)	(c)	
1	Monthly Charge - All Zones	$70.00			$70.00	
	Monthly Delivery Charge - All Zones					
2	First 1,000 m^3	6.0731		1.6339	7.7070	(8)
3	Next 9,000 m^3	4.8064		1.4870	6.2934	(8)
4	Next 20,000 m^3	4.0839		1.4033	5.4872	(8)
5	Next 70,000 m^3	3.6215		1.3496	4.9711	(8)
6	Over 100,000 m^3	1.8694		1.1465	3.0159	(8)
7	Delivery - Price Adjustment (All Volumes)	(0.0540)	(1)	0.2623	0.2083	(2)
	Gas Transportation Service					
8	Fort Frances	5.4555		(1.1385)	4.3170	
9	Western Zone	5.8639		(0.9455)	4.9184	
10	Northern Zone	7.2153		(0.2095)	7.0058	
11	Eastern Zone	8.3255		(0.4320)	7.8935	
12	Transportation - Price Adjustment (All Zones)	1.1127	(3)	(0.0786)	1.0341	(4)
	Storage Service					
13	Fort Frances	1.1964		0.0051	1.2015	
14	Western Zone	1.1941		0.2477	1.4418	
15	Northern Zone	1.5796		0.6964	2.2760	
16	Eastern Zone	1.8907		0.7400	2.6307	
17	Storage - Price Adjustment (All Zones)	-		0.1201	0.1201	(5)
	Commodity Cost of Gas and Fuel					
18	Fort Frances	12.7016		(0.1205)	12.5811	
19	Western Zone	12.7558		(0.1205)	12.6353	
20	Northern Zone	12.8230		(0.1205)	12.7025	
21	Eastern Zone	12.8825		(0.1205)	12.7620	
22	Commodity and Fuel - Price Adjustment (All Zones)	(2.1736)	(6)	(0.0225)	(2.1961)	(7)

Notes:
(1) Includes a temporary credit of (0.0540) cents/m^3 for the period October 1, 2012 to March 31, 2013.
(2) Includes a temporary credit of (0.0540) cents/m^3 for the period October 1, 2012 to March 31, 2013 and a temporary charge of 0.2623 cents/m3 for the period February 1, 2013 to December 31, 2013.
(3) Includes Prospective Recovery of 0.1718, 0.2734, 0.4322 and 0.2353 cents/m^3.
(4) Includes Prospective Recovery of 0.1718, 0.2734, 0.4322 and 0.2353 cents/m^3, and a temporary credit of (0.0786) cents/m^3 for the period February 1, 2013 to December 31, 2013.
(5) Includes a temporary charge of 0.1201 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(6) Includes Prospective Recovery of (0.7743), (0.6697), (0.8603) and 0.1307 cents/m^3.
(7) Includes Prospective Recovery of (0.7743), (0.6697), (0.8603) and 0.1307 cents/m^3, and a temporary credit of (0.0225) cents/m^3 for the period February 1, 2013 to December 31, 2013.
(8) EB-2011-0210, Rate Order, Working Papers, Schedule 24, Page 2, column (c).

UNION GAS LIMITED
Northern & Eastern Operations Area
Summary of Changes to Sales Rates
Rate 20 - Medium Volume Firm Service

Line No.	Particulars (cents/m^3)	EB-2012-0437 Approved January 1, 2013 Rate (a)	Rate Change (b)	EB-2011-0210 Approved January 1, 2013 Rate (c)
1	Monthly Charge	$777.19	$222.81	$1,000.00
	Delivery Demand Charge			
2	First 70,000 m^3	20.0760	7.7419	27.8179
3	All over 70,000 m^3	11.8057	4.5526	16.3583
	Delivery Commodity Charge			
4	First 852,000 m^3	0.2643	0.2732	0.5375 (3)
5	All over 852,000 m^3	0.1917	0.2014	0.3932 (3)
	Monthly Gas Supply Demand Charge			
6	Fort Frances	49.3344	(27.5832)	21.7512
7	Western Zone	57.0166	(21.9699)	35.0467
8	Northern Zone	86.6848	(0.9913)	85.6936
9	Eastern Zone	110.8603	(4.7904)	106.0700
10	Gas Supply Demand - Price Adjustment (All Zones)	-		-
	Commodity Transportation 1			
11	Fort Frances	4.2612	(0.8688)	3.3924
12	Western Zone	4.4236	(0.6945)	3.7291
13	Northern Zone	5.1192	(0.2215)	4.8977
14	Eastern Zone	5.6884	(0.2937)	5.3947
15	Transportation 1 - Price Adjustment (All Zones)	1.1138 (1)		1.1138 (1)
	Commodity Transportation 2			
16	Fort Frances	0.2893	(0.1358)	0.1535
17	Western Zone	0.2668	0.0005	0.2673
18	Northern Zone	0.4111	0.0027	0.4138
19	Eastern Zone	0.5383	0.0010	0.5393
	Commodity Cost of Gas and Fuel			
20	Fort Frances	12.7245	(0.1205)	12.6040
21	Western Zone	12.7788	(0.1205)	12.6583
22	Northern Zone	12.8461	(0.1205)	12.7256
23	Eastern Zone	12.9058	(0.1205)	12.7853
24	Commodity and Fuel - Price Adjustment (All Zones)	(2.1736) (2)		(2.1736) (2)
	Bundled Storage Service ($/GJ)			
25	Monthly Demand Charge	11.097	(1.454)	9.643
26	Commodity Charge	0.239	(0.083)	0.156
27	Storage Demand - Price Adjustment	-		-

Notes:
(1) Includes Prospective Recovery of 0.1721, 0.2736, 0.4325 and 0.2356 cents/m^3.
(2) Includes Prospective Recovery of (0.7743), (0.6697), (0.8603) and 0.1307 cents/m^3.
(3) EB-2011-0210, Rate Order, Working Papers, Schedule 24, Page 2, column (c).

UNION GAS LIMITED
Northern & Eastern Operations Area
Summary of Changes to Sales Rates
Rate 100 - Large Volume High Load Factor Firm Service

Line No.	Particulars (cents/m^3)	EB-2012-0437 Approved January 1, 2013 Rate (a)	Rate Change (b)	EB-2011-0210 Approved January 1, 2013 Rate (c)
1	Monthly Charge	$777.19	$722.81	$1,500.00
	Delivery Demand Charge			
2	All Zones	11.9158	3.4257	15.3415
	Delivery Commodity Charge			
3	All Zones	0.1657	0.0480	0.2137 (2)
	Monthly Gas Supply Demand Charge			
4	Fort Frances	88.0846	(26.9946)	61.0900
5	Western Zone	97.0663	(20.4649)	76.6014
6	Northern Zone	131.6881	4.0014	135.6895
7	Eastern Zone	159.8951	(0.4332)	159.4619
	Commodity Transportation 1			
8	Fort Frances	7.8681	(0.8527)	7.0154
9	Western Zone	7.9899	(0.7220)	7.2679
10	Northern Zone	8.5116	(0.3672)	8.1444
11	Eastern Zone	8.9385	(0.4214)	8.5171
	Commodity Transportation 2			
12	Fort Frances	0.2893	(0.1358)	0.1535
13	Western Zone	0.2668	0.0005	0.2673
14	Northern Zone	0.4111	0.0026	0.4138
15	Eastern Zone	0.5383	0.0010	0.5393
	Commodity Cost of Gas and Fuel			
16	Fort Frances	12.7245	(0.1205)	12.6040
17	Western Zone	12.7788	(0.1205)	12.6583
18	Northern Zone	12.8461	(0.1205)	12.7256
19	Eastern Zone	12.9058	(0.1205)	12.7853
20	Commodity and Fuel - Price Adjustment (All Zones)	(2.1736) (1)		(2.1736) (1)
	Bundled Storage Service ($/GJ)			
21	Monthly Demand Charge	11.097	(1.454)	9.643
22	Commodity Charge	0.239	(0.083)	0.156
23	Storage Demand - Price Adjustment	-		-

Notes:
(1) Includes Prospective Recovery of (0.7743), (0.6697), (0.8603) and 0.1307 cents/m^3.
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 24, Page 2, column (c).

UNION GAS LIMITED
Northern & Eastern Operations Area
Summary of Changes to Sales Rates

Line No.	Particulars (cents/m^3)	EB-2012-0437 Approved January 1, 2013 Rate	Rate Change	EB-2011-0210 Approved January 1, 2013 Rate
		(a)	(b)	(c)
	Rate 25 - Large Volume Interruptible Service			
1	Monthly Charge	$189.32	$185.68	$375.00
	Delivery Charge - All Zones *			
2	Maximum	3.7419	1.3463	5.0882
	Gas Supply Charges - All Zones			
3	Minimum	14.3135		14.3135
4	Maximum	140.5622		140.5622

* see Appendix C.

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Sales Rates

Line No.	Particulars (cents/m^3)	EB-2012-0437 Approved January 1, 2013 Rate (a)	Rate Change (b)	EB-2011-0210 Approved January 1, 2013 Rate (c)
	Utility Sales			
1	Commodity and Fuel	12.8825	(0.1205)	12.7620
2	Commodity and Fuel - Price Adjustment	(2.0978) (1)	(0.0853)	(2.1831) (2)
3	Transportation	4.6821	(0.2824)	4.3997
4	Total Gas Supply Commodity Charge	15.4668	(0.4882)	14.9786
	M4 Firm Commercial/Industrial			
5	Minimum annual gas supply commodity charge	5.2504	(0.4029)	4.8475
	M5A Interruptible Commercial/Industrial			
6	Minimum annual gas supply commodity charge	5.2504	(0.4029)	4.8475
	Storage and Transportation Supplemental Services - Rate T1, Rate T2 & Rate T3	$/GJ		$/GJ
	Monthly demand charges: ($/GJ)			
7	Firm gas supply service	63.207	0.118	63.325
8	Firm backstop gas	1.939	(0.093)	1.846
	Commodity charges:			
9	Gas supply	3.466		3.466
10	Backstop gas	5.015	(0.058)	4.957
11	Reasonable Efforts Backstop Gas	5.842	(0.110)	5.732
12	Supplemental Inventory	Note (3)		Note (3)
13	Supplemental Gas Sales Service (cents/m^3)	20.4642	(0.2669)	20.1973
14	Failure to Deliver	2.565	(0.0040)	2.561
15	Discretionary Gas Supply Service (DGSS)	Note (4)		Note (4)

Notes:
(1) Includes Prospective Recovery of (0.6712), (0.4624), (0.1104) and (0.8538) cents/m^3.
(2) Includes Prospective Recovery of (0.6712), (0.4624), (0.1104) and (0.8538) cents/m^3, and a temporary credit of (0.0853) cents/m^3 for the period February 1, 2013 to December 31, 2013.
(3) The charge for banked gas purchases shall be the higher of the daily spot gas cost at Dawn in the month of or the month following the month in which gas is sold under this rate and shall not be less than Union's approved weighted average cost of gas.
(4) Reflects the "back to back" price plus gas supply administration charge.

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Sales Rates

Line No.	Particulars (cents/m^3)	EB-2012-0437 Approved January 1, 2013 Rate	Rate Change	EB-2011-0210 Approved January 1, 2013 Rate
		(a)	(b)	(c)
	Rate M1 - Small Volume General Service Rate			
1	Monthly Charge	$21.00		$21.00
2	First 100 m^3	3.5562	0.2234	3.7795 (8)
3	Next 150 m^3	3.3617	0.2114	3.5730 (8)
4	All over 250 m^3	2.9017	0.1829	3.0845 (8)
5	Delivery - Price Adjustment (All Volumes)	(0.0483) (1)	0.0429	(0.0054) (2)
6	Storage Service	0.9735	(0.2367)	0.7368
7	Storage - Price Adjustment	-	(0.0513)	(0.0513) (3)
	Rate M2 - Large Volume General Service Rate			
8	Monthly Charge	$70.00		$70.00
9	First 1,000 m^3	3.7639	0.3778	4.1416 (8)
10	Next 6,000 m^3	3.6850	0.3804	4.0653 (8)
11	Next 13,000 m^3	3.4499	0.3881	3.8379 (8)
12	All over 20,000 m^3	3.1678	0.3973	3.5650 (8)
13	Delivery - Price Adjustment (All Volumes)	(0.0471) (4)	0.0826	0.0355 (5)
14	Storage Service	0.7172	0.0378	0.7550
15	Storage - Price Adjustment	-	0.0080	0.0080 (6)
	Rate M4 - Firm comm/ind contract rate			
	Monthly demand charge:			
16	First 8,450 m^3	45.2527	1.3712	46.6239
17	Next 19,700 m^3	19.6336	1.2714	20.9050
18	All over 28,150 m^3	16.3047	1.2584	17.5631
	Monthly delivery commodity charge:			
19	First block	0.5868	0.3753	0.9621 (8)
20	All remaining use	0.2477	0.1766	0.4243 (8)
21	Delivery - Price Adjustment (All Volumes)	0.0002 (7)		0.0002 (7)
22	Minimum annual delivery commodity charge	0.9006	0.2548	1.1554

Notes:
(1) Includes Prospective Recovery of 0.0000, 0.0000, 0.0001, 0.0001 and a temporary credit of (0.0485) cents/m^3 for the period October 1, 2012 to March 31, 2013.
(2) Includes Prospective Recovery of 0.0000, 0.0000, 0.0001, 0.0001, a temporary credit of (0.0485) cents/m^3 for the period October 1, 2012 to March 31, 2013 and a temporary charge of 0.0429 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(3) Includes a temporary credit of (0.0513) cents/m^3 for the period February 1, 2013 to December 31, 2013.
(4) Includes Prospective Recovery of 0.0000, 0.0000, 0.0001, 0.0001 and a temporary credit of (0.0473) cents/m^3 for the period October 1, 2012 to March 31, 2013.
(5) Includes Prospective Recovery of 0.0000, 0.0000, 0.0001, 0.0001 and a temporary credit of (0.0473) cents/m^3 for the period October 1, 2012 to March 31, 2013 and a temporary charge of 0.0826 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(6) Includes a temporary charge of 0.0080 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(7) Includes Prospective Recovery of 0.0000, 0.0000, 0.0001 and 0.0001 cents/m^3.
(8) EB-2011-0210, Rate Order, Working Papers, Schedule 24, Page 2, column (c).

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Sales Rates

Line No.	Particulars (cents/m^3)	EB-2012-0437 Approved January 1, 2013 Rate (a)		Rate Change (b)	EB-2011-0210 Approved January 1, 2013 Rate (c)	
	Rate M5A - interruptible comm/ind contract					
	Firm contracts *					
1	Monthly demand charge	27.4318		1.1934	28.6252	
2	Monthly delivery commodity charge	2.1615		(0.2238)	1.9377	(2)
3	Delivery - Price Adjustment (All Volumes)	0.0002	(1)		0.0002	(1)
	Interruptible contracts *					
4	Monthly Charge	$498.20		$191.80	$690.00	
	Daily delivery commodity charge:					
5	4,800 m^3 to 17,000 m^3	2.1964		0.7748	2.9712	(2)
6	17,000 m^3 to 30,000 m^3	2.0665		0.7748	2.8413	(2)
7	30,000 m^3 to 50,000 m^3	1.9982		0.7748	2.7730	(2)
8	50,000 m^3 to 70,000 m^3	1.9503		0.7748	2.7251	(2)
9	70,000 m^3 to 100,000 m^3	1.9160		0.7748	2.6908	(2)
10	100,000 m^3 to 140,870 m^3	1.8823		0.7748	2.6571	(2)
11	Delivery - Price Adjustment (All Volumes)	0.0002	(1)		0.0002	(1)
12	Annual minimum delivery commodity charge	2.5102		0.6543	3.1645	
	Rate M7 - Special large volume contract					
	Firm					
13	Monthly demand charge	25.1902		0.2022	25.3924	
14	Monthly delivery commodity charge	0.1005		0.2201	0.3206	(2)
15	Delivery - Price Adjustment	0.0002	(1)		0.0002	(1)
	Interruptible *					
	Monthly delivery commodity charge:					
16	Maximum	2.4667		1.4788	3.9455	
17	Delivery - Price Adjustment	0.0002	(1)		0.0002	(1)
	Seasonal *					
	Monthly delivery commodity charge:					
18	Maximum	2.2226		1.4788	3.7014	
19	Delivery - Price Adjustment	0.0002	(1)		0.0002	(1)
	Rate M9 - Large wholesale service					
20	Monthly demand charge	16.8055		(1.6367)	15.1688	
21	Monthly delivery commodity charge	0.2539		(0.0549)	0.1990	(2)
22	Delivery - Price Adjustment	0.0002	(1)		0.0002	(1)
	Rate M10 - Small wholesale service					
23	Monthly delivery commodity charge	2.5190		2.6544	5.1734	(2)

Notes:
(1) Includes Prospective Recovery of 0.0000, 0.0000, 0.0001 and 0.0001 cents/m^3.
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 24, Page 2, column (c).

* Price changes to individual interruptible and seasonal contract rates are provided in Appendix C.

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Contract Carriage Rates

Line No.	Particulars	EB-2012-0437 Approved January 1, 2013 Rate (a)	Rate Change (b)	EB-2011-0210 Approved January 1, 2013 Rate (c)
	Contract Carriage Service			
	T1 Storage and Transportation			
	Storage ($ / GJ)			
	Monthly demand charges:			
1	Firm space	0.010		-
	Firm Injection/Withdrawal Right			
2	Union provides deliverability inventory	1.544		-
3	Customer provides deliverability inventory	1.012		-
4	Firm incremental injection	1.012		-
5	Interruptible withdrawal	1.012		-
	Commodity charges:			
6	Withdrawal	0.040		-
7	Customer provides compressor fuel	0.007		-
8	Injection	0.040		-
9	Customer provides compressor fuel	0.007		-
10	Storage fuel ratio - customer provides fuel	0.597%		-
	Transportation (cents / m^3)			
11	Monthly demand charge first 140,870 m^3	19.0307		-
12	Monthly demand charge all over 140,870 m^3	13.0041		-
	Firm commodity charges:			
13	Union provides compressor fuel first 2,360,653 m^3	0.3430		-
14	Union provides compressor fuel all over 2,360,653 m^3	0.2293		-
15	Customer provides compressor fuel first 2,360,653 m^3	0.2264		-
16	Customer provides compressor fuel all over 2,360,653 m^3	0.1127		-
	Interruptible commodity charges: *			
17	Maximum - Union provides compressor fuel	2.4667		-
18	Maximum - customer provides compressor fuel	2.3501		-
19	Transportation fuel ratio - customer provides fuel	0.554%		-
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges			
20	Injection / Withdrawals	0.115		-
21	Customer provides compressor fuel	0.058		-
22	Transportation commodity charge (cents/m^3)	0.9687		-
23	Customer provides compressor fuel	0.8521		-
24	Monthly Charge	$1,793.52		-

* Price changes to individual interruptible contract rates are provided in Appendix C.

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Contract Carriage Rates

Line No.	Particulars	EB-2012-0437 Approved January 1, 2013 Rate (a)	Rate Change (b)	EB-2011-0210 Approved January 1, 2013 Rate (c)
	Contract Carriage Service			
	Rate T1 - Storage and Transportation			
	Storage ($ / GJ)			
	Monthly demand charges:			
1	Firm space	0.010	0.001	0.011
	Firm Injection/Withdrawal Right			
2	Union provides deliverability inventory	1.544	0.081	1.624
3	Customer provides deliverability inventory	1.012	0.185	1.197
4	Firm incremental injection	1.012	0.185	1.197
5	Interruptible withdrawal	1.012	0.185	1.197
	Commodity charges:			
6	Withdrawal	0.040	(0.011)	0.030
7	Customer provides compressor fuel	0.007	0.001	0.008
8	Injection	0.040	(0.011)	0.030
9	Customer provides compressor fuel	0.007	0.001	0.008
10	Storage fuel ratio - customer provides fuel	0.597%	-0.202%	0.395%
	Transportation (cents / m^3)			
11	Monthly demand charge first 28,150 m^3	-		31.9554
12	Monthly demand charge next 112,720 m^3	-		22.0775
	Firm commodity charges:			
13	Union provides compressor fuel - All volumes	-		0.1238
15	Customer provides compressor fuel - All volumes	-		0.0712
16				
	Interruptible commodity charges: *			
17	Maximum - Union provides compressor fuel	-		3.9455
18	Maximum - customer provides compressor fuel	-		3.8929
19	Transportation fuel ratio - customer provides fuel	-		0.250%
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges			
20	Injection / Withdrawals	-		0.108
21	Customer provides compressor fuel	-		0.061
22	Transportation commodity charge (cents/m^3)	-		1.1743
23	Customer provides compressor fuel	-		1.1218
24	Monthly Charge	-		$ 1,936.13

* Price changes to individual interruptible contract rates are provided in Appendix C.

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Contract Carriage Rates

Line No.	Particulars	EB-2012-0437 Approved January 1, 2013 Rate (a)	Rate Change (b)	EB-2011-0210 Approved January 1, 2013 Rate (c)
	Contract Carriage Service			
	Rate T2 - Storage and Transportation			
	Storage ($ / GJ)			
	Monthly demand charges:			
1	Firm space	0.010	0.001	0.011
	Firm Injection/Withdrawal Right			
2	Union provides deliverability inventory	1.544	0.081	1.624
3	Customer provides deliverability inventory	1.012	0.185	1.197
4	Firm incremental injection	1.012	0.185	1.197
5	Interruptible withdrawal	1.012	0.185	1.197
	Commodity charges:			
6	Withdrawal	0.040	(0.011)	0.030
7	Customer provides compressor fuel	0.007	0.001	0.008
8	Injection	0.040	(0.011)	0.030
9	Customer provides compressor fuel	0.007	0.001	0.008
10	Storage fuel ratio - customer provides fuel	0.597%	-0.202%	0.395%
	Transportation (cents / m^3)			
11	Monthly demand charge first 140,870 m^3	-		20.1911
12	Monthly demand charge all over 140,870 m^3	-		10.6802
	Firm commodity charges:			
13	Union provides compressor fuel - All volumes	-		0.0597
15	Customer provides compressor fuel - All volumes	-		0.0078
16				
	Interruptible commodity charges: *			
17	Maximum - Union provides compressor fuel	-		3.9455
18	Maximum - customer provides compressor fuel	-		3.8936
19	Transportation fuel ratio - customer provides fuel	-		0.247%
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges			
20	Injection / Withdrawals	-		0.108
21	Customer provides compressor fuel	-		0.061
22	Transportation commodity charge (cents/m^3)	-		0.7235
23	Customer provides compressor fuel	-		0.6716
24	Monthly Charge	-		$ 6,000.00

* Price changes to individual interruptible contract rates are provided in Appendix C.

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Contract Carriage Rates

Line No.	Particulars	EB-2012-0437 Approved January 1, 2013 Rate	Rate Change	EB-2011-0210 Approved January 1, 2013 Rate
		(a)	(b)	(c)
	Rate T3 - Storage and Transportation			
	Storage ($ / GJ)			
	Monthly demand charges:			
1	Firm space	0.010	0.001	0.011
	Firm Injection/Withdrawal Right			
2	Union provides deliverability inventory	1.544	0.081	1.624
3	Customer provides deliverability inventory	1.012	0.185	1.197
4	Firm incremental injection	1.012	0.185	1.197
5	Interruptible withdrawal	1.012	0.185	1.197
	Commodity charges:			
6	Withdrawal	0.040	(0.011)	0.030
7	Customer provides compressor fuel	0.007	0.001	0.008
8	Injection	0.040	(0.011)	0.030
9	Customer provides compressor fuel	0.007	0.001	0.008
10	Storage fuel ratio- Cust. provides fuel	0.597%	-0.202%	0.395%
	Transportation (cents / m^3)			
11	Monthly demand charge	8.9901	0.3681	9.3582
	Firm commodity charges			
12	Union supplies compressor fuel	0.2201	(0.1494)	0.0707
13	Customer provides compressor fuel	0.0681	(0.0574)	0.0107
14	Transportation fuel ratio- Cust. provides fuel	0.722%	-0.437%	0.285%
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges:			
15	Injection / Withdrawals	0.115	(0.007)	0.108
16	Customer provides compressor fuel	0.058	0.003	0.061
17	Transportation commodity charge (cents/m^3)	0.5156	(0.1373)	0.3783
18	Customer provides compressor fuel (cents/m^3)	0.3637	(0.0453)	0.3184
	Monthly Charge			
19	City of Kitchener	$17,549.76	$2,821.59	$20,371.35
20	Natural Resource Gas	$2,694.07	$433.14	$3,127.21
21	Six Nations	$898.02	$144.38	$1,042.40

UNION GAS LIMITED
Southern Operations Area
Summary of Changes to Unbundled Rates

Line No.	Particulars	EB-2012-0437 Approved January 1, 2013 Rate	Rate Change	EB-2011-0210 Approved January 1, 2013 Rate
		(a)	(b)	(c)
	U2 Unbundled Service			
	Storage ($ / GJ)			
	Monthly demand charges:			
	Standard Storage Service (SSS)			
1	Combined Firm Space & Deliverability	0.021	0.003	0.024
	Standard Peaking Service (SPS)			
2	Combined Firm Space & Deliverability	0.102	0.015	0.116
3	Incremental firm injection right	0.917	0.124	1.041
4	Incremental firm withdrawal right	0.917	0.124	1.041
	Commodity charges:			
5	Injection customer provides compressor fuel	0.015	0.011	0.026
6	Withdrawal customer provides compressor fuel	0.015	0.011	0.026
7	Storage fuel ratio - Customer provides fuel	0.597%	-0.202%	0.395%
	Authorized overrun services			
	Storage ($ / GJ)			
	Commodity charges:			
8	Injection customer provides compressor fuel	0.045	0.015	0.060
9	Withdrawal customer provides compressor fuel	0.045	0.015	0.060

UNION GAS LIMITED
Summary of Changes to Transportation Rates

Line No.	Particulars ($/GJ)	EB-2012-0437 Approved January 1, 2013 Rate		Rate Change	EB-2011-0210 Approved January 1, 2013 Rate	
		(a)		(b)	(c)	
	M12 Transportation Service					
	Firm Transportation					
	Monthly demand charges:					
1	Dawn to Kirkwall	1.978		0.033	2.011	
2	Dawn to Parkway	2.323		0.059	2.382	
3	Kirkwall to Parkway	0.345		0.027	0.372	
4	F24-T	0.689		(0.622)	0.068	
	M12-X Firm Transportation					
5	Between Dawn, Kirkwall and Parkway	2.868		0.093	2.961	
	Commodity charges:					
6	Easterly	Note (1)			Note (1)	
7	Westerly	Note (1)			Note (1)	
8	Parkway (TCPL) to Parkway (Cons)	Note (1)			Note (1)	
	Limited Firm/Interruptible					
	Monthly demand charges:					
9	Maximum	5.576		0.142	5.718	
	Commodity charges :					
10	Others	Note (1)			Note (1)	
	Authorized Overrun					
	Transportation commodity charges:					
	Easterly:					
11	Dawn to Kirkwall - Union supplied fuel	Note (1)			Note (1)	
12	Dawn to Parkway - Union supplied fuel	Note (1)			Note (1)	
13	Dawn to Kirkwall - Shipper supplied fuel	0.065	(1)	0.001	0.066	(1)
14	Dawn to Parkway - Shipper supplied fuel	0.076	(1)	0.002	0.078	(1)
15	Kirkwall to Parkway - Union supplied fuel	Note (1)			Note (1)	
16	Kirkwall to Parkway - Shipper supplied fuel	0.011	(1)	0.001	0.012	
17	Westerly - Union supplied fuel	Note (1)			Note (1)	
18	Westerly - Shipper supplied fuel	0.076	(1)	0.002	0.078	(1)
	M12-X Firm Transportation					
19	Between Dawn, Kirkwall and Parkway - Union supplied fuel	Note (1)			Note (1)	
20	Between Dawn, Kirkwall and Parkway - Shipper supplied fuel	0.094	(1)	0.003	0.097	
	M13 Transportation of Locally Produced Gas					
21	Monthly fixed charge per customer station	$655.83		270.769	$926.60	
22	Transmission commodity charge to Dawn	0.025		0.009	0.034	
23	Commodity charge - Union supplies fuel	0.021		(0.012)	0.009	(2)
24	Commodity charge - Shipper supplies fuel	Note (3)			Note (2)	
25	Authorized Overrun - Union supplies fuel	0.078		(0.001)	0.077	(2)
26	Authorized Overrun - Shipper supplies fuel	0.057	(3)	0.012	0.069	(3)

Notes:
(1) Monthly fuel rates and ratios per Schedule "C".
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 24, page 3, column (c).
(2) Plus customer supplied fuel per rate schedule.

UNION GAS LIMITED
Summary of Changes to Transportation Rates

Line No.	Particulars ($/GJ)	EB-2012-0437 Approved January 1, 2013 Rate (a)	Rate Change (b)	EB-2011-0210 Approved January 1, 2013 Rate (c)
	M16 Storage Transportation Service			
1	Monthly fixed charge per customer station	$664.27	$809.85	$1,474.12
	Monthly demand charges:			
2	East of Dawn	0.725	0.016	0.741
3	West of Dawn	0.967	0.092	1.059
4	Transmission commodity charge to Dawn	0.025	0.009	0.034
	Transportation Fuel Charges to Dawn:			
5	East of Dawn - Union supplied fuel	0.021	(0.012)	0.009 (1)
6	West of Dawn - Union supplied fuel	0.021	(0.012)	0.009 (1)
7	East of Dawn - Shipper supplied fuel	Note (2)		Note (2)
8	West of Dawn - Shipper supplied fuel	Note (2)		Note (2)
	Transportation Fuel Charges to Pools:			
9	East of Dawn - Union supplied fuel	0.024	(0.015)	0.009 (1)
10	West of Dawn - Union supplied fuel	0.027	(0.003)	0.024 (1)
11	East of Dawn - Shipper supplied fuel	Note (2)		Note (2)
12	West of Dawn - Shipper supplied fuel	Note (2)		Note (2)
	Authorized Overrun			
	Transportation Fuel Charges to Dawn:			
13	East of Dawn - Union supplied fuel	0.070	(0.003)	0.067 (1)
14	West of Dawn - Union supplied fuel	0.078	(0.001)	0.077 (1)
15	East of Dawn - Shipper supplied fuel	0.049 (2)	0.009	0.058 (2)
16	West of Dawn - Shipper supplied fuel	0.057 (2)	0.012	0.069 (2)
	Transportation Fuel Charges to Pools:			
17	East of Dawn - Union supplied fuel	0.048	(0.015)	0.033 (1)
18	West of Dawn - Union supplied fuel	0.059	(0.000)	0.059 (1)
19	East of Dawn - Shipper supplied fuel	0.024 (2)	(0.000)	0.024 (2)
20	West of Dawn - Shipper supplied fuel	0.032 (2)	0.003	0.035 (2)
	C1 Storage & Cross Franchise Transportation Service			
	Transportation service			
	Monthly demand charges:			
21	St. Clair / Bluewater & Dawn	0.967	0.092	1.059
22	Ojibway & Dawn	0.967	0.092	1.059
23	Parkway to Dawn	0.545	0.034	0.579
24	Parkway to Kirkwall	0.545	0.034	0.579
25	Kirkwall to Dawn	1.175	(0.154)	1.021
26	Dawn to Kirkwall	1.978	0.033	2.011
27	Dawn to Parkway	2.323	0.059	2.382
28	Kirkwall to Parkway	0.345	0.027	0.372
29	Dawn to Dawn-Vector	0.042	(0.013)	0.029
30	Dawn to Dawn-TCPL	0.220	(0.086)	0.134
	Short-term:			
31	Maximum	75.00		75.00
	Commodity charges:			
32	St. Clair / Bluewater & Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.025	(0.011)	0.014 (1)
33	St. Clair / Bluewater & Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.022	(0.011)	0.011 (1)
34	Ojibway & Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.030	(0.014)	0.016 (1)
35	Ojibway & Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.027	(0.003)	0.024 (1)
36	Parkway to Kirkwall / Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.020	(0.011)	0.009 (1)
37	Parkway to Kirkwall / Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.021	(0.006)	0.015 (1)
38	Kirkwall to Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.020	(0.011)	0.009 (1)
39	Kirkwall to Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.021	(0.012)	0.009 (1)
40	Dawn to Kirkwall - Union supplied fuel (Nov. 1 - Mar. 31)	0.063	(0.022)	0.041 (1)
41	Dawn to Kirkwall - Union supplied fuel (Apr. 1 - Oct. 31)	0.029	(0.012)	0.017 (1)
42	Dawn to Parkway - Union supplied fuel (Nov. 1 - Mar. 31)	0.063	(0.009)	0.054 (1)
43	Dawn to Parkway - Union supplied fuel (Apr. 1 - Oct.31)	0.029	(0.000)	0.029 (1)
44	Kirkwall to Parkway - Union supplied fuel (Nov. 1 - Mar. 31)	0.030	(0.008)	0.022 (1)
45	Kirkwall to Parkway - Union supplied fuel (Apr. 1 - Oct.31)	0.020	0.001	0.021 (1)

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 24, page 3, column (c).
(2) Plus customer supplied fuel per rate schedule.

UNION GAS LIMITED
Summary of Changes to Transportation Rates

Line No.	Particulars ($/GJ)	EB-2012-0437 Approved January 1, 2013 Rate (a)		Rate Change (b)	EB-2011-0210 Approved January 1, 2013 Rate (c)	
	C1 Storage & Cross Franchise Transportation Service					
	Transportation service cont'd					
1	St. Clair / Bluewater & Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31	Note (1)			Note (1)	
2	St. Clair / Bluewater & Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	Note (1)			Note (1)	
3	Ojibway & Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)	
4	Ojibway & Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	Note (1)			Note (1)	
5	Parkway to Kirkwall / Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)	
6	Parkway to Kirkwall / Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	Note (1)			Note (1)	
7	Kirkwall to Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)	
8	Kirkwall to Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	Note (1)			Note (1)	
9	Dawn to Kirkwall - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)	
10	Dawn to Kirkwall - Shipper supplied fuel (Apr. 1 - Oct. 31)	Note (1)			Note (1)	
11	Dawn to Parkway - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)	
12	Dawn to Parkway - Shipper supplied fuel (Apr. 1 - Oct.31)	Note (1)			Note (1)	
13	Kirkwall to Parkway - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)	
14	Kirkwall to Parkway - Shipper supplied fuel (Apr. 1 - Oct.31)	Note (1)			Note (1)	
15	Dawn to Dawn-Vector - Shipper supplied fuel (Nov. 1 - Mar. 31)	n/a			Note (1)	
16	Dawn to Dawn-Vector - Shipper supplied fuel (Apr. 1 - Oct . 31)	Note (1)			Note (1)	
17	Dawn to Dawn-TCPL - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)	
18	Dawn to Dawn-TCPL - Shipper supplied fuel (Apr. 1 - Oct . 31)	Note (1)			Note (1)	
	Interruptible commodity charges:					
19	Maximum	75.00			75.00	
20	Dawn(Tecumseh), Dawn(Facilities or TCPL), Dawn (Vector) and Dawn (TSLE)	Note (1)			Note (1)	
	Authorized Overrun					
	Firm transportation commodity charges:					
21	St. Clair / Bluewater & Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.058		(0.009)	0.049	(2)
22	St. Clair / Bluewater & Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.053		(0.007)	0.046	(2)
23	Ojibway & Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.064		(0.013)	0.051	(2)
24	Ojibway & Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.060		(0.001)	0.059	(2)
25	Parkway to Kirkwall / Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.081		0.039	0.120	(2)
26	Parkway to Kirkwall / Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.046		0.081	0.127	(2)
27	Kirkwall to Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.034		0.013	0.047	(2)
28	Kirkwall to Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.036		0.011	0.047	(2)
29	Dawn to Kirkwall - Union supplied fuel (Nov. 1 - Mar. 31)	0.127		0.013	0.140	(2)
30	Dawn to Kirkwall - Union supplied fuel (Apr. 1 - Oct. 31)	0.092		0.025	0.117	(2)
31	Dawn to Parkway - Union supplied fuel (Nov. 1 - Mar. 31)	0.139		0.027	0.166	(2)
32	Dawn to Parkway - Union supplied fuel (Apr. 1 - Oct.31)	0.104		0.037	0.141	(2)
33	Kirkwall to Parkway - Union supplied fuel (Nov. 1 - Mar. 31)	0.042		0.026	0.068	(2)
34	Kirkwall to Parkway - Union supplied fuel (Apr. 1 - Oct.31)	0.031		0.035	0.066	(2)
35	St. Clair / Bluewater & Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31	0.032	(1)	0.003	0.035	(1)
36	St. Clair / Bluewater & Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	0.032	(1)	0.003	0.035	(1)
37	Ojibway & Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.032	(1)	0.003	0.035	(1)
38	Ojibway & Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	0.032	(1)	0.003	0.035	(1)
39	Parkway to Kirkwall / Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.018	(1)	0.001	0.019	(1)
40	Parkway to Kirkwall / Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	0.018	(1)	0.001	0.019	(1)
41	Kirkwall to Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.039	(1)	(0.005)	0.034	(1)
42	Kirkwall to Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	0.039	(1)	(0.005)	0.034	(1)
43	Dawn to Kirkwall - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.065	(1)	0.001	0.066	(1)
44	Dawn to Kirkwall - Shipper supplied fuel (Apr. 1 - Oct. 31)	0.065	(1)	0.001	0.066	(1)
45	Dawn to Parkway - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.076	(1)	0.002	0.078	(1)
46	Dawn to Parkway - Shipper supplied fuel (Apr. 1 - Oct.31)	0.076	(1)	0.002	0.078	(1)
47	Kirkwall to Parkway - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.011	(1)	0.001	0.012	(1)
48	Kirkwall to Parkway - Shipper supplied fuel (Apr. 1 - Oct.31)	0.011	(1)	0.001	0.012	(1)
49	Dawn to Dawn-Vector - Shipper supplied fuel (Nov. 1 - Mar. 31)	n/a	(1)		0.001	(1)
50	Dawn to Dawn-Vector - Shipper supplied fuel (Apr. 1 - Oct . 31)	0.001	(1)	(0.000)	0.001	(1)
51	Dawn to Dawn-TCPL - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.007	(1)	(0.003)	0.004	(1)
52	Dawn to Dawn-TCPL - Shipper supplied fuel (Apr. 1 - Oct . 31)	0.007	(1)	(0.003)	0.004	(1)
	Short Term Firm transportation commodity charges:					
53	Maximum	75.00			75.00	

Notes:
(1) Plus customer supplied fuel per rate schedule.
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 24, page 3, column (c).

Appendix B

Decision and Rate Order

Rate Schedules

Board File No. EB-2011-0210

Dated: January 17, 2013

unionGas

RATE 01A - SMALL VOLUME GENERAL FIRM SERVICE

ELIGIBILITY

Any customer in Union's Fort Frances, Western, Northern or Eastern Zones who is an end user whose total gas requirements at that location are equal to or less than 50,000 m^3 per year.

SERVICES AVAILABLE

The following services are available under this rate schedule:

(a) **Sales Service**

For continuous supply of natural gas by Union and associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service, the Monthly, Delivery and Gas Supply Charges shall apply.

(b) **Transportation Service**

For continuous delivery on Union's distribution system from the Point of Receipt on TCPL's system to the Point of Consumption on the customer's premises of natural gas owned by the customer and transported by TCPL under a firm transportation service tariff or equivalent National Energy Board Order. For this service, the Monthly and Delivery Charges shall apply. Unless otherwise authorized by Union, customers who initiate a movement to Transportation Service from a Sales Service or Bundled Transportation Service must accept an assignment from Union of transportation capacity on upstream pipeline systems.

(c) **Bundled Transportation Service**

For continuous delivery by Union of gas owned by the customer and for the associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service the Monthly, and Delivery Charges, as well as the Storage and Transportation Charges of the Gas Supply Charge shall apply.

MONTHLY RATES AND CHARGES

Zone	Fort Frances	Western	Northern	Eastern
Rate Schedule No.	201	101	301	601
	APPLICABLE TO ALL SERVICES			
MONTHLY CHARGE	\$21.00	\$21.00	\$21.00	\$21.00
DELIVERY CHARGE	¢ per m^3	¢ per m^3	¢ per m^3	¢ per m^3
First 100 m^3 per month @	9.7347	9.7347	9.7347	9.7347
Next 200 m^3 per month @	9.2102	9.2102	9.2102	9.2102
Next 200 m^3 per month @	8.8375	8.8375	8.8375	8.8375
Next 500 m^3 per month @	8.4955	8.4955	8.4955	8.4955
Over 1,000 m^3 per month @	8.2130	8.2130	8.2130	8.2130
Delivery-Price Adjustment (All Volumes)	0.4510 (1)	0.4510 (1)	0.4510 (1)	0.4510 (1)

Notes:

(1) The Delivery - Price Adjustment is composed of a temporary credit of 0.0578 cents/m^3 for the period October 1, 2012 to March 31, 2013 and a temporary charge of 0.5088 cents/m^3 for the period February 1, 2013 to December 31, 2013.

ADDITIONAL CHARGES FOR SALES SERVICE

GAS SUPPLY CHARGES

Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

MONTHLY BILL

The monthly bill will equal the sum of the monthly charges plus the rates multiplied by the applicable gas quantities delivered plus all applicable taxes.
If the customer transports its own gas, the Gas Supply Charge under Sales Service will not apply.

MINIMUM MONTHLY BILL

The Minimum Monthly Bill shall be the Monthly Charge.

DELAYED PAYMENT

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

SERVICE AGREEMENT

Customers providing their own gas supply in whole or in part, for transportation by Union, must enter into a Service Agreement with Union.

TERMS AND CONDITIONS OF SERVICE

1. If multiple end-users are receiving service from a customer under this rate, for billing purposes, the Monthly Charge, the Delivery Charge and any other charge that is specific to the location of each end-user shall be used to develop a monthly bill for each end-user at each location. Upon request, possibly for a fee, Union will combine the individual bills on a single invoice or statement for administrative convenience. However, Union will not combine the quantities or demands of several end-use locations so that eligibility to a different rate class will result. Further, Union will not combine the monthly billing data of individual end-users to generate a single bill which is less than the sum of the monthly bills of the individual end-users involved at each location.

2. Customers must enter into a Service Agreement with Union prior to the commencement of service.

3. The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

RATE 10 - LARGE VOLUME GENERAL FIRM SERVICE

ELIGIBILITY

Any customer in Union's Fort Frances, Western, Northern or Eastern Zones who is an end-user whose total firm gas requirements at one or more Company-owned meters at one location exceed 50,000 m^3 per year.

SERVICES AVAILABLE

The following services are available under this rate schedule:

(a) **Sales Service**

For continuous supply of natural gas by Union and associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service, the Monthly, Delivery and Gas Supply Charges shall apply.

(b) **Transportation Service**

For continuous delivery on Union's distribution system from the Point of Receipt on TCPL's system to the Point of Consumption on the customer's premises of natural gas owned by the customer and transported by TCPL under a firm transportation service tariff or equivalent National Energy Board Order. For this service, the Monthly, and Delivery Charges shall apply. Unless otherwise authorized by Union, customers who initiate a movement to Transportation Service from a Sales Service or Bundled Transportation Service must accept an assignment from Union of transportation capacity on upstream pipeline systems. Customers may reduce their assignment of transportation capacity in compliance with Union's Turnback Policy.

(c) **Bundled Transportation Service**

For continuous delivery by Union of gas owned by the customer and for the associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service the Monthly, and Delivery Charges, as well as the Storage and Transportation Charges of the Gas Supply Charge shall apply.

MONTHLY RATES AND CHARGES

Zone	Fort Frances	Western	Northern	Eastern
Rate Schedule No.	210	110	310	610
APPLICABLE TO ALL SERVICES				
MONTHLY CHARGE	$70.00	$70.00	$70.00	$70.00
DELIVERY CHARGE	¢ per m^3	¢ per m^3	¢ per m^3	¢ per m^3
First 1,000 m^3 per month @	7.7070	7.7070	7.7070	7.7070
Next 9,000 m^3 per month @	6.2934	6.2934	6.2934	6.2934
Next 20,000 m^3 per month @	5.4872	5.4872	5.4872	5.4872
Next 70,000 m^3 per month @	4.9711	4.9711	4.9711	4.9711
Over 100,000 m^3 per month @	3.0159	3.0159	3.0159	3.0159
Delivery-Price Adjustment (All Volumes)	0.2083 (1)	0.2083 (1)	0.2083 (1)	0.2083 (1)

Notes:

(1) The Delivery - Price Adjustment is composed of a temporary credit of 0.0540 cents/m^3 for the period October 1, 2012 to March 31, 2013 and a temporary charge of 0.2623 cents/m^3 for the period February 1, 2013 to December 31, 2013.

ADDITIONAL CHARGES FOR SALES SERVICE

GAS SUPPLY CHARGES

Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

MONTHLY BILL

The monthly bill will equal the sum of the monthly charges plus the rates multiplied by the applicable gas quantities delivered plus all applicable taxes. If the customer transports its own gas, the Gas Supply Charge under Sales Service will not apply.

MINIMUM MONTHLY BILL

The Minimum Monthly Bill shall be the Monthly Charge.

DELAYED PAYMENT

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

SERVICE AGREEMENT

Customers providing their own gas supply in whole or in part, for transportation by Union and customers purchasing gas from Union with maximum daily requirements in excess of 3,000 m^3 per day must enter into a Service Agreement with Union.

TERMS AND CONDITIONS OF SERVICE

1. Service shall be for a minimum term of one year.

2. If multiple end-users are receiving service from a customer under this rate, for billing purposes, the Monthly Charge, the Delivery Charge and any other charge that is specific to the location of each end-user shall be used to develop a monthly bill for each end-user at each location. Upon request, possibly for a fee, Union will combine the individual bills on a single invoice or statement for administrative convenience. However, Union will not combine the quantities or demands of several end-use locations so that eligibility to a different rate class will result. Further, Union will not combine the monthly billing data of individual end-users to generate a single bill which is less than the sum of the monthly bills of the individual end-users involved at each location.

3. Customers must enter into a Service Agreement with Union prior to the commencement of service.

4. For the purposes of qualifying for a rate class, the total quantities of gas consumed or expected to be consumed on the customer's contiguous property will be used, irrespective of the number of meters installed.

5. The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

RATE 20 - MEDIUM VOLUME FIRM SERVICE

ELIGIBILITY

Any customer in Union's Fort Frances, Western, Northern or Eastern Zones who is an end-user or who is authorized to serve an end-user of gas through one or more Company-owned meters at one location, and whose total maximum daily requirements for firm or combined firm and interruptible service is 14,000 m^3 or more.

SERVICES AVAILABLE

The following services are available under this rate schedule:

(a) **Sales Service**

For continuous supply of natural gas by Union and associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service, the Monthly, Delivery and Gas Supply Charges shall apply.

(b) **Transportation Service**

For continuous delivery on Union's distribution system from the Point of Receipt on TCPL's system to the Point of Consumption on the customer's premises of natural gas owned by the customer. The customer is responsible for obtaining the requisite regulatory approvals for the supply and transmission of such gas to Union's distribution system. For this service, the Monthly, Delivery, Transportation Account and Diversion Transaction Charges shall apply. Unless otherwise authorized by Union, customers who initiate a movement to Transportation Service from a Sales Service or Bundled Transportation Service must accept an assignment from Union of transportation capacity on upstream pipeline systems. Customers may reduce their assignment of transportation capacity in compliance with Union's Turnback Policy.

(c) **Bundled Transportation Service**

For continuous delivery by Union of gas owned by the customer and for the associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service the Monthly, Delivery, Gas Supply Demand and Commodity Transportation Charges shall apply.

(d) **Storage Service**

For load balancing purposes for customers using Transportation Service on this rate schedule. If at the sole discretion of Union, adequate supplies exist, bundled and unbundled storage and delivery/redelivery services will be provided.

The charge for Bundled Storage Service will consist of the charges for Transportation Service plus the charges for Bundled Storage Service.

NOTE: Union has a short-term intermittent gas supply service under Rate 30 of which customers may avail themselves, if they qualify for use of the service.

MONTHLY RATES AND CHARGES

APPLICABLE TO ALL SERVICES - ALL ZONES (1)

MONTHLY CHARGE	$1,000.00
DELIVERY CHARGES (cents per month per m^3)	
Monthly Demand Charge for first 70,000 m^3 of Contracted Daily Demand	27.8179
Monthly Demand Charge for all units over 70,000 m^3 of Contracted Daily Demand	16.3583
Commodity Charge for first 852,000 m^3 of gas volumes delivered	0.5375
Commodity Charge for all units over 852,000 m^3 of gas volumes delivered	0.3932

NOTE
(1) Either the utility or a customer, or potential customer, may apply to the Ontario Energy Board to fix rates, charges and terms and conditions applicable thereto, different from the rates, charges and terms and conditions specified herein if changed rates, charges and terms and conditions are considered by either party to be necessary, desirable and in the public interest.

ADDITIONAL CHARGES FOR SALES SERVICE

Gas Supply Charge

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

Commodity Transportation

Charge 1 applies for all gas volumes delivered in the billing month up to the volume represented by the Contract Demand multiplied by the number of days in the billing month multiplied by 0.4.

Charge 2 applies for all additional gas volumes delivered in the billing month.

HEAT CONTENT ADJUSTMENT

The gas supply commodity charges hereunder will be adjusted upwards or downwards as described below if the average total heating value of the gas per cubic metre (m^3) determined in accordance with Union's Terms and Conditions in any month falls above or below 37.89 MJ per m^3, respectively.

The adjustment shall be determined by multiplying the amount otherwise payable by a fraction, where the numerator is the monthly weighted average total heating value per cubic meter and the denominator 37.89.

COMMISSIONING AND DECOMMISSIONING RATE

The contract may provide that the Monthly Demand Charges specified above shall not apply on all or part of the daily contracted demand used by the customer either during the testing, commissioning and phasing in of gas using equipment or, alternatively, in the decommissioning and phasing out of gas using equipment being displaced by other gas using equipment, for a period not to exceed one year ("the transition period"). To be eligible the new or displaced gas using equipment must be separately meterable. In such event, the contract will provide the following rates that such volume during the transitional period will be charged.

Zone	Fort Frances	Western	Northern	Eastern
Rate Schedule No.	220	120	320	620
MONTHLY CHARGE	$1,000.00	$1,000.00	$1,000.00	$1,000.00
DELIVERY CHARGES	cents per m^3	cents per m^3	cents per m^3	cents per m^3
Commodity Charge for each unit of gas volumes delivered	2.3666	2.3666	2.3666	2.3666

GAS SUPPLY CHARGES
The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

ADDITIONAL CHARGES FOR TRANSPORTATION AND STORAGE SERVICES – ALL ZONES

MONTHLY TRANSPORTATION ACCOUNT CHARGE

For customers that currently have installed or will require installing telemetering equipment	$219.43

BUNDLED (T-SERVICE) STORAGE SERVICE CHARGES

Monthly Demand Charge for each unit of Contracted Daily Storage Withdrawal Entitlement ($/GJ/Month)	$9.643
Monthly Storage Demand- Price Adjustment for each unit of Contracted Daily Storage Withdrawal Entitlement: ($/GJ/Month)	-
Commodity Charge for each unit of gas withdrawn from storage ($/GJ)	$0.156
Authorized Overrun Commodity Charge on each additional unit of gas Union authorizes for withdrawal from storage ($/GJ)	$0.473

The Authorized Overrun Commodity Charge is payable on all quantities on any Day in excess of the customer's contractual rights, for which authorization has been received. Overrun will be authorized by Union at its sole discretion.

DIVERSION TRANSACTION CHARGE

Charge to a customer Receiving Delivery of diverted gas each time such customer requests a diversion and Union provides the service:	$10.00

THE BILL

The bill will equal the sum of the charges for all services selected plus the rates multiplied by the applicable gas quantities delivered or withdrawn for each service chosen plus all applicable taxes. If the customer transports its own gas, the Gas Supply Charge under Sales Service will not apply. If the customer selects Union's Sales Service which includes the Gas Supply Charge, no additional charges for Transportation and Storage Services will apply.

MINIMUM BILL

The minimum bill shall be the Monthly Charge, the Transportation Account Charge and the Demand Charges, as applicable.

DELAYED PAYMENT

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

SERVICE AGREEMENT

All customers must enter into a Service Agreement with Union before receiving service under this rate schedule.

TERMS AND CONDITIONS OF SERVICE

1. Service shall be for a minimum term of one year.

2. If multiple end-users are receiving service from a customer under this rate, for billing purposes, the Monthly Charge, the Delivery Charge, the Transportation Account Charge and any other charge that is specific to the location of each end-user shall be used to develop a monthly bill for each end-user at each location. Upon request, possibly for a fee, Union will combine the individual bills on a single invoice or statement for administrative convenience. However, Union will not combine the quantities or demands of several end-use locations so that eligibility to a different rate class will result. Further, Union will not combine the billing data of individual end-users to generate a single bill which is less than the sum of the bills of the individual end-users involved at each location.

3. Customers must enter into a Service Agreement with Union prior to the commencement of service.

4. For the purposes of qualifying for a rate class, the total quantities of gas consumed or expected to be consumed on the customer's contiguous property will be used, irrespective of the number of meters installed.

5. The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

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RATE 25 - LARGE VOLUME INTERRUPTIBLE SERVICE

ELIGIBILITY

Any customer in Union's Fort Frances, Western, Northern or Eastern Zones who is an end-user or who is authorized to serve an end-user of gas through one or more Company-owned meters at one location, and whose total maximum daily interruptible requirement is 3,000 m^3 or more or the interruptible portion of a maximum daily requirement for combined firm and interruptible service is 14,000 m^3 or more and whose operations, in the judgement of Union, can readily accept interruption and restoration of gas service.

SERVICES AVAILABLE

The following services are available under this rate schedule:

(a) **Sales Service**

For interruptible supply of natural gas by Union and associated transportation services necessary to ensure its delivery in accordance with customer's needs. For this service, the Monthly, Delivery and Gas Supply Charges shall apply.

(b) **Transportation Service**

For delivery of natural gas owned by the customer on Union's distribution system from the Point of Receipt from TCPL's system to the Point of Consumption on the customer's or end-user's premises, providing that, in the judgement of Union, acting reasonably, the customer-owned gas does not displace service from Union under a Rate 20 or Rate 100 contract specific to that location. The customer is responsible for obtaining the requisite regulatory approvals for the supply and transmission of such gas to Union's distribution system. For this service, the Monthly, Delivery, Transportation Account and Diversion Transaction Charges shall apply.

NOTE: Union has a short-term intermittent gas supply service under Rate 30 which customers may avail themselves of, if they qualify for use of the service.

MONTHLY RATES AND CHARGES

APPLICABLE TO ALL SERVICES – ALL ZONES (1)

MONTHLY CHARGE	$375.00
DELIVERY CHARGES	cents per m^3
A Delivery Price for all volumes delivered to the customer to be negotiated between Union and the customer and the average price during the period in which these rates remain in effect shall not exceed:	5.0882

Notes:
(1) Either the utility or a customer, or potential customer, may apply to the Ontario Energy Board to fix rates, charges and terms and conditions applicable thereto, different from the rates, charges and terms and conditions specified herein if changed rates, charges and terms and conditions are considered by either party to be necessary, desirable and in the public interest.

ADDITIONAL CHARGES FOR SALES SERVICE

Gas Supply Charge
As per applicable rate provided in Schedule "A".

Interruptible Service
Applicable all year at a price agreed upon between Union and the customer and the average price during the period in which these rates remain in effect.

HEAT CONTENT ADJUSTMENT

The gas supply commodity charges hereunder will be adjusted upwards or downwards as described below if the average total heating value of the gas per cubic metre (m^3) determined in accordance with Union's Terms and Conditions in any month falls above or below 37.89 MJ per m^3, respectively.

The adjustment shall be determined by multiplying the amount otherwise payable by a fraction, where the numerator is the monthly weighted average total heating value per cubic meter and the denominator 37.89.

ADDITIONAL CHARGES FOR TRANSPORTATION – ALL ZONES

MONTHLY TRANSPORTATION ACCOUNT CHARGE:
For customers that currently have installed or will require installing telemetering equipment. $219.43

THE BILL

The bill will equal the sum of the monthly charges for all services selected plus the rates multiplied by the applicable gas volumes delivered or withdrawn for each service chosen plus all applicable taxes. If the customer transports its own gas, the Gas Supply Charge under Sales Service will not apply. If the customer selects Union's Sales Service which includes the Gas Supply Charge, no additional charges for Transportation will apply.

MINIMUM BILL

The minimum bill shall be the Monthly Charge and the Transportation Account Charge, if applicable.

DELAYED PAYMENT

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

SERVICE AGREEMENT

All customers must enter into a Service Agreement with Union before receiving service under this rate schedule.

TERMS AND CONDITIONS OF SERVICE

1. Service shall be for a minimum term of one year.

2. If multiple end-users are receiving service from a customer under this rate, for billing purposes, the Monthly Charge, the Delivery Charge, the Transportation Account Charge and any other charge that is specific to the location of each end-user shall be used to develop a monthly bill for each end-user at each location. Upon request, Union will combine the individual bills on a single invoice or statement for administrative convenience. However, Union will not combine the volumes or demands of several end-use locations so that eligibility to a different rate class will result. Further, Union will not combine the monthly billing data of individual end-users to generate a single bill which is less than the sum of the monthly bills of the individual end-users involved at each location.

3. Customers must enter into a Service Agreement with Union prior to the commencement of service.

4. For the purposes of qualifying for a rate class, the total volumes of gas consumed or expected to be consumed on the customer's contiguous property will be used, irrespective of the number of meters installed.

5. The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

RATE 30 - INTERMITTENT GAS SUPPLY SERVICE
AND SHORT TERM STORAGE / BALANCING SERVICE

ELIGIBILITY

Any customer in Union's Fort Frances, Western, Northern or Eastern Zones already connected to Union's gas distribution system who is an end-user or is authorized to serve an end-user.

SERVICE AVAILABLE

For intermittent, short-term gas supply which will be a substitute for energy forms other than Company owned gas sold under other rate schedules. This may include situations where customer-owned gas supplies are inadequate and short-term backstopping service is requested or during a situation of curtailment on the basis of price when the purchase price of Spot gas is outside the interruptible service price range. The gas supply service available hereunder is offered only in conjunction with service to the customer under an applicable firm or interruptible service rate schedule of Union. The service is for intermittent gas supply and short term storage / balancing service and will be billed in combination with Monthly, Delivery, and other applicable charges for such services under the applicable rate schedule. Gas supply under this rate will be provided when, at the sole discretion of Union, adequate supplies are available.

GAS SUPPLY CHARGE

The gas supply charge shall be $5.00 per 10^3m^3 plus the greater of the incremental cost of gas for Union and the customer's gas supply charge.

SHORT TERM STORAGE / BALANCING SERVICE

Short Term Storage / Balancing Service is:
i) a combined space and interruptible deliverability service for short-term or off-peak storage in Union's storage facilities, OR
ii) short-term firm deliverability, OR
iii) a component of an operational balancing service offered.

In negotiating the rate to be charged for service, the matters that are to be considered include:
i) the minimum amount of storage service to which a customer is willing to commit,
ii) whether the customer is contracting for firm or interruptible service during Union's peak or non-peak periods,
iii) utilization of facilities, and
iv) competition.

A commodity charge to be negotiated between Union and the customer not to exceed $6.000/GJ.

THE BILL

The bill for gas supply and/or short term supplemental services under this rate shall be rendered in conjunction with the billing for delivery and other services under the customer's applicable rate for such services.

SERVICE AGREEMENT

All customers must enter into a Service Agreement with Union for this service and must agree therein to curtail or interrupt use of gas under this rate schedule whenever requested to do so by Union.

TERMS AND CONDITIONS OF SERVICE

1. Failure of the customer to interrupt or curtail use of gas on this rate as requested by Union shall be subject to the Unauthorized Overrun Gas Penalty as provided in Union's Terms and Conditions. Anytime the customer has such failure, Union reserves the right to cancel service under this rate.

2. The Terms and Conditions of the applicable rate schedule for delivery of the gas sold hereunder shall also apply.

3. The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

RATE 100 – LARGE VOLUME HIGH LOAD FACTOR FIRM SERVICE

ELIGIBILITY

Any customer in Union's Fort Frances, Western, Northern or Eastern Zones who is an end-user or who is authorized to serve an end-user of gas through one or more Company-owned meters at one location, and whose maximum daily requirement for firm service is 100,000 m^3 or more, and whose annual requirement for firm service is equal to or greater than its maximum daily requirement multiplied by 256.

SERVICES AVAILABLE

The following services are available under this rate schedule:

(a) **Sales Service**

For continuous supply of natural gas by Union and associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service, the Monthly, Delivery and Gas Supply Charges shall apply.

(b) **Transportation Service**

For continuous delivery on Union's distribution system from the Point of Receipt on TCPL's system to the Point of Consumption on the customer's premises of natural gas owned by the customer. The customer is responsible for obtaining the requisite regulatory approvals for the supply and transmission of such gas to Union's distribution system. For this service, the Monthly, Delivery, Transportation Account and Diversion Transaction Charges shall apply. Unless otherwise authorized by Union, customers who initiate a movement to Transportation Service from a Sales Service or Bundled Transportation Service must accept an assignment from Union of transportation capacity on upstream pipeline systems. Customers may reduce their assignment of transportation capacity in compliance with Union's Turnback Policy.

(c) **Bundled Transportation Service**

For continuous delivery by Union of gas owned by the customer and for the associated transportation and storage services necessary to ensure deliverability in accordance with the customer's needs. For this service the Monthly, Delivery, Gas Supply Demand and Commodity Transportation Charges shall apply.

(d) **Storage Service**

For load balancing purposes for customers using Transportation Service on this rate schedule. If at the sole discretion of Union, adequate supplies exist, bundled and unbundled storage and delivery/redelivery services will be provided.

The charge for Bundled Storage Service will consist of the charges for Transportation Service plus the charges for Bundled Storage Service.

NOTE: Union has a short-term intermittent gas supply service under Rate 30 which customers may avail themselves of, if they qualify for use of the service.

MONTHLY RATES AND CHARGES

APPLICABLE TO ALL SERVICES - ALL ZONES (1)

MONTHLY CHARGE	$1,500.00
DELIVERY CHARGES (cents per Month per m^3 of Daily Contract Demand)	
Monthly Demand Charge for each unit of Contracted Daily Demand	15.3415
Commodity Charge for each unit of gas volumes delivered (cents/m^3)	0.2137

NOTE:
(1) Either the utility or a customer, or potential customer, may apply to the Ontario Energy Board to fix rates, charges and terms and conditions applicable thereto, different from the rates, charges and terms and conditions specified herein if changed rates, charges and terms and conditions are considered by either party to be necessary, desirable and in the public interest.

ADDITIONAL CHARGES FOR SALES SERVICE

Gas Supply Charges

The gas supply charge is comprised of charges for transportation and for commodity and fuel. The applicable rates are provided in Schedule "A".

Commodity Transportation
Charge 1 applies for all gas volumes delivered in the billing month up to the volume represented by the Contract Demand multiplied by the number of days in the billing month multiplied by 0.3.

Charge 2 applies for all additional gas volumes delivered in the billing month.

HEAT CONTENT ADJUSTMENT

The gas supply commodity charges hereunder will be adjusted upwards or downwards as described below if the average total heating value of the gas per cubic metre (m^3) determined in accordance with Union's Terms and Conditions in any month falls above or below 37.89 MJ per m^3, respectively.

The adjustment shall be determined by multiplying the amount otherwise payable by a fraction, where the numerator is the monthly weighted average total heating value per cubic meter and the denominator 37.89.

COMMISSIONING AND DECOMMISSIONING RATE

The contract may provide that the Monthly Demand Charges specified above shall not apply on all or part of the daily contracted demand used by the customer either during the testing, commissioning and phasing in of gas using equipment or, alternatively, in the decommissioning and phasing out of gas using equipment being displaced by other gas using equipment, for a period not to exceed one year ("the transitional period"). To be eligible the new or displaced gas using equipment must be separately meterable. In such event, the contract will provide the following rates that such volume during the transitional period will be charged.

Zone	Fort Frances	Western	Northern	Eastern
Rate Schedule No.	2100	1100	3100	6100
MONTHLY CHARGE	$1,500.00	$1,500.00	$1,500.00	$1,500.00
DELIVERY CHARGES	cents per m^3	cents per m^3	cents per m^3	cents per m^3
Commodity Charge for each unit of gas volumes delivered	0.9342	0.9342	0.9342	0.9342

GAS SUPPLY CHARGES

The gas supply charge is comprised of charges for transportation and for commodity and fuel. The applicable rates are provided in Schedule "A".

ADDITIONAL CHARGES FOR TRANSPORTATION AND STORAGE SERVICES – ALL ZONES

MONTHLY TRANSPORTATION ACCOUNT CHARGE	
For customers that currently have installed or will require installing telemetering equipment	$219.43
BUNDLED (T-SERVICE) STORAGE SERVICE CHARGES	
Monthly Demand Charge for each unit of Contracted Daily Storage Withdrawal Entitlement ($/GJ/Month)	$9.643
Monthly Storage Demand- Price Adjustment for each unit of Contracted Daily Storage Withdrawal Entitlement: ($/GJ/Month)	-
Commodity Charge for each unit of gas withdrawn from storage ($/GJ)	$0.156
Authorized Overrun Commodity Charge on each additional unit of gas Union authorizes for withdrawal from storage ($/GJ)	$0.473

The Authorized Overrun Commodity Charge is payable on all quantities on any Day in excess of the customer's contractual rights, for which authorization has been received. Overrun will be authorized by Union at its sole discretion.

DIVERSION TRANSACTION CHARGE

Charge to a customer Receiving Delivery of diverted gas each time such customer requests a diversion and Union provides the service: $10.00

THE BILL

The bill will equal the sum of the charges for all services selected plus the rates multiplied by the applicable gas quantities delivered or withdrawn for each service chosen plus all applicable taxes. If the customer transports its own gas, the Gas Supply Charge under Sales Service will not apply. If the customer selects Union's Sales Service which includes the Gas Supply Charge, no additional charges for Transportation and Storage Services will apply.

MINIMUM BILL

The minimum bill shall be the Monthly Charge, the Transportation Account Charge and the Demand Charges, as applicable.

DELAYED PAYMENT

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

SERVICE AGREEMENT

All customers must enter into a Service Agreement with Union before receiving service under this rate schedule.

TERMS AND CONDITIONS OF SERVICE

1. Service shall be for a minimum term of one year.

2. If multiple end-users are receiving service from a customer under this rate, for billing purposes, the Monthly Charge, the Delivery Charge, the Transportation Account Charge and any other charge that is specific to the location of each end-user shall be used to develop a monthly bill for each end-user at each location. Upon request, possibly for a fee, Union will combine the individual bills on a single invoice or statement for administrative convenience. However, Union will not combine the quantities or demands of several end-use locations so that eligibility to a different rate class will result. Further, Union will not combine the billing data of individual end-users to generate a single bill which is less than the sum of the bills of the individual end-users involved at each location.

3. Customers must enter into a Service Agreement with Union prior to the commencement of service.

4. For the purposes of qualifying for a rate class, the total quantities of gas consumed or expected to be consumed on the customer's contiguous property will be used, irrespective of the number of meters installed.

5. The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

RATE S1 - GENERAL FIRM SERVICE STORAGE RATES

ELIGIBILITY

Any customer or agent in Union's Fort Frances, Western, Northern or Eastern Zones who is authorized to serve an end-user of gas, paying for delivery services under Rate 01A or Rate 10.

SERVICES AVAILABLE

The following services are available under this rate schedule:

(a) **Transportation Service**

The customer is responsible for obtaining all Gas Supply services to the end-user including the requisite regulatory approvals for the supply and transmission of such gas to Union's distribution system. For this service, the Diversion Transaction Charge shall apply. Unless otherwise authorized by Union, customers who initiate a movement to Transportation Service from a Sales Service or Bundled Transportation Service must accept an assignment from Union of transportation capacity on upstream pipeline systems.

(b) **Storage Service**

For load balancing purposes for customers using Transportation Service on this rate schedule. If at the sole discretion of Union, adequate supplies exist, unbundled storage and delivery/redelivery services will be provided.

The charge for Unbundled Storage Service will consist of the charges for Transportation Service plus the charges for Unbundled Storage Service which must include charges for delivery/redelivery service to/from storage.

MONTHLY RATES AND CHARGES

UNBUNDLED STORAGE SERVICE CHARGES

Storage Space Charge Applied to Contracted Maximum Storage Space ($ per GJ per Month)	$0.085
Fuel Ratio Applied to all gas injected and withdrawn from storage (%)	0.395%
Commodity Charge Applied to all gas injected and withdrawn from storage ($ per GJ)	$0.026

UNBUNDLED STORAGE SERVICE AUTHORIZED OVERRUN CHARGES

Fuel Ratio Applied to all gas injected and withdrawn from storage (%)	0.853%
Commodity Charge Applied to all gas injected and withdrawn from storage ($ per GJ)	$0.053

The Authorized Overrun Commodity Charge is payable on all quantities on any Day in excess of the customer's contractual rights, for which authorization has been received. Overrun will be authorized by Union at its sole discretion.

UNBUNDLED STORAGE SERVICE UNAUTHORIZED OVERRUN CHARGES

If in any month, the customer has gas in storage in excess of the contracted Maximum Storage Space or the gas storage balance for the account of the customer is less than zero or the customer has injected or withdrawn volumes from storage which exceeds their contractual rights, and which has not been authorized by Union or provided for under a short term storage/balancing service, such an event will constitute an occurrence of Unauthorized Overrun. The Unauthorized Overrun rate during the November 1 to April 15 period will be $60.00 per GJ. The Unauthorized Overrun rate during the April 16 to October 31 period will be $6.000 per GJ.

Zone	Fort Frances	Western	Northern	Eastern
Delivery Service to Storage Facilities (1)				
Demand Charge ($/GJ/month)	N/A	$23.187	$9.083	$0.908
Commodity ($/GJ)	N/A	$0.049	$0.023	$0.008
Redelivery Service from Storage Facilities				
Demand Charge ($/GJ/month)	$1.798	$1.798	$1.798	$7.836
Commodity ($/GJ)	N/A	$0.035	$0.035	$0.049

Notes:
1. Delivery Service to Storage Facilities is not available to Northern Zone customers in the Sault Ste. Marie Delivery Area (SSMDA).
2. Daily Firm Injection and Withdrawal Rights shall be pursuant to the storage contract.
3. Storage Space, Withdrawal Rights, and Injection Rights are not assignable to any other party without the prior written consent of Union and where necessary, approval from the Ontario Energy Board.

Diversion Transaction Charge
Charge to a customer receiving delivery of diverted gas each time such customer requests a diversion and Union provides the service: $10.00

MONTHLY BILL

The monthly bill will equal the sum of the monthly charges for all services selected plus the rates multiplied by the applicable gas quantities delivered or withdrawn for each service chosen plus all applicable taxes.

DELAYED PAYMENT

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

TERMS AND CONDITIONS OF SERVICE

1. Customers must enter into a Service Agreement with Union prior to the commencement of service.

2. The identified rates represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

unionGas

Union Gas Limited
Northern and Eastern Operations Area
Gas Supply Charges

(A) Availability

Available to customers in Union's Fort Frances, Western, Northern and Eastern Delivery Zones.

(B) Applicability:

To all sales customers served under Rate 01A, Rate 10, Rate 20, Rate 100 and Rate 25.

(C) Rates

Utility Sales

Rate 01A (cents / m^3)

		Fort Frances	Western	Northern	Eastern
Storage		2.1507	2.3910	3.2252	3.5799
Storage - Price Adjustment	(2)	0.2109	0.2109	0.2109	0.2109
Commodity and Fuel	(1)	12.5811	12.6353	12.7025	12.7620
Commodity and Fuel - Price Adjustment	(3)	(2.2022)	(2.2022)	(2.2022)	(2.2022)
Transportation		4.9387	5.5401	7.6275	8.5153
Transportation - Price Adjustment	(4)	1.0523	1.0523	1.0523	1.0523
Total Gas Supply Charge		18.7315	19.6274	22.6162	23.9181

Rate 10 (cents / m^3)

		Fort Frances	Western	Northern	Eastern
Storage		1.2015	1.4418	2.2760	2.6307
Storage - Price Adjustment	(5)	0.1201	0.1201	0.1201	0.1201
Commodity and Fuel	(1)	12.5811	12.6353	12.7025	12.7620
Commodity and Fuel - Price Adjustment	(6)	(2.1961)	(2.1961)	(2.1961)	(2.1961)
Transportation		4.3170	4.9184	7.0058	7.8935
Transportation - Price Adjustment	(7)	1.0341	1.0341	1.0341	1.0341
Total Gas Supply Charge		17.0576	17.9536	20.9423	22.2443

Notes:
(1) The Commodity and Fuel rate includes a gas supply administration charge of 0.1933 cents/m^3.
(2) Includes a temporary charge of 0.2109 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(3) Includes a temporary credit of 0.0286 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(4) Includes a temporary credit of 0.0608 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(5) Includes a temporary charge of 0.1201 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(6) Includes a temporary credit of 0.0225 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(7) Includes a temporary credit of 0.0786 cents/m^3 for the period February 1, 2013 to December 31, 2013.

unionGas

Union Gas Limited
Northern and Eastern Operations Area
Gas Supply Charges

Utility Sales

Rate 20 (cents / m^3)

	Fort Frances	Western	Northern	Eastern
Commodity and Fuel (1)	12.6040	12.6583	12.7256	12.7853
Commodity and Fuel - Price Adjustment	(2.1736)	(2.1736)	(2.1736)	(2.1736)
Commodity Transportation - Charge 1	3.3924	3.7291	4.8977	5.3947
Transportation 1 - Price Adjustment	1.1138	1.1138	1.1138	1.1138
Commodity Transportation - Charge 2	0.1535	0.2673	0.4138	0.5393
Monthly Gas Supply Demand	21.7512	35.0467	85.6936	106.0700
Gas Supply Demand - Price Adjustment	-	-	-	-
Commissioning and Decommissioning Rate	4.1748	5.3411	9.6355	11.3980

Rate 100 (cents / m^3)

	Fort Frances	Western	Northern	Eastern
Commodity and Fuel (1)	12.6040	12.6583	12.7256	12.7853
Commodity and Fuel - Price Adjustment	(2.1736)	(2.1736)	(2.1736)	(2.1736)
Commodity Transportation - Charge 1	7.0154	7.2679	8.1444	8.5171
Commodity Transportation - Charge 2	0.1535	0.2673	0.4138	0.5393
Monthly Gas Supply Demand	61.0900	76.6014	135.6895	159.4619
Commissioning and Decommissioning Rate	5.9635	6.8653	10.0998	11.4478

Rate 25 (cents / m^3)

Gas Supply Charge:		Fort Frances	Western	Northern	Eastern
	Interruptible Service				
	Minimum	14.3135	14.3135	14.3135	14.3135
	Maximum	140.5622	140.5622	140.5622	140.5622

Notes:
(1) The Commodity and Fuel rate includes a gas supply administration charge of 0.1933 cents/m^3.

Effective: January 1, 2013
O.E.B. Order # EB-2011-0210

Chatham, Ontario

Supersedes EB-2012-0437 Rate Schedule effective January 1, 2013.

SMALL VOLUME GENERAL SERVICE RATE

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To general service customers whose total consumption is equal to or less than 50,000 m^3 per year.

(C) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated which may be higher than the identified rates.

a)	Monthly Charge		$21.00	
b)	Delivery Charge			
	First	100 m^3	3.7795 ¢ per m^3	
	Next	150 m^3	3.5730 ¢ per m^3	
	All Over	250 m^3	3.0845 ¢ per m^3	
	Delivery – Price Adjustment (All Volumes)		(0.0054) ¢ per m^3	(1)
c)	Storage Charge (if applicable)		0.7368 ¢ per m^3	
	Storage - Price Adjustment (All Volumes)		(0.0513) ¢ per m^3	(2)

Applicable to all bundled customers (sales and bundled transportation service).

d) Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

During any month in which a customer terminates service or begins service, the fixed charge for the month will be prorated to such customer.

Notes:
(1) The Delivery - Price Adjustment includes a temporary credit of 0.0485 cents/m^3 for the period October 1, 2012 to March 31, 2013 and a temporary charge of 0.0429 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(2) The Storage - Price Adjustment includes a temporary credit of 0.0513 cents/m^3 for the period February 1, 2013 to December 31, 2013.

(D) Supplemental Service to Commercial and Industrial Customers Under Group Meters

Combination of readings from several meters may be authorized by the Company and the Company will not reasonably withhold authorization in cases where meters are located on contiguous pieces of property of the same owner not divided by a public right-of-way

(E) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

(F) Direct Purchase

Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union, and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(G) Overrun Charge

In the event that a direct purchase customer fails to deliver its contracted volumes to Union, and Union has the capability to continue to supply the customer, Union will do so. The customer may pay 4.5164 ¢ per m^3 for the delivery and the total gas supply charge for utility sales provided in Schedule "A" per m^3, plus 7¢ per m^3.

(H) Bundled Direct Purchase Delivery

Where a customer elects transportation service under this rate schedule, the customer must enter into a Bundled T Gas Contract with Union for delivery of gas to Union. Bundled T Gas Contract Rates and Gas Purchase Contract Rates are described in rate schedule R1.

(I) Company Policy Relating to Terms of Service

a. Customers who temporarily discontinue service during any twelve consecutive months without payment of the monthly fixed charge for the months in which the gas is temporarily disconnected shall pay for disconnection and reconnection.

b. When gas is delivered at an absolute pressure in excess of 101.325 kilopascals, then for purposes of measurement, hereunder, such volume of gas shall be corrected to an absolute pressure of 101.325 kilopascals. Atmospheric pressure is assumed to be the levels shown below in kilopascals (absolute) regardless of the actual atmospheric pressure at which the gas is measured and delivered.

Zone	Assumed Atmospheric Pressure kPa
1	100.148
2	99.494
3	98.874
4	98.564
5	98.185
6	97.754
7	97.582
8	97.065
9	96.721
10	100.561
11	99.321
12	98.883

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LARGE VOLUME GENERAL SERVICE RATE

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To general service customers whose total consumption is greater than 50,000 m^3 per year.

(C) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated which may be higher than the identified rates.

a) Monthly Charge $70.00

b) Delivery Charge

First	1 000 m³	4.1416 ¢ per m³	
Next	6 000 m³	4.0653 ¢ per m³	
Next	13 000 m³	3.8379 ¢ per m³	
All Over	20 000 m³	3.5650 ¢ per m³	
Delivery – Price Adjustment (All Volumes)		0.0355 ¢ per m³	(1)

c) Storage Charge (if applicable) 0.7550 ¢ per m³

Storage - Price Adjustment (All Volumes) 0.0080 ¢ per m³ (2)

Applicable to all bundled customers (sales and bundled transportation service).

d) Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

During any month in which a customer terminates service or begins service, the fixed charge for the month will be prorated to such customer.

Notes:
(1) The Delivery - Price Adjustment includes a temporary credit of 0.0473 cents/m³ for the period October 1, 2012 to March 31, 2013 and a temporary charge of 0.0826 cents/m³ for the period February 1, 2013 to December 31, 2013.
(2) The Storage - Price Adjustment includes a temporary charge of 0.0080 cents/m³ for the period February 1, 2013 to December 31, 2013.

(D) Supplemental Service to Commercial and Industrial Customers Under Group Meters

Combination of readings from several meters may be authorized by the Company and the Company will not reasonably withhold authorization in cases where meters are located on contiguous pieces of property of the same owner not divided by a public right-of-way.

(E) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

(F) Direct Purchase

Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union, and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(G) Overrun Charge

In the event that a direct purchase customer fails to deliver its contracted volumes to Union, and Union has the capability to continue to supply the customer, Union will do so. The customer may pay 4.8967 ¢ per m^3 for the delivery and the total gas supply charge for utility sales provided in Schedule "A" per m^3, plus 7¢ per m^3.

(H) Bundled Direct Purchase Delivery

Where a customer elects transportation service under this rate schedule, the customer must enter into a Bundled T Gas Contract with Union for delivery of gas to Union. Bundled T Gas Contract Rates and Gas Purchase Contract Rates are described in rate schedule R1.

(I) Company Policy Relating to Terms of Service

a. Customers who temporarily discontinue service during any twelve consecutive months without payment of the monthly fixed charge for the months in which the gas is temporarily disconnected shall pay for disconnection and reconnection.

b. When gas is delivered at an absolute pressure in excess of 101.325 kilopascals, then for purposes of measurement, hereunder, such volume of gas shall be corrected to an absolute pressure of 101.325 kilopascals. Atmospheric pressure is assumed to be the levels shown below in kilopascals (absolute) regardless of the actual atmospheric pressure at which the gas is measured and delivered.

Zone	Assumed Atmospheric Pressure kPa
1	100.148
2	99.494
3	98.874
4	98.564
5	98.185
6	97.754
7	97.582
8	97.065
9	96.721
10	100.561
11	99.321
12	98.883

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FIRM INDUSTRIAL AND COMMERCIAL CONTRACT RATE

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To a customer who enters into a contract for the purchase or transportation of gas for a minimum term of one year that specifies a daily contracted demand between 4 800 m^3 and 140 870 m^3.

(C) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated which may be higher than the identified rates.

1. Bills will be rendered monthly and shall be the total of:

(i) A Monthly Demand Charge

First	8 450 m^3 of daily contracted demand	46.6239 ¢ per m^3
Next	19 700 m^3 of daily contracted demand	20.9050 ¢ per m^3
All Over	28 150 m^3 of daily contracted demand	17.5631 ¢ per m^3

(ii) A Monthly Delivery Commodity Charge

First 422 250 m^3 delivered per month	0.9621 ¢ per m^3
Next volume equal to 15 days use of daily contracted demand	0.9621 ¢ per m^3
For remainder of volumes delivered in the month	0.4243 ¢ per m^3
Delivery- Price Adjustment (All Volumes)	0.0002 ¢ per m^3

(iii) Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel. The applicable rates are provided in Schedule "A"

2. Overrun Charge

Authorized overrun gas is available provided that it is authorized by Union in advance. Union will not unreasonably withhold authorization. Overrun means gas taken on any day in excess of 103% of contracted daily demand. Authorized overrun will be available April 1 through October 31 and will be paid for at a Delivery Rate of 2.4949 ¢ per m^3 and, if applicable, the total gas supply charge for utility sales provided in Schedule "A" per m^3 for all volumes purchased.

Unauthorized overrun gas taken in any month shall be paid for at the rate of 4.5164 ¢ per m^3 for the delivery and the total gas supply charge for utility sales provided in Schedule "A" per m^3 for all gas supply volumes purchased.

3. Minimum Annual Charge

In each contract year, the customer shall purchase from Union or pay for a minimum volume of gas or transportation services equivalent to 146 days use of contracted demand. Overrun gas volumes will not contribute to the minimum volume. In the event that the customer shall not take such minimum volume the customer shall pay an amount equal to the deficiency from the minimum volume times a Delivery Charge of 1.1554 ¢ per m^3 and, if applicable a gas supply commodity charge provided in Schedule "A".

In the event that the contract period exceeds one year the annual minimum volume will be prorated for any part year.

(D) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

(E) Direct Purchase

Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union, and must acquire and maintain firm transportation on all upstream pipeline systems for all volumes. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(F) Bundled Direct Purchase Delivery

Where a customer elects transportation service under this rate schedule the customer must enter into a Bundled T Gas Contract with Union for delivery of gas to Union.

Bundled T Gas Contract Rates and Gas Purchase Contract Rates are described in rate schedule R1.

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INTERRUPTIBLE INDUSTRIAL AND COMMERCIAL CONTRACT RATE

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To a customer who enters into a contract for the purchase or transportation of gas for a minimum term of one year that specifies a daily contracted demand between 4 800 m³ and 140 870 m³ inclusive.

(C) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated which may be higher than the identified rates.

1. Interruptible Service

The price of all gas delivered by Union pursuant to any contract, contract amendment, or contract renewal shall be determined on the basis of the following schedules:

a) (i) Monthly Delivery Commodity Charge

Daily Contracted Demand Level (CD)	Price per m³
4 800 m³ ≤ CD < 17 000 m³	2.9712 ¢ per m³
17 000 m³ ≤ CD < 30 000 m³	2.8413 ¢ per m³
30 000 m³ ≤ CD < 50 000 m³	2.7730 ¢ per m³
50 000 m³ ≤ CD < 70 000 m³	2.7251 ¢ per m³
70 000 m³ ≤ CD < 100 000 m³	2.6908 ¢ per m³
100 000 m³ ≤ CD ≤ 140 870 m³	2.6571 ¢ per m³
Delivery- Price Adjustment (All Volumes)	0.0002 ¢ per m³

(ii) Days Use of Interruptible Contract Demand

The price determined under Paragraph 1(a) of "Rates" will be reduced by the amount based on the number of Days Use of Contracted Demand as scheduled below:

For 75 days use of contracted demand	0.0530 ¢ per m³
For each additional days use of contracted demand up to a maximum of 275 days, an additional discount of	0.00212 ¢ per m³

(iii) Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A"

(iv) Monthly Charge $690.00 per month

2. In each contract year, the customer shall take delivery from Union, or in any event pay for, if available and not accepted by the customer, a minimum volume of gas or transportation services as specified in the contract between the parties and which will not be less than 700 000 m³ per annum. Overrun volumes will not contribute to the minimum volume. In the event that the customer shall not take such minimum volume, the customer shall pay an amount equal to the deficiency from the minimum volume times a Delivery Charge of 3.1645 ¢ per m³, and if applicable, a gas supply charge provided in Schedule "A".

   In the event that the contract period exceeds one year, the annual minimum volume will be prorated for any part year.

3. Overrun gas is available without penalty provided that it is authorized by Union in advance. Union will not unreasonably withhold authorization. Overrun means gas taken on any day in excess of 105% of contracted daily demand.

   Unauthorized overrun gas taken in any month shall be paid for at the rate of 4.5164 ¢ per m³ for the delivery and the total gas supply charge for utility sales provided in Schedule "A" per m³ for all gas supply volumes purchased.

4. Non-Interruptible Service

   Union may agree, in its sole discretion, to combine an interruptible service with a firm service in which case the amount of firm daily demand to be delivered shall be agreed upon by Union and the customer.

   a) The monthly demand charge for firm daily deliveries will be 28.6252 ¢ per m³.

   b) The commodity charge for firm service shall be the rate for firm service at Union's firm rates net of a monthly demand charge of 28.6252 ¢ per m³ of daily contracted demand and a delivery commodity price adjustment of 0.0002 ¢ per m³.

   c) The interruptible commodity charge will be established under Clause 1 of this schedule.

(D) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

(E) Direct Purchase

Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union, and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(F) Bundled Direct Purchase Delivery

Where a customer elects transportation service under this rate schedule the customer must enter into a Bundled T Gas Contract with Union for delivery of gas to Union.

Bundled T Gas Contract Rates and Gas Purchase Contract Rates are described in rate schedule R1.

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SPECIAL LARGE VOLUME
INDUSTRIAL AND COMMERCIAL CONTRACT RATE

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To a Customer

a) who enters into a contract for the purchase or transportation of gas for a minimum term of one year that specifies a combined maximum daily requirement for firm, interruptible and seasonal service of at least 140 870 m^3, and a qualifying annual volume of at least 28 327 840 m^3; and

b) who has site specific energy measuring equipment installed at each Point of Consumption that will be used in determining energy balances.

For the purposes of qualifying for a rate class, the total quantities of gas consumed or expected to be consumed on the customer's contiguous property will be used, irrespective of the number of meters installed.

(C) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated which may be higher than the identified rates.

1. Bills will be rendered monthly and shall be the total of:

(i) A Monthly Demand Charge

A negotiated Monthly Demand Charge of up to 25.3924 ¢ per m^3 for each m^3 of daily contracted firm demand.

(ii) A Monthly Delivery Commodity Charge

(1) A Monthly Firm Delivery Commodity Charge for all firm volumes of 0.3206 ¢ per m^3 for each m^3, and a Delivery - Price Adjustment of 0.0002 ¢ per m^3.

(2) A Monthly Interruptible Delivery Commodity Charge for all interruptible volumes to be negotiated between Union and the customer not to exceed an annual average of 3.9455 ¢ per m^3.

(3) A Monthly Seasonal Delivery Commodity Charge for all seasonal volumes to be negotiated between Union and the customer not to exceed an annual average of 3.7014 ¢ per m^3.

(iii) Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

(iv) Overrun Gas

Overrun gas is available without penalty provided that it is authorized by Union in advance. Union will not unreasonably withhold authorization.

Unauthorized overrun gas taken in any month shall be paid for at the M1 rate in effect at the time the overrun occurs, plus, if applicable, the total gas supply charge for utility sales provided in Schedule "A" per m^3 for all the gas supply volumes purchased.

2. In negotiating the Monthly Interruptible and Seasonal Commodity Charges, the matters to be considered include:

(a) The volume of gas for which the customer is willing to contract,

(b) The load factor of the customer's anticipated gas consumption, the pattern of annual use, and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for,

(c) Interruptible or curtailment provisions, and

(d) Competition.

3. In each contract year, the customer shall take delivery from Union, or in any event, pay for if available and not accepted by the customer, a minimum volume of gas as specified in the contract between the parties. Overrun gas volumes will not contribute to the minimum volume.

4. The contract may provide that the Monthly Demand Charge specified in Rate Section 1 above shall not apply on all or part of the daily contracted firm demand used by the customer during the testing, commissioning, phasing in, decommissioning and phasing out of gas-using equipment for a period not to exceed one year (the "transition period"). In such event, the contract will provide for a Monthly Delivery Commodity Charge to be applied on such volume during the transition of 2.8549 ¢ per m^3 and the total gas supply charge for utility sales provided in Schedule "A" per m^3, if applicable.

5. Either the utility or a customer, or potential customer, may apply to the Ontario Energy Board to fix rates and other charges different from the rates and other charges specified herein if the changed rates and other charges are considered by either party to be necessary, desirable and in the public interest.

(D) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

(E) Direct Purchase

Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union, and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(F) Bundled Direct Purchase Delivery and Short Term Supplemental Services

Where a customer elects transportation service and/or a short term supplemental service under this rate schedule, the customer must enter into a Contract under rate schedule R1.

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LARGE WHOLESALE SERVICE RATE

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To a distributor who enters into a contract to purchase and/or receive delivery of a firm supply of gas for distribution to its customers and who agrees to take or pay for an annual quantity of at least two million cubic metres.

(C) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated which may be higher than the identified rates.

1. (i) A Monthly Demand Charge of 15.1688 ¢ per m^3 of established daily demand determined in accordance with the service contract, such demand charge to be computed on a calendar month basis and a pro-rata charge to be made for the fraction of a calendar month which will occur if the day of first regular delivery does not fall on the first day of a month,

   (ii) A Delivery Commodity Charge of 0.1990 ¢ per m^3, a Delivery Price Adjustment of 0.0002 ¢ per m^3 for gas delivered and,

   (iii) Gas Supply Charge (if applicable)

   The gas supply charge is comprised of charges for transportation and for commodity and fuel.
   The applicable rates are provided in Schedule "A".

(D) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

(E) Direct Purchase

Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union, and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(F) Overrun Charge

Authorized:

For all quantities on any day in excess of 103% of the customer's contractual rights, for which authorization has been received, the customer will be charged 0.6977 ¢ per m^3. Overrun will be authorized by Union at its sole discretion.

Unauthorized:

For all quantities on any day in excess of 103% of the customer's contractual rights, for which authorization has not been received, the customer will be charged 36.0 ¢ per m^3.

(G) Bundled Direct Purchase Delivery

Where a customer elects transportation service under this rate schedule the customer must enter into a Bundled T Gas Contract with Union for delivery of gas to Union.

Bundled T Gas Contract Rates and Gas Purchase Contract Rates are described in rate schedule R1.

SMALL WHOLESALE SERVICE RATE

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To a non-contract distributor who purchases and/or receives delivery of a firm supply of gas for distribution only to its own customers.

(C) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated which may be higher than the identified rates.

1. A Delivery Commodity Charge of 5.1734 ¢ per m^3 for gas delivered.

2. Gas Supply Charge (if applicable)

   The gas supply charge is comprised of charges for transportation and for commodity and fuel.
   The applicable rates are provided in Schedule "A".

(D) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

(E) Direct Purchase

Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union, and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(F) Overrun Charge

In the event that a direct purchase customer fails to deliver its contracted volumes to Union, and Union has the capability to continue to supply the customer, Union will do so. This gas shall be paid for at the rate of 4.5164 ¢ per m^3 for the delivery and, if applicable, the total gas supply charge for utility sales provided in Schedule "A" per m^3, plus 7 ¢ per m^3 for all gas supply volumes purchased.

(G) Bundled Direct Purchase Delivery

Where a customer elects transportation service under this rate schedule, the customer must enter into a Bundled T Gas Contract with Union for delivery of gas to Union.

Bundled T Gas Contract Rates and Gas Purchase Contract Rates are described in rate schedule R1.

Effective January 1, 2013 Chatham, Ontario
O.E.B. Order # EB-2011-0210

Supersedes EB-2012-0437 Rate Schedule effective January 1, 2013.

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BUNDLED DIRECT PURCHASE CONTRACT RATE

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To a customer who enters into a Receipt Contract or Gas Purchase Contract for delivery and/or sale of gas to Union.

(C) Rates

		Demand Charge Rate/GJ/month	Commodity Charges/Credits Rate/GJ
a)	Transportation by Union For gas delivered to Union at any point other than the Ontario Point(s) of Receipt, Union will charge a customer all approved tolls and charges, incurred by Union to transport the gas to the Ontario Point(s) of Receipt		
b)	Firm Backstop Gas Applied to the contracted Firm Backstop Gas Supply Service	$1.846	
	Backstop Gas Commodity Charge On all quantities supplied by Union to the Ontario Point(s) of Receipt		$4.957
c)	Reasonable Efforts Backstop Gas Paid on all quantities of gas supplied by Union to the customer's Point(s) of Consumption		$5.732
d)	Banked Gas Purchase		
	T-service		Note (1)
e)	Failure to Deliver Applied to all quantities not delivered to Union in the event the customer's supply fails		$2.561
f)	Short Term Storage / Balancing Service (2)		
	Maximum		$6.000
g)	Discretionary Gas Supply Service ("DGSS")		Note (3)

Notes:

(1) The charge for banked gas purchases shall be the higher of the daily spot cost at Dawn in the month of or the month following the month in which gas is sold under this rate and shall not be less than Union's approved weighted average cost of gas.

(2) Short Term Storage / Balancing Service is:

- i) a combined space and interruptible deliverability service for short-term or off-peak storage in Union's storage facilities, OR
- ii) short-term firm deliverability, OR
- iii) a component of an operational balancing service offered.

In negotiating the rate to be charged for short term storage services, the matters that are to be considered include:

- i) The minimum amount of storage service to which a customer is willing to commit,
- ii) Whether the customer is contracting for firm or interruptible service during Union's peak or non-peak periods,
- iii) Utilization of facilities, and
- iv) Competition

(3) Discretionary Gas Supply Service price reflects the "back-to-back" price plus gas supply administration charge.

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STORAGE AND TRANSPORTATION RATES
FOR CONTRACT CARRIAGE CUSTOMERS

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To a customer:

a) whose qualifying annual transportation volume for combined firm and interruptible service is at least 2 500 000 m^3 or greater and has a daily firm contracted demand up to 140,870 m^3; and

b) who enters into a Carriage Service Contract with Union for the transportation or the storage and transportation of Gas for use at facilities located within Union's gas franchise area; and

c) who has meters with electronic recording at each Point of Consumption; and

d) who has site specific energy measuring equipment installed at each Point of Consumption that will be used in determining energy balances; and

e) for whom Union has determined transportation and/or storage capacity is available.

For the purposes of qualifying for a rate class, the total quantities of gas consumed or expected to be consumed on the customer's contiguous property will be used, irrespective of the number of meters installed.

(C) Rates

The following rates shall be charged for all quantities contracted or handled as appropriate. The identified rates represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

STORAGE SERVICE:

			For Customers Providing Their Own Compressor Fuel	
	Demand Charge Rate/GJ/mo	Commodity Charge Rate/GJ	Fuel Ratio	Commodity Charge Rate/GJ
a) Annual Firm Storage Space Applied to contracted Maximum Annual Storage Space	$0.011			
b) Annual Firm Injection/Withdrawal Right: Applied to the contracted Maximum Annual Firm Injection/Withdrawal Right				
Union provides deliverability Inventory	$1.624			
Customer provides deliverability Inventory (4)	$1.197			
c) Incremental Firm Injection Right: Applied to the contracted Maximum Incremental Firm Injection Right	$1.197			
d) Annual Interruptible Withdrawal Right: Applied to the contracted Maximum Annual Interruptible Withdrawal Right	$1.197			

	Demand Charge Rate/GJ/mo	Commodity Charge Rate/GJ	For Customers Providing Their Own Compressor Fuel: Fuel Ratio	For Customers Providing Their Own Compressor Fuel: Commodity Charge Rate/GJ
e) Withdrawal Commodity Paid on all quantities withdrawn from storage up to the Maximum Daily Storage Withdrawal Quantity		$0.030	0.395%	$0.008
f) Injection Commodity Paid on all quantities injected into storage up to the Maximum Daily Storage Injection Quantity		$0.030	0.395%	$0.008
g) Short Term Storage / Balancing Service Maximum		$6.000		

Notes:

1. Demand charges for Annual Services are paid monthly during the term of the contract for not less than one year unless Union, in its sole discretion, accepts a term of less than one year. Demand charges apply whether Union or the customer provides the fuel.

2. Annual Firm Injection Rights are equal to 100% of their respective Annual Firm Withdrawal Rights. Injection Rights in excess of the Annual Firm Injection Rights will be charged at the Incremental Firm Injection Right.

3. Annual Firm Storage Space

   The maximum storage space available to a customer at the rates specified herein is determined by one of the following storage allocation methodologies:

   3.1 Aggregate Excess
   Aggregate excess is the difference between a customer's gas consumption in the 151-day winter period and consumption during the balance of the year. This calculation will be done using two years of historical data (with 25% weighting for each year) and one year of forecast data (with 50% weighting). If a customer is new, or an existing customer is undergoing a significant change in operations, the allocation will be based on forecast consumption only, as negotiated between Union and the customer. Once sufficient historical information is available for the customer, the standard calculation will be done. At each contract renewal, the aggregate excess calculation will be performed to set the new space allocation.

   3.2 Obligated daily contract quantity multiple of 15
   Obligated daily contract quantity is the firm daily quantity of gas which the customer must deliver to Union. The 15 x obligated daily contract quantity calculation will be done using the daily contract quantity for the upcoming contract year. At each contract renewal, the 15 x obligated daily contract quantity calculation will be performed to set the new space allocation.

   Customers may contract for less than their maximum entitlement of firm storage space.

4. Annual Injection/Withdrawal Right

   The maximum level of deliverability available to a customer at the rates specified herein is determined by one of the following methodologies:

   4.1 The greater of obligated daily contract quantity or firm daily contract demand less obligated daily contract quantity.

   Customers may contract for less than their maximum entitlement of deliverability. A customer may contract up to this maximum entitlement with a combination of firm and interruptible deliverability as specified in Section (C) Storage Service.

5. Additional storage space or deliverability, in excess of the allocated entitlements per Notes 3 and 4, may be available at market prices.

6. Storage Space and Withdrawal Rights are not assignable to any other party without the prior written consent of Union.

7. Deliverability Inventory being defined as 20% of annual storage space.

8. Short Term Storage / Balancing Service is:
   - i) a combined space and interruptible deliverability service for short-term or off-peak storage in Union's storage facilities, or
   - ii) short-term firm deliverability, or
   - iii) a component of an operational balancing service offered.

   In negotiating the rate to be charged for service, the matters that are to be considered include:
   - i) The minimum amount of storage service to which a customer is willing to commit,
   - ii) Whether the customer is contracting for firm or interruptible service during Union's peak or non-peak periods,
   - iii) Utilization of facilities, and
   - iv) Competition

TRANSPORTATION CHARGES:

	Demand Charge Rate/m³/mo	Commodity Charge Rate/m³	For Customers Providing Their Own Compressor Fuel: Fuel Ratio (5) (6)	For Customers Providing Their Own Compressor Fuel: Commodity Charge Rate/m³
a) Annual Firm Transportation Demand Applied to the Firm Daily Contract Demand				
First 28,150 m^3 per month	31.9554 ¢			
Next 112,720 m^3 per month	22.0775 ¢			
b) Firm Transportation Commodity Paid on all firm quantities redelivered to the customer's Point(s) of Consumption Commodity Charge (All volumes)		0.1238 ¢	0.250%	0.0712 ¢
c) Interruptible Transportation Commodity Paid on all interruptible quantities redelivered to the customer's Point(s) of Consumption Maximum		3.9455 ¢	0.250%	3.8929 ¢

Notes:

1. All demand charges are paid monthly during the term of the contract for not less than one year unless Union, at its sole discretion, accepts a term of less than one year. Demand charges apply whether Union or the customer provides the fuel.

2. In negotiating the rate to be charged for the transportation of gas under Interruptible Transportation, the matters that are to be considered include:

   a) The amount of the interruptible transportation for which customer is willing to contract,

   b) The anticipated load factor for the interruptible transportation quantities,

   c) Interruptible or curtailment provisions, and

   d) Competition.

3. In each contract year, the customer shall pay for a Minimum Interruptible Transportation Activity level as specified in the Contract. Overrun activity will not contribute to the minimum activity level.

4. Transportation fuel ratios do not apply to customers served from dedicated facilities directly connected to third party transmission systems with custody transfer metering at the interconnect.

5. Either Union or a customer, or potential customer, may apply to the Ontario Energy Board to fix rates and other charges different from the rates and other charges specified herein if the changed rates and other charges are considered by either party to be necessary, desirable and in the public interest.

SUPPLEMENTAL CHARGES:

Rates for supplemental services are provided in Schedule “A”.

Notes:

1. All demand charges are paid monthly during the term of the contract for not less than one year unless Union, in its sole discretion, accepts a term of less than one year.

OVERRUN SERVICE:

1. Annual Storage Space

Authorized

Authorized Overrun is provided as Storage/Balancing Service. It is payable on all quantities on any Day in excess of the customer’s contracted Maximum Storage Space. Overrun will be authorized by Union at is sole discretion. Storage Space Overrun equal to the customer’s firm deliveries from TCPL: less the customer’s Firm Daily Contract Demand, all multiplied by the Days of Interruption called during the period of November 1 to March 31, will be automatically authorized until the following July 1.

Unauthorized

If in any month, the customer has gas in storage in excess of the contracted Maximum Storage Space, and which has not been authorized by Union or provided for under a short term supplemental storage service, such an event will constitute an occurrence of Unauthorized Overrun. The Unauthorized Overrun rate will be $6.000 per GJ applied to the greatest excess for each occurrence.

If on any Day the gas storage balance for the account of the customer is less than zero, the Unauthorized Overrun charge will apply for each GJ of gas below a zero inventory level and this amount of gas shall be deemed not to have been withdrawn from storage. The gas shall be deemed to have been sold to the customer at the highest spot price at Dawn in the month of occurrence and the month following occurrence as identified in the Canadian Gas Price Reporter and shall not be less than Union’s approved weighted average cost of gas If the customer has contracted to provide its own deliverability inventory, the zero inventory level shall be deemed to mean twenty percent (20%) of the Annual Firm Storage Space.

2. Injection, Withdrawals and Transportation

Authorized

The following Overrun rates are applied to any quantities transported, injected or withdrawn in excess of 103% of the Contract parameters. Overrun will be authorized by Union at its sole discretion.

Automatic authorization of Injection Overrun will be given during all Days a customer has been interrupted.

	Union Providing Fuel	For Customers Providing Their Own Compressor Fuel Firm or Interruptible Service	
	Firm or Interruptible Service	Fuel Ratio	Commodity Charge
Storage Injections	\$0.108/GJ	0.853%	\$0.061/GJ
Storage Withdrawals	\$0.108/GJ	0.853%	\$0.061/GJ
Transportation	1.1743 ¢/m³	0.250%	1.1218 ¢/m³

Unauthorized

For all quantities on any Day in excess of 103% of the customer's contractual rights, for which authorization has not been received, the customer will be charged 4.5164 ¢ per m³ or \$1.194 per GJ, as appropriate.

3. Storage / Balancing Service

Authorized

The following Overrun rates are applied to any quantities stored in excess of the Contract parameters. Overrun will be authorized by Union Gas at its sole discretion.

	Firm Service Rate/GJ
Space	\$6.000
Injection / Withdrawal Maximum	\$6.000

OTHER SERVICES & CHARGES:

1. Monthly Charge

In addition to the rates and charges described previously for each Point of Consumption, a Monthly Charge shall be applied as follows:

Monthly Charge	$1,936.13

2. Diversion of Gas

The availability of the right to divert gas will be based on Union's ability to accommodate the diversion. The price to be charged for the right to divert shall be determined through negotiation.

3. Delivery Obligations

Unless otherwise authorized by Union, all other customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

4. Additional Service Information

Additional information on Union's T1 service offering can be found at:

The additional information consists of, but is not limited to, the following:
http://www.uniongas.com/business/accountservices/unionline/contractsRates/T1servicefeatures.asp

i. Storage space and deliverability entitlement;
ii. The determination of gas supply receipt points and delivery obligations;
iii. The nomination schedule;
iv. The management of multiple redelivery points by a common fuel manager; and
v. The availability of supplemental transactional services including title transfers.

(D) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

unionGas

STORAGE AND TRANSPORTATION RATES
FOR CONTRACT CARRIAGE CUSTOMERS

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To a customer:

a) who has a daily firm contracted demand of at least 140 870 m^3. Firm and/or interruptible daily contracted demand of less than 140,870 m^3 cannot be combined for the purposes of qualifying for this rate class; and

b) who enters into a Carriage Service Contract with Union for the transportation or the storage and transportation of Gas for use at facilities located within Union's gas franchise area; and

c) who has meters with electronic recording at each Point of Consumption; and

d) who has site specific energy measuring equipment installed at each Point of Consumption that will be used in determining energy balances; and

e) for whom Union has determined transportation and/or storage capacity is available.

For the purposes of qualifying for a rate class, the total quantities of gas consumed or expected to be consumed on the customer's contiguous property will be used, irrespective of the number of meters installed.

(C) Rates

The following rates shall be charged for all quantities contracted or handled as appropriate. The identified rates represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

STORAGE SERVICE:

			For Customers Providing Their Own Compressor Fuel	
	Demand Charge Rate/GJ/mo	Commodity Charge Rate/GJ	Fuel Ratio	Commodity Charge Rate/GJ
a) Annual Firm Storage Space Applied to contracted Maximum Annual Storage Space	$0.011			
b) Annual Firm Injection/Withdrawal Right: Applied to the contracted Maximum Annual Firm Injection/Withdrawal Right				
Union provides deliverability Inventory	$1.624			
Customer provides deliverability Inventory (4)	$1.197			
c) Incremental Firm Injection Right: Applied to the contracted Maximum Incremental Firm Injection Right	$1.197			
d) Annual Interruptible Withdrawal Right: Applied to the contracted Maximum Annual Interruptible Withdrawal Right	$1.197			

	Demand Charge Rate/GJ/mo	Commodity Charge Rate/GJ	For Customers Providing Their Own Compressor Fuel: Fuel Ratio	Commodity Charge Rate/GJ
e) Withdrawal Commodity Paid on all quantities withdrawn from storage up to the Maximum Daily Storage Withdrawal Quantity		$0.030	0.395%	$0.008
f) Injection Commodity Paid on all quantities injected into storage up to the Maximum Daily Storage Injection Quantity		$0.030	0.395%	$0.008
g) Short Term Storage / Balancing Service Maximum		$6.000		

Notes:

1. Demand charges for Annual Services are paid monthly during the term of the contract for not less than one year unless Union, in its sole discretion, accepts a term of less than one year. Demand charges apply whether Union or the customer provides the fuel.

2. Annual Firm Injection Rights are equal to 100% of their respective Annual Firm Withdrawal Rights. Injection Rights in excess of the Annual Firm Injection Rights will be charged at the Incremental Firm Injection Right.

3. Annual Firm Storage Space

   The maximum storage space available to a customer at the rates specified herein is determined by one of the following storage allocation methodologies:

   3.1 Aggregate Excess
   Aggregate excess is the difference between a customer's gas consumption in the 151-day winter period and consumption during the balance of the year. This calculation will be done using two years of historical data (with 25% weighting for each year) and one year of forecast data (with 50% weighting). If a customer is new, or an existing customer is undergoing a significant change in operations, the allocation will be based on forecast consumption only, as negotiated between Union and the customer. Once sufficient historical information is available for the customer, the standard calculation will be done. At each contract renewal, the aggregate excess calculation will be performed to set the new space allocation.

   3.2 Obligated daily contract quantity multiple of 15
   Obligated daily contract quantity is the firm daily quantity of gas which the customer must deliver to Union. The 15 x obligated daily contract quantity calculation will be done using the daily contract quantity for the upcoming contract year. At each contract renewal, the 15 x obligated daily contract quantity calculation will be performed to set the new space allocation.

   3.3 For new, large (daily firm transportation demand requirements in excess of 1,200,000 m^3/day) gas fired power generation customers, storage space is determined by peak hourly consumption x 24 x 4 days. Should the customer elect firm deliverability less than their maximum entitlement (see Note 4.2), the maximum storage space available at the rates specified herein is 10 x firm storage deliverability contracted, not to exceed peak hourly consumption x 24 x 4 days.

   Customers may contract for less than their maximum entitlement of firm storage space.

4. Annual Injection/Withdrawal Right

   The maximum level of deliverability available to a customer at the rates specified herein is determined by one of the following methodologies:

   4.1 The greater of obligated daily contract quantity or firm daily contract demand less obligated daily contract quantity.

   4.2 For new, large (daily firm transportation demand requirements in excess of 1,200,000 m^3/day) gas fired power generation customers, the maximum entitlement of firm storage deliverability is 24 times the customer's peak hourly consumption, with 1.2% firm deliverability available at the rates specified herein.

   Customers may contract for less than their maximum entitlement of deliverability. A customer may contract up to this maximum entitlement with a combination of firm and interruptible deliverability as specified in Section (C) Storage Service.

5. Additional storage space or deliverability, in excess of the allocated entitlements per Notes 3 and 4, may be available at market prices.

6. Storage Space and Withdrawal Rights are not assignable to any other party without the prior written consent of Union.

7. Deliverability Inventory being defined as 20% of annual storage space.

8. Short Term Storage / Balancing Service is:
   i) a combined space and interruptible deliverability service for short-term or off-peak storage in Union's storage facilities, or
   ii) short-term firm deliverability, or
   iii) a component of an operational balancing service offered.

   In negotiating the rate to be charged for service, the matters that are to be considered include:
   i) The minimum amount of storage service to which a customer is willing to commit,
   ii) Whether the customer is contracting for firm or interruptible service during Union's peak or non-peak periods,
   iii) Utilization of facilities, and
   iv) Competition

TRANSPORTATION CHARGES:

	Demand Charge Rate/m³/mo	Commodity Charge Rate/m³	For Customers Providing Their Own Compressor Fuel: Fuel Ratio (5) (6)	For Customers Providing Their Own Compressor Fuel: Commodity Charge Rate/m³
a) Annual Firm Transportation Demand Applied to the Firm Daily Contract Demand				
First 140,870 m³ per month	20.1911 ¢			
All over 140,870 m³ per month	10.6802 ¢			
b) Firm Transportation Commodity Paid on all firm quantities redelivered to the customer's Point(s) of Consumption				
Commodity Charge (All volumes)		0.0597 ¢	0.247%	0.0078 ¢
c) Interruptible Transportation Commodity Paid on all interruptible quantities redelivered to the customer's Point(s) of Consumption				
Maximum		3.9455 ¢	0.247%	3.8936 ¢

Notes:

1. All demand charges are paid monthly during the term of the contract for not less than one year unless Union, at its sole discretion, accepts a term of less than one year. Demand charges apply whether Union or the customer provides the fuel.

2. Effective January 1, 2007, new customers and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3/day and who are directly connected to i) the Dawn-Trafalgar transmission system in close proximity to Parkway or ii) a third party pipeline, have the option to pay for service using a Billing Contract Demand. The Billing Contract Demand shall be determined by Union such that the annual revenues over the term of the contract will recover the invested capital, return on capital and operating and maintenance costs associated with the dedicated service in accordance with Union's system expansion policy. The firm transportation demand charge will be applied to the Billing Contract Demand. For customers choosing the Billing Contract Demand option, the authorized transportation overrun rate will apply to all volumes in excess of the Billing Contract Demand but less than the daily firm demand requirement.

3. In negotiating the rate to be charged for the transportation of gas under Interruptible Transportation, the matters that are to be considered include:

    a) The amount of the interruptible transportation for which customer is willing to contract,

    b) The anticipated load factor for the interruptible transportation quantities,

    c) Interruptible or curtailment provisions, and

    d) Competition.

4. In each contract year, the customer shall pay for a Minimum Interruptible Transportation Activity level as specified in the Contract. Overrun activity will not contribute to the minimum activity level.

5. Transportation fuel ratios do not apply to customers served from dedicated facilities directly connected to third party transmission systems with custody transfer metering at the interconnect.

6. Firm transportation fuel ratio does not apply to new customers or existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3/day that contract for M12 Dawn to Parkway transportation service equivalent to 100% of their daily firm demand requirement. If a customer with a daily firm demand requirement in excess of 1,200,000 m^3/day contracts for M12 Dawn to Parkway transportation service at less than 100% of their firm daily demand requirement, the firm transportation fuel ratio will be applicable to daily volumes not transported under the M12 transportation contract.

7. Either Union or a customer, or potential customer, may apply to the Ontario Energy Board to fix rates and other charges different from the rates and other charges specified herein if the changed rates and other charges are considered by either party to be necessary, desirable and in the public interest.

SUPPLEMENTAL CHARGES:

Rates for supplemental services are provided in Schedule "A".

Notes:

1. All demand charges are paid monthly during the term of the contract for not less than one year unless Union, in its sole discretion, accepts a term of less than one year.

OVERRUN SERVICE:

1. Annual Storage Space

Authorized

Authorized Overrun is provided as Storage/Balancing Service. It is payable on all quantities on any Day in excess of the customer's contracted Maximum Storage Space. Overrun will be authorized by Union at is sole discretion. Storage Space Overrun equal to the customer's firm deliveries from TCPL: less the customer's Firm Daily Contract Demand, all multiplied by the Days of Interruption called during the period of November 1 to March 31, will be automatically authorized until the following July 1.

Unauthorized

If in any month, the customer has gas in storage in excess of the contracted Maximum Storage Space, and which has not been authorized by Union or provided for under a short term supplemental storage service, such an event will constitute an occurrence of Unauthorized Overrun. The Unauthorized Overrun rate will be $6.000 per GJ applied to the greatest excess for each occurrence.

If on any Day the gas storage balance for the account of the customer is less than zero, the Unauthorized Overrun charge will apply for each GJ of gas below a zero inventory level and this amount of gas shall be deemed not to have been withdrawn from storage. The gas shall be deemed to have been sold to the customer at the highest spot price at Dawn in the month of occurrence and the month following occurrence as identified in the Canadian Gas Price Reporter and shall not be less than Union's approved weighted average cost of gas If the customer has contracted to provide its own deliverability inventory, the zero inventory level shall be deemed to mean twenty percent (20%) of the Annual Firm Storage Space.

2. Injection, Withdrawals and Transportation

Authorized

The following Overrun rates are applied to any quantities transported, injected or withdrawn in excess of 103% of the Contract parameters. Overrun will be authorized by Union at its sole discretion.

Automatic authorization of Injection Overrun will be given during all Days a customer has been interrupted.

	Union Providing Fuel	For Customers Providing Their Own Compressor Fuel Firm or Interruptible Service	
	Firm or Interruptible Service	Fuel Ratio	Commodity Charge
Storage Injections	$0.108/GJ	0.853%	$0.061/GJ
Storage Withdrawals	$0.108/GJ	0.853%	$0.061/GJ
Transportation	0.7235 ¢/m³	0.247%	0.6716 ¢/m³

Unauthorized

For all quantities on any Day in excess of 103% of the customer's contractual rights, for which authorization has not been received, the customer will be charged 4.5164 ¢ per m³ or $1.194 per GJ, as appropriate.

3. Storage / Balancing Service

Authorized

The following Overrun rates are applied to any quantities stored in excess of the Contract parameters. Overrun will be authorized by Union Gas at its sole discretion.

	Firm Service Rate/GJ
Space	$6.000
Injection / Withdrawal Maximum	$6.000

OTHER SERVICES & CHARGES:

1. **Monthly Charge**

In addition to the rates and charges described previously for each Point of Consumption, a Monthly Charge shall be applied as follows:

Monthly Charge	$6,000.00

2. **Diversion of Gas**

The availability of the right to divert gas will be based on Union's ability to accommodate the diversion. The price to be charged for the right to divert shall be determined through negotiation.

3. **Delivery Obligations**

Effective January 1, 2007, new customers and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3/day who are delivering gas to Union under direct purchase arrangements may be entitled to non-obligated deliveries. The delivery options available to customers are detailed at www.uniongas.com/aboutus/regulatory/rates/deliveryobligations.asp.

Unless otherwise authorized by Union, all other customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

4. **Nominations**

Effective January 1, 2007, new customers and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3/day who have non obligated deliveries may contract to use Union's 5 additional nomination windows (13 in total) for the purposes of delivering gas to Union. These windows are in addition to the standard NAESB and TCPL STS nomination windows. Customers taking the additional nomination window service will pay an additional monthly demand charge of $0.068/GJ/day/month multiplied by the non-obligated daily contract quantity.

5. **Additional Service Information**

Additional information on Union's T2 service offering can be found at:

The additional information consists of, but is not limited to, the following:
http://www.uniongas.com/business/accountservices/unionline/contractsRates/T1servicefeatures.asp

i. Storage space and deliverability entitlement;
ii. The determination of gas supply receipt points and delivery obligations;
iii. The nomination schedule;
iv. The management of multiple redelivery points by a common fuel manager; and
v. The availability of supplemental transactional services including title transfers.

(D) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

STORAGE AND TRANSPORTATION RATES
FOR CONTRACT CARRIAGE CUSTOMERS

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To a Distributor:

a) whose minimum annual transportation of natural gas is 700 000 m^3 or greater; and

b) who enters into a Carriage Service Contract with Union for the transportation or the storage and transportation of Gas for distribution to its customers; and

c) who has meters with electronic recording at each Point of Redelivery; and

d) for whom Union has determined transportation and/or storage capacity is available.

(C) Rates

The following rates shall be charged for all quantities contracted or handled as appropriate. The identified rates represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

STORAGE SERVICE:

			For Customers Providing Their Own Compressor Fuel	
	Demand Charge Rate/GJ/mo	Commodity Charge Rate/GJ	Fuel Ratio	Commodity Charge Rate/GJ
a) Annual Firm Storage Space Applied to contracted Maximum Annual Storage Space	$0.011			
b) Annual Firm Injection/Withdrawal Right: Applied to the contracted Maximum Annual Firm Injection/Withdrawal Right				
Union provides deliverability Inventory	$1.624			
Customer provides deliverability Inventory (4)	$1.197			
c) Incremental Firm Injection Right: Applied to the contracted Maximum Incremental Firm Injection Right	$1.197			
d) Annual Interruptible Withdrawal Right: Applied to the contracted Maximum Annual Interruptible Withdrawal Right	$1.197			

	Demand Charge Rate/GJ/mo	Commodity Charge Rate/GJ	For Customers Providing Their Own Compressor Fuel: Fuel Ratio	For Customers Providing Their Own Compressor Fuel: Commodity Charge Rate/GJ
e) Withdrawal Commodity Paid on all quantities withdrawn from storage up to the Maximum Daily Storage Withdrawal Quantity		$0.030	0.395%	$0.008
f) Injection Commodity Paid on all quantities injected into storage up to the Maximum Daily Storage Injection Quantity		$0.030	0.395%	$0.008
g) Short Term Storage / Balancing Service Maximum		$6.000		

Notes:

1. Demand charges for Annual Services are paid monthly during the term of the contract for not less than one year unless Union, in its sole discretion, accepts a term of less than one year. Demand charges apply whether Union or the customer provides the fuel.

2. Annual Firm Injection Rights are equal to 100% of their respective Annual Firm Withdrawal Rights. Injection Rights in excess of the Annual Firm Injection Rights will be charged at the Incremental Firm Injection Right.

3. Annual Firm Storage Space

   The maximum storage space available to a customer at the rates specified herein is determined by one of the following storage allocation methodologies:

   3.1 Aggregate Excess
   Aggregate excess is the difference between a customer's gas consumption in the 151-day winter period and consumption during the balance of the year. This calculation will be done using two years of historical data (with 25% weighting for each year) and one year of forecast data (with 50% weighting). If a customer is new, or an existing customer is undergoing a significant change in operations, the allocation will be based on forecast consumption only, as negotiated between Union and the customer. Once sufficient historical information is available for the customer, the standard calculation will be done. At each contract renewal, the aggregate excess calculation will be performed to set the new space allocation.

   3.2 Obligated daily contract quantity multiple of 15
   Obligated daily contract quantity is the firm daily quantity of gas which the customer must deliver to Union. The 15 x obligated daily contract quantity calculation will be done using the daily contract quantity for the upcoming contract year. At each contract renewal, the 15 x obligated daily contract quantity calculation will be performed to set the new space allocation.

   Customers may contract for less than their maximum entitlement of firm storage space.

4. Annual Injection/Withdrawal Right

   The maximum level of deliverability available to a customer at the rates specified herein is determined to be the greater of obligated daily contract quantity or firm daily contract demand less obligated daily contract quantity.

   Customers may contract for less than their maximum entitlement of deliverability. A customer may contract up to this maximum entitlement with a combination of firm and interruptible deliverability as specified in Section (C) Storage Service.

5. Additional storage space or deliverability, in excess of the allocated entitlements per Notes 3 and 4, may be available at market prices.

6. Storage Space and Withdrawal Rights are not assignable to any other party without the prior written consent of Union.

7. Deliverability Inventory being defined as 20% of annual storage space.

8. Short Term Storage / Balancing Service is:
   i) a combined space and interruptible deliverability service for short-term or off-peak storage in Union's storage facilities, OR
   ii) short-term firm deliverability, OR
   iii) a component of an operational balancing service offered.

   In negotiating the rate to be charged for this service, the matters that are to be considered include:
   i) The minimum amount of storage service to which a customer is willing to commit,
   ii) Whether the customer is contracting for firm or interruptible service during Union's peak or non-peak periods,
   iii) Utilization of facilities, and
   iv) Competition

TRANSPORTATION CHARGES:

	Demand Charge Rate/m^3/mo	Commodity Charge Rate/m^3	For Customers Providing Their Own Compressor Fuel: Fuel Ratio (5) (6)	For Customers Providing Their Own Compressor Fuel: Commodity Charge Rate/m^3
a) Annual Firm Transportation Demand (1) Applied to the Firm Daily Contract Demand	9.3582 ¢			
b) Firm Transportation Commodity Paid on all firm quantities redelivered to the Customer's Point(s) of Redelivery		0.0707 ¢	0.285%	0.0107 ¢

Notes:

1. All demand charges are paid monthly during the term of the contract for not less than one year unless Union, in its sole discretion, accepts a term of less than one year. Demand charges apply whether Union or the customer provides the fuel.

SUPPLEMENTAL CHARGES

Rates for supplemental services are provided in Schedule "A".

Notes:

1. All demand charges are paid monthly during the term of the contract for not less than one year unless Union, in its sole discretion, accepts a term of less than one year.

OVERRUN SERVICE

1. Annual Storage Space

Authorized

Authorized Overrun is provided as Storage/Balancing Service. It is payable on all quantities on any Day in excess of the customer's contracted Maximum Storage Space. Overrun will be authorized by Union at is sole discretion.

Unauthorized

If in any month, the customer has gas in storage in excess of the contracted Maximum Storage Space, and which has not been authorized by Union or provided for under a short term supplemental storage service, such an event will constitute an occurrence of Unauthorized Overrun. The Unauthorized Overrun rate will be $6.000 per GJ applied to the greatest excess for each occurrence.

If on any Day, the gas storage balance for the account of the customer is less than zero, the Unauthorized Overrun charge will apply for each GJ of gas below a zero inventory level and this amount of gas shall be deemed not to have been withdrawn from storage. The gas shall be deemed to have been sold to the customer at the highest spot price at Dawn in the month of occurrence and the month following occurrence as identified in the Canadian Gas Price Reporter and shall not be less than Union's approved weighted average cost of gas. If the customer has contracted to provide its own deliverability inventory, the zero inventory level shall be deemed to mean twenty percent (20%) of the Annual Firm Storage Space.

2. Injection, Withdrawals and Transportation

Authorized

The following Overrun rates are applied to any quantities transported, injected or withdrawn in excess of 103% of the Contract parameters. Overrun will be authorized by Union at its sole discretion.

	Union Providing Fuel	For Customers Providing Their Own Compressor Fuel Firm or Interruptible Service	
	Firm or Interruptible Service	Fuel Ratio	Commodity Charge
Storage Injections	$0.108/GJ	0.853%	$0.061/GJ
Storage Withdrawals	$0.108/GJ	0.853%	$0.061/GJ
Transportation	0.3783 ¢/m³	0.285%	0.3184 ¢/m³

Unauthorized

For all quantities on any Day in excess of 103% of the customer's contractual rights, for which authorization has not been received, the customer will be charged 36.0¢ per m³ or $9.519 per GJ, as appropriate.

3. Short Term Storage Services

Authorized

The following Overrun rates are applied to any quantities stored in excess of the Contract parameters. Overrun will be authorized by Union Gas at its sole discretion.

	Firm Service Rate/GJ
Space	$6.000
Injection	
Maximum	$6.000

OTHER SERVICES & CHARGES

1. Monthly Charge

In addition to the rates and charges described previously for each Point of redelivery a Monthly Charge shall be applied to each specific customer as follows:

		Monthly Charge
City of Kitchener	$	20,371.35
NRG	$	3,127.21
Six Nations	$	1,042.40

If a customer combines Sales Service with Contract Carriage Service, the monthly charge will be prorated such that the customer will under both services pay no more than the above monthly charge.

2. Diversion of Gas

The availability of the right to divert gas will be based on Union's ability to accommodate the diversion. The price to be charged for the right to divert shall be determined through negotiation.

3. Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(D) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

unionGas

Effective
2013-01-01
Schedule "A"

Gas Supply Charges

(A) Availability:

Available to customers in Union's Southern Delivery Zone.

(B) Applicability:

To all sales customers served under Rate M1, Rate M2, Rate M4, Rate M5A, Rate M7, Rate M9, Rate M10 and storage and transportation customers taking supplemental services under Rate T1, Rate T2 and Rate T3.

(C) Rates:

	cents / m^3
Utility Sales	
Commodity and Fuel	12.7620 (1)
Commodity and Fuel - Price Adjustment	(2.1831) (2)
Transportation	4.3997
Total Gas Supply Commodity Charge	14.9786
Minimum Annual Gas Supply Commodity Charge	
Rate M4 Firm and Rate M5A Interruptible Contract	4.8475

Storage and Transportation Supplemental Services - Rate T1, Rate T2 & Rate T3	$/GJ
Monthly demand charges:	
Firm gas supply service	63.325
Firm backstop gas	1.846
Commodity charges:	
Gas supply	3.466
Backstop gas	4.957
Reasonable Efforts Backstop Gas	5.732
Supplemental Inventory	Note (3)
Supplemental Gas Sales Service (cents / m^3)	20.1973
Failure to Deliver: Applied to quantities not delivered to Union in the event the customer's supply fails	2.561
Discretionary Gas Supply Service (DGSS)	Note (4)

Notes:

(1) The Commodity and Fuel rate includes a gas supply administration charge of 0.1933 cents/ m^3.
(2) Includes a temporary credit of 0.0853 cents/m^3 for the period February 1, 2013 to December 31, 2013.
(3) The charge for banked gas purchases shall be the higher of the daily spot gas cost at Dawn in the month of or the month following the month in which gas is sold under this rate and shall not be less than Union's approved weighted average cost of gas.
(4) Reflects the "back to back" price plus gas supply administration charge.

Effective: January 1, 2013
O.E.B. Order # EB-2011-0210

Chatham, Ontario

Supersedes EB-2012-0437 Rate Schedule effective January 1, 2013.

unionGas

STORAGE RATES FOR
UNBUNDLED CUSTOMERS

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To a customer, or an agent, who is authorized to service residential and non-contract commercial and industrial end-users paying for the Monthly Fixed Charge and Delivery charge under Rate M1 or Rate M2:

a) who enters into an Unbundled Service Contract with Union for the storage of Gas for use at facilities located within Union's gas franchise area;

b) who contracts for Standard Peaking Service (SPS) with Union unless the customer can demonstrate that it has a replacement to the deliverability available in the SPS physically tied into Union's system and an OEB approved rate to provide the SPS replacement service;

c) who accepts daily estimates of consumption at Points of Consumption as prepared by Union so that they may nominate an equivalent amount from storage, upstream transportation, or Ontario Producers authorized to sell to third parties;

d) who nominates injections and withdrawals from storage and deliveries on upstream pipeline systems daily or Ontario Producers authorized to sell to third parties;

e) for whom Union has determined storage capacity is available; and

f) who accepts a monthly bill as prepared by Union.

(C) Rates

The following rates shall be charged for all volumes contracted or handled as appropriate. The identified rates represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

STORAGE SERVICE	Demand Charge Rate/GJ/mo	Fuel Ratio	Commodity Charge Rate/GJ
i) Standard Storage Service (SSS)			
a) Combined Storage Space & Deliverability Applied to contracted Maximum Storage Space	$0.024		
b) Injection Commodity		0.395%	$0.026
c) Withdrawal Commodity		0.395%	$0.026
ii) Standard Peaking Service (SPS)			
a) Combined Storage Space & Deliverability Applied to contracted Maximum Storage Space	$0.116		
b) Injection Commodity		0.395%	$0.026
c) Withdrawal Commodity		0.853%	$0.026

	Demand Charge Rate/GJ/mo	Fuel Ratio	Commodity Charge Rate/GJ
iii) Supplemental Service			
a) Incremental Firm Injection Right: (5) Applied to the contracted Maximum Incremental Firm Injection Right	$1.041		
b) Incremental Firm Withdrawal Right: (5) Applied to the contracted Maximum Incremental Firm Withdrawal Right	$1.041		
c) Short Term Storage / Balancing Service - Maximum			$6.000

Notes:

1. Demand charges for Annual Services are paid monthly during the term of the Contract, which shall not be less than one year, unless Union, in its sole discretion, accepts a term of less than one year.

2. Daily Firm Injection and Withdrawal Rights shall be pursuant to the Storage Contract.

3. Storage Space, Withdrawal Rights, and Injection Rights are not assignable to any other party without the prior written consent of Union and where necessary, approval from the Ontario Energy Board.

4. Short Term Storage / Balancing service (less than 2 years) is:
   i) a combined space and interruptible deliverability service for short-term or off-peak storage in Union's storage facilities, OR
   ii) short-term incremental firm deliverability, OR
   iii) a component of an operational balancing service offered.

   In negotiating the rate to be charged for service, the matters that are to be considered include:
   i) The minimum amount of storage service to which a customer is willing to commit,
   ii) Whether the customer is contracting for firm or interruptible service during Union's peak or non-peak periods,
   iii) Utilization of facilities,
   iv) Competition, and
   v) Term.

5. Union's ability to offer incremental injection and withdrawal rights is subject to annual asset availability.

OVERRUN SERVICE

1. Injection and Withdrawal

Authorized

	Fuel Ratio	Commodity Charge Rate/GJ
Injection	0.853%	$0.060
Withdrawal	0.853%	$0.060

The Authorized Overrun rate is payable on all quantities on any Day in excess of the customer's contractual rights, for which authorization has been received. Overrun will be authorized by Union at its sole discretion.

Unauthorized

If in any month, the customer has gas in storage in excess of the contracted Maximum Storage Space or the gas storage balance for the account of the customer is less than zero or the customer has injected or withdrawn volumes from storage which exceeds their contractual rights, and which has not been authorized by Union or provided for under a short term storage/balancing service, such an event will constitute an occurrence of Unauthorized Overrun. The Unauthorized Overrun rate during the November 1 to April 15 period will be $60.00 per GJ. The Unauthorized Overrun rate during the April 16 to October 31 period will be $6.000 per GJ.

OTHER SERVICES & CHARGES

1. Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must commit to provide a call at Parkway, throughout the winter period, for a specified number of days. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(D) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

TRANSPORTATION RATES

(A) Applicability

The charges under this schedule shall be applicable to a Shipper who enters into a Transportation Service Contract with Union.

Applicable Points

Dawn as a receipt point: Dawn (TCPL), Dawn (Facilities), Dawn (Tecumseh), Dawn (Vector) and Dawn (TSLE).

Dawn as a delivery point: Dawn (Facilities).

(B) Services

Transportation Service under this rate schedule shall be for transportation on Union's Dawn - Trafalgar facilities.

(C) Rates

The identified rates represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

	Monthly Demand Charge (applied to daily contract demand) Rate/GJ	Commodity and Fuel Charges Fuel Ratio %	AND	Commodity Charge Rate/GJ
Firm Transportation (1)				
Dawn to Parkway	$2.382			
Dawn to Kirkwall	$2.011	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Kirkwall to Parkway	$0.372			
Parkway to Dawn	n/a			
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway	$2.961	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)				
Dawn to Parkway – Maximum	$5.718	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$5.718			
Parkway (TCPL) to Parkway (Cons) (2)		0.153%		

Authorized Overrun (3)

Authorized overrun rates will be payable on all quantities in excess of Union's obligation on any day. The overrun charges payable will be calculated at the following rates. Overrun will be authorized at Union's sole discretion.

Transportation Overrun	If Union supplies fuel Commodity Charge Rate/GJ	Commodity and Fuel Charges Fuel Ratio %	AND	Commodity Charge Rate/GJ
Dawn to Parkway				$0.078
Dawn to Kirkwall		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.066
Kirkwall to Parkway				$0.012
Parkway to Dawn				$0.078
Parkway (TCPL) Overrun (4)	n/a	0.648%		n/a
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.097

(C) Rates (Cont'd)

Unauthorized Overrun

Authorized Overrun rates will be payable on all quantities up to 2% in excess of Union's contractual obligation.

The Unauthorized Overrun shall be the higher of the reported daily spot price of gas at either Dawn, Parkway, Niagara or Iroquois in the month of or the month following the month in which the overrun occurred plus 25% for all usage on any day in excess of 102% of Union's contractual obligation.

Nomination Variances

Where Union and the shipper have entered into a Limited Balancing Agreement ("LBA"), the rate for unauthorized parking or drafting which results from nomination variances shall equal the "Balancing Fee" rate as described under Article XXII of TransCanada PipeLines Transportation Tariff.

Notes for Section (C) Rates:

(1) The annual transportation commodity charge is calculated by application of the YCRR Formula, as per Section (D). The annual transportation fuel required is calculated by application of the YCR Formula, as per Section (D).

(2) This rate is for westerly transportation within the Parkway yard, from Parkway (TCPL) to Parkway (Cons) or Lisgar.

(3) For purposes of applying the YCRR Formula or YCR Formula (Section (D)) to transportation overrun quantities, the transportation commodity revenue will be deemed to be equal to the commodity charge of the applicable service as detailed in Section (B).

(4) This ratio will be applied to all gas quantities for which Union is obligated to deliver to Parkway (Cons) or Lisgar and has agreed to deliver to Parkway (TCPL) on an interruptible basis. This will be in addition to any rate or ratio paid for transportation easterly to Parkway (Cons) or Lisgar.

(5) A demand charge of $0.068/GJ/day/month will be applicable for customers contracting for firm all day transportation service in addition to the demand charges appearing on this schedule for firm transportation service to either Kirkwall or Parkway

(D) Transportation Commodity

The annual fuel charge in kind or in dollars for transportation service in any contract year shall be equal to the sum of the application of the following equation applied monthly for the 12 months April through March (The "YCRR" or "YCR" Formula). An appropriate adjustment in the fuel charges will be made in May for the previous 12 months ending March 31st to obtain the annual fuel charges as calculated using the applicable "YCRR" or "YCR" Formula. At Union's sole discretion Union may make more frequent adjustments than once per year. The YCRR and YCR adjustments must be paid/remitted to/from Shippers at Dawn within one billing cycle after invoicing.

(D) Transportation Commodity (Cont'd)

YCR = $\sum_{1}^{4}$ [(0.001529 X (QT1 + QT3)) + (DSFx(QT1 + QT3)) + F_{ST}] For June 1 to Sept. 30

plus

$\sum_{5}^{12}$ [0.001529 x (QT1 + Q3)) + (DWFxQT1) + F_{WT}] For Oct. 1 to May 31

YCRR = $\sum_{1}^{4}$ [(0.001529 x (QT1 + QT3)) + (DSFx(QT1 + QT3)) + F_{ST}]xR For June 1 to Sept. 30

plus

$\sum_{5}^{12}$ [(0.001529 x (QT1 + QT3)) + (DWFxQT1)+ F_{WT}]xR For Oct. 1 to May 31

where: DSF = 0.00000 for Dawn summer fuel requirements
DWF = 0.0020 for Dawn winter fuel requirements

in which:

YCR Yearly Commodity Required

The sum of 12 separate monthly calculations of Commodity Quantities required for the period from April through March.

YCRR Yearly Commodity Revenue Required

The sum of 12 separate monthly calculations of Commodity Revenue required for the period April through March.

QT1 Monthly quantities in GJ transported easterly hereunder received at Dawn at not less than 4 850 kPa but less than 5 860 kPa (compression required at Dawn).

QT3 Monthly quantities in GJ transported westerly hereunder received at the Parkway Delivery Point.

F_{WT} The individual Shipper's monthly share of compressor fuel used in GJ which was required at Union's Lobo, Bright, Trafalgar and Parkway Compressor Stations ("Lobo", "Bright", "Trafalgar" and "Parkway") to transport the same Shipper's QT1 monthly quantities easterly.

Lobo, Bright, Trafalgar and Parkway compressor fuel required by each Shipper will be calculated each month.

The monthly Lobo and Bright compressor fuel will be allocated to each Shipper in the same proportion as the Shipper's monthly quantities transported is to the monthly transported quantity for all users including Union.

The monthly Parkway and Trafalgar compressor fuel used will be allocated to each Shipper in the same proportion as the monthly quantity transported to Parkway (TCPL) for each user is to the total monthly quantity transported for all users including Union.

(D) Transportation Commodity (Cont'd)

F_{ST} The individual Shipper's monthly share of compressor fuel used in GJ which was required at Union's Lobo, Bright, Trafalgar and Parkway compressor stations to transport the same Shipper's quantity on the Trafalgar system.

Lobo, Bright, Trafalgar and Parkway compressor fuel required by each Shipper will be calculated each month.

R Union's weighted average cost of gas in $/GJ.

Notes

(i) In the case of Easterly flow, direct deliveries by TCPL at Parkway to Union or on behalf of Union to Union's Transportation Shippers will be allocated to supply Union's markets on the Dawn-Parkway facilities starting at Parkway and proceeding westerly to successive laterals until exhausted.

(E) Provision for Compressor Fuel

For a Shipper that has elected to provide its own compressor fuel.

Transportation Fuel

On a daily basis, the Shipper will provide Union at the delivery point and delivery pressure as specified in the contract, a quantity (the "Transportation Fuel Quantity") representing the Shipper's share of compressor fuel and unaccounted for gas for transportation service on Union's system.

The Transportation Fuel Quantity will be determined on a daily basis, as follows:

Transportation Fuel Quantity = Transportation Quantity x Transportation Fuel Ratio.

In the event that the actual quantity of fuel supplied by the Shipper was different from the actual fuel quantity as calculated using the YCR formula, an adjustment will be made in May for the previous 12 months ending March 31st.

Nominations

The Shipper will be required to nominate its Transportation Fuel Quantity in addition to its normal nominations for transportation services.

(F) Terms of Service

The General Terms & Conditions applicable to this rate schedule shall be in accordance with the attached Schedule "A" for contracts in effect before October 1, 2010. The General Terms & Conditions applicable to this rate schedule shall be in accordance with the attached Schedule "A 2010" for contracts in effect on or after October 1, 2010.

(G) Nominations

Nominations under this rate schedule shall be in accordance with the attached Schedule "B" for contracts in effect before October 1, 2010. Nominations under this rate schedule shall be in accordance with the attached Schedule "B 2010" for contracts in effect on or after October 1, 2010.

(H) Monthly Fuel Rates and Ratios

Monthly fuel rates and ratios under this rate schedule shall be in accordance with Schedule “C”.

(I) Receipt and Delivery Points and Pressures

Receipt and Delivery Points and Pressures under this rate schedule shall be in accordance with Schedule “D 2010” for contracts in effect on or after October 1, 2010.

SCHEDULE "A"

RATE M12
GENERAL TERMS & CONDITIONS

I. DEFINITIONS

Except where the context expressly requires or states another meaning, the following terms, when used in these General Terms & Conditions and in any contract into which these General Terms & Conditions are incorporated, shall be construed to have the following meanings:

1. "Contract" shall refer to the Contract to which these General Terms & Conditions shall apply, and into which they are incorporated;

2. "cubic metre" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

3. "day" shall mean a period of twenty-four (24) consecutive hours beginning at 9:00 a.m. Central Standard time. The reference date for any day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

4. "delivery" shall mean any gas that is delivered by Union into Shipper's possession, or to the possession of Shipper's agent;

5. "firm" shall mean service not subject to curtailment or interruption except under Articles XI and XII of this Schedule "A";

6. "gas" shall mean gas as defined in the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Sch. B, as amended, supplemented or re-enacted from time to time;

7. "gross heating value" shall mean the total heat expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state;

8. "interruptible service" shall mean service subject to curtailment or interruption, after notice, at any time;

9. “Interconnecting Pipeline” shall mean a pipeline that directly connects to the Union pipeline system;

10. "joule" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force. The term "megajoule" (MJ) shall mean 1,000,000 joules. The term “gigajoule” (GJ) shall mean 1,000,000,000 joules;

11. "limited interruptible service" shall mean gas service subject to interruption or curtailment on a limited number of days as specified in the Contract;

12. "m^3" shall mean cubic metre of gas and "10^3m^3" shall mean 1,000 cubic metres of gas;

13. "month" shall mean the period beginning at 9:00 a.m. Central Standard time on the first day of a calendar month and ending at 9:00 a.m. Central Standard time on the first day of the following calendar month;

14. "OEB" means the Ontario Energy Board;

15. "pascal" (Pa) shall mean the pressure produced when a force of one (1) newton is applied to an area of one (1) square metre. The term "kilopascal" (kPa) shall mean 1,000 pascals;

16. "receipt" shall mean any gas that is delivered into Union's possession, or the possession of Union’s agent;

17. "Shipper" shall have the meaning as defined in the Contract and shall also include Shipper's agent(s);

18. "TCPL" means TransCanada PipeLines Limited;

19. "cricondentherm hydrocarbon dewpoint" shall mean the highest hydrocarbon dewpoint temperature on the phase envelope;

20. "hydrocarbon dewpoint" shall mean temperature at a specific pressure where hydrocarbon vapour condensation begins;

21. "specific gravity" shall mean density of the gas divided by density of air, with both at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

22. "Wobbe Number" shall mean gross heating value of the gas divided by the square root of its specific gravity.

II. GAS QUALITY

1. Natural Gas: The minimum gross heating value of the gas delivered to/by Union hereunder, shall be thirty-six (36) megajoules per cubic metre. The maximum gross heating value of the gas delivered to/by Union hereunder shall be forty point two (40.2) megajoules per cubic metre. The gas to be delivered hereunder to Union may be a commingled supply from Shipper's gas sources of supply. The gas to be delivered by Union may be a commingled supply from Union's sources of gas supply; provided, however, that helium, natural gasoline, butane, propane and other hydrocarbons, except methane, may be removed prior to delivery to Shipper. Further, Union may subject, or permit the subjection of, the gas to compression, dehydration, cooling, cleaning and other processes.

2. Freedom from objectionable matter: The gas to be delivered to/by Union hereunder,

   a. shall be commercially free from bacteria, sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other objectionable substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to or interference with the proper operation of the lines, regulators, meters or other appliances through which it flows,

   b. shall not contain more than seven (7) milligrams of hydrogen sulphide per cubic metre of gas nor more than four hundred and sixty (460) milligrams of total sulphur per cubic metre of gas,

   c. shall not contain more than five (5) milligrams of mercaptan sulphur per cubic metre of gas,

   d. shall not contain more than two point zero (2.0) molar percent by volume of carbon dioxide in the gas,

   e. shall not contain more than zero point four (0.4) molar percent by volume of oxygen in the gas,

   f. shall not contain more than zero point five (0.5) molar percent by volume of carbon monoxide in the gas,

   g. shall not contain more than four point zero (4.0) molar percent by volume of hydrogen in the gas,

   h. shall not contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas,

   i. shall not have a cricondentherm hydrocarbon dewpoint exceeding minus eight (-8) degrees Celsius,

   j. shall have Wobbe Number from forty seven point fifty (47.50) megajoules per cubic metre of gas to fifty one point forty six (51.46) megajoules per cubic metre of gas, maximum of one point five (1.5) mole percent by volume of butane plus (C4+) in the gas, and maximum of four point zero (4.0) mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas.

3. Non-conforming Gas: In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Article II.

4. Quality of Gas Received: The quality of the gas to be received by Union hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Article II, but, Union will also accept gas of a

quality as set out in any other Interconnecting Pipeline's general terms and conditions, provided that all Interconnecting Pipelines accept such quality of gas. In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in Union's M12 Rate Schedule.

III. MEASUREMENTS

1. Storage, Transportation, and/or Sales Unit: The unit of the gas delivered to Union shall be a megajoule or a gigajoule. The unit of gas transported or stored by Union shall be a megajoule or a gigajoule. The unit of gas delivered by Union shall be a megajoule, a gigajoule, a cubic metre (m^3) or one thousand cubic metres (10^3m^3) at Union's discretion.

2. Determination of Volume and Energy:

   a. The volume and energy amounts determined under the Contract shall be determined in accordance with the Electricity and Gas Inspection Act (Canada), RSC 1985, c E-4- (the "**Act**") and the Electricity and Gas Inspection Regulations, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

   b. The supercompressibility factor shall be determined in accordance with either the "Manual for Determination of Supercompressibility Factors for Natural Gas" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

   c. The volume and/or energy of the gas delivered to/by Union hereunder shall be determined by the measurement equipment designated in Article VII herein.

   d. Upon request by Union, Shipper shall obtain measurement of the total quantity of gas received by Union hereunder from the Interconnecting Pipeline. Such measurement shall be done in accordance with established practices between Union and the Interconnecting Pipeline.

IV. RECEIPT POINT AND DELIVERY POINT

1. Unless otherwise specified in the Contract, the point or points of receipt for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection specified in the Contract, where Union takes possession of the gas.

2. Unless otherwise specified in the Contract, the point or points of delivery for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection as specified in the Contract where Shipper takes possession of the gas.

V. POSSESSION OF AND RESPONSIBILITY FOR GAS

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VI. FACILITIES ON SHIPPER'S PROPERTY

Except under those conditions where Union is delivering to TCPL for TCPL or Shipper at Union's Parkway Point of Delivery, or to an Interconnecting Pipeline, or where otherwise specified in the Contract, the following will apply:

1. Construction and Maintenance: Union, at its own expense may construct, maintain and operate on Shipper's property at the delivery point a measuring station properly equipped with a meter or meters and any other necessary measuring equipment for properly measuring the gas redelivered under the Contract. Shipper will grant to Union a lease and/or rights-of-way over property of Shipper as required by Union to install such facilities and to connect same to Union's pipeline.

2. Entry: Union, its servants, agents and each of them may at any reasonable time on notice (except in cases of emergency) to Shipper or his duly authorized representative enter Shipper's property for the purpose of constructing, maintaining, removing, operating and/or repairing station equipment.

3. Property: The said station and equipment will be and remain the property of Union notwithstanding it is constructed on and attached to the realty of Shipper, and Union may at its own expense remove it upon termination of the Contract and will do so if so requested by Shipper.

VII. MEASURING EQUIPMENT

1. Metering by Union: Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Article III herein.

2. Metering by Others: In the event that all or any gas delivered to/by Union hereunder is measured by a meter that is owned and operated by an Interconnecting Pipeline, then Union and Shipper agree to accept that metering for the purpose of determining the volume and energy of gas delivered to/by Union on behalf of the Shipper. The standard of measurement and tests for the gas delivered to/by Union hereunder shall be in accordance with the general terms and conditions as incorporated in that Interconnecting Pipeline company's gas tariff as approved by their regulatory body.

3. Check Measuring Equipment: Shipper may install, maintain and operate, at the redelivery point, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Union's measuring equipment at or near the delivery point, and shall be installed, maintained and operated in conformity with the same standards and specifications applicable to Union's metering facilities.

4. Rights of Parties: The measuring equipment installed by either party, together with any building erected by it for such equipment, shall be and remain its property. However, Union and Shipper shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring or checking the measurement of deliveries of gas to/by Union under the Contract. Either party will give the other party reasonable notice of its intention to carry out the acts herein specified. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

5. Calibration and Test of Measuring Equipment: The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Shipper, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment tested is found to be in error by not more than two per cent (2%). If, upon test, any measuring equipment is found to be in error by not more than two per cent (2%), previous recordings of such equipment shall be considered accurate in computing redeliveries of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than two percent (2%), the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations , as may be amended from time to time and in accordance with any successor statutes and regulations.

6. Preservation of Metering Records: Union and Shipper shall each preserve for a period of at least six (6) years all test data, and other relevant records.

7. Error in Metering or Meter Failure: In the event of an error in metering or a meter failure, (such error or failure being determined through check measurement by Union or any other available method), then Shipper shall enforce its rights as Shipper with the Interconnecting Pipeline(s) to remedy such error or failure including enforcing any inspection and/or verification rights and procedures.

VIII. BILLING

1. Monthly Billing Date: Union shall render bills on or before the 10th day of each month for all services furnished during the preceding month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding month's billing, an adjustment based on any difference between actual quantities and estimated quantities, without any interest charge. If presentation of a bill to Shipper is delayed after the 10th day of the month, then the time of payment shall be extended accordingly, unless Shipper is responsible for such delay.

2. Right of Examination: Both Union and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Contract.

IX. PAYMENTS

1. Monthly Payments: Shipper shall pay the invoiced amount directly into Union's bank account as directed on the invoice on or before the twentieth (20^{th}) day of each month. If the payment date is not a business day, then payment must be received in Union's account on the first business day preceding the twentieth (20th) day of the month.

2. Remedies for Non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due,

    a. Shipper shall pay to Union interest on the unpaid portion of the bill accruing at a rate per annum equal to the minimum commercial lending rate of Union's principal banker in effect from time to time from the due date until the date of payment.

    b. If such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the Contract, may suspend service(s) until such amount is paid. Notwithstanding such suspension, all demand charges shall continue to accrue hereunder as if such suspension were not in place.

    If Shipper in good faith disputes the amount of any such bill or part thereof Shipper shall pay to Union such amounts as it concedes to be correct. At any time thereafter, within twenty (20) days of a demand made by Union, Shipper shall furnish financial assurances satisfactory to Union, guaranteeing payment to Union of the amount ultimately found due upon such bill after a final determination. Such a final determination may be reached either by agreement, arbitration decision or judgement of the courts, as may be the case. Union shall not be entitled to suspend service(s) because of such non-payment unless and until default occurs in the conditions of such financial assurances or default occurs in payment of any other amount due to Union hereunder.

    Notwithstanding the foregoing paragraph(s), Shipper is not relieved from the obligation to continue its deliveries of gas to Union under the terms of any agreement, where Shipper has contracted to deliver specified quantities of gas to Union.

3. Billing Adjustments: If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, Union shall refund the amount of any such overcharge and interest shall accrue from and including the first day of such overcharge as paid to the date of refund and shall be calculated but not compounded at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker, and the Shipper shall pay the amount of any such undercharge, but without interest. In the event Union renders a bill to Shipper based upon measurement estimates, the required adjustment to reflect actual measurement shall be made on the bill next following the determination of such actual measurement, without any charge of interest. In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "bill" next following shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within six (6) years from the date of the incorrect billing. In the event any refund is issued with Shipper's gas bill, the aforesaid date of refund shall be deemed to be the date of the issue of bill.

X. ARBITRATION

If and when any dispute, difference or question shall arise between the parties hereto touching the Contract or anything herein contained, or the construction hereof, or the rights, duties or liabilities of the parties in relation to any matter hereunder, the matter in dispute shall be submitted and referred to arbitration within ten (10) days after written request of either party. Upon such request each party shall appoint an arbitrator, and the two so appointed shall appoint a third. A majority decision of the arbitrators shall be final and binding upon both parties. In all other respects the provisions of the Arbitration Act of the Province of Ontario, or any act passed in amendment thereof or substitution therefore, shall apply to each such submission. Operations under the Contract shall continue, without prejudice, during any such arbitration and the costs attributable to such arbitration shall be shared equally by the parties hereto.

XI. FORCE MAJEURE

1. The term "**force majeure**" as used herein shall mean acts of God, strikes, lockouts or any other industrial disturbance, acts of the public enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or lines of pipe, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority (civil or military), any act or omission that is excused by any event or occurrence of the character herein defined as constituting force majeure, any act or omission by parties not controlled by the party having the difficulty and any other similar cases not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

2. In the event that either the Shipper or Union is rendered unable, in whole or in part, by force majeure, to perform or comply with any obligation or condition of the Contract, such party shall give notice and full particulars of such force majeure in writing delivered by hand, fax or other direct written electronic means to the other party as soon as possible after the occurrence of the cause relied on and subject to the provision of this Article.

3. Neither party shall be entitled to the benefit of the provisions of force majeure hereunder if any or all of the following circumstances prevail: the failure resulting in a condition of force majeure was caused by the negligence of the party claiming suspension; the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation); the party claiming suspension failed to resume the performance of such condition obligations with reasonable dispatch; the failure was caused by lack of funds; the party claiming suspension did not, as soon as possible after determining, or within a period within which it should acting reasonably have determined, that the occurrence was in the nature of force majeure and would affect its ability to observe or perform any of its conditions or obligations under the Contract, give to the other party the notice required hereunder.

4. The party claiming suspension shall likewise give notice as soon as possible after the force majeure condition is remedied, to the extent that the same has been remedied, and that such party has resumed or is then in a position to resume the performance of the obligations and conditions of the Contract.

5. An event of force majeure on Union's system will excuse the failure to deliver gas by Union or the failure to accept gas by Union hereunder, and both parties shall be excused from performance of their obligations hereunder, except for payment obligations, to the extent of and for the duration of the force majeure.

6. Upstream or Downstream Force Majeure: An event of force majeure upstream or downstream of Union's system shall not relieve Shipper of any payment obligations.

7. Delay of Firm Transportation Services: Despite Article XI herein, if Union is prevented, by reason of an event of force majeure on Union's system from delivering gas on the Day or Days upon which Union has accepted gas from Shipper, Union shall thereafter make all reasonable efforts to deliver such quantities as soon as practicable and on such Day or Days as are agreed to by Shipper and Union. If Union accepts such gas on this basis, Shipper shall not receive any demand charge relief as contemplated under Article XI herein.

8. Demand Charge Relief for Firm Transportation Services: Despite Article XI herein, if on any Day Union fails to accept gas from Shipper by reason of an event of force majeure on Union's system and fails to deliver the quantity of gas

nominated hereunder by Shipper up to the firm Contract Demand for that Contract, then for that Day the Monthly demand charge shall be reduced by an amount equal to the applicable Daily Demand Rate, as defined in this paragraph, multiplied by the difference between the quantity of gas actually delivered by Union during such Day and the quantity of gas which Shipper in good faith nominated on such Day. The term "**Daily Demand Rate**" shall mean the Monthly demand charge or equivalent pursuant to the M12 Rate Schedule divided by the number of days in the month for which such rate is being calculated.

9. If, due to the occurrence of an event of force majeure as outlined above, the capacity for gas deliveries by Union is impaired, it will be necessary for Union to curtail Shipper's gas receipts to Union hereunder, via proration based on utilization of such facilities for the Day. This prorating shall be determined by multiplying the capability of such facilities as available downstream of the impairment on the Day, by a fraction where the numerator is Shipper's nominated firm quantity and the denominator is the total of all such nominated firm quantities for nominated services and planned consumption for in-franchise customers on the Day. For the purposes of this Article XI, firm services shall mean all firm services provided by Union to in-franchise customers and ex-franchise shippers.

XII. DEFAULT AND TERMINATION

In case of the breach or non-observance or non-performance on the part of either party hereto of any covenant, proviso, condition, restriction or stipulation contained in the Contract (but not including herein failure to take or make delivery in whole or in part of the gas delivered to/by Union hereunder occasioned by any of the reasons provided for in Article XI hereof) which has not been waived by the other party, then and in every such case and as often as the same may happen, the Non-defaulting party may give written notice to the Defaulting party requiring it to remedy such default and in the event of the Defaulting party failing to remedy the same within a period of thirty (30) days from receipt of such notice, the Non-defaulting party may at its sole option declare the Contract to be terminated and thereupon the Contract shall be terminated and be null and void for all purposes other than and except as to any liability of the parties under the same incurred before and subsisting as of termination. The right hereby conferred upon each party shall be in addition to, and not in derogation of or in substitution for, any other right or remedy which the parties respectively at law or in equity shall or may possess.

XIII. MODIFICATION

Subject to Union's M12 Rate Schedule, Schedule A, Article XV and the ability of Union to amend the M12 Rate Schedule with the approval of the OEB, no amendment or modification of the Contract shall be effective unless the same shall be in writing and signed by each of the Shipper and Union.

XIV. NON-WAIVER AND FUTURE DEFAULT

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XV. LAWS, REGULATIONS AND ORDERS

The Contract and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Contract shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Contract.

SCHEDULE "A 2010"

RATE M12
GENERAL TERMS & CONDITIONS

I. DEFINITIONS

Except where the context expressly requires or states another meaning, the following terms, when used in these General Terms & Conditions and in any contract into which these General Terms & Conditions are incorporated, shall be construed to have the following meanings:

"**Authorized Overrun**" shall mean the amount by which Shipper's Authorized Quantity exceeds the Contract Demand;

"**Available Capacity**" shall mean at any time, Union's remaining available capacity to provide Transportation Services;

"**Business Day**" shall mean any day, other than Saturday, Sunday or any days on which national banks in the Province of Ontario are authorized to close;

"**Contract**" shall refer to the Contract to which these General Terms & Conditions shall apply, and into which they are incorporated;

"**Contract Year**" shall mean a period of three hundred and sixty-five (365) consecutive days; provided however, that any such period which contains a date of February 29 shall consist of three hundred and sixty-six (366) consecutive days, commencing on November 1 of each year; except for the first Contract Year which shall commence on the Commencement Date and end on the first October 31 that follows such date;

"**cricondentherm hydrocarbon dewpoint**" shall mean the highest hydrocarbon dewpoint temperature on the phase envelope;

"**cubic metre**" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**Day**" shall mean a period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Clock Time. The reference date for any Day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

"**delivery**" shall mean any gas that is delivered by Union into Shipper's possession, or to the possession of Shipper's agent;

"Eastern Clock Time" shall mean the local clock time in the Eastern Time Zone on any Day;

"**Expansion Facilities**" shall mean any new facilities to be constructed by Union in order to provide Transportation Services;

"**firm**" shall mean service not subject to curtailment or interruption except under Articles XI, XII and XVIII herein;

"**gas**" shall mean gas as defined in the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Sch. B, as amended, supplemented or re-enacted from time to time;

"**gross heating value**" shall mean the total heat expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state;

"**hydrocarbon dewpoint**" shall mean temperature at a specific pressure where hydrocarbon vapour condensation begins;

"**Interruptible HUB Service Contract**" shall mean a contract between Shipper and Union under which Union provides interruptible HUB service;

"**interruptible service**" or "**Interruptible**" shall mean service subject to curtailment or interruption, after notice, at any time;

"**Interconnecting Pipeline**" shall mean a pipeline that directly connects to the Union pipeline system;

"**joule**" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force. The term "**megajoule**" (MJ) shall mean 1,000,000 joules. The term "**gigajoule**" (GJ) shall mean 1,000,000,000 joules;

"Loaned Quantities" shall mean those quantities of gas loaned to Shipper under the Facilitating Agreement;

"**m^3**" shall mean cubic metre of gas and "10^3m^3" shall mean 1,000 cubic metres of gas;

"**Month**" shall mean the period beginning at 10:00 a.m. Eastern Clock Time on the first day of a calendar month and ending at 10:00 a.m. Eastern Clock Time on the first day of the following calendar month;

"**NAESB**" shall mean North American Energy Standards Board;

"**OEB**" means the Ontario Energy Board;

"**Open Season**" or "**open season**" shall mean an open access auction or bidding process held by Union as a method of allocating capacity;

"**pascal**" (Pa) shall mean the pressure produced when a force of one (1) newton is applied to an area of one (1) square metre. The term "kilopascal" (kPa) shall mean 1,000 pascals;

"**receipt**" shall mean any gas that is delivered into Union's possession, or the possession of Union's agent;

"**Shipper**" shall have the meaning as defined in the Contract, and shall also include Shipper's agent(s);

"**specific gravity**" shall mean density of the gas divided by density of air, with both at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**Taxes**" shall mean any tax (other than tax on income or tax on property), duty, royalty, levy, license, fee or charge not included in the charges and rates as per the applicable rate schedule (including but not limited to charges under any form of cap and trade, carbon tax, or similar system) and that is levied, assessed or made by any governmental authority on the gas itself, or the act, right, or privilege of producing, severing, gathering, storing, transporting, handling, selling or delivering gas under the Contract;

"**TCPL**" means TransCanada PipeLines Limited;

"**Wobbe Number**" shall mean gross heating value of the gas divided by the square root of its specific gravity.

II. GAS QUALITY

1. Natural Gas: The minimum gross heating value of the gas delivered to/by Union hereunder, shall be thirty-six (36) megajoules per cubic metre. The maximum gross heating value of the gas delivered to/by Union hereunder shall be forty point two (40.2) megajoules per cubic metre. The gas to be delivered hereunder to Union may be a commingled supply from Shipper's gas sources of supply. The gas to be delivered by Union may be a commingled supply from Union's sources of gas supply; provided, however, that helium, natural gasoline, butane, propane and other hydrocarbons, except methane, may be removed prior to delivery to Shipper. Further, Union may subject, or permit the subjection of, the gas to compression, dehydration, cooling, cleaning and other processes.

2. Freedom from objectionable matter: The gas to be delivered to/by Union hereunder,

   a. shall be commercially free from bacteria, sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other objectionable substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to, or interference with, the proper operation of the lines, regulators, meters or other appliances through which it flows,

b. shall not contain more than seven (7) milligrams of hydrogen sulphide per cubic metre of gas, nor more than four hundred and sixty (460) milligrams of total sulphur per cubic metre of gas,

c. shall not contain more than five (5) milligrams of mercaptan sulphur per cubic metre of gas,

d. shall not contain more than two point zero (2.0) molar percent by volume of carbon dioxide in the gas,

e. shall not contain more than zero point four (0.4) molar percent by volume of oxygen in the gas,

f. shall not contain more than zero point five (0.5) molar percent by volume of carbon monoxide in the gas,

g. shall not contain more than four point zero (4.0) molar percent by volume of hydrogen in the gas,

h. shall not contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas,

i. shall not have a cricondentherm hydrocarbon dewpoint exceeding minus eight (-8) degrees Celsius,

j. shall have Wobbe Number from forty seven point fifty (47.50) megajoules per cubic metre of gas to fifty one point forty six (51.46) megajoules per cubic metre of gas, maximum of one point five (1.5) mole percent by volume of butane plus (C4+) in the gas, and maximum of four point zero (4.0) mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas.

3. Non-conforming Gas: In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Article II.

4. Quality of Gas Received: The quality of the gas to be received by Union hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Article II, but, Union will also accept gas of a quality as set out in any other Interconnecting Pipeline's general terms and conditions, provided that all Interconnecting Pipelines accept such quality of gas. In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in Union's M12 Rate Schedule.

III. MEASUREMENTS

1. Storage, Transportation, and/or Sales Unit: The unit of the gas delivered to Union shall be a megajoule or a gigajoule. The unit of gas transported or stored by Union shall be a megajoule or a gigajoule. The unit of gas delivered by Union shall be a megajoule, a gigajoule, a cubic metre (m^3) or one thousand cubic metres (10^3m^3) at Union's discretion.

2. Determination of Volume and Energy:

a. The volume and energy amounts determined under the Contract shall be determined in accordance with the Electricity and Gas Inspection Act (Canada), RSC 1985, c E-4- (the "**Act**") and the Electricity and Gas Inspection Regulations, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

b. The supercompressibility factor shall be determined in accordance with either the "Manual for Determination of Supercompressibility Factors for Natural Gas" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

c. The volume and/or energy of the gas delivered to/by Union hereunder shall be determined by the measurement equipment designated in Article VII herein.

d. Upon request by Union, Shipper shall obtain measurement of the total quantity of gas received by Union hereunder from the Interconnecting Pipeline. Such measurement shall be done in accordance with established practices between Union and the Interconnecting Pipeline.

IV. RECEIPT POINT AND DELIVERY POINT

1. Unless otherwise specified in the Contract, the point or points of receipt and point or points of delivery for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection specified in the Contract, where possession of the gas changes from one party to the other, and as per Schedule "D 2010".

V. POSSESSION OF AND RESPONSIBILITY FOR GAS

1. Union accepts no responsibility for any gas prior to such gas being delivered to Union at the Receipt Point or after its delivery by Union at the Delivery Point. As between the parties hereto, Union shall be deemed to be in control and possession of and responsible for all such gas from the time that such gas enters Union's system until such gas is delivered to Shipper.

2. Shipper agrees that Union is not a common carrier and is not an insurer of Shipper's gas, and that Union shall not be liable to Shipper or any third party for loss of gas in Union's possession, except to the extent such loss is caused entirely by Union's negligence or wilful misconduct.

VI. FACILITIES ON SHIPPER'S PROPERTY

Except under those conditions where Union is delivering to TCPL for TCPL or Shipper at Parkway (TCPL), or to an Interconnecting Pipeline, or where otherwise specified in the Contract, the following will apply:

1. <u>Construction and Maintenance:</u> Union, at its own expense may construct, maintain and operate on Shipper's property at the delivery point a measuring station properly equipped with a meter or meters and any other necessary measuring equipment for properly measuring the gas redelivered under the Contract. Shipper will grant to Union a lease and/or rights-of-way over property of Shipper as required by Union to install such facilities and to connect same to Union's pipeline.

2. <u>Entry:</u> Union, its servants, agents and each of them may at any reasonable time on notice (except in cases of emergency) to Shipper or his duly authorized representative enter Shipper's property for the purpose of constructing, maintaining, removing, operating and/or repairing station equipment.

3. <u>Property:</u> The said station and equipment will be and remain the property of Union notwithstanding it is constructed on and attached to the realty of Shipper, and Union may at its own expense remove it upon termination of the Contract and will do so if so requested by Shipper.

VII. MEASURING EQUIPMENT

1. <u>Metering by Union:</u> Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Article III herein.

2. <u>Metering by Others</u>: In the event that all or any gas delivered to/by Union hereunder is measured by a meter that is owned and operated by an Interconnecting Pipeline, then Union and Shipper agree to accept that metering for the purpose of determining the volume and energy of gas delivered to/by Union on behalf of the Shipper. The standard of measurement and tests for the gas delivered to/by Union hereunder shall be in accordance with the general terms and conditions as incorporated in that Interconnecting Pipeline company's gas tariff as approved by its regulatory body.

3. <u>Check Measuring Equipment:</u> Shipper may install, maintain and operate, at the redelivery point, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Union's measuring equipment at or near the delivery point, and shall be installed, maintained and operated in conformity with the same standards and specifications applicable to Union's metering facilities.

4. <u>Rights of Parties:</u> The measuring equipment installed by either party, together with any building erected by it for such equipment, shall be and remain its property. However, Union and Shipper shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done

in connection with the other's measuring equipment used in measuring or checking the measurement of deliveries of gas to/by Union under the Contract. Either party will give the other party reasonable notice of its intention to carry out the acts herein specified. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

5. Calibration and Test of Measuring Equipment: The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Shipper, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment tested is found to be in error by not more than two per cent (2%). If, upon test, any measuring equipment is found to be in error by not more than two per cent (2%), previous recordings of such equipment shall be considered accurate in computing receipts and deliveries of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than two percent (2%), the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations, as may be amended from time to time and in accordance with any successor statutes and regulations.

6. Preservation of Metering Records: Union and Shipper shall each preserve for a period of at least six (6) years all test data, and other relevant records.

7. Error in Metering or Meter Failure: In the event of an error in metering or a meter failure, (such error or failure being determined through check measurement by Union or any other available method), then Shipper shall enforce its rights as Shipper with the Interconnecting Pipeline(s) to remedy such error or failure including enforcing any inspection and/or verification rights and procedures.

VIII. BILLING

1. Monthly Billing Date: Union shall render bills on or before the tenth (10th) day of each month for all Transportation Services furnished during the preceding Month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding Month's billing, an adjustment based on any difference between actual quantities and estimated quantities, without any interest charge. If presentation of a bill to Shipper is delayed after the tenth (10th) day of the month, then the time of payment shall be extended accordingly, unless Shipper is responsible for such delay.

2. Right of Examination: Both Union and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Contract.

3. Amendment of Statements: For the purpose of completing a final determination of the actual quantities of gas handled in any of the Transportation Services to Shipper, the parties shall have the right to amend their statement for a period equal to the time during which the Interconnecting Pipeline retains the right to amend their statements, which period shall not exceed three (3) years from the date of termination of the Contract.

IX. PAYMENTS

1. Monthly Payments: Shipper shall pay the invoiced amount directly into Union’s bank account as directed on the invoice on or before the twentieth (20th) day of each month. If the payment date is not a Business Day, then payment must be received in Union’s account on the first Business Day preceding the twentieth (20th) day of the month.

2. Remedies for Non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due,

   a. Shipper shall pay to Union interest on the unpaid portion of the bill accruing at a rate per annum equal to the minimum commercial lending rate of Union's principal banker in effect from time to time from the due date until the date of payment; and,

b. If such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the Contract, may suspend Services until such amount is paid. Notwithstanding such suspension, all demand charges shall continue to accrue hereunder as if such suspension were not in place.

If Shipper in good faith disputes the amount of any such bill or part thereof Shipper shall pay to Union such amounts as it concedes to be correct. At any time thereafter, within twenty (20) days of a demand made by Union, Shipper shall furnish financial assurances satisfactory to Union, guaranteeing payment to Union of the amount ultimately found due upon such bill after a final determination. Such a final determination may be reached either by agreement, arbitration decision or judgement of the courts, as may be the case. Union shall not be entitled to suspend Services because of such non-payment unless and until default occurs in the conditions of such financial assurances or default occurs in payment of any other amount due to Union hereunder.

Notwithstanding the foregoing, Shipper is not relieved from the obligation to continue its deliveries of gas to Union under the terms of any agreement, where Shipper has contracted to deliver specified quantities of gas to Union.

3. Billing Adjustments: If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, Union shall refund the amount of any such overcharge and interest shall accrue from and including the first day of such overcharge as paid to the date of refund and shall be calculated but not compounded at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker, and the Shipper shall pay the amount of any such undercharge, but without interest. In the event Union renders a bill to Shipper based upon measurement estimates, the required adjustment to reflect actual measurement shall be made on the bill next following the determination of such actual measurement, without any charge of interest. In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "**bill next following**" shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within three (3) years from the date of the incorrect billing. In the event any refund is issued with Shipper's bill, the aforesaid date of refund shall be deemed to be the date of the issue of bill.

4 Taxes:

In addition to the charges and rates as per the applicable rate schedules and price schedules, Shipper shall pay all Taxes which are imposed currently or subsequent to the execution of the Contract by any legal authority having jurisdiction and any amount in lieu of such Taxes paid or payable by Union.

5. Set Off:

If either party shall, at any time, be in arrears under any of its payment obligations to the other party under the Contract, then the party not in arrears shall be entitled to reduce the amount payable by it to the other party in arrears under the Contract, or any other contract, by an amount equal to the amount of such arrears or other indebtedness to the other party. In addition to the foregoing remedy, Union may, upon forty-eight (48) hours verbal notice, to be followed by written notice, take possession of any or all of Shipper's gas under the Contract or any enhancement to the Contract, which shall be deemed to have been assigned to Union, to reduce such arrears or other indebtedness to Union.

X. ARBITRATION

If and when any dispute, difference or question shall arise between the parties hereto touching the Contract or anything herein contained, or the construction hereof, or the rights, duties or liabilities of the parties in relation to any matter hereunder, the matter in dispute shall be submitted and referred to arbitration within ten (10) days after written request of either party. Upon such request each party shall appoint an arbitrator, and the two so appointed shall appoint a third. A majority decision of the arbitrators shall be final and binding upon both parties. In all other respects the provisions of the Arbitration Act, 1991, or any act passed in amendment thereof or substitution therefore, shall apply to each such submission. Operations under the Contract shall continue, without prejudice, during any such arbitration and the costs attributable to such arbitration shall be shared equally by the parties hereto.

XI. FORCE MAJEURE

1. The term "**force majeure**" as used herein shall mean acts of God, strikes, lockouts or any other industrial disturbance, acts of the public enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or lines of pipe, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority (civil or military), any act or omission that is excused by any event or occurrence of the character herein defined as constituting force majeure, any act or omission by parties not controlled by the party having the difficulty and any other similar cases not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

2. In the event that either the Shipper or Union is rendered unable, in whole or in part, by force majeure, to perform or comply with any obligation or condition of the Contract, such party shall give notice and full particulars of such force majeure in writing delivered by hand, fax or other direct written electronic means to the other party as soon as possible after the occurrence of the cause relied on and subject to the provision of this Article.

3. Neither party shall be entitled to the benefit of the provisions of force majeure hereunder if any or all of the following circumstances prevail: the failure resulting in a condition of force majeure was caused by the negligence of the party claiming suspension; the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation); the party claiming suspension failed to resume the performance of such condition obligations with reasonable dispatch; the failure was caused by lack of funds; the party claiming suspension did not, as soon as possible after determining, or within a period within which it should acting reasonably have determined, that the occurrence was in the nature of force majeure and would affect its ability to observe or perform any of its conditions or obligations under the Contract, give to the other party the notice required hereunder.

4. The party claiming suspension shall likewise give notice as soon as possible after the force majeure condition is remedied, to the extent that the same has been remedied, and that such party has resumed or is then in a position to resume the performance of the obligations and conditions of the Contract.

5. An event of force majeure on Union's system will excuse the failure to deliver gas by Union or the failure to accept gas by Union hereunder, and both parties shall be excused from performance of their obligations hereunder, except for payment obligations, to the extent of and for the duration of the force majeure.

6. Upstream or Downstream Force Majeure: An event of force majeure upstream or downstream of Union's system shall not relieve Shipper of any payment obligations.

7. Delay of Firm Transportation Services: Despite Article XI herein, if Union is prevented, by reason of an event of force majeure on Union's system from delivering gas on the Day or Days upon which Union has accepted gas from Shipper, Union shall thereafter make all reasonable efforts to deliver such quantities as soon as practicable and on such Day or Days as are agreed to by Shipper and Union. If Union accepts such gas on this basis, Shipper shall not receive any demand charge relief as contemplated under Article XI herein.

8. Demand Charge Relief for Firm Transportation Services: Despite Article XI herein, if on any Day Union fails to accept gas from Shipper by reason of an event of force majeure on Union's system and fails to deliver the quantity of gas nominated hereunder by Shipper up to the firm Contract Demand for that Contract, then for that Day the Monthly demand charge shall be reduced by an amount equal to the applicable Daily Demand Rate, as defined in this paragraph, multiplied by the difference between the quantity of gas actually delivered by Union during such Day and the quantity of gas which Shipper in good faith nominated on such Day. The term "**Daily Demand Rate**" shall mean the Monthly demand charge or equivalent pursuant to the M12 Rate Schedule divided by the number of days in the month for which such rate is being calculated.

9. If, due to the occurrence of an event of force majeure as outlined above, the capacity for gas deliveries by Union is impaired, it will be necessary for Union to curtail Shipper's gas receipts to Union hereunder, via proration based on utilization of such facilities for the Day. This prorating shall be determined by multiplying the capability of such facilities as available downstream of the impairment on the Day, by a fraction where the numerator is Shipper's nominated firm quantity and the denominator is the total of all such nominated firm quantities for nominated services and planned consumption for

in-franchise customers on the Day. For the purposes of this Article XI, firm services shall mean all firm services provided by Union to in-franchise customers and ex-franchise shippers.

XII. DEFAULT AND TERMINATION

In case of the breach or non-observance or non-performance on the part of either party hereto of any covenant, proviso, condition, restriction or stipulation contained in the Contract (but not including herein failure to take or make delivery in whole or in part of the gas delivered to/by Union hereunder occasioned by any of the reasons provided for in Article XI herein) which has not been waived by the other party, then and in every such case and as often as the same may happen, the non-defaulting party may give written notice to the defaulting party requiring it to remedy such default and in the event of the defaulting party failing to remedy the same within a period of thirty (30) days from receipt of such notice, the non-defaulting party may at its sole option declare the Contract to be terminated and thereupon the Contract shall be terminated and be null and void for all purposes other than and except as to any liability of the parties under the same incurred before and subsisting as of termination. The right hereby conferred upon each party shall be in addition to, and not in derogation of or in substitution for, any other right or remedy which the parties respectively at law or in equity shall or may possess.

XIII. AMENDMENT

Subject to Article XV herein and the ability of Union to amend the applicable rate schedules and price schedules, with the approval of the OEB (if required), no amendment or modification of the Contract shall be effective unless the same shall be in writing and signed by each of the Shipper and Union.

XIV. NON-WAIVER AND FUTURE DEFAULT

No waiver of any provision of the Contract shall be effective unless the same shall be in writing and signed by the party entitled to the benefit of such provision and then such waiver shall be effective only in the specific instance and for the specified purpose for which it was given. No failure on the part of Shipper or Union to exercise, and no course of dealing with respect to, and no delay in exercising, any right, power or remedy under the Contract shall operate as a waiver thereof.

XV. LAWS, REGULATIONS AND ORDERS

The Contract and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Contract shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Contract.

XVI ALLOCATION OF CAPACITY

1. A potential shipper may request firm transportation service on Union's system at any time. Any request for firm M12 transportation service must include: potential shipper's legal name, Receipt Point(s), Delivery Point(s), Commencement Date, Initial Term, Contract Demand and proposed payment. This is applicable for M12 service requests for firm transportation service with minimum terms of ten (10) years where Expansion Facilities are required or a minimum term of five (5) years for use of existing capacity.

2. If requests for firm transportation services cannot be met through existing capacity such that the only way to satisfy the requests for transportation service would require the construction of Expansion Facilities which create new capacity, Union shall allocate any such new capacity by open season, subject to the terms of the open season, and these General Terms and Conditions.

3. If requests for long-term firm transportation service can be met through existing facilities upon which long-term capacity is becoming available, Union shall allocate such long-term capacity by open season, subject to the terms of the open season, and these General Terms and Conditions. "**Long-term**", for the purposes of this Article XVI, means, in the case of a transportation service, a service that has a term of one year or greater.

4. Capacity requests received during an open season shall be awarded starting with those bids with the highest economic value. If the economic values of two or more independent bids are equal, then service shall be allocated on a pro-rata basis. The economic value shall be based on the net present value which shall be calculated based on the proposed per-unit rate and the proposed term of the contract and without regard to the proposed Contract Demand ("**NPV**").

5. Union may at any time allocate capacity to respond to any M12 transportation service request through an open season. If a potential shipper requests M12 transportation service that can be provided through Available Capacity that was previously offered by Union in an open season but was not awarded, then:

   a. Any such request must conform to the requirements of Section 1 of this Article XVI;

   b. Union shall allocate capacity to serve such request pursuant to this Section 5, and subject to these General Terms and Conditions and Union's standard form M12 transportation contract;

   c. Union may reject a request for M12 transportation service for any of the following reasons:

      i) if there is insufficient Available Capacity to fully meet the request, but if that is the only reason for rejecting the request for service, Union must offer to supply the Available Capacity to the potential shipper;

      ii) if the proposed monthly payment is less than Union's Monthly demand charge plus fuel requirements for the applicable service;

      iii) if prior to Union accepting the request for transportation service Union receives a request for transportation service from one or more other potential shippers and there is, as a result, insufficient Available Capacity to service all the requests for service, in which case Union shall follow the procedure in Section 5 d hereof; -

      iv) if Union does not provide the type of transportation service requested; or

      v) if all of the conditions precedent specified in Article XXI Sections 1 and 2 herein have not been satisfied or waived.

   d. Union will advise the potential shipper in writing whether Union accepts or rejects the request for service, subject to Article XVI 5 c, within 5 calendar days of receiving a request for M12 transportation service. If Union rejects a request for service, Union shall inform the potential shipper of the reasons why its request is being rejected; and

   e. If Union has insufficient Available Capacity to service all pending requests for transportation service Union may:

      i) Reject all the pending requests for transportation service and conduct an open season; or

      ii) Union shall inform all the potential shippers who have submitted a pending request for transportation service that it does not have sufficient capacity to service all pending requests for service, and Union shall provide all such potential shippers with an equal opportunity to submit a revised request for service. Union shall then allocate the Available Capacity to the request for transportation service with the highest economic value to Union. If the economic values of two or more requests are equal, then service shall be allocated on a pro-rata basis. The economic value of any request shall be based on the NPV.

XVII. RENEWALS

Contracts with an Initial Term of five (5) years or greater will continue in full force and effect beyond the Initial Term, automatically renewing for a period of one (1) year, and every one (1) year thereafter. Shipper may reduce the Contract Demand or terminate the Contract with notice in writing by Shipper at least two (2) years prior to the expiration thereof.

XVIII. SERVICE CURTAILMENT

1. Union shall have the right to curtail or not to schedule part or all of Transportation Services, in whole or in part, on all or a portion of its pipeline system at any time for reasons of Force Majeure or when, in Union sole discretion, acting reasonably, capacity or operating conditions so require or it is desirable or necessary to make modifications, repairs or operating

changes to its pipeline system. Union shall provide Shipper such notice of such curtailment as is reasonable under the circumstances. If due to any cause whatsoever Union is unable to receive or deliver the quantities of Gas which Shipper has requested, then Union shall order curtailment by all Shippers affected and to the extent necessary to remove the effect of the disability. Union has a priority of service policy to determine the order of service curtailment. In order to place services on the priority of service list, Union considers the following business principles: appropriate level of access to core services, customer commitment, encouraging appropriate contracting, materiality, price and term, and promoting and enabling in-franchise consumption.

The Priority ranking for all services utilizing Union Gas' storage, transmission and distribution system as applied to both in-franchise and ex-franchise services are as follows; with number 1 having the highest priority and the last interrupted.

1. Firm In-franchise Transportation and Distribution services and firm Ex-franchise services (Note 1)
2. In-franchise Interruptible Distribution services
3. C1/M12 IT Transport and IT Exchanges with Take or Pay rates
4. Balancing (Hub Activity) < = 100 GJ/d; Balancing (Direct Purchase) < = 500 GJ/d; In-franchise distribution authorized overrun (Note 3)
5. C1/M12 IT Transport and IT Exchanges at premium rates
6. C1/M12 Overrun < = 20% of CD (Note 4)
7. Balancing (Direct Purchase) > 500 GJ/d
8. Balancing (Hub Activity) > 100 GJ/d; C1/M12 IT Transport and IT Exchanges
9. C1/M12 Overrun > 20% of CD
10. C1/M12 IT Transport and IT Exchanges at a discount
11. Late Nominations

Notes:

1. Nominated services must be nominated on the NAESB Timely Nomination Cycle otherwise they are considered to be late nomination and are therefore interruptible.
2. Higher value or more reliable IT is contemplated in the service and contract, when purchase at market competitive prices.
3. Captures the majority of customers that use Direct Purchase balancing transactions.
4. Captures the majority of customers that use overrun.

2. Union reserves the right to change its procedures for sharing interruptible capacity and will provide Shipper with two (2) months prior notice of any such change.

3. Maintenance: Union's facilities from time to time may require maintenance or construction. If such maintenance or construction is required, and in Union's sole opinion, acting reasonably, such maintenance or construction may impact Union's ability to meet Shipper's requirements, Union shall provide at least ten (10) days notice to Shipper, except in the case of an emergency. In the event the maintenance impacts on Union's ability to meet Shipper's requirements, Union shall not be liable for any damages and shall not be deemed in breach of the Contract. To the extent that Union's ability to accept and/or deliver Shipper's gas is impaired, the Monthly demand charge shall be reduced in accordance with Article XI Section 8 and available capacity allocated in accordance with Article XI Section 9 herein.

   Union shall use reasonable efforts to determine a mutually acceptable period during which such maintenance or construction will occur and also to limit the extent and duration of any impairments. Union will endeavour to schedule and complete the maintenance and construction, which would normally be expected to impact on Union's ability to meet Shipper's requirements, during the period from April 1 through to November 1.

XIX. SHIPPER'S REPRESENTATIONS AND WARRANTIES

1. Shipper's Warranty: Shipper warrants that it will, if required, maintain, or have maintained on its behalf, all external approvals including the governmental, regulatory, import/export permits and other approvals or authorizations that are required from any federal, state or provincial authorities for the gas quantities to be handled under the Contract. Shipper further warrants that it shall maintain in effect the Facilitating Agreements.

2. Financial Representations: Shipper represents and warrants that the financial assurances (including the Initial Financial Assurances and Security) (if any) shall remain in place throughout the term hereof, unless Shipper and Union agree otherwise. Shipper shall notify Union in the event of any change to the financial assurances throughout the term hereof.

Should Union have reasonable grounds to believe that Shipper will not be able to perform or continue to perform any of its obligations under the Contract as a result of one of the following events ("**Material Event**");

a. Shipper is in default, which default has not been remedied, of the Contract or is in default of any other material contract with Union or another party; or,

b. Shipper's corporate or debt rating falls below investment grade according to at least one nationally recognized rating agency; or,

c. Shipper ceases to be rated by a nationally recognized agency; or,

d. Shipper has exceeded credit available as determined by Union from time to time,

then Shipper shall within fourteen (14) days of receipt of written notice by Union, obtain and provide to Union a letter of credit or other security in the form and amount reasonably required by Union (the "**Security**"). The Security plus the Initial Financial Assurances shall not exceed twelve (12) months of Monthly demand charges (in accordance with Article IX herein) multiplied by Contract Demand. In the event that Shipper does not provide to Union such Security within such fourteen (14) day period, Union may deem a default under the Default and Termination provisions of Article XII herein.

In the event that Shipper in good faith, reasonably believes that it should be entitled to reduce the amount of or value of the Security previously provided, it may request such a reduction from Union and to the extent that the Material Event has been mitigated or eliminated, Union shall return all or a portion of the Security to Shipper within fourteen (14) Business Days after receipt of the request.

The following paragraphs 3 and/or 4 are only applicable if indicated in Schedule 1 of the Contract.

3. Point of Consumption Warranty: Shipper represents and warrants that, throughout the term of this Contract, all quantities of gas received by Union hereunder at the Receipt Point and/or all Loaned Quantities will be consumed in the U.S.A. Should any quantities of gas hereunder be directed to an end user in Canada, Shipper shall immediately notify Union that such quantities of gas will be consumed in Canada, as failure to do so will make Shipper liable to Union for any Taxes and related interest and penalties thereon, made as a result of such change.

4. Tax Registration re GST: Shipper warrants and represents that it is unregistered and a Non-Resident for purposes of the Excise Tax Act. Shipper agrees to notify Union within ten (10) working days if it becomes registered. "GST/HST" shall mean the Government of Canada's Goods and Services Tax or Harmonized Sales Tax as legislated under The Excise Tax Act, as may be amended from time to time.

XX. MISCELLANEOUS PROVISIONS

1. Permanent Assignment: Shipper may assign the Contract to a third party ("Assignee"), up to the Contract Demand, (the "Capacity Assigned"). Such assignment shall require the prior written consent of Union and release of obligations by Union for the Capacity Assigned from the date of assignment. Such consent and release shall not be unreasonably withheld and shall be conditional upon the Assignee providing, amongst other things, financial assurances as per Article XXI herein. Any such assignment will be for the full rights, obligations and remaining term of the Contract as relates to the Capacity Assigned.

2. Temporary Assignment: Shipper may, upon notice to Union, assign all or a part of its service entitlement under the Contract (the "Assigned Quantity") and the corresponding rights and obligations to an Assignee on a temporary basis for not less than one calendar month. Such assignment shall not be unreasonably withheld and shall be conditional upon the Assignee executing the Facilitating Agreement as per Article XXI herein. Notwithstanding such assignment, Shipper shall remain obligated to Union to perform and observe the covenants and obligations contained herein in regard to the Assigned Quantity to the extent that Assignee fails to do so.

3. Title to Gas: Shipper represents and warrants to Union that Shipper shall have good and marketable title to, or legal authority to deliver to Union, all gas delivered to Union hereunder. Furthermore, Shipper hereby agrees to indemnify and save Union harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of claims of any or all third parties to such gas or on account of Taxes, or other charges thereon.

XXI. PRECONDITIONS TO TRANSPORTATION SERVICES

1. The obligations of Union to provide Transportation Services hereunder are subject to the following conditions precedent, which are for the sole benefit of Union and which may be waived or extended in whole or in part in the manner provided in the Contract:

   a. Union shall have obtained, in form and substance satisfactory to Union, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required to provide the Transportation Services; and,

   b. Union shall have obtained all internal approvals that are necessary or appropriate to provide the transportation Services; and,

   c. Union shall have received from Shipper the requisite financial assurances reasonably necessary to ensure Shipper's ability to honour the provisions of the Contract (the "**Initial Financial Assurances**"). The Initial Financial Assurances, if required, will be as determined solely by Union; and,

   d. Shipper and Union shall have entered into the Interruptible HUB Service Contract or equivalent (the "**Facilitating Agreement**") with Union.

2. The obligations of Shipper hereunder are subject to the following conditions precedent, which are for the sole benefit of Shipper and which may be waived or extended in whole or in part in the manner provided in the Contract:

   a. Shipper shall, as required, have entered into the necessary contracts with Union and/or others to facilitate the Transportation Services contemplated herein, including contracts for upstream and downstream transportation, and shall specifically have an executed and valid Facilitating Agreement; and shall, as required, have entered into the necessary contracts to purchase the gas quantities handled under the Contract; and,

   b. Shipper shall have obtained, in form and substance satisfactory to Shipper, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required from federal, state, or provincial authorities for the gas quantities handled under the Contract; and,

   c. Shipper shall have obtained all internal approvals that are necessary or appropriate for the Shipper to execute the Contract.

3. Union and Shipper shall each use due diligence and reasonable efforts to satisfy and fulfil the conditions precedent specified in this Article XXI Section 1 a, c, and d and Section 2 a and b. Each party shall notify the other forthwith in writing of the satisfaction or waiver of each condition precedent for such party's benefit. If a party concludes that it will not be able to satisfy a condition precedent that is for its benefit, such party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations thereunder.

4. If any of the conditions precedent in this Article XXI Section 1 c or Section 2 are not satisfied or waived by the party entitled to the benefit of that condition by the Conditions Date as such term is defined in the Contract, then either party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations hereunder, provided that any rights or remedies that a party may have for breaches of the Contract prior to such termination and any liability a party may have incurred before such termination shall not thereby be released.

<u>SCHEDULE "B"</u>

RATE M12
NOMINATIONS

a) For Services provided either under this rate schedule or referenced to this rate schedule:

i) For Services required on any day Shipper shall provide Union with a nomination (the “Shipper's Nomination”) of the quantity it desires to be handled at the applicable Receipt Point and/or Delivery Point. Such Shipper's Nomination is to be provided in writing so as to be received by Union's Gas Management Services on or before 1230 hours in the Eastern time zone, unless agreed to otherwise in writing by the parties, on the business day immediately preceding the day for which service is requested.

ii) If, in Union's sole opinion, operating conditions permit, a change in Shipper's Nomination may be accepted after 1230 hours in the Eastern time zone.

iii) For customers electing firm all day transportation service, nominations shall be provided to Union’s Gas Management Services as outlined in the F24 –T Agreement.

b) Union shall determine whether or not all or any portion of Shipper's Nomination will be accepted. In the event Union determines that it will not accept such nomination, Union shall advise Shipper, on or before 1730 hours in the Eastern time zone on the business day immediately preceding the day for which service is requested, of the reduced quantity (the "Quantity Available") for Services at the applicable points. Forthwith after receiving such advice from Union but no later than 1800 hours in the Eastern time zone on the same day, Shipper shall provide a "Revised Nomination" to Union which shall be no greater than the Quantity Available. If such Revised Nomination is not provided within the time allowed as required above or such Revised Nomination is greater than the Quantity Available, then the Revised Nomination shall be deemed to be the Quantity Available. If the Revised Nomination (delivered within the time allowed as required above) is less than the Quantity Available, then such lesser amount shall be the Revised Nomination.

c) That portion of a Shipper's Nomination or Revised Nomination, as set out in (a) and (b), above, which Union shall accept for Services hereunder, shall be known as Shipper's "Authorized Quantity".

d) If on any day the actual quantities handled by Union, for each of the Services authorized, exceed Shipper's Authorized Quantity, and such excess was caused by either Shipper's incorrect nomination or by its delivering or receiving too much gas, then the amount by which the actual quantities handled for each of the Services exceed Shipper's Authorized Quantity, such excess shall be deemed "Unauthorized Overrun".

e) The daily quantity of gas nominated by Shipper will be delivered by Shipper at rates of flow that are as nearly constant as possible, however, Union shall use reasonable efforts to take receipt of gas on any day at an hourly rate of flow up to one twentieth (1/20) of the quantity received for that day. Union shall have the right to limit Services when on any day the cumulative hourly imbalance between receipts and deliveries exceeds one twentieth (1/20) of the quantity handled for that day, for each applicable Service.

f) A nomination for a daily quantity of gas on any day shall remain in effect and apply to subsequent days unless and until Union receives a new nomination from Shipper or unless Union gives Shipper written notice that it is not acceptable in accordance with either (a) or (b) of this schedule.

g) Except for periods of gas or quantity balancing as provided in the Contract, nominations by Shipper for deliveries to Union and redeliveries by Union shall be the same delivery of gas by Union either to Shipper or a Shipper’s Account with Union.

SCHEDULE "B 2010"

RATE M12
NOMINATIONS

1. For Transportation Services required on any Day under the Contract, Shipper shall provide Union with a nomination(s) providing the Shipper's requested Receipt Point(s), contract numbers, the applicable service, the quantity of Gas to be transported, the requested Delivery Point(s), and such additional information as Union determines to be necessary (a "**Nomination**").

2. All Nominations shall be submitted by electronic means via *Unionline*. Union, in its sole discretion, may amend or modify the nominating procedures or *Unionline* at any time. Nominations shall be submitted so as to be received by Union in accordance with timelines established by Union, which reflect the NAESB standard nomination cycles. Union will accept all nominations on each of the nomination cycles. Nominations made after the applicable deadline shall not be accepted except at the sole discretion of Union. All times referred to herein are Eastern Clock Time. For greater certainty, NAESB nomination cycle timelines are as follows:

   a. The Timely Nomination Cycle: 12:45 pm for Nominations leaving control of the nominating party; 3:30 pm for receipt of Quantities Available by Shipper; 4:30 pm for receipt of completed confirmations by Union from upstream and downstream connected parties; 5:30 pm for receipt of Scheduled Quantities by Shipper (Day prior to flow).

   b. The Evening Nomination Cycle: 7:00 pm for Nominations leaving control of the nominating party; 9:00 pm for receipt of Quantities Available by Shipper; 10:00 pm for receipt of completed confirmations by Union from upstream and downstream connected parties; 11:00 pm for receipt of Scheduled Quantities by Shipper (Day prior to flow).

   c. The Intra-day 1 Nomination Cycle: 11:00 am for Nominations leaving control of the nominating party; 1:00 pm for receipt of Quantities Available by Shipper; 2:00 pm for receipt of completed confirmations by Union from upstream and downstream connected parties; 3:00 pm for receipt of Scheduled Quantities Available by Shipper, on Day. Quantities Available resulting from Intra-day 1 Nominations should be effective at 6:00 pm on same Day.

   d. The Intra-day 2 Nomination Cycle: 6:00 pm for Nominations leaving control of the nominating party: 8:00 pm for receipt of Quantities Available by Shipper; 9:00 pm for receipt of completed confirmations by Union from upstream and downstream connected parties; 10:00 pm for receipt of Scheduled Quantities by Shipper on Day. Quantities Available resulting from Intra-day 2 Nominations should be effective at 10:00 pm on same Day.

3. Union shall determine whether or not all or any portion of the Nomination will be scheduled at each nomination cycle. With respect to each nomination cycle, in the event Union determines that it will not schedule such Nomination, Union shall advise Shipper of the reduced quantity (the "**Quantities Available**") for Transportation Services at the applicable points as outlined in each nomination cycle. After receiving such advice from Union, but no later than one half hour after the Quantities Available deadline as outlined in each nomination cycle, Shipper shall provide a revised nomination ("**Revised Nomination**") to Union which shall be no greater than the Quantity Available. If such Revised Nomination is not provided within the time allowed as required above or such Revised Nomination is greater than the Quantities Available, then the Revised Nomination shall be deemed to be the Quantities Available. If the Revised Nomination (delivered with the time allowed as required above) is less than the Quantity Available, then such lessor amount shall be the Revised Nomination.

4. For Shippers electing firm all day transportation service, nominations shall be provided to Union's Gas Management Services as outlined in the F24 –T Agreement.

5. For Transportation Services requiring Shipper to provide compressor fuel in kind, the nominated fuel requirements will be calculated by rounding to the nearest whole GJ.

6. All Timely Nominations shall have rollover options. Specifically, Shippers shall have the ability to nominate for several days, months or years, provided the Nomination start date and end date are both within the term of the Transportation Agreement.

7. Nominations received after the nomination deadline shall, if accepted by Union, be scheduled after Nominations received before the nomination deadline.

8. All Services are required to be nominated in whole Gigajoules (GJ).

9. To the extent Union is unable to complete a Nomination confirmation due to inaccurate, untimely or incomplete data involving an Interconnecting Pipeline entity, Union shall undertake reasonable efforts to confirm the transaction on a non-discriminatory basis until such time that the transaction is adequately verified by the parties, or until such time that Union determines that the Nomination is invalid at which time the Union shall reject the Nomination.

10. That portion of a Shipper's Nomination or Revised Nomination, as set out in paragraphs 1 and 3 above, which Union shall schedule for Transportation Services hereunder, shall be known as Shipper's "**Authorized Quantity**".

11. If on any day the actual quantities handled by Union, for each of the Transportation Services authorized, exceed Shipper's Authorized Quantity, and such excess was caused by either Shipper's incorrect nomination or by its delivering or receiving too much gas, then the amount by which the actual quantities handled for each of the Transportation Services exceed Shipper's Authorized Quantity shall be deemed "**Unauthorized Overrun**".

12. The daily quantity of gas nominated by Shipper will be delivered by Shipper at rates of flow that are as nearly constant as possible, however, Union shall use reasonable efforts to take receipt of gas on any day at an hourly rate of flow up to one twentieth ($1/20^{th}$) of the quantity received for that day. Union shall have the right to limit Transportation Services when on any day the cumulative hourly imbalance between receipts and deliveries exceeds one twentieth ($1/20^{th}$) of the quantity handled for that day, for each applicable Transportation Service.

13. The parties hereto recognize that with respect to Transportation Services, on any day, receipts of gas by Union and deliveries of gas by Union may not always be exactly equal, but each party shall cooperate with the other in order to balance as nearly as possible the quantities transacted on a daily basis, and any imbalances arising shall be allocated to the Facilitating Agreement and shall be subject to the respective terms and charges contained therein, and shall be resolved in a timely manner.

14. Shipper may designate a third party as agent for purposes of providing a Nomination, and for giving and receiving notices related to Nominations, and Union shall only accept nominations from the agent. Shipper shall provide Union with written notice of such designation, such notice to be acceptable to Union. Any such designation, if acceptable to Union, shall be effective starting the Month following the receipt of the written notice and will remain in effect until revoked in writing by Shipper.

UNION GAS LIMITED
M12 Monthly Transportation Fuel Ratios and Rates
Firm or Interruptible Transportation Commodity
Effective January 1, 2013

	VT1 Easterly Dawn to Parkway (TCPL) With Dawn Compression		VT1 Easterly Dawn to Kirkwall, Lisgar, Parkway (Consumers) With Dawn Compression		VT3 Westerly Parkway to Kirkwall, Dawn	
Month	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)
April	0.802	0.045	0.533	0.030	0.153	0.009
May	0.567	0.032	0.359	0.020	0.153	0.009
June	0.463	0.026	0.260	0.014	0.357	0.020
July	0.451	0.025	0.248	0.014	0.356	0.020
August	0.355	0.020	0.154	0.009	0.354	0.020
September	0.352	0.020	0.154	0.009	0.351	0.020
October	0.697	0.039	0.463	0.026	0.153	0.009
November	0.840	0.047	0.603	0.034	0.153	0.009
December	0.945	0.053	0.702	0.039	0.153	0.009
January	1.086	0.060	0.831	0.046	0.153	0.009
February	1.033	0.057	0.786	0.044	0.153	0.009
March	0.972	0.054	0.719	0.040	0.153	0.009

	M12-X Easterly Kirkwall to Parkway (TCPL)		M12-X Easterly Kirkwall to Lisgar Parkway (Consumers)		M12-X Westerly Parkway to Kirkwall, Dawn	
Month	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)
April	0.422	0.024	0.153	0.009	0.268	0.015
May	0.361	0.020	0.153	0.009	0.268	0.015
June	0.357	0.020	0.153	0.009	0.268	0.015
July	0.356	0.020	0.153	0.009	0.268	0.015
August	0.354	0.020	0.153	0.009	0.268	0.015
September	0.351	0.020	0.153	0.009	0.268	0.015
October	0.387	0.022	0.153	0.009	0.268	0.015
November	0.389	0.022	0.153	0.009	0.153	0.009
December	0.396	0.022	0.153	0.009	0.153	0.009
January	0.408	0.023	0.153	0.009	0.153	0.009
February	0.400	0.022	0.153	0.009	0.153	0.009
March	0.406	0.023	0.153	0.009	0.153	0.009

UNION GAS LIMITED

M12 Monthly Transportation Authorized Overrun Fuel Ratios and Rates

Firm or Interruptible Transportation Commodity

Effective January 1, 2013

	VT1 Easterly Dawn to Parkway (TCPL) With Dawn Compression		VT1 Easterly Dawn to Kirkwall, Lisgar, Parkway (Consumers) With Dawn Compression		VT3 Westerly Parkway to Kirkwall, Dawn	
Month	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)
April	1.402	0.156	1.133	0.129	0.753	0.120
May	1.167	0.143	0.959	0.119	0.753	0.120
June	1.063	0.138	0.860	0.114	0.957	0.132
July	1.051	0.137	0.848	0.113	0.956	0.132
August	0.955	0.131	0.754	0.108	0.954	0.131
September	0.952	0.131	0.754	0.108	0.951	0.131
October	1.297	0.151	1.063	0.125	0.753	0.120
November	1.440	0.158	1.203	0.133	0.753	0.120
December	1.545	0.164	1.302	0.139	0.753	0.120
January	1.686	0.172	1.431	0.146	0.753	0.120
February	1.633	0.169	1.386	0.143	0.753	0.120
March	1.572	0.166	1.319	0.140	0.753	0.120

	M12-X Easterly Kirkwall to Parkway (TCPL)		M12-X Easterly Kirkwall to Lisgar Parkway (Consumers)		M12-X Westerly Parkway to Kirkwall, Dawn	
Month	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)
April	1.022	0.069	0.753	0.054	0.868	0.127
May	0.961	0.066	0.753	0.054	0.868	0.127
June	0.957	0.065	0.753	0.054	0.868	0.127
July	0.956	0.065	0.753	0.054	0.868	0.127
August	0.954	0.065	0.753	0.054	0.868	0.127
September	0.951	0.065	0.753	0.054	0.868	0.127
October	0.987	0.067	0.753	0.054	0.868	0.127
November	0.989	0.067	0.753	0.054	0.753	0.120
December	0.996	0.068	0.753	0.054	0.753	0.120
January	1.008	0.068	0.753	0.054	0.753	0.120
February	1.000	0.068	0.753	0.054	0.753	0.120
March	1.006	0.068	0.753	0.054	0.753	0.120

SCHEDULE "D 2010"

RATE M12
RECEIPT AND DELIVERY POINTS AND PRESSURES

1. Receipt and Delivery Points:

The following defines each Receipt Point and/or Delivery Point, as indicated (R= Receipt Point; D= Delivery Point)

R,D	**DAWN (FACILITIES):**	Union's Compressor Station site situated in the northwest corner of Lot Twenty-Five (25), Concession II, in the Township of Dawn-Euphemia, in the County of Lambton. This point is applicable for quantities of gas that have been previously transported or stored under other contracts that Shipper may have in place with Union.
R	**DAWN (TCPL):**	At the junction of Union's and TCPL's facilities, at or adjacent to Dawn (Facilities).
R	**DAWN (TECUMSEH):**	At the junction of Union's and Enbridge Gas Distribution Inc.'s (Enbridge) Tecumseh Gas Storage's facilities, at or adjacent to Dawn (Facilities).
R	**DAWN (TSLE):**	At the junction of Union's and Enbridge Gas Distribution Inc.'s ("**Enbridge**") NPS 16 Tecumseh Sombra Line Extension facilities; at or adjacent to Dawn (Facilities)
R	**DAWN (VECTOR):**	At the junction of Union's and Vector Pipeline Limited Partnership ("**Vector**") facilities, at or adjacent to Dawn (Facilities).
R,D	**PARKWAY (TCPL):**	At the junction of Union's and TCPL's facilities, at or adjacent to Union's facilities situated in the Part Lot 9 and Part Lot 10, Concession IX, New Survey, Town of Milton, Regional Municipality of Halton (now part of City of Mississauga)
R,D	**KIRKWALL:**	At the junction of Union's and TCPL's facilities at or adjacent to Union's facilities situated in Part Lot Twenty-Five (25), Concession 7, Town of Flamborough.
D	**PARKWAY (CONSUMERS):**	At the junction of Union's and Enbridge's facilities, at or adjacent to Union's facilities situated in Part Lot 9 and Part Lot 10, Concession IX, New Survey, Town of Milton, Regional Municipality of Halton (now part of City of Mississauga)
D	**LISGAR:**	At the junction of the facilities of Union and Enbridge situated at 6620 Winston Churchill Boulevard, City of Mississauga.

2. Receipt and Delivery Pressures:

(a) All Gas tendered by or on behalf of Shipper to Union shall be tendered at the Receipt Point(s) at Union's prevailing pressure at that Receipt Point, or at such pressure as per operating agreements between Union and the applicable Interconnecting Pipeline as amended or restated from time to time.

(b) All Gas tendered by or on behalf of Union to Shipper shall be tendered at the Delivery Point(s) at Union's prevailing pressure at that Delivery Point or at such pressure as per agreements between Union and the applicable Interconnecting Pipeline as amended or restated from time to time.

(c) Under no circumstances shall Union be obligated to receive or deliver gas hereunder at pressures exceeding the maximum allowable operating pressures prescribed under any applicable governmental regulations; nor shall Union be required to make any physical deliveries or to accept any physical receipts which its existing facilities cannot accommodate.

unionGas

TRANSPORTATION OF LOCALLY PRODUCED GAS

(A) Applicability

The charges under this rate schedule shall be applicable to a customer who enters into a contract with Union for gas received at a local production point to be transported to Dawn.

Applicable Points

Dawn as a delivery point: Dawn (Facilities).

(B) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

Demand Commodity

	Demand Charge Rate/Month	Commodity Charge Union Provides Fuel Rate/GJ	Customer Provides Own Fuel Fuel Ratio
1. Monthly fixed charge per Customer Station	$926.60		
2. Transmission Commodity Charge		$0.034	
3. Delivery Commodity Charge		$0.009	0.153%

These charges are in addition to the transportation, storage and/or balancing charges which shall be paid for under Rate M12 or Rate C1, or other services that may be negotiated.

4. Overrun Services

Authorized Overrun

Authorized overrun will be payable on all quantities transported in excess of Union's obligation on any day. The overrun charges payable will be calculated at $0.077 /GJ. Overrun will be authorized at Union's sole discretion.

	Commodity Charge Union Provides Fuel Rate/GJ	Customers Provides Own Fuel Commodity Charge Rate/GJ	Customers Provides Own Fuel Fuel Ratio
Authorized Overrun Charge	$0.077	$0.069	0.153%

Unauthorized Overrun

Authorized Overrun rates payable on all volumes up to 2% in excess of Union's contractual obligation.

The Unauthorized Overrun rate during the November 1 to April 15 period will be $50 per GJ for all usage on any day in excess of 102% of Union's contractual obligation. The Unauthorized Overrun rate during the April 16 to October 31 period will be $9.373 per GJ for all usage on any day in excess of 102% of Union's contractual obligation.

(C) Terms of Service

General Terms & Conditions applicable to this rate shall be in accordance with the attached Schedule "A" in effect before January 1, 2013. The General Terms & Conditions applicable to this rate schedule shall be in accordance with the attached Schedule "A 2013" for contracts in effect on or after January 1, 2013.

Effective January 1, 2013 Chatham, Ontario
O.E.B. Order # EB-2011-0210

Supersedes EB-2012-0437 Rate Schedule effective January 1, 2013.

SCHEDULE "A"

GENERAL TERMS & CONDITIONS
M13 TRANSPORTATION AGREEMENT

I. DEFINITIONS

Except where the context expressly requires or states another meaning, the following terms, when used in these General Terms & Conditions and in any contract into which these General Terms & Conditions are incorporated, shall be construed to have the following meanings:

1. "Banking Day" shall mean a day on which the general offices of the Canadian Imperial Bank of Commerce, 99 King St. W., Chatham, Ontario are open for business;

2. "business day" shall mean a day on which the general offices of Union in Chatham, Ontario are open for business;

3. "Contract" shall refer to the Contract to which these General Terms & Conditions shall apply, and into which they are incorporated;

4. "contract year" shall mean a period of three hundred and sixty-five (365) consecutive days, beginning on the day agreed upon by Union and Shipper as set forth in the Contract, or on any anniversary of such date; provided, however, that any such period which contains a date of February 29 shall consist of three hundred and sixty-six (366) consecutive days;

5. "day" shall mean a period of twenty-four (24) consecutive hours beginning at 9:00 a.m. Central Standard time. The reference date for any day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

6. "month" shall mean the period beginning at 9:00 a.m. Central Standard time on the first day of a calendar month and ending at 9:00 a.m. Central Standard time on the first day of the following calendar month;

7. "firm" shall mean service not subject to curtailment or interruption except under Articles XI and XII of this Schedule "B";

8. "interruptible service" shall mean service subject to curtailment or interruption, after notice, at any time;

9. "gas" shall mean gas as defined in the Ontario Energy Board Act, R.S.O. 1980, c. 332, as amended, supplemented or reenacted from time to time;

10. "cubic metre" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

11. "m^3" shall mean cubic metre of gas and "10^3m^3" shall mean 1,000 cubic metres of gas;

12. "pascal" (Pa) shall mean the pressure produced when a force of one (1) newton is applied to an area of one (1) square metre. The term "kilopascal" (kPa) shall mean 1,000 pascals;

13. "joule" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force. The term "megajoule" (MJ) shall mean 1,000,000 joules. The term “gigajoule” (GJ) shall mean 1,000,000,000 joules;

14. "gross heating value" shall mean the total heat expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state;

15. "Shipper" shall have the meaning as defined in the Contract and shall also include Shipper’s agent(s);

16. "subsidiary" shall mean a company in which more than fifty (50) per cent of the issued share capital (having full voting rights under all circumstances) is owned or controlled directly or indirectly by another company, by one or more subsidiaries of such other company, or by such other company and one or more of its subsidiaries;

17. "TCPL" means TransCanada PipeLines Limited;

18. "NOVA" means NOVA Gas Transmission Ltd;

19. "Panhandle" means CMS Panhandle Eastern Pipeline Company;

20. "MichCon" means Michigan Consolidated Gas Company;

21. "SCPL" means St. Clair Pipelines (1996) Ltd.;

22. "OEB" means the Ontario Energy Board;

23. "NEB" means the National Energy Board (Canada);

    i. "GLGT" means Great Lakes Gas Transmission Company;

    ii. "CMS" means CMS Gas Transmission and Storage Company; and,

    iii. "Consumers" means The Consumers' Gas Company, Limited.

24. "cricondentherm hydrocarbon dewpoint" shall mean the highest hydrocarbon dewpoint temperature on the phase envelope;

25. "hydrocarbon dewpoint" shall mean temperature at a specific pressure where hydrocarbon vapour condensation begins;

26. "specific gravity" shall mean density of the gas divided by density of air, with both at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute; and,

27. "Wobbe Number" shall mean gross heating value of the gas divided by the square root of its specific gravity.

<u>II. GAS QUALITY</u>

1. <u>Natural Gas:</u> The minimum gross heating value of the gas delivered to/by Union hereunder, shall be thirty-six (36) megajoules per cubic metre. The maximum gross heating value of the gas delivered to/by Union hereunder shall be forty point two (40.2) megajoules per cubic metre. The gas to be delivered hereunder to Union may be a commingled supply from Shipper's gas sources of supply. The gas to be delivered by Union may be a commingled supply from Union's sources of gas supply; provided, however, that helium, natural gasoline, butane, propane and other hydrocarbons, except methane, may be removed prior to delivery to Shipper. Further, Union may subject, or permit the subjection of, the gas to compression, dehydration, cooling, cleaning and other processes.

2. <u>Freedom from objectionable matter</u>: The gas to be delivered to Union at the Receipt Point(s) hereunder,

    a. shall be commercially free from bacteria, sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other objectionable substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to, or interference with, the proper operation of the lines, regulators, meters or other appliances through which it flows,

    b. shall not contain more than seven (7) milligrams of hydrogen sulphide per cubic metre of gas, nor more than one hundred (100) milligrams of total sulphur per cubic metre of gas,

    c. shall not contain more than five (5) milligrams of mercaptan sulphur per cubic metre of gas,

    d. shall not contain more than two point zero (2.0) molar percent by volume of carbon dioxide in the gas,

    e. shall not contain more than zero point four (0.4) molar percent by volume of oxygen in the gas,

f. shall not contain more than zero point five (0.5) molar percent by volume of carbon monoxide in the gas,

g. shall not contain more than four point zero (4.0) molar percent by volume of hydrogen in the gas,

h. shall not contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas,

i. shall not have a cricondentherm hydrocarbon dewpoint exceeding minus eight (-8) degrees Celsius,

j. shall have Wobbe Number from forty seven point fifty (47.50) megajoules per cubic metre of gas to fifty one point forty six (51.46) megajoules per cubic metre of gas, maximum of one point five (1.5) mole percent by volume of butane plus (C4+) in the gas, and maximum of four point zero (4.0) mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas,

k. shall not exceed forty-three degrees Celsius (43ºC), and,

l. shall not be odourized by Shipper.

3. Non-conforming Gas:

a. In the event that the quality of the gas does not conform or if Union, acting reasonably, suspects the quality of the gas may not conform to the specifications herein, then Shipper shall, if so directed by Union acting reasonably, forthwith carry out, at Shipper's cost, whatever field testing of the gas quality as may be required to ensure that the quality requirements set out herein are met, and to provide Union with a certified copy of such tests. If Shipper does not carry out such tests forthwith, Union may conduct such test and Shipper shall reimburse Union for all costs incurred by Union for such testing.

b. If Shipper's gas fails at any time to conform to the requirements of this Article II, Union, in addition to its other remedies, may refuse to accept delivery of gas at the Receipt Points hereunder until such deficiency has been remedied by Shipper. Each Party agrees to notify the other verbally, followed by written notification, of any such deficiency of quality.

4. Quality of Gas Received: The quality of the gas to be received by Union at the Receipt Point(s) hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Article II, but, Union will use reasonable efforts to accept gas of a quality that may deviate from the quality standards set out therein.

5. Quality of Gas at Dawn: The quality of the gas to be delivered to Union at Dawn (Facilities) or the gas to be delivered by Union to Shipper at Dawn (Facilities) hereunder is to be of a merchantable quality and in accordance with the quality standards and measurement standards as set out by Union in this Article II, except that total sulphur limit shall be not more than four hundred and sixty (460) milligrams per cubic metre of gas. In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Article II.

III. MEASUREMENTS

1. Service Unit: The unit of the gas delivered to Union shall be a quantity of 10^3m^3. The unit of gas delivered by Union shall be a megajoule, a gigajoule, a cubic metre (m^3) or one thousand cubic metres (10^3m^3) at Union's discretion.

2. Determination of Volume and Energy:

a. The volume and energy amounts determined under the Contract shall be determined in accordance with the Electricity and Gas Inspection Act (Canada), RSC 1985, c E-4- (the "**Act**") and the Electricity and Gas Inspection Regulations, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

b. The supercompressibility factor shall be determined in accordance with either the "Manual for Determination of Supercompressibility Factors for Natural Gas" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

c. The volume and/or energy of the gas delivered to/by Union hereunder shall be determined by the measurement equipment designated in Article VI herein.

IV. POINT OF RECEIPT AND POINT OF DELIVERY

1. Unless otherwise specified in the Contract, the point or points of receipt for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection specified in the Contract, where Union takes possession of the gas. Whenever the phrase “receipt point” appears herein, it shall mean Point of Receipt as defined in this Article IV.

2. Unless otherwise specified in the Contract, the point or points of delivery for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection as specified in the Contract, where Shipper takes possession of the gas. Whenever the phrase “delivery point” shall appear herein, it shall mean Point of Delivery as defined in this Article IV.

V. FACILITIES ON CUSTOMER'S PROPERTY

N/A.

VI. MEASURING EQUIPMENT

1. Metering by Union: Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Article III herein.

2. Metering by Others: In the event that all or any gas received or delivered hereunder is measured by a meter that is owned and operated by an upstream or downstream transporter (the “Transporter”) whose facilities may or may not interconnect with Union’s, then Union and Shipper agree to accept that metering for the purpose of determining the volume and energy of gas received or delivered on behalf of the Shipper. The standard of measurement and tests for the gas delivered to/by Union pursuant to this Article VII, Section 2 shall be in accordance with the general terms and conditions as incorporated in that Transporter’s gas tariff as approved by Transporter’s regulatory body.

3. Check Measuring Equipment: Shipper may install, maintain and operate, at the Receipt Point, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Union's measuring equipment at or near the Receipt Point, and shall be installed, maintained and operated in conformity with the same standards and specifications applicable to Union's metering facilities.

4. Calibration and Test of Measuring Equipment: The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Shipper, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment tested is found to be in error by not more than two per cent (2%). If, upon test, any measuring equipment is found to be in error by not more than two per cent (2%), previous recordings of such equipment shall be considered accurate in computing receipts of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than two percent (2%), the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations, as may be amended from time to time and in accordance with any successor statutes and regulations.

5. Preservation of Metering Records: Union and Shipper shall each preserve for a period of at least six (6) years all test data, and other relevant records.

VII. BILLING

1. Monthly Billing Date: Union shall render bills on or before the 10th day of each month for all services furnished during the preceding month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding month's billing, an adjustment based on any difference between actual quantities and estimated quantities. If presentation of a bill to Shipper is delayed after the 10th day of the month, then the time of payment shall be extended accordingly, unless Shipper is responsible for such delay.

2. Right of Examination: Both Union and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Contract.

VIII. PAYMENTS

1. Monthly Payments: Shipper shall pay the invoiced amount directly into Union's bank account as directed on the invoice on or before the twentieth (20^{th}) day of each month. If the payment date is not a business day, then payment must be received in Union's account on the first business day preceding the twentieth (20^{th}) day of the month.

2. Remedies for Non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due, Shipper shall pay to Union interest on the unpaid portion of the bill accruing at a rate per annum equal to the minimum commercial lending rate of Union's principal banker in effect from time to time from the due date until the date of payment. If such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the Contract may suspend service(s) until such amount is paid, provided however, that if Shipper, in good faith shall dispute the amount of any such bill or part thereof and shall pay to Union such amounts as it concedes to be correct and at any time thereafter within twenty (20) days of a demand made by Union shall furnish good and sufficient surety bond satisfactory to Union, guaranteeing payment to Union of the amount ultimately found due upon such bill after a final determination which may be reached either by agreement, arbitration decision or judgement of the courts, as may be the case, then Union shall not be entitled to suspend service(s) because of such non-payment unless and until default be made in the conditions of such bond or in payment for any further service(s) to Shipper hereunder.

3. Billing Adjustments: If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, Union shall refund the amount of any such overcharge and interest shall accrue from and including the first day of such overcharge as paid to the date of refund and shall be calculated but not compounded at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker, and the Shipper shall pay the amount of any such undercharge, but without interest. In the event Union renders a bill to Shipper based upon measurement estimates, the required adjustment to reflect actual measurement shall be made on the bill next following the determination of such actual measurement, without any charge of interest. In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "bill" next following shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within six (6) years from the date of the incorrect billing. In the event any refund is issued with Shipper's bill, the aforesaid date of refund shall be deemed to be the date of the issue of invoice.

IX. ARBITRATION

If and when any dispute, difference or question shall arise between the parties hereto touching the Contract or anything herein contained, or the construction hereof, or the rights, duties or liabilities of the parties in relation to any matter hereunder, the matter in dispute shall be submitted and referred to arbitration within ten (10) days after written request of either party. Upon such request each party shall appoint an arbitrator, and the two so appointed shall appoint a third. A majority decision of the arbitrators shall be final and binding upon both parties. In all other respects the provisions of the Arbitration Act of the Province of Ontario, or any act passed in amendment thereof or substitution therefore, shall apply to each such submission. Operations under this Contract shall continue, without prejudice, during any such arbitration and the costs attributable to such arbitration shall be shared equally by the parties hereto.

X. FORCE MAJEURE

N/A

XI. DEFAULT AND TERMINATION

N/A

XII. MODIFICATION

N/A

XIII. NONWAIVER AND FUTURE DEFAULT

N/A

XIV. LAWS, REGULATIONS AND ORDERS

The Contract and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Contract shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Contract.

RATE M13
GENERAL TERMS & CONDITIONS

I. DEFINITIONS

Except where the context expressly requires or states another meaning, the following terms, when used in these General Terms & Conditions and in any contract into which these General Terms & Conditions are incorporated, shall be construed to have the following meanings:

"**Aid to Construction"** shall include any and all costs, expenses, amounts, damages, obligations, or other liabilities (whether of a capital or operating nature, and whether incurred before or after the date of the Contract) actually paid by Union (including amounts paid to affiliates for services rendered in accordance with the Affiliate Relationships Code as established by the OEB) in connection with or in respect of satisfying the conditions precedent set out in Article XXI herein (including without limitation the cost of construction, installation and connection of any required meter station as described in Article IX, Section 6, the obtaining of all governmental, regulatory and other third party approvals, and the obtaining of rights of way) whether resulting from Union's negligence or not, except for any costs that have arisen from the gross negligence, fraud, or wilful misconduct of Union;

"**Average Local Producer Heat**" ("**ALPH**") shall mean the heat content value as set by Union, and shall be determined by volumetrically averaging the gross heat content of all produced gas delivered to the Union system by Ontario Local Producers. The ALPH shall be expressed in GJ/10^3m^3 and may be adjusted from time to time by Union;

"**Business Day**" shall mean any day, other than Saturday, Sunday or any days on which national banks in the Province of Ontario are authorized to close;

"**Contract**" shall refer to the Contract to which these General Terms & Conditions shall apply, and into which they are incorporated;

"**Contract Year**" shall mean a period of three hundred and sixty-five (365) consecutive days; provided however, that any such period which contains a date of February 29 shall consist of three hundred and sixty-six (366) consecutive days, commencing on November 1 of each year; except for the first Contract Year which shall commence on the Commencement Date and end on the first October 31 that follows such date;

"**cricondentherm hydrocarbon dewpoint**" shall mean the highest hydrocarbon dewpoint temperature on the phase envelope;

"**cubic metre**" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**Dawn Quantity**" shall mean the total daily quantity of gas in GJ delivered at Dawn (Facilities), which is equal to the total energy of all gas supplied daily to Union at the Receipt Point(s). The Dawn Quantity shall be calculated utilizing the following factor equation: Dawn Quantity = Produced Volume x ALPH;

"**Day**" shall mean a period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Clock Time. The reference date for any Day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

"**Delivery Point**" shall mean the point where Union shall deliver the Dawn Quantity and/or Market Quantity to Shipper and as further defined in Schedule 1 of the Contract;

"**Distribution Demand**" shall mean the varying demand for the supply of gas, as determined by Union, on Union's pipeline and distribution system for users of gas who are supplied or delivered gas by Union's pipeline and distribution system;

"Eastern Clock Time" shall mean the local clock time in the Eastern Time Zone on any Day;

"**firm**" shall mean service not subject to curtailment or interruption except under Articles XI, XII and XVIII herein;

"**Firm Daily Variability Demand**" shall mean the established quantity set forth in Schedule 2 of the Contract, which is the permitted difference between the Dawn Quantity and the Market Quantity;

"**gas**" shall mean gas as defined in the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Sch. B, as amended, supplemented or re-enacted from time to time;

"**gross heating value**" shall mean the total heat expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state;

"**hydrocarbon dewpoint**" shall mean temperature at a specific pressure where hydrocarbon vapour condensation begins;

"**Interruptible HUB Service Contract**" shall mean a contract between Shipper and Union under which Union provides interruptible HUB service;

"**Interconnecting Pipeline**" shall mean a pipeline that directly connects to the Union pipeline and distribution system;

"**joule**" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force. The term "**megajoule**" (MJ) shall mean 1,000,000 joules. The term "**gigajoule**" (GJ) shall mean 1,000,000,000 joules;

"**m^3**" shall mean cubic metre of gas and "**10^3m^3**" shall mean 1,000 cubic metres of gas;

"**MAOP"** shall mean the maximum allowable operating pressure of Union's pipeline and distribution system and as further defined in Schedule 1 of the Contract;

"**Market Quantity**" shall mean the daily quantity in GJ nominated for Name Change Service that Day by Shipper at Dawn (Facilities);

"**Maximum Daily Quantity**" shall mean the maximum quantity of gas Shipper may deliver to Union at a Receipt Point on any Day, as further defined in Schedule 1;

"**Month**" shall mean the period beginning at 10:00 a.m. Eastern Clock Time on the first day of a calendar month and ending at 10:00 a.m. Eastern Clock Time on the first day of the following calendar month;

"**Name Change Service**" shall mean an interruptible administrative service whereby Union acknowledges for Shipper a change in title of a gas quantity from Shipper to a third party at the Delivery Point;

"**OEB**" means the Ontario Energy Board;

"**pascal**" "**(Pa)**" shall mean the pressure produced when a force of one (1) newton is applied to an area of one (1) square metre. The term "**kilopascal**" "**(kPa)"** shall mean 1,000 pascals;

"**Produced Volume**" shall mean the aggregate of all actual volumes of gas in 10^3m^3, delivered by Shipper to Union at all Receipt Points on any Day;

"**Producer Balancing Account**" shall mean the gas balance held by Union for Shipper, or owed by Shipper to Union, at the Delivery Point. Where the Producer Balancing Account is zero or a positive number, the account is in a credit position, and where the Producer Balancing Account is less than zero, the account is in a debit position;

"**Producer Balancing Service**" shall mean a Service whereby Union either calculates a credit or debit to the Producer Balancing Account by subtracting the Market Quantity from the Dawn Quantity. Where such amount is greater than zero, Union will credit the Producer Balancing Account, or where such amount is less than zero, Union will debit the Producer Balancing Account. This Service shall be performed on a retroactive basis on the terms and conditions contained in Schedule 2 of the Contract, as may be revised from time to time by Union;

"Receipt Point" shall mean the point(s) where Union shall receive gas from Shipper;

"**Sales Agreement**" shall mean the Ontario Gas Purchase Agreement(s) entered into between Shipper and Union;

"**Shipper**" shall have the meaning as defined in the Contract, and shall also include Shipper's agent(s);

"**specific gravity**" shall mean density of the gas divided by density of air, with both at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**System Capacity**" shall mean the volumetric capacity that exists from time to time within Union's pipeline and distribution system which determines Union's ability to accept volumes of gas into Union's pipeline and distribution system hereunder. System Capacity shall be determined by Union and such determination, in addition to the physical characteristics of Union's pipeline and distribution system Distribution Demand, shall also include consideration of Union's local Distribution Demand, Union's total system Distribution Demand, availability of Union's gas storage capacity, and other gas being purchased and/or delivered into Union's pipeline and distribution system;

"**Taxes**" shall mean any tax (other than tax on income or tax on property), duty, royalty, levy, license, fee or charge not included in the charges and rates as per the applicable rate schedule (including but not limited to charges under any form of cap and trade, carbon tax, or similar system) and that is levied, assessed or made by any governmental authority on the gas itself, or the act, right, or privilege of producing, severing, gathering, storing, transporting, handling, selling or delivering gas under the Contract;

"**Wobbe Number**" shall mean gross heating value of the gas divided by the square root of its specific gravity.

II. GAS QUALITY

1. Natural Gas: The minimum gross heating value of the gas delivered to/by Union hereunder, shall be thirty-six (36) megajoules per cubic metre. The maximum gross heating value of the gas delivered to/by Union hereunder shall be forty point two (40.2) megajoules per cubic metre. The gas to be delivered hereunder to Union may be a commingled supply from Shipper's gas sources of supply. The gas to be delivered by Union may be a commingled supply from Union's sources of gas supply; provided, however, that helium, natural gasoline, butane, propane and other hydrocarbons, except methane, may be removed prior to delivery to Shipper. Further, Union may subject, or permit the subjection of, the gas to compression, dehydration, cooling, cleaning and other processes.

2. Freedom from objectionable matter: The gas to be delivered to Union at the Receipt Point(s) hereunder,

   a. shall be commercially free from bacteria, sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other objectionable substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to, or interference with, the proper operation of the lines, regulators, meters or other appliances through which it flows,

   b. shall not contain more than seven (7) milligrams of hydrogen sulphide per cubic metre of gas, nor more than one hundred (100) milligrams of total sulphur per cubic metre of gas,

   c. shall not contain more than five (5) milligrams of mercaptan sulphur per cubic metre of gas,

   d. shall not contain more than two point zero (2.0) molar percent by volume of carbon dioxide in the gas,

   e. shall not contain more than zero point four (0.4) molar percent by volume of oxygen in the gas,

   f. shall not contain more than zero point five (0.5) molar percent by volume of carbon monoxide in the gas,

   g. shall not contain more than four point zero (4.0) molar percent by volume of hydrogen in the gas,

   h. shall not contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas,

   i. shall not have a cricondentherm hydrocarbon dewpoint exceeding minus eight (-8) degrees Celsius,

   j. shall have Wobbe Number from forty seven point fifty (47.50) megajoules per cubic metre of gas to fifty one point forty six (51.46) megajoules per cubic metre of gas, maximum of one point five (1.5) mole percent by volume of butane plus (C4+) in the gas, and maximum of four point zero (4.0) mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas,

k. shall not exceed forty-three degrees Celsius (43ºC), and,

l. shall not be odourized by Shipper.

3. Non-conforming Gas:

a. In the event that the quality of the gas does not conform or if Union, acting reasonably, suspects the quality of the gas may not conform to the specifications herein, then Shipper shall, if so directed by Union acting reasonably, forthwith carry out, at Shipper's cost, whatever field testing of the gas quality as may be required to ensure that the quality requirements set out herein are met, and to provide Union with a certified copy of such tests. If Shipper does not carry out such tests forthwith, Union may conduct such test and Shipper shall reimburse Union for all costs incurred by Union for such testing.

b. If Shipper's gas fails at any time to conform to the requirements of this Article II, Union, in addition to its other remedies, may refuse to accept delivery of gas at the Receipt Points hereunder until such deficiency has been remedied by Shipper. Each Party agrees to notify the other verbally, followed by written notification, of any such deficiency of quality.

4. Quality of Gas Received: The quality of the gas to be received by Union at the Receipt Point(s) hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Article II, but, Union will use reasonable efforts to accept gas of a quality that may deviate from the quality standards set out therein.

5. Quality of Gas at Dawn: The quality of the gas to be delivered to Union at Dawn (Facilities) or the gas to be delivered by Union to Shipper at Dawn (Facilities) hereunder is to be of a merchantable quality and in accordance with the quality standards and measurement standards as set out by Union in this Article II, except that total sulphur limit shall be not more than four hundred and sixty (460) milligrams per cubic metre of gas. In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Article II.

III. MEASUREMENTS

1. Service Unit: The unit of the gas delivered to Union shall be a quantity of 10^3m^3. The unit of gas delivered by Union shall be a megajoule, a gigajoule, a cubic metre (m^3) or one thousand cubic metres (10^3m^3) at Union's discretion.

2. Determination of Volume and Energy:

a. The volume and energy amounts determined under the Contract shall be determined in accordance with the Electricity and Gas Inspection Act (Canada), RSC 1985, c E-4- (the "**Act**") and the Electricity and Gas Inspection Regulations, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

b. The supercompressibility factor shall be determined in accordance with either the "**Manual for Determination of Supercompressibility Factors for Natural Gas**" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

c. The volume and/or energy of the gas delivered to/by Union hereunder shall be determined by the measurement equipment designated in Article VII herein.

IV. RECEIPT POINT AND DELIVERY POINT

The point(s) of receipt and point of delivery for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection specified in Schedule 1 of the Contract, where possession of the gas changes from one party to the other.

V. POSSESSION OF AND RESPONSIBILITY FOR GAS

1. Union accepts no responsibility for any gas prior to such gas being delivered to Union at the Receipt Point or after its delivery by Union at the Delivery Point. As between the parties hereto, Union shall be deemed to be in control and possession of and responsible for all such gas from the time that such gas enters Union's system until such gas is delivered to Shipper.

2. Shipper agrees that Union is not a common carrier and is not an insurer of Shipper's gas, and that Union shall not be liable to Shipper or any third party for loss of gas in Union's possession, except to the extent such loss is caused entirely by Union's negligence or wilful misconduct.

VI. FACILITIES ON SHIPPER'S PROPERTY

1. Union shall provide, at the Receipt Point(s), according to the terms hereunder, the meter station required to receive and measure the Produced Volume of gas received by Union from Shipper. Shipper agrees, if requested by Union, to provide Union with sufficient detailed information regarding Shipper's current and expected operations in order to aid Union in Union's design of the meter station.

2. Pursuant to Article VI. Section 1 herein, Union shall purchase, install and maintain, at the Receipt Point(s):

   a. a meter and any associated recording gauges as are necessary; and,

   b. a suitable gas odourizing injection facility where Union deems such facility to be necessary.

3. All equipment installed by Union at the Receipt Point(s) shall remain the property of Union at all times, notwithstanding the fact that it may be affixed to Shipper's property. Union shall be entitled to remove said equipment at any time within a period of sixty (60) days from any termination or expiry of the Contract. Shipper shall take all necessary steps to ensure Union may enter onto the Receipt Point(s) to remove such equipment for a period of sixty (60) days after termination or expiry of the Contract or the Sales Agreement.

4. Upon Union's request Shipper shall, at Shipper's own cost and expense:

   a. obtain a registered lease or freehold ownership at the Receipt Point(s) sufficient to provide Union with free uninterrupted access to, from, under and above the Receipt Point(s), for a term (and extended terms) identical to the Contract, plus sixty (60) days, and shall provide Union with a bona fide copy of such lease agreement prior to Union commencing the construction of the meter station;

   b. furnish, install, set, and maintain suitable pressure and volume control equipment and such additional equipment as required on Shipper's delivery system, to protect against the overpressuring of Union's facilities, and to limit the daily flow of gas to the corresponding Maximum Daily Quantity applicable to the Receipt Point(s);

   c. supply, install and maintain a gravel or cut stone covering on each Receipt Point and shall maintain such Receipt Point(s) in a safe and workmanlike manner; and,

   d. install and maintain a fence satisfactory to Union around the perimeter of each Receipt Point which will adequately secure and protect Union's equipment therein.

5. Shipper shall within thirty (30) days of the delivery of an invoice by Union, reimburse Union for any actual costs reasonably incurred by Union for any repair, replacement, relocation, or upgrading of any meter station requested by Shipper, or as required by law, or by duly constituted regulatory body, or through good engineering practice. Union shall be responsible for any costs incurred by Union to correct an error made by Union.

VII. MEASURING EQUIPMENT

1. Metering by Union: Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Article III herein.

2. Metering by Others: In the event that all or any gas received or delivered hereunder is measured by a meter that is owned and operated by an upstream or downstream transporter (the "**Transporter**") whose facilities may or may not interconnect with Union's, then Union and Shipper agree to accept that metering for the purpose of determining the volume and energy of gas received or delivered on behalf of the Shipper. The standard of measurement and tests for the gas delivered to/by Union pursuant to this Article VII, Section 2 shall be in accordance with the general terms and conditions as incorporated in that Transporter's gas tariff as approved by Transporter's regulatory body.

3. Check Measuring Equipment: Shipper may install, maintain and operate, at the Receipt Point, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Union's measuring equipment at or near the Receipt Point, and shall be installed, maintained and operated in conformity with the same standards and specifications applicable to Union's metering facilities.

4. Calibration and Test of Measuring Equipment: The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Shipper, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment tested is found to be in error by not more than two per cent (2%). If, upon test, any measuring equipment is found to be in error by not more than two per cent (2%), previous recordings of such equipment shall be considered accurate in computing receipts of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than two percent (2%), the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations, as may be amended from time to time and in accordance with any successor statutes and regulations.

5. Preservation of Metering Records: Union and Shipper shall each preserve for a period of at least six (6) years all test data, and other relevant records.

VIII. BILLING

1. Monthly Billing Date: Union shall render bills on or before the tenth (10th) day of each month for all Services furnished during the preceding Month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding Month's billing, an adjustment based on any difference between actual quantities and estimated quantities, without any interest charge. If presentation of a bill to Shipper is delayed after the tenth (10th) day of the month, then the time of payment shall be extended accordingly, unless Shipper is responsible for such delay.

2. Right of Examination: Both Union and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Contract.

3. Amendment of Statements: For the purpose of completing a final determination of the actual quantities of gas handled in any of the Services to Shipper, the parties shall have the right to amend their statement for a period equal to the time during which the companies, that transport the gas contemplated herein for Union and Shipper, retain the right to amend their statements, which period shall not exceed three (3) years from the date of termination of the Contract.

IX. PAYMENTS

1. Monthly Payments: Shipper shall pay the invoiced amount directly into Union's bank account as directed on the invoice on or before the twentieth (20th) day of each month. If the payment date is not a Business Day, then payment must be received in Union's account on the first Business Day preceding the twentieth (20th) day of the month.

2. Remedies for Non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due,

   a. Shipper shall pay to Union interest on the unpaid portion of the bill accruing at a rate per annum equal to the minimum commercial lending rate of Union's principal banker in effect from time to time from the due date until the date of payment; and,

b. If such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the Contract, may suspend Services until such amount is paid. Notwithstanding such suspension, all demand charges shall continue to accrue hereunder as if such suspension were not in place.

If Shipper in good faith disputes the amount of any such bill or part thereof Shipper shall pay to Union such amounts as it concedes to be correct. At any time thereafter, within twenty (20) days of a demand made by Union, Shipper shall furnish financial assurances satisfactory to Union, guaranteeing payment to Union of the amount ultimately found due upon such bill after a final determination. Such a final determination may be reached either by agreement, arbitration decision or judgement of the courts, as may be the case. Union shall not be entitled to suspend Services because of such non-payment unless and until default occurs in the conditions of such financial assurances or default occurs in payment of any other amount due to Union hereunder.

Notwithstanding the foregoing, Shipper is not relieved from the obligation to continue its deliveries of gas to Union under the terms of any agreement, where Shipper has contracted to deliver specified quantities of gas to Union.

3. Billing Adjustments: If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, Union shall refund the amount of any such overcharge and interest shall accrue from and including the first day of such overcharge as paid to the date of refund and shall be calculated but not compounded at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker, and the Shipper shall pay the amount of any such undercharge, but without interest. In the event Union renders a bill to Shipper based upon measurement estimates, the required adjustment to reflect actual measurement shall be made on the bill next following the determination of such actual measurement, without any charge of interest. In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "**bill next following**" shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within three (3) years from the date of the incorrect billing. In the event any refund is issued with Shipper's bill, the aforesaid date of refund shall be deemed to be the date of the issue of bill.

4. Taxes: In addition to the charges and rates as per the applicable rate schedules and price schedules, Shipper shall pay all Taxes which are imposed currently or subsequent to the execution of the Contract by any legal authority having jurisdiction and any amount in lieu of such Taxes paid or payable by Union.

5. Set Off: If either party shall, at any time, be in arrears under any of its payment obligations to the other party under the Contract, then the party not in arrears shall be entitled to reduce the amount payable by it to the other party in arrears under the Contract, or any other contract, by an amount equal to the amount of such arrears or other indebtedness to the other party. In addition to the foregoing remedy, Union may, upon forty-eight (48) hours verbal notice, to be followed by written notice, take possession of any or all of Shipper's gas under the Contract, which shall be deemed to have been assigned to Union, to reduce such arrears or other indebtedness to Union.

6. Station and Connection Costs: In the event that a meter station must be constructed and/or installed in order to give effect to this Contract, Shipper agrees to pay Union for a portion, as determined by Union, of Union's actual cost, as hereinafter defined, for constructing and installing such station. Shipper also agrees to pay the actual costs to connect such station to Union's pipeline and distribution system. Union shall advise Shipper as to the need for a meter station and shall provide Shipper with an estimate of the Aid to Construction. Such Aid to Construction shall include the costs of all pipe, fittings and materials, third party labour costs and Union's direct labour, labour saving devices, vehicles and mobile equipment, but shall exclude the purchase costs of gas pressure control equipment and gas meters installed by Union.

X. ARBITRATION

If and when any dispute, difference or question shall arise between the parties hereto touching the Contract or anything herein contained, or the construction hereof, or the rights, duties or liabilities of the parties in relation to any matter hereunder, the matter in dispute shall be submitted and referred to arbitration within ten (10) days after written request of either party. Upon such request each party shall appoint an arbitrator, and the two so appointed shall appoint a third. A majority decision of the arbitrators shall be final and binding upon both parties. In all other respects the provisions of the

Arbitration Act, 1991, or any act passed in amendment thereof or substitution therefore, shall apply to each such submission. Operations under the Contract shall continue, without prejudice, during any such arbitration and the costs attributable to such arbitration shall be shared equally by the parties hereto.

XI. FORCE MAJEURE

1. The term "**force majeure**" as used herein shall mean acts of God, strikes, lockouts or any other industrial disturbance, acts of the public enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or lines of pipe, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority (civil or military), any act or omission that is excused by any event or occurrence of the character herein defined as constituting force majeure, any act or omission by parties not controlled by the party having the difficulty and any other similar cases not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

2. In the event that either the Shipper or Union is rendered unable, in whole or in part, by force majeure, to perform or comply with any obligation or condition of the Contract, such party shall give notice and full particulars of such force majeure in writing delivered by hand, fax or other direct written electronic means to the other party as soon as possible after the occurrence of the cause relied on and subject to the provision of this Article.

3. Neither party shall be entitled to the benefit of the provisions of force majeure hereunder if any or all of the following circumstances prevail: the failure resulting in a condition of force majeure was caused by the negligence of the party claiming suspension; the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation); the party claiming suspension failed to resume the performance of such condition obligations with reasonable dispatch; the failure was caused by lack of funds; the party claiming suspension did not, as soon as possible after determining, or within a period within which it should acting reasonably have determined, that the occurrence was in the nature of force majeure and would affect its ability to observe or perform any of its conditions or obligations under the Contract, give to the other party the notice required hereunder.

4. The party claiming suspension shall likewise give notice as soon as possible after the force majeure condition is remedied, to the extent that the same has been remedied, and that such party has resumed or is then in a position to resume the performance of the obligations and conditions of the Contract.

5. An event of force majeure on Union's system will excuse the failure to deliver gas by Union or the failure to accept gas by Union hereunder, and both parties shall be excused from performance of their obligations hereunder, except for payment obligations, to the extent of and for the duration of the force majeure.

6. Upstream or Downstream Force Majeure: An event of force majeure upstream or downstream of Union's system shall not relieve Shipper of any payment obligations.

7. Delay of Services: Despite Article XI herein, if Union is prevented, by reason of an event of force majeure on Union's system from delivering gas on the Day or Days upon which Union has accepted gas from Shipper, Union shall thereafter make all reasonable efforts to deliver such quantities as soon as practicable and on such Day or Days as are agreed to by Shipper and Union. If Union accepts such gas on this basis, Shipper shall not receive any demand charge relief as contemplated under Article XI herein.

8. Firm Daily Variability Demand Charge Relief: Despite Article XI herein, if on any Day Union fails to accept gas from Shipper by reason of an event of force majeure on Union's system and fails to deliver the quantity of gas nominated hereunder by Shipper up to the Firm Daily Variability Demand for that Contract, then for that Day the Monthly charge shall be reduced by an amount equal to the applicable Firm Daily Variability Demand Rate, as defined in this paragraph, multiplied by the difference between the quantity of gas actually delivered by Union during such Day and the quantity of gas which Shipper in good faith nominated on such Day. The term "**Firm Daily Variability Demand Rate**" shall mean the monthly Firm Daily Variability Demand charge as provided in Schedule 2 of the Contract, divided by the number of days in the month for which such rate is being calculated.

XII. DEFAULT AND TERMINATION

In case of the breach or non-observance or non-performance on the part of either party hereto of any covenant, proviso, condition, restriction or stipulation contained in the Contract (but not including herein failure to take or make delivery in whole or in part of the gas delivered to/by Union hereunder occasioned by any of the reasons provided for in Article XI herein) which has not been waived by the other party, then and in every such case and as often as the same may happen, the non-defaulting party may give written notice to the defaulting party requiring it to remedy such default and in the event of the defaulting party failing to remedy the same within a period of thirty (30) days from receipt of such notice, the non-defaulting party may at its sole option declare the Contract to be terminated and thereupon the Contract shall be terminated and be null and void for all purposes other than and except as to any liability of the parties under the same incurred before and subsisting as of termination. The right hereby conferred upon each party shall be in addition to, and not in derogation of or in substitution for, any other right or remedy which the parties respectively at law or in equity shall or may possess.

In the event that this Contract is terminated pursuant to this Article XII, the parties hereto agree that they shall continue to be bound only by the terms and conditions set forth in the Contract but only for the purpose of determining the actual quantities in Shipper's Producer Balancing Account with such determination being subject to Article X. Such extended period of time shall not exceed one (1) year from the date of termination of this Contract.

XIII. AMENDMENT

Subject to Article XV herein and the ability of Union to amend the applicable rate schedules and price schedules, with the approval of the OEB (if required), no amendment or modification of the Contract shall be effective unless the same shall be in writing and signed by each of the Shipper and Union.

XIV. NON-WAIVER AND FUTURE DEFAULT

No waiver of any provision of the Contract shall be effective unless the same shall be in writing and signed by the party entitled to the benefit of such provision and then such waiver shall be effective only in the specific instance and for the specified purpose for which it was given. No failure on the part of Shipper or Union to exercise, and no course of dealing with respect to, and no delay in exercising, any right, power or remedy under the Contract shall operate as a waiver thereof.

XV. LAWS, REGULATIONS AND ORDERS

The Contract and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Contract shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Contract.

XVI. RESERVED FOR FUTURE USE

N/A

XVII. RENEWALS

The Contract will continue in full force and effect beyond the Initial Term, automatically renewing for a period of one (1) year, and every one (1) year thereafter, subject to notice in writing by either party of termination at least three (3) months prior to the expiration thereof.

XVIII. SERVICE CURTAILMENT

1. Excepting instances of emergency, Shipper and Union agree to give at least twenty-four (24) hours verbal notice before a

planned curtailment of receipt or delivery, shut-down or start-up.

2. Shipper shall complete and maintain a plan which depicts all of the Shipper's gas production facilities including all emergency shut off valves and emergency equipment and provide a copy to Union upon Union's request. Shipper shall provide to Union the names and telephone numbers of those persons whom Union may contact in the event of an emergency situation arising within the Shipper's facilities.

3. In the event that Union is notified by a third party or if Union becomes aware of an emergency situation in which Shipper's gas production site, pipeline or associated equipment is involved, Union shall immediately notify Shipper or Shipper's representative of such emergency condition.

4. Union shall have the right, at all times, to reconstruct or modify Union's pipeline and distribution system and the pressure carried therein, notwithstanding that such reconstruction or modification may reduce the System Capacity available to receive Shipper's gas, or Shipper's ability to deliver gas to Union. Should Union expect any such reconstruction or modification to reduce the delivery or receipt of gas by either party, Union will, where able, provide Shipper with six (6) months' notice or as much notice as is reasonably practical in the circumstances. Union shall use reasonable efforts to assist the Shipper in meeting its Market Quantity in these circumstances.

XIX. SHIPPER'S REPRESENTATIONS AND WARRANTIES

1. Shipper's Warranty: Shipper warrants that it will, if required, maintain, or have maintained on its behalf, all external approvals including the governmental, regulatory, import/export permits and other approvals or authorizations that are required from any federal, state or provincial authorities for the gas quantities to be handled under the Contract. Shipper further warrants that it shall maintain in effect the Facilitating Agreements.

2. Financial Representations: Shipper represents and warrants that the financial assurances (including the Initial Financial Assurances and Security), if any, shall remain in place throughout the term hereof unless Shipper and Union agree otherwise. Shipper shall notify Union in the event of any change to the financial assurances (including the Initial Financial Assurances and Security), if any, throughout the term hereof. Should Union have reasonable grounds to believe that Shipper will not be able to perform or continue to perform any of its obligations under the Contract for any reason (a "**Material Event**"), then Shipper shall within fourteen (14) days of receipt of written notice by Union, obtain and provide to Union a letter of credit or other security in the form and amount reasonably required by Union (the "**Security**"). In the event that Shipper does not provide to Union such Security, Union may deem a default in accordance with the provisions of Article XII herein.

   In the event that Shipper in good faith, reasonably believes that it should be entitled to reduce the amount of or value of the Security previously provided, it may request such a reduction from Union and to the extent that the Material Event has been mitigated or eliminated, Union shall return all or a portion of the Security to Shipper within fourteen (14) Business Days after receipt of the request.

3. Licence: Shipper represents and warrants to Union that Shipper possesses a licence to produce gas in the Province of Ontario.

XX. MISCELLANEOUS PROVISIONS

1. Assignment: Shipper may assign the Contract to a third party ("**Assignee**"), up to the Maximum Daily Quantity, (the "**Capacity Assigned**"). Such assignment shall require the prior written consent of Union and release of obligations by Union for the Capacity Assigned from the date of assignment. Such consent and release shall not be unreasonably withheld and shall be conditional upon the Assignee providing, amongst other things, financial assurances as per Article XXI herein. Any such assignment will be for the full rights, obligations and remaining term of the Contract as relates to the Capacity Assigned.

2. Title to Gas: Shipper represents and warrants to Union that Shipper shall have good and marketable title to, or legal authority to deliver to Union, all gas delivered to Union hereunder. Furthermore, Shipper hereby agrees to indemnify and save Union harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of claims of any or all third parties to such gas or on account of Taxes, or other charges thereon.

XXI. PRECONDITIONS TO SERVICES

1. The obligations of Union to provide Services hereunder are subject to the following conditions precedent, which are for the sole benefit of Union and which may be waived or extended in whole or in part in the manner provided in the Contract:

   a. Union shall have obtained, in form and substance satisfactory to Union, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required to provide the Services; and,

   b. Union shall have obtained all internal approvals that are necessary or appropriate to provide the Services; and,

   c. Union shall have received from Shipper the requisite financial assurances reasonably necessary to ensure Shipper's ability to honour the provisions of the Contract (the "**Initial Financial Assurances**"). The Initial Financial Assurances, if required, will be as determined solely by Union; and,

   d. Shipper and Union shall have entered into the Interruptible HUB Service Contract or equivalent (the "**Facilitating Agreement**") with Union; and,

   e. Union shall, where applicable, have obtained all internal and external approvals including the governmental, regulatory and other approvals or authorizations required to construct any facilities necessary to provide the Services hereunder, which approvals and authorizations, if granted upon conditions, shall be conditions satisfactory to Union; and,

   f. Union shall, where applicable, have completed and placed into service those facilities necessary to provide the Services hereunder; and,

   g. Further to Article IX Section 6 herein, Shipper shall pay to Union a payment ("**First Prepayment**") towards the Aid to Construction at the time of the execution of this Agreement. Shipper shall pay a payment prior to installation of the meter station ("**Second Prepayment**"). The foregoing payments are specified in the attached Schedule 1 for the first meter station ("**Receipt Point #1**") to be installed under this contract. Payments for additional meter stations will be handled by written mutual agreement between the parties. Shipper shall pay Union the difference if the actual Aid to Construction is more than the Prepayments, within thirty (30) days of the delivery of an invoice from Union on which the actual costs for construction and installation of facilities are stated. Union shall pay Shipper the difference if the actual Aid to Construction is less than the Prepayments. In the event Shipper terminates this Agreement prior to Union incurring any costs related to the construction, installation or connection of the meter station, Shipper's Prepayments shall be returned to Seller, without interest, within fifteen (15) days notice to Union of such termination by Shipper. In the event Union has incurred costs, as set out herein, relative to the construction, installation or connection of the meter station prior to being notified by Shipper of Shipper's intention to terminate the Agreement, Union shall deduct such actual costs from Union's return of Shipper's Prepayments. "**Prepayments**" shall mean the sum of the First Prepayment and the Second Prepayment.

2. The obligations of Shipper hereunder are subject to the following conditions precedent, which are for the sole benefit of Shipper and which may be waived or extended in whole or in part in the manner provided in the Contract:

   a. Shipper shall, as required, have entered into the necessary contracts with Union and/or others to facilitate the Services contemplated herein, including contracts for upstream and downstream transportation, and shall specifically have an executed and valid Facilitating Agreement; and,

   b. Shipper shall have obtained, in form and substance satisfactory to Shipper, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required from federal, state, or provincial authorities for the gas quantities handled under the Contract; and,

   c. Shipper shall have obtained all internal approvals that are necessary or appropriate for the Shipper to execute the Contract; and,

d. Shipper shall have cancelled or renegotiated its Sales Agreement, on terms satisfactory to Union, as applicable.

3. Union and Shipper shall each use due diligence and reasonable efforts to satisfy and fulfil the conditions precedent specified in this Article XXI Section 1 a, c, d, e, f, g, and Section 2 a, b, and d. Each party shall notify the other forthwith in writing of the satisfaction or waiver of each condition precedent for such party's benefit. If a party concludes that it will not be able to satisfy a condition precedent that is for its benefit, such party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations thereunder.

4. If any of the conditions precedent in this Article XXI Section 1 c or Section 2 are not satisfied or waived by the party entitled to the benefit of that condition by the Conditions Date as such term is defined in the Contract, or if any of the Shipper payments required under the condition precedent in this Article XXI Section 1 g have not been paid as required in such section, then either party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations hereunder, provided that any rights or remedies that a party may have for breaches of the Contract prior to such termination and any liability a party may have incurred before such termination shall not thereby be released.

unionGas

STORAGE AND TRANSPORTATION SERVICES TRANSPORTATION CHARGES

(A) Availability

The charges under this rate schedule shall be applicable for transportation service rendered by Union for all quantities transported to and from embedded storage pools located within Union's franchise area and served using Union's distribution and transmission assets.

Applicable Points

Dawn as a receipt point: Dawn (Facilities).
Dawn as a delivery point: Dawn (Facilities).

(B) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

a) Charges Applicable to both Firm and/or Interruptible Transportation Services:

Monthly Fixed Charge per customer station ($ per month) (1)	$1,474.12
Transmission Commodity Charge to Dawn ($ per GJ)	$0.034

Transportation Fuel	**Customers located East of Dawn**	**Customers located West of Dawn**
Fuel Charges to Dawn:		
Commodity Rate - Union provides fuel ($ per GJ)	$0.009	$0.009
Fuel Ratio - customer provides fuel (%)	0.153%	0.153%
Fuel Charge to the Pool		
Commodity Rate - Union provides fuel ($ per GJ)	$0.009	$0.024
Fuel Ratio - customer provides fuel (%)	0.153%	0.435%

b) Firm Transportation Demand Charges: (2)

	Customers located East of Dawn	**Customers located West of Dawn**
Monthly Demand Charge applied to contract demand ($ per GJ)	$0.741	$1.059

Authorized Overrun:

The authorized overrun rate payable on all quantities transported in excess of Union's obligation any day shall be:

	Customers located East of Dawn	**Customers located West of Dawn**
Firm Transportation:		
Charges to Dawn		
Commodity Rate - Union provides fuel ($ per GJ)	$0.067	$0.077
Commodity Rate - customer provides fuel ($ per GJ)	$0.058	$0.069
Fuel Ratio - customer provides fuel (%)	0.153%	0.153%
Charges to the Pool		
Commodity Rate - Union provides fuel ($ per GJ)	$0.033	$0.059
Commodity Rate - customer provides fuel ($ per GJ)	$0.024	$0.035
Fuel Ratio - customer provides fuel (%)	0.153%	0.435%

Overrun will be authorized at Union's sole discretion.

Unauthorized Overrun

Authorized Overrun rates payable on all transported quantities up to 2% in excess of Union's contractual obligation.

The Unauthorized Overrun rate during the November 1 to April 15 period will be $50 per GJ for all usage on any day in excess of 102% of Union's contractual obligation. The Unauthorized Overrun rate during the April 16 to October 31 period will be $9.373 per GJ for all usage on any day in excess of 102% of Union's contractual obligation.

Charges aforesaid in respect of any given month in accordance with General Terms & Conditions shall be payable no later than the twenty-fifth day of the succeeding month.

Notes for Section (B) Rates:

(1) The monthly fixed charge will be applied once per month per customer station regardless of service being firm, interruptible or a combination thereof.

(2) Demand charges will be applicable to customers firm daily contracted demand or the firm portion of a combined firm and interruptible service.

(C) Terms of Service

The General Terms & Conditions applicable to this rate schedule shall be in accordance with the attached Schedule “A” for contracts in effect before October 1, 2010. The General Terms & Conditions applicable to this rate schedule shall be in accordance with the attached Schedule “A 2013” for contracts in effect on or after January 1, 2013.

SCHEDULE "A"

GENERAL TERMS & CONDITIONS
M16 TRANSPORTATION AGREEMENT

I. DEFINITIONS

Except where the context expressly requires or states another meaning, the following terms, when used in these General Terms & Conditions and in any contract into which these General Terms & Conditions are incorporated, shall be construed to have the following meanings:

1. "Banking Day" shall mean a day on which the general offices of the Canadian Imperial Bank of Commerce, 99 King St. W., Chatham, Ontario are open for business;

2. "business day" shall mean a day on which the general offices of Union in Chatham, Ontario are open for business;

3. "Contract" shall refer to the Contract to which these General Terms & Conditions shall apply, and into which they are incorporated;

4. "contract year" shall mean a period of three hundred and sixty-five (365) consecutive days, beginning on the day agreed upon by Union and Shipper as set forth in the Contract, or on any anniversary of such date; provided, however, that any such period which contains a date of February 29 shall consist of three hundred and sixty-six (366) consecutive days;

5. "day" shall mean a period of twenty-four (24) consecutive hours beginning at 9:00 a.m. Central Standard time. The reference date for any day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

6. "month" shall mean the period beginning at 9:00 a.m. Central Standard time on the first day of a calendar month and ending at 9:00 a.m. Central Standard time on the first day of the following calendar month;

7. "firm" shall mean service not subject to curtailment or interruption except under Articles XI and XII of this Schedule "B";

8. "interruptible service" shall mean service subject to curtailment or interruption, after notice, at any time;

9. "gas" shall mean gas as defined in the Ontario Energy Board Act, R.S.O. 1980, c. 332, as amended, supplemented or reenacted from time to time;

10. "cubic metre" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

11. "m^3" shall mean cubic metre of gas and "10^3m^3" shall mean 1,000 cubic metres of gas;

12. "pascal" (Pa) shall mean the pressure produced when a force of one (1) newton is applied to an area of one (1) square metre. The term "kilopascal" (kPa) shall mean 1,000 pascals;

13. "joule" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force. The term "megajoule" (MJ) shall mean 1,000,000 joules. The term "gigajoule" (GJ) shall mean 1,000,000,000 joules;

14. "gross heating value" shall mean the total heat expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state;

15. "Shipper" shall have the meaning as defined in the Contract, and shall also include Shipper's agent(s);

16. "subsidiary" means a company in which more than fifty (50) per cent of the issued share capital (having full voting rights under all circumstances) is owned or controlled directly or indirectly by another company, by one or more subsidiaries of such other company, or by such other company and one or more of its subsidiaries;

17. "TCPL" means TransCanada PipeLines Limited;

18. "NOVA" means Gas Transmission Ltd.;

19. "Panhandle" means CMS Panhandle Eastern Pipeline Company;

20. "MichCon" means Michigan Consolidated Gas Company;

21. "SCPL" means St. Clair Pipelines (1996) Ltd.;

22. "OEB" means the Ontario Energy Board;

23. "NEB" means the National Energy Board (Canada);

24. "GLGT" means Great Lakes Gas Transmission Company;

25. "CMS" means CMS Gas Transmission and Storage Company;

26. "Consumers" means The Consumers' Gas Company, Limited;

27. "cricondentherm hydrocarbon dewpoint" shall mean the highest hydrocarbon dewpoint temperature on the phase envelope;

28. "hydrocarbon dewpoint" shall mean temperature at a specific pressure where hydrocarbon vapour condensation begins;

29. "specific gravity" shall mean density of the gas divided by density of air, with both at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute; and,

30. "Wobbe Number" shall mean gross heating value of the gas divided by the square root of its specific gravity.

II. GAS QUALITY

1. Natural Gas: The minimum gross heating value of the gas delivered to/by Union hereunder, shall be thirty-six (36) megajoules per cubic metre. The maximum gross heating value of the gas delivered to/by Union hereunder shall be forty point two (40.2) megajoules per cubic metre. The gas to be delivered hereunder to Union may be a commingled supply from Shipper's gas sources of supply. The gas to be delivered by Union may be a commingled supply from Union's sources of gas supply; provided, however, that helium, natural gasoline, butane, propane and other hydrocarbons, except methane, may be removed prior to delivery to Shipper. Further, Union may subject, or permit the subjection of, the gas to compression, dehydration, cooling, cleaning and other processes.

2. Freedom from objectionable matter: The gas to be delivered to Union at the Receipt Point(s) hereunder,

    a. shall be commercially free from bacteria, sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other objectionable substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to, or interference with, the proper operation of the lines, regulators, meters or other appliances through which it flows,

    b. shall not contain more than seven (7) milligrams of hydrogen sulphide per cubic metre of gas, nor more than one hundred (100) milligrams of total sulphur per cubic metre of gas,

    c. shall not contain more than five (5) milligrams of mercaptan sulphur per cubic metre of gas,

    d. shall not contain more than two point zero (2.0) molar percent by volume of carbon dioxide in the gas,

    e. shall not contain more than zero point four (0.4) molar percent by volume of oxygen in the gas,

f. shall not contain more than zero point five (0.5) molar percent by volume of carbon monoxide in the gas,

g. shall not contain more than four point zero (4.0) molar percent by volume of hydrogen in the gas,

h. shall not contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas,

i. shall not have a cricondentherm hydrocarbon dewpoint exceeding minus eight (-8) degrees Celsius,

j. shall have Wobbe Number from forty seven point fifty (47.50) megajoules per cubic metre of gas to fifty one point forty six (51.46) megajoules per cubic metre of gas, maximum of one point five (1.5) mole percent by volume of butane plus (C4+) in the gas, and maximum of four point zero (4.0) mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas,

k. shall not exceed forty-three degrees Celsius (43ºC), and,

l. shall not be odourized by Shipper.

3. Non-conforming Gas:

a. In the event that the quality of the gas does not conform or if Union, acting reasonably, suspects the quality of the gas may not conform to the specifications herein, then Shipper shall, if so directed by Union acting reasonably, forthwith carry out, at Shipper's cost, whatever field testing of the gas quality as may be required to ensure that the quality requirements set out herein are met, and to provide Union with a certified copy of such tests. If Shipper does not carry out such tests forthwith, Union may conduct such test and Shipper shall reimburse Union for all costs incurred by Union for such testing.

b. If Shipper's gas fails at any time to conform to the requirements of this Article II, Union, in addition to its other remedies, may refuse to accept delivery of gas at the Receipt Points hereunder until such deficiency has been remedied by Shipper. Each Party agrees to notify the other verbally, followed by written notification, of any such deficiency of quality.

c. With respect to Article II 2. h. herein, Union may accept the gas subject to Shipper's obligations under the Dehydration Contract, if applicable.

4. Quality of Gas Received: The quality of the gas to be received by Union at the Receipt Point(s) hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Article II.

5. Quality of Gas at Dawn: The quality of the gas to be delivered to Union at Dawn (Facilities) or the gas to be delivered by Union to Shipper at Dawn (Facilities) hereunder is to be of a merchantable quality and in accordance with the quality standards and measurement standards as set out by Union in this Article II, except that total sulphur limit shall be not more than four hundred and sixty (460) milligrams per cubic metre of gas. In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Article II.

6. Odourization of Gas:

a. Union may odourize or deliver odourized gas under the Contract,

b. Shipper shall if requested by Union monitor the mercaptan sulphur content of the gas delivered to Union under the Contract and shall provide at no cost to Union a continuous signal quantifying the mercaptan sulphur content in milligrams per cubic metre.

III. MEASUREMENTS

1. Storage, Transportation, and/or Sales Unit: The unit of the gas delivered to Union shall be a megajoule or a gigajoule. The unit of gas transported or stored by Union shall be a megajoule or a gigajoule. The unit of gas delivered by Union shall be a megajoule, a gigajoule, a cubic metre (m^3) or one thousand cubic metres (10^3m^3) at Union's discretion.

2. Determination of Volume and Energy:

a. The volume and energy amounts determined under the Contract shall be determined in accordance with the Electricity and Gas Inspection Act (Canada), RSC 1985, c E-4- (the "**Act**") and the Electricity and Gas Inspection Regulations, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

b. The supercompressibility factor shall be determined in accordance with either the "Manual for Determination of Supercompressibility Factors for Natural Gas" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

c. The volume and/or energy of the gas delivered to/by Union hereunder shall be determined by the measurement equipment designated in Article VII herein.

d. Upon request by Union, Shipper shall obtain measurement of the total quantity of gas received by Union hereunder from the Interconnecting Pipeline. Such measurement shall be done in accordance with established practices between Union and the Interconnecting Pipeline.

IV. POINT OF RECEIPT AND POINT OF DELIVERY

1. Unless otherwise specified in the Contract, the point or points of receipt for all gas to be covered thereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection specified in the Contract, where Union takes possession of the gas. Whenever the phrase "receipt point" appears herein, it shall mean Point of Receipt as defined in this Article IV.

2. Unless otherwise specified in the Contract, the point or points of delivery for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection as specified in the Contract, where Shipper takes possession of the gas. Whenever the phrase "delivery point" shall appear hereon, it shall mean Point of Delivery as defined in this Article IV.

V. POSSESSION OF AND RESPONSIBILITY FOR GAS

N/A

VI. FACILITIES ON SHIPPER'S PROPERTY

N/A

VII. MEASURING EQUIPMENT

1. Metering by Union: Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Article III herein.

2. Metering by Others: In the event that all or any gas delivered to/by Union hereunder is measured by a meter that is owned and operated by an Interconnecting Pipeline, then Union and Shipper agree to accept that metering for the purpose of determining the volume and energy of gas delivered to/by Union on behalf of the Shipper. The standard of measurement and tests for the gas delivered to/by Union hereunder shall be in accordance with the general terms and conditions as incorporated in that Interconnecting Pipeline company's gas tariff as approved by its regulatory body.

3. Check Measuring Equipment: Shipper may install, maintain and operate, at the Custody Transfer Point, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Union's measuring equipment at or near the Custody Transfer Point, and shall be installed, maintained and operated in conformity with the same standards and specifications applicable to Union's metering facilities.

4. Rights of Parties: The measuring equipment installed by either party, together with any building erected by it for such equipment, shall be and remain its property. However, Union and Shipper shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring or checking the measurement of deliveries of gas to/by Union under the Contract. Either party will give the other party reasonable notice of its intention to carry out the acts herein specified. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

5. Calibration and Test of Measuring Equipment: The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Shipper, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment tested is found to be in error by not more than two per cent (2%). If, upon test, any measuring equipment is found to be in error by not more than two per cent (2%), previous recordings of such equipment shall be considered accurate in computing receipts and deliveries of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than two percent (2%), the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations, as may be amended from time to time and in accordance with any successor statutes and regulations.

6. Preservation of Metering Records: Union and Shipper shall each preserve for a period of at least six (6) years all test data, and other relevant records.

7. Error in Metering or Meter Failure: In the event of an error in metering or a meter failure (such error or failure being determined through check measurement by Union or any other available method), then Shipper shall enforce its rights as Shipper with the Interconnecting Pipeline(s) to remedy such error or failure including enforcing any inspection and/or verification rights and procedures.

VIII. BILLING

1. Monthly Billing Date: Union shall render bills on or before the 10th day of each month for all services furnished during the preceding month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding month's billing, an adjustment based on any difference between actual quantities and estimated quantities. If presentation of a bill to Shipper is delayed after the 10th day of the month, then the time of payment shall be extended accordingly, unless Shipper is responsible for such delay.

2. Right of Examination: Both Union and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Contract.

IX. PAYMENTS

1. Monthly Payments: Shipper shall pay the invoiced amount directly into Union’s bank account as directed on the invoice on or before the twentieth (20^{th}) day of each month. If the payment date is not a business day, then payment must be received in Union’s account on the first business day preceding the twentieth (20^{th}) day of the month.

2. Remedies for Non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due, Shipper shall pay to Union interest on the unpaid portion of the bill accruing at a rate per annum equal to the minimum commercial lending rate of Union's principal banker in effect from time to time from the due date until the date of payment. If such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the Contract may suspend service(s) until such amount is paid, provided however, that if Shipper, in good faith shall dispute the amount of any such bill or part thereof and shall pay to Union such amounts as it concedes to be correct and at any time thereafter within twenty (20) days of a demand made by Union shall furnish good and sufficient surety bond satisfactory to Union, guaranteeing payment to Union of the amount ultimately found due upon such bill after a final determination which may be reached either by agreement, arbitration decision or

judgement of the courts, as may be the case, then Union shall not be entitled to suspend service(s) because of such non-payment unless and until default be made in the conditions of such bond or in payment for any further service(s) to Shipper hereunder.

Notwithstanding the foregoing paragraph, this does not relieve Shipper from the obligation to continue its deliveries of gas under the terms of any agreement, where Shipper has contracted to deliver specified quantities of gas to Union.

3. Billing Adjustments: If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, Union shall refund the amount of any such overcharge and interest shall accrue from and including the first day of such overcharge as paid to the date of refund and shall be calculated but not compounded at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker, and the Shipper shall pay the amount of any such undercharge, but without interest. In the event Union renders a bill to Shipper based upon measurement estimates, the required adjustment to reflect actual measurement shall be made on the bill next following the determination of such actual measurement, without any charge of interest. In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "bill" next following shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within six (6) years from the date of the incorrect billing. In the event any refund is issued with Shipper's bill, the aforesaid date of refund shall be deemed to be the date of the issue of invoice.

X. ARBITRATION

If and when any dispute, difference or question shall arise between the parties hereto touching the Contract or anything herein contained, or the construction hereof, or the rights, duties or liabilities of the parties in relation to any matter hereunder, the matter in dispute shall be submitted and referred to arbitration within ten (10) days after written request of either party. Upon such request each party shall appoint an arbitrator, and the two so appointed shall appoint a third. A majority decision of the arbitrators shall be final and binding upon both parties. In all other respects the provisions of the Arbitration Act of the Province of Ontario, or any act passed in amendment thereof or substitution therefore, shall apply to each such submission. Operations under this Contract shall continue, without prejudice, during any such arbitration and the costs attributable to such arbitration shall be shared equally by the parties hereto.

XI. FORCE MAJEURE

N/A

XII. DEFAULT AND TERMINATION

N/A

XIII. MODIFICATION

N/A

XIV. NONWAIVER AND FUTURE DEFAULT

N/A

XV. LAWS, REGULATIONS AND ORDERS

The Contract and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Contract shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Contract.

RATE M16
GENERAL TERMS & CONDITIONS

I. DEFINITIONS

Except where the context expressly requires or states another meaning, the following terms, when used in these General Terms & Conditions and in any contract into which these General Terms & Conditions are incorporated, shall be construed to have the following meanings:

"**Aid to Construction"** shall include any and all costs, expenses, amounts, damages, obligations, or other liabilities (whether of a capital or operating nature, and whether incurred before or after the date of the Contract) actually paid by Union (including amounts paid to affiliates for services rendered in accordance with the Affiliate Relationships Code as established by the OEB) in connection with or in respect of satisfying the conditions precedent set out in Article XXI herein (including without limitation the construction and placing into service of the Union Expansion Facilities, the obtaining of all governmental, regulatory and other third party approvals, and the obtaining of rights of way) whether resulting from Union's negligence or not, except for any costs that have arisen from the gross negligence, fraud, or wilful misconduct of Union;

"**Authorized Overrun**" shall mean the amount by which Shipper's Authorized Quantity exceeds the firm and interruptible contract demands;

"**Authorized Quantity**" shall have the meaning given thereto in Schedule "B 2010" of the C1 Rate Schedule;

"**Business Day**" shall mean any day, other than Saturday, Sunday or any days on which national banks in the Province of Ontario are authorized to close;

"**Contract**" shall refer to the Contract to which these General Terms & Conditions shall apply, and into which they are incorporated;

"**Contract Year**" shall mean a period of three hundred and sixty-five (365) consecutive days, beginning on the Commencement Date or on any anniversary of such date; provided, however, that any such period which contains a date of February 29 shall consist of three hundred and sixty-six (366) consecutive days;

"**cricondentherm hydrocarbon dewpoint**" shall mean the highest hydrocarbon dewpoint temperature on the phase envelope;

"**cubic metre**" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**Custody Transfer Point**" That point on the piping system at the Pool Station which is at the Shipper side of the insulating flange on the Union Expansion Facilities, and which point shall serve as the point of custody transfer;

"**Day**" shall mean a period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Clock Time. The reference date for any Day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

"**Dehydration Contract**" shall mean the contract for Dehydration Service between Union and the Shipper as detailed in Schedule 1 of the Contract;

"**Delivery Point**" shall mean the point(s) where Union shall deliver gas to Shipper as defined in Schedule 1 of the Contract;

"Eastern Clock Time" shall mean the local clock time in the Eastern Time Zone on any Day;

"**firm**" shall mean service not subject to curtailment or interruption except under Articles XI, XII and XVIII herein;

"**gas**" shall mean gas as defined in the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sch. B, as amended, supplemented or re-enacted from time to time;

"**gross heating value**" shall mean the total heat expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state;

"**hydrocarbon dewpoint**" shall mean temperature at a specific pressure where hydrocarbon vapour condensation begins;

"**Interconnecting Pipeline**" shall mean a pipeline that directly connects to the Union pipeline system;

"**interruptible**" shall mean service subject to curtailment or interruption, after notice, at any time;

"**joule**" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force. The term "**megajoule**" (MJ) shall mean 1,000,000 joules. The term "**gigajoule**" (GJ) shall mean 1,000,000,000 joules;

"**m^3**" shall mean cubic metre of gas and "**10^3m^3**" shall mean 1,000 cubic metres of gas;

"**Month**" shall mean the period beginning at 10:00 a.m. Eastern Clock Time on the first day of a calendar month and ending at 10:00 a.m. Eastern Clock Time on the first day of the following calendar month;

"**OEB**" means the Ontario Energy Board;

"**pascal**" "**(Pa)**" shall mean the pressure produced when a force of one (1) newton is applied to an area of one (1) square metre. The term "**kilopascal**" "**(kPa)** " shall mean 1,000 pascals;

"**Pool Quantity**" shall mean the actual daily quantity of gas delivered to or received from Shipper at the Custody Transfer Point;

"**Pool Station**" shall mean the physical location of Union's measurement and control facilities to the pool; the pool name as detailed in Schedule 1 of the Contract;

"**Receipt Point**" shall mean any one of the points where Union shall receive gas from Shipper as detailed in Schedule 1 of the Contract;

"**Shipper**" shall have the meaning as defined in the Contract, and shall also include Shipper's agent(s);

"**Shipper Quantity**" shall, on any Day, be equal to the greater of: (i) the Authorized Quantity for that Day; and (ii) the nomination duly made by Shipper in good faith prior to the nomination deadline for the first nomination window applicable for that Day; provided that in no event shall the Shipper Quantity exceed the firm contract demand;

"**specific gravity**" shall mean density of the gas divided by density of air, with both at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**Taxes**" shall mean any tax (other than tax on income or tax on property), duty, royalty, levy, license, fee or charge not included in the charges and rates as per the applicable rate schedule (including but not limited to charges under any form of cap and trade, carbon tax, or similar system) and that is levied, assessed or made by any governmental authority on the gas itself, or the act, right, or privilege of producing, severing, gathering, storing, transporting, handling, selling or delivering gas under the Contract;

"**TCPL**" means TransCanada PipeLines Limited;

"**Union Expansion Facilities**" shall mean any facilities necessary for Union to provide the Services, including without limiting the generality of the foregoing:

a. a meter and any associated recording gauges as are necessary;

b. pressure and/or flow control devices, over pressure protection and telemetry equipment as are necessary;

c. a suitable gas odourizing injection facility if Union deems such a facility to be necessary

d. piping, fittings, material, filtration facilities, cathodic protection and insulating flanges;

e. gas chromatograph, moisture analyzer, piping, fittings, material, filtration facilities, cathodic protection and insulating flanges;

"**Wobbe Number**" shall mean gross heating value of the gas divided by the square root of its specific gravity.

II. GAS QUALITY

1. Natural Gas: The minimum gross heating value of the gas delivered to/by Union hereunder, shall be thirty-six (36) megajoules per cubic metre. The maximum gross heating value of the gas delivered to/by Union hereunder shall be forty point two (40.2) megajoules per cubic metre. The gas to be delivered hereunder to Union may be a commingled supply from Shipper's gas sources of supply. The gas to be delivered by Union may be a commingled supply from Union's sources of gas supply; provided, however, that helium, natural gasoline, butane, propane and other hydrocarbons, except methane, may be removed prior to delivery to Shipper. Further, Union may subject, or permit the subjection of, the gas to compression, dehydration, cooling, cleaning and other processes.

2. Freedom from objectionable matter: The gas to be delivered to Union at the Receipt Point(s) hereunder,

a. shall be commercially free from bacteria, sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other objectionable substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to, or interference with, the proper operation of the lines, regulators, meters or other appliances through which it flows,

b. shall not contain more than seven (7) milligrams of hydrogen sulphide per cubic metre of gas, nor more than one hundred (100) milligrams of total sulphur per cubic metre of gas,

c. shall not contain more than five (5) milligrams of mercaptan sulphur per cubic metre of gas,

d. shall not contain more than two point zero (2.0) molar percent by volume of carbon dioxide in the gas,

e. shall not contain more than zero point four (0.4) molar percent by volume of oxygen in the gas,

f. shall not contain more than zero point five (0.5) molar percent by volume of carbon monoxide in the gas,

g. shall not contain more than four point zero (4.0) molar percent by volume of hydrogen in the gas,

h. shall not contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas,

i. shall not have a cricondentherm hydrocarbon dewpoint exceeding minus eight (-8) degrees Celsius,

j. shall have Wobbe Number from forty seven point fifty (47.50) megajoules per cubic metre of gas to fifty one point forty six (51.46) megajoules per cubic metre of gas, maximum of one point five (1.5) mole percent by volume of butane plus (C4+) in the gas, and maximum of four point zero (4.0) mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas,

k. shall not exceed forty-three degrees Celsius (43ºC), and,

l. shall not be odourized by Shipper.

3. Non-conforming Gas:

a. In the event that the quality of the gas does not conform or if Union, acting reasonably, suspects the quality of the gas may not conform to the specifications herein, then Shipper shall, if so directed by Union acting reasonably, forthwith carry out, at Shipper's cost, whatever field testing of the gas quality as may be required to ensure that the quality requirements set out herein are met, and to provide Union with a certified copy of such tests. If Shipper does not carry out such tests forthwith, Union may conduct such test and Shipper shall reimburse Union for all costs incurred by Union for such testing.

b. If Shipper's gas fails at any time to conform to the requirements of this Article II, Union, in addition to its other remedies, may refuse to accept delivery of gas at the Receipt Points hereunder until such deficiency has been remedied by Shipper. Each Party agrees to notify the other verbally, followed by written notification, of any such deficiency of quality.

c. With respect to Article II 2. h. herein, Union may accept the gas subject to Shipper's obligations under the Dehydration Contract, if applicable.

4. Quality of Gas Received: The quality of the gas to be received by Union at the Receipt Point(s) hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Article II.

5. Quality of Gas at Dawn: The quality of the gas to be delivered to Union at Dawn (Facilities) or the gas to be delivered by Union to Shipper at Dawn (Facilities) hereunder is to be of a merchantable quality and in accordance with the quality standards and measurement standards as set out by Union in this Article II, except that total sulphur limit shall be not more than four hundred and sixty (460) milligrams per cubic metre of gas. In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Article II.

6. Odourization of Gas:

a. Union may odourize or deliver odourized gas under the Contract,

b. Shipper shall if requested by Union monitor the mercaptan sulphur content of the gas delivered to Union under the Contract and shall provide at no cost to Union a continuous signal quantifying the mercaptan sulphur content in milligrams per cubic metre.

III. MEASUREMENTS

1. Storage, Transportation, and/or Sales Unit: The unit of the gas delivered to Union shall be a megajoule or a gigajoule. The unit of gas transported or stored by Union shall be a megajoule or a gigajoule. The unit of gas delivered by Union shall be a megajoule, a gigajoule, a cubic metre (m^3) or one thousand cubic metres (10^3m^3) at Union's discretion.

2. Determination of Volume and Energy:

a. The volume and energy amounts determined under the Contract shall be determined in accordance with the Electricity and Gas Inspection Act (Canada), RSC 1985, c E-4- (the "**Act**") and the Electricity and Gas Inspection Regulations, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

b. The supercompressibility factor shall be determined in accordance with either the "Manual for Determination of Supercompressibility Factors for Natural Gas" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

c. The volume and/or energy of the gas delivered to/by Union hereunder shall be determined by the measurement equipment designated in Article VII herein.

d. Upon request by Union, Shipper shall obtain measurement of the total quantity of gas received by Union hereunder from the Interconnecting Pipeline. Such measurement shall be done in accordance with established practices between Union and the Interconnecting Pipeline.

IV. RECEIPT POINT AND DELIVERY POINT

The point or points of receipt and point or points of delivery for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection specified in Schedule 1 of the Contract, where possession of the gas changes from one party to the other.

V. POSSESSION OF AND RESPONSIBILITY FOR GAS

1. Union accepts no responsibility for any gas prior to such gas being delivered to Union at the Receipt Point or after its delivery by Union at the Delivery Point. As between the parties hereto, Union shall be deemed to be in control and possession of and responsible for all such gas from the time that such gas enters Union's system until such gas is delivered to Shipper.

2. Shipper agrees that Union is not a common carrier and is not an insurer of Shipper's gas, and that Union shall not be liable to Shipper or any third party for loss of gas in Union's possession, except to the extent such loss is caused entirely by Union's negligence or wilful misconduct.

VI. FACILITIES ON SHIPPER'S PROPERTY

1. All of the Union Expansion Facilities shall remain the property of Union. Union shall be entitled to remove said equipment at any time within a period of sixty (60) days from any termination or expiry of the Contract. Shipper shall take all necessary steps to ensure Union may enter the Pool Station to remove such equipment for a period of sixty (60) days after termination or expiry of the Contract.

2. Shipper shall, at Shipper's own cost and expense:

   a. obtain the Pool Station Land Rights; and

   b. furnish, install, set, and maintain suitable pressure and quantity control equipment and such additional equipment as required on Shipper's delivery system, to protect against the over pressuring of Union's facilities as set out in Article VI of the Contract and Schedule 1 of the Contract, protect Union from receiving gas not meeting the quality specification as set out in Article II herein, and to limit the daily flow of gas to the corresponding parameters as set out in the Article II of the Contract.

3. Shipper shall within thirty (30) days of the delivery of an invoice by Union, reimburse Union for any actual costs reasonably incurred by Union for any repair, replacement, relocation, or upgrading of any meter station or any Union Expansion Facilities requested by Shipper, or as required by law or by duly constituted regulatory body, or through good engineering practice. Union shall be responsible for any costs incurred by Union to correct an error made by Union.

4. Operation and Maintenance: Subject to this Article VI Section 3, each party shall be fully responsible for the continued operation, maintenance, repair and replacement of its respective facilities. Both parties agree to maintain cathodic protection on their respective facilities.

5. Inspection: Each party shall inspect its facilities as required by industry standards or by the appropriate regulatory body.

6. Each party shall decide, in its sole discretion, whether its facilities need to be repaired or replaced. In the event that repair or replacement is needed, the party undertaking such work will, to the extent possible, give the other party sixty (60) days' notice and will ensure that the work be done in a manner so as to minimize the amount of time the pipeline has restricted flows.

VII. MEASURING EQUIPMENT

1. <u>Metering by Union:</u> Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Article III herein.

2. Metering by Others: In the event that all or any gas delivered to/by Union hereunder is measured by a meter that is owned and operated by an Interconnecting Pipeline, then Union and Shipper agree to accept that metering for the purpose of determining the volume and energy of gas delivered to/by Union on behalf of the Shipper. The standard of measurement and tests for the gas delivered to/by Union hereunder shall be in accordance with the general terms and conditions as incorporated in that Interconnecting Pipeline company's gas tariff as approved by its regulatory body.

3. Check Measuring Equipment: Shipper may install, maintain and operate, at the Custody Transfer Point, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Union's measuring equipment at or near the Custody Transfer Point, and shall be installed, maintained and operated in conformity with the same standards and specifications applicable to Union's metering facilities.

4. Rights of Parties: The measuring equipment installed by either party, together with any building erected by it for such equipment, shall be and remain its property. However, Union and Shipper shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring or checking the measurement of deliveries of gas to/by Union under the Contract. Either party will give the other party reasonable notice of its intention to carry out the acts herein specified. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

5. Calibration and Test of Measuring Equipment: The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Shipper, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment tested is found to be in error by not more than two per cent (2%). If, upon test, any measuring equipment is found to be in error by not more than two per cent (2%), previous recordings of such equipment shall be considered accurate in computing receipts and deliveries of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than two percent (2%), the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations, as may be amended from time to time and in accordance with any successor statutes and regulations.

6. Preservation of Metering Records: Union and Shipper shall each preserve for a period of at least six (6) years all test data, and other relevant records.

7. Error in Metering or Meter Failure: In the event of an error in metering or a meter failure, (such error or failure being determined through check measurement by Union or any other available method), then Shipper shall enforce its rights as Shipper with the Interconnecting Pipeline(s) to remedy such error or failure including enforcing any inspection and/or verification rights and procedures.

VIII. BILLING

1. Monthly Billing Date: Union shall render bills on or before the tenth (10th) day of each month for all Services furnished during the preceding Month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding Month's billing, an adjustment based on any difference between actual quantities and estimated quantities, without any interest charge. If presentation of a bill to Shipper is delayed after the tenth (10th) day of the month, then the time of payment shall be extended accordingly, unless Shipper is responsible for such delay.

2. Right of Examination: Both Union and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Contract.

3. Amendment of Statements: For the purpose of completing a final determination of the actual quantities of gas handled under the Contract, Union shall have the right to amend its statements for a period equal to the time during which the

Interconnecting Pipeline retains the right to amend their statements, which period shall not exceed three (3) years from the date of termination of the Contract.

IX. PAYMENTS

1. Monthly Payments: Shipper shall pay the invoiced amount directly into Union's bank account as directed on the invoice on or before the twentieth (20th) day of each month. If the payment date is not a Business Day, then payment must be received in Union's account on the first Business Day preceding the twentieth (20th) day of the month.

2. Remedies for Non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due,

   a. Shipper shall pay to Union interest on the unpaid portion of the bill accruing at a rate per annum equal to the minimum commercial lending rate of Union's principal banker in effect from time to time from the due date until the date of payment; and,

   b. If such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the Contract, may suspend Services until such amount is paid. Notwithstanding such suspension, all demand charges shall continue to accrue hereunder as if such suspension were not in place.

   If Shipper in good faith disputes the amount of any such bill or part thereof Shipper shall pay to Union such amounts as it concedes to be correct. At any time thereafter, within twenty (20) days of a demand made by Union, Shipper shall furnish financial assurances satisfactory to Union, guaranteeing payment to Union of the amount ultimately found due upon such bill after a final determination. Such a final determination may be reached either by agreement, arbitration decision or judgement of the courts, as may be the case. Union shall not be entitled to suspend Services because of such non-payment unless and until default occurs in the conditions of such financial assurances or default occurs in payment of any other amount due to Union hereunder.

   Notwithstanding the foregoing, Shipper is not relieved from the obligation to continue its deliveries of gas to Union under the terms of any agreement, where Shipper has contracted to deliver specified quantities of gas to Union.

3. Billing Adjustments: If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, Union shall refund the amount of any such overcharge and interest shall accrue from and including the first day of such overcharge as paid to the date of refund and shall be calculated but not compounded at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker, and the Shipper shall pay the amount of any such undercharge, but without interest. In the event Union renders a bill to Shipper based upon measurement estimates, the required adjustment to reflect actual measurement shall be made on the bill next following the determination of such actual measurement, without any charge of interest. In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "**bill next following**" shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within three (3) years from the date of the incorrect billing. In the event any refund is issued with Shipper's bill, the aforesaid date of refund shall be deemed to be the date of the issue of bill.

4. Taxes: In addition to the charges and rates as per the applicable rate schedules and price schedules, Shipper shall pay all Taxes which are imposed currently or subsequent to the execution of the Contract by any legal authority having jurisdiction and any amount in lieu of such Taxes paid or payable by Union.

5. Set Off: If Shipper shall, at any time, be in arrears under any of its payment obligations to Union under the Contract, then Union shall be entitled to reduce the amount payable by Union to Shipper under the Contract or any other contract by an amount equal to the amount of such arrears or other indebtedness to Union. In addition to the foregoing remedy, Union may, upon forty-eight (48) hours verbal notice, to be followed by written notice, take possession of any or all of Shipper's gas under the Contract, which shall be deemed to have been assigned to Union, to reduce such arrears or other indebtedness to Union.

6. Aid to Construction: Shipper agrees to reimburse Union for the Aid to Construction.

In the event Union has incurred costs, as set out herein, relative to the construction, installation or connection of the gas metering station prior to being notified by Shipper of Shipper's intention to terminate the Contract, Shipper shall promptly remit to Union such actual costs on presentation to Shipper of an invoice for same from Union.

All applicable Taxes will be applied to all amounts to be paid under this Section. Shipper warrants and represents that no payment to be made by Shipper under the Contract is subject to any withholding tax.

X. ARBITRATION

If and when any dispute, difference or question shall arise between the parties hereto touching the Contract or anything herein contained, or the construction hereof, or the rights, duties or liabilities of the parties in relation to any matter hereunder, the matter in dispute shall be submitted and referred to arbitration within ten (10) days after written request of either party. Upon such request each party shall appoint an arbitrator, and the two so appointed shall appoint a third. A majority decision of the arbitrators shall be final and binding upon both parties. In all other respects the provisions of the Arbitration Act, 1991, or any act passed in amendment thereof or substitution therefore, shall apply to each such submission. Operations under the Contract shall continue, without prejudice, during any such arbitration and the costs attributable to such arbitration shall be shared equally by the parties hereto.

XI. FORCE MAJEURE

1. The term "**force majeure**" as used herein shall mean acts of God, strikes, lockouts or any other industrial disturbance, acts of the public enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or lines of pipe, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority (civil or military), any act or omission that is excused by any event or occurrence of the character herein defined as constituting force majeure, any act or omission by parties not controlled by the party having the difficulty and any other similar cases not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

2. In the event that either the Shipper or Union is rendered unable, in whole or in part, by force majeure, to perform or comply with any obligation or condition of the Contract, such party shall give notice and full particulars of such force majeure in writing delivered by hand, fax or other direct written electronic means to the other party as soon as possible after the occurrence of the cause relied on and subject to the provision of this Article.

3. Neither party shall be entitled to the benefit of the provisions of force majeure hereunder if any or all of the following circumstances prevail: the failure resulting in a condition of force majeure was caused by the negligence of the party claiming suspension; the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation); the party claiming suspension failed to resume the performance of such condition obligations with reasonable dispatch; the failure was caused by lack of funds; the party claiming suspension did not, as soon as possible after determining, or within a period within which it should acting reasonably have determined, that the occurrence was in the nature of force majeure and would affect its ability to observe or perform any of its conditions or obligations under the Contract, give to the other party the notice required hereunder.

4. The party claiming suspension shall likewise give notice as soon as possible after the force majeure condition is remedied, to the extent that the same has been remedied, and that such party has resumed or is then in a position to resume the performance of the obligations and conditions of the Contract.

5. An event of force majeure on Union's system will excuse the failure to deliver gas by Union or the failure to accept gas by Union hereunder, and both parties shall be excused from performance of their obligations hereunder, except for payment obligations, to the extent of and for the duration of the force majeure.

6. Upstream or Downstream Force Majeure: An event of force majeure upstream or downstream of Union's system shall not relieve Shipper of any payment obligations.

7. Delay of Firm Transportation Services: Despite Article XI herein, if Union is prevented, by reason of an event of force majeure on Union's system from delivering gas on the Day or Days upon which Union has accepted gas from Shipper, Union shall thereafter make all reasonable efforts to deliver such quantities as soon as practicable and on such Day or Days as are agreed to by Shipper and Union. If Union accepts such gas on this basis, Shipper shall not receive any demand charge relief as contemplated under Article XI herein.

8. Demand Charge Relief for Firm Transportation Services: Despite Article XI herein, if on any Day Union fails to accept gas from Shipper by reason of an event of force majeure on Union's system and fails to deliver the quantity of gas nominated hereunder by Shipper up to the firm contract demand for the Contract, then for that Day the Monthly demand charge shall be reduced by an amount equal to the applicable Daily Demand Rate, as defined in this paragraph, multiplied by the difference between the quantity of gas actually delivered by Union during such Day and the quantity of gas which Shipper in good faith nominated on such Day. The term "**Daily Demand Rate**" shall mean the Monthly demand charge or equivalent pursuant to the C1 Rate Schedule divided by the number of days in the month for which such rate is being calculated.

9. In addition to the definition of force majeure in Article XI, Section 1 herein, for the purposes of the Contract, it shall also include the unforeseen reduction in natural gas usage and/or capacity of the local transmission system as described in Schedule 1 of the Contract, regardless of the duration of such unforeseen reduction, or any other cause, whether of the kind herein enumerated or otherwise, not within the reasonable control of the party claiming relief hereunder and which, by the exercise of due diligence, such party is unable to prevent or overcome.

XII. DEFAULT AND TERMINATION

In case of the breach or non-observance or non-performance on the part of either party hereto of any covenant, proviso, condition, restriction or stipulation contained in the Contract (but not including herein failure to take or make delivery in whole or in part of the gas delivered to/by Union hereunder occasioned by any of the reasons provided for in Article XI herein) which has not been waived by the other party, then and in every such case and as often as the same may happen, the non-defaulting party may give written notice to the defaulting party requiring it to remedy such default and in the event of the defaulting party failing to remedy the same within a period of thirty (30) days from receipt of such notice, the non-defaulting party may at its sole option declare the Contract to be terminated and thereupon the Contract shall be terminated and be null and void for all purposes other than and except as to any liability of the parties under the same incurred before and subsisting as of termination. The right hereby conferred upon each party shall be in addition to, and not in derogation of or in substitution for, any other right or remedy which the parties respectively at law or in equity shall or may possess.

XIII. AMENDMENT

Subject to Article XV herein and the ability of Union to amend the applicable rate schedules and price schedules, with the approval of the OEB (if required), no amendment or modification of the Contract shall be effective unless the same shall be in writing and signed by each of the Shipper and Union.

XIV. NON-WAIVER AND FUTURE DEFAULT

No waiver of any provision of the Contract shall be effective unless the same shall be in writing and signed by the party entitled to the benefit of such provision and then such waiver shall be effective only in the specific instance and for the specified purpose for which it was given. No failure on the part of Shipper or Union to exercise, and no course of dealing with respect to, and no delay in exercising, any right, power or remedy under the Contract shall operate as a waiver thereof.

XV. LAWS, REGULATIONS AND ORDERS

The Contract and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Contract shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Contract.

XVI. <u>RESERVED FOR FUTURE USE</u>

N/A

XVII. <u>RENEWALS</u>

The Contract will continue in full force and effect beyond the Initial Term, automatically renewing for a period of one (1) year, and every one (1) year thereafter. Shipper or Union may reduce the contract demands or terminate the Contract, with notice in writing to the other party, at least two (2) years prior to the expiration thereof.

XVIII. <u>SERVICE CURTAILMENT</u>

1. <u>Capacity Sharing</u>: Where requests for interruptible service hereunder exceed the capacity available for such Service, Union will authorize nominations from shippers and allocate capacity as per Union's procedures and policies and shippers shall be so advised. Any interruptible service provided herein are subordinate to any and all firm service supplied by Union, and subordinate to Union's own operational or system requirements.

2. <u>Capacity Procedures</u>: Union reserves the right to change its procedures and policies for sharing interruptible capacity and will provide Shipper with two (2) months' notice of any such change.

3. <u>Maintenance</u>: Union's facilities from time to time may require maintenance or construction. In the event that such event occurs and in Union's sole opinion, acting reasonably, may impact its ability to meet Shipper's requirements, Union shall provide at least ten (10) days' notice to the Shipper, except in the case of emergencies. In the event the maintenance impacts Union's ability to meet Shipper's requirements, Union shall not be liable for any damages and shall not be deemed to be in breach of the Contract. To the extent that Union's ability to receive or deliver gas is impaired, Demand Charge Relief shall be calculated and credited to Shipper's invoice in accordance with Article XI, Section 8 herein. Union shall use reasonable efforts to determine a mutually acceptable period during which such maintenance or construction will occur and also to limit the extent and duration of any impairments. Union will endeavour to schedule and complete the maintenance and construction, that can be scheduled and completed, and which would normally be expected to impact on Union's ability to meet its obligations of any Contract Year, during the period from April 1 through to October 31.

4. <u>Shipper's Facilities</u>: Shipper shall complete and maintain a plan which depicts all of Shipper's production storage facilities including all emergency shut off valves and emergency equipment and provide a copy to Union upon Union's request. Shipper shall provide to Union the names and telephone numbers of those persons whom Union may contact in the event of an emergency situation arising within the Shipper's facilities.

XIX. <u>SHIPPER'S REPRESENTATIONS AND WARRANTIES</u>

1. <u>Shipper's Warranty</u>: Shipper warrants that it will, if required, maintain, or have maintained on its behalf, all external approvals including the governmental, regulatory, import/export permits and other approvals or authorizations that are required from any federal, state or provincial authorities for the gas quantities to be handled under the Contract. Shipper further warrants that it shall maintain in effect the Facilitating Agreements.

2. <u>Financial Representations</u>: Shipper represents and warrants that the financial assurances (including the Initial Financial Assurances and Security), if any, shall remain in place throughout the term hereof unless Shipper and Union agree otherwise. Shipper shall notify Union in the event of any change to the financial assurances (including the Initial Financial Assurances and Security), if any, throughout the term hereof. Should Union have reasonable grounds to believe that Shipper will not be able to perform or continue to perform any of its obligations under the Contract for any reason (a "**Material Event**"), then Shipper shall within fourteen (14) days of receipt of written notice by Union, obtain and provide to Union a letter of credit or other security in the form and amount reasonably required by Union (the "**Security**"). In the event that Shipper does not provide to Union such Security, Union may deem a default in accordance with the provisions of Article XII herein.

In the event that Shipper in good faith, reasonably believes that it should be entitled to reduce the amount of or value of the Security previously provided, it may request such a reduction from Union and to the extent that the Material Event has been mitigated or eliminated, Union shall return all or a portion of the Security to Shipper within fourteen (14) Business Days after receipt of the request.

3. Regulatory Approval: Shipper represents and warrants to Union that Shipper possesses all licenses and permits needed to inject gas into, store gas in, and remove gas from the pool.

XX. MISCELLANEOUS PROVISIONS

1. Assignment: Shipper may not assign the Contract without the written consent of Union and, if required, the approval of the OEB. Should Union consent to the assignment, and if OEB approval is needed, Union will apply for OEB approval with all costs of the application to be paid by Shipper.

2. Title to Gas: Shipper represents and warrants to Union that Shipper shall have good and marketable title to, or legal authority to deliver to Union, all gas delivered to Union hereunder. Furthermore, Shipper hereby agrees to indemnify and save Union harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of claims of any or all third parties to such gas or on account of Taxes, or other charges thereon.

XXI. PRECONDITIONS TO TRANSPORTATION SERVICES

1. The obligations of Union to provide Services hereunder are subject to the following conditions precedent, which are for the sole benefit of Union and which may be waived or extended in whole or in part in the manner provided in the Contract:

   a. Union shall have obtained, in form and substance satisfactory to Union, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required to provide the Services; and,

   b. Union shall have obtained all internal approvals that are necessary or appropriate to provide the Services; and,

   c. Union shall have received from Shipper the requisite financial assurances reasonably necessary to ensure Shipper's ability to honour the provisions of the Contract (the "**Initial Financial Assurances**"). The Initial Financial Assurances, if required, will be as determined solely by Union; and,

   d. Shipper and Union shall have entered into the Interruptible HUB Service Contract or equivalent (the "**Facilitating Agreement**") with Union; and,

   e. Shipper shall have paid any amounts owing pursuant to Schedule 1 Aid to Construction; and,

   f. With regard to the Union Expansion Facilities:

      i. Union shall have obtained, in form and substance satisfactory to Union, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations required to construct the Union Expansion Facilities;

      ii. Union shall have obtained all internal approvals that are necessary or appropriate to construct the Union Expansion Facilities;

      iii. Union shall have completed and placed into service the Union Expansion Facilities; and,

   g. Shipper shall, at Shipper's own cost and expense, have obtained a registered lease or freehold ownership in Union's favour for the Union Expansion Facilities located at the Pool Station satisfactory to Union and sufficient to provide Union with free uninterrupted access to, from, under and above the Pool Station for a term (and extended terms) identical to the Contract, plus sixty (60) days (such land rights being referred to as the “**Pool Station Land Rights**”), and shall provide Union with a bona fide copy of such agreements prior to Union commencing the construction of the Union Expansion Facilities.

2. The obligations of Shipper hereunder are subject to the following conditions precedent, which are for the sole benefit of Shipper and which may be waived or extended in whole or in part in the manner provided in the Contract:

   a. Shipper shall, as required, have entered into the necessary contracts with Union and/or others to facilitate the Services contemplated herein, including contracts for upstream and downstream transportation, and shall specifically have an executed and valid Facilitating Agreement; and shall, as required, have entered into the necessary contracts to purchase the gas quantities handled under the Contract; and,

   b. Shipper shall have obtained, in form and substance satisfactory to Shipper, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required from federal, state, or provincial authorities for the gas quantities handled under the Contract; and,

   c. Shipper shall have obtained all internal approvals that are necessary or appropriate for the Shipper to execute the Contract.

3. Union and Shipper shall each use due diligence and reasonable efforts to satisfy and fulfil the conditions precedent specified in this Article XXI Section 1 a, c, d, e, f i., f iii., and g and Section 2 a and b. Each party shall notify the other forthwith in writing of the satisfaction or waiver of each condition precedent for such party’s benefit. If a party concludes that it will not be able to satisfy a condition precedent that is for its benefit, such party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations thereunder.

4. If any of the conditions precedent in this Article XXI Section 1 c or Section 2 are not satisfied or waived by the party entitled to the benefit of that condition by the Conditions Date as such term is defined in the Contract, then either party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations hereunder, provided that any rights or remedies that a party may have for breaches of the Contract prior to such termination and any liability a party may have incurred before such termination shall not thereby be released.

CROSS FRANCHISE TRANSPORTATION RATES

(A) Applicability

To a Shipper who enters into a Contract with Union for delivery by Shipper of gas to Union at one of Union's points listed below for redelivery by Union to Shipper at one of Union's points.

Applicable Points	(1)	(2)
	Ojibway	WDA
	St. Clair	NDA
	Dawn*	SSMDA
	Parkway	SWDA
	Kirkwall	CDA
	Bluewater	EDA

*Dawn as a receipt point: Dawn (TCPL), Dawn (Facilities), Dawn (Tecumseh), Dawn (Vector) and Dawn (TSLE).

*Dawn as a delivery point: Dawn (Facilities).

(B) Services

Transportation Service under this rate schedule is transportation on Union's pipeline facilities between any two Points as specified in Section (A), column 1.

(C) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

Transportation Service:

	Monthly Demand Charge (applied to daily contract demand)	Commodity Charges			
		If Union supplies fuel Commodity Charge		If Shipper supplies fuel Fuel Ratio	
		Apr.1-Oct.31	Nov.1-Mar.31	Apr.1-Oct.31	Nov.1-Mar.31
	Rate/GJ	Rate/GJ	Rate/GJ	%	%
a) Firm Transportation					
Between:					
St.Clair & Dawn	$1.059	$0.011	$0.014	0.201%	0.258%
Ojibway & Dawn	$1.059	$0.024	$0.016	0.435%	0.295%
Bluewater & Dawn	$1.059	$0.011	$0.014	0.201%	0.258%
From:					
Parkway to Kirkwall	$0.579	$0.015	$0.009	0.268%	0.153%
Parkway to Dawn	$0.579	$0.015	$0.009	0.268%	0.153%
Kirkwall to Dawn	$1.021	$0.009	$0.009	0.153%	0.153%
Dawn to Kirkwall	$2.011	$0.017	$0.041	0.310%	0.728%
Dawn to Parkway	$2.382	$0.029	$0.054	0.527%	0.975%
Kirkwall to Parkway	$0.372	$0.021	$0.022	0.370%	0.400%
b) Interruptible and Short Term (1 year or less) Firm Transportation:					
Maximum		$75.00	$75.00		
c) Firm Transportation between two points within Dawn					
Dawn to Dawn-Vector	$0.029	n/a	n/a	0.330%	0.153%
Dawn to Dawn-TCPL	$0.134	n/a	n/a	0.153%	0.342%
d) Interruptible Transportation between two points within Dawn*					
*includes Dawn (TCPL), Dawn Facilities, Dawn (Tecumseh), Dawn (Vector) and Dawn (TSLE)				0.153%	0.153%

(C) Rates (Cont'd)

Authorized Overrun:

The following Overrun rates are applied to any quantities transported in excess of the Contract parameters. Overrun will be authorized at Union's sole discretion.

	If Union supplies fuel		Commodity Charges If Shipper supplies fuel		
	Commodity Charge		Fuel Ratio		Commodity Charge
a) Firm Transportation	Apr.1-Oct.31 Rate/GJ	Nov.1-Mar.31 Rate/GJ	Apr.1-Oct.31 %	Nov.1-Mar.31 %	Rate/GJ
Between:					
St.Clair & Dawn	$0.046	$0.049	0.201%	0.258%	$0.035
Ojibway & Dawn	$0.059	$0.051	0.435%	0.295%	$0.035
Bluewater & Dawn	$0.046	$0.049	0.201%	0.258%	$0.035
From:					
Parkway to Kirkwall	$0.127	$0.120	0.868%	0.753%	$0.019
Parkway to Dawn	$0.127	$0.120	0.868%	0.753%	$0.019
Kirkwall to Dawn	$0.047	$0.047	0.849%	0.849%	$0.034
Dawn to Kirkwall	$0.117	$0.140	0.910%	1.328%	$0.066
Dawn to Parkway	$0.141	$0.166	1.127%	1.575%	$0.078
Kirkwall to Parkway	$0.066	$0.068	0.970%	1.000%	$0.012
b) Firm Transportation within Dawn					
Dawn to Dawn-Vector	n/a	n/a	0.330%	0.153%	$0.001
Dawn to Dawn-TCPL	n/a	n/a	0.153%	0.342%	$0.004

Authorized overrun for short-term firm transportation is available at negotiated rates.

Unauthorized Overrun:

The Unauthorized Overrun rate shall be the higher of the reported daily spot price of gas at either, Dawn, Parkway, Niagara, Iroquois or Chicago in the month of or the month following the month in which the overrun occurred plus 25% for all usage on any day in excess of 102% of Union's contractual obligation.

Notes for Section (C) Rates:

(1) A demand charge of $0.068/GJ/day/month will be applicable to customers contracting for firm all day transportation service in addition to the demand charges appearing on this schedule for all firm transportation service paths.

(D) Terms of Service

The General Terms & Conditions applicable to this rate schedule shall be in accordance with the attached Schedule "A" for contracts in effect before October 1, 2010. The General Terms & Conditions applicable to this rate schedule shall be in accordance with the attached Schedule "A 2010" for contracts in effect on or after October 1, 2010.

(E) Nominations

Nominations under this rate schedule shall be in accordance with the attached Schedule "B" for contracts in effect before October 1, 2010. Nominations under this rate schedule shall be in accordance with the attached Schedule "B 2010" for contracts in effect on or after October 1, 2010.

(F) Receipt and Delivery Points and Pressures

Receipt and Delivery Points and Pressures under this rate schedule shall be in accordance with Schedule "C 2010" for contracts in effect on or after October 1, 2010.

SCHEDULE "A"

RATE C1
GENERAL TERMS & CONDITIONS

I. DEFINITIONS

Except where the context expressly requires or states another meaning, the following terms, when used in these General Terms & Conditions and in any contract into which these General Terms & Conditions are incorporated, shall be construed to have the following meanings:

1. "Contract" shall refer to the Contract to which these General Terms & Conditions shall apply, and into which they are incorporated;

2. "cubic metre" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

3. "day" shall mean a period of twenty-four (24) consecutive hours beginning at 9:00 a.m. Central Standard time. The reference date for any day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

4. "delivery" shall mean any gas that is delivered by Union into Shipper's possession, or to the possession of Shipper's agent;

5. "firm" shall mean service not subject to curtailment or interruption except under Articles XI and XII of this Schedule "A";

6. "gas" shall mean gas as defined in the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Sch. B, as amended, supplemented or re-enacted from time to time;

7. "gross heating value" shall mean the total heat expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state;

8. "interruptible service" shall mean service subject to curtailment or interruption, after notice, at any time;

9. “Interconnecting Pipeline” shall mean a pipeline that directly connects to the Union pipeline system;

10. "joule" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force. The term "megajoule" (MJ) shall mean 1,000,000 joules. The term “gigajoule” (GJ) shall mean 1,000,000,000 joules;

11. "limited interruptible service" shall mean gas service subject to interruption or curtailment on a limited number of days as specified in the Contract;

12. "m^3" shall mean cubic metre of gas and "10^3m^3" shall mean 1,000 cubic metres of gas;

13. "month" shall mean the period beginning at 9:00 a.m. Central Standard time on the first day of a calendar month and ending at 9:00 a.m. Central Standard time on the first day of the following calendar month;

14. "OEB" means the Ontario Energy Board;

15. "pascal" (Pa) shall mean the pressure produced when a force of one (1) newton is applied to an area of one (1) square metre. The term "kilopascal" (kPa) shall mean 1,000 pascals;

16. "receipt" shall mean any gas that is delivered into Union's possession, or the possession of Union’s agent;

17. "Shipper" shall have the meaning as defined in the Contract and shall also include Shipper's agent(s);

18. "TCPL" means TransCanada PipeLines Limited;

19. "cricondentherm hydrocarbon dewpoint" shall mean the highest hydrocarbon dewpoint temperature on the phase envelope;

20. "hydrocarbon dewpoint" shall mean temperature at a specific pressure where hydrocarbon vapour condensation begins;

21. "specific gravity" shall mean density of the gas divided by density of air, with both at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

22. "Wobbe Number" shall mean gross heating value of the gas divided by the square root of its specific gravity.

II. GAS QUALITY

1. Natural Gas: The minimum gross heating value of the gas delivered to/by Union hereunder, shall be thirty-six (36) megajoules per cubic metre. The maximum gross heating value of the gas delivered to/by Union hereunder shall be forty point two (40.2) megajoules per cubic metre. The gas to be delivered hereunder to Union may be a commingled supply from Shipper's gas sources of supply. The gas to be delivered by Union may be a commingled supply from Union's sources of gas supply; provided, however, that helium, natural gasoline, butane, propane and other hydrocarbons, except methane, may be removed prior to delivery to Shipper. Further, Union may subject, or permit the subjection of, the gas to compression, dehydration, cooling, cleaning and other processes.

2. Freedom from objectionable matter: The gas to be delivered to/by Union hereunder,

   a. shall be commercially free from bacteria, sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other objectionable substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to, or interference with, the proper operation of the lines, regulators, meters or other appliances through which it flows,

   b. shall not contain more than seven (7) milligrams of hydrogen sulphide per cubic metre of gas, nor more than four hundred and sixty (460) milligrams of total sulphur per cubic metre of gas,

   c. shall not contain more than five (5) milligrams of mercaptan sulphur per cubic metre of gas,

   d. shall not contain more than two point zero (2.0) molar percent by volume of carbon dioxide in the gas,

   e. shall not contain more than zero point four (0.4) molar percent by volume of oxygen in the gas,

   f. shall not contain more than zero point five (0.5) molar percent by volume of carbon monoxide in the gas,

   g. shall not contain more than four point zero (4.0) molar percent by volume of hydrogen in the gas,

   h. shall not contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas,

   i. shall not have a cricondentherm hydrocarbon dewpoint exceeding minus eight (-8) degrees Celsius,

   j. shall have Wobbe Number from forty seven point fifty (47.50) megajoules per cubic metre of gas to fifty one point forty six (51.46) megajoules per cubic metre of gas, maximum of one point five (1.5) mole percent by volume of butane plus (C4+) in the gas, and maximum of four point zero (4.0) mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas.

3. Non-conforming Gas: In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Article II.

4. Quality of Gas Received: The quality of the gas to be received by Union hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Article II, but, Union will also accept gas of a

quality as set out in any other Interconnecting Pipeline's general terms and conditions, provided that all Interconnecting Pipelines accept such quality of gas. In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in Union's C1 Rate Schedule.

III. MEASUREMENTS

1. Storage, Transportation, and/or Sales Unit: The unit of the gas delivered to Union shall be a megajoule or a gigajoule. The unit of gas transported or stored by Union shall be a megajoule or a gigajoule. The unit of gas delivered by Union shall be a megajoule, a gigajoule, a cubic metre (m^3) or one thousand cubic metres (10^3m^3) at Union's discretion.

2. Determination of Volume and Energy:

   a. The volume and energy amounts determined under the Contract shall be determined in accordance with the Electricity and Gas Inspection Act (Canada), RSC 1985, c E-4- (the "**Act**") and the Electricity and Gas Inspection Regulations, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

   b. The supercompressibility factor shall be determined in accordance with either the "Manual for Determination of Supercompressibility Factors for Natural Gas" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

   c. The volume and/or energy of the gas delivered to/by Union hereunder shall be determined by the measurement equipment designated in Article VII herein.

   d. Upon request by Union, Shipper shall obtain measurement of the total quantity of gas received by Union hereunder from the Interconnecting Pipeline. Such measurement shall be done in accordance with established practices between Union and the Interconnecting Pipeline.

IV. RECEIPT POINT AND DELIVERY POINT

1. Unless otherwise specified in the Contract, the point or points of receipt for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection specified in the Contract, where Union takes possession of the gas.

2. Unless otherwise specified in the Contract, the point or points of delivery for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection as specified in the Contract where Shipper takes possession of the gas.

V. POSSESSION OF AND RESPONSIBILITY FOR GAS

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VI. FACILITIES ON SHIPPER'S PROPERTY

Except under those conditions where Union is delivering to TCPL for TCPL or Shipper at Union's Parkway Point of Delivery, or to an Interconnecting Pipeline, or where otherwise specified in the Contract, the following will apply:

1. Construction and Maintenance: Union, at its own expense may construct, maintain and operate on Shipper's property at the delivery point a measuring station properly equipped with a meter or meters and any other necessary measuring equipment for properly measuring the gas redelivered under the Contract. Shipper will grant to Union a lease and/or rights-of-way over property of Shipper as required by Union to install such facilities and to connect same to Union's pipeline.

2. Entry: Union, its servants, agents and each of them may at any reasonable time on notice (except in cases of emergency) to Shipper or his duly authorized representative enter Shipper's property for the purpose of constructing, maintaining, removing, operating and/or repairing station equipment.

3. Property: The said station and equipment will be and remain the property of Union notwithstanding it is constructed on and attached to the realty of Shipper, and Union may at its own expense remove it upon termination of the Contract and will do so if so requested by Shipper.

VII. MEASURING EQUIPMENT

1. Metering by Union: Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Article III herein.

2. Metering by Others: In the event that all or any gas delivered to/by Union hereunder is measured by a meter that is owned and operated by an Interconnecting Pipeline, then Union and Shipper agree to accept that metering for the purpose of determining the volume and energy of gas delivered to/by Union on behalf of the Shipper. The standard of measurement and tests for the gas delivered to/by Union hereunder shall be in accordance with the general terms and conditions as incorporated in that Interconnecting Pipeline company's gas tariff as approved by their regulatory body.

3. Check Measuring Equipment: Shipper may install, maintain and operate, at the redelivery point, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Union's measuring equipment at or near the delivery point, and shall be installed, maintained and operated in conformity with the same standards and specifications applicable to Union's metering facilities.

4. Rights of Parties: The measuring equipment installed by either party, together with any building erected by it for such equipment, shall be and remain its property. However, Union and Shipper shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring or checking the measurement of deliveries of gas to/by Union under the Contract. Either party will give the other party reasonable notice of its intention to carry out the acts herein specified. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

5. Calibration and Test of Measuring Equipment: The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Shipper, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment tested is found to be in error by not more than two per cent (2%). If, upon test, any measuring equipment is found to be in error by not more than two per cent (2%), previous recordings of such equipment shall be considered accurate in computing receipts and deliveries of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than two percent (2%), the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations, as may be amended from time to time and in accordance with any successor statutes and regulations.

6. Preservation of Metering Records: Union and Shipper shall each preserve for a period of at least six (6) years all test data, and other relevant records.

7. Error in Metering or Meter Failure: In the event of an error in metering or a meter failure, (such error or failure being determined through check measurement by Union or any other available method), then Shipper shall enforce its rights as Shipper with the Interconnecting Pipeline(s) to remedy such error or failure including enforcing any inspection and/or verification rights and procedures.

VIII. BILLING

1. Monthly Billing Date: Union shall render bills on or before the 10th day of each month for all services furnished during the preceding month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding month's billing, an adjustment based on any difference between actual quantities and estimated quantities, without any interest charge. If presentation of a bill to Shipper is delayed after the 10th day of the month, then the time of payment shall be extended accordingly, unless Shipper is responsible for such delay.

2. Right of Examination: Both Union and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Contract.

IX. PAYMENTS

1. Monthly Payments: Shipper shall pay the invoiced amount directly into Union's bank account as directed on the invoice on or before the twentieth (20th) day of each month. If the payment date is not a business day, then payment must be received in Union's account on the first business day preceding the twentieth (20th) day of the month.

2. Remedies for Non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due,

   a. Shipper shall pay to Union interest on the unpaid portion of the bill accruing at a rate per annum equal to the minimum commercial lending rate of Union's principal banker in effect from time to time from the due date until the date of payment.

   b. If such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the Contract, may suspend service(s) until such amount is paid. Notwithstanding such suspension, all demand charges shall continue to accrue hereunder as if such suspension were not in place.

   If Shipper in good faith disputes the amount of any such bill or part thereof Shipper shall pay to Union such amounts as it concedes to be correct. At any time thereafter, within twenty (20) days of a demand made by Union, Shipper shall furnish financial assurances satisfactory to Union, guaranteeing payment to Union of the amount ultimately found due upon such bill after a final determination. Such a final determination may be reached either by agreement, arbitration decision or judgement of the courts, as may be the case. Union shall not be entitled to suspend service(s) because of such non-payment unless and until default occurs in the conditions of such financial assurances or default occurs in payment of any other amount due to Union hereunder.

   Notwithstanding the foregoing paragraph(s), Shipper is not relieved from the obligation to continue its deliveries of gas to Union under the terms of any agreement, where Shipper has contracted to deliver specified quantities of gas to Union.

3. Billing Adjustments: If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, Union shall refund the amount of any such overcharge and interest shall accrue from and including the first day of such overcharge as paid to the date of refund and shall be calculated but not compounded at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker, and the Shipper shall pay the amount of any such undercharge, but without interest. In the event Union renders a bill to Shipper based upon measurement estimates, the required adjustment to reflect actual measurement shall be made on the bill next following the determination of such actual measurement, without any charge of interest. In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "bill" next following shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within six (6) years from the date of the incorrect billing. In the event any refund is issued with Shipper's gas bill, the aforesaid date of refund shall be deemed to be the date of the issue of bill.

X. ARBITRATION

If and when any dispute, difference or question shall arise between the parties hereto touching the Contract or anything herein contained, or the construction hereof, or the rights, duties or liabilities of the parties in relation to any matter hereunder, the matter in dispute shall be submitted and referred to arbitration within ten (10) days after written request of either party. Upon such request each party shall appoint an arbitrator, and the two so appointed shall appoint a third. A majority decision of the arbitrators shall be final and binding upon both parties. In all other respects the provisions of the Arbitration Act of the Province of Ontario, or any act passed in amendment thereof or substitution therefore, shall apply to each such submission. Operations under the Contract shall continue, without prejudice, during any such arbitration and the costs attributable to such arbitration shall be shared equally by the parties hereto.

XI. FORCE MAJEURE

1. The term "**force majeure**" as used herein shall mean acts of God, strikes, lockouts or any other industrial disturbance, acts of the public enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or lines of pipe, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority (civil or military), any act or omission that is excused by any event or occurrence of the character herein defined as constituting force majeure, any act or omission by parties not controlled by the party having the difficulty and any other similar cases not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

2. In the event that either the Shipper or Union is rendered unable, in whole or in part, by force majeure, to perform or comply with any obligation or condition of the Contract, such party shall give notice and full particulars of such force majeure in writing delivered by hand, fax or other direct written electronic means to the other party as soon as possible after the occurrence of the cause relied on and subject to the provision of this Article.

3. Neither party shall be entitled to the benefit of the provisions of force majeure hereunder if any or all of the following circumstances prevail: the failure resulting in a condition of force majeure was caused by the negligence of the party claiming suspension; the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation); the party claiming suspension failed to resume the performance of such condition obligations with reasonable dispatch; the failure was caused by lack of funds; the party claiming suspension did not, as soon as possible after determining, or within a period within which it should acting reasonably have determined, that the occurrence was in the nature of force majeure and would affect its ability to observe or perform any of its conditions or obligations under the Contract, give to the other party the notice required hereunder.

4. The party claiming suspension shall likewise give notice as soon as possible after the force majeure condition is remedied, to the extent that the same has been remedied, and that such party has resumed or is then in a position to resume the performance of the obligations and conditions of the Contract.

5. An event of force majeure on Union's system will excuse the failure to deliver gas by Union or the failure to accept gas by Union hereunder, and both parties shall be excused from performance of their obligations hereunder, except for payment obligations, to the extent of and for the duration of the force majeure.

6. Upstream or Downstream Force Majeure: An event of force majeure upstream or downstream of Union's system shall not relieve Shipper of any payment obligations.

7. Delay of Firm Transportation Services: Despite Article XI herein, if Union is prevented, by reason of an event of force majeure on Union's system from delivering gas on the Day or Days upon which Union has accepted gas from Shipper, Union shall thereafter make all reasonable efforts to deliver such quantities as soon as practicable and on such Day or Days as are agreed to by Shipper and Union. If Union accepts such gas on this basis, Shipper shall not receive any demand charge relief as contemplated under Article XI herein.

8. Demand Charge Relief for Firm Transportation Services: Despite Article XI herein, if on any Day Union fails to accept gas from Shipper by reason of an event of force majeure on Union's system and fails to deliver the quantity of gas nominated hereunder by Shipper up to the firm Contract Demand for that Contract, then for that Day the Monthly demand charge shall be reduced by an amount equal to the applicable Daily Demand Rate, as defined in this paragraph, multiplied by the difference between the quantity of gas actually delivered by Union during such Day and the quantity of gas which Shipper in good faith nominated on such Day. The term "**Daily Demand Rate**" shall mean the Monthly demand charge or equivalent pursuant to the C1 Rate Schedule divided by the number of days in the month for which such rate is being calculated.

9. If, due to the occurrence of an event of force majeure as outlined above, the capacity for gas deliveries by Union is impaired, it will be necessary for Union to curtail Shipper's gas receipts to Union hereunder, via proration based on utilization of such facilities for the Day. This prorating shall be determined by multiplying the capability of such facilities as available downstream of the impairment on the Day, by a fraction where the numerator is Shipper's nominated firm quantity and the denominator is the total of all such nominated firm quantities for nominated services and planned consumption for in-franchise customers on the Day. For the purposes of this Article XI, firm services shall mean all firm services provided by Union to in-franchise customers and ex-franchise shippers.

XII. DEFAULT AND TERMINATION

In case of the breach or non-observance or non-performance on the part of either party hereto of any covenant, proviso, condition, restriction or stipulation contained in the Contract (but not including herein failure to take or make delivery in whole or in part of the gas delivered to/by Union hereunder occasioned by any of the reasons provided for in Article XI hereof) which has not been waived by the other party, then and in every such case and as often as the same may happen, the Non-defaulting party may give written notice to the Defaulting party requiring it to remedy such default and in the event of the Defaulting party failing to remedy the same within a period of thirty (30) days from receipt of such notice, the Non-defaulting party may at its sole option declare the Contract to be terminated and thereupon the Contract shall be terminated and be null and void for all purposes other than and except as to any liability of the parties under the same incurred before and subsisting as of termination. The right hereby conferred upon each party shall be in addition to, and not in derogation of or in substitution for, any other right or remedy which the parties respectively at law or in equity shall or may possess.

XIII. MODIFICATION

Subject to Union's C1 Rate Schedule, Schedule A, Article XV and the ability of Union to amend the C1 Rate Schedule with the approval of the OEB, no amendment or modification of the Contract shall be effective unless the same shall be in writing and signed by each of the Shipper and Union.

XIV. NON-WAIVER AND FUTURE DEFAULT

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XV. LAWS, REGULATIONS AND ORDERS

The Contract and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Contract shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Contract.

SCHEDULE "A 2010"

RATE C1
GENERAL TERMS & CONDITIONS

I. DEFINITIONS

Except where the context expressly requires or states another meaning, the following terms, when used in these General Terms & Conditions and in any contract into which these General Terms & Conditions are incorporated, shall be construed to have the following meanings:

"**Authorized Overrun**" shall mean the amount by which Shipper's Authorized Quantity exceeds the Contract Demand;

"**Available Capacity**" shall mean at any time, Union's remaining available capacity to provide Transportation Services;

"**Business Day**" shall mean any day, other than Saturday, Sunday or any days on which national banks in the Province of Ontario are authorized to close;

"**Contract**" shall refer to the Contract to which these General Terms & Conditions shall apply, and into which they are incorporated;

"**Contract Year**" shall mean a period of three hundred and sixty-five (365) consecutive days; provided however, that any such period which contains a date of February 29 shall consist of three hundred and sixty-six (366) consecutive days, commencing on November 1 of each year; except for the first Contract Year which shall commence on the Commencement Date and end on the first October 31 that follows such date;

"**cricondentherm hydrocarbon dewpoint**" shall mean the highest hydrocarbon dewpoint temperature on the phase envelope;

"**cubic metre**" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**Day**" shall mean a period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Clock Time. The reference date for any Day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

"**delivery**" shall mean any gas that is delivered by Union into Shipper's possession, or to the possession of Shipper's agent;

"Eastern Clock Time" shall mean the local clock time in the Eastern Time Zone on any Day;

"**Expansion Facilities**" shall mean any new facilities to be constructed by Union in order to provide Transportation Services;

"**firm**" shall mean service not subject to curtailment or interruption except under Articles XI, XII and XVIII herein;

"**gas**" shall mean gas as defined in the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Sch. B, as amended, supplemented or re-enacted from time to time;

"**gross heating value**" shall mean the total heat expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state;

"**hydrocarbon dewpoint**" shall mean temperature at a specific pressure where hydrocarbon vapour condensation begins;

"**Interruptible HUB Service Contract**" shall mean a contract between Shipper and Union under which Union provides interruptible HUB service;

"**interruptible service**" or "**Interruptible**" shall mean service subject to curtailment or interruption, after notice, at any time;

"**Interconnecting Pipeline**" shall mean a pipeline that directly connects to the Union pipeline system;

"**joule**" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force. The term "**megajoule**" (MJ) shall mean 1,000,000 joules. The term "**gigajoule**" (GJ) shall mean 1,000,000,000 joules;

"**Limited Firm**" shall mean gas service subject to interruption or curtailment on a limited number of Days as specified in the Contract;

"Loaned Quantities" shall mean those quantities of gas loaned to Shipper under the Facilitating Agreement;

"**m^3**" shall mean cubic metre of gas and "10^3m^3" shall mean 1,000 cubic metres of gas;

"**Month**" shall mean the period beginning at 10:00 a.m. Eastern Clock Time on the first day of a calendar month and ending at 10:00 a.m. Eastern Clock Time on the first day of the following calendar month;

"**NAESB**" shall mean North American Energy Standards Board;

"**OEB**" means the Ontario Energy Board;

"**Open Season**" or "**open season**" shall mean an open access auction or bidding process held by Union as a method of allocating capacity;

"**pascal**" "**(Pa)**" shall mean the pressure produced when a force of one (1) newton is applied to an area of one (1) square metre. The term "kilopascal" **"(kPa)**" shall mean 1,000 pascals;

"**receipt**" shall mean any gas that is delivered into Union's possession, or the possession of Union's agent;

"**Shipper**" shall have the meaning as defined in the Contract, and shall also include Shipper's agent(s);

"**specific gravity**" shall mean density of the gas divided by density of air, with both at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**Taxes**" shall mean any tax (other than tax on income or tax on property), duty, royalty, levy, license, fee or charge not included in the charges and rates as per the applicable rate schedule (including but not limited to charges under any form of cap and trade, carbon tax, or similar system) and that is levied, assessed or made by any governmental authority on the gas itself, or the act, right, or privilege of producing, severing, gathering, storing, transporting, handling, selling or delivering gas under the Contract;

"**TCPL**" means TransCanada PipeLines Limited;

"**Wobbe Number**" shall mean gross heating value of the gas divided by the square root of its specific gravity.

II. GAS QUALITY

1. Natural Gas: The minimum gross heating value of the gas delivered to/by Union hereunder, shall be thirty-six (36) megajoules per cubic metre. The maximum gross heating value of the gas delivered to/by Union hereunder shall be forty point two (40.2) megajoules per cubic metre. The gas to be delivered hereunder to Union may be a commingled supply from Shipper's gas sources of supply. The gas to be delivered by Union may be a commingled supply from Union's sources of gas supply; provided, however, that helium, natural gasoline, butane, propane and other hydrocarbons, except methane, may be removed prior to delivery to Shipper. Further, Union may subject, or permit the subjection of, the gas to compression, dehydration, cooling, cleaning and other processes.

2. Freedom from objectionable matter: The gas to be delivered to/by Union hereunder,

   a. shall be commercially free from bacteria, sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other objectionable substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to, or interference with, the proper operation of the lines, regulators, meters or other appliances through which it flows,

   b. shall not contain more than seven (7) milligrams of hydrogen sulphide per cubic metre of gas, nor more than four hundred and sixty (460) milligrams of total sulphur per cubic metre of gas,

   c. shall not contain more than five (5) milligrams of mercaptan sulphur per cubic metre of gas,

   d. shall not contain more than two point zero (2.0) molar percent by volume of carbon dioxide in the gas,

   e. shall not contain more than zero point four (0.4) molar percent by volume of oxygen in the gas,

   f. shall not contain more than zero point five (0.5) molar percent by volume of carbon monoxide in the gas,

   g. shall not contain more than four point zero (4.0) molar percent by volume of hydrogen in the gas,

   h. shall not contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas,

   i. shall not have a cricondentherm hydrocarbon dewpoint exceeding minus eight (-8) degrees Celsius,

   j. shall have Wobbe Number from forty seven point fifty (47.50) megajoules per cubic metre of gas to fifty one point forty six (51.46) megajoules per cubic metre of gas, maximum of one point five (1.5) mole percent by volume of butane plus (C4+) in the gas, and maximum of four point zero (4.0) mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas.

3. Non-conforming Gas: In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Article II.

4. Quality of Gas Received: The quality of the gas to be received by Union hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Article II, but, Union will also accept gas of a quality as set out in any other Interconnecting Pipeline's general terms and conditions, provided that all Interconnecting Pipelines accept such quality of gas. In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in Union's C1 Rate Schedule.

III. MEASUREMENTS

1. Storage, Transportation, and/or Sales Unit: The unit of the gas delivered to Union shall be a megajoule or a gigajoule. The unit of gas transported or stored by Union shall be a megajoule or a gigajoule. The unit of gas delivered by Union shall be a megajoule, a gigajoule, a cubic metre (m^3) or one thousand cubic metres (10^3m^3) at Union's discretion.

2. Determination of Volume and Energy:

   a. The volume and energy amounts determined under the Contract shall be determined in accordance with the Electricity and Gas Inspection Act (Canada), RSC 1985, c E-4- (the "**Act**") and the Electricity and Gas Inspection Regulations, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

   b. The supercompressibility factor shall be determined in accordance with either the "Manual for Determination of Supercompressibility Factors for Natural Gas" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

c. The volume and/or energy of the gas delivered to/by Union hereunder shall be determined by the measurement equipment designated in Article VII herein.

d. Upon request by Union, Shipper shall obtain measurement of the total quantity of gas received by Union hereunder from the Interconnecting Pipeline. Such measurement shall be done in accordance with established practices between Union and the Interconnecting Pipeline.

IV. <u>RECEIPT POINT AND DELIVERY POINT</u>

1. Unless otherwise specified in the Contract, the point or points of receipt and point or points of delivery for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection specified in the Contract, where possession of the gas changes from one party to the other, and as per Schedule “C 2010”.

V. <u>POSSESSION OF AND RESPONSIBILITY FOR GAS</u>

1. Union accepts no responsibility for any gas prior to such gas being delivered to Union at the Receipt Point or after its delivery by Union at the Delivery Point. As between the parties hereto, Union shall be deemed to be in control and possession of and responsible for all such gas from the time that such gas enters Union's system until such gas is delivered to Shipper.

2. Shipper agrees that Union is not a common carrier and is not an insurer of Shipper’s gas, and that Union shall not be liable to Shipper or any third party for loss of gas in Union’s possession, except to the extent such loss is caused entirely by Union’s negligence or wilful misconduct.

VI. <u>FACILITIES ON SHIPPER’S PROPERTY</u>

Except under those conditions where Union is delivering to TCPL for TCPL or Shipper at Parkway (TCPL), or to an Interconnecting Pipeline, or where otherwise specified in the Contract, the following will apply:

1. <u>Construction and Maintenance:</u> Union, at its own expense may construct, maintain and operate on Shipper's property at the delivery point a measuring station properly equipped with a meter or meters and any other necessary measuring equipment for properly measuring the gas redelivered under the Contract. Shipper will grant to Union a lease and/or rights-of-way over property of Shipper as required by Union to install such facilities and to connect same to Union's pipeline.

2. <u>Entry:</u> Union, its servants, agents and each of them may at any reasonable time on notice (except in cases of emergency) to Shipper or his duly authorized representative enter Shipper's property for the purpose of constructing, maintaining, removing, operating and/or repairing station equipment.

3. <u>Property:</u> The said station and equipment will be and remain the property of Union notwithstanding it is constructed on and attached to the realty of Shipper, and Union may at its own expense remove it upon termination of the Contract and will do so if so requested by Shipper.

VII. <u>MEASURING EQUIPMENT</u>

1. <u>Metering by Union:</u> Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Article III herein.

2. <u>Metering by Others</u>: In the event that all or any gas delivered to/by Union hereunder is measured by a meter that is owned and operated by an Interconnecting Pipeline, then Union and Shipper agree to accept that metering for the purpose of determining the volume and energy of gas delivered to/by Union on behalf of the Shipper. The standard of measurement and tests for the gas delivered to/by Union hereunder shall be in accordance with the general terms and conditions as incorporated in that Interconnecting Pipeline company’s gas tariff as approved by its regulatory body.

3. Check Measuring Equipment: Shipper may install, maintain and operate, at the redelivery point, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Union's measuring equipment at or near the delivery point, and shall be installed, maintained and operated in conformity with the same standards and specifications applicable to Union's metering facilities.

4. Rights of Parties: The measuring equipment installed by either party, together with any building erected by it for such equipment, shall be and remain its property. However, Union and Shipper shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring or checking the measurement of deliveries of gas to/by Union under the Contract. Either party will give the other party reasonable notice of its intention to carry out the acts herein specified. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

5. Calibration and Test of Measuring Equipment: The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Shipper, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment tested is found to be in error by not more than two per cent (2%). If, upon test, any measuring equipment is found to be in error by not more than two per cent (2%), previous recordings of such equipment shall be considered accurate in computing receipts and deliveries of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than two percent (2%), the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations, as may be amended from time to time and in accordance with any successor statutes and regulations.

6. Preservation of Metering Records: Union and Shipper shall each preserve for a period of at least six (6) years all test data, and other relevant records.

7. Error in Metering or Meter Failure: In the event of an error in metering or a meter failure, (such error or failure being determined through check measurement by Union or any other available method), then Shipper shall enforce its rights as Shipper with the Interconnecting Pipeline(s) to remedy such error or failure including enforcing any inspection and/or verification rights and procedures.

VIII. BILLING

1. Monthly Billing Date: Union shall render bills on or before the tenth (10th) day of each month for all Transportation Services furnished during the preceding Month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding Month's billing, an adjustment based on any difference between actual quantities and estimated quantities, without any interest charge. If presentation of a bill to Shipper is delayed after the tenth (10th) day of the month, then the time of payment shall be extended accordingly, unless Shipper is responsible for such delay.

2. Right of Examination: Both Union and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Contract.

3. Amendment of Statements: For the purpose of completing a final determination of the actual quantities of gas handled in any of the Transportation Services to Shipper, the parties shall have the right to amend their statement for a period equal to the time during which the Interconnecting Pipeline retains the right to amend their statements, which period shall not exceed three (3) years from the date of termination of the Contract.

IX. PAYMENTS

1. Monthly Payments: Shipper shall pay the invoiced amount directly into Union's bank account as directed on the invoice on or before the twentieth (20^{th}) day of each month. If the payment date is not a Business Day, then payment must be received in Union's account on the first Business Day preceding the twentieth (20th) day of the month.

2. Remedies for Non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due,

   a. Shipper shall pay to Union interest on the unpaid portion of the bill accruing at a rate per annum equal to the minimum commercial lending rate of Union's principal banker in effect from time to time from the due date until the date of payment; and,

   b. If such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the Contract, may suspend Services until such amount is paid. Notwithstanding such suspension, all demand charges shall continue to accrue hereunder as if such suspension were not in place.

   If Shipper in good faith disputes the amount of any such bill or part thereof Shipper shall pay to Union such amounts as it concedes to be correct. At any time thereafter, within twenty (20) days of a demand made by Union, Shipper shall furnish financial assurances satisfactory to Union, guaranteeing payment to Union of the amount ultimately found due upon such bill after a final determination. Such a final determination may be reached either by agreement, arbitration decision or judgement of the courts, as may be the case. Union shall not be entitled to suspend Services because of such non-payment unless and until default occurs in the conditions of such financial assurances or default occurs in payment of any other amount due to Union hereunder.

   Notwithstanding the foregoing, Shipper is not relieved from the obligation to continue its deliveries of gas to Union under the terms of any agreement, where Shipper has contracted to deliver specified quantities of gas to Union.

3. Billing Adjustments: If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, Union shall refund the amount of any such overcharge and interest shall accrue from and including the first day of such overcharge as paid to the date of refund and shall be calculated but not compounded at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker, and the Shipper shall pay the amount of any such undercharge, but without interest. In the event Union renders a bill to Shipper based upon measurement estimates, the required adjustment to reflect actual measurement shall be made on the bill next following the determination of such actual measurement, without any charge of interest. In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "**bill next following**" shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within three (3) years from the date of the incorrect billing. In the event any refund is issued with Shipper's bill, the aforesaid date of refund shall be deemed to be the date of the issue of bill.

4. Taxes:

   In addition to the charges and rates as per the applicable rate schedules and price schedules, Shipper shall pay all Taxes which are imposed currently or subsequent to the execution of the Contract by any legal authority having jurisdiction and any amount in lieu of such Taxes paid or payable by Union.

5. Set Off:

   If either party shall, at any time, be in arrears under any of its payment obligations to the other party under the Contract, then the party not in arrears shall be entitled to reduce the amount payable by it to the other party in arrears under the Contract, or any other contract, by an amount equal to the amount of such arrears or other indebtedness to the other party. In addition to the foregoing remedy, Union may, upon forty-eight (48) hours verbal notice, to be followed by written notice, take possession of any or all of Shipper's gas under the Contract or any enhancement to the Contract, which shall be deemed to have been assigned to Union, to reduce such arrears or other indebtedness to Union.

X. ARBITRATION

If and when any dispute, difference or question shall arise between the parties hereto touching the Contract or anything herein contained, or the construction hereof, or the rights, duties or liabilities of the parties in relation to any matter hereunder, the matter in dispute shall be submitted and referred to arbitration within ten (10) days after written request of either party. Upon such request each party shall appoint an arbitrator, and the two so appointed shall appoint a third. A majority decision of the arbitrators shall be final and binding upon both parties. In all other respects the provisions of the Arbitration Act, 1991, or any act passed in amendment thereof or substitution therefore, shall apply to each such submission. Operations under the Contract shall continue, without prejudice, during any such arbitration and the costs attributable to such arbitration shall be shared equally by the parties hereto.

XI. FORCE MAJEURE

1. The term "**force majeure**" as used herein shall mean acts of God, strikes, lockouts or any other industrial disturbance, acts of the public enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or lines of pipe, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority (civil or military), any act or omission that is excused by any event or occurrence of the character herein defined as constituting force majeure, any act or omission by parties not controlled by the party having the difficulty and any other similar cases not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

2. In the event that either the Shipper or Union is rendered unable, in whole or in part, by force majeure, to perform or comply with any obligation or condition of the Contract, such party shall give notice and full particulars of such force majeure in writing delivered by hand, fax or other direct written electronic means to the other party as soon as possible after the occurrence of the cause relied on and subject to the provision of this Article.

3. Neither party shall be entitled to the benefit of the provisions of force majeure hereunder if any or all of the following circumstances prevail: the failure resulting in a condition of force majeure was caused by the negligence of the party claiming suspension; the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation); the party claiming suspension failed to resume the performance of such condition obligations with reasonable dispatch; the failure was caused by lack of funds; the party claiming suspension did not, as soon as possible after determining, or within a period within which it should acting reasonably have determined, that the occurrence was in the nature of force majeure and would affect its ability to observe or perform any of its conditions or obligations under the Contract, give to the other party the notice required hereunder.

4. The party claiming suspension shall likewise give notice as soon as possible after the force majeure condition is remedied, to the extent that the same has been remedied, and that such party has resumed or is then in a position to resume the performance of the obligations and conditions of the Contract.

5. An event of force majeure on Union's system will excuse the failure to deliver gas by Union or the failure to accept gas by Union hereunder, and both parties shall be excused from performance of their obligations hereunder, except for payment obligations, to the extent of and for the duration of the force majeure.

6. Upstream or Downstream Force Majeure: An event of force majeure upstream or downstream of Union's system shall not relieve Shipper of any payment obligations.

7. Delay of Firm Transportation Services: Despite Article XI herein, if Union is prevented, by reason of an event of force majeure on Union's system from delivering gas on the Day or Days upon which Union has accepted gas from Shipper, Union shall thereafter make all reasonable efforts to deliver such quantities as soon as practicable and on such Day or Days as are agreed to by Shipper and Union. If Union accepts such gas on this basis, Shipper shall not receive any demand charge relief as contemplated under Article XI herein.

8. Demand Charge Relief for Firm Transportation Services: Despite Article XI herein, if on any Day Union fails to accept gas from Shipper by reason of an event of force majeure on Union's system and fails to deliver the quantity of gas nominated hereunder by Shipper up to the firm Contract Demand for that Contract, then for that Day the Monthly demand charge shall be reduced by an amount equal to the applicable Daily Demand Rate, as defined in this paragraph, multiplied by the difference between the quantity of gas actually delivered by Union during such Day and the quantity of gas which Shipper in good faith nominated on such Day. The term "**Daily Demand Rate**" shall mean the Monthly demand charge or equivalent pursuant to the C1 Rate Schedule divided by the number of days in the month for which such rate is being calculated.

9. If, due to the occurrence of an event of force majeure as outlined above, the capacity for gas deliveries by Union is impaired, it will be necessary for Union to curtail Shipper's gas receipts to Union hereunder, via proration based on utilization of such facilities for the Day. This prorating shall be determined by multiplying the capability of such facilities as available downstream of the impairment on the Day, by a fraction where the numerator is Shipper's nominated firm quantity and the denominator is the total of all such nominated firm quantities for nominated services and planned consumption for in-franchise customers on the Day. For the purposes of this Article XI, firm services shall mean all firm services provided by Union to in-franchise customers and ex-franchise shippers.

XII. <u>DEFAULT AND TERMINATION</u>

In case of the breach or non-observance or non-performance on the part of either party hereto of any covenant, proviso, condition, restriction or stipulation contained in the Contract (but not including herein failure to take or make delivery in whole or in part of the gas delivered to/by Union hereunder occasioned by any of the reasons provided for in Article XI herein) which has not been waived by the other party, then and in every such case and as often as the same may happen, the non-defaulting party may give written notice to the defaulting party requiring it to remedy such default and in the event of the defaulting party failing to remedy the same within a period of thirty (30) days from receipt of such notice, the non-defaulting party may at its sole option declare the Contract to be terminated and thereupon the Contract shall be terminated and be null and void for all purposes other than and except as to any liability of the parties under the same incurred before and subsisting as of termination. The right hereby conferred upon each party shall be in addition to, and not in derogation of or in substitution for, any other right or remedy which the parties respectively at law or in equity shall or may possess.

XIII. <u>AMENDMENT</u>

Subject to Article XV herein and the ability of Union to amend the applicable rate schedules and price schedules, with the approval of the OEB (if required), no amendment or modification of the Contract shall be effective unless the same shall be in writing and signed by each of the Shipper and Union.

XIV. <u>NON-WAIVER AND FUTURE DEFAULT</u>

No waiver of any provision of the Contract shall be effective unless the same shall be in writing and signed by the party entitled to the benefit of such provision and then such waiver shall be effective only in the specific instance and for the specified purpose for which it was given. No failure on the part of Shipper or Union to exercise, and no course of dealing with respect to, and no delay in exercising, any right, power or remedy under the Contract shall operate as a waiver thereof.

XV. <u>LAWS, REGULATIONS AND ORDERS</u>

The Contract and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Contract shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Contract.

XVI. ALLOCATION OF CAPACITY

1. A potential shipper may request transportation service on Union's system at any time. Any request for C1 transportation service must include: potential shipper's legal name, Receipt Point(s), Delivery Point(s), Commencement Date, Initial Term, Contract Demand, proposed payment, and type of transportation service requested.

2. If requests for firm transportation services cannot be met through existing capacity such that the only way to satisfy the requests for transportation service would require the construction of Expansion Facilities which create new capacity, Union shall allocate any such new capacity by open season, subject to the terms of the open season, and these General Terms and Conditions.

3. If requests for long-term transportation service can be met through existing facilities upon which long-term capacity is becoming available, Union shall allocate such long-term capacity by open season, subject to the terms of the open season, and these General Terms and Conditions. "**Long-term**", for the purposes of this Article XVI, means, in the case of a transportation service, a service that has a term of one year or greater.

4. Capacity requests received during an open season shall be awarded starting with those bids with the highest economic value. If the economic values of two or more independent bids are equal, then service shall be allocated on a pro-rata basis. The economic value shall be based on the net present value which shall be calculated based on the proposed per-unit rate and the proposed term of the contract and without regard to the proposed Contract Demand ("**NPV**").

5. Union may at any time allocate capacity to respond to any C1 transportation service request through an open season. If a potential shipper requests C1 transportation service that can be provided through Available Capacity that was previously offered by Union in an open season but was not awarded, then:

   a. Any such request must conform to the requirements of Section 1 of this Article XVI;

   b. Union shall allocate capacity to serve such request pursuant to this Section 5, and subject to these General Terms and Conditions and Union's standard form C1 transportation contract;

   c. Union may reject a request for C1 transportation service for any of the following reasons:

      i) if there is insufficient Available Capacity to fully meet the request, but if that is the only reason for rejecting the request for service, Union must offer to supply the Available Capacity to the potential shipper;

      ii) if the proposed monthly payment is less than Union's Monthly demand charge plus fuel requirements for the applicable service;

      iii) if prior to Union accepting the request for transportation service Union receives a request for transportation service from one or more other potential shippers and there is, as a result, insufficient Available Capacity to service all the requests for service, in which case Union shall follow the procedure in Section 5 d hereof;

      iv) if Union does not provide the type of transportation service requested; or

      v) if all of the conditions precedent specified in Article XXI Sections 1 and 2 herein have not been satisfied or waived.

   d. Union will advise the potential shipper in writing whether Union accepts or rejects the request for service, subject to Article XVI 5(c) within 5 calendar days of receiving a request for C1 transportation service. If Union rejects a request for service, Union shall inform the potential shipper of the reasons why its request is being rejected; and

   e. If Union has insufficient Available Capacity to service all pending requests for transportation service Union may:

      i) Reject all the pending requests for transportation service and conduct an open season; or

      ii) Union shall inform all the potential shippers who have submitted a pending request for transportation service that it does not have sufficient capacity to service all pending requests for service, and Union shall provide all such potential shippers with an equal opportunity to submit a revised request for service. Union shall then allocate the Available Capacity to the request for transportation service with the highest economic value to Union. If the economic values of two or more requests are equal, then service shall be allocated on a pro-rata basis. The economic value of any request shall be based on the NPV.

XVII. RENEWALS

Contracts with an Initial Term of five (5) years or greater, with Receipt Points and Delivery Points of Parkway or Kirkwall or Dawn (Facilities), will continue in full force and effect beyond the Initial Term, automatically renewing for a period of one (1) year, and every one (1) year thereafter. Shipper may reduce the Contract Demand or terminate the Contract with notice in writing by Shipper at least two (2) years prior to the expiration thereof.

For all other contracts, the Contract will continue in full force and effect until the end of the Initial Term, but shall not renew.

XVIII. SERVICE CURTAILMENT

1. Union shall have the right to curtail or not to schedule part or all of Transportation Services, in whole or in part, on all or a portion of its pipeline system at any time for reasons of Force Majeure or when, in Union sole discretion, acting reasonably, capacity or operating conditions so require or it is desirable or necessary to make modifications, repairs or operating changes to its pipeline system. Union shall provide Shipper such notice of such curtailment as is reasonable under the circumstances. If due to any cause whatsoever Union is unable to receive or deliver the quantities of Gas which Shipper has requested, then Union shall order curtailment by all Shippers affected and to the extent necessary to remove the effect of the disability. Union has a priority of service policy to determine the order of service curtailment. In order to place services on the priority of service list, Union considers the following business principles: appropriate level of access to core services, customer commitment, encouraging appropriate contracting, materiality, price and term, and promoting and enabling in-franchise consumption.

   The Priority ranking for all services utilizing Union Gas' storage, transmission and distribution system as applied to both in-franchise and ex-franchise services are as follows; with number 1 having the highest priority and the last interrupted.

   1. Firm In-franchise Transportation and Distribution services and firm Ex-franchise services (Note 1)
   2. In-franchise Interruptible Distribution services
   3. C1/M12 IT Transport and IT Exchanges with Take or Pay rates
   4. Balancing (Hub Activity) < = 100 GJ/d; Balancing (Direct Purchase) < = 500 GJ/d; In-franchise distribution authorized overrun (Note 3)
   5. C1/M12 IT Transport and IT Exchanges at premium rates
   6. C1/M12 Overrun < = 20% of CD (Note 4)
   7. Balancing (Direct Purchase) > 500 GJ/d
   8. Balancing (Hub Activity) > 100 GJ/d; C1/M12 IT Transport and IT Exchanges
   9. C1/M12 Overrun > 20% of CD
   10. C1/M12 IT Transport and IT Exchanges at a discount
   11. Late Nominations

   Notes:
   1. Nominated services must be nominated on the NAESB Timely Nomination Cycle otherwise they are considered to be late nomination and are therefore interruptible.
   2. Higher value or more reliable IT is contemplated in the service and contract, when purchase at market competitive prices.
   3. Captures the majority of customers that use Direct Purchase balancing transactions.
   4. Captures the majority of customers that use overrun.

2. Union reserves the right to change its procedures for sharing interruptible capacity and will provide Shipper with two (2) months prior notice of any such change.

3. Maintenance: Union's facilities from time to time may require maintenance or construction. If such maintenance or construction is required, and in Union's sole opinion, acting reasonably, such maintenance or construction may impact

Union's ability to meet Shipper's requirements, Union shall provide at least ten (10) days notice to Shipper, except in the case of an emergency. In the event the maintenance impacts on Union's ability to meet Shipper's requirements, Union shall not be liable for any damages and shall not be deemed in breach of the Contract. To the extent that Union's ability to accept and/or deliver Shipper's gas is impaired, the Monthly demand charge shall be reduced in accordance with Article XI Section 8 and available capacity allocated in accordance with Article XI Section 9 herein.

Union shall use reasonable efforts to determine a mutually acceptable period during which such maintenance or construction will occur and also to limit the extent and duration of any impairments. Union will endeavour to schedule and complete the maintenance and construction, which would normally be expected to impact on Union's ability to meet Shipper's requirements, during the period from April 1 through to November 1.

XIX. SHIPPER'S REPRESENTATIONS AND WARRANTIES

1. Shipper's Warranty: Shipper warrants that it will, if required, maintain, or have maintained on its behalf, all external approvals including the governmental, regulatory, import/export permits and other approvals or authorizations that are required from any federal, state or provincial authorities for the gas quantities to be handled under the Contract. Shipper further warrants that it shall maintain in effect the Facilitating Agreements.

2. Financial Representations: Shipper represents and warrants that the financial assurances (including the Initial Financial Assurances and Security) (if any) shall remain in place throughout the term hereof, unless Shipper and Union agree otherwise. Shipper shall notify Union in the event of any change to the financial assurances throughout the term hereof. Should Union have reasonable grounds to believe that Shipper will not be able to perform or continue to perform any of its obligations under the Contract as a result of one of the following events ("**Material Event**");

   a. Shipper is in default, which default has not been remedied, of the Contract or is in default of any other material contract with Union or another party; or,

   b. Shipper's corporate or debt rating falls below investment grade according to at least one nationally recognized rating agency; or,

   c. Shipper ceases to be rated by a nationally recognized agency; or,

   d. Shipper has exceeded credit available as determined by Union from time to time,

   then Shipper shall within fourteen (14) days of receipt of written notice by Union, obtain and provide to Union a letter of credit or other security in the form and amount reasonably required by Union (the "**Security**"). The Security plus the Initial Financial Assurances shall not exceed twelve (12) months of Monthly demand charges (in accordance with Article IX herein) multiplied by Contract Demand. In the event that Shipper does not provide to Union such Security within such fourteen (14) day period, Union may deem a default under the Default and Termination provisions of Article XII herein.

   In the event that Shipper in good faith, reasonably believes that it should be entitled to reduce the amount of or value of the Security previously provided, it may request such a reduction from Union and to the extent that the Material Event has been mitigated or eliminated, Union shall return all or a portion of the Security to Shipper within fourteen (14) Business Days after receipt of the request.

   The following paragraphs 3 and/or 4 are only applicable if indicated in Schedule 1 of the Contract.

3. Point of Consumption Warranty: Shipper represents and warrants that, throughout the term of this Contract, all quantities of gas received by Union hereunder at the Receipt Point and/or all Loaned Quantities will be consumed in the U.S.A. Should any quantities of gas hereunder be directed to an end user in Canada, Shipper shall immediately notify Union that such quantities of gas will be consumed in Canada, as failure to do so will make Shipper liable to Union for any Taxes and related interest and penalties thereon, made as a result of such change.

4. Tax Registration re GST: Shipper warrants and represents that it is unregistered and a Non-Resident for purposes of the Excise Tax Act. Shipper agrees to notify Union within ten (10) working days if it becomes registered. "GST/HST" shall

mean the Government of Canada's Goods and Services Tax or Harmonized Sales Tax as legislated under The Excise Tax Act, as may be amended from time to time.

XX. MISCELLANEOUS PROVISIONS

1. Permanent Assignment: Shipper may assign the Contract to a third party ("Assignee"), up to the Contract Demand, (the "Capacity Assigned"). Such assignment shall require the prior written consent of Union and release of obligations by Union for the Capacity Assigned from the date of assignment. Such consent and release shall not be unreasonably withheld and shall be conditional upon the Assignee providing, amongst other things, financial assurances as per Article XXI herein. Any such assignment will be for the full rights, obligations and remaining term of the Contract as relates to the Capacity Assigned.

2. Temporary Assignment: Shipper may, upon notice to Union, assign all or a part of its service entitlement under the Contract (the "Assigned Quantity") and the corresponding rights and obligations to an Assignee on a temporary basis for not less than one calendar month. Such assignment shall not be unreasonably withheld and shall be conditional upon the Assignee executing the Facilitating Agreement as per Article XXI herein. Notwithstanding such assignment, Shipper shall remain obligated to Union to perform and observe the covenants and obligations contained herein in regard to the Assigned Quantity to the extent that Assignee fails to do so.

3. Title to Gas: Shipper represents and warrants to Union that Shipper shall have good and marketable title to, or legal authority to deliver to Union, all gas delivered to Union hereunder. Furthermore, Shipper hereby agrees to indemnify and save Union harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of claims of any or all third parties to such gas or on account of Taxes, or other charges thereon.

XXI. PRECONDITIONS TO TRANSPORTATION SERVICES

1. The obligations of Union to provide Transportation Services hereunder are subject to the following conditions precedent, which are for the sole benefit of Union and which may be waived or extended in whole or in part in the manner provided in the Contract:

    a. Union shall have obtained, in form and substance satisfactory to Union, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required to provide the Transportation Services; and,

    b. Union shall have obtained all internal approvals that are necessary or appropriate to provide the Transportation Services; and,

    c. Union shall have received from Shipper the requisite financial assurances reasonably necessary to ensure Shipper's ability to honour the provisions of the Contract (the "**Initial Financial Assurances**"). The Initial Financial Assurances, if required, will be as determined solely by Union; and,

    d. Shipper and Union shall have entered into the Interruptible HUB Service Contract or equivalent (the "**Facilitating Agreement**") with Union.

2. The obligations of Shipper hereunder are subject to the following conditions precedent, which are for the sole benefit of Shipper and which may be waived or extended in whole or in part in the manner provided in the Contract:

    a. Shipper shall, as required, have entered into the necessary contracts with Union and/or others to facilitate the Transportation Services contemplated herein, including contracts for upstream and downstream transportation, and shall specifically have an executed and valid Facilitating Agreement; and shall, as required, have entered into the necessary contracts to purchase the gas quantities handled under the Contract; and,

    b. Shipper shall have obtained, in form and substance satisfactory to Shipper, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required from federal, state, or provincial authorities for the gas quantities handled under the Contract; and,

c. Shipper shall have obtained all internal approvals that are necessary or appropriate for the Shipper to execute the Contract.

3. Union and Shipper shall each use due diligence and reasonable efforts to satisfy and fulfil the conditions precedent specified in this Article XXI Section 1 a, c, and d and Section 2 a and b. Each party shall notify the other forthwith in writing of the satisfaction or waiver of each condition precedent for such party's benefit. If a party concludes that it will not be able to satisfy a condition precedent that is for its benefit, such party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations thereunder.

4. If any of the conditions precedent in this Article XXI Section 1 c or Section 2 are not satisfied or waived by the party entitled to the benefit of that condition by the Conditions Date as such term is defined in the Contract, then either party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations hereunder, provided that any rights or remedies that a party may have for breaches of the Contract prior to such termination and any liability a party may have incurred before such termination shall not thereby be released.

SCHEDULE "B"

RATE C1
NOMINATIONS

a) For Services provided either under this rate schedule or referenced to this rate schedule:

i) For Services required on any day Shipper shall provide Union with a nomination (the "Shipper's Nomination") of the quantity it desires to be handled at the applicable Receipt Point, and/or Delivery Point. Such Shipper's Nomination is to be provided in writing so as to be received by Union's Gas Management Services on or before 1230 hours in the Eastern time zone, unless agreed to otherwise in writing by the parties, on the business days immediately preceding the day for which service is requested.

ii) If, in Union's sole opinion, operating conditions permit, a change in Shipper's Nomination may be accepted after 1230 hours in the Eastern time zone.

iii) For customers electing firm all day transportation, nominations shall be provided to Union's Gas Management Services as outlined in the F24 –T Agreement.

b) Union shall determine whether or not all or any portion of Shipper's Nomination will be accepted. In the event Union determines that it will not accept such nomination, Union shall advise Shipper, on or before 1730 hours in the Eastern time zone on the business day immediately preceding the day for which service is requested, of the reduced quantity (the "Quantity Available") for Services at the applicable points. Forthwith after receiving such advice from Union but no later than 1800 hours in the Eastern time zone on the same day, Shipper shall provide a "Revised Nomination" to Union which shall be no greater than the Quantity Available. If such Revised Nomination is not provided within the time allowed as required above or such Revised Nomination is greater than the Quantity Available, then the Revised Nomination shall be deemed to be the Quantity Available. If the Revised Nomination (delivered within the time allowed as required above) is less than the Quantity Available, then such lesser amount shall be the Revised Nomination.

c) That portion of a Shipper's Nomination or Revised Nomination, as set out in (a) and (b), above, which Union shall accept for Services hereunder, shall be known as Shipper's "Authorized Quantity".

d) If on any day the actual quantities handled by Union, for each of the Services authorized, exceed Shipper's Authorized Quantity, and such excess was caused by either Shipper's incorrect nomination or by its delivering or receiving too much gas, then the amount by which the actual quantities handled for each of the Services exceed Shipper's Authorized Quantity, such excess shall be deemed "Unauthorized Overrun".

e) The daily quantity of gas nominated by Shipper will be delivered by Shipper at rates of flow that are as nearly constant as possible, however, Union shall use reasonable efforts to take receipt of gas on any day at an hourly rate of flow up to one twentieth (1/20) of the quantity received for that day. Union shall have the right to limit Services when on any day the cumulative hourly imbalance between receipts and deliveries exceeds one twentieth (1/20) of the quantity handled for that day, for each applicable Service.

f) A nomination for a daily quantity of gas on any day shall remain in effect and apply to subsequent days unless and until Union receives a new nomination from the Shipper or unless Union gives Shipper written notice that it is not acceptable in accordance with either (a) or (b) of this schedule.

g) Except for periods of gas or quantity balancing as provided in the Contract, nominations by Shipper for deliveries to Union and redeliveries by Union shall be the same delivery of gas by Union either to Shipper or a Shipper's Account with Union.

SCHEDULE "B 2010"

RATE C1
NOMINATIONS

1. For Transportation Services required on any Day under the Contract, Shipper shall provide Union with a nomination(s) providing the Shipper's requested Receipt Point(s), contract numbers, the applicable service, the quantity of Gas to be transported, the requested Delivery Point(s), and such additional information as Union determines to be necessary (a "**Nomination**").

2. All Nominations shall be submitted by electronic means via *Unionline*. Union, in its sole discretion, may amend or modify the nominating procedures or *Unionline* at any time. Nominations shall be submitted so as to be received by Union in accordance with timelines established by Union, which reflect the NAESB standard nomination cycles. Union will accept all nominations on each of the nomination cycles. Nominations made after the applicable deadline shall not be accepted except at the sole discretion of Union. All times referred to herein are Eastern Clock Time. For greater certainty, NAESB nomination cycle timelines are as follows:

    a. The Timely Nomination Cycle: 12:45 pm for Nominations leaving control of the nominating party; 3:30 pm for receipt of Quantities Available by Shipper; 4:30 pm for receipt of completed confirmations by Union from upstream and downstream connected parties; 5:30 pm for receipt of Scheduled Quantities by Shipper (Day prior to flow).

    b. The Evening Nomination Cycle: 7:00 pm for Nominations leaving control of the nominating party; 9:00 pm for receipt of Quantities Available by Shipper; 10:00 pm for receipt of completed confirmations by Union from upstream and downstream connected parties; 11:00 pm for receipt of Scheduled Quantities by Shipper (Day prior to flow).

    c. The Intra-day 1 Nomination Cycle: 11:00 am for Nominations leaving control of the nominating party; 1:00 pm for receipt of Quantities Available by Shipper; 2:00 pm for receipt of completed confirmations by Union from upstream and downstream connected parties; 3:00 pm for receipt of Scheduled Quantities Available by Shipper, on Day. Quantities Available resulting from Intra-day 1 Nominations should be effective at 6:00 pm on same Day.

    d. The Intra-day 2 Nomination Cycle: 6:00 pm for Nominations leaving control of the nominating party: 8:00 pm for receipt of Quantities Available by Shipper; 9:00 pm for receipt of completed confirmations by Union from upstream and downstream connected parties; 10:00 pm for receipt of Scheduled Quantities by Shipper on Day. Quantities Available resulting from Intra-day 2 Nominations should be effective at 10:00 pm on same Day.

3. Union shall determine whether or not all or any portion of the Nomination will be scheduled at each nomination cycle. With respect to each nomination cycle, in the event Union determines that it will not schedule such Nomination, Union shall advise Shipper of the reduced quantity (the "**Quantities Available**") for Transportation Services at the applicable points as outlined in each nomination cycle. After receiving such advice from Union, but no later than one half hour after the Quantities Available deadline as outlined in each nomination cycle, Shipper shall provide a revised nomination ("**Revised Nomination**") to Union which shall be no greater than the Quantity Available. If such Revised Nomination is not provided within the time allowed as required above or such Revised Nomination is greater than the Quantities Available, then the Revised Nomination shall be deemed to be the Quantities Available. If the Revised Nomination (delivered with the time allowed as required above) is less than the Quantity Available, then such lessor amount shall be the Revised Nomination.

4. For Shippers electing firm all day transportation service, nominations shall be provided to Union's Gas Management Services as outlined in the F24 –T Agreement.

5. For Transportation Services requiring Shipper to provide compressor fuel in kind, the nominated fuel requirements will be calculated by rounding to the nearest whole GJ.

6. All Timely Nominations shall have rollover options. Specifically, Shippers shall have the ability to nominate for several days, months or years, provided the Nomination start date and end date are both within the term of the Transportation Agreement.

7. Nominations received after the nomination deadline shall, if accepted by Union, be scheduled after Nominations received before the nomination deadline.

8. All Services are required to be nominated in whole Gigajoules (GJ).

9. To the extent Union is unable to complete a Nomination confirmation due to inaccurate, untimely or incomplete data involving an Interconnecting Pipeline entity, Union shall undertake reasonable efforts to confirm the transaction on a non-discriminatory basis until such time that the transaction is adequately verified by the parties, or until such time that Union determines that the Nomination is invalid at which time the Union shall reject the Nomination.

10. That portion of a Shipper's Nomination or Revised Nomination, as set out in paragraphs 1 and 3 above, which Union shall schedule for Transportation Services hereunder, shall be known as Shipper's "**Authorized Quantity**".

11. If on any day the actual quantities handled by Union, for each of the Transportation Services authorized, exceed Shipper's Authorized Quantity, and such excess was caused by either Shipper's incorrect nomination or by its delivering or receiving too much gas, then the amount by which the actual quantities handled for each of the Transportation Services exceed Shipper's Authorized Quantity shall be deemed "**Unauthorized Overrun**".

12. The daily quantity of gas nominated by Shipper will be delivered by Shipper at rates of flow that are as nearly constant as possible, however, Union shall use reasonable efforts to take receipt of gas on any day at an hourly rate of flow up to one twentieth ($1/20^{th}$) of the quantity received for that day. Union shall have the right to limit Transportation Services when on any day the cumulative hourly imbalance between receipts and deliveries exceeds one twentieth ($1/20^{th}$) of the quantity handled for that day, for each applicable Transportation Service.

13. The parties hereto recognize that with respect to Transportation Services, on any day, receipts of gas by Union and deliveries of gas by Union may not always be exactly equal, but each party shall cooperate with the other in order to balance as nearly as possible the quantities transacted on a daily basis, and any imbalances arising shall be allocated to the Facilitating Agreement and shall be subject to the respective terms and charges contained therein, and shall be resolved in a timely manner.

14. Shipper may designate a third party as agent for purposes of providing a Nomination, and for giving and receiving notices related to Nominations, and Union shall only accept nominations from the agent. Shipper shall provide Union with written notice of such designation, such notice to be acceptable to Union. Any such designation, if acceptable to Union, shall be effective starting the Month following the receipt of the written notice and will remain in effect until revoked in writing by Shipper.

<u>SCHEDULE "C 2010"</u>

RATE C1
RECEIPT AND DELIVERY POINTS AND PRESSURES

1. Receipt and Delivery Points:

The following defines each Receipt Point and/or Delivery Point, as indicated (R= Receipt Point; D= Delivery Point)

R, D	**<u>DAWN (FACILITIES):</u>**	Union's Compressor Station site situated in the northwest corner of Lot Twenty-Five (25), Concession II, in the Township of Dawn-Euphemia, in the County of Lambton. This point is applicable for quantities of gas that have been previously transported or stored under other contracts that Shipper may have in place with Union.
R, D	**<u>DAWN (TCPL):</u>**	At the junction of Union's and TCPL's facilities, at or adjacent to Dawn (Facilities).
R, D	**<u>DAWN (TECUMSEH):</u>**	At the junction of Union's and Enbridge Gas Distribution Inc.'s (Enbridge) Tecumseh Gas Storage's facilities, at or adjacent to Dawn (Facilities).
R, D	**<u>DAWN (TSLE):</u>**	At the junction of Union's and Enbridge Gas Distribution Inc.'s ("**Enbridge**") NPS 16 Tecumseh Sombra Line Extension facilities; at or adjacent to Dawn (Facilities)
R, D	**<u>DAWN (VECTOR):</u>**	At the junction of Union's and Vector Pipeline Limited Partnership ("**Vector**") facilities, at or adjacent to Dawn (Facilities).
R, D	**<u>PARKWAY (TCPL):</u>**	At the junction of Union's and TCPL's facilities, at or adjacent to Union's facilities situated in the Part Lot 9 and Part Lot 10, Concession IX, New Survey, Town of Milton, Regional Municipality of Halton (now part of City of Mississauga)
R, D	**<u>KIRKWALL:</u>**	At the junction of Union's and TCPL's facilities at or adjacent to Union's facilities situated in Part Lot Twenty-Five (25), Concession 7, Town of Flamborough.
D	**<u>PARKWAY (CONSUMERS)</u>:**	At the junction of Union's and Enbridge's facilities, at or adjacent to Union's facilities situated in Part Lot 9 and Part Lot 10, Concession IX, New Survey, Town of Milton, Regional Municipality of Halton (now part of City of Mississauga)
D	**<u>LISGAR:</u>**	At the junction of the facilities of Union and Enbridge situated at 6620 Winston Churchill Boulevard, City of Mississauga.
R, D	**<u>OJIBWAY:</u>**	At the junction of Union's and Panhandle Eastern Pipe Line Company, LP's ("**Panhandle**") facilities, located at the International Border between Canada and the United States in the St. Clair River.
R, D	**<u>ST.CLAIR (MICHCON):</u>**	At the junction of Michigan Consolidated Gas Company's ("**MichCon**") and St. Clair Pipelines L.P.'s facilities, located at the International Border between Canada and the United States in the St. Clair River.

R, D	**BLUEWATER:**	At the junction of Bluewater Gas Storage, LLC ("**Bluewater**") and St. Clair Pipelines L.P.'s facilities, located at the International Border between Canada and the United States in the St. Clair River.

2. Receipt and Delivery Pressures:

(a) All Gas tendered by or on behalf of Shipper to Union shall be tendered at the Receipt Point(s) at Union's prevailing pressure at that Receipt Point, or at such pressure as per operating agreements between Union and the applicable Interconnecting Pipeline as amended or restated from time to time.

(b) All Gas tendered by or on behalf of Union to Shipper shall be tendered at the Delivery Point(s) at Union's prevailing pressure at that Delivery Point or at such pressure as per agreements between Union and the applicable Interconnecting Pipeline as amended or restated from time to time.

(c) Under no circumstances shall Union be obligated to receive or deliver gas hereunder at pressures exceeding the maximum allowable operating pressures prescribed under any applicable governmental regulations; nor shall Union be required to make any physical deliveries or to accept any physical receipts which its existing facilities cannot accommodate.

Appendix C

Decision and Rate Order

Summary of Average Rate and Price Adjustment Changes for Rates 25, M5A, M7, T1, T2 Interruptible Contract Services

Board File No. EB-2011-0210

Dated: January 17, 2013

UNION GAS LIMITED
Infranchise Customers
Summary of Average Interruptible Rate and Price Adjustment Changes for Rates 25, M5A, M7, T1 and T2
Effective January 1, 2013

Line No.	Particulars (cents / m^3)	Monthly Charge Increase / (Decrease)	Monthly Demand Charge Increase / (Decrease)	Delivery Commodity Charge Increase / (Decrease)	Delivery - Price Adjustment Increase / (Decrease)	Gas Commodity Price Adjustment Increase / (Decrease)
		(a)	(b)	(c)	(d)	(e)
	Rate 25					
1	All Zones	$185.68		0.7014		(0.2720) (1)
	Rate M5A					
2	Interruptible	$191.80		0.7748		
	Rate M7					
3	Interruptible			0.3196		
4	Seasonal			0.3196		
	Rate T1 Redesign - Interruptible					
5	Transportation - Union supplies fuel	$142.62		0.2227		
6	Transportation - Customer supplies fuel	$142.62		0.2868		
	Rate T2 Redesign - Interruptible					
7	Transportation - Union supplies fuel	$4,206.48		0.2221		
8	Transportation - Customer supplies fuel	$4,206.48		0.2868		

Notes:
(1) Applies to Sales service customers only.

Appendix D

Decision and Rate Order

Customer Notices

Board File No. EB-2011-0210

Dated: January 17, 2013

Important Information About Your Rates
February 2013
Rate 201 – Fort Frances

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 201 customer in the Fort Frances area using 2,200 m^3 of natural gas a year will be $30.07. The enclosed bill uses the new approved rates.

Gas Used

The gas commodity rate decreased by 0.1205 ¢/m^3 to 12.5811 ¢/m^3. For most customers the annual decrease will be about $2.67.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.9510 ¢/m^3 to 4.9387 ¢/m^3. For most customers the annual decrease will be about $20.92.

Storage

The storage rate increased by 0.2783 ¢/m^3 to 2.1507 ¢/m^3. For most customers the annual increase will be about $6.13.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $47.53.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 201 customer in the Fort Frances area using 2,200 m^3 of natural gas a year.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Gas used	12.5811 ¢/m^3	-$2.67
Gas price adjustment	-2.2022 ¢/m^3	$0.00
Transportation to Union Gas	4.9387 ¢/m^3	-$20.92
Transportation price adjustment	1.0523 ¢/m^3	$0.00
Storage	2.1507 ¢/m^3	$6.13
Storage price adjustment	0.2109 ¢/m^3	$0.00
Delivery First 100 m^3 Next 200 m^3 Next 200 m^3 Next 500 m^3 All Over 1,000 m^3	 9.7347 ¢/m^3 9.2102 ¢/m^3 8.8375 ¢/m^3 8.4955 ¢/m^3 8.2130 ¢/m^3	$47.53
Delivery price adjustment	0.4510 ¢/m^3	$0.00
Monthly charge	$21.00	$0.00
Total annual impact		**$30.07**

Important Information About Your Rates
February 2013
Rate 201 – Fort Frances
Energy Marketer Customer

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 201 customer in the Fort Frances area using 2,200 m^3 of natural gas a year and buying gas from an energy marketer will be $32.74. The enclosed bill uses the new approved rates.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.9510 ¢/m^3 to 4.9387 ¢/m^3. For most customers the annual decrease will be about $20.92.

Storage

The storage rate increased by 0.2783 ¢/m^3 to 2.1507 ¢/m^3. For most customers the annual increase will be about $6.13.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $47.53.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 201 customer in the Fort Frances area using 2,200 m^3 of natural gas a year and buying gas from an energy marketer.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Transportation to Union Gas	4.9387 ¢/m^3	-$20.92
Transportation price adjustment	1.0523 ¢/m^3	$0.00
Storage	2.1507 ¢/m^3	$6.13
Storage price adjustment	0.2109 ¢/m^3	$0.00
Delivery First 100 m^3 Next 200 m^3 Next 200 m^3 Next 500 m^3 All Over 1,000 m^3	 9.7347 ¢/m^3 9.2102 ¢/m^3 8.8375 ¢/m^3 8.4955 ¢/m^3 8.2130 ¢/m^3	$47.53
Delivery price adjustment	0.4510 ¢/m^3	$0.00
Monthly charge	$21.00	$0.00
Total annual impact		**$32.74**

* Depending on the terms of your retail energy marketer contract, you may or may not be affected by Union Gas' changes to transportation rates. Please contact your retail energy marketer directly at the phone number that appears on your bill if you have questions.

Important Information About Your Rates
February 2013
Rate 101 – Northwestern Ontario

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 101 customer in Northwestern Ontario using 2,200 m^3 of natural gas a year will be $39.67. The enclosed bill uses the new approved rates.

Gas Used

The gas commodity rate decreased by 0.1205 ¢/m^3 to 12.6353 ¢/m^3. For most customers the annual decrease will be about $2.65.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.7580 ¢/m^3 to 5.5401 ¢/m^3. For most customers the annual decrease will be about $16.67.

Storage

The storage rate increased by 0.5210 ¢/m^3 to 2.3910 ¢/m^3. For most customers the annual increase will be about $11.46.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $47.53.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 101 customer in Northwestern Ontario using 2,200 m^3 of natural gas a year.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Gas used	12.6353 ¢/m^3	-$2.65
Gas price adjustment	-2.2022 ¢/m^3	$0.00
Transportation to Union Gas	5.5401 ¢/m^3	-$16.67
Transportation price adjustment	1.0523 ¢/m^3	$0.00
Storage	2.3910 ¢/m^3	$11.46
Storage price adjustment	0.2109 ¢/m^3	$0.00
Delivery First 100 m^3 Next 200 m^3 Next 200 m^3 Next 500 m^3 All Over 1,000 m^3	 9.7347 ¢/m^3 9.2102 ¢/m^3 8.8375 ¢/m^3 8.4955 ¢/m^3 8.2130 ¢/m^3	$47.53
Delivery price adjustment	0.4510 ¢/m^3	$0.00
Monthly charge	$21.00	$0.00
Total annual impact		**$39.67**

Important Information About Your Rates
February 2013
Rate 101 – Northwestern Ontario
Energy Marketer Customer

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 101 customer in Northwestern Ontario using 2,200 m^3 of natural gas a year and buying gas from an energy marketer will be $42.32. The enclosed bill uses the new approved rates.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.7580 ¢/m^3 to 5.5401 ¢/m^3. For most customers the annual decrease will be about $16.67.

Storage

The storage rate increased by 0.5210 ¢/m^3 to 2.3910 ¢/m^3. For most customers the annual increase will be about $11.46.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $47.53.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 101 customer in Northwestern Ontario using 2,200 m^3 of natural gas a year and buying gas from an energy marketer.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Transportation to Union Gas	5.5401 ¢/m^3	-$16.67
Transportation price adjustment	1.0523 ¢/m^3	$0.00
Storage	2.3910 ¢/m^3	$11.46
Storage price adjustment	0.2109 ¢/m^3	$0.00
Delivery First 100 m^3 Next 200 m^3 Next 200 m^3 Next 500 m^3 All Over 1,000 m^3	 9.7347 ¢/m^3 9.2102 ¢/m^3 8.8375 ¢/m^3 8.4955 ¢/m^3 8.2130 ¢/m^3	$47.53
Delivery price adjustment	0.4510 ¢/m^3	$0.00
Monthly charge	$21.00	$0.00
Total annual impact		**$42.32**

* Depending on the terms of your retail energy marketer contract, you may or may not be affected by Union Gas' changes to transportation rates. Please contact your retail energy marketer directly at the phone number that appears on your bill if you have questions.

Important Information About Your Rates
February 2013
Rate 301 – Northern Ontario

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 301 customer in Northern Ontario using 2,200 m^3 of natural gas a year will be $65.77. The enclosed bill uses the new approved rates.

Gas Used

The gas commodity rate decreased by 0.1205 ¢/m^3 to 12.7025 ¢/m^3. For most customers the annual decrease will be about $2.66.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.0220 ¢/m^3 to 7.6275 ¢/m^3. For most customers the annual decrease will be about $0.48.

Storage

The storage rate increased by 0.9712 ¢/m^3 to 3.2252 ¢/m^3. For most customers the annual increase will be about $21.38.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $47.53.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 301 customer in Northern Ontario using 2,200 m³ of natural gas a year.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Gas used	12.7025 ¢/m³	-$2.66
Gas price adjustment	-2.2022 ¢/m³	$0.00
Transportation to Union Gas	7.6275 ¢/m³	-$0.48
Transportation price adjustment	1.0523 ¢/m³	$0.00
Storage	3.2252 ¢/m³	$21.38
Storage price adjustment	0.2109 ¢/m³	$0.00
Delivery First 100 m³ Next 200 m³ Next 200 m³ Next 500 m³ All Over 1,000 m³	 9.7347 ¢/m³ 9.2102 ¢/m³ 8.8375 ¢/m³ 8.4955 ¢/m³ 8.2130 ¢/m³	$47.53
Delivery price adjustment	0.4510 ¢/m³	$0.00
Monthly charge	$21.00	$0.00
Total annual impact		**$65.77**

Important Information About Your Rates
February 2013
Rate 301 – Northern Ontario
Energy Marketer Customer

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 301 customer in Northern Ontario using 2,200 m^3 of natural gas a year and buying gas from an energy marketer will be $68.43. The enclosed bill uses the new approved rates.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.0220 ¢/m^3 to 7.6275 ¢/m^3. For most customers the annual decrease will be about $0.48.

Storage

The storage rate increased by 0.9712 ¢/m^3 to 3.2252 ¢/m^3. For most customers the annual increase will be about $21.38.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $47.53.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 301 customer in Northern Ontario using 2,200 m^3 of natural gas a year and buying gas from an energy marketer.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Transportation to Union Gas	7.6275 ¢/m^3	-$0.48
Transportation price adjustment	1.0523 ¢/m^3	$0.00
Storage	3.2252 ¢/m^3	$21.38
Storage price adjustment	0.2109 ¢/m^3	$0.00
Delivery First 100 m^3 Next 200 m^3 Next 200 m^3 Next 500 m^3 All Over 1,000 m^3	 9.7347 ¢/m^3 9.2102 ¢/m^3 8.8375 ¢/m^3 8.4955 ¢/m^3 8.2130 ¢/m^3	$47.53
Delivery price adjustment	0.4510 ¢/m^3	$0.00
Monthly charge	$21.00	$0.00
Total annual impact		**$68.43**

* Depending on the terms of your retail energy marketer contract, you may or may not be affected by Union Gas' changes to transportation rates. Please contact your retail energy marketer directly at the phone number that appears on your bill if you have questions.

Important Information About Your Rates
February 2013
Rate 601 – Eastern Ontario

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 601 customer in Eastern Ontario using 2,200 m^3 of natural gas a year will be $61.82. The enclosed bill uses the new approved rates.

Gas Used

The gas commodity rate decreased by 0.1205 ¢/m^3 to 12.7620 ¢/m^3. For most customers the annual decrease will be about $2.66.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.2444 ¢/m^3 to 8.5153 ¢/m^3. For most customers the annual decrease will be about $5.36.

Storage

The storage rate increased by 1.0159 ¢/m^3 to 3.5799 ¢/m^3. For most customers the annual increase will be about $22.34.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $47.50.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 601 customer in Eastern Ontario using 2,200 m^3 of natural gas a year.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Gas used	12.7620 ¢/m^3	-$2.66
Gas price adjustment	-2.2022 ¢/m^3	$0.00
Transportation to Union Gas	8.5153 ¢/m^3	-$5.36
Transportation price adjustment	1.0523 ¢/m^3	$0.00
Storage	3.5799 ¢/m^3	$22.34
Storage price adjustment	0.2109 ¢/m^3	$0.00
Delivery First 100 m^3 Next 200 m^3 Next 200 m^3 Next 500 m^3 All Over 1,000 m^3	 9.7347 ¢/m^3 9.2102 ¢/m^3 8.8375 ¢/m^3 8.4955 ¢/m^3 8.2130 ¢/m^3	$47.50
Delivery price adjustment	0.4510 ¢/m^3	$0.00
Monthly charge	$21.00	$0.00
Total annual impact		**$61.82**

Important Information About Your Rates
February 2013
Rate 601 – Eastern Ontario
Energy Marketer Customer

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 601 customer in Eastern Ontario using 2,200 m^3 of natural gas a year and buying gas from an energy marketer will be $64.48. The enclosed bill uses the new approved rates.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.2444 ¢/m^3 to 8.5153 ¢/m^3. For most customers the annual decrease will be about $5.36.

Storage

The storage rate increased by 1.0159 ¢/m^3 to 3.5799 ¢/m^3. For most customers the annual increase will be about $22.34.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $47.50.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 601 customer in Eastern Ontario using 2,200 m^3 of natural gas a year and buying gas from an energy marketer.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Transportation to Union Gas	8.5153 ¢/m^3	-$5.36
Transportation price adjustment	1.0523 ¢/m^3	$0.00
Storage	3.5799 ¢/m^3	$22.34
Storage price adjustment	0.2109 ¢/m^3	$0.00
Delivery First 100 m^3 Next 200 m^3 Next 200 m^3 Next 500 m^3 All Over 1,000 m^3	 9.7347 ¢/m^3 9.2102 ¢/m^3 8.8375 ¢/m^3 8.4955 ¢/m^3 8.2130 ¢/m^3	$47.50
Delivery price adjustment	0.4510 ¢/m^3	$0.00
Monthly charge	$21.00	$0.00
Total annual impact		**$64.48**

* Depending on the terms of your retail energy marketer contract, you may or may not be affected by Union Gas' changes to transportation rates. Please contact your retail energy marketer directly at the phone number that appears on your bill if you have questions.

Important Information About Your Rates
February 2013
Rate 210 – Fort Frances

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 210 customer in the Fort Frances area using 93,000 m^3 of natural gas a year will be $224.40. The enclosed bill uses the new approved rates.

Gas Used

The gas commodity rate decreased by 0.1205 ¢/m^3 to 12.5811 ¢/m^3. For most customers the annual decrease will be about $112.11.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 1.1385 ¢/m^3 to 4.3170 ¢/m^3. For most customers the annual decrease will be about $1,058.82.

Storage

The storage rate increased by 0.0051 ¢/m^3 to 1.2015 ¢/m^3. For most customers the annual increase will be about $4.72.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $1,390.61.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 210 customer in the Fort Frances area using 93,000 m^3 of natural gas a year.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Gas used	12.5811 ¢/m^3	-$112.11
Gas price adjustment	-2.1961 ¢/m^3	$0.00
Transportation to Union Gas	4.3170 ¢/m^3	-$1,058.82
Transportation price adjustment	1.0341 ¢/m^3	$0.00
Storage	1.2015 ¢/m^3	$4.72
Storage price adjustment	0.1201 ¢/m^3	$0.00
Delivery First 1,000 m^3 Next 9,000 m^3 Next 20,000 m^3 Next 70,000 m^3 All Over 100,000 m^3	 7.7070 ¢/m^3 6.2934 ¢/m^3 5.4872 ¢/m^3 4.9711 ¢/m^3 3.0159 ¢/m^3	$1,390.61
Delivery price adjustment	0.2083 ¢/m^3	$0.00
Monthly charge	$70.00	$0.00
Total annual impact		**$224.40**

Important Information About Your Rates
February 2013
Rate 210 – Fort Frances
Energy Marketer Customer

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 210 customer in the Fort Frances area using 93,000 m^3 of natural gas a year and buying gas from an energy marketer will be $336.51. The enclosed bill uses the new approved rates.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 1.1385 ¢/m^3 to 4.3170 ¢/m^3. For most customers the annual decrease will be about $1,058.82.

Storage

The storage rate increased by 0.0051 ¢/m^3 to 1.2015 ¢/m^3. For most customers the annual increase will be about $4.72.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $1,390.61.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 210 customer in the Fort Frances area using 93,000 m^3 of natural gas a year and buying gas from an energy marketer.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Transportation to Union Gas	4.3170 ¢/m^3	-$1,058.82
Transportation price adjustment	1.0341 ¢/m^3	$0.00
Storage	1.2015 ¢/m^3	$4.72
Storage price adjustment	0.1201 ¢/m^3	$0.00
Delivery First 1,000 m^3 Next 9,000 m^3 Next 20,000 m^3 Next 70,000 m^3 All Over 100,000 m^3	 7.7070 ¢/m^3 6.2934 ¢/m^3 5.4872 ¢/m^3 4.9711 ¢/m^3 3.0159 ¢/m^3	$1,390.61
Delivery price adjustment	0.2083 ¢/m^3	$0.00
Monthly charge	$70.00	$0.00
Total annual impact		**$336.51**

* Depending on the terms of your retail energy marketer contract, you may or may not be affected by Union Gas' changes to transportation rates. Please contact your retail energy marketer directly at the phone number that appears on your bill if you have questions.

Important Information About Your Rates
February 2013
Rate 110 – Northwestern Ontario

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 110 customer in Northwestern Ontario using 93,000 m^3 of natural gas a year will be \$629.57. The enclosed bill uses the new approved rates.

Gas Used

The gas commodity rate decreased by 0.1205 ¢/m^3 to 12.6353 ¢/m^3. For most customers the annual decrease will be about \$112.12.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.9455 ¢/m^3 to 4.9184 ¢/m^3. For most customers the annual decrease will be about \$879.30.

Storage

The storage rate increased by 0.2477 ¢/m^3 to 1.4418 ¢/m^3. For most customers the annual increase will be about \$230.38.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about \$1,390.61.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 110 customer in Northwestern Ontario using 93,000 m³ of natural gas a year.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Gas used	12.6353 ¢/m³	-$112.12
Gas price adjustment	-2.1961 ¢/m³	$0.00
Transportation to Union Gas	4.9184 ¢/m³	-$879.30
Transportation price adjustment	1.0341 ¢/m³	$0.00
Storage	1.4418 ¢/m³	$230.38
Storage price adjustment	0.1201 ¢/m³	$0.00
Delivery First 1,000 m³ Next 9,000 m³ Next 20,000 m³ Next 70,000 m³ All Over 100,000 m³	 7.7070 ¢/m³ 6.2934 ¢/m³ 5.4872 ¢/m³ 4.9711 ¢/m³ 3.0159 ¢/m³	$1,390.61
Delivery price adjustment	0.2083 ¢/m³	$0.00
Monthly charge	$70.00	$0.00
Total annual impact		**$629.57**

Important Information About Your Rates
February 2013
Rate 110 – Northwestern Ontario
Energy Marketer Customer

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 110 customer in Northwestern Ontario using 93,000 m^3 of natural gas a year and buying gas from an energy marketer will be $741.69. The enclosed bill uses the new approved rates.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.9455 ¢/m^3 to 4.9184 ¢/m^3. For most customers the annual decrease will be about $879.30.

Storage

The storage rate increased by 0.2477 ¢/m^3 to 1.4418 ¢/m^3. For most customers the annual increase will be about $230.38.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $1,390.61.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 110 customer in Northwestern Ontario using 93,000 m^3 of natural gas a year and buying gas from an energy marketer.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Transportation to Union Gas	4.9184 ¢/m^3	-$879.30
Transportation price adjustment	1.0341 ¢/m^3	$0.00
Storage	1.4418 ¢/m^3	$230.38
Storage price adjustment	0.1201 ¢/m^3	$0.00
Delivery		
First 1,000 m^3	7.7070 ¢/m^3	$1,390.61
Next 9,000 m^3	6.2934 ¢/m^3	
Next 20,000 m^3	5.4872 ¢/m^3	
Next 70,000 m^3	4.9711 ¢/m^3	
All Over 100,000 m^3	3.0159 ¢/m^3	
Delivery price adjustment	0.2083 ¢/m^3	$0.00
Monthly charge	$70.00	$0.00
Total annual impact		**$741.69**

* Depending on the terms of your retail energy marketer contract, you may or may not be affected by Union Gas' changes to transportation rates. Please contact your retail energy marketer directly at the phone number that appears on your bill if you have questions.

Important Information About Your Rates
February 2013
Rate 310 – Northern Ontario

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 310 customer in Northern Ontario using 93,000 m^3 of natural gas a year will be $1,730.64. The enclosed bill uses the new approved rates.

Gas Used

The gas commodity rate decreased by 0.1205 ¢/m^3 to 12.7025 ¢/m^3. For most customers the annual decrease will be about $112.09.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.2095 ¢/m^3 to 7.0058 ¢/m^3. For most customers the annual decrease will be about $194.84.

Storage

The storage rate increased by 0.6964 ¢/m^3 to 2.2760 ¢/m^3. For most customers the annual increase will be about $647.59.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $1,389.98.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 310 customer in Northern Ontario using 93,000 m^3 of natural gas a year.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Gas used	12.7025 ¢/m^3	-$112.09
Gas price adjustment	-2.1961 ¢/m^3	$0.00
Transportation to Union Gas	7.0058 ¢/m^3	-$194.84
Transportation price adjustment	1.0341 ¢/m^3	$0.00
Storage	2.2760 ¢/m^3	$647.59
Storage price adjustment	0.1201 ¢/m^3	$0.00
Delivery First 1,000 m^3 Next 9,000 m^3 Next 20,000 m^3 Next 70,000 m^3 All Over 100,000 m^3	 7.7070 ¢/m^3 6.2934 ¢/m^3 5.4872 ¢/m^3 4.9711 ¢/m^3 3.0159 ¢/m^3	$1,389.98
Delivery price adjustment	0.2083 ¢/m^3	$0.00
Monthly charge	$70.00	$0.00
Total annual impact		**$1,730.64**

Important Information About Your Rates
February 2013
Rate 310 – Northern Ontario
Energy Marketer Customer

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 310 customer in Northern Ontario using 93,000 m^3 of natural gas a year and buying gas from an energy marketer will be $1,842.73. The enclosed bill uses the new approved rates.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.2095 ¢/m^3 to 7.0058 ¢/m^3. For most customers the annual decrease will be about $194.84.

Storage

The storage rate increased by 0.6964 ¢/m^3 to 2.2760 ¢/m^3. For most customers the annual increase will be about $647.59.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $1,389.98.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 310 customer in Northern Ontario using 93,000 m³ of natural gas a year and buying gas from an energy marketer.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Transportation to Union Gas	7.0058 ¢/m³	-$194.84
Transportation price adjustment	1.0341 ¢/m³	$0.00
Storage	2.2760 ¢/m³	$647.59
Storage price adjustment	0.1201 ¢/m³	$0.00
Delivery		$1,389.98
First 1,000 m³	7.7070 ¢/m³	
Next 9,000 m³	6.2934 ¢/m³	
Next 20,000 m³	5.4872 ¢/m³	
Next 70,000 m³	4.9711 ¢/m³	
All Over 100,000 m³	3.0159 ¢/m³	
Delivery price adjustment	0.2083 ¢/m³	$0.00
Monthly charge	$70.00	$0.00
Total annual impact		**$1,842.73**

* Depending on the terms of your retail energy marketer contract, you may or may not be affected by Union Gas' changes to transportation rates. Please contact your retail energy marketer directly at the phone number that appears on your bill if you have questions.

Important Information About Your Rates
February 2013
Rate 610 – Eastern Ontario

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 610 customer in Eastern Ontario using 93,000 m^3 of natural gas a year will be $1,565.83. The enclosed bill uses the new approved rates.

Gas Used

The gas commodity rate decreased by 0.1205 ¢/m^3 to 12.7620 ¢/m^3. For most customers the annual decrease will be about $112.10.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.4320 ¢/m^3 to 7.8935 ¢/m^3. For most customers the annual decrease will be about $401.73.

Storage

The storage rate increased by 0.7400 ¢/m^3 to 2.6307 ¢/m^3. For most customers the annual increase will be about $688.15.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $1,391.51.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 610 customer in Eastern Ontario using 93,000 m^3 of natural gas a year.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Gas used	12.7620 ¢/m^3	-$112.10
Gas price adjustment	-2.1961 ¢/m^3	$0.00
Transportation to Union Gas	7.8935 ¢/m^3	-$401.73
Transportation price adjustment	1.0341 ¢/m^3	$0.00
Storage	2.6307 ¢/m^3	$688.15
Storage price adjustment	0.1201 ¢/m^3	$0.00
Delivery First 1,000 m^3 Next 9,000 m^3 Next 20,000 m^3 Next 70,000 m^3 All Over 100,000 m^3	 7.7070 ¢/m^3 6.2934 ¢/m^3 5.4872 ¢/m^3 4.9711 ¢/m^3 3.0159 ¢/m^3	$1,391.51
Delivery price adjustment	0.2083 ¢/m^3	$0.00
Monthly charge	$70.00	$0.00
Total annual impact		**$1,565.83**

Important Information About Your Rates
February 2013
Rate 610 – Eastern Ontario
Energy Marketer Customer

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate 610 customer in Eastern Ontario using 93,000 m^3 of natural gas a year and buying gas from an energy marketer will be $1,677.93. The enclosed bill uses the new approved rates.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.4320 ¢/m^3 to 7.8935 ¢/m^3. For most customers the annual decrease will be about $401.73.

Storage

The storage rate increased by 0.7400 ¢/m^3 to 2.6307 ¢/m^3. For most customers the annual increase will be about $688.15.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $1,391.51.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate 610 customer in Eastern Ontario using 93,000 m^3 of natural gas a year and buying gas from an energy marketer.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Transportation to Union Gas	7.8935 ¢/m^3	-$401.73
Transportation price adjustment	1.0341 ¢/m^3	$0.00
Storage	2.6307 ¢/m^3	$688.15
Storage price adjustment	0.1201 ¢/m^3	$0.00
Delivery First 1,000 m^3 Next 9,000 m^3 Next 20,000 m^3 Next 70,000 m^3 All Over 100,000 m^3	 7.7070 ¢/m^3 6.2934 ¢/m^3 5.4872 ¢/m^3 4.9711 ¢/m^3 3.0159 ¢/m^3	$1,391.51
Delivery price adjustment	0.2083 ¢/m^3	$0.00
Monthly charge	$70.00	$0.00
Total annual impact		**$1,677.93**

* Depending on the terms of your retail energy marketer contract, you may or may not be affected by Union Gas' changes to transportation rates. Please contact your retail energy marketer directly at the phone number that appears on your bill if you have questions.

Important Information About Your Rates
February 2013
Rate M1 – Southern Ontario

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill decrease for a typical Rate M1 customer in Southern Ontario using 2,200 m^3 of natural gas a year will be $9.39. The enclosed bill uses the new approved rates.

Gas Used

The gas commodity rate decreased by 0.1205 ¢/m^3 to 12.7620 ¢/m^3. For most customers the annual decrease will be about $2.66.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.2824 ¢/m^3 to 4.3997 ¢/m^3. For most customers the annual decrease will be about $6.21.

Storage

The storage rate decreased by 0.2367 ¢/m^3 to 0.7368 ¢/m^3. For most customers the annual decrease will be about $5.18.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $4.66.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate M1 customer in Southern Ontario using 2,200 m^3 of natural gas a year.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Gas used	12.7620 ¢/m^3	-$2.66
Gas price adjustment	-2.1831 ¢/m^3	$0.00
Transportation to Union Gas	4.3997 ¢/m^3	-$6.21
Storage	0.7368 ¢/m^3	-$5.18
Storage price adjustment	-0.0513 ¢/m^3	$0.00
Delivery First 100 m^3 Next 150 m^3 All over 250 m^3	 3.7795 ¢/m^3 3.5730 ¢/m^3 3.0845 ¢/m^3	$4.66
Delivery price adjustment	-0.0054 ¢/m^3	$0.00
Monthly charge	$21.00	$0.00
Total annual impact		**-$9.39**

Important Information About Your Rates
February 2013
Rate M1 – Southern Ontario
Energy Marketer Customer

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill decrease for a typical Rate M1 customer in Southern Ontario using 2,200 m^3 of natural gas a year and buying gas from an energy marketer will be $0.52. The enclosed bill uses the new approved rates.

Storage

The storage rate decreased by 0.2367 ¢/m^3 to 0.7368 ¢/m^3. For most customers the annual decrease will be about $5.18.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $4.66.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate M1 customer in Southern Ontario using 2,200 m^3 of

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Storage	0.7368 ¢/m^3	-$5.18
Storage price adjustment	-0.0513 ¢/m^3	$0.00
Delivery First 100 m^3 Next 150 m^3 All over 250 m^3	 3.7795 ¢/m^3 3.5730 ¢/m^3 3.0845 ¢/m^3	$4.66
Delivery price adjustment	-0.0054 ¢/m^3	$0.00
Monthly charge	$21.00	$0.00
Total annual impact		**-$0.52**

Important Information About Your Rates
February 2013
Rate M2 – Southern Ontario

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate M2 customer in Southern Ontario using 73,000 m^3 of natural gas a year will be $12.23. The enclosed bill uses the new approved rates.

Gas Used

The gas commodity rate decreased by 0.1205 ¢/m^3 to 12.7620 ¢/m^3. For most customers the annual decrease will be about $88.00.

Transportation to Union Gas

The transportation to Union Gas rate decreased by 0.2824 ¢/m^3 to 4.3997 ¢/m^3. For most customers the annual decrease will be about $206.14.

Storage

The storage rate increased by 0.0378 ¢/m^3 to 0.7550 ¢/m^3. For most customers the annual increase will be about $27.62.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $278.72.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate M2 customer in Southern Ontario using 73,000 m^3 of natural gas a year.

CHARGES	RATES at Jan 1, 2013	ANNUAL increase or decrease
Gas used	12.7620 ¢/m^3	-$88.00
Gas price adjustment	-2.1831 ¢/m^3	$0.01
Transportation to Union Gas	4.3997 ¢/m^3	-$206.14
Storage	0.7550 ¢/m^3	$27.62
Storage price adjustment	0.0080 ¢/m^3	$0.00
Delivery First 1,000 m^3 Next 6,000 m^3 Next 13,000 m^4 All over 20,000 m^3	 4.1416 ¢/m^3 4.0653 ¢/m^3 3.8379 ¢/m^3 3.5650 ¢/m^3	$278.72
Delivery price adjustment	0.0355 ¢/m^3	$0.02
Monthly charge	$70.00	$0.00
Total annual impact		**$12.23**

Important Information About Your Rates
February 2013
Rate M2 – Southern Ontario
Energy Marketer Customer

The Ontario Energy Board has approved changes to the rates Union Gas charges its customers effective January 1, 2013. The total annual bill increase for a typical Rate M2 customer in Southern Ontario using 73,000 m^3 of natural gas a year and buying gas from an energy marketer will be $306.36. The enclosed bill uses the new approved rates.

Storage

The storage rate increased by 0.0378 ¢/m^3 to 0.7550 ¢/m^3. For most customers the annual increase will be about $27.62.

Delivery

The delivery rates that vary with consumption increased based on our forecast cost of delivering natural gas to your home or business. For most customers the annual increase will be about $278.72.

New Rates

The table below shows the new, approved rates used to calculate your natural gas bill as of January 1, 2013. Annual bill impacts exclude the temporary charges and credits shown on the price adjustment lines on your bill. The annual impacts are based on a typical Rate M2 customer in Southern Ontario using 73,000 m^3 of natural gas a year and buying gas from an energy marketer.

CHARGES	**RATES at Jan 1, 2013**	**ANNUAL increase or decrease**
Storage	0.7550 ¢/m^3	$27.62
Storage price adjustment	0.0080 ¢/m^3	$0.00
Delivery		
First 1,000 m^3	4.1416 ¢/m^3	
Next 6,000 m^3	4.0653 ¢/m^3	$278.72
Next 13,000 m^4	3.8379 ¢/m^3	
All over 20,000 m^3	3.5650 ¢/m^3	
Delivery price adjustment	0.0355 ¢/m^3	$0.02
Monthly charge	$70.00	$0.00
Total annual impact		**$306.36**

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. Your new rates are shown on the accompanying **Rate 20** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

Delivery

Approved 2013 delivery rates reflect a rate class average increase of 47.8% from the previously approved January 1, 2013 rates for Rate 20 customers. Individual customer impacts will vary.

Transportation

Changes in the gas transportation rate, **if applicable to your service**, reflect the changes in the costs to provide transportation service effective January 1, 2013.

Bundled-T Storage Service

The storage demand and commodity charges, **which apply to bundled storage service only**, have decreased to $9.643/GJ and $0.156/GJ respectively, reflecting the change in forecast costs to provide bundled storage service effective January 1, 2013.

Gas Supply Charges

New rates, **if applicable to your service**, reflect a decrease in Union Gas' forecast cost to purchase natural gas for the next 12 months. The changes by zone are detailed in the attached appendix.

Adjusting your gas rate in this way ensures that you are billed at a rate that more closely reflects the market price of natural gas and avoids large out-of-period adjustments. Union Gas does not earn income on the sale of the natural gas commodity. The price we pay for the gas commodity is passed on directly to customers with no profit included.

We appreciate and thank you for your business. If you have any questions about the rate changes, please call your account representative. Our staff will be pleased to answer your questions.

Rate 20 + Appendix A (Rate 20)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. Your new rates are shown on the accompanying **Rate 25** schedule. Changes in the rate levels are detailed in the attached appendix. The enclosed bill uses the new approved rates.

Delivery

Approved 2013 delivery rates reflect a rate class average increase of 30.6% from the previously approved January 1, 2013 rates for Rate 25 customers. Individual customer impacts will vary.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate 25 + Appendix A + Appendix C (Rate 25)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. Your new rates are shown on the accompanying **Rate 100** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

Delivery

Approved 2013 delivery rates reflect a rate class average increase of 30.2% from the previously approved January 1, 2013 rates for Rate 100 customers. Individual customer impacts will vary.

Transportation

Changes in the gas transportation rate, **if applicable to your service**, reflect the changes in the costs to provide transportation service effective January 1, 2013.

Bundled-T Storage Service

The storage demand and commodity charges, **which apply to bundled storage service only**, have decreased to $9.643/GJ and $0.156/GJ respectively, reflecting the change in forecast costs to provide bundled storage service effective January 1, 2013.

Gas Supply Charges

New rates, **if applicable to your service**, reflect a decrease in Union Gas' forecast cost to purchase natural gas for the next 12 months. The changes by zone are detailed on the attached appendix.

Adjusting your gas rate in this way ensures that you are billed at a rate that more closely reflects the market price of natural gas and avoids large out-of-period adjustments. Union Gas does not earn income on the sale of the natural gas commodity. The price we pay for the gas commodity is passed on directly to customers with no profit included.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate 100 + Appendix A (Rate 100)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. Your new rates are shown on the accompanying **Rate M4** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

Delivery

Approved 2013 delivery rates reflect a rate class average increase of 15.5% from the previously approved January 1, 2013 rates for Rate M4 customers. Individual customer impacts will vary.

Transportation

The cost to transport natural gas to Ontario, **if applicable to your service,** has changed, resulting in a decrease in the transportation rate by 0.2824 cents/m^3 to 4.3997 cents/m^3.

Gas Supply

The gas commodity charge, **if applicable to your service**, has decreased by 0.1205 cents/m^3 to 12.7620 cents/m^3. This change reflects the decrease in Union Gas' forecast cost to purchase natural gas for the next 12 months.

Adjusting your gas rate in this way ensures that you are billed at a rate that more closely reflects the market price of natural gas and avoids large out-of-period adjustments.

Union Gas does not earn income on the sale of the natural gas commodity. The price we pay for the gas commodity is passed on directly to customers with no profit included.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate M4 + Appendix A (Rate M4)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. Your new rates are shown on the accompanying **Rate M5A** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

Delivery

Approved 2013 delivery rates reflect a rate class average increase of 37.6% from the previously approved January 1, 2013 rates for Rate M5A customers. Individual customer impacts will vary.

Transportation

The cost to transport natural gas to Ontario, **if applicable to your service,** has changed, resulting in a decrease in the transportation rate by 0.2824 cents/m^3 to 4.3997 cents/m^3.

Gas Supply

The gas commodity charge, **if applicable to your service**, has decreased by 0.1205 cents/m^3 to 12.7620 cents/m^3. This change reflects the decrease in Union Gas' forecast cost to purchase natural gas for the next 12 months.

Adjusting your gas rate in this way ensures that you are billed at a rate that more closely reflects the market price of natural gas and avoids large out-of-period adjustments.

Union Gas does not earn income on the sale of the natural gas commodity. The price we pay for the gas commodity is passed on directly to customers with no profit included.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate M5A + Appendix A + Appendix C (Rate M5A)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. Your new rates are shown on the accompanying **Rate M7** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

Delivery

Approved 2013 delivery rates reflect a rate class average increase of 12.3% from the previously approved January 1, 2013 rates for Rate M7 customers. Individual customer impacts will vary.

Transportation

The cost to transport natural gas to Ontario, **if applicable to your service,** has changed, resulting in a decrease in the transportation rate by 0.2824 cents/m^3 to 4.3997 cents/m^3.

Gas Supply

The gas commodity charge, **if applicable to your service**, has decreased by 0.1205 cents/m^3 to 12.7620 cents/m^3. This change reflects the decrease in Union Gas' forecast cost to purchase natural gas for the next 12 months.

Adjusting your gas rate in this way ensures that you are billed at a rate that more closely reflects the market price of natural gas and avoids large out-of-period adjustments.

Union Gas does not earn income on the sale of the natural gas commodity. The price we pay for the gas commodity is passed on directly to customers with no profit included.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate M7 + Appendix A + Appendix C (Rate M7)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. Your new rates are shown on the accompanying **Rate M9** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

Delivery

Approved 2013 delivery rates reflect a rate class average decrease of 11.3% from the previously approved January 1, 2013 rates for Rate M9 customers. Individual customer impacts will vary.

Transportation

The cost to transport natural gas to Ontario, **if applicable to your service,** has changed, resulting in a decrease in the transportation rate by 0.2824 cents/m^3 to 4.3997 cents/m^3.

Gas Supply

The gas commodity charge, **if applicable to your service**, has decreased by 0.1205 cents/m^3 to 12.7620 cents/m^3. This change reflects the decrease in Union Gas' forecast cost to purchase natural gas for the next 12 months.

Adjusting your gas rate in this way ensures that you are billed at a rate that more closely reflects the market price of natural gas and avoids large out-of-period adjustments.

Union Gas does not earn income on the sale of the natural gas commodity. The price we pay for the gas commodity is passed on directly to customers with no profit included.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate M9 + Appendix A (Rate M9)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. Your new rates are shown on the accompanying **Rate M10** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

Delivery

Approved 2013 delivery rates reflect a rate class average increase of 105.4% from the previously approved January 1, 2013 rates for Rate M10 customers. Individual customer impacts will vary.

Transportation

The cost to transport natural gas to Ontario, **if applicable to your service,** has changed, resulting in a decrease in the transportation rate by 0.2824 cents/m^3 to 4.3997 cents/m^3.

Gas Supply

The gas commodity charge, **if applicable to your service**, has decreased by 0.1205 cents/m^3 to 12.7620 cents/m^3. This change reflects the decrease in Union Gas' forecast cost to purchase natural gas for the next 12 months.

Adjusting your gas rate in this way ensures that you are billed at a rate that more closely reflects the market price of natural gas and avoids large out-of-period adjustments.

Union Gas does not earn income on the sale of the natural gas commodity. The price we pay for the gas commodity is passed on directly to customers with no profit included.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate M10 + Appendix A (Rate M10)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) has approved changes to the rates Union Gas charges its customers. New rates for **Rate R1** will be applied to bills effective January 1, 2013. Your new rates are shown on the accompanying rate schedule. Changes to supplemental service rates reflect changes in gas supply costs effective January 1, 2013.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate R1
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

Effective January 1, 2013, the Ontario Energy Board (OEB) approved the split of existing Rate T1 into new Rate T1 and Rate T2 rate classes with distinct rate structures. Your new rates are shown on the accompanying **Rate T1** schedule. Changes in the rates are detailed in the attached appendix. Changes to supplemental service rates reflect changes in gas supply costs effective January 1, 2013. The enclosed bill uses the new approved rates.

Storage and Transportation

Approved 2013 storage and transportation rates reflect a rate class average increase of 22.0% from the previously approved January 1, 2013 rates for Rate T1 customers. Individual customer impacts will vary based on usage.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate T1 + Appendix A + Appendix C (Rate T1)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

Effective January 1, 2013, the Ontario Energy Board (OEB) approved the split of existing Rate T1 into new Rate T1 and Rate T2 rate classes with distinct rate structures. Your new rates are shown on the accompanying **Rate T2** schedule. Changes in the rates are detailed in the attached appendix. Changes to supplemental service rates reflect changes in gas supply costs effective January 1, 2013. The enclosed bill uses the new approved rates.

Storage and Transportation

Approved 2013 storage and transportation rates reflect a rate class average decrease of 22.3% from the previously approved January 1, 2013 rates for Rate T1 customers. Individual customer impacts will vary based on usage.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate T2 + Appendix A + Appendix C (Rate T2)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. Your new rates are shown on the accompanying **Rate T3** schedule. Changes in the rates are detailed in the attached appendix. Changes to supplemental service rates reflect changes in gas supply costs effective January 1, 2013. The enclosed bill uses the new approved rates.

Storage and Transportation

Approved 2013 storage and transportation rates reflect a rate class average decrease of 0.6% from the previously approved January 1, 2013 rates for Rate T3 customers. Individual customer impacts will vary based on usage.

We appreciate and thank you for your business. If you have any questions about the rate change, please call your Account Representative. Our staff will be pleased to answer your questions.

Rate T3 + Appendix A (Rate T3)
[Rate schedule attached]

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. These new rates reflect changes in the overall cost of providing service to natural gas transportation customers. Your new rates are shown on the accompanying **Rate M12** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

We appreciate and thank you for your business. If you have any questions about the rate changes please call your Account Representative. Our staff will be pleased to answer your questions.

Attachments: Rate M12 Rate Schedule and Appendix A

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. These new rates reflect changes in the overall cost of providing service to natural gas transportation customers. Your new rates are shown on the accompanying **Rate M13** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

We appreciate and thank you for your business. If you have any questions about the rate changes please call your Account Representative. Our staff will be pleased to answer your questions.

Attachments: Rate M13 Rate Schedule and Appendix A

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. These new rates reflect changes in the overall cost of providing service to natural gas transportation customers. Your new rates are shown on the accompanying **Rate M16** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

We appreciate and thank you for your business. If you have any questions about the rate changes please call your Account Representative. Our staff will be pleased to answer your questions.

<u>Attachments:</u> Rate M16 Rate Schedule and Appendix A

AN IMPORTANT NOTICE ABOUT YOUR GAS RATES

January 2013

The Ontario Energy Board (OEB) approved changes to the rates Union Gas charges customers effective January 1, 2013. These new rates reflect changes in the overall cost of providing service to natural gas transportation customers. Your new rates are shown on the accompanying **Rate C1** schedule. Changes in the rates are detailed in the attached appendix. The enclosed bill uses the new approved rates.

We appreciate and thank you for your business. If you have any questions about the rate changes please call your Account Representative. Our staff will be pleased to answer your questions.

Attachments: Rate C1 Rate Schedule and Appendix A

Appendix E

Decision and Rate Order

Miscellaneous Non-Energy Charges

Board File No. EB-2011-0210

Dated: January 17, 2013

UNION GAS LIMITED
Miscellaneous Non-Energy Charges

Line No.	Service	Fee
	Residential Customer Class Service	
1	Connection Charge	$35
2	Temporary Seal - Turn-off (Seasonal)	$22
3	Temporary Seal - Turn-on (Seasonal)	$35
4	Landlord Turn-on	$35
5	Disconnect/Reconnect for Non-Payment	$65
	Commercial/Industrial Customer Class Service	
6	Connection Charge	$38
7	Temporary Seal - Turn-off (Seasonal)	$22
8	Temporary Seal - Turn-on (Seasonal)	$38
9	Landlord Turn-on	$38
10	Disconnect/Reconnect for Non-Payment	$65
	Statement of Account/History Statements	
11	History Statement (previous year)	$15/statement
12	History Statement (beyond previous year)	$40/hour
13	Duplicate Bills * (if processed by system)	No charge
14	Duplicate Bills * (if manually processed)	$15/statement
	Dispute Meter Test Charges	
15	Meter Test - Residential Meter	$50 flat fee for removal and test
16	Meter Test - Commercial/Industrial Meter	Hourly charge based on actual costs
	Direct Purchase Administration Charges	
17	Monthly fee per bundled t-service contract or unbundled U2 contract	$75.00
18	Monthly per customer fee	$0.19
19	Invoice Vendor Adjustment (IVA) fee (for each successfully submitted IVA transaction)	$1.09

Notes:

* Duplicate bill charges only apply when customer wants two copies of a bill. Lost bills from the last billing period will be replaced free of charge.

Appendix F

Decision and Rate Order

Board Directives

Board File No. EB-2011-0210

Dated: January 17, 2013

Board Directives

1. File an expert, independent review of Union's gas supply plan, gas supply planning process and gas supply planning methodology prior to Union's next rates proceeding.

2. File sufficient evidence to support the proposed allocation of Union North and Union South Distribution Maintenance - Equipment on Customer Premises costs to rate classes in proportion to the allocation of customer station gross plant, including a definition for this maintenance category and a delineation of what has changed since EB-2005-0520 as part of Union's 2014 rates filing.

3. Undertake a review of the allocation of Kirkwall metering costs as part of Union's updated cost allocation study and file it with Union's 2014 rates filing.

4. File up to date continuity schedules related to Union's non-utility storage business as part of Union's 2014 rates filing.

5. Hire an independent consultant to update the Review of Cost Allocation for Unregulated and Regulated Storage Operations report filed in EB-2011-0038 as part of its 2014 rates filing.

6. Undertake a comprehensive cost allocation study which includes the M1/M2 and R01/R10 breakpoint reduction proposal no later than Union's 2014 rates filing. The study is to include an analysis regarding the allocation of costs for Distribution Maintenance – Meter and Regulator Repairs related to the customers that would be moving rate classes.

7. Prepare and file separate audited financial statements for the portion of the business that is subject to rate regulation no later than June 30th each year.

8. File sufficient evidence at the time the balance in the Short-term Storage Deferral account is to be disposed to allow the Board to confirm that Union has appropriately prioritized the sale of its utility storage space and calculated the balance in the account in accordance with the Board's decision.

9. File a report relating to storage encroachment, similar to that ordered by the Board in EB-2011-0038 at the time the Short-term Storage Account is to be disposed.

10. File a calculation for the payment by Union’s non-utility business to its utility business for storage encroachment, if any, at the time the Short-term Storage account is to be disposed.

Appendix G

Decision and Rate Order

Accounting Orders

Board File No. EB-2011-0210

Dated: January 17, 2013

UNION GAS LIMITED

Accounting Entries for
Short-term Storage and Other Balancing Services
Deferral Account No. 179-70

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 571 Storage Revenue
Credit	-	Account No. 179-70 Other Deferred Charges - Short-term Storage and Other Balancing Services

To record, as a debit (credit) in Deferral Account No. 179-70 the utility portion of actual net revenues for Short-term Storage and Other Balancing Services, less the 10% shareholder incentive to provide these services and less the net revenue forecast for these services as approved by the Board for ratemaking purposes. The utility portion of actual net revenues for Short-term Storage and Other Balancing Services is determined by allocating total margins received from the sale of these services based on the utility share of the total quantity of the services sold each calendar year. The utility share reflects the transactions supported by utility storage space (up to the 100 PJ cap – both planned and excess over planned).

Debit	-	Account No. 571 Storage Revenue
Credit	-	Account No. 179-70 Other Deferred Charges – Short-term Storage and Other Balancing Services

To record, as a credit in Deferral Account No. 179-70 payments by Union Gas Limited’s non-utility business to its utility business for storage encroachment.

Debit	-	Account No.179-70 Other Deferred Charges - Short-term Storage and Other Balancing Services
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-70, interest on the balance in Deferral Account No. 179-70. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

<u>UNION GAS LIMITED</u>

Accounting Entries for
Lost Revenue Adjustment Mechanism
<u>Deferral Account No. 179-75</u>

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-75 Other Deferred Charges - Lost Revenue Adjustment Mechanism
Credit	-	Account No. 529 Other Sales

To record, as a debit (credit) in Deferral Account No. 179-75, the difference between actual margin reductions related to Union's DSM plans and the margin reduction included in gas delivery rates as approved by the Board.

Debit	-	Income Account No. 179-75 Other Deferred Charges - Lost Revenue Adjustment Mechanism
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-75, interest expense on the balance in Deferral Account No. 179-75. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Transportation Tolls and Fuel – Northern and Eastern Operations Area
Deferral Account No. 179-100

This account is applicable to the Northern and Eastern Operations of Union Gas Limited. Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-100 Other Deferred Charges - Transportation Tolls and Fuel – Northern and Eastern Operations Area
Credit	-	Account No. 663 Transportation of Gas by Others

To record, as a debit (credit) in Deferral Account No. 179-100, the difference in the costs between the actual per unit transportation and associated fuel costs and the forecast per unit transportation and associated fuel costs included in the rates as approved by the Board.

Debit	-	Account No. 179-100 Other Deferred Charges - Transportation Tolls and Fuel – Northern and Eastern Operations Area
Credit	-	Account No. 663 Transportation of Gas by Others

To record, as a debit (credit) in Deferral Account No. 179-100 charges that result from the Limited Balancing Agreement.

Debit	-	Account No. 500 Sales Revenue
Credit	-	Account No. 179-100 Other Deferred Charges - Transportation Tolls and Fuel – Northern and Eastern Operations Area

To record, as a credit (debit) in Deferral Account No. 179-100 revenue from T-Service customers for load balancing service resulting from the Limited Balancing Agreement.

Debit	-	Account No. 179-100 Other Deferred Charges - Transportation Tolls and Fuel – Northern and Eastern Operations Area
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-100 interest expense on the balance in Deferral Account No. 179-100. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Unbundled Services Unauthorized Storage Overrun
Deferral Account No. 179-103

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

Debit	-	Account No.571 Storage Revenue
Credit	-	Account No. 179-103 Other Deferred Charges – Unbundled Services Unauthorized Storage Overrun

To record as a credit (debit) in Deferral Account No. 179-103 any unauthorized storage overrun charges incurred by customers electing unbundled service.

Debit	-	Account No. 179-103 Other Deferred Charges – Unbundled Services Unauthorized Storage Overrun
Credit	-	Account No. 323 Other Interest Expense

To record as a debit (credit) in Deferral Account No. 179-103, interest on the balance in Deferral Account No. 179-103. Simple interest will be computed on the monthly opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

<u>**UNION GAS LIMITED**</u>

Accounting Entries for
North Purchase Gas Variance Account
<u>**Deferral Account No. 179-105**</u>

This account is applicable to the Northern and Eastern Operations area of Union Gas Limited. Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-105 Other Deferred Charges – North Purchase Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-105, the difference between the unit cost of gas purchased each month for the Northern and Eastern Operations area and the unit cost of gas included in the gas sales rates as approved by the Board, including the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates.

Debit	-	Account No. 179-105 Other Deferred Charges - North Purchase Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-105, interest expense on the balance in Deferral Account No. 179-105. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
South Purchase Gas Variance Account
Deferral Account No. 179-106

This account is applicable to the Southern Operations area of Union Gas Limited. Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-106 Other Deferred Charges – South Purchase Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-106, the difference between the unit cost of gas purchased each month for the Southern Operations and the unit cost of gas included in the gas sales rates as approved by the Board, including the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates.

Debit	-	Account No. 179-106 Other Deferred Charges - South Purchase Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-106, interest expense on the balance in Deferral Account No. 179-106. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Spot Gas Variance Account
Deferral Account No. 179-107

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-107 Other Deferred Charges –Spot Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-107, the difference between the unit cost of spot gas purchased each month and the unit cost of gas included in the gas sales rates as approved by the Board on the spot volumes purchased in excess of planned purchases.

Debit	-	Account No. 623 Cost of Gas
Credit	-	Account No. 179-107 Other Deferred Charges –Spot Gas Variance Account

To record, as a credit (debit) in Deferral Account No. 179-107, the approved gas supply charges recovered through the delivery component of rates.

Debit	-	Account No. 179-107 Other Deferred Charges – Spot Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-107, interest expense on the balance in Deferral Account No. 179-107. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

<u>**UNION GAS LIMITED**</u>

Accounting Entries for
Unabsorbed Demand Cost (UDC) Variance Account
<u>**Deferral Account No. 179-108**</u>

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-108 Other Deferred Charges – Unabsorbed Demand Cost Variance Account
Credit	-	Account No. 663 Transportation of Gas by Others

To record, as a debit (credit) in Deferral Account No. 179-108, the difference between the actual unabsorbed demand costs incurred by Union and the amount of unabsorbed demand charges included in rates as approved by the Board.

Debit	-	Account No. 663 Transportation of Gas by Others
Credit	-	Account No.179-108 Other Deferred Charges – Unabsorbed Demand Cost Variance Account

To record, as a credit (debit) in Deferral Account No. 179-108, the benefit from the temporary assignment of unutilized capacity under Union's transportation contracts to the Northern and Eastern Operations Area. The benefit will be equal to the recovery of pipeline demand charges and other charges resulting from the temporary assignment of unutilized capacity that have been included in gas sales rates.

Debit	-	Account No. 179-108 Other Deferred Charges – Unabsorbed Demand Cost Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-108, interest expense on the balance in Deferral Account No. 179-108. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Inventory Revaluation Account
Deferral Account No. 179-109

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

Debit - Account No. 179-109
Other Deferred Charges – Inventory Revaluation

Credit - Account No. 152
Gas in Storage - Available for Sale

To record, as a debit (credit) in Deferral Account No. 179-109, the decrease (increase) in the value of gas inventory available for sale to sales service customers due to changes in Union's weighted average cost of gas approved by the Board for rate making purposes.

Debit - Account No. 179-109
Other Deferred Charges – Inventory Revaluation Account

Credit - Account No. 323
Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-109, interest expense on the balance in Deferral Account No. 179-109. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

<u>UNION GAS LIMITED</u>

Accounting Entries for
Demand Side Management Variance Account
<u>Deferral Account No. 179-111</u>

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-111 Demand Side Management Variance Account
Credit	-	Account No. 728 General Expense

To record as a debit (credit) in Deferral Account No. 179-111, the difference between actual and the approved direct DSM expenditure budget currently approved for recovery in rates, provided that any excess over the approved direct DSM expenditure budget does not exceed 15% of the direct DSM expenditure budget. Any excess over the approved direct DSM expenditure budget for the year must be for incremental DSM volume savings that are cost effective as determined by the Total Resource Cost Test.

Debit	-	Account No.179-111 Other Deferred Charges – Demand Side Management Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-111, interest expense on the balance in Deferral Account No. 179-111. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

<u>**UNION GAS LIMITED**</u>

Accounting Entries for
Gas Distribution Access Rule (GDAR) Costs
<u>**Deferral Account No. 179-112**</u>

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-112 Other Deferred Charges - Deferred Gas Distribution Access Rule (GDAR) Costs
Credit	-	Account No. 728 General Expense

To record, as a debit (credit) in Deferral Account No. 179-112 the difference between the actual costs required to implement the appropriate process and system changes to achieve compliance with GDAR and the costs included in rates as approved by the Board.

Debit	-	Account No.179-112 Other Deferred Charges - Deferred Gas Distribution Access Rule (GDAR) Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-112, interest on the balance in Deferral Account No. 179-112. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Shared Savings Mechanism
Deferral Account No. 179-115

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179 -115 Shared Savings Mechanism
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit in Deferral Account No. 179-115, the shareholder incentive earned by the Company in relation to its Demand Side Management (DSM) Programs.

Debit	-	Account No.179- 115 Other Deferred Charges – Shared Savings Mechanism
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in Deferral Account No. 179 -115, interest expense on the balance in Deferral Account No. 179-115. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Carbon Dioxide Offset Credits
Deferral Account No. 179-117

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179 -117 Carbon Dioxide Offset Credits
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit in Deferral Account No. 179-117, the amounts representing proceeds from the sale of or other dealings in carbon dioxide offset credits earned as a result of Union's DSM activity.

Debit	-	Account No.179 -117 Other Deferred Charges – Carbon Dioxide Offset Credits
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in Deferral Account No. 179 -117, interest expense on the balance in Deferral Account No. 179-117. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

<u>UNION GAS LIMITED</u>

Accounting Entries for
Average Use Per Customer
<u>Deferral Account No. 179-118</u>

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 500 Sales Revenue
Credit	-	Account No. 179-118 Other Deferred Charges - Average Use Per Customer

To record as a debit (credit) in Deferral Account No. 179-118 the margin variance resulting from the difference between the actual rate of decline in use-per-customer and forecast rate of decline in use-per-customer included in gas delivery rates as approved by the Board in 2013. Actual and forecast rate of declines in use-per-customer will be calculated on a percentage and rate class specific basis for rate classes M1, M2, 01 and 10, be normalized for weather and exclude the impacts attributed to DSM which are captured in the Lost Revenue Adjustment Mechanism Deferral Account No. 179-75.

Debit	-	Account No. 179-118 Other Deferred Charges - Average Use Per Customer
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-118, interest on the balance in Deferral Account No. 179-118. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
CGAAP to IFRS Conversion Costs
Deferral Account No. 179-120

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-120 Other Deferred Charges - CGAAP to IFRS Conversion Costs
Credit	-	Account No. 728 General Expense

To record, as a debit (credit) in Deferral Account No. 179-120 the difference between the actual incremental one-time administrative costs incurred to convert accounting policies and processes from their current compliance with Canadian Generally Accepted Accounting Principles (CGAAP) to their future compliance with International Financial Reporting Standards (IFRS) and the costs included in rates as approved by the Board.

Debit	-	Account No.179-120 Other Deferred Charges - CGAAP to IFRS Conversion Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-120, interest on the balance in Deferral Account No. 179-120. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

<u>UNION GAS LIMITED</u>

Accounting Entries for
Conservation Demand Management
<u>Deferral Account No. 179-123</u>

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 312 Non-Gas Operating Revenue
Credit	-	Account No.179-123 Other Deferred Charges – Conservation Demand Management

To record, as a credit in Deferral Account No. 179-123, 50% of the actual revenues generated from the Conservation Demand Management (CDM) program that will be paid to customers upon approval by the Board for rate making purposes.

Debit	-	Account No.179-123 Other Deferred Charges – Conservation Demand Management
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-123, interest expense on the balance in Deferral Account No. 179-123. Simple interest will be computed monthly on the opening balance in the said account at the short term debt rate as approved by the Board in EB-2006-0117.

<u>UNION GAS LIMITED</u>

Accounting Entries for
Demand Side Management Incentive
<u>Deferral Account No. 179-126</u>

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-126 Other Deferred Charges – Demand Side Management Incentive
Credit	-	Account No. 319 Other Income

To record, as a debit in Deferral Account No. 179-126, the shareholder incentive earned by the Company in relation to its Demand Side Management (DSM) Programs.

Debit	-	Account No.179-126 Other Deferred Charges – Demand Side Management Incentive
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-126, interest on the balance in Deferral Account No. 179-126. Simple interest will be computed monthly on the opening balance in the said account at the short term debt rate as approved by the Board in EB-2006-0117.

<u>UNION GAS LIMITED</u>

Accounting Entries for
Pension Charge on Transition to US GAAP
<u>Deferral Account No. 179-127</u>

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-127 Other Deferred Charges – Pension Charge on Transition to US GAAP
Credit	-	Account No. 212 Retained Earnings

To record, as a debit in Deferral Account No. 179-127, the amount recognized in retained earnings associated with transitioning accounting standards and reporting to US Generally Accepted Accounting Principles (GAAP) for previously unrecorded pension expenses.

UNION GAS LIMITED

Accounting Entries for
Gas Supply Plan Review – Consultant Cost
Deferral Account No. 179-128

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-128 Other Deferred Charges – Gas Supply Plan Review – Consultant Cost
Credit	-	Account No. 728 General Expense

To record as a debit in Deferral Account No. 179-128 the costs of hiring a consultant to undertake a review of the gas supply plan, gas supply planning process and gas supply planning methodology as directed by the Board in EB-2011-0210.

Debit	-	Account No. 179-128 Other Deferred Charges – Gas Supply Plan Review – Consultant Cost
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in Deferral Account No. 179-128, interest on the balance in Deferral Account No. 179-128. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Preparation of Audited Utility Financial Statements
Deferral Account No. 179-129

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-129 Other Deferred Charges – Preparation of Audited Utility Financial Statements
Credit	-	Account No. 728 General Expense

To record as a debit in Deferral Account No. 179-129 the costs of the annual preparation of audited utility financial statements as directed by the Board in EB-2011-0210.

Debit	-	Account No. 179-129 Other Deferred Charges – Preparation of Audited Utility Financial Statements
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in Deferral Account No. 179-129, interest on the balance in Deferral Account No. 179-129. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Upstream Transportation Optimization
Deferral Account No. 179-131

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-131 Other Deferred Charges – Upstream Transportation Optimization
Credit	-	Account No. 626 Exchange Gas

To record as a debit in Deferral Account No. 179-131 a receivable from customers and a reduction in cost of gas for the unit rate of optimization revenues refunded to in-franchise customers multiplied by the actual distribution transportation volumes.

Debit	-	Account No. 579 Miscellaneous Operating Revenue
Credit	-	Account No. 179-131 Other Deferred Charges – Upstream Transportation Optimization

To record as a credit in Deferral Account No. 179-131 a payable to customers and a reduction in transportation revenue equal to the ratepayer portion (90%) of the actual net revenue from gas supply optimization activities.

Debit	-	Account No. 323 Other Interest Expense
Credit	-	Account No. 179-131 Other Deferred Charges – Upstream Transportation Optimization

To record, as a debit (credit) in Deferral Account No. 179-131, interest on the balance in Deferral Account No. 179-131. Simple interest will be computed monthly upon finalization of the year- end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

Appendix H

Decision and Rate Order

Summary of Unit Rates for 2013 Adjustments

Board File No. EB-2011-0210

Dated: January 17, 2013

UNION GAS LIMITED
Union In-Franchise General Service
Summary of 2013 Retroactive Rate Adjustments by Rate Class

Line No.	Rate Class	Total Amount for Recovery/(Refund) Jan. 01 - Jan. 31, 2013 ($000's)	Billing Units for Disposition (1) ($10^3 m^3$)	Unit Price Adjustment for Prospective Recovery (cents/m^3)
		(a)	(b)	(c) = (a/b) x 100
	Northern and Eastern Operations Area			
	Rate 01			
1	Delivery	3,638	715,042	0.5088
2	Gas Transportation	(435)	715,042	(0.0608)
3	Storage	1,508	715,042	0.2109
4	Gas Supply Commodity	(148)	518,344	(0.0286)
5	Total Rate 01	4,563		
	Rate 10			
6	Delivery	714	272,136	0.2623
7	Gas Transportation	(214)	272,136	(0.0786)
8	Storage	327	272,136	0.1201
9	Gas Supply Commodity	(29)	130,939	(0.0225)
10	Total Rate 10	797		
	Southern Operations Area			
	Rate M1			
11	Delivery	1,037	2,415,555	0.0429
12	Gas Transportation	(1,116)	1,866,122	(0.0598)
13	Storage	(1,240)	2,415,555	(0.0513)
14	Gas Supply Commodity	(476)	1,866,122	(0.0255)
15	Total Rate M1 (2)	(1,795)		
	Rate M2			
16	Delivery	665	804,982	0.0826
17	Gas Transportation	(188)	315,029	(0.0598)
18	Storage	65	804,982	0.0080
19	Gas Supply Commodity	(80)	315,029	(0.0255)
20	Total Rate M2 (2)	460		
21	Total In-franchise General Service	4,026		

Notes:
(1) EB-2011-0210 Forecast volumes for the prospective period from February 01, 2013 to December 31, 2013.
(2) Rate M1/M2 Supplemental Meter Service: the additional meter charge of $15/month billed in January 2013 will be refunded to those specific accounts with February bills.

COMMISSION DE RÉGLEMENTATION ET D'APPELS DE L'ÎLE

THE ISLAND REGULATORY AND APPEALS COMMISSION

Prince Edward Island
Île-du-Prince-Édouard
CANADA

Docket UE20942
Order UE16-04R

IN THE MATTER of an

application by Maritime Electric Company, Limited to approve the rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental thereto;

AND IN THE MATTER of

the Electric Power Act, R.S.P.E.I. 1988, Cap. E-4 and the Island Regulatory and Appeals Commission Act, R.S.P.E.I. 1988, Cap. I-11;

BEFORE THE COMMISSION

on Monday, the 11th day of July, 2016.

Scott MacKenzie Q.C., Chair
Douglas Clow, CPA, CA, Vice-Chair
John Broderick, Commissioner
Michael Campbell, Commissioner

Order

IN THE MATTER of an

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Appearances & Witnesses

1. **For Maritime Electric Company, Limited**
   Counsel:
   Spencer Campbell, Q.C.
   Thomas P. Laughlin

   Witnesses:
   John D. Gaudet, P.Eng. Vice President, Corporate Planning & Energy Supply
   Steve Loggie, CPA, CA Vice President, Finance and Chief Financial Officer
   Angus Orford, P.Eng. Vice President, Customer Service
   Jason Roberts, CPA, CA Director, Regulatory and Financial Planning
   Ron LeBlanc, P.Eng. Manager, Production and Energy Supply

2. **Interveners**
   The Government of Prince Edward Island, as represented by the Minister of Transportation, Infrastructure and Energy
   Counsel:
   J. Gordon MacKay, Q.C.
   Staff:
   Kim Horrelt, P.Eng., Chief Executive Officer, PEI Energy Corporation
   Mark Victor, P.Eng., Senior Engineer, PEI Energy Corporation

3. **Public Participants**
   Tony Reddin & Jordan MacPhee, Environmental Coalition of Prince Edward Island
   Hon. Jamie Fox. Interim Leader, PC Party of PEI

4. **For The Island Regulatory and Appeals Commission**
   Counsel:
   Thomas Matheson, Q.C.
   Nicole McKenna
   Staff:
   Mark Lanigan, CPA, CA Director, Corporate Services and Appeals
   Dawn Murphy, Recording Secretary

IN THE MATTER an

application by Maritime Electric Company, Limited to approve the rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental thereto;

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Electric Power Act, R.S.P.E.I. 1988, Cap. E-4 and the Island Regulatory and Appeals Commission Act, R.S.P.E.I. 1988, Cap. I-11;

Reasons for Order

1. Introduction

[1] This is an application made by Maritime Electric Company, Limited (the "Applicant", "Maritime Electric" or the "Company") pursuant to the Electric Power Act, R.S.P.E.I. 1988, Cap. E-4 ("EPA") seeking, among other things, an order of the Island Regulatory and Appeals Commission (the "Commission") approving amendments to the rates, tolls and charges for electric service for the three-year period from March 1, 2016 to February 28, 2019.

[2] The Application was filed pursuant to Section 20(1) of the EPA which reads as follows:

> **Variation of rates, submission for review and approval**
>
> 20. (1) Whenever any public utility wishes to vary any existing rates, tolls or charges, or to establish any new rates, tolls or charges for any service, it shall submit for the review and approval of the Commission a schedule of such proposed rates, tolls and charges together with and appended thereto all rules and regulations which, in any manner, relate to the rates, tolls and charges; the Commission may approve, after reviewing the schedule and rules and regulations submitted, the schedule of rates, tolls

> and charges and the rules and regulations either in whole or in part, or may determine and fix new rates, tolls and charges, and amend the rules and regulations, as it sees fit.

[3] Maritime Electric filed a general rate application with the Commission on October 28th, 2015. In its initial filing, Maritime Electric sought, among other things, a return on average common equity of 9.7% within an allowed range of 9.5% to 9.9%, and an electricity rate increase equivalent to 2.5% for the typical rural residential customer. The initial filing sought to set rates, tolls and charges for electric service for the one-year period from March 1, 2016 to February 28, 2017.

[4] In January 2016, Maritime Electric filed with the Commission an agreement between Maritime Electric and the Government of Prince Edward Island (the "Agreement"). The Agreement addressed or agreed to amend certain matters raised in Maritime Electric's general rate application and in a related application dealing with rates of depreciation.

[5] As a result of the Agreement, Maritime Electric filed amendments to its general rate application on February 5th, 2016. As part of its amended filing, Maritime Electric proposed to set rates, tolls and charges for electric service over the three-year period from March 1, 2016 to February 28, 2019. The Company sought, among other things, a return on average common equity of 9.35% and an annual increase in electricity rates equivalent to 2.3% for the typical customer, effective March 1 in each of 2016, 2017 and 2018.

[6] A public hearing was held on February 25, 2016 to consider the proposed amendments to electricity rates and other related matters. On February 29, 2016, the Commission issued Order UE16-04, and advised that detailed reasons for the Order would follow in due course.

[7] Following are the detailed reasons in support of Commission Order UE16-04.

2. Regulation of Public Utilities in P.E.I.

[8] The Applicant, Maritime Electric, owns and operates a fully integrated system providing for the purchase, generation, transmission, distribution and sale of electricity throughout Prince Edward Island. The Company's head office is located in Charlottetown with generating facilities in Charlottetown and Borden-Carleton. The Company has contractual entitlement to capacity and energy from NB Power's Point Lepreau nuclear generating station and an agreement for the purchase of capacity and system energy from NB Power delivered via two submarine cables. The cables are leased from the Province of Prince Edward Island. The Company also purchases 92.5 MW of wind powered energy under contract with the PEI Energy Corporation.

[9] Maritime Electric is a "public utility" as defined in the EPA and, as such, is subject to regulatory oversight by the Commission. The Commission's jurisdiction to regulate public utilities is founded in both the EPA and the Island Regulatory and Appeals Commission Act, R.S.P.E.I. 1988, Cap. I-11 (the "IRAC Act").

[10] Since the Commission was first created in 1991, its jurisdiction to regulate public utilities under the EPA has been in an ongoing state of change. In 1994, the Government introduced a price cap on electricity rates equivalent to New Brunswick rates plus 10%. While the price cap was in effect, the Commission was authorized to "monitor" but not "regulate" utilities. In 2004, the legislation reverted to full cost of service regulation, requiring the Commission's approval for any changes to the rates, tolls and charges for electricity. Cost of service regulation remained in effect until 2010, when the Government, through amendments to the EPA, introduced legislatively fixed electricity rates as part of the PEI Energy Accord (the "Energy Accord"). The Energy Accord continued for a five-year period, from March 1, 2011 to February 29, 2016. As a result of the expiration of the Energy Accord, the Commission was required to set the rates, tolls and charges for electricity effective March 1, 2016.

[11] In accordance with the EPA, Maritime Electric has a monopoly to provide electric service in the Province of PEI. Section 2.1(1) of the EPA states that "No person other than Maritime Electric Company, Limited shall provide service in the province, or in a part of the province". The only exception to this monopoly are those customers served by the City of Summerside's electric utility.

[12] Regulatory oversight is of increased importance when dealing with a monopoly, such as Maritime Electric's, due to a lack of competition and natural market forces. However, the financial benefits associated with a monopoly must be balanced against the onerous requirements imposed on Maritime Electric to provide "reasonably safe and adequate" electric service, at all times and to all parts of the Province. This is not without challenges, risk and expense for the Company.

[13] The Commission is required, in accordance with the EPA, to set rates, tolls and charges for electric service that are "reasonable, publicly justifiable, and non-discriminatory". In doing so, the Commission must balance the interests of ratepayers and the interests of the utility. This duty was explained by the Supreme Court of Canada in the leading case of Northwestern Utilities, Limited v. The City of Edmonton and Board of Public Utility Commissioners of Alberta, [1929] SCC 186 [Northwestern Utilities]:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested.

3. Overview of Proceedings

[14] In 2015, Maritime Electric filed with the Commission five separate applications pursuant to the EPA. These applications generally dealt with the following matters:

- Approval of a proposed energy efficiency and demand side management ("DSM") plan (Commission Docket UE21406) ("DSM Application");
- Approval of proposed expenditures to design, construct and commission a 50 MW combustion turbine generator (Commission Docket UE20723) ("CT4 Application");
- Approval of proposed amendments to the rates of depreciation for several classes of property beginning January 1, 2016 (Commission Docket UE21603) ("Depreciation Rate Application");
- Approval of proposed amendments to the rates, tolls and charges for electric service for the period beginning March 1, 2016 (Commission Docket UE20942) ("General Rate Application"); and
- Approval of a proposed annual capital budget for 2016 (Commission Docket UE20724) ("Capital Budget").

[15] The Commission provided public notice of each application and allowed for the involvement of the public, including in the exchange of interrogatories. All filings in respect of the above noted applications were made available to the public and can be viewed on the Commission's website.

[16] On November 3, 2015, the Commission issued Order UE15-01 approving the Capital Budget as filed.

[17] Also on November 3, 2015, the Commission issued Order UE15-02 with respect to the DSM Application. The Commission refused to accept the majority of the DSM plan as filed by Maritime Electric, approving only the public outreach and education components. The Commission has since engaged the services of expert consultants with respect to DSM and a report is forthcoming. The Commission expects that Maritime Electric and the Government will work together to develop a DSM plan that is consistent with, and complimentary to, the Provincial Energy Strategy that is currently being developed by the Government. A further order will be issued with respect to the DSM Application in due course.

[18] On January 29, 2016, the Commission issued Order UE16-02 accepting Maritime Electric's withdrawal of the CT4 Application, subject to certain conditions. The Order was issued in response to a letter and supporting document filed by Maritime Electric advising that the Company has the ability to procure access to 50 MW of firm capacity and requesting that the CT4 Application be withdrawn accordingly.

[19] The General Rate Application was initially filed with the Commission on October 28, 2015. The Commission issued a Notice of Application that provided an overview of the proposed amendments to the rates, tolls and charges for electric service being sought by Maritime Electric and also provided information on how the public could view, comment and ask questions with respect to the application.

[20] In response to the initial filing in the General Rate Application, Mr. Roger King issued interrogatories to Maritime Electric and received responses. No other public comment was received with respect to the initial filing. The Government of Prince Edward Island did not participate in the interrogatory process and did not seek formal intervener status at the time of the initial filing.

[21] On January 29, 2016, Maritime Electric filed the Agreement with the Commission. The Agreement addressed the matters raised in the General Rate Application and the Depreciation Rate Application, as well as other matters relating to electric service in the Province.

[22] Upon receipt of the Agreement, the Commission issued Procedural Order UE16-01. The Procedural Order directed that the General Rate Application and the Depreciation Rate Application would be consolidated into a single matter in Commission Docket UE20942 and heard together at a public hearing. The Procedural Order further directed that the public hearing would commence at 9:30 a.m. on February 25, 2016, and set certain timelines for submissions by the parties, interveners and the public.

[23] Also on January 29, 2016, the Commission issued a Notice of Public Hearing. The Notice provided information regarding the Agreement, including the key terms, how the Agreement could be viewed, how the public could participate or provide comments, as well as the date, time and location of the public hearing. The Notice was published on the Commission's website and in local newspapers.

[24] On February 1, 2016, the Government of Prince Edward Island, as represented by the Minister of Transportation, Infrastructure and Energy, sought formal intervener status in the application. On February 16, 2016, the Commission also received a request for intervener status from the Environmental Coalition of Prince Edward Island Ltd. ("ECOPEI"). However, upon further inquiry, ECOPEI advised the Commission that it did not intend to call evidence at the hearing, but instead requested only the opportunity to ask questions of witnesses called on behalf of Maritime Electric and/or the Government.

[25] On February 19, 2016, the Commission issued Procedural Order UE16-03. In accordance with the Procedural Order, the Government was granted formal intervener status in the application. ECOPEI was not granted intervener status, but was permitted to participate in the manner requested, including the questioning of witnesses called on behalf of Maritime Electric and/or the Government.

[26] The Commission also received comments via email from Mr. Tom Courtney, a resident of PEI who opposed the proposed increase in electricity rates. No other written comments were received from the public.

[27] Members of the public were also invited to make oral submissions at the public hearing. Although individuals seeking to make oral submissions were required to register with the Commission in advance of the hearing, no individuals registered. At the commencement of the hearing, the Honourable Jamie Fox, Interim Leader of the Official Opposition, requested the opportunity to make submissions. This request was granted by the Commission. No other oral submissions were made by members of the public.

4. Commission Approach to Settlement Agreements

[28] The Commission notes at the outset that it is not a party to the Agreement and does not consider itself to be, in any way, bound by the terms of the Agreement. The Commission's jurisdiction to regulate public utilities, including Maritime Electric, is founded in the EPA. Although the Agreement is evidence that certain matters are supported by the Government, the Commission must still exercise its jurisdiction to set rates, tolls and charges for electric service that it determines to be reasonable, publicly justifiable, and non-discriminatory.

[29] Negotiated settlements, such as the Agreement, are becoming increasingly more common in utility regulation across Canada, particularly in Alberta and Nova Scotia. The Commission views negotiated settlements favorably in the context of utility regulation. A negotiated settlement brings interested parties to the table, giving consumers, industries and utilities a voice without the need for a costly - and potentially intimidating - regulatory hearing. Multi-year agreements, whenever possible, are to be encouraged as allowing for rate stability and decreasing the cost of regulation - a cost that is ultimately borne by ratepayers.

[30] Numerous regulators across Canada have legislation, procedural rules and/or common law that govern the negotiated settlement process. These rules, such as those developed by the Alberta Utilities Commission ("AUC"), provide a procedural framework from the initiation of the negotiated settlement process to the approval by the regulator. The AUC rules, for example, address issues such as notice to interested parties, the disclosure of relevant information, and the evidence that must be filed in support of an application to approve a negotiated settlement.

[31] Despite being common in other jurisdictions, this is the first time the Commission has been presented with a negotiated settlement in the context of utility regulation. As a result, the Commission does not currently have the benefit of legislation or procedural rules to assist in the consideration of the Agreement. Instead, the Commission, with the approval of the parties, has adopted the following principles set forth by the Nova Scotia Utility and Review Board ("NSUARB") and the Alberta Court of Appeal.

[32] Once the interested parties reach a negotiated settlement, the agreement is not simply approved by "rubber stamp" of the regulator. Instead, a regulator presented with a negotiated settlement is required to determine if the agreement is in the public interest (see Nova Scotia Power Inc. (Re), 2012 NSUARB 227 at para. 24). A settlement agreement does not replace an "appropriate and informed review by the Board as to what is in the overall public interest" (see ATCO Electric Ltd. v. Alberta (Energy and Utilities Board), 2004 ABCA 215 [ATCO] at para. 139).

[33] Although the "public interest" in the rate-setting context traditionally requires a balance between the interests of the utility and the interests of ratepayers, this will not always be the case when considering a negotiated settlement.

[34] When a regulator is presented with a "package deal" negotiated settlement agreed to by a utility, and the agreement is approved by the regulator in its entirety, the public interest to be considered is that of the consuming public generally; the regulator is under no obligation to consider the utility's economic interests. If the regulator alters, or proposes to alter, the terms and conditions of a negotiated settlement, then the regulator's consideration of the public interest will include both the interests of the consuming public and the economic interests of the utility (see ATCO at para. 140-143).

[35] Although the Commission has adopted these principles in the context of the present application, it fully intends to work with all interested parties to develop and implement procedural rules governing the negotiated settlement process for future applications. The Commission is particularly interested in ensuring that all interested parties are represented at the negotiating table. It is noteworthy that other jurisdictions have a consumer advocate appointed to represent certain interests, most notably that of the residential consumer. The Commission recognizes the value of a consumer advocate, in some form, and expects the Government and Maritime Electric to present options to the Commission as to how to best represent these interests in the event of future negotiated settlements.

5. Overview of the Application and the Agreement

[36] On January 29, 2016, Maritime Electric filed with the Commission the Agreement as between the Company and the Government. The Agreement, dated January 28, 2016, was executed by Fred J. O'Brien, President and Chief Executive Officer of Maritime Electric, and the Honourable Paula J. Biggar, Minister of Transportation, Infrastructure and Energy.

[37] Also on January 29, 2016, Maritime Electric filed Minutes of Settlement with the Commission. In accordance with the Minutes, the parties acknowledged that the Agreement differed from the relief sought in Maritime Electric's initial filing. In so far as there were any differences, the parties requested that the terms of the Agreement would prevail. Maritime Electric and the Government jointly requested that the Agreement be approved and that the Commission set new electricity rates effective March 1, 2016 on the basis of the Agreement.

[38] Upon review of the Agreement, the Commission determined that it differed, in many respects, from the initial filing of Maritime Electric in support of its General Rate Application. As a result, the Commission ordered Maritime Electric to file an amended application with the Commission. The purpose of requesting the amended application was to provide support and validation for certain matters agreed to by Maritime Electric and the Government, particularly where the Agreement differed from Maritime Electric's initial request for relief.

[39] Maritime Electric filed its amended application with the Commission on February 5, 2016.The amended application included the following reconciliation and comparison between the relief sought in the initial application versus the relief sought in the Agreement:

	Initial Application	**Agreement**
Proposed Rate Setting Term	1 Year (March 1, 2016 - February 28, 2017)	3 years (March 1, 2016 - February 28, 2019)
Return on Average Common Equity - 2016	9.70% for setting revenue requirement within an allowed range of 9.50% to 9.90%	9.35%
Average Common Equity	2016 - 40.5%	2016 - 40.9% 2017 - 40.0% 2018 - 40.0%
Regulatory Costs - 2016	$1,009,300	$802,300
Financing Costs - 2016	$12,705,600	$12,388,100
Cost Allocation Proposal	Residential Second Block/GS1	Pending Further Detailed Study
Customer Electricity Costs	2.5% (Typical Customer)	2.3% per year (Typical Customer)
Rate of Return Adjustment (RORA) Refund Period	2 years	3 years

[40] Following receipt of the Agreement and the amended application, the Commission issued interrogatories to both Maritime Electric and the Government. Responses to all interrogatories were received in advance of the public hearing and made available on the Commission's website.

[41] The Commission has made the following findings based on the evidence as presented by the interested parties and members of the public.

5.1 Rates, Tolls & Charges

a) Evidence

Proposed Rate Increase

[42] In its initial filing, Maritime Electric sought a one-year increase in electricity rates equivalent to a 2.5% increase for the typical rural residential customer consuming an average of 650 kWh/month. The actual level of consumption by a customer would determine if the increase in electricity costs would be more or less than the typical customer. The rate increase, if approved by the Commission, would be in effect for a one-year period from March 1, 2016 to February 28, 2017. The rates initially proposed by Maritime Electric for each class of customers are set out in Schedule 16-1 to the initial filing.

[43] In its amended filing, Maritime Electric proposed to set electricity rates for a three-year period from March 1, 2016 to February 28, 2019. The Company requested an annual increase of 2.3% for the typical electric customer in each class. The impact on annual electricity costs would vary from customer to customer based on their actual electricity consumption. The increases, if approved, would come into effect annually on March 1, 2016, March 1, 2017, and March 1, 2018.

Cost Allocation & Rate Structure

[44] Maritime Electric filed, as part of its initial filing, a cost allocation study prepared by Chymko Consulting Ltd. at the request of Maritime Electric (the "2014 Cost Allocation Study"). The 2014 Cost Allocation Study was based on Maritime Electric's statement of earnings for the twelve months ending December 31, 2014.

[45] A significant component of cost allocation and rate structure in this Province is the continued use of the "residential second block". The residential second block offers a reduced rate per kWh for residential customers who consume in excess of 2,000 kWh per month. The residential second block not only encourages energy consumption, the evidence filed discloses that it results in the residential rate class paying less than the actual cost to provide service to that class.

[46] The cost of providing service to the various classes of customers is measured by using a revenue-to-cost ("RTC") ratio. A RTC ratio below 100% indicates that revenue for that rate class should be increased, while a RTC ratio above 100% indicates that revenue for that rate class should be decreased. Maritime Electric views a RTC range of 90/110 as an acceptable range for the Company's rate classes.

[47] The 2014 Cost Allocation Study (like cost allocation studies in the past) confirmed the existence of disproportionate RTC ratios in Maritime Electric's current rate structure. While the RTC ratio for the residential rate classes (excluding seasonal and farm customers) was 92%, the RTC ratio for the general service rate class was in excess of 110%. In simplified terms, the RTC ratios suggest that the general service rate class is subsidizing residential consumers.

[48] For these reasons, Maritime Electric initially proposed to increase the residential second block from 2,000 kWh per month to 3,000 kWh effective March 1, 2016, then to 3,800 kWh effective March 1, 2017, and finally to 5,000 kWh effective March 1, 2018. According to Maritime Electric's evidence, a 5,000 kWh per month threshold was an appropriate threshold to capture the large majority of the highest consumption residential electricity consumers (with dwellings). The estimated $773,000 of incremental residential rate class revenue generated by the proposed change over the three-year transition period would be used to lower electricity costs for general service customers.

[49] As part of its amended filing, Maritime Electric sought to defer any changes to the residential second block. Instead, Maritime Electric proposed consulting with stakeholders and undertaking a rate design study to determine the appropriate class for all or some farms, and filing an updated cost allocation study using 2017 financial data.

[50] The deferral of changes to the residential second block was supported by the Government. The Government presented evidence that it is developing a new Provincial Energy Strategy, the results of which could lead to new policy direction on electricity supply and/or usage. The Government also noted that changes to the second block rate could have a significant financial impact on certain consumers. It submitted that consultation should occur with affected consumers prior to implementing any changes, and suggested that there may be opportunities to mitigate the financial burden through programs resulting from the Provincial Energy Strategy and DSM.

[51] In response to the Commission's interrogatories, both Maritime Electric and the Government confirmed that they were not aware of any other jurisdiction in North America that utilizes a discounted pricing structure in the residential rate class.

[52] Also on the issue of cost allocation, Maritime Electric proposed the preparation of a cost allocation classification study with respect to Point Lepreau. The Point Lepreau nuclear generating facility is a base load facility with substantially all costs as fixed long term facility costs, with relatively minor fuel costs. In the 2014 Cost Allocation Study, the annual fixed costs incurred under the Point Lepreau participation agreement are classified as all demand related, with a minor fuel cost component classified as energy. Maritime Electric proposes to undertake a detailed review and analysis of the Point Lepreau costs to determine the most appropriate methodology to be employed in future cost allocation studies to classify the annual fixed costs as between demand and energy.

b) Findings

Proposed Rate Increase

[53] The Commission encourages multi-year rate setting, whenever possible, so as to allow for stable and predictable electricity rates for consumers. Multi-year rate setting also reduces the utility's regulatory costs - costs that are ultimately borne by the consumer.

[54] The Commission accepts as reasonable the proposed annual increase in electricity rates of 2.3% during the three-year period from March 1, 2016 to February 28, 2019. In accordance with section 20 of the EPA, Maritime Electric shall charge the rates, tolls and charges for electric service as set out in Appendix 1 hereto for the period from March 1, 2016 to February 28, 2019.

[55] The rates, tolls and charges in Appendix 1 are based upon the forecast values and input values set forth in Appendix 2 hereto. In response to the Commission's interrogatory, Maritime Electric advised that the schedule of inputs in Appendix 2 is based upon actual results to December 31, 2015 and management's best estimates for 2016 to 2018. Both Maritime Electric and the Government confirmed that they are not aware of any information that would suggest that the inputs in Appendix 2 are now inaccurate or will differ in any material way from the projections contained therein.

[56] Both Maritime Electric, as applicant, and the Government, as intervener, shall notify the Commission, in a timely manner, of any material change to any of the inputs set forth in Appendix 2. Maritime Electric shall also file with the Commission, on or before February 28 in each of 2017, 2018 and 2019, the actual values associated with each of the inputs set forth in Appendix 2, based on the Company's actual financial results for the preceding year.

Cost Allocation & Rate Structure

[57] The Commission accepts the proposed deferral of changes to the residential second block pending completion of the Provincial Energy Strategy and the DSM plan. The deferral is intended to allow for consultation with impacted consumers and to explore opportunities to mitigate the financial burden through programs resulting from the Provincial Energy Strategy and DSM.

[58] However, the Commission has, on numerous occasions, expressed concerns with the continued existence of the residential second block (see, for example, Commission Order UE10-03). The residential second block is not based on cost of service; in effect, it is a method to subsidize electricity costs for certain classes of consumers, most notably farm operations. For this reason, the elimination of second block has historically been opposed by the farming community and by the governments of the day. Examples of this opposition are clearly seen in Commission Order UE10-03.

[59] The Commission views the continued existence of the residential second block as being contrary to the principles behind the EPA, which directs that the rates, tolls and charges for electric power should be reasonable, publicly justifiable and non-discriminatory. The Commission fully expects that Maritime Electric and the Government will work together over the next two years to develop a proposed rate structure that is fair and non-discriminatory for all ratepayers. Given the evidence presented on this application regarding the cross-subsidization of rate classes, the Commission is hereby putting Maritime Electric and the Government on notice that any proposed continuation of the residential second block rate in future rate applications will require compelling evidence of its equity to ratepayers.

[60] Accordingly, Maritime Electric shall undertake a rate design study to consider changes to the multi-block residential energy pricing structure, and related changes to Maritime Electric's other rate structures. The rate design study and a proposed rate structure shall be filed with the Commission on or before April 30, 2018. Maritime Electric shall also file an updated cost allocation study with the Commission on or before June 30, 2018, based on the Company's financial results to December 31, 2017. Finally, Maritime Electric shall prepare and file with the Commission a Point Lepreau cost allocation classification study on or before April 30, 2017.

5.2 Return on Average Common Equity

[61] At common law, a regulated public utility is entitled to earn a "fair return" on the capital invested in its enterprise. As explained by the Supreme Court of Canada in Northwestern Utilities:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

[62] The EPA codifies this common law principle in section 24, which states that a public utility is entitled to earn an annual return on its investment that is "just and reasonable":

> 24. (1) Every public utility shall be entitled to earn annually such return as the Commission considers just and reasonable, computed by using the rate base as fixed and determined by the Commission for each type of service furnished, rendered or supplied by such public utility, and the return shall be in addition to the expenses as the Commission may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Commission according to this Act and the rules and regulations made by the Commission hereunder.

[63] It is the role of the Commission to determine the return on average common equity ("ROE") that is just and reasonable in the circumstances.

a) Evidence

[64] In its initial filing, Maritime Electric sought a ROE of 9.7%, within an allowed range of 9.5% to 9.9%, for a one-year period from March 1, 2016 to February 28, 2017. The proposed ROE was based on a forecast average common equity of 40.5% for 2016. In support of this position, Maritime Electric filed a report prepared by James M. Coyne, Senior Vice President of Concentric Energy Advisors ("Concentric") at the request of Maritime Electric.

[65] Mr. Coyne concluded that Maritime Electric's proposed ROE was consistent with the allowed ROE for other investor-owned electric utilities across Canada, particularly those in Atlantic Canada, given the relative risk of Maritime Electric to those utilities.

[66] The Concentric report identified a number of business and financial risks unique to Maritime Electric, including:

- greater risk associated with adverse economic conditions due to Maritime Electric's small size;
- weaker electric sales growth in coming years due to macroeconomic and demographic trends;

- greater operating risks associated with:
  - Maritime Electric's reliance on NB Power for a large percentage of its energy supply;
  - the need for on-island generation assets as a back-up in case of supply interruption;
  - weather-related service interruptions; and
  - additional operational and contractual complexities associated with on-island wind generation facilities;
- higher political/regulatory risk due to the "active role of government, as demonstrated by past changes in legislation as well as by the broad mandate of the PEI Energy Commission [sic]."

[67] Based on these and other factors, Mr. Coyne concluded that "the business risk of Maritime Electric today is above average and somewhat higher than its Canadian and U.S. peers".

[68] In its amended filing, Maritime Electric requested a lesser ROE of 9.35% for the period March 1, 2016 to February 28, 2019, based on average common equity of 40.9% in 2016 and 40% in 2017 and 2018. In support of this amended ROE, the Government, as intervener, filed an independent report prepared by Grant Thornton LLP at the request of the PEI Energy Corporation.

[69] The Grant Thornton report confirmed that during the period from 2010 to 2015, the ROEs approved by Canadian regulators had decreased. In Nova Scotia, the ROE decreased by 0.35% during this period, while the ROE in Newfoundland decreased by 0.2%. The proposed ROE for Maritime Electric, if approved, would result in a decrease of 0.4% from the legislated ROE of 9.75% in place during the Energy Accord.

[70] The proposed ROE of 9.35% was supported by the Government. In response to the Commission's interrogatory requesting rationalization for the proposed ROE, the Government stated in part:

> In rationalizing the agreed upon ROE, Government recognized that past regulatory decisions allowed for a risk premium, presumably for the purpose of protecting Maritime Electric's S&P [Standard & Poor's] debt rating. On this basis and in the interests of continued rate stability, it was deemed prudent to reach agreement on an ROE reduction of 0.4 percent (for an allowed ROE of 9.35 percent). This reduction is in the range of what has been seen in other Canadian jurisdictions over the past five years.

[71] In response to the Commission's interrogatory, Maritime Electric reiterated many of the factors identified by Concentric as increasing the Company's overall risk profile relative to other Atlantic Canadian electric utilities and comparable Canadian utilities. Based on these continuing risk factors, Maritime Electric submitted that a risk premium of 25 to 50 basis points was just and reasonable.

[72] ECOPEI submitted that an ROE of 9.35% was "an extremely high return on average common equity" and advocated for a more modest ROE that was comparable to monopolies in other jurisdictions.

b) Findings

[73] The Commission accepts the proposed ROE of 9.35% based on average common equity of 40.9% in 2016 and 40% in 2017 and 2018. The ROE shall be in effect for the 2016, 2017 and 2018 calendar years, and thereafter until varied by the Commission.

[74] An ROE of 9.35% represents a reduction of 0.4% from the legislated ROE of 9.75% in effect during the Energy Accord. A reduction of this magnitude is consistent with what has been seen in other Canadian jurisdictions, including in Atlantic Canada, as noted in the review undertaken by Grant Thornton.

[75] The Commission also accepts that a ROE risk premium is appropriate due to the unique risk factors that exist in this Province, as set out by Concentric and Maritime Electric. The Commission recognizes, in particular, that Maritime Electric faces incremental risk relative to other utilities due to the frequency in which the regulatory framework in this Province has been changed over the last twenty years. Such changes may be perceived by investors as increasing the regulatory risk of the Company, resulting in the need for a higher risk premium when compared to similar utilities in other jurisdictions. The Commission recognizes the Company's responsibilities for electricity supply which are unique when compared to other Canadian distribution utilities. The Commission is reluctant to assign a value to the risk premium, and views this as an assessment to be conducted based on the circumstances as they exist at the time of each rate application.

[76] The Commission accepts the Company's average rate base set forth in Appendix 2 hereto for 2016, 2017 and 2018. However, Maritime Electric shall file with the Commission, within six months from the date of Commission Order UE16-04, confirmation of its rate base, including details of all accounts comprising its rate base. Maritime Electric shall also file with the Commission, on or before February 28 in each of 2017, 2018 and 2019:

a) the audited rate of return on average rate base for the previous fiscal year; and
b) the audited rate of return on average common equity for the previous fiscal year.

5.3 Energy Cost Adjustment Mechanism ("ECAM")

a) Evidence

[77] The Energy Cost Adjustment Mechanism ("ECAM") has been in place in this Province since the early 1970s and is one component of the amount charged to ratepayers for electric service. The ECAM is intended to provide a smoothing effect to the collection or rebate of costs. It enables Maritime Electric to collect/return fluctuations in approved energy related costs above/below the forecast base amount per kWh included in the basic rates.

[78] Under the operation of the ECAM, Maritime Electric charges to expense, on a monthly basis, an amount equal to the net purchased and produced energy for the month, multiplied by a base rate per kWh. This amount is subtracted from the actual cost of energy purchased or produced during the month, with the difference (positive or negative) added to the Company's balance sheet for future recovery from, or return to, customers over a period of time and as approved by the Commission.

[79] In its evidence, Maritime Electric noted significant fluctuations in the ECAM Costs Recoverable From (Payable To) Customers. These costs varied from negative $5,061,928 in 2014, to a forecast $2,881,920 in 2015 and $1,532,952 in 2016. Maritime Electric submits that these fluctuations are driven in part by how the ECAM base rate was previously set, and in part by the manner in which the rate charged to customers for ECAM was calculated.

[80] So as to reduce such fluctuations, Maritime Electric proposes:

a) to reset the base rate at the forecast rate per kWh for energy supply costs during the year for which revised customer rates are sought; and
b) to modify the ECAM to reflect forecast energy supply costs in customers' rates during the period in which they will be incurred.

[81] According to Maritime Electric's evidence, the Energy Purchase Agreement between NB Power and Maritime Electric has been extended for an additional three years, to February 28, 2019. This extension allows the Company to reasonably estimate the average unit cost of energy purchases for the three-year period, barring any unplanned events (for example, unplanned outages at Point Lepreau or curtailments in excess of forecast amounts). In addition, NB Power has recently granted a one-year extension of an existing capacity agreement and an incremental increase of 50 MW of firm transmission service to PEI, reducing the risk of significant curtailments.

b) Findings

[82] The Commission accepts as reasonable the modified ECAM set forth in Appendix 3 hereto. The modified ECAM shall apply to the approved basic rates for meter readings taken on or after March 1, 2016.

[83] The Commission also accepts as reasonable the following ECAM base rates per kWh:

	March 1, 2016	March 1, 2017	March 1, 2018
ECAM Base Rate per kWh ($)	0.08605	0.08988	0.09161

[84] The Commission accepts Maritime Electric's submission that these changes to the ECAM will reduce the amount of energy costs being deferred (collected) for future collection (return), and will result in the timely collection of energy costs through basic rates. Such results are viewed favorably by the Commission as being in the public interest.

5.4 Rate of Return Adjustment ("RORA")

a) Evidence

[85] The Rate of Return Adjustment ("RORA") account represents over earnings by Maritime Electric, in excess of the allowed return on average common equity, during the term of the Energy Accord. In accordance with the legislated Accord, these excess earnings are to be returned to customers, with interest, at the conclusion of the Energy Accord.

[86] The RORA account was implemented by Commission Order UE11-04 in December 2011, being the first year of the Energy Accord. Maritime Electric recognized that in the absence of regulatory adjustment, it would have exceeded the allowed 9.75% return on average common equity.

[87] According to Maritime Electric's submissions, the excess earnings were due to sales growth being higher than forecast when developing the Accord. As a result, Maritime Electric sought and received direction from the Commission to establish a RORA account to defer amounts in excess of the allowed return. In accordance with Commission Order UE11-04, the RORA account; also, accrued interest at the Company's cost of short-term borrowing.

[88] On March 1, 2013, Maritime Electric began refunding to customers the actual 2011 RORA and the forecast 2012 RORA at the rate of $0.00071/kWh. This refund rate is reflected in the rates legislated during the continuation of the Energy Accord for the period from March 1, 2013 to February 29, 2016.

[89] Maritime Electric confirmed that it also recorded a RORA in 2013, 2014 and 2015. The Company submits that the excess earnings earned during the Energy Accord continuation were also due to higher than forecast sales growth, driven primarily by the accelerated adoption of electricity based sources for space heating.

[90] In its initial filing, Maritime Electric forecast the balance of the RORA Account, to February 2016, to be $15,035,081. It proposed to refund the RORA to customers over a two-year period from March 1, 2016 to February 28, 2018. The Company estimated a return of $6,384,400 (48%) of the RORA balance between March 1, 2016 and February 28, 2017 by applying a credit of $0.00533/kWh for each rate class. The disposition of the balance of the RORA account would be addressed in the Company's 2017 rate application.

[91] In its amended filing, Maritime Electric confirmed the balance of the RORA account was $15,156,765 as of December 31, 2015. It did not provide an updated forecast for January and February 2016. Maritime Electric proposed that the balance of the RORA account be refunded over a three-year period - rather than a two-year period - beginning March 1, 2016. The three-year period was proposed to smooth the impact on customers' electricity rates over the term of the Agreement.

b) Findings

[92] The Commission accepts as reasonable the refund of the balance of the RORA account to ratepayers over the three-year period from March 1, 2016 to February 28, 2019. In doing so, the term of repayment is consistent with the term of the Agreement.

[93] The Commission also accepts the following refund rates per kWh as proposed by Maritime Electric:

	March 1, 2016	March 1, 2017	March 1, 2018
RORA Rebate per kWh ($)	0.00410	0.00473	0.00345

[94] However, the Commission does express concern about the level of over earning by Maritime Electric during the term of the Energy Accord. Although the balance of the RORA account is now being refunded, it is being refunded to present-day ratepayers, rather than to those ratepayers who contributed to the excess earnings. The Commission is of the view that over earnings must be regulated more closely in the future to both limit the amount of over earning and ensure a timely refund to ratepayers. Maritime Electric is therefore ordered to file with the Commission the monthly balance of the RORA account as part of its monthly reporting requirements, and to further file the year-end balance of the RORA account on or before February 28 in each of 2017, 2018 and 2019.

[95] The Commission also expresses concern over Article 4.1 of the Agreement entered into between Maritime Electric and the Government. Article 4.1 uses the word "recover" when discussing the RORA account. The Commission recognizes that, in the event of an over-refund from the RORA account, Maritime Electric may seek Commission approval to collect the amount of any such over-refund from ratepayers. However, in the absence of an over-refund, Maritime Electric shall not otherwise be entitled to recover any amounts from the RORA account and shall specifically not be entitled to recover from the RORA account in the event the Company does not attain a return on average common equity of 9.35%. Maritime Electric agrees with this finding and advises the Commission it was not the intent of Article 4.1 to permit recovery from RORA for any under-earnings.

[96] Ideally for ratepayers, a public utility would never over earn beyond its allowed rate of return. However, the Commission recognizes that the inputs prepared by Maritime Electric are forecast values that will, in all likelihood, differ from actual results. Therefore, any over earnings during the three-year period from March 1, 2016 to February 28, 2019 shall be deposited to a separate RORA account. Maritime Electric shall report the balance of this new RORA account to the Commission monthly and annually, and the balance, including accrued interest at the Company's short term borrowing rate, shall be refunded to ratepayers commencing March 1, 2019 or as further directed by the Commission.

5.5 Weather Normalization Mechanism

a) Evidence

[97] Maritime Electric seeks to implement a weather normalization reserve to mitigate volume and/or demand fluctuations caused by temperature changes relative to historical averages. According to Maritime Electric's evidence, weather normalization reserves are common throughout the utility industry and are part of a broader group of deferral reserves designed to mitigate volume or demand fluctuations.

[98] Maritime Electric does not currently utilize a weather normalization reserve. The Company's request arises from increased volatility in sales revenue and energy supply costs caused by the increased use of electricity for space heating in recent years.

[99] Generally, a weather normalization mechanism allows a utility to "reserve" revenue earned in colder-than-average years for use in warmer-than-average years. In a year when heating degree days ("HDD") are higher than normal, a marginal net revenue amount would be subtracted from the Company's income statement and added to the weather normalization reserve. In a year when HDD are lower than normal, a marginal net revenue amount would be added to the Company's income statement and subtracted from the weather normalization reserve.

[100] According to Maritime Electric's evidence, the weather normalization reserve on the Company's balance sheet should, over time, net to zero. As a result, Maritime Electric does not anticipate the need for an adjustment mechanism to deal with reserve balances.

b) Findings

[101] The Commission approves the weather normalization reserve, on an interim basis only, for the period from January 1, 2016 to February 28, 2019.

[102] The Commission does have concerns about the impact that a weather normalization reserve may have on the RORA account, in particular, that contributions to the RORA account - and the associated refunds to ratepayers - may be diminished as a result of the weather normalization reserve. In light of these concerns, Maritime Electric shall file with the Commission, as part of its monthly reporting requirements, the monthly balance of the weather normalization reserve. Maritime Electric shall also file with the Commission, on or before February 28 in each of 2017, 2018 and 2019, the year-end balance of the weather normalization reserve.

[103] The Commission reiterates that the weather normalization reserve is approved on an interim basis only. The Commission will determine the appropriateness of continuing a permanent weather normalization reserve based upon review and analysis of the monthly and annual reports.

5.6 Depreciation Rates

a) Evidence

[104] As of March 1, 2016, the determination of appropriate depreciation rates is within the Commission's jurisdiction by virtue of section 23 of the EPA, which provides:

> 23. Every public utility shall carry a proper and adequate depreciation account when the Commission, after investigation, determines that the depreciation account can be reasonably required; the Commission shall ascertain and determine what are proper and adequate rates of depreciation of the several classes of property of each public utility.

[105] The application of section 23 of the EPA was suspended during the five-year period in which the Energy Accord was in effect. As a result, depreciation rates were not regulated by the Commission during that period.

[106] Similarly, the Commission did not have jurisdiction to regulate depreciation rates while the price cap regulation was in effect, from 1994 to 2004.

[107] The Commission did, however, have authority to regulate Maritime Electric's depreciation rates from 2004 to 2010, and issued a number of orders dealing with depreciation during that period. In April 2006, the Commission ordered Maritime Electric to file an updated depreciation study by August 31, 2006 (see Commission Order UE06-02). Although Maritime Electric did file an updated depreciation study, the Commission found it did not comply with certain limitations imposed by the EPA, most notably section 47(6). As a result, Maritime Electric was ordered to file a further depreciation study within 36 months (see Commission Order UE07-01). The completion of the depreciation study was ultimately deferred at the request of Maritime Electric (see Commission Order UE08-07). At that time, Maritime Electric reported experiencing "significant transitional accounting issues" arising from the adoption of International Financial Reporting Standards. Maritime Electric was ordered to provide quarterly updates to the Commission on the proposed accounting standards.

[108] In December 2010, the Government introduced the Energy Accord. As a result of the Accord, section 23 of the EPA was suspended, as was the Commission's jurisdiction to regulate depreciation rates. Instead, input factors, including depreciation rates, were legislated by the Government during the term of the Accord.

[109] Recognizing the end of the Energy Accord in February 2016, Maritime Electric engaged Gannett Fleming to prepare a depreciation study (the "2014 Depreciation Study"). The 2014 Depreciation Study was based on the Company's financial results and assets in service up to and including December 31, 2014.

[110] On July 23, 2015, Maritime Electric filed its Depreciation Rate Application with the Commission. The 2014 Depreciation Study was included as part of that application.

[111] Maritime Electric proposes to adopt the depreciation rates recommended in the 2014 Depreciation Study, effective January 1, 2016. The Company submits that the proposed changes to the depreciation rates incorporate the estimated average service life of assets and a prudent allowance for the cost of removal of assets upon retirement. According to Maritime Electric, the proposed changes to depreciation rates will serve to prevent further increases in the accumulated reserve variance, assuming status quo in other variables. The proposed changes to depreciation rates would result in an increase of approximately $1.981 million (based on 2014 asset values) in annual depreciation expense.

[112] Maritime Electric also requests an adjustment to depreciation rates to incorporate the amortization of the accumulated reserve variance associated with the Charlottetown Thermal Generating Station's ("CTGS") impending retirement. This increase to the depreciation rates would result in an estimated increase in annual depreciation expense of $2.117 million, based on 2014 asset values. The Company proposes that further steps required to amortize the accumulated reserve variance with respect to all other asset classes be deferred until the filing of a subsequent depreciation study.

[113] Finally, Maritime Electric proposes to undertake two further studies:

- a decommissioning study with respect to the CTGS that would provide an estimate of the cost of decommissioning and retiring the facility and that also incorporates the Company's plans to potentially stage the retirement of individual generation units at the CTGS; and

- a depreciation study based on financial results up to December 31, 2017. The Company proposes that the depreciation study would include:

    - recommendations on the amortization of the accumulated reserve variance for all other assets classes;

    - an updated proposed depreciation rate adjustment recommendation reflecting the Company's updated plans with respect to the timing of the retirement of the CTGS; and

    - the findings from the decommissioning study to ensure a plan is implemented to provide for adequate and prudent depreciation rates and an adequate reserve for future site removal of the CTGS.

[114] Maritime Electric's amended filing did not alter its requests for relief with respect to matters of depreciation. The Agreement adopted all of the aforementioned proposals made by Maritime Electric with respect to depreciation.

[115] The Commission raised concerns with Maritime Electric's request that depreciation rates be set effective January 1, 2016, as the Commission's authority to regulate depreciation rates under section 23 of the EPA was suspended until March 1, 2016. Maritime Electric explained that the input factors, including depreciation rates, were legislatively set under the Energy Accord only until December 31, 2015, notwithstanding that electricity rates were legislated until February 29, 2016. As a result, depreciation rates were not established for the period from January 1, 2016 to February 29, 2016.

[116] Maritime Electric relies on certain provisions of the EPA and the IRAC Act in support of the Commission's authority to set depreciation rates prior to March 1, 2016. In particular, Maritime Electric relies on section 12 of the IRAC Act that allows the Commission to review, rescind or vary any order or decision made by it, including previous orders and decisions with respect to rates of depreciation. Maritime Electric also notes that the Commission retains a general power of supervision with respect to public utilities, pursuant to section 26 of the EPA. Finally, Maritime Electric relies on sections 48(1)(b) and 48.1(1)(b) of the EPA as allowing the Commission to regulate input factors, including depreciation rates, prior to March 1, 2016.

b) Findings

[117] The Commission accepts that certain of Maritime Electric's classes of property, including the CTGS, are under-depreciated. The Commission also accepts that the depreciation rates for Maritime Electric's classes of property as proposed in the 2014 Depreciation Study are proper and adequate. The Commission further accepts that it has jurisdiction, pursuant to the IRAC Act and the EPA, to establish depreciation rates effective as of January 1, 2016.

[118] The Commission therefore orders that Maritime Electric shall adopt the depreciation rates set forth in Appendix 5 hereto, effective as of January 1, 2016 (the "Depreciation Rates"). The Depreciation Rates shall remain in effect until varied by the Commission. Maritime Electric shall record and incorporate into the Depreciation Rates the recommended amortization of the accumulated reserve variance associated with the CTGS commencing in 2016 and as outlined in Appendix 6 hereto. The Commission considers it reasonable to defer the amortization of the accumulated reserve variance with respect to all other asset classes so as to balance the rate impact resulting from the change in Depreciation Rates.

[119] On or before June 30, 2018, Maritime Electric shall file with the Commission a decommissioning study with respect to the CTGS as well as an updated depreciation study based on financial results to December 31, 2017.

5.7 Interconnection Upgrade Project

[120] The amended filing advises the Commission that Maritime Electric has entered into a Memorandum of Understanding and a Construction Agency Agreement with the PEI Energy Corporation with respect to the Interconnection Upgrade Project (the "Project").

[121] Generally, the Project is to install two subsea cables with 180 MW capacity each to supplement and/or replace the two existing 40-year-old subsea cables and includes related new infrastructure in both New Brunswick and Prince Edward Island to interconnect with existing electrical transmission infrastructure.

[122] The Company has included in the forecast financial data the Company's share of the Project costs as estimated at the time of the hearing. These costs are included in the forecast rate increase for 2017 and 2018. It also makes assumptions concerning Company revenues from the Open Access Transmission Tariff ("OATT").

[123] The amended filing notes that the Company will seek recovery of its portion of the Project costs as a component of the ECAM and that these adjustments will survive the expiration of the Agreement.

[124] The Commission understands that the Project involves Federal Government funding and that the Project cost, less Federal Government funding, will be financed by the PEI Government and the net cost of the Project will be billed by the PEI Government to MECL, who in turn will recover these costs from ratepayers.

[125] The Commission understands that the net Project costs as initially determined and included in the amended filing are included in the 2.3% increase in rates for 2017 and 2018, respectively. The Commission requires the Company to file any proposal to adjust rates for any differential between proposed Project costs and actual Project costs, once determined.

[126] The Commission understands that the revenue associated with any changes to the current interim OATT will require Commission approval as part of a separate Company filing. This may affect the rate increase for 2016, 2017 and 2018 depending upon the materiality of the OATT rate changes associated with final Project costs.

5.8 Demand Side Management ("DSM")

[127] The amended filing includes funding for a DSM program that is yet to be approved by the Commission. The funding level included in the amended filing is consistent with the funding initially proposed and rejected by the Commission in Commission Order UE15-02.

[128] The Company indicates that a new DSM program will be put forward for Commission approval and thus has maintained the funding as proposed previously in the amended filing. These DSM costs are part of the 2.3% rate increase for 2016, 2017, and 2018.

[129] Any further DSM programs or expenditures by Maritime Electric require Commission approval as part of a separate DSM filing. The rate increase for 2016, 2017 and 2018 may also require adjustment depending upon the level of DSM expenditures ultimately approved by the Commission.

6. Disposition

[130] The foregoing reasons follow Commission Order UE16-04, issued on the 29th day of February, 2016 in Commission Docket UE20942, a copy of which is attached hereto and forms part of this decision.

DATED at Charlottetown, Prince Edward Island, this 11th day of July, 2016.

BY THE COMMISSION:

Scott MacKenzie Q.C., Chair

Douglas Clow, CPA, CA, Vice-Chair

John Broderick, Commissioner

Michael Campbell, Commissioner

APPENDIX:

Appendix 1 - UE16-04

COMMISSION DE RÉGLEMENTATION ET D'APPELS DE L'ÎLE

THE ISLAND REGULATORY AND APPEALS COMMISSION
Prince Edward Island
Île-du-Prince-Édouard
CANADA

Docket UE20942
Order UE16-04R

IN THE MATTER of an application by Maritime Electric Company, Limited to approve the rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental thereto;AND IN THE MATTER of the Electric Power Act, R.S.P.E.I. 1988, Cap. E-4 and the Island Regulatory and Appeals Commission Act, R.S.P.E.I. 1988, Cap. I-11;

BEFORE THE COMMISSION on Monday, the 11th day of July, 2016.

Scott MacKenzie Q.C., Chair
Douglas Clow, CPA, CA, Vice-Chair
John Broderick, Commissioner
Michael D. Campbell, Commissioner

Order

IN THE MATTER of

an application by Maritime Electric Company, Limited to approve the rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental thereto;

Order

Whereas on July 23, 2015, Maritime Electric Company, Limited ("Maritime Electric") filed an application with the Island Regulatory and Appeals Commission (the "Commission") seeking to amend rates of depreciation with respect to Maritime Electric's several classes of property for the period beginning January 1, 2016 (Commission Docket UE#21603) ("Depreciation Rate Application");

And Whereas on October 28, 2015, Maritime Electric filed an application with the Commission seeking to approve proposed amendments to the rates, tolls and charges for electric service for the period beginning March 1, 2016 (Commission Docket UE#20942) ("General Rate Application");

And Whereas notices of the Depreciation Rate Application and the General Rate Application were published by the Commission on August 7, 2015 and October 28, 2015, respectively;

And Whereas on January 29, 2016, Maritime Electric filed with the Commission an agreement between Maritime Electric and the Government of Prince Edward Island ("Agreement"), which Agreement addresses or agrees to amend certain matters raised in the General Rate Application and the Depreciation Rate Application, as well as other matters relating to electric service in the Province of Prince Edward Island;

And Whereas on January 29, 2016, the Commission issued a procedural order directing that the General Rate Application and the Depreciation Rate Application be consolidated and heard together in Commission Docket UE#20942 (the "Amended Application");

And Whereas a Notice of Public Hearing with respect to the Amended Application was published by the Commission on January 29, 2016;

And Whereas the Notice of Public Hearing outlined certain details of the Agreement and invited members of the public to comment on the Amended Application and to participate in a public hearing;

And Whereas Maritime Electric filed an updated application record with the Commission on February 5, 2016;

And Whereas interrogatories were exchanged and public comments were received with respect to the Depreciation Rate Application, the General Rate Application, and the Amended Application;

And Whereas a public hearing was held with respect to the Amended Application on February 25, 2016;

And Whereas the Government of Prince Edward Island was granted formal intervener status in the Amended Application and permitted to call evidence and cross-examine witnesses at the public hearing;

And Whereas the Environmental Coalition of Prince Edward Island Ltd. was permitted to ask questions of witnesses and make an oral submission at the public hearing;

And Whereas the Leader of the Official Opposition was permitted to make an oral submission at the public hearing;

And Whereas no other individuals requested intervener status or the opportunity to make an oral submission at the public hearing;

AND UPON considering the written and oral submissions received from the parties and from members of the public;

NOW THEREFORE, pursuant to the Electric Power Act, R.S.P.E.I. 1988, Cap. E-4 and pursuant to the Island Regulatory and Appeals Commission Act, R.S.P.E.I. 1988, Cap. I-11,

IT IS ORDERED THAT

Rates, Tolls & Charges

1. Maritime Electric shall charge the rates, tolls and charges for electric service as set out in Appendix 1 hereto for the period from March 1, 2016 to February 28, 2019, which rates, tolls and charges are based upon the forecast values and input values set forth in Appendix 2 hereto.

Return on Average Common Equity

2. Maritime Electric shall be entitled to earn a maximum return on average common equity of 9.35 per cent for each of the calendar years 2016, 2017 and 2018, and thereafter until varied by the Commission.

Energy Cost Adjustment Mechanism

3. The Energy Cost Adjustment Mechanism ("ECAM") set forth in Appendix 3 hereto shall apply to the approved basic rates for meter readings taken on or after March 1, 2016.

4. The base rate per kWh for use in the ECAM shall be as set forth in Appendix 2 hereto for each of the years March 1, 2016 to February 28, 2017; March 1, 2017 to February 28, 2018; March 1, 2018 to February 28, 2019, and thereafter until varied by the Commission.

Rate of Return Adjustment

5. During the period from March 1, 2016 to February 28, 2019, Maritime Electric shall refund to ratepayers the balance of the Rate of Return Adjustment ("RORA") account accumulated to December 31, 2015, being $15,156,765. The balance of the RORA account shall be refunded at the rates as set out in Appendix 2 hereto for each of the years March 1, 2016 to February 28, 2017; March 1, 2017 to February 28, 2018; March 1, 2018 to February 28, 2019, and thereafter until varied by the Commission.

6. Any over earnings accumulated during the period from January 1, 2016 to February 28, 2019 shall be deposited to a separate RORA account, the balance of which shall be refunded to ratepayers commencing March 1, 2019, or as further directed by the Commission.

7. With the exception of any amounts over-refunded to ratepayers, Maritime Electric shall not be permitted to recover any amounts from the RORA account(s), and in particular, Maritime Electric shall not be permitted to recover from the RORA account(s) in the event it does not attain a return on average common equity of 9.35 per cent. In the event of an over-refund, Maritime Electric shall not be permitted to recover all or part of the over-refund from ratepayers without the approval of the Commission.

Weather Normalization Mechanism

8. The Weather Normalization Mechanism and Reserve Account set forth in Appendix 4 hereto is approved, on an interim basis, for the period January 1, 2016 to February 28, 2019. The Commission shall determine the appropriateness of continuing a permanent Weather Normalization Mechanism and Reserve Account.

Depreciation Rates

9. Maritime Electric shall adopt the depreciation rates set forth in Appendix 5 hereto, effective as of January 1, 2016 (the "Depreciation Rates"). The Depreciation Rates shall remain in effect until varied by the Commission.

10. Maritime Electric shall record and incorporate into the Depreciation Rates the recommended amortization of the accumulated reserve variance associated with the Charlottetown Thermal Generating Station commencing in 2016 and as outlined in Appendix 6 hereto.

Further Studies

11. Maritime Electric shall undertake a rate design study to consider changes to the multi-block residential energy pricing structure, and related changes to Maritime Electric's other rate structures. The rate design study and a proposed rate structure shall be filed with the Commission on or before April 30, 2018.

12. On or before April 30, 2017, Maritime Electric shall prepare and file with the Commission a Point Lepreau cost allocation classification study.

13. On or before June 30, 2018, Maritime Electric shall file with the Commission an updated cost allocation study based on financial results to December 31, 2017.

14. On or before June 30, 2018, Maritime Electric shall file with the Commission a decommissioning study with respect to the Charlottetown Thermal Generating Station.

15. On or before June 30, 2018, Maritime Electric shall file with the Commission an updated depreciation study based on financial results to December 31, 2017.

Annual & Monthly Reporting

16. In addition to all existing reporting requirements and the reporting requirements set out herein, Maritime Electric shall file with the Commission on or before February 28 in each of 2017, 2018 and 2019:

    a. the actual values associated with each of the inputs set forth in Appendix 2 hereto, based on Maritime Electric's actual financial results for the preceding year;

    b. the year-end balance of the RORA account(s);

    c. the year-end balance of the Weather Normalization Reserve Account;

    d. the audited rate of return on average rate base for the previous fiscal year; and

    e. the audited rate of return on average common equity for the previous fiscal year.

17. In addition to Maritime Electric's current monthly reporting requirements, Maritime Electric shall file with the Commission as part of its monthly reports:

    a. the monthly balance of the RORA account(s); and

    b. the monthly balance of the Weather Normalization Reserve Account.

18. Maritime Electric shall file with the Commission, within six (6) months from the date of this Order, confirmation of its rate base, including details of all accounts comprising its rate base.

Material Change

19. As agreed to by the parties, Maritime Electric, as applicant, and the Government of Prince Edward Island, as intervener and a party to the Amended Application, shall notify the Commission of any material change to any of the inputs set forth in Appendix 2 hereto in a timely manner.

Reasons to Follow

20. The Commission shall provide detailed reasons for the Order granted herein in due course.

DATED at Charlottetown, Prince Edward Island, this 11th day of July, 2016.

BY THE COMMISSION:

Scott MacKenzie Q.C., Chair

Douglas Clow, CPA, CA, Vice-Chair

John Broderick, Commissioner

Michael D. Campbell, Commissioner

NOTICE

Section 12 of the *Island Regulatory and Appeals Commission Act* reads as follows:

> 12. The Commission may, in its absolute discretion, review, rescind or vary any order or decision made by it, or rehear any application before deciding it.

Parties to this proceeding seeking a review of the Commission's decision or order in this matter may do so by filing with the Commission, at the earliest date, a written Request for Review, which clearly states the reasons for the review and the nature of the relief sought.

Sections 13.(1), 13(2), 13(3), and 13(4) of the *Act* provide as follows:

> 13.(1) An appeal lies from a decision or order of the Commission to the Court of Appeal upon a question of law or jurisdiction.
>
> (2) The appeal shall be made by filing a notice of appeal in the Court of Appeal within twenty days after the decision or order appealed from and the rules of court respecting appeals apply with the necessary changes.
>
> (3) The Commission shall be deemed to be a party to the appeal.
>
> (4) No costs shall be payable by any party to an appeal under this section unless the Court of Appeal, in its discretion, for special reasons, so orders.

IRAC140A(04/07)

NOTE: In accordance with IRAC's Records Retention and Disposition Schedule, the material contained in the official file regarding this matter will be retained by the Commission for a period of 5 years.

2005-1

IN THE MATTER OF the Public Utilities Act
Revised Statutes of Yukon, 2002, c. 186, as amended

and

An Application by Yukon Energy Corporation
for Approval of 2005 Revenue Requirements

BEFORE:	B. Morris, Chair	)	January 27, 2005
	W. Shanks	)	
	R. Hancock	)	
	M. Phillips	)	

YUKON UTILITIES BOARD
EXHIBIT A-7

DAY	ENTERED BY	DATE
	DLemke	Feb 4/05

BOARD ORDER 2005-1

WHEREAS:

A. On December 13, 2004, Yukon Energy Corporation ("YEC", "the Company") filed with the Yukon Utilities Board ("the Board"), pursuant to the *Public Utilities Act* ("the Act"), and *Order-In-Council 1995/90*, an Application requesting an Order granting new rates for Secondary (interruptible) Energy and the Faro Mine site, on an interim refundable basis, effective with consumption January 1, 2005; and

B. The Application proposes the creation of a new Income Stabilization Trust and does not request any increase in firm rates charged to residential and commercial customers in 2005; and

C. The Application proposes for Secondary (interruptible) Energy, a new quarterly rate-setting mechanism to maintain the retail rate at 70 percent of the customers' avoided cost of fuel oil. This will result in a retail rate of 5.5 cents per kW.h. as of January 1, 2005; and

D. The Application also proposes for the Faro mine site, to change the current rate schedule to the normal General Service - Government rate; and

E. By Order 2004-1, the Board approved an interim refundable increase in rates to Secondary (interruptible) Energy customers and to the Faro mine site as requested in the Application. Board Order 2004-1 further scheduled a Workshop into the Application for January 13, 2005, and a Pre-hearing Conference for January 14, 2005; and

F. On January 11, 2005, the Utilities Consumer's Group ("UCG") filed two motions. The first UCG motion requested that the Board no longer use the services of certain British Columbia Utilities Commission ("BCUC") staff namely, Mr. W.J. Grant and Mr. B. McKinlay, for any type of facilitation or mediation. The second UCG motion requested that the Board order Yukon Electrical Company Limited ("YECL") to file a rate application as soon as possible to be heard by the Board in conjunction with YEC's Application ("the Companies"); and

G. At the Pre-hearing Conference, the Board established a deadline for submissions on the second UGC motion; and

H. On January 19, 2005, the Board received a Notice of Motion from Mr. Percival, a registered intervenor, that the Board require both YEC and YECL to file a General Rate Application. By letter dated January 20, 2005 the Board established a deadline for submissions on the Percival motion; and

I. The Board has reviewed the Notice of Motions from UGC and Mr. Percival and the related submissions.

NOW THEREFORE the Board orders with Reasons for Decision attached as Appendix A that:

1. In regard to the first UCG motion, this has been resolved and no further action by the Board is required.

2. The second UCG motion and the Percival motion are denied.

3. YEC and YECL are to jointly file a report with the Board by Thursday, September 1, 2005, that provides information on the revenue-to-cost ratios by customer class for both Companies utilizing the most recent cost of service allocation study.

DATED at the City of Whitehorse, in the Yukon Territory, this 4th day of February 2005.

BY ORDER

Brian Morris

Brian Morris
Chair

IN THE MATTER OF the Public Utilities Act
Revised Statutes of Yukon, 2002, c. 186, as amended

and

An Application by Yukon Energy Corporation
for Approval of 2005 Revenue Requirements

Reasons for Decision

1.0 Background

On December 13, 2004, Yukon Energy Corporation ("YEC", "the Company") filed with the Yukon Utilities Board ("the Board"), pursuant to the *Public Utilities Act* ("the Act"), and *Order-In-Council 1995/90*, an Application requesting an Order granting new rates for Secondary (interruptible) Energy and the Faro Mine site, on an interim refundable basis, effective with consumption January 1, 2005.

By Order 2004-1, the Board approved for YEC the requested interim refundable rate increases and set the current firm rates charged to residential and commercial customers as interim effective January 1, 2005. Order 2004-1 also scheduled a Workshop and a Pre-hearing Conference into the Application for January 13, 2005, and January 14, 2005, respectively.

2.0 Notices of Motion and Timetable for Submissions

On January 11, 2005 the Utilities Consumer's Group ("UCG") filed two motions. The first UCG motion requested that the Board no longer use the services of certain British Columbia Utilities Commission ("BCUC") staff namely, Mr. W.J. Grant and Mr. B. McKinlay for any type of facilitation or mediation. At the Pre-hearing Conference, Board Counsel informed the Board and the parties in attendance that Mr. McKinlay is no longer with the BCUC and Mr. Grant does not intend to take any further involvement in the proceedings (Transcript pp. 7-8). Accordingly, the Board finds that this UCG motion has been resolved and no further action by the Board is required.

The second UCG motion requested that the Board order Yukon Electrical Company Limited ("YECL") to file a rate application as soon as possible to be heard by the Board in conjunction with YEC's Application. At the Pre-hearing Conference, the Board instructed the parties that submissions on the UCG motion were to be filed with the Board and other intervenors by January 21, 2005, and the UCG was to file a response to the submissions by January 26, 2005 (Transcript p. 47).

Also at the Pre-hearing Conference the Board received a request from Mr. Percival, a registered intervenor, that the Board require both YEC and YECL to file a General Rate Application. The Board directed that if Mr. Percival chose to make a formal request, it be in the form of a Notice of Motion (Transcript p. 49). On January 18, 2005, Mr. Percival filed a Notice of Motion requesting that the Board require both YEC and YECL to file a General Rate

Application. By letter dated January 20, 2005, the Board instructed YEC and all registered intervenors ("the parties") that submissions on Mr. Percival's motion were to be filed with the Board and the parties by January 25, 2005 and Mr. Percival was to file a response to the submissions by January 27, 2005.

3.0 Reasons for Motions, Submissions and Reply on the Notices of Motion

3.1 Second UCG Notice of Motion and Percival Notice of Motion

The second UCG motion requested that the Board order YECL to file a rate application as soon as possible to be heard by the Board in conjunction with YEC's Application. UCG's reasons in support of the motion are that YECL's last application was in 1996, YECL's allowed rate of return on equity of 11.5 percent has not been reviewed since 1996 and that it would be convenient and less costly to hold a YECL assembly at the same time as a YEC hearing.

The Percival motion is similar to the second UCG motion. The Percival motion requests that the Board issue an order that suspends the YEC proceeding until YEC files a revised and complete General Rate Application ("GRA") with an accompanying fully distributed cost of service study. The Percival motion also requests that the Board order YECL to file a similar GRA with a fully distributed cost of service study. This motion also requests that YEC and YECL should be required to consult and cooperate in the filing of their GRAs when it comes to rates, rate setting procedures and service regulations (consistent with previous Board Orders and Yukon Government Orders in Council as may apply).

The main reasons for the Percival motion are that:

- It has been almost ten years since the last full public review of YEC and YECL ("the Companies"),
- Board Order 1996-7 required the Companies to adjust rates for all customer classes over a ten year period to reflect a cost of service in the range of 90 percent to 110 percent,
- The Companies could include any effects that might occur with the termination, extension or expansion of the Yukon Government's Rate Stabilization Fund which is scheduled to expire in March 31, 2005.
- If the Board does not agree to YEC's proposed method of recovering its revenue requirements then the Board would need to consider other options than an across-the-board rate increase to all customers including the Wholesale Power Rate to YECL.

Submissions in support of the second UCG motion and the Percival motion were received from Mr. Gary McRobb, MLA, Kluane, and Mr. P. McMahon. These submissions made similar points as are contained in the motions and their reasons. These submissions disagreed with YEC's argument for an expeditious hearing or YECL's estimate of time to prepare a rate application.

Submissions opposed to the second UCG motion and the Percival motion were received from YEC, YECL and the Yukon Chamber of Commerce. YEC argued that there is an insufficient basis to the second UCG motion and the Percival motion and they should be dismissed as:

- There is no requirement under the Act for a joint review of YEC and YECL,
- The passage of time is an insufficient reason to delay the review of the YEC Application,
- The YEC Application provides an orderly process to set YEC and YECL rates for the next few years,
- If YEC's proposed Income Stabilization Trust is not approved then the revenue requirements increase could be recovered by an adjustment to Rider J,
- The Board has never directed a utility to file a rate application involuntarily,
- Revenue requirements is separate from rate and rate class cost of service, and
- It is not feasible to review revenue to cost ratios until YECL revenues have been reviewed.

YECL argued that the second UCG motion and the Percival motion should be dismissed as it is not reasonable or practical for the Board to require a rate application to be filed in the circumstances requested, that if a direction to file an application is made it should require the filing to occur in advance of the test year and it is more appropriate to await the YECL Annual Report filing then evaluate if a YECL GRA should be filed for 2006. YECL also argued that the 2005 YEC hearing should proceed and there could be two separate 2006 Phase I Revenue Requirements Applications for YEC and YECL then a joint Phase II Application to allocate the Board's approved revenue requirements to the applicable rate zones then to rate class.

Replies were received from UCG and from Mr. McRobb on Mr. Percival's behalf on the submissions made by the parties to their motions.

4.0 Board Conclusions

YEC and YECL are now two separate companies and the Board finds that a combined GRA is no longer necessary for the Board to review the revenue requirements of YEC. The Board also considers that it is able to review the revenue requirements of YEC without a concurrent examination of the revenue to cost ratios by customer class. Accordingly, the second motion of the UCG and the Percival motion are denied.

The Board will review the YECL's Annual Report that is filed by March 31, 2005, and determine in due course whether a YECL rate application should be filed in accordance with Sections 50 and 51 of the Act.

The Board requires the Companies to jointly file a report by Thursday September 1, 2005, that provides information on the revenue to cost ratios by customer class for both Companies utilizing the most recent cost of service allocation study. If the report indicates that the revenue to cost ratios by customer class are outside the range of 90 percent to 110 percent, then the Companies are to provide their views on whether an updated cost of service allocation study should be undertaken or if a rate shift proposal can be made based on the most recent cost of service allocation study.

Purpose iv: To Assist in Consistency in Decision-Making by the Agency

By consistency in decision-making I refer to similar circumstances rendering similar results.

Consistency is important in agency decision-making. It permits the rational development and arrangement of public affairs. Where economic or other planning decisions must be made on the basis of past action or likely expectations, inconsistent decisions by decision-makers can cause financial and other hardships. And inconsistency in action increases uncertainty and costs to participants as it becomes difficult for consultants and advisors to give advice as to rights and action to be taken.

There is also a psychological importance to consistency in decision-making. It appears to be a basic aspect of human nature that we all expect to be treated the same in similar circumstances. Where this does not happen (and the result is perceived as being less advantageous to the individual) there is a feeling of resentment, a feeling that the decision-maker is acting without good reason (arbitrarily) and a general refusal to accept the decision which can lead to social disorder or malcontent.[19.5]

Furthermore, in creating a legislative scheme, absent some very unusual and express direction to the contrary, Parliament does not generally intend that scheme to be administered arbitrarily. Striving for consistency in decision-making assists in the avoidance of arbitrary decision-making.

Inconsistent decisions can also result in inefficiencies in the system by leading to increases in applications brought as applicants hope to secure alternative approaches which best serve their personal interests — perhaps even in hopeless cases, on the basis of "who knows — maybe I'll strike it lucky!"

Inconsistent action leads to appeals, judicial reviews with resulting costs to parties and agency in costs, re-hearings, etc.[19.6]

Inconsistent action creates insecurity and lack of confidence in agency decision-making. If agency members regularly adopt different approaches in similar situations it calls into question the validity of earlier decision-making and shakes the confidence of the public in the agency.

Inconsistency in decision-making can also increase the length of proceedings as participants argue over alternative approaches taken in past.

Inconsistency can cause stress and disunity between decision-makers and a perception of a struggle between alternative views for dominance.

Inconsistency can *sometimes* mask sloppy thinking and a failure to force the mind to fully address an issue.

Yet many agencies operate under circumstances that work against consistency. They must operate under statutes that must be interpreted and which often are not clear or may even contain inconsistencies resulting from revision and drafting additions over the years. In addition, as discussed earlier, agencies must decide each application on the basis of the specific circumstances of each case. Agencies are not bound by internal precedent and cannot bind themselves to follow their earlier decisions. Subject to legislative or judicial direction, each decision-maker is required to interpret the law, and exercise discretion according to his or her conscience in each case.[19.7] This is not a fluke or an unintended consequence. Parliament *could* make rules if it thought it appropriate, or it could authorize the making of rules by some other entity.

The fact that most decision-making by agencies is done through individual members or panels of members rather than the agency as a whole also increases the chances of inconsistent decision-making. This difficulty is compounded by the fact that some agencies are composed of large numbers of individuals spread over a wide geographic area making communication between them difficult. Consistency may also be a problem for agencies which are composed of *ad hoc* decision-makers or part-time decision-makers who do not interact and again are unable to communicate easily or often. Agencies with large number of new short-term decision-makers can develop consistency problems as the unfamiliarity of the members with either the legislation, the realities of the area in which the agency works, and the policies of the agency leads to different decisions being made.

Consistency problems can also arise where there are complex areas of law, in areas where individual members lack expertise, or in areas in which there is no easily demonstrable correct answer and one is often trying to develop the more subjective "best" answer.

Legislative schemes often involve the application of a great deal of discretionary decision-making by agencies where the agency has a choice to determine what may be appropriate in specific circumstances, often in areas of opinion where there is no clear absolute answer

Guidelines can assist in consistent decision-making by providing an easily accessible source of thinking and advice to agency decision-makers wherever located that keeps them advised of the agency thinking respecting policy or legal interpretation. Such guidelines can provide the decision-makers with starting points in their thinking respecting individual cases.[19.7.1]

The value of guidelines respecting consistency is that they expose decision-makers to well-considered views of general application which can serve as starting points in the decision-maker's deliberations. But they should not be end points as well. They cannot be treated as rules — unless there is valid legislative direction to do so.[19.8] Decision-makers cannot fetter their discretion or judgment by blinding and automatically following guidelines to the exclusion of their own deliberations or consideration of the particular circumstances of the specific case before them.

Thus great care must be taken by an agency in the drafting and use of guidelines to avoid the impression that those guidelines are used as more than mere instruments of assistance but as laws or the means to avoid the agency exercising its discretion or judgment on a case-by-case basis. The agency should not write its guidelines in a way that gives the impression that they should be departed from only in unusual circumstances, or otherwise adopt internal processes that increase the difficulties for an agency member to depart from a guideline, or otherwise operate to discourage such departures.[19.9]

At the same time a party cannot sit in the bush, refuse to provide the agency with any countervailing arguments or evidence respecting the applicability of the guideline and then later complain if the agency decides to apply the guideline.[19.10]

I will return to the use of policy guidelines later in this chapter. The concept of the fettering of discretion is also discussed extensively in chapter 5B "Discretion" under the heading: "5B.5(c) Discretion Must Be Exercised on the Merits of Each Case".

I like guidelines. As outlined in this chapter they are of real value to the operation of agencies. I very much doubt that I could have performed my work as well on my first administrative agency without the significant effort made by the individuals who conceived the various policy and procedural positions set out in that agency's guidelines. Having said that, it is equally important that decision-makers not adopt an undue reliance on the use of guidelines. It is important that decision-makers not lose their edge. One of the dangers of experience, and the over-reliance on guidelines, is the temptation to rely on system and to lose the ability to know when something is different and requires a response that is out of the ordinary. This is a real concern in administrative decision-making where the inability to recognize the unusual case and properly react thereto can cost real money or inflict significant harm. Agencies focus significant resources on the concern for the "rogue decision-maker" — an individual who acts outside of agency policy. But, as many modern media reports and official inquiries are revealing a significant problem — agencies which fail their public mandate because they are unable to see beyond their standard response — Guideline and policy development is an important tool to assist agencies make better decisions and avoid arbitrariness. However, it is impossible to capture every situation in a policy; and the principle that one always remains willing to deviate from policy should be more than mere lip service. One must always remain vigilant and able to detect when something is not the norm — notwithstanding its outward appearance. This requires a continuing sensitivity and awareness to the particulars of the specific.

FOOTNOTES

[19.5] In *SCA Packaging Ltd. v. Boyle (Northern Ireland)* [2009] ICR 1056, [2009] UKHL 37, [2009] IRLR 746 (U.K.H.L.) Lord Hope of Craighead made the following comments respecting the interpretation of a term in a U.K. statute dealing with discrimination relating to disabilities:

> The definition of "disability" lies at the heart of the Disability Discrimination Act 1995. So a proper understanding of what it means is essential if all those who are disabled, as that term is defined in the Act, are to be brought within its protection. Parliament went to considerable lengths to define this expression. First, there is the general test laid down in section 1(1), which provides:

> Subject to the provisions of Schedule 1, a person has a disability for the purposes of this Act if he has a physical or mental impairment which has a substantial and long-term adverse effect on his ability to carry out normal day-to-day activities.

> Then there are provisions in Schedule 1 which examine the issue in much more detail. In each paragraph there is a power to make regulations in the light of how the paragraph to which it relates is working out in practice. And there are the provisions that the Schedule itself sets out. Not only is it important that these detailed provisions should be understood and applied in the right way. It is important that they should be interpreted uniformly throughout the United Kingdom.

19.6 The irony in this is that inconsistency in itself is not grounds for judicial review (*Domtar Inc. v. Québec (Comme d'appel en matière de lesions professionnelles)* [1993] 2 S.C.R. 756).

19.7 *Ontario (Minister of Municipal Affairs & Housing) v. Transcanada Pipelines Ltd.* (2000), 186 D.L.R. (4th) 403 (Ont. C.A.) ("A tribunal is not bound to follow its own decisions on similar issues although it may consider an earlier decision persuasive and find that it is of assistance in deciding the issue before it."); *Canada (Minister of Employment & Immigration) v. Jawhari* (1992), 59 F.T.R. 22 (Fed. T.D.) (not open to Immigration and Refugee Board to determine application solely on basis of an earlier Board decision, the matter had to be determined on its own merits.).

19.7.1 In *El-Hennawy v. Law Society of Upper Canada,* 2014 CarswellOnt 953, 2014 ONSC 375 (Ont. Div. Ct.) the Divisional Court has held that Convocation of the Law Society of Upper Canada had the authority to make non-binding guidelines to structure the exercise of its discretion in making indemnification grants. The Court noted that the guidelines were a way of structuring the exercise of the Society's discretion and providing some consistency.

19.8 *Kripps v. Canada (Attorney General)* (2002), 219 F.T.R. 146 (Fed. T.D.).

19.9 In illustration see *Ha v. Canada (Minister of Citizenship & Immigration),* 2004 CarswellNat 247, 2004 FCA 49, 11 Admin. L.R. (4th) 306, 236 D.L.R. (4th) 485 (Fed. C.A.). See also *Tremblay v. Québec (Commission des Affaires socials),* [1992] 1 S.C.R. 952, 90 D.L.R. (4th) 609 (S.C.C.) where systemic pressure on board members to consult other members of the agency in full board meetings before departing from previous agency decisions was found to be improper.

See also the trial and appeal level decisions in *Thamotharem v. Canada (Minister of Citizenship & Immigration)*, 2006 CarswellNat 6, 2006 FC 16 (Fed. T.D.); reversed 2007 CarswellNat 1391, 2007 FCA 198, 60 Admin. L.R. (4th) 247 (Fed. C.A.), leave to appeal to S.C.C. refused 383 N.R. 400 (note), 2007 CarswellNat 4334, 2007 CarswellNat 4335, [2007] S.C.C.A. No. 394 (S.C.C. Dec 13, 2007). In that case the Immigration and Refugee Board had issued a guideline which provided that a hearing would start with the agency's questioning of a claimant (rather than the claimant's counsel leading off the hearing). The guideline used mandatory language ("the standard practice will be") and provided that the member might deviate in "exceptional circumstances". The trial level proceeding found that among other things there was also evidence that the agency managers were required to monitor the compliance with the guidelines of individual members; that members not complying were personally asked by the Vice-Chair to explain their deviation; and the application of the guidelines in appropriate circumstances was a factor in a member's performance appraisal. The trial level decision found that the guideline fettered the discretion of the members.

On appeal, the Federal Court of Appeal reversed the trail decision on this issue. In doing so it also took a somewhat different view of the facts. The account to the Vice-Chair allegedly required of non-compliant members and the performance review aspects of the trial decision were not mentioned. Instead the Court of Appeal appears to have focused on the language of the guideline, monitoring by the agency for compliance, and an expectation that deviations from the guidelines would be explained in reasons. (The Court of Appeal also dismissed the fact that some members might in fact *feel* that they were bound — holding that if that was so their individual decisions could be challenged for fettering.)

In minority reasons concurring in the result, Justice Sharlow appears to have felt that the guideline was just written incorrectly and that, properly understood, each member continued to have the unfettered discretion to adopt any order of procedure required by the circumstances of each claim.

Justice Evans writing for the majority held that neither the monitoring nor the expectation that deviations should be explained in reasons amounted to fettering.

> 86. Evidence that the Immigration and Refugee Board "monitors" members' deviations from the standard order of questioning does not, in my opinion, create the kind of coercive environment which would make Guideline 7 an improper fetter on members' exercise of their decision-making powers. On a voluntary basis, members complete, infrequently and inconsistently, a hearing information sheet asking them, among other things, to explain when and why they had not followed "standard practice" on the order of questioning. There was no evidence that any member had been threatened with a sanction for non-compliance. Given the Board's legitimate interest in promoting consistency, I do not find it at all sinister that the Board does not attempt to monitor the frequency of members' compliance with the "standard practice".
>
> 87. Nor is it an infringement of members' independence that they are expected to explain in their reasons why a case is exceptional and warrants a departure from the standard order of questioning. Such an expectation serves the interests of coherence and consistency in the Board's decision-making in at least two ways. First, it helps to ensure that members do not arbitrarily ignore Guideline 7. Second, it is a way of developing criteria for determining if circumstances are "exceptional" for the purpose of paragraph 23 and of providing guidance to other members, and to the Bar, on the exercise of discretion to depart from the standard order of questioning in future cases.

With respect to the language of the guidelines, the majority reasons agreed that it appeared to be mandatory. However, in holding that this mandatory language did not amount to a fettering the majority reasons appear to hold that binding procedural discretion was acceptable provided that the member had a "meaningful degree" of discretion to depart therefrom. This aspect of the decision is discussed in more detail below in note 35.

19.10 *VIA Rail Canada Inc. v. Canadian Transportation Agency,* 2007 CarswellNat 608, 2007 SCC 15, J.E. 2007-670 (S.C.C.). In this case the Supreme Court of Canada held that the National Transportation Agency did not err in reaching a decision against VIA Rail by taking into account standards set out in its 1998 Rail Code. The Rail Code was the result of a "voluntary, consensus-building process involving extensive consultation with the transportation industry, the community of persons with disabilities and other government ." Developed in consultation with an expert human rights agency, the Rail Code standards represent objectives that rail carriers, including VIA, publicly accepted. Its purpose was to function as self-imposed regulation, establishing minimum standards all rail carriers agreed to meet. The Code itself gave notice that: "It is expected that this [passenger rail car accessibility] Part of the Code of Practice will be followed by VIA Rail Canada Inc." VIA Rail, itself, had agreed to the Code.

> 147 It was, accordingly, a proper factor in the Agency's analysis, especially since the anticipation of compliance is reflected in the language of the Rail Code itself, which provides, in s. 1.1.1: "It is expected that this [passenger rail car accessibility] Part of the Code of Practice will be followed by VIA Rail Canada Inc." The fact that the Rail Code was voluntarily agreed to and not government-imposed reinforces, rather than detracts from its relevance as a factor for assessing VIA's "undue hardship" arguments. VIA knew it had agreed to, and was expected to comply with, the Rail Code.

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