Terasen Gas

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

16705 Fraser Highway
Surrey, B.C. V3S 2X7
Tel: (604) 592-7784
Fax: (604) 592-7890
Email: scott.thomson@terasengas.com
www.terasengas.com

September 2, 2005

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Mr. R.J. Pellatt, Commission Secretary

Dear Sir:

RE: Terasen Gas Inc. ("Terasen Gas") or ("TGI")
Terasen Gas (Vancouver Island) Inc. ("TGVI")
Return on Equity and Capital Structure
Response to Commission IR No. 1

Please find attached TGI and TGVI's response to Commission Information Request No. 1. It should be noted that due to the size of the electronic document, the Information Response and appendices are being uploaded to the Commission website in sections. Furthermore, as it is believed that most Intervenors email systems will not be able to cope with a document of this size, TGI and TGVI will not be forwarding the appendices to this submission. The full submission including all appendices will be available on the Terasen Gas website at the following location on Tuesday September 6, 2005.

http://www.terasengas.com/_Publications/Regulatory/Submissions/VancouverIslandSunshineCoast/default.htm

Also, as requested in Commission IR 1, No 71.3 and 71.5, TGI and TGVI have attached a working model (excel) as part of this submission.

Questions concerning this application may be directed to Scott Thomson (604) 592-7784 or Tom Loski (604) 592-7464.

All of which is respectfully submitted,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC.

Scott A. Thomson

cc: Registered Intervenors

1.0 General

1.1 Please provide data on Terasen Inc. revenues in each year since 1988, broken down between Pipeline, Distribution and Other business units. For Distribution, please provide revenue data with and without the cost of gas included.

Response:

Revenues	Natural gas distribution (incl. cost of gas)	Natural gas distribution (excl. cost of gas)	Petroleum transportation	Other
1988	$276.1	$116.5	$63.0	
1989	$586.4	$240.3	$76.2	
1990	$607.9	$251.5	$83.1	
1991	$613.4	$258.2	$94.3	
1992	$593.9	$243.2	$99.1	$6.0
1993	$678.1	$290.5	$99.6	$16.9
1994	$708.0	$280.7	$105.9	$40.1
1995	$735.5	$333.5	$114.0	$45.4
1996	$724.3	$361.3	$132.8	$44.3
1997	$765.8	$390.6	$129.1	$39.0
1998	$742.4	$404.2	$135.4	$47.2
1999	$844.7	$402.5	$129.4	$66.5
2000	$1,085.4	$427.0	$132.5	$87.7
2001	$1,420.3	$488.5	$143.1	$102.9
2002	$1,402.7	$595.5	$136.0	$168.5
2003	$1,497.9	$608.2	$200.0	$178.7
2004	$1,494.1	$608.7	$225.5	$237.4

1.2 Please provide a summary of TGI's allowed ROE and actual ROE for each year since rate regulation for BC Gas commenced. Also, for each year when a PBR mechanism was in effect, please include a record of all incentives earned, and the impact of these incentives in terms of the percentage of actual ROE earned.

Response:

TGI's allowed and actual ROE (pre and post earnings sharing), including off system sales incentives, since the inception of rate regulation for BC Gas is as follows:

	TGI					
				Off System Sale Incentive Program (GSMIP) - Dollars in Millions		
	Allowed ROE	Actual Pre-Earnings Sharing ROE	Actual Post-Earnings Sharing ROE	TGI Share	Core Market Share	Total
1992	12.25%	9.061%		-	-	-
1993	N/A	11.909%		-	-	-
1994	10.65%	9.727%		-	-	-
1995	12.00%	12.030%	-	-	-	-
1996	11.00%	11.803%	-	-	-	-
1997	10.25%	11.266%	-	$ 5.1	$ 26.4	$ 31.5
1998	10.00%	9.405%	9.703%	$ 2.7	$ 50.5	$ 53.2
1999	9.25%	10.698%	9.974%	$ 1.4	$ 56.0	$ 57.4
2000	9.50%	10.748%	10.124%	$ 2.1	$ 83.8	$ 85.9
2001	9.25%	9.375%	9.313%	$ 2.9	$ 143.9	$ 146.8
2002	9.13%	10.032%	-	$ 1.2	$ 32.2	$ 33.4
2003	9.42%	10.226%	-	$ 1.1	$ 29.7	$ 30.8
2004	9.15%	9.460%	9.305%	$ 1.1	$ 30.8	$ 31.9

1.3 Please provide the dollar impact to TGI and TGVI of an absolute 1% increase in the equity thickness of each company.

Response:

An absolute 1% increase in the equity thickness to TGI will translate to an equity injection of $23.9 million dollars. The after-tax earned return to TGI will increase by approximately $2.2 million.

An absolute 1% increase in the equity thickness to TGVI will translate to an equity injection of $4.5 million. The after-tax earned return to TGVI will increase by approximately $0.4 million.

1.4 Please provide the dollar impact to TGI and TGVI of a 25 basis points increase to the ROE of each company.

Response:

A 25 basis points increase to the ROE of TGI will increase the after-tax earned return to TGI by approximately $2 million.

A 25 basis points increase to the ROE of TGVI will increase the after-tax earned return to TGVI by approximately $0.4 million.

1.5 Please provide a copy of the Terasen Inc. Annual Report for 2004.

Response:

Please see Appendix 1.5

2.0 Reference: Cover letter, p. 2

Terasen says that:

> *"There have been significant reductions in the yields on long-term Canada bonds used to determine the allowed return on equity since the automatic adjustment mechanism was first introduced, and material changes in general economic conditions and the risk profile of TGI over that period of time. These changes, and the allowed returns on equity calculated through the automatic adjustment mechanism, have resulted in significant negative consequences for utility investments in British Columbia."*

2.1 Please provide a detailed record of Terasen's bond ratings since 1988, its ROE since 1988, all of its debt issues since 1988 (and the corresponding premium on the benchmark bond), the yields on matching long-term Canada bonds since 1988, and Terasen's stock price since 1988.

Response:

Please see Appendix 2.1

2.2 Please provide the DBRS single A market spreads on the matching long-term Canada bonds since 1988.

Response:

Terasen has made inquiries of DBRS to obtain this information. DBRS has advised that this information is no longer published by them and Terasen does not have another source for similar data.

2.3 Please list the significant negative consequences for utility investments that have resulted since 1994, and comment on the specific determining factors of these negative consequences.

Response:

The principal negative consequence has been that the BC Utilities are not being fairly compensated relative to their Canadian and U.S. peers. As a result, they are disadvantaged in competing for capital. The disadvantage extends to intra-company competition for capital, when the parent company decides to which of its existing investments or to what new investments it will allocate capital to achieve the best risk-adjusted returns. The low allowed returns and thin common equity ratios disincent the utilities from undertaking additional investment to attach new customers. They put undue pressure on other costs in order to be able to enhance actual returns to more compensatory levels; ultimately, they will put utilities into the position of choosing between achieving compensatory returns for investors and service quality. The low levels of allowed returns and thin common equity ratios also put pressure on debt ratings, as declines in allowed returns squeeze the key cash flow ratios that debt rating agencies focus on.

3.0 Reference: Cover letter, p. 2

Terasen says that:

> *At today's prevailing long term Government of Canada bond yields of 4.21%, the current automatic adjustment mechanism would yield a benchmark ROE of 7.71% and there are signals that bond yields may move lower…*

3.1 Please elaborate on the signals that bond yields may move lower. Please comment on what factors or signals, if any, might suggest that bond yields may move higher.

Response:

A slowing of growth in the U.S. and/or world economy could result in lower long-term bond yields globally as well as in Canada. Factors that could impair economic growth include rising commodity prices, particularly oil, as well as potential weakness in residential property markets that, in many jurisdictions, are considered to be overheated and potentially experiencing "bubble" conditions. In addition, a continued strengthening of the Canadian dollar due to high oil prices could result in lower bond yields if the Bank of Canada responds to the monetary policy impact of an appreciating currency by keeping short-term interest rates lower than would otherwise be the case.

Factors that could cause bond yields to move higher could include increasing inflation rates or a severe drop in commodity and energy prices, causing capital outflows from Canada.

TGI and TGVI were not purporting to predict long-term interest rates in the referenced statement. Rather, the Company's intention was to note that, although long-term Canadian interest rates are at historically low levels, bond yields could continue to move lower, further disadvantaging TGI and TGVI relative to their peers and further weakening credit ratios.

4.0 Reference: Cover Letter, p. 3
TGVI 2006-2007 Revenue Requirements Application

On page 3 of the Cover Letter:

> *"Terasen Gas (Vancouver Island) Inc. submits that the common equity component in the capital structure of TGVI allowed for rate making purposes should be 40% (as compared to the 35%). Terasen Gas (Vancouver Island) further submits that it be granted a 75 basis point increment over the allowed return on equity for TGI (i.e. 11.25% when the forecast yield on long-term Canada bonds in 5.25%) to reflect TGVI's greater risk profile."*

4.1 In 2004 what was TGVI's financial status as an investment grade debt investment?

Response:

TGVI did not have credit ratings, nor had TGVI issued debt during 2004, so there is no third-party rating agency or investor validation of the credit status of TGVI.

4.2 Please provide the present financing status of TGVI and its plans to repay approximately $176 million of its existing long term debt on January 11, 2006 when it matures. What are the necessary refinancing objectives that need to be satisfied before a bond issue is floated?

Response:

TGVI has been in discussions with investment bankers for purposes of arranging a combined bank and bond financing. TGVI is seeking financing that would close in the fourth quarter of 2005, in order to refinance its existing debt prior to the scheduled debt repayment of $176 million on January 11, 2006.

The structure that TGVI is seeking would consist of a $150 million operating facility and between $200 million and $250 million debentures, to refinance the existing term bank debt and short-term borrowings advances, as well as provide a short-term working capital facility.

The financing is not yet in place. Primary remaining objectives to be satisfied before a debenture issue can be launched include:

- Satisfactory investment grade ratings are obtained;
- BCUC approval of the debt financing:
- Satisfactory terms and conditions agreed by potential investors in the credit agreement and trust indenture;
- Satisfactory market conditions with respect to investor demand, interest rates and term selection.

4.3 TGVI in its 2006-2007 Revenue Requirements Application has assumed that $250 million of long-term debentures will be financed at an average rate of 6.13%. Please provide the anticipated term of the long-term debenture. Please also identify the relevant long-term Government of Canada bond, its yield, and the risk premium to arrive at the 6.13%.

Response:

The rate assumption in the revenue requirement application was based on a $125 million 10-year debenture and a $125 million long-term debenture. A generic forecast of Government of Canada bond yields for each term was used. Specific Government of Canada bonds were not used as a forecast basis. The forecast 10-year rate was 4.5% and the long-term rate was 5%. The new issue spreads utilized were 1.25% and 1.5%, respectively. The interest rates, therefore, were 5.75% and 6.5%, for a blended rate of 6.125%.

The actual term of any debentures issued will be determined if and when they are issued.

4.3.1 Does TGVI currently have bond ratings issued by any of the recognized bond rating services in Canada? If so, please provide the report(s). If not, what is the anticipated bond rating that the 6.13% rate is based on and the assumptions used?

Response:

TGVI does not currently have bond ratings.

The 6.13% rate was based on an assumption that TGVI would be able to obtain an investment grade credit rating, albeit lower ratings than Terasen Gas Inc. TGVI's approved capital structure will have a bearing on the level of the prospective credit rating.

4.3.2 Is the 6.13% interest rate based on the assumption of a 40% common equity component and 75 basis points risk premium for TGVI?

Response:

Yes.

4.3.3 Please provide all presentations and documentation made to financial analysts and bond rating agencies since 2001 in regard to TGVI.

Response:

Appendix 4.3.3 contains a powerpoint presentation and financial model provided to both DBRS and Moody's in July 2005 for the purposes of obtaining a long term credit rating in support of the proposed refinancing of TGVI. The following documents were also provided to the rating agencies and can be provided if needed:

- 2001-2004 TGVI financial statements
- Vancouver Island Natural Gas Pipeline Agreement
- 1995 Special Direction to the BCUC

There have been no other presentations or documentation made to bond rating agencies and no presentations or documentation to financial analysts in regard to TGVI since Terasen Inc. acquired TGVI.

4.3.4 Please provide all financial analyst reports and bond rating agency reports since 2001 in regard to TGVI.

Response:

As TGVI does not have credit ratings nor public shareholders, there are no such reports.

4.3.5 Please provide all financial analyst reports and bond rating agency reports since 2001 for Terasen Gas Inc. or Terasen Inc. that mention TGVI.

Response:

Please refer to Appendix 4.3.5

4.4 How many bond rating agency reports does TGVI plan to receive before issuing investment grade debt? What is the anticipated timing of issuance of the bond rating report(s)?

Response:

TGVI is anticipating indicative ratings to be obtained on a non-public basis from DBRS and Moody's. One or both of the ratings will be made public concurrently if and when bonds are offered.

4.5 If the bond rating report(s) are not available in the evidentiary phase of the hearing, would it be prudent to wait until TGVI has received a credit rating report(s) that assesses the utility's financial risk before making a decision for a change in ROE?

Response:

The credit rating reports are expected to be available prior to the close of the evidentiary phase of the hearing. This application deals with the generic ROE automatic adjustment mechanism which impacts all utilities regulated by the BCUC and, whether or not the reports are available, this application should be dealt with by the Commission, keeping in mind the dual obligations of the regulator to both rate payers and investors. .

4.6 TGVI and TGI have implemented the Utilities Strategies Project that harmonizes the business processes and financial systems with those used by TGI. Would the change in management and integration by a larger established company, TGI, with its larger pool of internal resources to draw upon, be considered a reduction of business risk to TGVI than when it was stand-alone? If not, why not?

Response:

The integration of TGVI has resulted in TGVI's customers benefiting from operational economies of scale and scope that they would not have access to if TGVI were, in fact, a stand-alone utility. These synergies benefits resulting from the Utilities Strategy Project will benefit ratepayers through lower costs. To the extent that these lower costs contribute to cost competitiveness they can and should have a positive benefit on business risk all other things being equal. This modest risk mitigation is overshadowed by factors such as the accumulated revenue deficiencies in the RDDA, gas cost pressures and the pending elimination of the Royalty Revenues in 2012 given the residential customer base is already capped at the electric equivalent rate and is not fully recovering costs.

The application of the stand-alone principle ensures that it is the inherent risk of the particular utility which is the determinant of the appropriate capital structure return on equity, not the parent's capital structure or the resources of an affiliated company. TGVI's allowed return and capital structure should be determined irrespective of ownership and affiliation. These parameters should not change simply because ownership has changed. The fair return determination always proceeds on the premise of efficient management of the utility.

Finally, current commodity costs and uncertainty regarding the retention of BC Hydro as a firm transportation customer on the TGVI system greatly over shadow the benefits derived from the productivity gains resulting from the restructuring that followed the acquisition of TGVI by Terasen.

4.7 Is the Customer Care Conversion CPCN for TGVI another instance of harmonization of computer systems and business processes from "meter to cash" that reduces business risk? If not, why not?

Response:

TGI and TGVI do not agree that the harmonization of computer systems and business processes reduce business risk in a meaningful way.

The Customer Care Conversion will increase operational efficiency and protect cost efficiencies realized through the restructuring initiatives, but overall it is not expected to have a material bearing on cost of service. The CPCN application outlined modest cost/benefits to customers, and the Company was required to backstop the realization of those benefits as well as the costs of the project with no recourse to customers. Arguably the project modestly increases the Company's business risk.

To the extent that harmonization of systems and processes reduces costs, those cost decreases may result in the delivered cost of natural gas being somewhat lower than it would otherwise have been, but the delivered cost of natural gas in B.C. is less competitive with electricity than it has been in the past, and less competitive than elsewhere in Canada.

4.8 When did Terasen Inc. purchase TGVI?

Response:

The purchase was effective from January 1, 2002, and closed on March 7, 2002.

4.8.1 What was the price to book ratio of the purchase?

Response:

TGVI's common shares and Class A preferred shares had a book value of $252 million, for which Terasen paid a purchase price of approximately $260 million. The resulting price to book ratio was 1.03 times. The purchase price and book value for the TGVI common shares and Class A preferred shares were as follows:

	Purchase Price	Book Value	Price/Book Ratio

Class A Preferred Shares	$60 million	$84 million	0.71
Common Shares	$200 million	$168 million	1.19
Total Equity	$260 million	$252 million	1.03

4.8.2 What was the debt investment grade status of TGVI at the time of the purchase?

Response:

TGVI did not have credit ratings at the time of the purchase.

4.8.3 Did Terasen Gas Inc. conduct due diligence for the purchase of Centra Gas British Columbia Inc.? Was Terasen aware of all the risks and rewards in the ownership of Centra including all outstanding agreements and obligations?

Response:

No. Terasen Inc., not Terasen Gas Inc., purchased Centra Gas (now TGVI). Terasen Inc. acquired Centra Gas British Columbia Inc. and was responsible for and funded such due diligence activities. Terasen Inc. had a relatively short period of exclusivity within which to make its assessment and confirm its offer. As such it did not have complete and full knowledge of all risks and potential rewards of ownership but satisfied itself that it was interested in completing the transaction. Terasen Inc. as shareholder of TGVI understood the risks of ownership of TGVI were greater than those of TGI and as such expected that the capital structure and TGVI allowed for rate making purposes would appropriately reflect the risks of TGVI and that TGVI would be allowed the opportunity to earn a fair and reasonable return, commensurate with such higher risks, both in accordance with common regulatory principles of rate base rate of return regulation over time.

It should be noted that at the time of the acquisition of TGVI by Terasen Inc. the equity component of the capital structure and the return on equity of TGVI were determined in accordance with the Special Direction to the Commission. The Special Direction provides that after 2002 the equity component of TGVI's rate base and the return on equity would be determined in accordance with regulatory principles that are generally applied by the BCUC from time to time to gas distribution utilities operating within B.C. (section 4.2).

At the time of the acquisition, Terasen Inc. did not contemplate the recent run up in gas commodity prices and had anticipated that additional gas fired electricity generation would be constructed on Vancouver Island that would increase system utilization and lead to increased revenues from BC Hydro. In the aftermath of BC Hydro's decision to abandon Duke Point TGVI now understands that BC Hydro is evaluating the practicality of turning the ICP into a peaking facility which puts firm load at risk and jeopardizes recovery of RDDA by 2011, greatly increasing business risk.

4.8.4 Please outline all the regulatory framework changes (Special Direction, major agreements, amending agreements, rate design, etc.) from the purchase of Centra to the present.

Response:

On December 6, 2001, B.C. Gas Inc. applied to the Commission for approval of the acquisition of Centra Gas B.C. Ltd ("Centra Gas"). On February 4, 2002, in its Orders G-8-02, G-9-02 and G-10-02, Commission approved the acquisition. Consent to a change in control of Centra Gas was also required and granted from the Province of British Columbia, through amendments to the Vancouver Island Natural Gas Pipeline Act on July 4, 2002. Below is a listing of all major regulatory framework changes from the official date of acquisition to present:

Revenue Requirements

On July 31, 2002, Centra Gas applied for approval of its 1999 to 2001 actual revenue deficiencies and its forecast 2003 to 2005 revenue requirements for its Vancouver Island and Sunshine Coast service areas. The Application was reviewed through a Negotiated Settlement Process. On January 14, 2003 Commission Approved the Application as per Order G-2-03.

The 2003 Annual Review requested approval of the 2002 Actual Revenue Deficiency, Forecast 2004 Royalty Adjusted Cost of Gas, Amortization of the forecast Gas Cost Variance Account Balance, the creation of an Apartment Rate Class-AGS and 2004 Customer Rates and the incremental OM&A costs of the Sooke extension as forecast in the CPCN Application. Commission Order G-81-03 approved this application.

The 2004 Annual Review application requested approval of proposed rates for 2005 of the 2003 actual revenue surplus, a proposed operating lease arrangement to allocate 10 percent of the SAP related costs to TGVI from Terasen Gas Inc. ("TGI"), $8.0 million in capital additions related to the Utilities Strategy Project, allocation of Shared Services costs to TGVI, 10 percent allocation of Gas Supply Core Administration costs to TGVI, 2005 Core Customer Rates, setting the Gas Cost Variance Account ("GCVA") Rate Rider D to zero, 2005 Firm Transportation and Interruptible rates, 2005 OM&A capitalization, forecast 2005 Royalty Adjusted Cost of Gas, and amortization of the forecast GCVA Balance; and $22,000 in incremental operating, maintenance and administrative expenses ("OM&A") of the Sooke main extension for 2005. Commission Order G-113-04 approved this application but directed that $78,500 be removed from project costs for the Sooke extension.

On July 20, 2005 TGVI filed an application with the Commission for approval of its 2006 and 2007 rates and revenue requirements.

Rates and Rate Design

On September 11, 2002, Centra Gas applied to the Commission for approval of an Amendment to Industrial Gas Sales Agreement with the University of Victoria covering the period August 25, 2002 to December 31, 2002. . The Commission approved the Amendment effective August 25, 2002. The Amendment to Industrial Gas Sales Agreement continued in effect December 31, 2002.

A Rate Design application was made on September 30, 2002. This document has set the framework for rate setting at TGVI beginning in 2003. On June 5, 2003 as per Commission Order G-42-03, the following was approved:

- Core customer class segmentation and a "soft-cap" methodology for setting core customer rates, together with proposed by Centra Gas effective January 1, 2003.
- A rate for Firm Transportation ("FT") service of $1.074/GJ, effective January 1, 2003. For the interim period between the Island Cogeneration Plant's ("ICP") Commercial Operation Date of April 12, 2002 and December 31, 2002, the Commission approves the interim ICP FT rate as permanent.
- A summer Interruptible Transportation ("IT") rate of $1.074/GJ, equal to the approved FT rate, effective January 1, 2003. The Commission approves a winter IT rate of $1.492/GJ, equal to the approved FT rate at a 72 percent load factor, effective January 1, 2003.
- The Commission approves the interim ICP IT rate as permanent for the period prior to January 1, 2003.
- The Amending Agreements with BC Hydro.
- Recovery of $700,000 of its COSA and rate design costs, to be allocated as a general cost in rates, amortized over 3 years beginning in 2003.

VIGJV and BC Hydro filed appeals to the Court of Appeal of the Commission's Decision. Both appeals were dismissed. BC Hydro also sought reconsideration of certain aspects of the Decision. The BC Hydro application for reconsiderations was denied by the Commission. TGVI sought reconsideration of the effective date of the new rates for BC Hydro, which reconsideration application was adjourned pending the hearing of the appeals.

<u>Revenue Deficiency Deferral Account ("RDDA")</u>

Prior to 2003, Terasen Inc. funded the annual revenue deficiency through the issuance of preferred shares and subordinated debt at rates established by Special Direction which forms part of the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA") and approved by the Lieutenant Governor in Council through Order in Council 1510.

From 2003 onwards, TGVI has applied to fully recover its cost of service through approval of its Annual Review application. As part of its 2003 and 2004, TGVI applied for approval of the cumulative balance in the RDDA Account. In both 2003 and 2004 the cumulative balance was approved as per Commission Order G-81-03 and G-113-04.

<u>VIGJV Agreements</u>

The VIGJV and PCEC (now TGVI) entered into the VIGJV Transportation Service Agreement ("JVTSA") and the VIGJV Peaking Gas Management Agreement ("JVPSMA") effective December 14, 1995. TGVI and VIGJV entered into an Amending Agreement to amend the terms of the JVTSA and the JVPGMA on October 27, 2004. By Vancouver Island Natural Gas Pipeline Special Direction No. 2 (ordered through Order in Council, 1224 dated December 11, 2004), the Commission was directed to approve the Amending Agreement, which was done by Commission Order G-113-04 dated December 14, 2004.

<u>BC Hydro Agreements</u>

There are two key agreements with BC Hydro: The BC Hydro Transportation Service Agreement ("BCH TSA") under which gas is transported to the ICP and the Peaking Agreement ("BCHPA") under which gas is made available to TGVI during cold weather. Both are originally dated March 7, 2001 and there have been amendments as of September 1, 2001, October 17, 2002, September 30, 2003, October 29, 2004 and December 17, 2004. The BCHTSA and the BCHPA are both short term agreements expiring in October 31, 2005.

At the present time there is no long-term contractual commitment from BC Hydro for the transportation of gas to ICP.

LNG Facility CPCN

On June 18, 2004 TGVI filed a Resource Plan and on August 4, 2004, the Company filed an Application for a Certificate of Public Convenience & Necessity (CPCN) to construct and operate a Liquefied Natural Gas ("LNG") Storage Facility, at a location referred to as Mount Hayes. The Commission, in its Order No. G-38-04, established a regulatory agenda for that application, including an oral public hearing and which ended January 14, 2005. The Commission approved the CPCN Application by Order No. C-2-05 dated February 15th, 2005 subject to TGVI meeting several conditions. These conditions were:

- The Engineering Procurement and Construction ("EPC") bid price that TGVI accepts for the LNG facility will not exceed 110 percent of $75.9 million (i.e. $83.5 million);
- a firm long-term TSA for service to ICP and DPP will be executed by TGVI and BC Hydro and approved by the Commission prior to commencement of construction of the LNG project;
- an LNG Storage Agreement that assures TGVI of Mitigation revenue consistent with the amounts that TGVI used in its financial analysis will be executed by TGVI and Terasen Gas Inc. ("Terasen Gas") and approved by the Commission prior to the commencement of the construction of the LNG project; and
- the CPCN will terminate if construction of the LNG project has not commenced by December 31, 2005.

On April 25, 2005, TGVI advised the Commission that it had entered into an EPC Contract with Horton Chicago Bridge & Iron ("HCBI") for the LNG facility based on a firm contract price formula that was valid until June 17, 2005. The Commission acknowledged TGVI's April 25, 2005 submission, in a letter (Log 9956) dated May 16, 2005.

TGVI submitted an application on March 31, 2005 seeking Commission approval of its LNG Storage and Delivery Agreement with Terasen Gas. Concurrently Terasen Gas submitted its application for approval of the same agreement. The Commission approved the agreement in its Order No. G-44-05.

TGVI and BC Hydro had concluded extensive discussions regarding transportation service to ICP and the proposed generation facility at Duke Point, prepared draft agreements, and TGVI had consulted with its stakeholders. However, on June 17, 2005 BC Hydro notified TGVI, the Commission and the public that it as abandoning the proposed Duke Point Project. Consequently, a long-term TSA to serve the Duke Point project was not executed and the condition relating to that a long-term TSA with BC Hydro was not satisfied.

4.8.5 Please provide a table of the actual and forecast RDDA year-end balance from 1995 to 2007. Also include the RDDA balance at the time of purchase.

Response:

Terasen Inc. acquired Centra Gas (now TGVI) in 2002. The 2002 RDDA balance was $87,910,503.

		RDDA Year End Balance			
		2005-06 Gas Cost Update	As Filed *(Note 1)*	Variance	
1995	Actual	$17,480,665	$17,480,665	$0	
1996	Actual	$28,113,422	$28,113,422	$0	
1997	Actual	$36,954,237	$36,954,237	$0	
1998	Actual	$51,665,155	$51,665,155	$0	
1999	Actual	$67,133,612	$67,133,612	$0	
2000	Actual	$72,811,221	$72,811,221	$0	
2001	Actual	$85,036,894	$85,036,894	$0	
2002	Actual	$87,910,503	$87,910,503	$0	
2003	Actual	$75,287,752	$75,287,752	$0	
2004	Actual	$60,921,090	$60,921,090	$0	*(Note 2)*
2005	Forecast	$50,245,749	$50,742,279	($496,530)	*(Note 3)*
2006	Forecast	$46,065,148	$45,225,491	$839,657	*(Note 4)*
2007	Forecast	$35,668,234	$36,466,811	($798,577)	*(Note 5)*

Notes:

1. Forecast RDDA balance per TGVI 2006-07 Revenue Requirement Application submitted on July 20, 2005.

2. The 2004 RDDA balance has not yet been approved by BCUC.

3. There is an increase in net gas cost of $538K in 2005. The higher revenue requirement also results in $402K more in Cost of Service. The rate design logic dictates that the revenue collected based on the higher revenue requirement can be adjusted up by $1.437M. Hence, 2005 revenue surplus is $497K higher or the 2005 RDDA balance is $497K lower.

4. There is an increase in net gas cost of $3.144M in 2006. The higher revenue requirement also results in $1.076M more in Cost of Service. The rate design logic dictates that the revenue collected based on the higher revenue requirement can only be adjusted up by $2.847M. The higher 2005 revenue surplus helps reduce 2006 deemed interest on subordinated debt by $36K. Hence, 2006 revenue surplus is $1.337M lower or the 2006 RDDA balance is $840K higher ($1337K - $497K).

5. There is no change in net gas cost in 2007. However, the rate design logic dictates that the higher rates set in 2006 will be applied in 2007 after comparing with the alternate fuel rates. The revenue collected is $2.805M higher which leads to $1.157M more in Cost of Service, mainly in Income Tax Expense ($987K). The lower cumulative revenue surplus (2005-06) increases 2007 deemed interest on subordinated debt by $10K. Hence, 2007 revenue surplus is $1.638M lower or the 2007 RDDA balance is $798K lower ($840 - $1,638K).

The RDDA balance depends heavily on the business environment in which Terasen operates. The situation is highlighted when a more current forecast of 2005/06 gas commodity costs is incorporated in the calculation of the RDDA balance. With 17% higher gas price forecast in 2006, the RDDA balance increases by over $3 million. The forecast balance is also very dependent on the assumptions respecting the future of the contracts with BC Hydro. The above assumptions assume that BC Hydro will continue to contract for transportation on a firm basis at 2004/05 levels. If the BC Hydro contract demand decreases, or if ICP were to operate in a manner that only interruptible supplies of gas were required, the forecast RDDA balance could increase significantly, and the prospect of fully recovering the RDDA balance by 2011 would be jeopardized.

4.8.6 In the 2006-2007 TGVI Revenue Requirements Application on page 8 it states: "TGVI's shareholder funded the annual revenue deficiency through the issuance of preferred shares and subordinated debt at rates established by the Special Direction." Please elaborate on the risk associated with the shareholder funding. What has happened to the preferred shares since the purchase?

Response:

Section 2.10(j) of the 1995 Special Direction to the BCUC provides that starting in 2003 TGVI's cost of service shall include an amount for the redemption of the Class A or B instruments, "that the BCUC determines to be appropriate in order to amortize the balance of the Revenue Deficiency Deferral Account over the shortest period reasonably possible, <u>having regard for Centra's competitive position relative to alternative energy sources and the desirability of reasonable rates.</u>" (emphasis added).

TGVI's shareholder is required to fund operating shortfalls up to a cumulative level of $120 million. Given the Special Direction, the main risk associated with the shareholder funding, both historically and prospectively, is the potential impact of higher gas prices on TGVI's relative competitiveness versus electric rates on Vancouver Island and preservation of existing load.. Since the purchase, the Class A preferred shares (now represented by Class B subordinated debt) have been partially repaid in accordance with the Special Direction, as TGVI has been able to maintain competitive pricing relative to electricity up to now. Prospectively, the pay down of the shareholder financing will depend on gas costs, load retention and competitive alternative energy rates.

The ability to repay the subordinated debt depends on TGVI's ability to reduce the RDDA balance. As noted in the response above, the prospect of RDDA recovery has been jeopardized by recent events.

5.0 Reference: Cover letter, pp. 4-5

Terasen expresses "significant concern" that a utility seeking to attract capital is in competition not just with utilities and other companies in Canada, but also with participants in capital markets beyond Canada. Terasen says that the "changed circumstances require a different response if British Columbia wishes to be seen as an attractive place in which to invest capital."

5.1 Has Terasen's significant concern in this regard been alleviated to any degree by the recent agreement to purchase Terasen by Kinder Morgan?

Response:

No. Kinder Morgan's decision to acquire Terasen Inc. was motivated by its interest in Terasen Inc.'s petroleum transportation business, and particularly the growth potential in Terasen Pipelines arising from growth in the Alberta oil sands. It is highly unlikely that Kinder Morgan would have proposed its acquisition if Terasen Gas was Terasen's only asset, let alone pay a premium at or near the levels proposed in the current transaction.

Whether a utility is widely owned by shareholders or a wholly-owned subsidiary of another entity, returns on invested capital must be adequate to ensure that investors, whether public shareholders or a parent company, are incented to provide capital needed for utility investment and provide a fair and reasonable return on capital already invested .

5.2 What is the premium above market price and the Price to Book ratio paid by Kinder Morgan for Terasen Inc.?

Response:

Kinder Morgan's offer price of $35.75 per Terasen share represents a premium of 164% over Terasen's June 30, 2005 book value per share of $13.53.

5.3 Has Terasen Gas misconstrued in any way the implications of the changed circumstances in terms of capital investments in Canada versus the U.S. in light of the recent offer to purchase Terasen by Kinder Morgan? Is this not evidence that Terasen concerns about attracting capital could be overstated?

Response:

No. See the response to 5.1 above.

5.4 *To what extent would observed differences between Canadian and US ROEs be explained by differences in legislation, tax laws, accounting practices, risk considerations arising from different capital structures, and other regulatory considerations unique to specific jurisdictions?*

<u>Response:</u>

There are no differences in legislation of which Terasen or Ms. McShane are aware that could explain the differences in allowed returns on equity. The fair return standard that is espoused in regulatory decisions and judicial precedents is the same in both Canada and the U.S. With respect to tax laws, dividends have historically been taxed at lower rates in Canada compared to the U.S. However, that has not been the case since 2003, when the U.S. Tax Act lowered the tax rate on dividends to 15%. Nevertheless, even prior to that time, a substantial portion of investment in both countries was held in tax deferred accounts (RRSPs, 401Ks, IRAs, pension funds) on which no current taxes were assessed. In both countries, the marginal tax rate for these investments was, and continues to be, zero.

With respect to accounting practices, there are no differences, of which Terasen or Ms. McShane are aware, other than the regulatory approach to income taxes that would result in a difference in allowed ROEs. In regard to the income tax allowance, U.S. utilities are regulated on normalized taxes, whereas Canadian utilities are regulated on flow-through taxes. All other things equal, utilities on flow-through taxes would be considered riskier, since (1) flow-through taxes for growing utilities result in lower cash flows; and (2) there is no guarantee that a utility on flow-through taxes will be able to recover the taxes in future years when they must be paid. With respect to risk considerations, please see Ms. McShane's testimony at lines 1211 to 1250.

6.0 Reference: Cover Letter, p. 6 The Financial Times and Circumstances Have Changed

The cover letter makes reference to the North America Free Trade Agreement that came into effect in 1994 for the profound changes that have been taking place in the attraction and retention of capital. Reference is also made to the new rules governing allowed foreign content in RRSPs and pension funds as reflective of the demand for capital to be free to leave the country.

6.1 In order to provide context to the profound changes described in the letter, please provide the historical annual data (1980 to 2004) on economic and financial indicators such as the Canadian direct investment inflow/outflow as percentages of GDP, and portfolio investment inflow/outflow as percentages of GDP.

Response:

Please refer to Appendix 6.1, which contains the following data for 1985-2004:

(1) Portfolio transactions related to Canadian investment abroad
(2) Portfolio transactions related to foreign investment in Canada
(3) Direct investment by Canadians abroad
(4) Direct investment by foreigners in Canada
(5) Canadian GDP in current dollars.

6.2 Please comment if the data compiled for the response to the above IR are able to support the description that profound changes have been taking place and support the concern that there may be a flight of capital from Canada.

Response:

The data provided in response to BCUC IR No. 1 6.1 indicate that the cross-border flows of capital as a percent of GDP have increased significantly over the past 20 years. The data provided in response to BCUC IR No. 1 6.1 highlight the increased mobility of capital. The removal of the foreign content constraint on pension funds and RRSP's occurred subsequent to the most recent data. The demonstrated increased mobility of capital, in conjunction with the removal of the foreign content cap, support the conclusion that investors will move their capital to investments with the best risk/reward profiles, and support the description that profound changes have been taking pace and the concern that there may be a flight of capital from Canada.

6.2.1 If the Canadian capital inflows and outflows data could not adequately support the contention that there have been profound changes in the attraction and retention of capital, please provide the other data sets or information that Terasen relies on to support that view.

Response:

Please see Appendix 6.2.1, which shows the trend in the foreign investments of trusteed pension funds. The data indicates a rising percentage of funds allocated to foreign investments generally, and stocks specifically, since 1993.

6.2.2 Please comment if investment outflows have declined after 2000.

Response:

Yes. There was a decline subsequent to the equity market bust in 2000; the focus on Canadian securities since that time can be attributed to the rise in the income trust market and, more recently, the boom in oil prices, which has had a positive impact on Canadian resource stocks.

6.2.3 Please comment if the reduction in long-term federal government borrowing has resulted in lower contribution to investment inflows after 1994.

Response:

No. The following table shows the net inflow of capital from foreign investment in federal government bonds (including those of any federal Crown Corporations) from 1993-2004.

Year	$ millions
1993	1,264
1994	1,027
1995	1,339
1996	225
1997	744
1998	541
1999	1,989
2000	-984
2001	1,950
2002	11,171
2003	11,910
2004	10,821

6.3 Do the Companies believe that foreign exchange risk is one of the main variables in *international investments? If no, please explain why not.*

Response:

Foreign exchange is an important risk factor, one which can be diversified and/or hedged.

6.3.1 *Please provide the annual exchange rates (1989 to 2004) for: (i) Canada and U.S. bilateral dollar exchange rates; (ii) Canadian dollar exchange value on a trade-weighted index; and (iii) US dollar exchange value on a comparable trade-weighted index.*

Response:

Please see to Appendix 6.3.1

7.0 Reference: *Cover Letter, pp. 6, 7 The Financial Times and Circumstances Have Changed; Application, Tab 2, Appendix C, p. 2 Application, Tab 2, Statistical Exhibits, Schedule 6*

The cover letter states that in Canada, equity returns enjoyed a smaller spread over bond returns than did U.S. equity returns. It concludes that when the regulatory models used to determine the allowed equity returns for utilities have not been updated to reflect changes in the capital markets, the result is that utilities in B.C. and elsewhere in Canada are provided with inadequate returns and are handicapped when they seek to attract capital.

> *"Since the spread between equity returns and bond returns was narrower in Canada it followed from the use of the equity risk premium test that investors in the common equity of utilities in Canada would realize a smaller premium over bond returns than they would in the U.S."*
>
> *"A key reason for equity risk premiums to be lower in Canada than in the U.S. has not been that equity returns have been lower in Canada, but rather that historically long-term interest rates have been higher in Canada."*

7.1 In the selected indicators of economic activity in Tab 2 Schedule 6, please confirm that between 1989 (base year) and the discrete years of 1994, 1998 and 2004, Canada achieved lower growth than the U.S. based on both GDP (chained dollars and nominal dollars) and industrial production indices.

<u>Response:</u>

It is confirmed. However, these results are impacted by the restructuring that occurred in Canada in the early 1990s, and the aggressive approach taken to combat inflation.

The post-restructuring rates of change (1994-2004) are virtually identical between the two countries.

7.1.1 Since utilities are considered to be the quintessential mature industry and mature industries are those whose growth parallels that of the overall economy, is it reasonable to estimate that the expected long-term growth rates for utilities in Canada to be lower than those of the utilities in the U.S. given Canada's lower estimated economic growth? If no, please explain why not.

<u>Response:</u>

Yes. Based on the current long-term consensus forecasts of economic growth (Consensus Forecasts, *Consensus Economics*, March 2005). However, given the upward movements in energy prices, the positive impact on the oil and gas sector may lead to upward revisions in economic growth projects for Canada, with a corresponding increase in growth expectations for Canadian utilities. Even if long-term growth in Canada were lower, this does not suggest the utility cost of equity is lower. The cost of equity is also a function of (1) dividend yields; (2) near-term growth expectations; and (3) how long it is expected to take near-term growth expectations to trend toward long-term growth in the economy. Lower growth expectations would lead to lower stock prices and higher dividend yields. Further, if the U.S. utilities are perceived as having higher risk-adjusted return prospects than Canadian utilities, Canadian capital will flow to U.S. utility investments.

7.1.1.1 Tab 2 Appendix C, p.2 mentions that the FERC relies on GDP growth to estimate expected long-term nominal GDP growth in its standard DCF cost of equity models for gas and oil pipelines. Given the lower nominal GDP growth in Canada, please explain the basis of DBRS recommendation that there should be a movement towards an increase in the allowed return on equity to make it more consistent with U.S. returns.

.

Response:

Neither TGI nor Ms. McShane know what factors DBRS considered or what analyses they performed. However, the fact that economists project lower longer-term nominal growth in GDP for Canada should not lead to the conclusion that the DCF cost of equity is lower for Canadian utilities. All other things equal, a higher expected rate of growth would tend to be offset by a lower dividend yield. Further, as noted in response to 7.1.1, if the U.S. utilities are perceived as having higher risk-adjusted return prospects than Canadian utilities, Canadian capital will flow to U.S. utility investments.

7.2 Please confirm that between 1989 (base year) and the discrete years of 1994, 1998 and 2004, Canada had experienced lower inflation rates than the U.S. based on GDP deflator or CPI.

Response:

It is confirmed. However, the only relevance of 1989 is that StatsCon indexes many of its economic indices to 1989; the base year is changed periodically. To a large extent, the differences between Canada and the U.S. over the periods specified in the question reflect lower rates of inflation in Canada from 1984-1994, which covers the period of recession and the introduction of the inflation targets in 1991.

From 1994-2004, inflation as measured by the GDP deflator indices were virtually identical in the two countries (1.9% in Canada versus 1.8% in the U.S.) CPI inflation was 0.5% higher in the U.S.

Over the entire post-World War II period, 1947-2004, the rates of CPI growth were very similar, 4.0% in the U.S. versus 4.2% in Canada.

7.2.1 Please comment on the extent that the different historical inflation rates in *the U.S. and Canada could have an impact, if any, on their respective expected returns on equity and bond yields.*

Response:

Theoretically, both the cost of equity and the yield on long-term government bonds include compensation for expected inflation and for the real cost of capital. The inflation component will be formed in part by experienced rates of inflation, including the extent to which experienced rates of inflation deviated from the *ex ante* expected rates. All other things equal, a higher expected rate of inflation will translate into a higher cost of capital. In the case of Canada and the U.S., the long-term expected yields on 10-year government bonds, as represented in the most recent forecasts of Consensus Forecasts, *Consensus Economics* (April 2005), are anticipated to be quite close. The forecast for Canada for the period 2006-2015 is 5.5%; for the U.S., it is 5.6%.

7.3 For the Table on "Trend in After-tax Corporate Profits in Canada and the United States" as presented in Tab 2, Schedule 6, p.2., please explain the purpose in comparing the corporate after-tax profits. How useful is the comparison given the significantly different industrial structures of the U.S. and Canadian economies?

Response:

The referenced schedule provides a perspective on the relative importance of corporate profits to Gross Domestic Product over time and a perspective on the relative performance of the corporate sector throughout the business cycle in the two countries.

8.0 Reference: Cover Letter, p. 9 Financial Flexibility to Compete

The application letter states that S&P's views on Canadian regulation resulted in the downgrade of TGI's rating from BBB+ to BBB on June 26, 2003.

8.1 Please provide information on other regulated utilities in the U.S. and Canada that S&P downgraded in the aftermath of the collapse of Enron.

Response:

With respect to the U.S., in April 2002, in its "*Industry Report Card: U.S. Electric-Gas-Water*", Standard & Poor's stated that,

> *"Enron Corp.'s bankruptcy has not directly resulted in other negative ratings actions in this [merchant generation] section. Still, the subsequent loss of investor confidence for the broader category of energy traders has affected liquidity in the bank and capital markets, including the commercial paper market where the appetite for 'A-2' rated paper has diminished significantly."*

S&P attributed the downward ratings trend in the electric and combined energy industry to,

> *"weakening financial profiles, largely attributable to debt raised to fund unregulated business ventures of acquisitions. Investment outside the traditional regulated utility business has increased overall business risk."*

S&P stated,

> *"For regulated utilities, such as transmission and distribution (electricity, gas, and water), state regulators continue to exert tremendous influence over credit quality despite the advance of deregulation in the electricity industry (albeit at a much slower pace). For many utilities, regulation remains reasonably supportive, rarely contributing to negative rating actions."*

Downgrades as a result of regulatory decisions were described as *"notable exceptions."*

In the April 2003 *Report Card*, S&P stated,

> *"The ratings trend for the traditional, regulated U.S. investor-owned electric and gas industry remains relatively stable, with little of the downward pressure experienced elsewhere in the power industry. With limited exceptions, regulation is expected to remain reasonably supportive of credit quality."*

The October 2003 *Report Card* stated,

> *"The ratings trend year-to-date for the traditional, nondiversified, and regulated U.S. investor-owned electricity and gas industry remains relatively stable, with little of the downward pressure experienced elsewhere in the energy industry. Downward rating pressure on these companies typically results from the strained credit quality of their nonregulated affiliates. With limited exceptions, regulation has continued to remain reasonably supportive of credit quality."*

In December 2003, S&P reported,

> *"Ratings in the broader U.S. utility sector (electric, gas, pipeline, and water) largely reflect two trends. Ratings stability for traditional nondiversified utilities is one trend. The other is ratings deterioration for diversified utilities, with even greater ratings deterioration for issuers with major exposure to merchant power markets."*

In contrast to the U.S. experience, on March 6, 2003, S&P placed a number of Canadian pipeline and utility companies, including Terasen Inc. and Terasen Gas Inc., on Creditwatch Negative in a report entitled "Canadian Utility Regulation Reassessed as a Ratings Factor". A copy of the report can be found in Appendix 8.1.

The following issuers were downgraded within 12 months of the March 2003 report, and each downgrade cited S&P's perception of the regulatory environment as a contributing factor to the downgrades.

Company	Rating at March 2003	Subsequent Rating
ATCO Ltd.	A+	A
BC Gas Inc. (now Terasen Inc.)	BBB+	BBB
Borealis Infrastructure Trust (Enersource)	A+	A-
Electricity Distributors Finance Corp.	A-	BBB+
Fortis Inc.	A-	BBB+
Hamilton Utilities Corp.	A+	A
Hydro-Ottawa Holdings Inc.	A	BBB+
Oakville Hydro Corp.	A-	BBB+
Toronto Hydro Corp.	A	A-

9.0 Reference: Cover letter, p. 10

Terasen says that:

> *"At that time, preferred shares were classified as equity for financial statement purposes and were considered to provide significant equity benefits for debt-holders."*

9.1 At that time and since, please discuss how financial analysts have treated preferred shares. Have they not treated preferred shares as debt even though for accounting purposes they are treated as equity?

Response:

Over the past ten years, Canadian financial analysts have changed their perception of the characteristics of preferred shares and other forms of hybrid equity. This has occurred as financial analysts have generally placed decreasing reliance on the GAAP financial statement presentation of liabilities and equity as a definitive guide to financial condition, particularly since the collapse of Enron. In fact, it can be argued that the GAAP presentation of hybrid equity has followed the changing perception of investors and financial analysts over the past ten years.

As a profession, financial analysis has become more sophisticated in the past ten to 15 years, like most other professions. This is particularly true with respect to corporate debt research. Over this time period most Canadian investment dealers have created or significantly expanded corporate debt research groups alongside their equity research groups. The credit rating agencies have also refined their methodologies over time.

In the 1980s and early 1990s, preferred shares were widely used by Canadian companies to raise financing with equity characteristics that did not cause dilution to common shareholders. During this time, all preferred shares were classified as equity for accounting purposes. Beginning in 1996, preferred shares carrying an obligation to redeem the shares for cash at the holder's option ("hard retractable preferred shares") were reclassified as indebtedness for accounting purposes. In 2000, the CICA proposed in an exposure draft to reclassify preferred shares which could be settled with a variable number of the issuer's shares ("soft retractable preferred shares") from equity to indebtedness for accounting purposes. This change was implemented effective January 1, 2005.

Another factor affecting the changing perception of hybrid securities in Canada has been the changing influence of different rating agencies. Prior to 2000, the dominant rating agencies in the Canadian utility sector were DBRS and Canadian Bond Rating Service. DBRS has historically given relatively high equity credit to preferred shares. For example, in a recent rating methodology report, DBRS indicated that it assigns 70% to 85% "equity" weighting to conventional preferred shares.

In October 2000, CBRS was acquired by Standard and Poor's, and S&P's analytical approach was applied to the companies previously rated by CBRS. Shortly thereafter, Moody's Investors Service significantly expanded its presence in Canada. The result of this expansion was that S&P and Moody's became significantly more influential among Canadian utility investors. The treatment of hybrid securities by S&P and Moody's is significantly more conservative than that of DBRS. For example, in a recent rating methodology report, S&P indicated that it assigns 20% to 50% "equity" weighting to conventional preferred shares. During one conversation between Terasen management and S&P analysts in 2002, an S&P analyst questioned why utilities would issue hybrid equities at all, since the same effect (in S&P's mind) could be achieved by issuing conventional debt.

10.0 Reference: Cover letter, pp. 12-13

10.1 Please provide a comparative figure for the average annual natural gas and electricity bills for Terasen Gas' entire service area.

Response:

The annual residential natural gas and electricity bills for Terasen Gas' entire service area: Lower Mainland, Inland and Columbia are tabulated below. The use rates are derived from 2005 Normalized Use Rate Forecast.

	Annual Bill		
	Lower Mainland	Inland	Columbia
Annual Usage (GJ)	110	90	95
Basic Charge	$128	$128	$128
Delivery Charge	$294	$241	$254
Commodity Cost	$930	$752	$806
Total Gas Bill	$1,353	$1,121	$1,189
Electricity Bill	$1,664	$1,361	$1,437
Gas/Electricity Advantage	19%	18%	17%

TGI is currently preparing its October 1 gas cost flow through application. TGI anticipates that the current level of forward gas commodity prices will necessitate a burner tip increase in excess of 10%, dramatically reducing the remaining cost advantage of gas over electric rates.

10.2 Terasen states that TGI has a higher degree of business risk than other similar companies in Canada and the Pacific Northwest. Is this statement made only in consideration of the comparative gas and electricity costs to residential customers? Please elaborate on the reasons for this assertion.

Response:

No. Of the utilities noted, TGI operates the geographically largest and most disperse local distribution company with concomitant extremes in terrain, weather conditions and population densities, all of which impact on operations and costs. The Company has a significant reliance on a low load factor residential customer base, with very little in service territory gas storage. TGI competes with the rest of Canada and parts of the U.S. for North Eastern BC gas supply and is the primary shipper on the Duke British Columbia transmission system shouldering approximately 24% of the cost of service of that system and related impacts of de-contracting on that system (the Duke B.C. system is experiencing significant de-contracting with costs being shifted to the remaining shippers). All of these factors contribute to increased business risk through potential impacts on shareholder borne costs or through competitive cost pressures where increased delivered gas costs are passed through to customers (in light of the rate compression between natural gas and electricity rates in British Columbia for residential, commercial and industrial customers and users).

In addition, ATCO gas has no exposure to credit risk on gas commodity purchases as it no longer has a merchant role on behalf of its customers having sold its retail gas business to Direct Energy. Consequently it no longer is exposed to non-recovery of gas commodity costs nor at risk for commodity accounts receivable from customers.

10.3 Please comment on whether any of the utilities listed in Table 1 face greater or less business risk than Terasen in other aspects, and explain why.

<u>Response:</u>

Gaz Metro faces similar competitive rate issues to Terasen in that it competes with low hydro electric rates but Gaz Metro has a substantially higher allowed equity component in its Capital Structure and higher ROE to compensate, as compared to TGI. Gaz Metro also faces similar short-term revenue risks to Terasen, given its weather-normalization mechanism. Its regulatory risk is relatively low; as it has an incentive mechanism that has added as much as 195 basis points to its allowed return. Gaz Metro's supply risk is somewhat higher than Terasen's, given Gaz Metro's location relative to supply sources.

All of the other companies noted enjoy substantial competitive cost advantages to energy alternatives and have higher allowed returns and thicker equity in their capital structures while being protected from energy price risk through deferral accounts.

ATCO Gas in Alberta has exited commodity supply altogether and the Alberta government has effectively capped natural gas prices through a rebate mechanism for residential customers. In addition, ATCO Gas has no exposure to credit risk on gas commodity purchases as it no longer has a merchant role on behalf of its customers having sold its retail gas business to Direct Energy. Consequently, it no longer is exposed to non-recovery of gas commodity costs nor at risk for commodity accounts receivable from customers. There is also significant service territory storage (plus the proximity of gas supplies) in Alberta that assist in lowering unit delivery costs. Supply risks are lower than Terasen's since ATCO Gas is located in the heart of the Western Canada Sedimentary Basin. Its short-term revenue risks are slightly higher than Terasen's since it has no weather-normalization mechanism. (About 50% of delivery costs are recovered in fixed charges.) Its regulatory risks are viewed as somewhat higher, as Alberta has been described by DBRS as a cumbersome regulatory environment.

For the Ontario LDCs, the combination of these utilities' dual-fired industrial load that can be curtailed and the availability of service territory storage reduces load factor adjusted delivery costs and makes natural gas more competitive. In addition, in Ontario, as well as Alberta, gas as a fuel for power generation is viewed very positively with Ontario aggressively moving away from coal generated power. This is a contrast to BC where gas seems to be being lumped in as "just another fossil fuel". Duke Point has been cancelled, significant risk exists that ICP will be converted from base load to peak generation and Burrard Thermal's continued existence remains threatened. The I-5 corridor continues to be at risk of capacity shortfall during times of cold weather or low hydro conditions which in turn exacerbates commodity price disconnects and excursions relative to the balance of North American gas prices as well as BC electric rates.

Neither Union or Enbridge has weather-normalization clauses, so their short-term revenue risks are somewhat lower. With access to both Canadian and U.S. supplies, only with storage facilities, their supply risks are not dissimilar to Terasen's. With respect to regulatory risks, they are somewhat higher than Terasen's given the experience of Ontario government's intervention, regulatory process in the electricity industry.

With respect to the relative economic strength of the various utilities' service areas, as noted in response to IR 38.1, TGI's industrial load is more concentrated in a single resource-based industry than either Enbridge Gas or Union Gas. The forestry/pulp & paper industry in Terasen's service area is particularly challenged at this time. In comparison, ATCO Gas (which does not directly serve a material industrial base) is operating in an economic environment that is booming with the surge in energy prices.

Northwest Natural Gas (NWN) compares favourably to TGI in virtually all business risk categories. NWN has been assigned the lowest possible business risk profile score by S&P (1), and is rated A+ by S&P. S&P's business risk profile score is the result of NWN's supportive regulation in Oregon, a high-growth service area, a favourable competitive position, a predominantly residential customer base, and a reliable gas supply. NWN has both a conservation tariff, protecting its margins against declines in usage levels, and a weather-normalization clause. While some U.S. utilities operate with historic test years, NWN has a forward test year. Its purchased gas adjustment clause defers two-thirds of differences between actual and forecast gas costs; the company hedges 90% of gas supply and owns its own storage facilities (12.8 Bcf). NWN operates with normalized taxes (compared to TGI's flow-through methodology), which not only improves cash flows, but lowers the risk that the costs will not be recoverable when the taxes become payable. Its allowed common equity ratio and ROE are 49.5% and 10.2% respectively.

11.0 Reference: Cover Letter, p. 12; Application Tab 1, p.2

The application letter states that TGI has higher risk today than in 1994 and 1999 and it also has a higher degree of business risk than other similar companies in Canada and the Pacific Northwest.

> *"Business risk for a gas distribution utility ultimately relates to the enterprise's ability to recover its investment in its assets or "rate base" and its ability to achieve its allowed return on equity."*

11.1 Please provide a table showing the allowed return on equity for TGI and TGVI from 1994 to 2004 and the accompanying actual return on equity. Where the actual return on equity is below the allowed return, please provide detailed explanation.

Response:

TGI's 1994 to 2004 allowed return on equity, with explanations are as follows:

	Allowed ROE	TGI Actual Pre-Earnings Sharing ROE	Actual Post-Earnings Sharing ROE	Reasons for Variance
1994	10.65%	9.727%		Weather was 7.2% warmer than normal plus RSAM was not applicable to summer usage volumes
1995	12.00%	12.030%	-	
1996	11.00%	11.803%	-	
1997	10.25%	11.266%	-	
1998	10.00%	9.405%	9.703%	Employee severances due to corporate restructuring
1999	9.25%	10.698%	9.974%	
2000	9.50%	10.748%	10.124%	
2001	9.25%	9.375%	9.313%	
2002	9.13%	10.032%	-	
2003	9.42%	10.226%	-	
2004	9.15%	9.460%	9.305%	

Prior to 1996 Centra Gas B.C. Inc. and Pacific Coast Energy Corp were operated as separate companies each providing service under separate agreements with the Province. For 1996 and beyond, the combined companies optimized performance within the context of the Vancouver Island Natural Gas Pipeline Agreement and with recognition of the new regulatory role of the BCUC.

Summing the separate actual results of years prior to 1996 will not provide meaning information on how the two companies would have performed if they had been managed jointly under the same conditions.

TGVI's 1996 to 2004 allowed return on equity, with explanations are as follows:

	TGVI			
	Allowed Utility ROE	**Actual Utility ROE**	**Actual Utility ROE before RDDA balancing**	**Reasons for Variance**
1996	11.70% [1]	11.687% [3]	-3.019%	
1997	10.75% [2]	9.318% [4]	3.462%	$1.867mil VINGPA Provision
1998	10.50% [2]	8.588% [4]	4.835%	$1.867mil VINGPA Provision
1999	9.75% [2]	7.762% [5]	0.667%	$1.867mil VINGPA Provision
2000	10.00% [2]	8.398% [6]	8.758%	$1.867mil VINGPA Provision
2001	9.75% [2]	8.129% [7]	4.409%	$1.867mil VINGPA Provision
2002	9.63% [2]	8.023% [7]	10.643%	$1.867mil VINGPA Provision
2003	9.92% [2]	8.678% [8]	N/A	$1.867mil VINGPA Provision
2004	9.65% [2]	8.439% [9]	N/A	$1.867mil VINGPA Provision

NOTES:

(1) Centra Gas British Columbia Inc. 1998/1999 General Rate Application - Response to Staff Information Request No. 1 Item 7.2.

(2) Annual BCUC ROE for a Low-Risk Benchmark Utility plus 50 basis points risk premium (BC Gas/TGI + 50bp).

(3) Centra Gas British Columbia Inc. 1998/1999 General Rate Application - Tab 19, Schedule 28.

(4) Centra Gas British Columbia Inc. 1998 Annual Report.

(5) Centra Gas British Columbia Inc. 1999 Annual Report.

(6) Centra Gas British Columbia Inc. 2001 Annual Report.

(7) Centra Gas British Columbia Inc. 2002 Annual Report.

(8) Terasen Gas (Vancouver Island) Inc. 2003 Annual Report.

(9) Terasen Gas (Vancouver Island) Inc. 2004 Annual Report.

The column "Actual Utility ROE" for TGVI set out above is misleading. It should be noted that for each of the years 1996 through 2001 TGVI had revenue deficiencies that were funded by the shareholder. It is only after the funding of revenue deficiencies that the TGVI ROE in the table above for those years was achieved. The true achieved returns prior to shareholder funding are reflected in the third column "Actual Utility ROE before RDDA Balancing".

12.0 Reference: Application, Tab 1, p. 2
Terasen Gas Business Risks

On Tab 1, page 2 TGI states:

> *"A utility's ability to manage risk is in part dependent on the way it is allowed to interact with customers. Over time, TGI has been encouraged by stakeholders and through the regulatory process to exit performing service work downstream of the customer's meter where competitive markets have an opportunity to work. In addition, the expansion of commodity unbundling to commercial customers further removes TGI from its customers."*

12.1 Is it TGI's position that its exit from service work downstream of the meter and the implementation of commodity unbundling has increased business risk to the utility?

Response:

TGIs' exit from downstream service work and the implementation of commercial unbundling are instances that reduce the amount or degree of direct customer interaction by TGI, leading to increased business risk. TGI believes that direct customer interaction is important in allowing TGI to maintain its corporate image and in maintaining avenues for the communication of messaging regarding natural gas versus the increasing number of alternative energy options available to customers.

Exiting from service work downstream of the meter negatively impacted customer satisfaction levels for a period of time. Anytime customer satisfaction levels are negatively impacted this is a business risk as customer satisfaction plays a key role in retaining and growing the business.

The business plan to implement commercial unbundling has been a similar exercise. Terasen was able to engage stakeholders to determine the value proposition for customers. Terasen has demonstrated a process to better define a mutuality of interests but business risks will increase if customers are not satisfied with the outcomes or if they are not able to access timely and accurate information about their energy options.

12.2 Would TGI consider the exit from the competitive markets downstream of the meter a reduction of business risk? If not, why not. To what extent is the risk of losses greater in the competitive market exited by TGI than the risk within the monopoly's core business? Please elaborate.

Response:

The exit from the downstream business reduces the amount or degree of customer contact. Direct customer contact is important in allowing Terasen to communicate messaging regarding natural gas versus alternative energy solutions available to customers. The risk in the business downstream of the meter is non payment risk which is the same as the non-payment risk that TGI has today.

12.3 Please confirm that the commodity unbundled customers still receive customer bills from TGI. Also, do these unbundled customers still receive bill inserts similar to non-unbundled customers regarding margin (delivery charge) changes?

Response:

Commodity unbundled customers continue to receive a combined bill from the Utility which includes both the Utility delivery and midstream changes as well as the marketer's commodity charge. All customers receive both messages and inserts related to changes to delivery components regardless of whether they have elected to receive their gas from a marketer.

12.4 When did TGI acquire the BC Hydro Mainland Gas Division customers?

Response:

Inland Natural Gas Co. Ltd, a predecessor Company to TGI, acquired the B.C. Hydro Mainland Gas Division on September 30, 1988 from the Province of B.C. under the Hydro and Power Authority Privatization Act. A Services Agreement was negotiated in September of 1988 with BC Hydro in order for BC Hydro to continue to perform customer care functions until Inland Natural Gas (later BC Gas Utility and then TGI) put in place the required capability.

12.4.1 Please elaborate on the billing history (including specific dates) of these Lower Mainland customers. Who provided the billing services? How many customers were involved and which rate classes?

Response:

In July of 1988 an agreement was put in place under which BC Hydro continued to provide customer care services, including billing through a joint billing approach, for all Lower Mainland customers. The number of customers by rate class, at the time of the asset transfer, are listed in the table below.

On July 2, 2002 Terasen Gas repatriated the customer care services from BC Hydro and transferred the service responsibility to CustomerWorks LP. The Disposition of Assets and Approval of Customer Care Agreements was approved by the BCUC in Commission Order G-29-02 Dated April 17, 2002. The number of customers by rate class as at July 2, 2002 are listed in the table below. At this time all Lower Mainland customers began to receive a separate monthly gas bill directly from Terasen Gas.

Rate Class	July 18, 1988	July 2, 2002	December 31, 2004
Residential	360,441	478,539	494,756
Small Commercial	41,511	50,437	50,304
Large Commercial	(Included above)	4,600	4,242
NGV	35	43	36
Industrial	524	1,606	1,775
Total	402,511	535,225	551,113

12.4.2 When did TGI start billing its Lower Mainland customers? Approximately how many bill statements have been sent out under its own name without BC Hydro since the conversion of these customers? Would this development be a significant change since 1994?

<u>Response:</u>

All Lower Mainland customers have received a separate monthly gas bill from Terasen Gas since repatriating the gas customers from BC Hydro on July 2, 2002. The estimated number of bills issued since that time is as follows:

Year	Number of Statements
2002	3,230,418
2003	6,518,040
2004	6,594,312

This represented a time of significant change for both Terasen and its customers in terms of an ability to ensure a more direct way to create customer awareness and education on the products and services that Terasen was allowed to offer and costs that could be recovered in its rates and it provided benefits to customers through avoided costs which they would have been exposed under a future BC Hydro billing system upgrade. It did however increase the business risk of Terasen Gas to a degree in that it eliminated a powerful credit and collection tool, that being the threat of discontinued electric service for non payment of the combined bills. Subsequent to repatriation, bad debt experience more than doubled in the lower mainland service area. It has taken three years of effort and an improved economy to bring bad debt experience almost back into line with pre-repatriation levels.

12.5 Does Terasen Gas consider that sending out its own bills allows it to better interact with its own customers? Does the improved interaction allow it to reduce business risk?

<u>Response:</u>

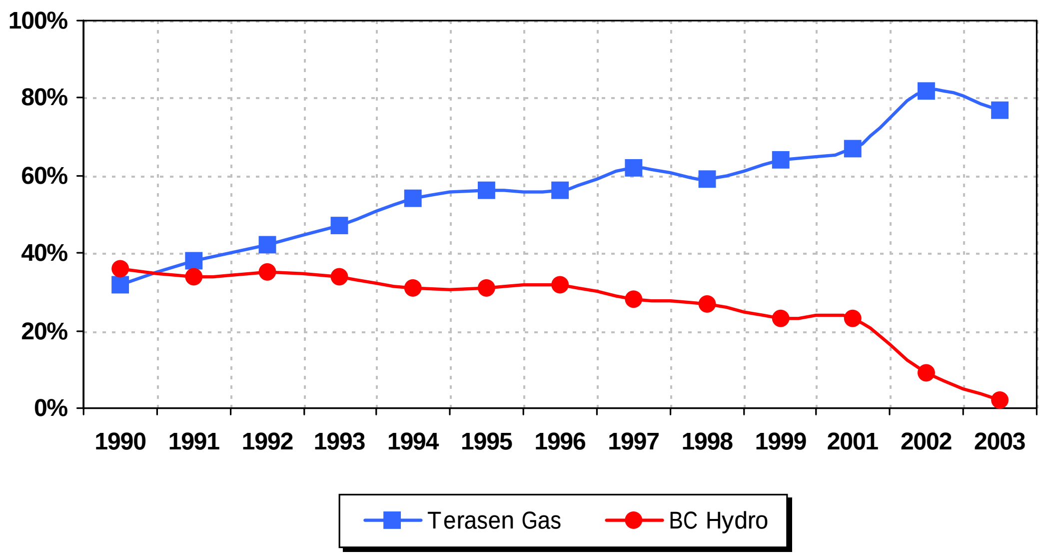
Having a separate Terasen natural gas bill does allow for improved opportunities when communicating with customers. However because of the nature of the pricing of the natural gas commodity versus electricity in BC, some customers perceive that electricity is a less expensive (and more stable) source of energy for home and hot water heating. With price increases and volatility of natural gas commodity costs expected to continue, pressure for customers to question how they can reduce their energy costs has increased. The separate bill allows Terasen to increase customer education and awareness but does not reduce the business risks associated with customers making decisions to reduce or change their energy choices due to such perceptions.

12.6 *Please provide all name recognition survey results for TGI from 1994 to 2004. Has there been a shift in TGI customers mistakenly identifying TGI as a Crown Corporation?*

Response:

Terasen Gas has been monitoring the image of the corporation and customer attitudes on an annual basis since 1989. The survey tracks core customer satisfaction and corporate awareness measures among residential customers plus other issues of interest. Specifically, in the area of name recognition the survey measures whether residential customers are able to name Terasen Gas as the company that provided natural gas to their home. The results below reflect the "unaided" response levels for the years 1990 to 2003. "Unaided" in this survey means that customers are not provided with the name of the company who commissioned the survey prior to the question being asked. In 2004 the survey approach was revised although the specific question related to name recognition was incorporated into the new study. For 2004 the percentage of customers who were able to name Terasen Gas as the company that provided gas to their home was 86% as compared to 77% in 2003.

Unaided Awareness of Corporate Name



The question related to customer perception of Terasen Gas as a crown corporation had not been included in the historical Corporate Monitor for the 10 year period under review. A question was however introduced in an independent brand tracking study in 1999. In 2002 a specific question related to corporate ownership was introduced in the annual market survey process. The results of the 1999 study as well as the study period of 2002 to 2004 are presented below.

Survey Question: *"As far as you are aware, which of the following best describes Terasen Gas?*

	1999	2002	2003	2004
A Crown Corporation	25%	32%	25%	18%
A Part of BC Hydro	55%	26%	19%	19%
An Investor-Owned Corporation	17%	23%	37%	42%
Don't Know / Not Sure? Refused	3%	19%	19%	21%

13.0 Reference: Application, Tab 1, pp. 2-6; Figures 1, 2 and 3
Terasen Gas Business Risks

13.1 Please provide the assumptions used to calculate Figures 1, 2 and 3.

Response:

Common assumptions for Figures 1, 2 and 3:

1. Since the delivery rates prior to 1998 were seasonal, the 2005 forecasted use was split 35/65 to account for the summer and winter uses respectively.

2. Efficiency of gas equipment is 90% relative to 100% for electricity.

3. Terasen Gas amount includes the basic charge.

4. BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use.

Specific assumption for Figure 1 (Lower Mainland):

1. Natural gas use of 110 GJ.

2. Provincial sales taxes are not included in the rates or calculations.

Specific assumptions for Figure 2 (Inland):

1. Natural gas use of 90 GJ.

2. Franchise fees and provincial sales taxes are not included in the rates or calculations. Customers residing within municipal boundaries in the Inland Service Area will be charged an additional 3.09% to recover franchise fees where applicable.

Specific assumptions for Figure 3 (Columbia):

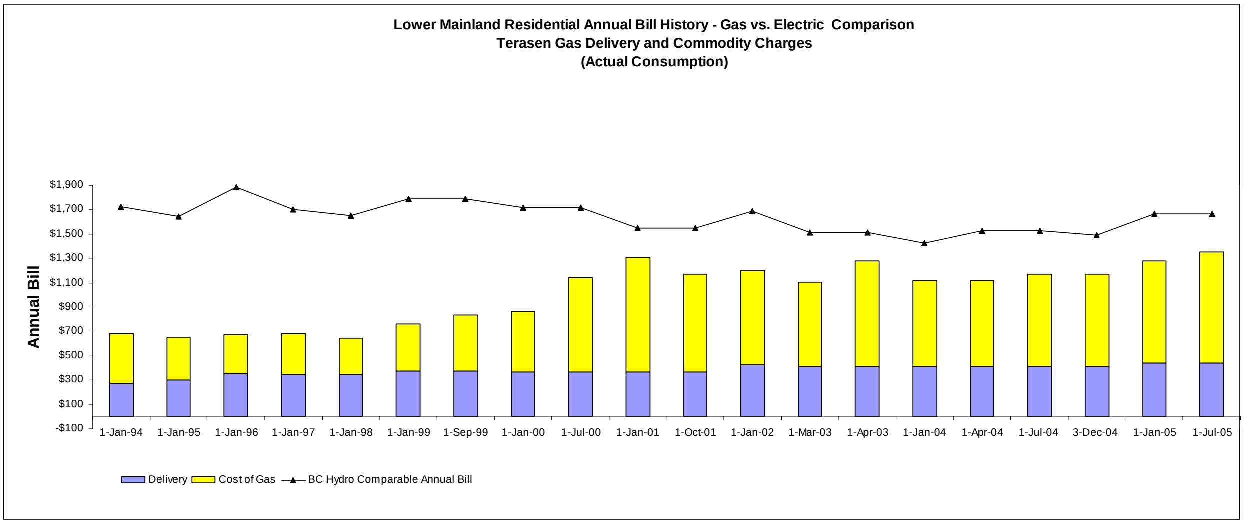
1. Natural gas use of 95 GJ.

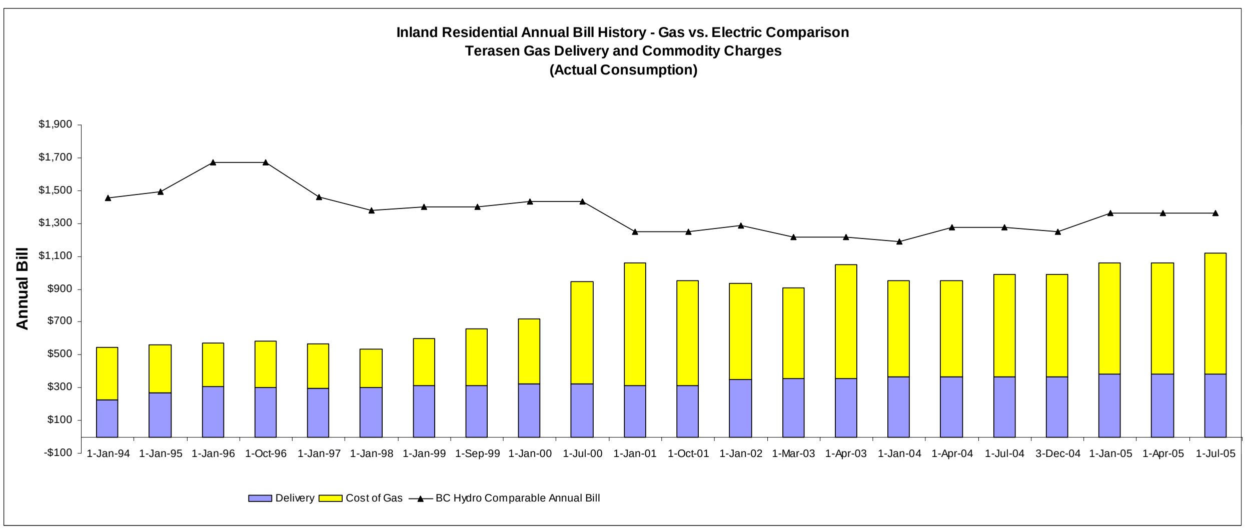
2. Franchise fees and provincial sales taxes are not included in the rates or calculations. Customers residing within municipal boundaries in the Columbia Service Area will be charged an additional 3.09% to recover franchise fees where applicable.

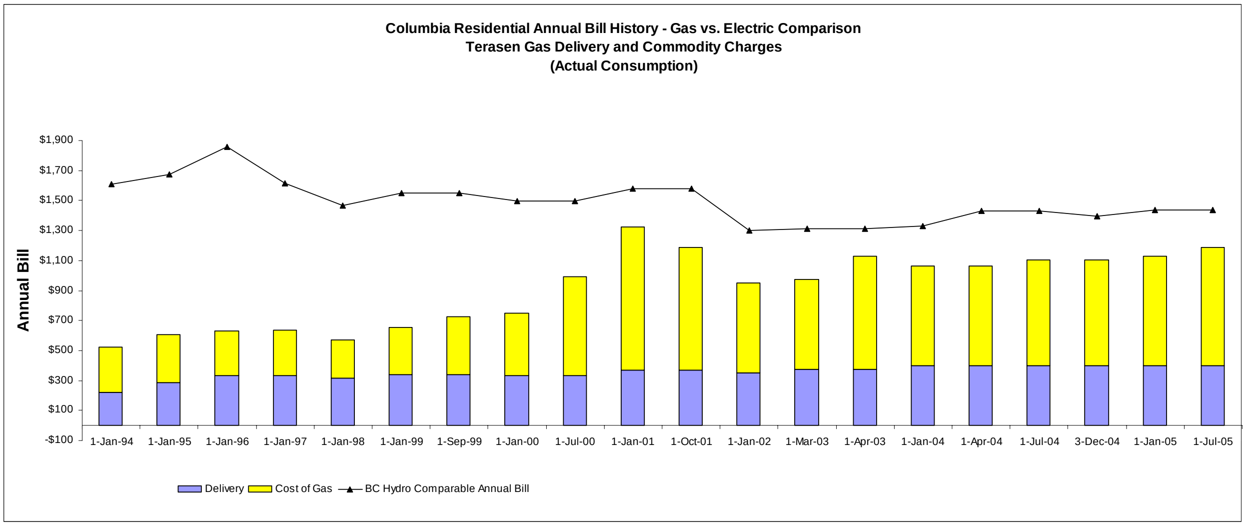
13.2 Please recalculate Figures 1, 2 and 3 using actual consumption in each year for each bill. State any assumptions.

Response:

Figures 1, 2 and 3 using actual consumptions are shown below:







Common assumptions for Figures 1, 2 and 3:

1. Actual annual average uses (GJ) per customer consumptions are used.
2. The delivery rates prior to 1998 were seasonal, therefore the 2005 forecasted use rate seasonal ratios were assumed for calculation purposes.
3. Efficiency of gas equipment is 90% relative to 100% for electricity.
4. Terasen Gas amount includes the basic charge.
5. BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use.

Specific assumption for Figure 1 (Lower Mainland):

1. Provincial sales taxes are not included in the rates or calculations.

Specific assumptions for Figure 2 (Inland):

1. Franchise fees and provincial sales taxes are not included in the rates or calculations. Customers residing within municipal boundaries in the Inland Service Area will be charged an additional 3.09% to recover franchise fees where applicable.

Specific assumptions for Figure 3 (Columbia):

1. Franchise fees and provincial sales taxes are not included in the rates or calculations. Customer residing within municipal boundaries in the Columbia Service Area will be charged an additional 3.09% to recover franchise fees where applicable.

14.0 Reference: Application, Tab 1, p. 3
Terasen Gas Business Risks

At Tab 1, page 3 TGI states:

"When natural gas commodity prices spiked in the winter of 2000/01, industrial users exercised fuel switching alternatives and residential/small commercial customer use rates declined dramatically."

14.1 Please quantify the industrial users that exercised fuel switching both in amount of GJ, duration period, and number of customers. How many of these industrial users have terminated the use of natural gas? Given the small margins earned on industrial sales, was TGI significantly disadvantaged?

Response:

Terasen Gas did not detect significant fuel switching immediately after the winter 2000/01 and shortly thereafter prior to 2003 as customers evaluated the costs and benefits of switching to alternative fuel technologies.

Since 2003, Terasen Gas has identified ten industrial customers who have exercised fuel switching, and several more have indicated that they are planning to switch to using more economic alternative fuels (primarily wood waste). Fuel switching has predominantly occurred among industrial customers in the greenhouse, wood products, and pulp & paper sectors.

Although none of the customers who have already switched fuel sources has terminated the use of natural gas, their reduced consumption has been substantial. In 2004, Terasen Gas estimates that fuel switching resulted in a loss of 1.5 million GJ. None of these customers has resumed natural gas consumption to levels prior to 2004, and several of these customers have indicated in telephone conversations that they are not expecting to go back to burning natural gas at levels prior to 2004.

14.2 To what extent, if at all, could the decline of residential/small customer use rates be a factor that actually assists in retaining these customers? What was the recorded and normalized average use for a typical Lower Mainland residential customer in 2000 compared to 2004? How much in 2004 did the typical Lower Mainland customer save by reducing its consumption?

Response:

The analysis below shows that the decline in use rates from 2000 to 2004 has not resulted in lower annual natural gas bills for the typical residential customer in the Lower Mainland, which is a significant factor in a customer's fuel choice.

Use rates for residential customers in the Lower Mainland were substantially lower in 2004 than in 2000. Refer to the table below for a summary of both normalized and recorded actual use rates for these customers from 2000 to 2004.

Lower Mainland Residential Use Rates

Year	Normal Actual	Recorded Actual
2000	116.9	118.8
2001	105.2	109.7
2002	113.0	114.2
2003	111.6	104.9
2004	109.8	99.2

Despite the drop in use rates over the last five years, residential customers in the Lower Mainland have not saved any money by reducing their consumption. Rising natural gas prices have meant that the typical Lower Mainland residential customer is paying more for natural gas in 2004 compared to 2000 while consuming less. The following table provides an estimate of a typical annual bill for these customers during the last five years. The first column provides an average customer's bill using normalized (i.e. weather adjusted) consumption. For comparison, the second column provides an average customer's bill using 2005 forecasted normalized consumption, holding consumption constant for prior years. In both cases, since 2000, customers are paying more for use of natural gas.

Estimated Annual Bill for Residential, Lower Mainland Customers

Year	Annual Bill (based on normalized actual use rate)	Annual Bill (based on 2005 forecast use rate)
2000	$ 1,121	$ 1,059
2001	$ 1,149	$ 1,200
2002	$ 1,162	$ 1,134
2003	$ 1,362	$ 1,340
2004	$ 1,288	$ 1,288
2005F	$ 1,353	$ 1,353

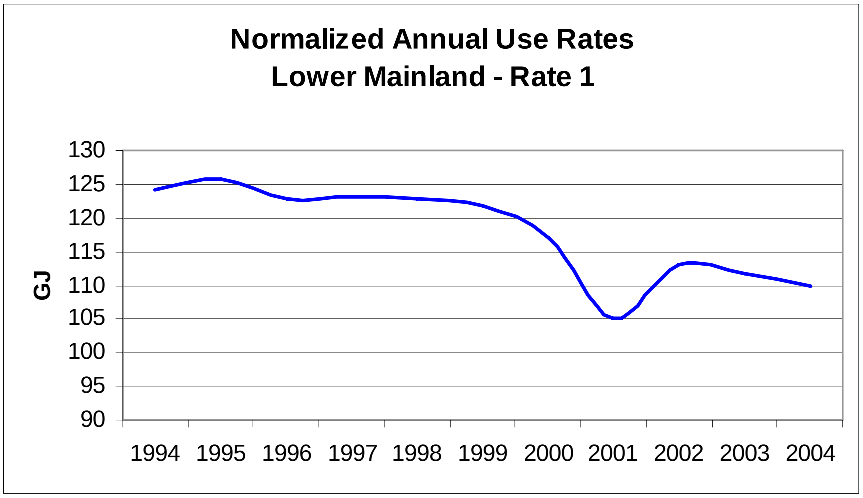
Notes: 1. 2005 forecast use rate is 110 GJ
2. annual bill is calculated using the tariff effective at December 31 of each year

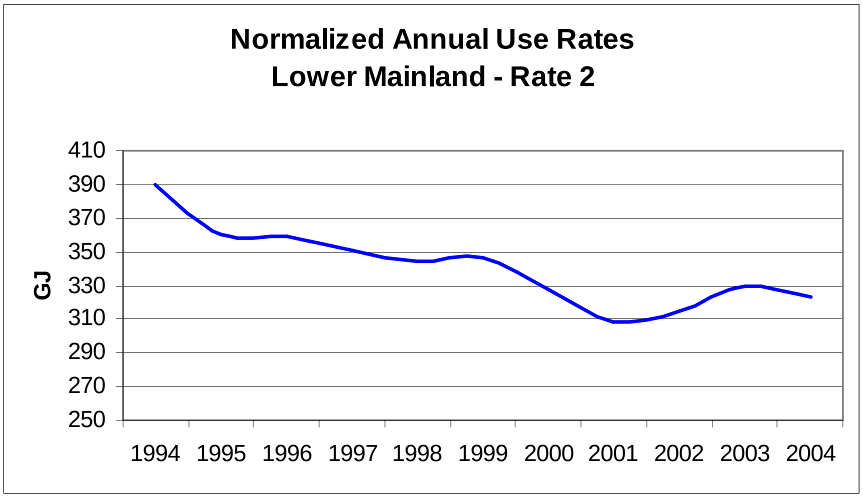
Further, increasing natural gas prices, particularly in recent weeks are expected to result in additional increases to customers' annual bills for 2005.

14.3 *Does Terasen Gas have any quantifiable evidence of residential or small commercial customers permanently substituting away from natural gas to an alternative energy since 2000? If so, please provide the information.*

Response:

No, although we have noted a decline in annual use rates has been noted for these customers from 2000 onward. Refer to the following two figures for a graphical representation of this downward trend.





In addition, as noted in its response to Question 20.1, Terasen Gas has observed a declining market share of natural gas in new single family homes into the 80% to 85% range from historical levels of 90%+, an indicator of the declining competitive position of natural gas relative to other energy choices.

Please refer to IR Response No. 18.1 which provides further discussion on the impact on customer attachments following the price shock experienced during the winter of 2000-1.

15.0 Reference: Application, Tab 1, p. 7

15.1 Please provide an expanded version of Table 1 that illustrates the gas versus electric price advantage in each of the last 5 years.

Response:

An expanded version of Table 1 can be found in Appendix 15.1. *Please note that* not all of the utilities have forwarded complete information as of September 2, 2005.

With regards to Gas Costs forecasts, Terasen Gas' 2005 Third Quarter Gas Cost Report for the Lower Mainland, Inland and Columbia service areas is scheduled to be filed with the Commission on or before September 8, 2005. Terasen Gas is currently working on preparing this quarterly gas cost report and initial indications, based on recent forward commodity prices, are that a gas cost flow through will be required effective October 1, 2005 to eliminate a forecast under-recovery of gas costs. Further analysis is required before the actual amount of any commodity rate increase that Terasen Gas will be requesting in its Third Quarter Gas Cost Report is known. However, preliminary results indicate that the rate increase required to Lower Mainland residential customer rates, effective October 1, 2005, may exceed 10% at the burner tip.

16.0 Reference: Application, Tab 1, pp. 8-9

16.1 Please provide the actual data on which Table 2 and Figure 5 are based.

Response:

Data used in Table 2, New Construction Proportion of Single vs Multi-Family Dwellings

	SFD	MFD	SFD %	MFD %
1990	10,590	14,610	42%	58%
1991	11,444	11,291	50%	50%
1992	12,944	15,261	46%	54%
1993	11,031	19,760	36%	64%
1994	10,354	17,912	37%	63%
1995	7,218	12,794	36%	64%
1996	8,186	12,412	40%	60%
1997	7,815	13,566	37%	63%
1998	5,681	9,516	37%	63%
1999	5,645	6,025	48%	52%
2000	4,912	5,693	46%	54%
2001	5,348	8,158	40%	60%
2002	7,685	9,827	44%	56%
2003	8,572	12,070	42%	58%
2004	9,325	16,120	37%	63%

Note: Data source CMHC, adjusted for TGI service territory, excludes rural starts

Data used in Figure 5, New Construction Starts & TGI Net Customer Additions

	Single-Family	Multi-Family	Customer Adds
1990	10,590	14,610	n/a
1991	11,444	11,291	n/a
1992	12,944	15,261	22,593
1993	11,031	19,760	22,012
1994	10,354	17,912	20,471
1995	7,218	12,794	15,931
1996	8,186	12,412	15,718
1997	7,815	13,566	14,235
1998	5,681	9,516	8,231
1999	5,645	6,025	11,763
2000	4,912	5,693	6,909
2001	5,348	8,158	3,626
2002	7,685	9,827	7,388
2003	8,572	12,070	6,406
2004	9,325	16,120	10,768

16.2 *For each of the years reported in Table 2, please provide actual data on net customer additions broken down by new premises, conversions of existing housing stock, and re-occupancy of vacant premises.*

Response:

Terasen Gas Annual Customer Additions - Component Estimate

	New Premises & Reoccupation	Conversions	Removals / Abandonments	Net Additions
1990	n/a	n/a	n/a	n/a
1991	n/a	n/a	n/a	n/a
1992	25,901	4,927	(995)	29,834
1993	28,455	6,035	(1,085)	33,405
1994	24,907	7,140	(1,173)	30,874
1995	20,962	6,413	(2,095)	25,280
1996	20,239	5,685	(376)	25,548
1997	19,283	5,976	(447)	24,812
1998	12,789	4,611	(552)	16,848
1999	13,246	3,993	(366)	16,873
2000	9,007	2,848	(1,039)	10,817
2001	6,219	1,387	(915)	6,691
2002	9,856	1,816	(874)	10,798
2003	15,097	1,440	(8,077)	8,460
2004	18,267	1,816	(4,099)	15,984

Notes:

1. All Terasen Gas companies included.
2. Net customer additions includes non-residential additions.
3. Component breakout of net additions is an estimate only.

Terasen Gas does not track specific data that allows for a break out new premises, conversions, or reoccupation of vacant premises. The table above provides a numerical estimate of these components. The net customer additions in this table include all rate classes for TGI, TGVI, TGS, and TGW. Generally, residential additions comprise between 90%-95% of net additions in a typical year.

17.0 Reference: Application Tab 1, p. 10 Customer Attraction Challenges; Application Tab 1pp. 12, 13 Net Customer Additions

17.1 The application states that over the past decade the challenge to growth and the business risk profile has increased. It mentions the Bank of Canada, in its overnight rate announcement, that a reduction of monetary stimulus will be required over time. The application states that any short-term interest rate hikes would result in a significant risk that housing construction will not be sustained at current levels.

17.1.1 Please comment if an anticipated increase in the short-term interest rate would affect the expected value of equity market returns, all other things being equal.

Response:

Increases in interest rates that are intended to contain inflation could produce lower equity market returns in the short-run, if there is a subsequent slow-down in economic activity. Increases in interest rates can flow through to higher costs for businesses (and lower profits) as well as to consumers, whose spending may be curtailed.

While increases in long- and short-term interest rates are not perfectly correlated, increases in long-term rates typically accompany, or follow, increases in short-term rates.

Reductions in the returns achieved by equity investors in the market as the level of interest rates rise are a signal that the cost of equity has risen.

17.1.2 Please comment if, and how, an anticipated increase in the short-term interest rate would affect the value of the Canadian dollar versus the U.S. dollar, all other things being equal.

Response:

An increase in short-term rates, all other things equal (e.g., no corresponding increase in short-term rates in the U.S.), would tend to increase the value of the Canadian dollar.

17.2 Table 3 shows that in 1998 and 1999, net customer additions were respectively 54 percent and 100 percent of new construction. Please explain the significant variability in those two years relative to the previous six years.

Response:

The numbers provided in Table 3 provide a high level statistic comparing new housing starts to net additions on Terasen Gas' system. Some of the variation in the percentage numbers reported year over year are unrelated to Terasen Gas' ability to capture market share of new housing starts but instead are due to timing differences in the reporting of data and changes in net customer additions components unrelated to new housing starts (i.e. conversions, account terminations due to lock-offs).

For the 1998 and 1999 percentages, the primary cause of the variation year over year is due to timing differences in reporting of new construction housing starts to net customer additions on Terasen Gas' system. CMHC reports housing starts in the period (i.e. year) when construction begins. Sometimes, there is significant time delay between when a housing start is reported to when the dwelling is connected to Terasen Gas' system, with the net customer addition reported the following calendar year. This in turn leads to variability in the percentages being reported year over year that is unrelated to Terasen Gas' ability to capture market share of new housing starts. For example, by simply averaging the 1998 and 1999 percentages of 54% and 100% over the two years, the resulting number of 77% is then more in line with the previous six years.

Although subject to variation year over year due to the reporting issues discussed above, the percentages provided in the table do still accurately illustrate the challenge that Terasen Gas currently faces in capturing new housing starts.

18.0 Reference: Application, Tab 1, p. 10
Customer Attraction Challenges

On Tab 1, page 10 TGI states:

"Currently housing starts are higher than the long run average."

"…TGI's growth prospects are highly affected by housing start levels."

"There is significant risk that housing construction will not be sustained at current levels."

"Therefore, over the past decade, the challenge to growth and the business risk profile has increased."

18.1 Please elaborate on the linkage between growth and increased business risk. If TGI had modest customer growth of 1 percent by adding economic customers would that increase or decrease business risk?

Response:

It depends. A number of factors are at play here.

Affordable gas distribution delivery service is affected by the gas utility's ability to attract and retain its customer base and at the same time maintain and increase its system throughput levels. By continuing to grow the use of its delivery system through adding additional economic customers and increasing its use from existing customers, the gas utility will be better positioned to realize greater economies of scale and as a result remain competitive relative to other competing energy sources, challenged with a similar task of maximizing its economies of scale. Therefore, adding economic customers contributes to reducing business risk.

However, with delivered natural gas commodity prices closing in on the competitive alternative of electricity and high by historic standards, consumers are receiving price signals to conserve and reduce demand. This is evidenced by the declining use rates since the mid 1990's and the sharp drop following the price spike in the winter of 2000/01. As customer use rates decline, new customer attachments must first offset this lost load simply to maintain delivery rates even in the absence of inflationary pressures and productivity requirements.

Therefore, modest growth of only 1% may in fact increase business risk since it will not offset reductions in throughput from the reduced consumption of other customers.

18.2 In the "BC Gas Main Extension Review – November 2001" on page 1 it stated: "It is in the interest of ratepayers that BC Gas connect customers to main extensions that are economic to build (i.e., main extensions where the present value of the revenues gained from customers exceeds the present value of the construction costs). The MX Test is used to assess potential system extensions to either ensure that they are economic (and therefore non-contributory), or to calculate the required projections in the MX Test allows BC Gas to minimize contribution requirements when extending gas service, while avoiding cross-subsidization from existing ratepayers."

18.2.1 Please elaborate on the history of the Main Extension policy from 1990 to present. How has the policy changed over the years? How stringent were the controls in 1990 and 1994 to discourage uneconomic additions?

Response:

Prior to 1994 the main extension (MX) policies that were in place for BC Gas (now TGI) were the MX policies of the predecessor companies that were amalgamated in 1988 to form BC Gas. These policies were characterized by “net revenue” tests which were considered a simplified proxy for more detailed economic evaluations. The Lower Mainland had a five year net revenue test while the interior divisions had a six year net revenue test. This approach to the MX test was a simple comparison of five or six years of undiscounted net revenue (gross revenue less gas costs) against the direct cost of the main extension. There may have been some economic basis upon which these net revenue MX tests were initially established but the simplified methodology of these models meant there were a number of ways that uneconomic customers could be added to the system. Since the net revenue tests considered mains costs only but did not consider the costs of service lines, metering costs or other incremental costs there was no straightforward way to determine whether the customers added on main extensions were economic or not, even if the MX policy was applied consistently.

In its August 5, 1992 Decision on BC Gas’ 1992 Revenue Requirements Application the Commission directed BC Gas to file a proposal for a system-wide MX test before or concurrent with its general rate design application. BC Gas proposed a discounted cash flow (DCF) model in its 1993 Phase B Rate Design Application which the Commission approved with some modifications. The new MX test in effect increased the economic hurdle that individual MX projects needed to pass to proceed without a customer contribution. The DCF MX Test that was approved in the Commission’s October 25, 1993 Decision was implemented in 1994 and stayed in place in the same form through 1996. Compared with the former net revenue tests, the DCF MX Test considered many more elements of the incremental costs imposed on the distribution system and employed standard principles of project financial analysis. As such the focus on adding economic customers was increased with the adoption of this model.

In 1995 and 1996 the Commission conducted a generic hearing and review of system extension tests of the gas and electric utilities in the province. This culminated in the release of the BCUC’s Utility System Extension Test Guidelines on September 5, 1996. This generic review considered a number of additional aspects of the economics of system extensions such as the treatment of upstream costs (e.g., system improvements), externalities and the harmonization of utility system extension tests with the principles of integrated resource planning. The main changes that were made to the BC Gas MX Test as a result of the generic review were adding an allowance for upstream system improvements into the cost side of the DCF analysis and reducing the project analysis period to 20 years from the 33 years used from 1994 to 1996. Both of these changes further increased the economic hurdle that MX projects needed to pass. After implementation of revised DCF model in 1997 the Company also developed a load estimating program that was incorporated into the MX Test. For new residential customers, the load estimating model accounted for factors such as house size, number and type of gas appliances, location within the province, insulation levels and others. This addition to the MX Test reduced the likelihood of load estimating errors.

18.2.2 When was the MX Test implemented? Was the MX Test implemented arising from a concern of adding uneconomic customers? What new fees arose from the new Main Extension policy? Discuss the implications of the change in fees to a customer and how it has affected customer growth.

Response:

As discussed in the previous response, TGI's DCF MX Test was introduced initially in 1994 and revised in 1997.

The DCF MX Test was implemented due to concern around adding uneconomic customers and the effects uneconomic customers would have on the rates of existing customers.

No new fees arose directly from the new main extension policy. Several new fees or fee increases related to customer connections arose in the same timeframe as the Commission's generic review of utility system extensions. Application Fees for new and existing services were increased to make these fees more in line with the cost of processing such applications. The Service Line Installation Fee (SLIF) and Service Line Cost Allowance (SLCA) were introduced in 1997 in an effort to deal with the economics of service lines. In combination these fees were considered an appropriate alternative to running an economic evaluation of every service line which would have had considerable associated administrative burden. The SLIF is a fee of $215 that must be paid toward any new residential or small commercial service line. In combination with the $85 new service Application Fee a new service installation would typically pay $300 in total. Please see further comment on the service line policy in the response to Question 18.2.4 below.

18.2.3 For 1994 (or closest previous year) please provide a copy of a post-implementation review report of main extensions concerning the economic viability of new customer additions.

Response:

Terasen Gas does not have any post-implementation review reports from the 1994 time frame that deal directly with the economic viability of new customer additions. Terasen Gas filed MX review reports for several years with the BCUC with the final one submitted in 2001 for MX projects from 2000. (The Commission indicated in Letter No. L-7-02 that it was no longer necessary for Terasen Gas (BC Gas) to file these reports.) These reports compared actual results with forecast for mains capital costs and customer attachments. While there were some variances on individual MX projects, these reports did not find significant variations in aggregate from forecast to actual for capital costs and customer attachments. It is possible to draw a rough inference from the fact that actual MX capital costs and customer additions track forecast quite well that the economic viability of new customer additions is reasonably assured.

Furthermore, as indicated in the answer to question 19.3, Terasen Gas believes that meeting the M/X test does not ensure that a customer will remain a customer for the period required to ensure full recovery of, and on, capital invested. The M/X test does not protect Terasen Gas against the risk of the price of natural gas service being uncompetitive against electricity. For example, erosion in the competitiveness of natural gas service including the commodity price and delivery margin relative to alternative fuels, primarily electricity may lead to a loss of a customer over time. This is a situation that Terasen Gas faces with the recent gas commodity price volatility in the marketplace.

18.2.4 Please elaborate on the service line installation policy in 2004 compared to the present policy. With the new policy, what are the implications in the context of adding new customers and adding economic customers?

Response:

This response assumes that the reference to 2004 in the question should really be 1994 (since no recent changes have occurred in the Terasen Gas service line policy).

As discussed above, the current Terasen Gas service line installation policy was implemented in 1997 after consideration by the BCUC in the Company's 1996 rate design proceeding. Some revisions were made in 1999 through a separate application. In summary, under the current tariff, an applicant requiring a new service line will pay the $85 Application Fee, the $215 SLIF and any amounts by which the direct service line installation costs exceed the SLCA of $1,100. Prior to 1997 the applicant paid only the application fee and an excess footage charge for service lines over 20 metres in length. The introduction of the SLIF was expected to discourage small load attachments that were likely uneconomic. The use of the SLCA was considered to be better than an excess footage charge since it recognized that the length of the service line was not always an accurate predictor of costs. The new policy was expected to deter the low volume uneconomic customers from attaching and thereby enhancing the likelihood that new service lines were economic.

18.2.5 For 2004 please provide the total actual cost of a typical installation (main to meter) for a Lower Mainland customer, all fees charged to the customer, contributions from the customer, average length of service line, and the expected average usage. State the assumptions including cost components.

Response:

For 2004 the actual average cost for service line and meter (i.e. from main to meter) was $1,207. Customers are charged an Application Fee of $85 and a Service Line Installation Fee of $215. Application fees are included in the utility's Other Revenue but the Service Line Installation Fee is coded as a Contribution in Aid of Construction. When the cost of a service line exceeds $1,100, the amount of the excess is also charged to the customer and coded as a contribution in aid of construction. A 'typical' service line cost less than $1,100 and the customer would not incur Service Line Installation Fee above $215.

Service Line	$923
Meter	284
Total Cost	$1,207
# of Service Line Installations	9,353
2004 Residential Normalized Actual Usage	109.8 GJ

The average service line length is not reported in the information system, but rather the number of service lines installed.

18.2.5.1 Please repeat the above question for a customer in 1994.

Response:

The information for 1994 is no longer available. The following pages from an information response given in 1996 (related to BC Gas Utility Ltd. Rate Design Application) provide a prospective average cost for the service line and meter for residential, small commercial and large commercial customers. (BC Gas Utility Ltd., 1996 Rate Design, Volume 3 Response to Information Requests, Tab G Inland Industrial Customers, Item 11, Pages 2.0 – 2.2).

The cost of a typical residential and small commercial installation for a service line and meter would be approximately $1,100 or $1,300 (in 2004 $) (using a 200 or 400 meter set (Lines 1 and 3) on pages 2.0 and 2.1). For Large Commercial customer there is a greater dispersion for what might be a typical installation from as low as approximately $1,750 or $2,050 (in 2004$) (Page 2.2, Line 3, Col. i) for a 800 meter set to $3,700 or $4,300 (in 2004$) for a 3M (Line 11, Col. i).

In 1994 a new customer which required a service line installation was charged an application fee of $75.00. There was no Service Line Installation Fee. The cost of the service line was not charged to the customer as long as the total length of the service line was 20 metres or shorter and followed BC Gas' preferred route. A contribution in aid may be required if the customer wanted the service line to follow a different route that was more expensive than BC Gas' choice, the additional cost of the service line being greater than 20 metres, if extra non-standard construction costs were required for creek crossings or extra depth and frost conditions due to winter construction. (BC Gas Tariff, General Terms and Conditions, Section 10 – Service Lines, and Standard Fees and Charges Schedule).

In 1994 the residential actual average usage was 119.7 GJ, and in 1996 the actual average usage was 130.6 GJ.

Please see Appendix 18.2.5.1 which shows Customer waiting factors for 1996.

18.3 Please elaborate on the current SAP Order Fulfillment process and the benefits compared to the previous Work Management System process used in 1994.

Response:

The Order Fulfillment (OF) process was implemented in Jan 2003, using SAP software. SAP is current day enterprise software adopted by Terasen Gas in primarily as the financial software. Several subsequent add-on modules including SAP-PM (Preventive Maintenance) and SAP-OF replaced disparate stand alone systems and the existing Work Management System (WMS). The technical drivers for adopting the SAP- OF software were the age of WMS (12 years), the lack of support for OS/2 (the operating system behind WMS) and the functionality of the SAP-OF software in a customer sensitive marketplace.

The implementation of the Order Fulfillment process focused on improving the relationship with customers, particularly builders and developers, centralization of the front and back office Customer Additions Capital work. Planning and clerical groups were downsized through efficiency gains, job initiation was centralized, processes were standardized for handling customer requests, a quasi call centre was created to handle customer installation requests from start to finish, a resource capacity / optimization tool was developed to match field resources to work initiated, and an install promise date was provided to the customer. The creation of the “Install Centre” with expanded working hours and standardized service sought to reduce delays and inconsistencies experienced by builders/developers/customers using the one local planner model.

The Service Delivery Enhancement Project, (implemented June 2005) is a further evolution of the Order Fulfillment process and has effectively given Terasen daily tracking and reporting on work order statuses, real time scheduling and resource availability, job site readiness confirmation, employee process compliance, and scale-ability of operations in response to changes in activity levels. For field crews, the biggest change has been having a mobile laptop in their truck and having to provide real time updates to the central office.

The Work Management System (WMS) was developed and implemented largely in-house in the early nineties to replace a paper based work management process. WMS was used to manage field work including operations, maintenance, emergencies, projects and customer addition installation activity. Jobs were initiated in WMS from a maintenance schedule or on demand (emergencies, customer additions, etc). Field work was initiated from each Regional Centre, sometimes at the branch level, and planned, assigned and dispatched locally. Field crews received job packages directly from the branch or via inter-office mail. Field crews worked the jobs, updated the package information, returned the job packages to the Regional offices for costing, closing and completion.

The financial benefits have been significant – reductions in O&M (salaries, wages, vehicles, muster space and equipment costs), reductions in Planning costs in Capital work through employee and vehicle reductions.

In 2002, the year prior to Order Fulfillment (OF) implementation and process centralization, the Area and Specialty Planners headcount was 53 with most operating a vehicle, performing site visits and utilizing computer, communications and space facilities at local musters. Following OF implementation in Jan 2003, the number of positions was reduced to 33, a reduction of 38%. The number of vehicles was reduced by 29. Only a handful were then designated to individuals and a vehicle pool was made available to the new positions.

The annual savings in salary and vehicle costs as a result of OF implementation was approximately $1.3 million which was roughly split 20% O&M and 80% Capital. Service installation unit costs dropped from $1070/service to $861/service in the year of OF implementation. Mains installation unit costs dropped from $36/metre to $32/metre in the same time period. While there are several factors that contributed to the reduction, the planning component has historically been roughly 20% of the cost and contributed to achieving this result.

18.3.1 How has the system new system improved work processes, internal and external communication, data gathering, information processing and flow, operating costs, and capital costs when a new customer signs up for service? Would this be an example of a new technological improvement that has reduced the operational risks (thus business risks) of the utility? With the new system, how has the average time from service application to installation been reduced as measured by the number of days?

Response:

Work Processes: Centralization, standardization and documentation of the work process were key elements of the Order Fulfillment (OF) process. There were staff reductions and cost savings as a result of project implementation.

Internal and External Communications: Standardization of the process ensured that customers benefited from the same service levels province wide; customers enjoyed the benefit of expanded hours of business and received a consistent service.

Data Gathering: Customer information and job files are now electronic and accessible to any authorized employee in the install centre; prior to OF this information was maintained by the local planner, either in file cabinets or in personal memory.

Information Processing & Flow: OF was a further evolution to an on-line electronic tool versus the combination of paper files and WMS system info that was maintained prior to 2003.

Operating & Capital Costs: The OF project was implemented in Jan 2003 and resulted in immediate Operating cost savings through staff and vehicle reductions primarily in the Planning department. The unit costs on capital work have also been holding steady despite inflationary increases in labour, contractor and vehicle rates.

Order Fulfillment is an example of a technology change that has reduced the operational costs of the company, which savings have been passed on to customers. it’s the primary focus of Order Fulfillment was being able to respond consistently and efficiently to customer requests in periods with fluctuating activity levels.

There is no significant change in operating risk as a result of Order Fulfillment. Prior to Order Fulfillment the Company was effectively providing service, but at a higher cost that was borne by customers.

Terasen Gas does not currently measure the time between service application and installation as this duration varies from customer to customer. Install promise dates are established with the customer based on a combination of projected site readiness dates and crew resource availability. The time may be as low as 5 days and as high as 180 days depending on the notice received from the customer and the size of the project. The OF process introduced an alternate and more suitable metric for Terasen Gas which measures the number of installations completed on the appointment date.

18.4 Would TGI agree that adding uneconomic customers increases the business risk of the utility?

<u>Response:</u>

Yes, holding all other variables constant

18.5 Would TGI agree that adding economic customer decreases the business risk of the utility?

<u>Response:</u>

Yes, holding all other variables constant. See response to 18.1.

19.0 Reference: Application, Tab 1, pp. 10-11
Customer Attraction Challenges

On Tab 1, page 10 TGI states:

"Today, approximately 2/3rds of all housing starts are multiple units and TGI's estimated capture rates in this segment are running at less than 20%."

On Tab 1, page 11 TGI states:

> *"This decreased competitiveness is reflected in the significant decline in net customer additions compared to housing starts."*

19.1 What is the cost of installation for a multifamily unit compared to the revenues generated from consumption? Are multifamily units economic customers?

<u>Response:</u>

There is not 'a' cost to attaching a multi family unit. The cost of serving a multifamily complex can vary significantly depending on several factors whether or not the service header is tying into an existing main or if a main extension is required, the length (route) and size the service header(s) must be, the number of risers and type of regulators (manifolds) and the quantity and type of meter sets required.

The following table shows the number of units, and costs for four multifamily complexes that were completed within the last twelve months.

MULTI FAMILY ATTACHMENTS

Line No.	Particulars		Townhome Langley	Townhome Richmond	Townhome Coquitlam	Vertical Subdivision Vancouver
1	# of Units Served		70	59	71	28
2	Estimated Annual Use / Unit (GJ)		75	81	70	97
3	Estimated Annual Load (GJ)		5,250	4,779	4,970	2,716
4	Delivery Margin Rates as at 1/1/04					
5	Basic Charge per Month	$ 10.75				
6	Delivery Charge per GJ	$ 2.677				
7	Annual Revenue		$ 23,084	$ 20,404	$ 22,464	$ 10,883
8	Total Attachment Costs		36,250	28,795	36,574	24,317
9	Service Line Installation Fee / Line	$215	(4,085)	(2,365)	(3,870)	(1,505)
10	Main Extension Contribution		-	-	-	-
11	Subtotal		32,165	26,430	32,704	22,812
12	Residential Meter / Unit	$75	5,250	4,425	5,325	2,100
13	Total Cost		$ 37,415	$ 30,855	$ 38,029	$ 24,912
14	Connection Fee / Unit	$85	$ 5,950	$ 5,015	$ 6,035	$ 2,380

Prospectively, the main extension test calculates the contribution in aid of construction that is required if the discounted cash flows are negative. Almost all of the main extensions to serve multifamily complexes do not require a contribution in aid of construction. The only contribution in aid from attaching a multifamily complex is from the Service Line Installation Fee. Prospectively, all multifamily complexes that are attached must meet the MX test.

However, meeting the MX test does not ensure that a customer will remain a customer for the length of time required to ensure full recovery of, and on, the capital invested.

19.2 Please provide a definition of "multifamily dwelling".

Response:

As defined by CHMC (Canada Mortgage and Housing Corporation), Multi-family dwelling comprises three types of dwelling units:

1. Semi-detached - This category each one of two dwellings separated by a common wall extending from ground to roof or by a garage.
2. Row - This category comprises only single-attached houses in a row of three or more dwellings.
3. Apartment and other.- This category includes dwelling units found in a wide range of structures such as: duplexes, double-duplexes, triplexes, row-duplexes, apartments proper and dwellings over, or at the back of, a store or other non-residential structure.

19.2.1 Is a townhouse complex with 10 units considered 10 dwellings and potentially 10 natural gas customers?

Response:

Canada Mortgage Housing Corporation ("CMHC") considers a new townhouse complex with 10 units, 10 individual new multi-family house starts.

From Terasen Gas' perspective, the 10 unit townhouse complex is counted as 10 gas customers if each unit has a separate gas meter attached to it. In the situation where only one gas meter is required to serve the 10 unit townhouse complex, then from Terasen Gas' perspective, the complex is counted as 1 natural gas customer.

A complexity arises in assessing Terasen's capture of housing starts due to the fact that two ten unit townhouse complexes would count for 20 housing starts, whereas Terasen might put a central boiler in one complex with one meter resulting in a single customer attachment and install individual meters in the second complex resulting in 10 customer attachments. In total we would have 11 customers against 20 housing starts (notionally 55% capture rate) notwithstanding the fact that we are serving 100% of the housing starts in question. Existing information systems capture only new customer attachments as evidenced by a new customer account (meter).

19.2.2 Is a high-rise condominium with 200 units considered 200 dwellings and potentially 200 natural gas customers?

Response:

Yes, please refer to answer in Question 19.2.1.

Canada Mortgage Housing Corporation ("CMHC") considers a high-rise condominium with 200 units, 200 individual new multi-family house starts (dwelling).

From Terasen Gas' perspective, the 200 unit high rise condominium is counted as 200 gas customers if each unit has a separate gas meter attached to it. In the situation where only one gas meter is required to serve the 200 unit high rise condominium, then from Terasen Gas' perspective, the complex is counted as 1 natural gas customer.

19.2.3 How would the statistics be skewed if the high-rise condominium strata-corporation signed up as a single customer to service its 200 units? Please elaborate on the impact of the statistics cited in pages 10 to 12.

Response:

Table 2 on page 11 comparing the relative proportion of single family to multi family housing starts as reported by CMHC would remain unaffected as CMHC currently counts the 200 units as 200 multi family housing starts, irrespective of how Terasen Gas counts the units.

Figure 5 on page 12 comparing CMHC reported new construction starts to Terasen Gas' net customer additions recorded would change with Terasen Gas' reported net customer additions decreasing. To date, most high-rise condominium strata corporations have signed up for gas service with Terasen Gas as a single commercial customer (i.e. a Rate Schedule 2 or 3 customer). However, there are situations where each condo unit is individually metered. In such cases, Terasen Gas counts each individually metered condo unit as a customer.

Table 3 on page 12 expressing net customer additions as a percentage of CMHC reported new construction housing starts would decrease if new high-rise condominiums with multi units were all counted each as a single gas customer. There are situations where each condo unit is individually gas metered. In such cases, Terasen Gas counts each individually metered condo unit as a customer. With the suggested change outlined in the question, the number of net customer additions Terasen Gas would report would decline.

19.2.4 What is the default rate of a strata-corporation compared to a residential customer?

Response:

Terasen Gas does not track a breakout of this segment separate from residential customers as a group.

19.2.4.1 If the default is lower for a strata-corporation, would this be an example of lower business risk to the utility since there is less chance of default?

Response:

In isolation and based on the assumptions stated in the question, yes. However, Terasen Gas does not the track the specific data that is needed to confirm whether or not these assumptions are in fact true.

Default risk is but one risk however. Individually metered units provide diversification of risk of loss of customers. For example, if one customer vacates for a period of time, the utility will lose basic charges and delivery margin but will continue to serve the remaining customers in the complex. If the strata identifies an alternative energy form or upgrades equipment to permanently reduce consumption, then load is reduced or eliminated permanently.

19.3 In the Lower Mainland single-detached dwellings have grown in size. What is the typical consumption of single-detached dwelling in the Lower Mainland? Are these larger houses economic customers?

Response:

Terasen Gas does not specifically track consumption in the Rate 1 residential service class by the type of housing stock (i.e. single family, townhouses, etc) as customers included in the Rate 1 residential service class consist of any residential housing building that meets the volume threshold for the rate class and is also individually metered (i.e. detached house, townhouse, individually metered condo unit).

Terasen Gas estimates that the average single-detached dwelling in the Lower Mainland consumes in total approximately 110 gigajoules in a normal weather year, with an estimated 70 gigajoules for space heating, 25 gigajoules for water heating and 15 gigajoules for other uses such as a fireplace.

These larger single-detached dwelling customers have been subject to the Mains Extension and the Service Line Installation tests and therefore meet those tests. However, meeting the tests does not ensure that the building will remain a customer for the period required to ensure full recovery of, and on, capital invested.

20.0 Reference: Application, Tab 1, p. 12
Customer Attraction Challenges

On Tab 1, page 12 TGI provides Table 3 Terasen Gas Net Customer Additions vs. New Customers.

20.1 Please provide a similar schedule to Table 3 that compares new customer single-detached dwellings additions versus new construction single-detached dwellings. Provide estimates if necessary.

Response:

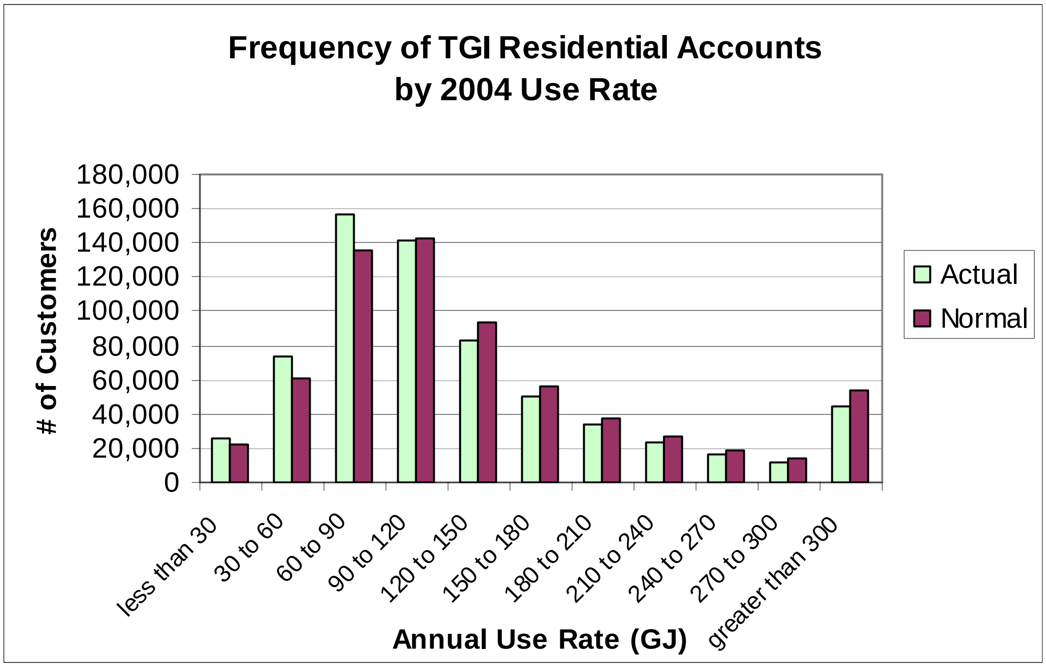
Please note edit below – JW Sep 1

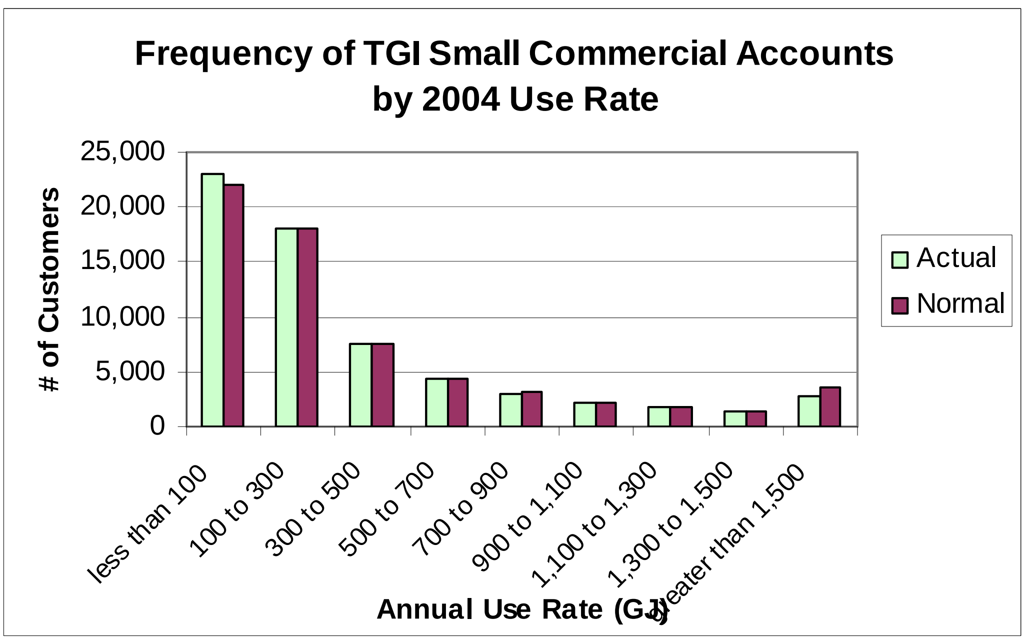
Terasen Gas does not track specific data of this type. Terasen Gas estimates that its capture rate of new single detached dwelling construction is historically in the range of 90%-94%. However, over the last few years the capture rate has declined to a range of 80%-84%.

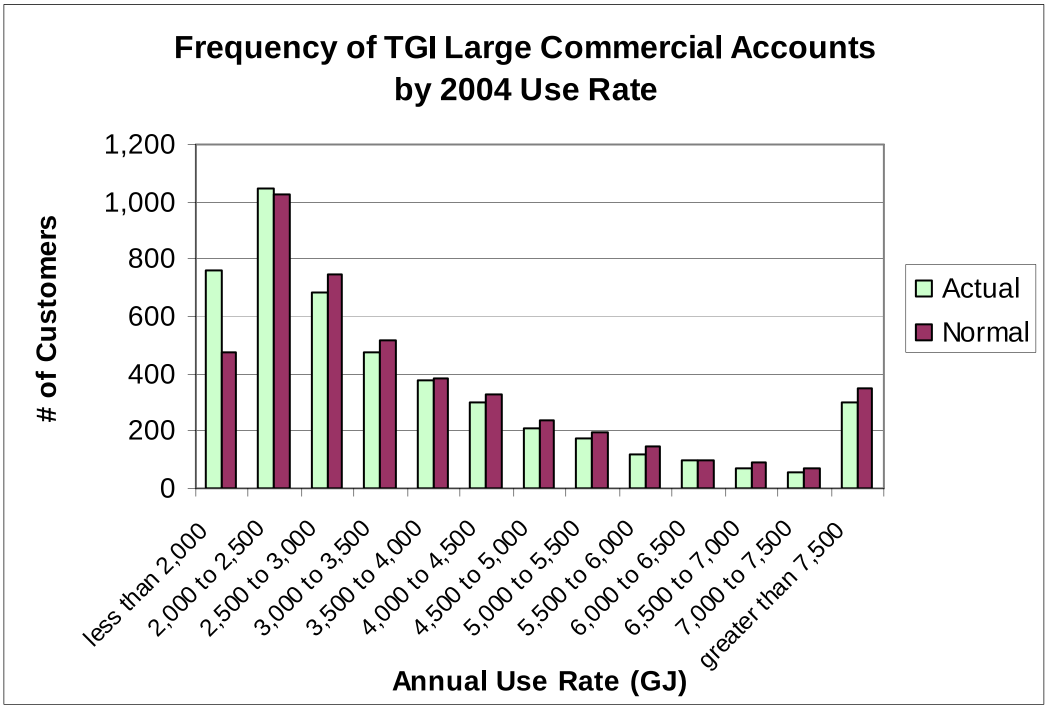
20.2 For TGI please provide a histogram frequency distribution of annual use per customer for 1994, 1999, and 2004 using recorded and normalized figures for each of the residential, small commercial, and large commercial customer classes. Use the same scale for each year.

Response:

Please refer to the following figures for histogram frequencies for TGI's residential, small commercial and large commercial 2004 use rates. Only histograms have been provided for 2004 as detailed consumption records for all customers in the respective rate classes required to construct similar histograms for 1994 and 1999 for the Lower Mainland were kept on the old BC Hydro billing systems and were not converted on repatriation. As such, they are not available.


Frequency of TGI Residential Accounts
by 2004 Use Rate
# of Customers
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
less than 30
30 to 60
60 to 90
90 to 120
120 to 150
150 to 180
180 to 210
210 to 240
240 to 270
270 to 300
greater than 300
Annual Use Rate (GJ)
Actual
Normal


Frequency of TGI Small Commercial Accounts
by 2004 Use Rate
# of Customers
25,000
20,000
15,000
10,000
5,000
0
less than 100
100 to 300
300 to 500
500 to 700
700 to 900
900 to 1,100
1,100 to 1,300
1,300 to 1,500
greater than 1,500
Annual Use Rate (GJ)
Actual
Normal



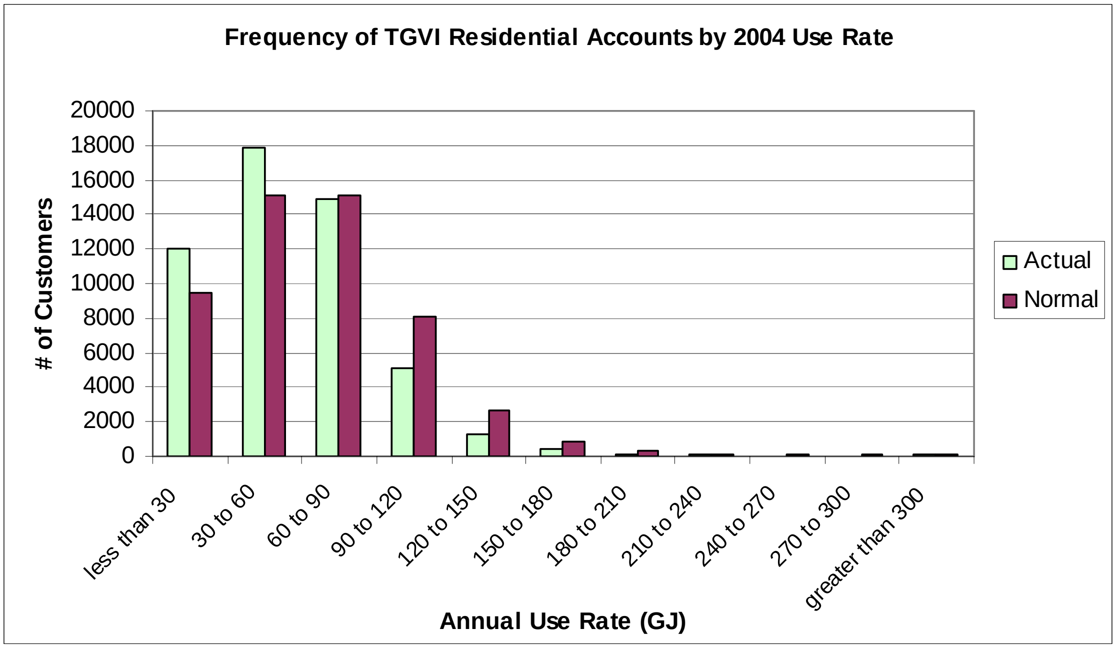
Each histogram categorizes the number of customers into an interval under both actual (i.e. recorded) or normal (i.e. weather adjusted) consumption scenarios. In each histogram, the total number of customers cumulatively for 2004 in each rate class for the actual and normal scenarios is the same. However, the distribution of the customers for the actual and normal scenarios is different as the result of normalizing the consumption data.

For example, in 2004, the weather was warmer than normal. After applying normalization factors, each customer's actual consumption was adjusted higher. With the interval ranges kept the same under both the actual and normal scenarios, normalizing has the effect of shifting some customers into a higher interval range.

20.3 For TGVI please provide a histogram frequency distribution of annual use per customer for each year from 1994 to 2004 using recorded and normalized figures for each of the residential, small commercial, and large commercial customer classes. Use the same scale for each year.

<u>Response:</u>

Please refer to discussion in answer to Question 20.2.



Frequency of TGVI Residential Accounts by 2004 Use Rate
# of Customers
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
less than 30
30 to 60
60 to 90
90 to 120
120 to 150
150 to 180
180 to 210
210 to 240
240 to 270
270 to 300
greater than 300
Annual Use Rate (GJ)
Actual
Normal

21.0 Reference: Application, Tab 1, pp. 13-14

21.1 Please provide data summarizing TGI and TGVI use rates, customer additions, total customers and total load for all customer classes in each of the last 5 years.

<u>Response:</u> TGVI Use Rates, Customer Additions, Total Customers and Total Load:

	TGVI	Actual Volume (TJ)	Use Rate (GJ)	Customers	Customer Additions
2000	SGS-1	1,578	70	21,624	(2,236)
	SGS-11	2,274	62	39,186	5,309
	SGS-2	71	268	238	(31)
	SGS-12	45	276	186	56
	TOTAL RES	3,968		61,234	3,098
	SGS-1	133	81	1,541	(294)
	SGS-11	171	75	2,410	318
	SGS-2	401	365	1,111	(123)
	SGS-12	265	337	801	87
	LGS-1	1,044	1,023	1,014	(87)
	LGS-11	540	990	575	138
	LGS-2	1,030	2,493	404	(54)
	LGS-12	509	2,475	220	63
	LGS-3 ACR-1	-		-	-
	LGS-3 APT R	226	9,464	23	(1)
	LGS-3 COM	1,149	16,142	70	(12)
	LGS-13	531	14,179	41	17
	CRR	1,113	52,995	21	(2)
	E-PLUS	-		-	-
	TOTAL COMM	7,111		8,231	50
	TOTAL TRANS	16,404	N/A	3	1
	2000 Total	27,483		69,468	3,149
2001	SGS-1	1,394	68	20,129	(1,495)
	SGS-11	2,281	56	42,304	3,118
	SGS-2	56	244	224	(14)
	SGS-12	50	266	202	16
	TOTAL RES	3,781		62,859	1,625
	SGS-1	119	80	1,428	(113)
	SGS-11	178	72	2,542	132
	SGS-2	356	328	1,065	(46)
	SGS-12	268	307	908	107
	LGS-1	984	988	984	(30)
	LGS-11	582	951	651	76
	LGS-2	998	2,542	384	(20)
	LGS-12	529	2,323	230	10
	LGS-3 ACR-1	5	5,473	1	1
	LGS-3 APT R	208	9,039	23	-
	LGS-3 COM	1,201	16,495	73	3
	LGS-13	612	14,858	45	4
	CRR	920	46,242	20	(1)
	E-PLUS	45	22,719	2	2
	TOTAL COMM	7,005		8,356	125
	TOTAL TRANS	16,289	N/A	3	-
	2001 Total	27,075		71,218	1,750

	TGVI	Actual Volume (TJ)	Use Rate (GJ)	Customers	Customer Additions
2002	SGS-1	1,309	69	18,599	(1,530)
	SGS-11	2,501	56	46,404	4,100
	SGS-2	54	244	220	(4)
	SGS-12	53	255	202	-
	TOTAL RES	3,917		65,425	2,566
	SGS-1	110	82	1,270	(158)
	SGS-11	199	75	2,743	201
	SGS-2	343	329	1,011	(54)
	SGS-12	287	306	986	78
	LGS-1	950	989	953	(31)
	LGS-11	659	956	768	117
	LGS-2	985	2,576	384	-
	LGS-12	545	2,276	256	26
	LGS-3 ACR-1	5	5,452	1	-
	LGS-3 APT R	211	9,488	22	(1)
	LGS-3 COM	1,142	16,096	76	3
	LGS-13	752	14,748	54	9
	CRR	969	48,731	20	-
	E-PLUS	47	23,475	2	-
	TOTAL COMM	7,207		8,546	190
	TOTAL TRANS	22,399	N/A	3	-
	2002 Total	33,523		73,974	2,756
2003	RGS	3,960	59	67,981	N/A
	TOTAL RES	3,960		67,981	2,556
	SCS 1	262	65	3,949	N/A
	SCS 2	521	294	1,776	N/A
	LCS 1	1,309	893	1,489	N/A
	LCS 2	1,265	2,306	558	N/A
	APT R (S2-L1)	745	1,211	610	N/A
	APT R (L3)	201	9,140	22	N/A
	LCS 3	2,169	16,343	125	N/A
	HLF	61	N/A	12	N/A
	ILF	88	N/A	8	N/A
	CRR	591	77,598	3	N/A
	TOTAL COMM	7,212		8,552	6
	TOTAL TRANS	21,169	N/A	3	-
	2003 Total	32,341		76,536	2,562

	TGVI	Actual Volume (TJ)	Use Rate (GJ)	Customers	Customer Additions
2004	RGS	3,830	55	71,932	3,951
	TOTAL RES	3,830		71,932	3,951
	SCS 1	245	61	4,034	85
	SCS 2	493	278	1,783	7
	LCS 1	1,254	854	1,482	(7)
	LCS 2	1,235	2,235	548	(10)
	APT R (S2-L1)	998	1,343	768	158
	APT R (L3)	1		-	(22)
	LCS 3	2,159	16,053	130	5
	HLF	262	39,539	7	(5)
	ILF	113	12,816	9	1
	CRR	213	71,156	3	-
	TOTAL COMM	6,972		8,764	212
	TOTAL TRANS	21,536	N/A	3	-
	2004 Total	32,339		80,699	4,163

TGI Use Rates, Customer Additions, Total Customers and Total Load:

	TGI	Actual Volume (TJ)	Use Rate (GJ)	Customers	Customer Additions
2000	Rate 1	76,543	113	678,712	6,317
	Rate 2	23,913	332	72,440	899
	Rate 3	21,992	3,749	5,782	(168)
	Rate 4	289	N/A	-	-
	Rate 5	10,335	16,603	607	(31)
	Rate 6	546	9,748	57	2
	Rate 7	1,060	70,661	9	(12)
	Rate 22	45,494	805,212	58	3
	Rate 23	2,448	6,294	435	92
	Rate 25	8,584	37,980	302	152
	Rate 27	5,455	64,177	89	8
	2000 Total	196,660	-	758,491	7,262
2001	Rate 1	69,143	102	683,547	4,835
	Rate 2	22,241	307	72,491	51
	Rate 3	19,310	3,393	5,601	(181)
	Rate 4	168	N/A	3	3
	Rate 5	8,384	14,931	516	(91)
	Rate 6	452	8,080	55	(2)
	Rate 7	294	39,173	6	(3)
	Rate 22	40,286	688,657	59	1
	Rate 23	2,733	5,364	584	149
	Rate 25	9,842	27,922	403	101
	Rate 27	5,628	61,505	94	5
	2001 Total	178,482	-	763,359	4,868

	TGI	Actual Volume (TJ)	Use Rate (GJ)	Customers	Customer Additions
2002	Rate 1	74,745	109	690,907	7,360
	Rate 2	22,675	315	71,667	(824)
	Rate 3	19,207	3,454	5,519	(82)
	Rate 4	178	N/A	1	(2)
	Rate 5	6,493	12,934	488	(28)
	Rate 6	326	5,883	56	1
	Rate 7	100	18,186	5	(1)
	Rate 22	41,169	691,923	60	1
	Rate 23	3,498	5,462	697	113
	Rate 25	12,985	29,783	469	66
	Rate 27	6,090	63,439	98	4
	2002 Total	187,467	-	769,967	6,608
2003	Rate 1	68,360	98	697,213	6,306
	Rate 2	21,042	295	70,923	(744)
	Rate 3	17,376	3,196	5,353	(166)
	Rate 4	148	N/A	1	-
	Rate 5	5,597	11,697	469	(19)
	Rate 6	241	5,029	40	(16)
	Rate 7	84	15,283	6	1
	Rate 22	39,384	661,913	59	(1)
	Rate 23	3,557	4,653	832	135
	Rate 25	13,347	26,990	520	51
	Rate 27	5,713	58,294	98	-
	2003 Total	174,849	-	775,514	5,547

	TGI	Actual Volume (TJ)	Use Rate (GJ)	Customers	Customer Additions
2004	**Rate 1**	66,026	94	707,929	10,716
	Rate 2	20,487	287	71,759	836
	Rate 3	17,284	3,315	5,075	(278)
	Rate 4	134	N/A		(1)
	Rate 5	4,915	11,058	420	(49)
	Rate 6	318	7,851	41	1
	Rate 7	68	13,547	4	(2)
	Rate 22	38,554	664,732	57	(2)
	Rate 23	4,281	4,616	1,023	191
	Rate 25	14,287	26,755	548	28
	Rate 27	5,405	54,594	100	2
	2004 Total	171,759	-	786,956	11,442

Notes:
1. TGVI transportation includes Squamish & ICP
2. TGVI use rates are calculated as the sum of monthly volumes divided by the monthly number of customers (not applicable to HLF & ILF in 2003 because 12 months of data are not available)
3. TGI use rates are calculated as the actual volume divided by the average of the year-end & prior year's year-end customers
4. TGI data includes all transportation customers and volumes, but excludes Burrard Thermal and Transportation TGVI (PCEC).
5. Fort Nelson is not included in TGI.
6. Revelstoke is included in TGI.

21.2 With respect to use rates, please discuss, for TGI and TGVI separately, the incremental positive and negative impacts on business risk that are associated with either an increase or a decrease to use rates.

Response:

As outlined in the Application, Terasen Gas equates the level of business risk it faces to the enterprise’s ability to recover its investment in its assets or “rate base” and its ability to achieve its allowed return on equity. This in turn is impacted by the attractiveness or competitiveness of natural gas as an energy source compared to alternate energy forms such as electricity and the growing renewable energy sector such as geothermal, wind and solar power.

The competitiveness of natural gas service including commodity to customers is dependent not only on prevailing market demand and supply conditions for the different competing energy commodities but also on the gas distribution utility’s ability to provide safe, reliable and affordable gas distribution delivery service to its customers.

For TGI, decreased use rates result in increased pressure on delivery rates, other things being equal. This reduces competitiveness, makes customer attraction more challenging and makes it more difficult to retain customers and maintain economies of scale. These factors increase business risk. Increased customer use rates result in opposite impacts and benefits, however higher use rates will eventually result in increased system reinforcement requirements as well. See also the response to question 18.1.

For TGVI, the impacts are directionally similar to those outlined for TGI, however the starting point for comparison is that of a higher risk environment for TGVI. With certain TGVI rate classes rates already at or above the competitive alternative electricity rates, further rate pressure due to declining use results in the inability to recover full cost of service from those rate classes and jeopardizes recovery of, and on, the investment in rate base. Further, TGVI currently must recover $60 million in cumulative revenue deficiencies (net of tax) prior to 2012 when its Royalty Revenue entitlement expires under VINGPA and when it must become fully self sustaining. The loss of Royalty Revenues in an environment which is already challenging, will substantially and adversely affect TGVI. Additional rate pressure due to declining use rates could further jeopardize the financial viability of the utility.

22.0 Reference: Application, Tab 1, p. 13
Declining Annual Use Rates

On Tab 1, page 13 TGI states:

"The annual use of natural gas by residential customers declined steadily through the 1990's and is forecast to continue to decline in the future"

"This decline in use rates places upward pressure on customers' rates, and contributes to the compression of natural gas and electricity rates"

22.1 Please elaborate for an existing residential customer on the bill impact of using less consumption through energy conservation. Would lower consumption multiplied by a higher unit rate be similar to a higher consumption multiplied by a lower unit rate?

Response:

The answer would depend on the relative changes in consumption and delivered gas rates. At a macro level, if use rate decline in gas consumption is the result of measures that have a similar effect on the consumption of electricity, such as activities to improve the insulation of a home, the competitive positions and choice of natural gas or electric for home heating remains unaffected, as energy consumption will be reduced in both cases regardless of energy choice.

For practical purposes, an individual customer is going to be financially better off by reducing consumption where there is no cost to reduce consumption (ie turning the thermostat down and wearing an extra sweater). An individual typical residential customer who cuts their energy consumption by 10% would save both delivery and commodity charges on approximately 11 GJs of gas per year.

If all gas customers did that, then Terasen would be forced to increase delivery rates by approximately 11% in order to recover all costs of operations. Given that commodity charges are over 2/3 of the variable cost delivered, customers would still be further ahead as they continue to save the commodity charges. However, the total delivered cost per unit of energy would increase and reduce competitiveness with alternative forms such as electric. This may result in customer attraction and retention problems.

22.2 For TGI from 1994 to 2004 provide the estimated average annual usage for residential single family, residential multi-family, and combined residential customers added in each year. State any assumptions.

Response:

Terasen Gas does not track specific data that allows for a breakout of average annual use rates by these dwelling types. Although its possible to provide average annual use rates by rate class, single and multi-family dwelling types are found in a number of different rate classes. The commercial rate classes for example, include residential multi-family, as well as customers that belong to a broad range of industries.

Please refer to Tab 1, page 14, for a graphical presentation of historical rate 1 residential average annual use rates. Rate 1 includes primarily single family residences, but also multi-family residences where they are individually metered. Also refer to response 19.3.

22.3 For TGVI from 1994 to 2004 provide the estimated average annual usage for residential single family, residential multi-family, and combined residential customers added in each year. State any assumptions.

Response:

Please see response to 22.2 and to 19.3.

23.0 Reference: Application, Tab 1, p. 16
Cost Management Pressures

On Tab 1, page 16 TGI states:

> *"Pressure on unit costs is increasing due to increased driving time and more complex work environments…"*

23.1 Please elaborate on the SAP Order Fulfillment and AM/FM projects. How have these projects integrated the information flow and resources to better manage the complex work environments? How have these projects help mitigate the cost pressures faced by the utility?

Response:

The two software applications, SAP-OF and AMFM, are used collaboratively by the Terasen Install Centre employees when reviewing customer requests for new installations. SAP- OF is used to capture initial customer information and facilitates the employee/customer dialogue by using a series of standard questions that generally results in a work order being raised, work planned, assigned and dispatched to a field resource.

Install Coordinators are able to view existing and proposed gas mains on AMFM (essentially an on-line mapping database of Terasen mains, services, stations, valves, etc) to determine the feasibility of attaching a new customer or subdivision. AMFM is updated by the Drafting department as gas piping is installed or removed and represents the most current view of the Terasen gas system. It is also the primary tool used to assess emergencies caused by third parties and to understand where system improvements are required to maintain reliable and cost effective gas supply to customers.

SAP-OF is the tool used by the Install Coordinators to prepare cost estimates, review crew or contractor availability, assign work, establish promise dates and track job progress. The tool has enabled Terasen to optimize the use of company and contractor crews and manage the work that is routed to these groups.

Unit costs today are similar to those experienced in 1999 despite several years of inflation and significant headcount reductions in both the office and the field. There is a significant reliance on contractor resources for the install field work which allows Terasen to more easily adjust field resources in response to field activity levels.

Both SAP-OF and AMFM resulted in the centralization of two core office operating groups (Planning and Drafting); at the time of implementation there were significant employee reductions and cost savings to both Capital and O&M budgets. For specific details with respect to the AMFM project refer to the AMFM Project Completion Report submitted to BCUC in May 2002.

23.2 How has the dispatch of crews and crew assignment changed since 1994? Elaborate on the use of telecommunications, computerization, crew size, crew assignment, and crew flexibility.

Response:

In 1994, applications for gas service were taken over the counter and over the phone; crew field work was dispatched primarily from the local office; work orders were raised on the Work Management System (WMS), planned locally or regionally and assigned to local crews; crews received job packages, completed the work in the field, completed the paperwork, returned the job package to the local office for costing, billing, drafting; the crew did not have a computer in their vehicle or a cell phone; communication was primarily through the Terasen mobile radio system; crew size was generally three persons: a crew leader, equipment (backhoe) operator, and a utility-person (labourer).

From 1994 -2004, Terasen reduced the number and size of construction crews in-house in response to decreased activities and cost management. The install crews maintained today by Terasen are primarily for emergency response and complex installation work. The routine installation work is generally assigned to one of several contract field install resources.

In 2004, there are no local offices open to the public; the front and back office gas application, planning, drafting, closing and other clerical activities have all been centralized to the Surrey Operations Centre; resource planners create schedules for in-house crews and contractors; Install Coordinators draw from these resources to assign work and establish installation promise dates with customers; work can now essentially be sent to the crews on-line. Crews now have laptops and cell phones in their vehicles, call customers to confirm site readiness and installation appointments, provide real-time updates on work order status, and provide the central Operations Centre with an up-to-date status of their availability and location, particularly in relation to emergency response.

The typical crew today is three persons, however there is generally more flexibility in the arrangement; the backhoe operator is usually a dependent contractor and the distribution service technician (formerly utility person) is a multi-skilled employee who can be deployed on either construction or customer service work depending on the need. The crew leader is the third component of the group and manages these individuals, the work assigned to them and the relationship with the customer.

23.3 Please provide the average emergency response times from 1994 to 2004 for TGI.

Response:

The historical emergency response time (in minutes) for TGI by year is as follows:

1994-1996: no longer available

1997 22.2

1998 21.0

1999 21.0

2000 21.2

2001 21.7

2002 20.5

2003 22.0

2004 21.5

23.4 Please elaborate on the types of computer information systems in 1994 compared to the present. What are the present SAP modules in use today? Please provide a brief description of each function. Is the integrated nature of SAP a tool to reduce cost pressures?

Response:

The vast majority of computer information systems in 1994 were stand-alone mainframe based transactional systems. There was one client-server application used to manage operational work. In a lot of cases, especially for maintenance of pipe facilities and capacity planning, the mainframe would just produce lists and the information on these lists would have to be transcribed onto paper maps. None of these systems were connected in that information from one system would not automatically feed another system that would require it.

The current SAP footprint is as follows:

Financial Accounting (FI)

- FI is about external financial reporting, payments and receipts of cash, and fixed assets.

Controlling (CO)

- CO is about internal cost management, budgeting, departmental reporting and day-to-day decision making.

Asset Management (AM)

AM is about tracking and managing the lifecycle of a fixed asset.

Project Systems (PS)

PS is about managing large scale jobs and can be used for costing, budgeting, estimating, planning, commitments, scheduling, and tracking.

Industry Solutions (IS)

IS represent add on functionality particular to an industry, rather than general to all SAP users. At Terasen Gas, we use a component of IS-U/CCS (Industry Solution for Utilities / Customer Care System) called DM (Device Management) used to manage our Meter Assets

Sales and Distribution (SD)

SD is about the sales and pricing of services, the creation of billing requests, pricing of the services provided and materials used, preparation of invoices, and the recording of accounting transactions

Materials Management (MM)

- MM is about handling of materials:

Plant Maintenance (PM)

- PM is about maintenance of assets

Human Resources (HR)

- Human resources is about managing personnel records.

(Customer) Service Management (SM)

SM is about providing service to customers

Business Warehouse (BW)

- BW provides operational and performance reporting for the following business units / key business processes:

SAP has helped to keep cost pressures under control. Notwithstanding this assisted, the price of natural gas, as delivered to the customer, is much less competitive with electricity than it was in 1994.

24.0 Reference: Application Tab 1, p. 17
Declining Differentiation of Deferral Account

The Application states that while there is a higher predictability of reported earnings through the use of revenue stabilization accounts which is beneficial, there is no significant reduction in business risks facing utilities with such accounts.

In accepting BC Gas' proposal for a Revenue Stabilization Adjustment Mechanism ("RSAM") in its Aug 4, 1994 Revenue Requirements Decision, the Commission reminded BC Gas that the Commission's June 1994 ROE Decision determined that the BC Gas ROE should be reduced by ten basis points if the RSAM was approved.

24.1 Does TGI agree that the RSAM reduces the risk of the utility by an amount such that a reduction of at least ten basis points is appropriate? If not, then please explain why BC Gas would have been motivated to continue with the RSAM request given the Commission's prior comments.

Response:

TGI agrees that there is some risk mitigation through the use of RSAM but it is not significant since the expectation was that positive and negative balances under varying weather conditions would tend to offset over time, maintaining equity for both the Utility and its customers.

TGI continued with the RSAM request because the RSAM mechanism stabilizes its earnings to the point where volatility in earnings is comparable to industry norms for a distribution utility utilizing traditional rate designs. As well, the RSAM also minimizes unwarranted rate instability due to volatile changes in normal temperature which is good for TGI's customers.

25.0 Reference: Application, Tab 1, p. 17
Rate Regulated Accounting Changes

On Tab 1, page 17 TGI states:

> *"Over the past two years, the Canadian Institute of Chartered Accountants has undertaken a project to review and change how rate regulated enterprises recognize and measure regulated assets and liabilities."*
>
> *"The industry has actively intervened in this process over the past two years, and an exposure draft on this matter is anticipated in the spring of 2006."*

25.1 Once the exposure draft is issued, please elaborate on the process and timeline of how the exposure draft becomes a standard. Once a standard has been made what is the usual implementation period?

<u>Response:</u>

The following discussion of the process used by the Canadian Institute of Chartered Accountants has been excerpted from information available on their website. "Exposure drafts are released for public comment only on written approval by two-thirds of all members of the Accounting Standards Board ("AcSB"). The exposure draft process gives those who will be affected an opportunity to express their views while the AcSB is in the process of developing the standard.

The AcSB is very aware of the need to develop and issue standards in a timely fashion, while at the same time giving all who wish to do so an adequate opportunity to respond. There is usually an approximate sixty day comment period allowed to respond to the exposure draft. In some circumstances, the AcSB may decide to forego exposure for a stated reason, such as if it determines that little new input will be obtained from exposure or re-exposure of a proposal, or if it determines that all affected parties have already been consulted by other means.

The AcSB analyzes and considers all of the comments received in response to each exposure draft. In addition, the AcSB or staff may meet with a variety of interested parties who wish to express their views. If the AcSB decides that the exposure draft should be amended to reflect the concerns of respondents, the AcSB determines whether this would represent a "significant change" from the exposure draft, requiring re-exposure. Re-exposure involves the same process of issuing a revised exposure draft, followed by a comment period. The AcSB can also decide not to re-expose if two-thirds of all members so vote.

Final approval and issuance of the final standard requires the votes of two-thirds of all members in writing. New material is published in the electronic version of the CICA Handbook – Accounting as soon as possible. The paper version is issued quarterly, and includes any material released in the electronic version in the previous three months. The AcSB sets effective dates for new accounting standards for periods sufficiently advanced that those using the paper version should not be affected."

We would anticipate that if an exposure draft on recognition and measurement issues for rate-regulated enterprises is issued in the second quarter of 2006 for comment that the effective period would not commence before January 1, 2007.

26.0 Reference: Application, Tab 1, p. 17
Declining Differentiation of Deferral Accounts

On Tab 1, page 17 TGI states:

> *"With accurate forecasting of normal weather over the long term, and setting aside the impacts of the timing of cash flows, any benefit that might be attributable to operating with revenue stabilization accounts is largely neutralized."*
>
> *"Moreover, utilities that do not have regulatory relief through revenue stabilization mechanisms can seek to mimic their effects through the use of weather hedges, thereby protecting those utilities from weather related shortfalls."*

26.1 Would the utility agree that for revenues subject to weather stabilization there is minimal or no risk in realizing the revenues for financial statement purposes? If TGI disagrees, when was the last time revenues booked for financial statement purposes were not realized by actual cash flows?

Response:

TGI agrees that historically there has been minimal risk in realizing, for financial statement purposes, forecast revenues subject to weather stabilization. Under current accounting for rate regulated enterprises, it is permissible to create regulatory assets for weather stabilized revenue recognition. Recovery of such revenues in future cash flows is accomplished through rate riders and amortized over a rolling three year period in the case of TGI.

TGVI and TGI are currently in uncharted territory in terms of the absolute cost of commodity and price volatility and at present, TGI has approximately $64 million of cumulative revenues that have been booked for financial statement purposes that have not been realized by actual case flows. Given the nature of the three year amortization methodology, whereby one third of the year's opening deferred balance is amortized through a rider, there is ongoing exposure to potential non-recovery. As previously indicated, deferral accounts do not guarantee future recoveries.

As the delivered price of natural gas moves closer to that of electricity the risk of non-recovery increases since the movement to electricity from gas could allow consumers to avoid payment of amounts recorded in weather stabilization accounts.

26.2 *What are the CICA requirements for revenue recognition? Would the utility agree that if the utility did not have a revenue stabilization mechanism that the risk arising from any differences in forecast is a risk to the shareholder that could require higher compensation to assume that risk?*

Response:

Section 1000 of the CICA Handbook defines revenue as "increases in economic resources, either by way of inflows or enhancements of assets or reductions of liabilities, resulting from the ordinary activities of an entity. Revenues of entities normally arise from the sale of goods, the rendering of services or the use by others of entity resources yielding rent, interest, royalties or dividends."

The Revenue Stabilization Mechanism follows the principles of rate-making which is not specifically dealt with in the CICA Handbook. The revenue stabilization account recognizes the economic principle that the Company has entered into a contractual obligation with customers to provide a product to them, although that product may or may not be delivered to a specific customer. CICA Handbook Section states that the recognition of revenue requires that the revenue is measurable and that ultimate collection is reasonably assured. The Revenue Stabilization Mechanism meets this criteria.

TGI's revenue stabilization mechanism protects it from forecast variances on core customer use rates and related delivery margin only. It doesn't protect from forecast variances on actual numbers of core customers nor does it protect on transportation and industrial sales customers. As indicated in the application, there is some value to having the RSAM due to the increased predictability of reported earnings. RSAM does not protect cash flow variances in the year incurred nor does it provide absolute guarantees of eventual recovery (See 26.1).

An additional benefit to the RSAM mechanism is that it reduces friction with customers around use rate forecasting accuracy in that it allocates core delivery margin shortfalls and surpluses back to those customer groups that generate them in a given year rather than spreading them over all customer classes. When the RSAM was introduced the Commission reduced TGI's allowed return by 10 basis points. It should be noted that one of the reasons that the RSAM was introduced was to remove a disincentive to implementing DSM initiatives that the then Commission Chair, Marc Jacaard was interested in promoting. As such Terasen was not satisfied with the reduction in allowed ROE but went along with it for the mutual benefits to customers and the Company. In the settlement approved by the Commission on July 25, 1995 for a three year test period (96-98), the following was said with respect to the ROE: "Commencing in 1996 BC Gas will be entitled to increase its equity risk premium from 290 basis points to 300 basis points in the determination of the BC Gas rate of return on common equity pursuant to the formula established by the Commission in its Decision of June 10, 1994. It had previously dropped it from 300 to 290 in approving the RSAM in Phase II of the 94/95 Revenue Requirements decision dated August 4, 1994."

26.3 Please identify the Canadian utilities that use weather hedges to protect weather related shortfalls. What is the cost of purchasing a weather hedge expressed in cost per gigajoule for a sales customer?

Response:

Both Union Gas and Nova Scotia Power have used weather hedges or derivatives.

The cost of a hedge is dependent on the specifics of the contract. For example, on September 9,2002, Union entered into an agreement with Entergy Koch Trading, LP to hedge gas sales and distribution margin against a warm weather outcome for November -December 2002.

The agreement was a "costless" collar with a floor of 945 heating degree days ("HDDs"), and a strike amount of 1,045 HDDs. The value of each heating degree-day was set at the average distribution margin per heating degree-day for the period (as estimated by Union) of $8 1,00O/HDD. The agreement set the maximum payout by either party of CDN $10 million. There was no premium associated with this contract.

The actual heating degree-days for the period November to December 2002 were 1,064.4. Union paid Entergy Koch $1,571,400 (1 9.4 HDD x $8 1,000 / HDD). The amount paid under the hedge was recorded as a reduction of gas sales and distribution revenue in 2002 offsetting the revenues Union received from customers as a result of colder weather.

26.4 TGI has the Revenue Stabilization Adjustment Mechanism (“RSAM”). RSAM captures any difference as a result of forecast error between recorded and forecast. Weather differences are captured within the forecast difference.

26.4.1 Is the above explanation an accurate description of RSAM?

Response:

The above description of RSAM is too general. . The RSAM account deals with the Company’s delivery margin and stabilizes the margins recovered from residential and commercial customers. The RSAM stabilizes delivery margin received from these customer classes on a use per customer basis. If customer use rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, the Company records the delivery charge differences in the RSAM account for refunding or charging through a rate rider to the RSAM rate classes over the ensuing three years. Having an RSAM mechanism does not offer the company protection against forecasting errors due to variances between recorded and forecast number of customers nor does it mitigate any forecasting risks associated with the non-RSAM customer classes such as Industrial customers.

26.4.2 Which Canadian utilities have weather normalization accounts and which have *revenue stabilization accounts? Which Canadian utilities don't have any of these two types of deferral accounts?*

Response:

Terasen Gas and Pacific Northern Gas have revenue stabilization accounts.

Newfoundland Power, Gazifère and Gaz Metro have weather normalization accounts.

FortisBC, the Alberta, Ontario and investor-owned utilities in the Maritimes Provinces have neither.

The gas pipelines have neither; however, their revenues are not weather-sensitive.

TGVI, Heritage Gas and Enbridge Gas New Brunswick have revenue deficiency accounts.

26.5 Please list all approved TGI deferral accounts and note if other Canadian utilities would typically have similar accounts. If available, identify which utilities have the same deferral account.

Response: Please refer to the table Appendix 26.5 Table, for a list of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. deferral accounts, in comparison with other Canadian utilities. It is important to note that other utilities may have deferral accounts that TGI and TGVI do not have, to address specific business risks that they operate under. An example of this is included in the attached Appendix 26.5 Decision with Reasons, Union Gas 2004 Revenue Requirement Application, Section 10 Deferral Accounts.

26.6 Please list all approved or requested 2006-2007 TGVI deferral accounts and note if other Canadian utilities would typically have similar accounts. If available, identify which utilities have the same deferral account.

Please see response to 26.5

26.7 Please provide the percentage of delivery margin revenues for TGI and TGVI for which the Companies are at risk without deferral account protection.

Response:

For TGI, the approved 2005 delivery margin, including other operating revenues, totals $522.1 million. Of this amount, $110.5 million or 21.2% is subject to risk without deferral account protection. Margins subject to forecasting risk consists of Non-RSAM class customers of $82.4 million or 15.8%, other operating revenues of $26.0 million or 5% and new customer additions of $2.1 million or 0.4%.

Using TGI's most recent complete fiscal year results as an example, TGI missed its 2004 approved delivery margins (including other operating revenues) by $4.5 million dollars, or 0.9 % of delivery margin so deferral account protection does not mitigate all risks.

For TGVI, the approved 2005 delivery margin, including other operating revenues, is $118.0 million. Of this amount, $18.0 million of forecast revenue surplus is at risk without deferral account protection. The $18.0 million equates to 15.3% of TGVI's delivery margin.

The TGVI Revenue Deficiency Deferral Account provides apparent protection against revenue risk, but it only does so through the shareholder funding the revenue deficiencies. Therefore, in reality, all revenues are at shareholder risk. It is expected that in the longer term, if and when the RDDA balance is reduced to zero, a mechanism similar to TGI's RSAM would be put in place. The risk for TGVI is not so much delivery margins risk, but rather credit collections risk and whether its rates can ever be competitive, particularly after Royalty revenues cease after 2011.

27.0 Reference: Application, Tab 1, p. 18
Declining Differentiation of Deferral Accounts

On Tab 1, page 17 TGI states:

> *"So while there is a higher predictability of reported earnings through the use of revenue stabilization accounts which is beneficial, there is no significant reduction in business risks facing utilities with such accounts. In fact, analysts regularly predict stock valuations based on normalized earnings and compare companies through the use of normalized price/earnings ratios."*

27.1 Is the statement that analysts predict stock valuations based on normalized earnings a reference to rate regulated utilities or to competitive companies?

Response:

The statement refers to both rate regulated utilities and competitive companies.

27.1.1 If it is a reference to a rate regulated utilities please provide recent examples by analysts that compare normalized earnings and normalized price/earnings ratios for utilities (preferably gas) with and without a revenue stabilization account.

Response:

Please see Appendix 27.1.1, which contains analyst reports from RBC and CIBC on the fourth quarter 2004 earnings results for Enbridge Inc., which have examples of normalized earnings and have been annotated to highlight these examples. These samples illustrate how normalized earnings for rate regulated entities without revenue stabilization accounts are used in earnings multiple comparisons with their peer group. Analyst reports on Terasen Inc. for the same periods by the same analysts have also been included to show the comparable treatment between companies with and without revenue stabilization accounts.

27.2 Does business risk include certainty of receiving operating revenues? Does a rate stabilization account provide certainty of revenues?

Response:

Yes, business risk includes the risk of receiving operating revenues, but a rate stabilization account does not provide certainty of revenues. Rate stabilization accounts provide for building recovery of revenue shortfalls or return of revenue surpluses in future rates. If rates become uneconomic and load destruction occurs, future recovery of revenue shortfalls will become impaired. Whether or not a revenue stabilization account exists, a utility still runs the risk of not being able to recover its investment in rate base if it cannot maintain economic rates.

28.0 Reference: Tab 2, Statistical Exhibits, Schedule 5

Please provide a Schedule for the companies shown in Tab 2, Schedule 5 page 1 that compares the Allowed returns with the Actual returns from 1995 to 2004.

Response:

Please refer to Appendix 28.0.

29.0 Reference: Application, Tab 1, p. 18

Terasen reports that from the perspective of potential returns on equity investments, analysts normalize earnings for their evaluations and forecasts.

29.1 Please explain the typical normalization methodology used by such analysts.

Response:

Based on guidance from company management and analytical adjustments made at the analyst's discretion, analysts will assess which components of earnings are "non-recurring", or should be excluded to determine the future earnings prospects of a company. In natural gas distribution, the earnings impact of weather fluctuations are commonly normalized by analysts, with the impact of weather commonly quantified by management in the discussion of earnings results.

29.2 Please explain further Terasen's view that business risks are not significantly reduced through the use of revenue stabilization accounts even though there is higher predictability of reported earnings. Is the reason simply because such accounts have no immediate impact on cash flow, as Terasen notes on p. 17? Please elaborate on any additional reasons, if any.

Response:

Deferral accounts provide greater predictability of earnings over the short term. However, the factors that tend to cause short-term volatility in earnings, such as weather, have little bearing on whether utility shareholders will be able to earn a fair return on, and of, their investment in the long term. Deferral accounts are not effective as a means to address a long-term impairment in a utility's ability to recover it's cost of service from customers, because deferral accounts presume the utility's ability to recover deferred costs in future rates from customers. In fact, if inappropriately applied, deferral accounts can increase risk for utility shareholders if they are used to postpone the recovery of prudently incurred costs to future periods when the utility may be unable to recover, or the regulator may refuse the recovery of, such costs.

30.0 Reference: Application, Tab 1

30.1 For each business risk discussed in Tab 1, please provide Terasen's view on the degree to which it is able to diversify such risk, and the relative consideration the Commission should give to such risk in the context of the Application.

Response:

The business risks that are discussed in Tab 1 are all diversifiable to differing degrees by an investor who can choose different utility investments on the basis of geography, economics of the service area, competitive factors, and regulation.

The distinction between diversifiable and non-diversifiable risks is only meaningful in the context of the CAPM test. In the DC test, for example, it is the firm-specific circumstances which determine dividend yield and growth prospects.

Moreover, whereas the investor may be able to diversify his or her risks, Terasen Gas cannot. To illustrate, Terasen Gas' capital structure decisions are based on firm- and industry-specific business risk factors, not on those aspects which an investor might, in the context of an investment portfolio, be able to diversify away. It follows logically that if the firm-specific business risks were diversifiable from a particular utility's perspective, all utilities would have the same capital structure. Consequently, the Commission needs to give weight to Terasen's company-specific risks in determining the capital structure and return on equity.

31.0 Reference: Application, Tab 2, p. 3

The Testimony states that the allowed common equity ratios of other major gas distributors which are comparable in business risk to Terasen Gas are in the range of 35-38% and that the capital structures all contain some preferred shares.

Please explain when and why Terasen decided to redeem all of its preferred shares.

Response:

The TGI preferred shares were redeemed when they matured. A component of Terasen Gas' negotiated 1998-2000 PBR settlement, which was approved by the BCUC on July 23, 1997 was that the preferred shares would be replaced with debt when they matured. In its application preceding those negotiations TGI did not propose the redemption of the preferred shares and did not advocate the redemption during the negotiations. As a result of confidentiality commitments TGI cannot discuss the positions regarding the preferred shares taken by Commission Staff and Intervenors

32.0 Reference: Application Tab 2, pp. 4, 5 Equity Market Risk Premium; Tab 2 Schedule 5

The testimony of Kathleen McShane states that long Canada yields have declined significantly since the mid-1990s, while the expected value of the equity market has not similarly declined. The resulting equity market risk premium is thus wider in today's low interest rate environment. The testimony also states that the spreads between utility and government of Canada bond yields are relatively high.

32.1 In its July 2005 Monetary Policy Update, the Bank of Canada says on page 4 that "Long-term government bond yields in both countries have fallen by between 20 and 30 basis points. This decline has been part of a global phenomenon, with longer-term yields in most industrial countries at very low levels. While this may partly reflect several technical factors, the low yields would be consistent with strong desired global savings relative to business investment. Risk premiums on corporate bonds are also very low."

32.1.1 Does Ms McShane agree with the Bank of Canada statement that the risk premiums on corporate bonds are also very low?

Response:

Yes, if the comparison is to spreads prevailing during 2001-2003. Please see discussion at Tab 2, page 36, lines 966-979.

32.1.1.1 Please supplement the Table in Tab 2, Schedule 7, p. 1with the spreads between Canada A-rated utility bond and long-term Canada bond.

Response:

Please refer to Appendix 32.1.1.1

32.1.1.2 Please provide the yield of the 30 year bond/debenture recently issued by TGI and comment on its yield compared to the outstanding bond yields in the Table in Tab 2 Schedule 7.

Response:

The yield spread at the data of issue (settlement data February 25, 2005) was 118 basis points). The average spread of the outstanding issues at the end of February for the utilities included in the Canada A-rated utility bond series in Schedule 7 was 111 basis points.

They include long term issues of utilities with at least one rating in the A category. The bonds must mature no earlier than 2025. The individual issuers, their debt ratings, the issues, the spreads for each issue can be found below.

Company	Debt Ratings		Coupon	Maturity	Yield	Spread over Long-Term Canada (4.76%)
	DBRS	S&P				
BC Gas Utility (Terasen Gas)	A	BBB	6.95	09/21/29	5.93	117
Enbridge Inc.	A	A-	7.22	07/24/30	5.98	122
			7.20	06/18/32	5.98	122
			6.05	02/12/29	5.75	99
			6.90	15/11/32	5.73	97
Enbridge Pipeline	A(high)	A-	6.10	07/14/28	5.98	122
Enbridge Gas	A	A-	6.65	11/03/27	5.73	97
			6.10	05/19/28	5.73	97
			7.60	10/29/26	5.73	97
EPCOR Utilities	A(low)	BBB+	6.80	06/28/29	6.01	125
Gaz Metro	A	A	7.20	11/19/27	5.59	83
			7.05	10/30/30	5.59	83
			6.30	31/10/33	5.59	71
Nova Scotia Power	A(low)	BBB+	8.85	05/19/25	5.91	115
			8.30	24/07/31	6.00	124
			6.89	21/03/36	6.13	137
			6.95	25/08/33	6.00	124
TransCanada PipeLines	A	A-	6.89	08/07/28	5.90	114
			6.28	05/26/28	5.90	114
			6.50	12/09/30	5.90	114
			8.23	16/01/31	5.90	114
Union Gas Limited	A	BBB	8.65	11/10/25	5.78	102
Westcoast Energy	A(low)	BBB	6.75	12/15/27	6.01	125

			7.30 7.15	12/18/26 03/20/31	5.98 6.01	122 125

The series only includes long-term utility issues whose yields are tracked by RBC Securities. As a result, the series does not include some of the higher rated issuers, whose inclusion would lower the average (e.g., AltaLink, CU Inc., and FortisAlberta).

These spreads are provided by the major investment banks, which regularly estimate the spread for new utility issues for various terms.

To provide further perspective, the tables below provide the recent indicated spreads for new issues for some of the higher rated utilities.

The estimated spreads for a new 30-year issue in late August 2005 for Terasen Gas and some of the higher rated utilities were as follows:

	Ratings		**TD Securities (August 18, 2005)**	**RBC Capital Markets (August 22, 2005)**	**BMO Nesbitt Burns (August 22, 2005)**	**CIBC World Markets (August 22, 2005)**	**National Bank Financial (August 22, 2005)**
	DBRS	**S&P**					
Terasen Gas	A	BBB	115	120	117	119	118
AltaLink	A	A-	90	--	--	--	80
CU Inc.	A(high)	A	82	80	78	--	80
Enbridge Gas	A	A-	90	90	90	91	80
Enbridge Pipeline	A(high)	A-	90	90	90	--	80
FortisAlberta	A(low)	n/a	93	--	105	--	--
Gas Metro	A	A	90	80	80	--	80

The corresponding indicated spreads for the other utilities included in the A-rated utilities series are:

	Ratings		**TD Securities (August 18, 2005)**	**RBC Capital Markets (August 22, 2005)**	**BMO Nesbitt Burns (August 22,**	**CIBC World Markets (August 22, 2005)**	**National Bank Financial (August 22,**
	DBRS	**S&P**					

					2005)		2005)
Enbridge Inc.	A	A-	110	114	116	114	114
EPCOR Utilities	A(low)	BBB+	115	126	--	123	127
Nova Scotia Power	A(low)	BBB+	127	122	127	128	125
TransCanada PipeLines	A	A-	115	114	114	114	114
Union Gas	A	BBB	115	114	122	115	114
Westcoast Energy	A(low)	BBB	127	125	132	136	128

32.2 Tab 2, Schedule 5, p. 3 shows the differences in US and Canada allowed ROEs and equity risk premiums. Tab 2, p. 5 mentions that there is a 100 basis point gap in favour of U.S. utilities when comparing allowed returns for U.S. and Canadian utilities. Are exchange rates more variable than allowed ROEs?

Response:

Yes.

32.2.1 Looking back at the period 1990 to 2004, how much would the risk in annual currency fluctuation compensate for the higher allowed ROEs in the U.S. for Canadian investors?

Response:

The allowed returns in each country are based on the risks faced by the utilities and the cost of capital environment. In Ms. McShane's view, the absolute levels of the allowed returns are unrelated to the risks of currency fluctuations.

32.2.2 Please respond to the above question on a forward looking basis.

Response:

The same response applies to the assessment on a forward-looking basis.

33.0 Reference: Application, Tab 2, p. 5

33.1 Please provide a list and brief description of all significant business risks faced by the low-risk industrial firms.

Response:

The major categories of business risks faced by the low risk industrial companies include:

(1) Market Risks

Market risks revolved around the competitive environment for the firm's products and services and its exposure to the business cycle (both domestic and global).

(2) Supply-Related Risks

Supply risks include access to inputs, including the potential for supply of inputs to be interrupted; the risk that the cost of inputs will squeeze margins; and risks associated with failures in distribution to end markets.

(3) Operational Risks

Operational risks related to the potential for production interruption or cost increases due to such factors as the age of facilities, or efficiency of the facilities.

(4) Regulatory Risks

Regulatory risks include legislation that would raise production costs or impede production. It would also include factors related to international trade barriers (e.g. tariffs).

33.2 Paragraph 'e' states that a comparison of the allowed returns for U.S. and Canadian utilities reveals a 100 basis point gap in favour of U.S. utilities, not explained by differences in risk or capital market conditions between the two countries.

Please identify, by reference to the appropriate schedule if applicable, the U.S. and Canadian utilities surveyed that are the basis of the above statement. Please also provide a list or description of U.S. or Canadian utilities that were excluded from the survey along with the criteria used for excluding them.

Response:

The U.S. utility allowed ROEs reflect all of the gas and electric cases collected by Regulatory Research Associates (over 700 cases between 1990 and 2005). To Ms. McShane's knowledge, there are no specific criteria for excluding utilities. However, a review of the specific cases covered indicated that the survey focuses on the larger utilities.

With respect to the Canadian utilities, the coverage was intended to include the larger, investor-owned utilities with some capital market indicators (e.g., debt ratings). The Canadian utilities covered appear on Schedule 5, page 2 of 3.

33.3 Also with reference to paragraph 'e', please explain the methodology for excluding differences in risk or capital market conditions as a reason for the 100 basis point gap.

<u>Response:</u>

Please see discussion at Tab 2, pages 45-47.

34.0 Reference: Application, Tab 2, p. 5
Executive Summary

On Tab 2, page 5 Ms. McShane states: "Globalization of capital markets means that Canadian utilities are competing for capital with alternative investments world-wide. Globalization of capital markets provides Canadian investors opportunities for higher returns at similar risk levels than available in the domestic market. The returns allowed for Canadian utilities need to recognize that Canadian investors' opportunities are not limited to domestic investments."

Duke Energy Corp. acquired Westcoast Energy Inc. in early 2002. After the sale Duke Energy traded on the New York Stock Exchange (symbol DUK) and as exchangeable shares on the Toronto Stock Exchange (symbol DX).

34.1 Does Ms. McShane accept that despite a higher level of openness to trade in goods and services and capital flows, the foreign exchange risk is a friction to investment abroad?

Response:

Foreign exchange risk remains a factor in considering whether to invest abroad. Foreign exchange risks can be hedged and/or diversified.

34.2 What has been the annual return to holder of Duke Energy shares to a resident of the U.S. since the purchase?

Response:

The compound annual return calculation from the end of March 2002 to December 2004 (excluding the impact of the compounding of dividends) for a U.S. holder of Duke Energy shares traded on the NYSE was approximately -8.9%.

34.3 What has been the annual return to holder of Duke Energy shares to a resident of Canada since the purchase?

Response:

The annual return for a holder of Duke Energy exchangeable shares traded on the Toronto Stock Exchange was approximately -16.1%..

Canadian investors may also have opted to acquire the more liquid NYSE-traded Duke Energy shares.

34.4 Is there a difference in returns between the two residents? Why or why not?

Response:

The difference in return between the NYSE-traded shares and the TSE-traded exchangeable shares is primarily due to the change in the U.S./Canadian exchange rate over the 2002-2004 period; the less liquidity in the exchangeable shares may have also had some impact on their return.

34.5 If the Canadian resident cashed-out the Duke Energy shares and instead purchased a representative basket of Canadian pipeline/utilities stocks what would have been the return? Explain any difference between the returns of the Canadian resident holding the basket compared to holding Duke Energy shares.

Response:

An investor who put equal dollar amounts in Canadian Utilities, Emera, Enbridge Inc., Fortis, Gaz Metro, Terasen and TransCanada at the end of March 2002 would have achieved an annual compound return of 14.5% between March 2002 and December 2004.

34.6 The Duke Energy purchase of Westcoast Energy allowed the Westcoast shareholder to receive either cash, Duke Energy stock, exchangeable share or a combination. Is Ms. McShane aware of approximately the percentage of former Westcoast Energy Inc. shares still continued to be held as Duke Energy shares by Canadian residents? If Ms. McShane is not aware of the percentage, what is Ms. McShane opinion of whether former Westcoast Energy shareholders would have cashed-out or continued to hold shares in Duke Energy?

Response:

It is not feasible to determine the percentage of former Westcoast Energy Inc. shares still held as Duke Energy shares by Canadian residents, as Westcoast shareholders had the option to take either exchangeable shares or Duke common shares, and there is limited information available on the flows of Duke Energy common shares since the acquisition. It is likely that some former Westcoast shareholders would have sold their Duke shares since the Westcoast acquisition, while other holders would have likely retained their Duke shares, and other Canadian investors have likely acquired Duke shares since the Westcoast acquisition.

34.7 What is Terasen's current expectation concerning the options for and probability of shareholders of Terasen Inc. cashing-out rather than holding Kinder Morgan shares?

Response:

Terasen is optimistic that many Terasen Inc. shareholders will continue to hold Kinder Morgan shares given the growth opportunities in the combined entity's petroleum transportation businesses, and the strong track records established by the Kinder Morgan and Terasen management teams. Terasen's individual shareholders are unlikely to find it necessary to sell Kinder Morgan shares to settle capital gains tax liabilities given the large cash component of Kinder Morgan's offer, and many Canadian individual investors own shares in U.S. companies notwithstanding any tax differences between Canadian and U.S. share ownership.

With respect to Terasen shares that are held by Canadian index funds, it is likely that Kinder Morgan shares received by Canadian index funds that mirror the S&P/TSX Composite Index will flow to index funds that mirror the S&P 500 index in the U.S., as Kinder Morgan is not part of the S&P/TSX Composite Index, but its increase in shares outstanding will increase its weight on the S&P 500 index (and therefore require S&P 500 index fund buying).

35.0 Reference: Application Tab 2, p. 8

Ms. McShane's testimony says that she used several DCF models to a sample of low risk utilities and that the results of the various models indicate an expected equity return of 9.25%.

35.1 Please list the sample of low risk utilities used for the various tests. Alternatively, please refer to the applicable list in the appropriate Schedule of the Statistical Exhibits.

Response:

Please see the discussion at pages 84-90, Appendix C and Schedules 19-22.

35.2 How many DCF models were applied to the sample? Please provide a description of all of the DCF models tried and the expected equity return that resulted from each model.

Response:

Please see the discussion at pages 84-90, Appendix C and Schedules 19-22.

36.0 Reference: Application, Tab 2, p. 9

36.1 Why should significant weight be given to the comparable earnings test in arriving at the recommended ROE for a benchmark low risk utility?

Response:

In general, weight should be given to each of the three tests, Risk Premium, DCF and Comparable earnings, since each of the tests has its flaws, and each brings a different perspective to what constitutes a fair return. With specific respect to the comparable earnings test, please see lines 2399 to 2451.

36.2 Please summarize any views or concerns about the comparable earnings test expressed by Canadian Regulatory Boards in recent decisions on ROE and capital structure. Please compare and contrast these views with those expressed by the BCUC in its 1999 ROE decision.

Response:

In RP-2002-0158 (Union Gas Ltd. And Enbridge Gas Distribution Inc.), the Ontario Energy Board referenced subjectivity with assembling an acceptable list of comparable companies, the selection of a suitable time period, and the heavy reliance on past performance as an indicator of future performance.

In Decision 2004-052 (Generic Cost of Capital), the AEUB concluded that the test did not accurately measure the required market return of the comparable companies. The Board also referenced concerns it had listed in prior decisions: selection problems, accounting differences, market power concerns, and problems matching the current business cycle stage. The AEUB did note that all traditional ROE tests have methodological problems.

The concerns expressed by the BCUC were: (a) their conclusion was that comparable earnings does not measure the opportunity cost of capital. This conclusion is similar to that reached by the AEUB, when it concluded that the comparable earnings result did not measure the required return of the comparable companies; (b) the use of accounting data, similar to the EUB's concern; and (c) sample selection, similar to the OEB and EUB.

36.3 Please discuss the circumstances under which significant weight should be given to the comparable earnings test in light of any concerns discussed in answer to the previous question.

Response:

Ms. McShane recognizes that the comparable earnings test entails application issues that need to be addressed. In response to BCUC IR No. 1, 81.1, Ms. McShane has discussed how these issues were addressed.

Similar issues arise in applying each of the traditional return on equity tests. For example, the issue of period selection is mentioned in BCUC IR No. 1, 36.2 above; period selection is also an issue in applying the risk premium test. The issue of sample selection is also an issue in the risk premium test, since it is the risk measures of comparables that determine the relative risk adjustment. The OEB's decision mentioned the comparable earnings test's heavy reliance on past performance as an indicator of future performance. The equity risk premium test entails the same issue, both with regard to the market returns and the risk measures. The recognition that each test entails judgements, and that each test has different strengths and weaknesses is the key reason for giving weight to all the tests.

In Ms. McShane's view, the main stumbling block for regulators today seems to be the acceptance, in principle, that the comparable earnings test results are a relevant measure of the opportunity cost of equity in an original cost regulation framework, one in which the allowed return on equity is not set on a market value base, but on a book value base. A full discussion of this issue, and why it leads to the relevance of the comparable earnings test, is discussed at Tab 2, lines 628-706. The Public Utilities Board of Alberta in Decision E91093, as cited at lines 742-747 of Tab 2, reached a similar conclusion with regard to the relevance of the comparable earnings test:

> "The Board recognizes that, in the competitive world, pricing and investment decisions are based on the current market values of assets and the current cost of new capital. However, because the investment base for regulatory purposes is stated on original cost book values, a rate of return such as that determined under the comparable earnings test becomes meaningful." (p. 195).

The conclusions reached in that decision are no less true today.

Further, the Commission may be of the view that the use of an equity risk premium-related mechanism to adjust allowed ROEs also requires that the equity risk premium test be the sole test used to set the "base" allowed ROE. That is not the case. There is no valid reason to exclude the comparable earnings test in setting the initial return, simply because one is relying on the risk premium test to adjust subsequent years' returns.

37.0 Reference: Application, Tab 2, p. 13

The testimony notes that the Commission's approach of allowing for both different capital structures and different equity risk premiums is also the approach that has been taken in Ontario and Quebec.

37.1 For each regulated gas utility in Ontario and Quebec please provide a summary of debt ratings and Board decisions on capital structures and equity risk premiums over the last 5 years.

Response:

Ontario

There are three gas utilities in Ontario. The utilities and their allowed common equity ratios are:

Enbridge Gas	35%	(plus 3.1% preferred shares)
Union Gas	35%	(plus 3.5% preferred shares)
Natural Resource Gas	50%	

Their allowed common equity ratios have not changed in the past five years.

The risk premiums for Enbridge and Union were initially set for automatic ROE formula purposes in 1997.

The risk premiums were at a long Canada yield of 7.25%, and were:

Enbridge	3.40%
Union	3.55%

The automatic adjustment formula adopted was a 75% sliding scale. The initial risk premiums and formula were reconfirmed in January 2004. The allowed risk premiums at a forecast long Canada yield of 5.25% would be 3.90% for Enbridge and 4.05% for Union. NRG's allowed risk premium was set in 1997 and is the same as Enbridge Gas.

The debt rating history is as follows:

	DBRS		S&P					
	1999-2000	2001-present	Pre-2001			2001-present		
Enbridge	A(high)	A	A			A-		
Union	A for past 5 years		2001	3/2002	8/2002	1/2003	6/2003	2/2004
			A-	A+	A	A-	BBB+	BBB
NRG	None							

<u>Québec</u>

The two gas utilities in Québec are Gaz Metro and Gazifère and their allowed common equity ratios are:

Gaz Metro	38.5%	(plus 7.5% preferred shares)
Gazifère	40.0%	

The allowed common equity ratios have not changed in the last five years.

The equity risk premium for Gaz Metro was initially set in 1999 at 3.88% at a long Canada yield of 5.76%, with a 75% sliding scale. The base return and automatic adjustment mechanism were reconfirmed in 2004. Gazifère had its base return set in 1999 also, with the same sliding scale. Continuation of the automatic adjustment mechanism for Gazifère was also confirmed in 2004. Gazifère's risk premium is 40 basis points higher than Gaz Metro's.

	DBRS	S&P
Gaz Metro	A for past five years	A since 2001
Gazifère	None	

38.0 Reference: Application, Tab 2, p. 15

The testimony says that given the nature and size of its industrial base, Terasen Gas is inherently riskier than utilities with a more economically diverse and/or less industrial-based customer profile.

38.1 Please provide a comprehensive discussion of the nature of and size of Terasen's load relative to comparable utilities in other Canadian jurisdictions.

Response:

TGI's industrial load represents 39% of total load and 14% of total margin (including Burrard Thermal). The industrial load is dominated by resource-based industries, which account for 62% of total industrial volumes. The resource-based industries include wood products and pulp and paper (47%), mining (6%) agriculture/greenhouse (8%), and petroleum (2%). Thus, a single resource-based industry is predominant. (TGVI's industrial load accounts for 66% of total load (38% of margin), including the cogen plant. Its industrial base is 100% resource-based; the seven customers making up the Joint Venture are all pulp and paper mills.)

By comparison, ATCO Gas has no significant industrial load. All of its former major industrial/producer customers are served directly by ATCO Pipelines.

With respect to Union Gas, its utility revenues include both distribution and transmission and storage services (primarily to other utilities). The latter accounts for approximately 20% of revenues. Within distribution volumes, contract volumes – which include large commercial customers – account for 68% of total volumes (15% of distribution revenues, or about 12% of total revenues, including storage and transmission). Eight industries account for at least 5% each of industrial volumes: steel; chemical; cogeneration; pulp and paper; refining; automotive; non-ferrous metals; and food & beverage. Thus, although the proportions of Union and Terasen's Gas' total industrial margin are similar, Union does not have the same dominance of one resource-based industry.

Enbridge Gas Distribution's industrial load is approximately 35% resource-based and 65% non-resource based. The majority of Enbridge's non-resource based industrial customers are engaged in diverse forms of manufacturing. DBRS describes Enbridge Gas' distribution area as:

> "consisting of central, eastern, and the Niagara Peninsula regions of Ontario, has a number of attractive characteristics: (a) It is one of the fastest growing areas in the province, in terms of both population and economic prosperity, and Enbridge Gas has experienced an average customer growth rate of roughly 3.4% annually over the past five years. (b) The area has a high population density, which contributes to a competitive cost structure. (c) The Company's customer profile and revenues are heavily weighted with higher margin and more stable residential and commercial customer categories, which ensures that the Company's earnings have a relatively low exposure to the economic cycle". (DBRS, June 1, 2005 *Credit Rating Report.*)

38.2 Please explain in greater detail why, given the nature and size of its industrial base, Terasen Gas is inherently riskier.

Response:

The level of inherent long-run risk a utility faces arising from its industrial base relates to several factors:

(a) how much of the volume and margin is accounted for by industrial customers;

(b) the concentration of the industrial base among industries and individual customers; and,

(c) the specific industries in which the industrial load is concentrated.

If a utility's industrial customer base is dominated by a single industry, the downturns in, or failures of, that industry are more likely to have a material impact on the utility than those of an industry that accounts for a materially smaller proportion of the utility's load. If a utility serves 10 different industries, each accounting for 10 percent of the load, cyclical downturns in one are more likely to be offset by upturns in another, since the cycles of different industries are not perfectly correlated. Similarly, for a utility with a diversified industrial base, if one industry is no longer able to compete successfully, there is a higher probability that the success of another industry will offset the misfortunes of the failed industry.

In Terasen's case, the industrial base is concentrated in the pulp and paper industry, one whose cyclical prospects are tied to the strength of export markets and the value of the Canadian dollar, and whose long-term health is dependent on the B.C. industry's ability to compete in global markets. The collapse of the B.C. pulp and paper industry would be far more damaging to Terasen than any single industry served by Enbridge Gas Distribution.

38.3 Please compare the margins earned by TGI and TGVI from industrial sales and transportation service with those of the other utilities Terasen has compared itself with.

Response:

TGI	14%
TGVI	38%
ATCO Gas	2%
Enbridge Gas	9%
Gaz Metro	15%
Union Gas	15% [1/]

[1/] Union Gas margins not available; in-franchise contract revenues (including commercial customers) as a percent of total in-franchise revenues; excludes revenues from storage and transportation

39.0 Reference: Application, Tab 2, p. 16, paragraph 5

39.1 Please explain in greater detail why, in your opinion, the business risks of Terasen Gas exceed those of electric transmission utilities in Alberta.

Response:

The electric transmission utilities in Alberta bear no volume risk. Their forecast revenue requirement is paid in monthly increments by the independent system operator. Their forecast risks are mitigated by the fact that they have a deferral account for major capital projects that are assigned by the independent system operator. Many of the system planning and operating responsibilities of the transmission system previously borne by the integrated utilities have been shifted to the independent system operator.

39.2 Please explain in greater detail why you would judge that TransCanada Pipelines and Nova Gas Transmission face no higher business risk than Terasen.

Response:

TCPL recovers virtually 100% of its approved costs in demand charges; NGTL's method of regulation results in no throughput risk. Currently, TCPL's costs of unutilized capacity are reallocated to existing customers. Both TCPL and NGTL have flow-through deferral accounts for various forecast cost categories. Both face some competitive (pipe-on-pipe) and supply risks (due to declines in the Western Canada Sedimentary Basin); on balance the long-term competitive/supply risks are no higher than TGI's.

From the regulator's perspective, in arriving at its decision to set NGTL's allowed common equity ratio at 35%, the EUB noted higher short-term risks relative to the electric transmission utilities, primarily due to competition and credit risks. The Board also viewed NGTL's longer-term risks as potentially higher than the electric transmission utilities', due to supply risk, although the EUB determined that risk could be identified early enough to allow NGTL to apply to the Board for adjustments to throughput forecasts and/or depreciation rates. The differences in risks led the Board to set NGTL's allowed common equity ratio two percentage points higher than the electric transmission utilities'. The 35% ratio represents a three percentage point increase from the last Board-determined value.

With respect to TCPL, the NEB concluded in both RH-4-2001 and RH-2-2004 that the supply and competitive risks had increased (from RH-2-94 and RH-2-2001 respectively), leading to increases in the common equity ratio from 30% to 33% to 36%.

39.3 Please provide and explain your judgment of the relative risk faced by all NEB-regulated pipelines. Please provide the capital structures and debt ratings of these utilities.

Response:

Ms. McShane has not undertaken a business risk analysis of the other pipelines, nor has there been any recent analysis put forth in a regulatory forum from which trends in risk were discussed or conclusions on the appropriate capital structure drawn.

The allowed capital structures and debt ratings of the gas pipelines (other than TCPL) that are governed by the multi-pipeline (RH-2-94) decision are:

	Allowed Equity Ratios	Debt Ratings	
		DBRS	S&P
TCPL-BC System (formerly ANG)	30%	NR	NR
Foothills	30%	NR	NR
TQM	30%	A(low)	BBB+
Westcoast (Mainline)	31%	A(low)	BBB

While the NEB allowed ROE's are as noted in the above table, it must be recognized that the pipeline companies operate under incentive tolling arrangements with their shippers and the actual achieved returns are higher

40.0 Reference: Application, Tab 2, p. 18
TGVI Common Equity Ratio and Risk Premium

On Tab 2, page 18 it states: "TGVI is requesting that the Commission approve a 40% common equity ratio and a 75 basis point incremental equity risk premium relative to the benchmark low risk utility."

40.1 Please elaborate on the history of TGVI's approved common equity ratio, the incremental equity risk premium, preferred shares, and the preferred shares dividend rate, up to and including the current risk premium and capital structure.

Response:

The deemed capital structure of the regulated utility has been 65% debt and 35% equity since the Vancouver Island natural Gas Pipeline Agreement ("VINGPA") and the Special Direction became effective in early 1996. The equity risk premium has been throughout this period has been +50 basis points over the benchmark of a low risk utility. As part of the settlement to the Company's last revenue requirement the Company stayed with a +50 basis points from the filed request of +100 basis points.

As part of the VINGPA and the Special Direction the Class A preferred shares were used to finance a non rate base deferral account (Revenue Deficiency Deferral Account – RDDA). The preferred dividend rate was set by formula at 58% of the Current 5 Year Canada Rate plus 275 basis points. In 2003 the preferred shares were redeemed and replaced with shareholder funded debt, to finance the RDDA account.

Until the end of 2002 the capital structure and return on equity were prescribed by the Special Direction. Section 4.2 of the Special Direction provides that after December 31, 2002 the capital structure and return on equity for the Single Entity (which TGVI is) shall be determined in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas transportation and distribution utilities operating within B.C.

40.2 Please provide TGVI's approved and actual recorded return on equity since inception to 2004. Explain any favourable and unfavourable differences.

Response:

Prior to 1996, Centra Gas B.C. Inc. and Pacific Coast Enegy Corp. were operated as separate companies, each providing service under separate agreements with the province. For 1996 and beyond, the combined companies optimized performance within the context of the Vancouver Island Natural Gas Pipeline Agreement and the Special Direction with recognition of the new regulatory role of the BCUC. See the response to Information Request No. 11.1

41.0 Reference: Application, Tab 2, p. 18
TGVI as a Greenfield Utility

On Tab 2, page 18 it states: "TGVI is a relatively small greenfield utility…"

41.1 What are the indicators of when a greenfield utility transforms into a mature utility? How many years does it normally take to become a mature utility?

Response:

A greenfield utility transforms into a mature utility when:

(a) it is able to set rates for different customer classes at revenue/cost ratios of approximately 1.0, and is no longer reliant on price-setting mechanisms that expressly set rates to be competitive with alternative energy sources;

(b) its customer growth rates have reached levels that are in line with those of mature utilities;

(c) it has been able to recover the preponderance of any accrued revenue deficiencies; and,

(d) the excess capacity originally built into the system to accommodate future growth and take advantage of economies of scale has been reduced to a minimal level.

There is no standard number of years for becoming a mature utility. It depends on various factors, including the prices of alternative fuels and the ability to convert customers from their existing energy source.

41.2 At what date does Ms. McShane estimate that TGVI will become a mature utility?

Response:

The best estimate is 2012; whether the transformation to a mature utility occurs by that date depends on such factors as those indicated in BCUC IR No. 1, 41.2.

41.3 *Please rank TGVI against other Canadian gas utilities in terms of number of customers and GJ delivered.*

Response:

	Customers	**GJ Delivered**
TGVI	80,700	18,815,000
AltaGas Utilities	59,900	14,432,000
ATCO Gas	914,326	219,867,000
Enbridge Gas Distribution	1,676,380	473,157,500
Enbridge Gas New Brunswick	3,143	2,302,824
Gaz Metro	157,718	207,483,000
Gazifère	30,023	5,833,230
Heritage Gas	138	13,907
Natural Resource Gas	5,943	925,000
Terasen Gas	779,461	171,759,000
Union Gas	1,222,384	563,189,980

42.0 Reference: Application, Tab 2, p. 19
TGVI Load

On Tab 2, page 19 it states: "TGVI's load remains largely industrial (close to 70%), attributable to seven pulp and paper mills (the Joint Venture) and a cogeneration plant. The contract with the Joint Venture was amended, and extended into the fall of 2004 for an additional two years past the original renewal period to 2012. However, under the amended contract the firm demand was reduced by approximately 67% compared to the prior agreement."

42.1 This extension allows for certainty of revenues for an additional two years. Would this be a positive change providing certainty for TGVI?

Response:

The extension of the contract, all other things equal, is a positive change.

42.2 Is the firm demand reduction a negative change?

Response:

The reduction in the firm demand is a negative change.

42.3 Relatively, would the risks be about the same when certainty is offset by a lower firm demand?

Response:

On balance, from a long-term risk perspective, the reduction in firm demand more than offsets the extension of the contract for two years.

42.4 What does Ms. McShane consider to be an optimal mix of residential/small commercial, large commercial and industrial customers (based on delivery margin revenues)?

Response:

There is no precise mix that would be considered optimal. A load balanced among residential, commercial and industrial customers allows a system to operate, all other things equal, at lower unit costs than a load dominated by weather-sensitive customers, particularly when storage is limited. Further, it is not simply the percentage of the margin from a customer class that is important, particularly in the industrial class. Concentration within a specific industry and/or with a small number of customers are also important risk factors.

Moreover, the risk profile of a utility will be impacted if the service area is highly dependent on a single industry, even if the utility does not derive a significant percentage of its margin directly from that industry (e.g., forestry industry for TGI, particularly in the interior of the Province). Factors that negatively impact the industry will likely have secondary impacts on commercial enterprises served by the utility, and potentially on residential customers as well.

In TGVI's case, its heavy reliance on the pulp and paper industry and BC Hydro (38% of total margin) exposes it to substantially more long-term risk than an LDC with a more balanced and diverse delivery/revenue mix.

43.0 Reference: Application, Tab 2, p. 19
TGVI Supply Risks

On Tab 2, page 19 it states: "TGVI faces greater supply risks than the typical LDC, due to its dependence on a single pipeline system that traverses rugged terrain, and comprises both underwater and marine crossings."

43.1 What is the average system age of TGVI and TGI's service, mains and transmission lines? Is a younger system less risky than an older system?

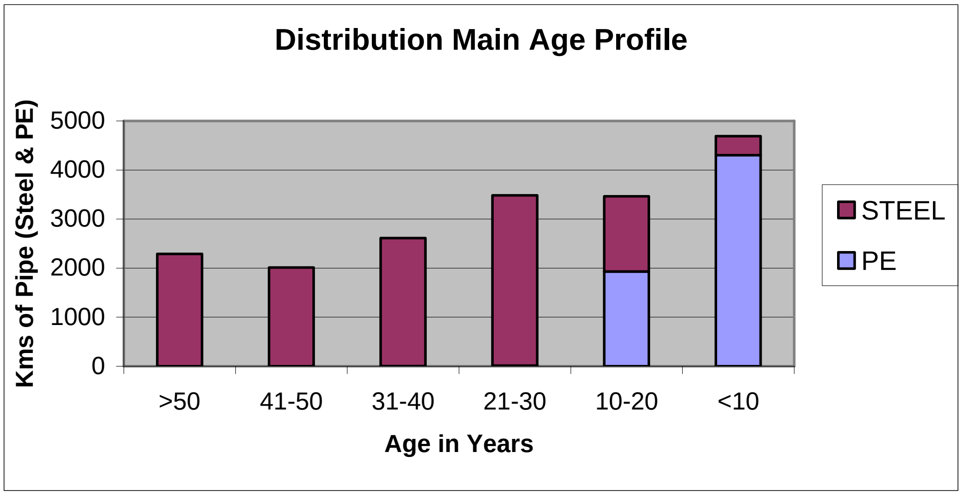
Response:

A younger system, all things being equal, should have less physical infrastructure integrity issues than an older system. A younger system is installed using newer technology and the latest in materials. The polyethylene (PE) pipe commonly installed today is subject to less age related physical breakdown than the steel pipe of twenty years ago. Newer systems may however be subjected to more damage due to the digging community not being aware of the new installations and the amount of construction activity that is conducted in newer areas versus mature established areas.

Below is the TGI Mains age profile from April 2003. Virtually all the new mains (400 km) installed since the profile was taken have been PE. The average age range is in the 20-30 years age bracket. A TGI Services age profile is unavailable however for the most part the company expects that it maintains a similar profile to the Mains as service installations paralleled main installations.

Table of Distribution Main Age Profile

Yrs	PE (km)	Steel (km)	Total (km)
>50	0	2291	2291
41-50	0	2014	2014
31-40	4	2609	2613
21-30	12	3472	3484
10-20	1931	1530	3461
<10	4302	390	4692
Total	6250	12305	18555



A combined age profile for TGI and TGVI Transmission pipe can be found in Appendix 43.1. The entire transmission system on TGVI (614.5 km) was installed in 1990-91 (14-15 years old). The average age of the TGI system is in the 30-39 year age bracket.

Terasen Gas (Vancouver Island) Inc – Distribution Mains Age Profile

Date Range	PE (km)	Steel (km)	Total (km)	Age in Years
Unknown & >1899	4	0	4	>55
1900 to 1949	0	10	10	>55
1950 to 1959	0	60	60	46-55
1960 to 1969	0	19	19	36-45
1970 to 1979	2	53	55	26-35
1980 to 1989	103	28	131	16-25
1990 to 1999	2122	130	2252	5-15
2000 to 2005 August YTD	395	28	423	<5
	2625	328	2954	

Notes:

1) 90% of the Distribution Mains are less than 15 years old.

2) Source : AMFM August 25th, 2005

43.2 What is the number of leaks per kilometre for TGI and TGVI for 2003 and 2004?

Response:

The calculation of this metric is based on the same methodology as the current TGI SQI directional indicator (leaks per km of distribution main).

TGI:	2003:	.0040
	2004:	.0045
TGVI:	2003:	.0114
	2004:	.0185

43.3 In the last ten years how many unscheduled disruptions of service have occurred in the underwater and marine crossings? Please elaborate on any disruption of service.

Response:

None.

43.4 Does the redundant second marine crossing reduce risk? If not, why not?

Response:

Yes. The two 10" pipelines run in close proximity to each other but two lines are less riskier than one from the standpoint of physical integrity. There is however a higher risk to external damage by having two lines of pipe exposed versus one.. It must also be noted that the two lines are only on the marine crossing. TGVI is dependent on one transmission pipeline in all other areas, and has no storage in its service area, or alternate means of obtaining gas supply, if the single pipeline fails.

43.5 Is the rugged terrain of TGVI similar to the rugged terrain encountered in the service areas of TGI? If not, how are they different?

Response:

Yes. Various terrain conditions found on Vancouver Island are comparable to terrain conditions found on the mainland with the exception of the marine crossings. Generally speaking, the Vancouver Island and Sunshine Coast service territory, both Distribution and Transmission has a larger percentage of rocky areas than on the Mainland. The TGVI transmission system traverses very rugged terrain in comparison to the mainland system in general.

It should also be noted that the weather patterns differ quite considerably from other parts of the TGI system. The TGVI transmission system traverses a portion of the Coastal Mountain range. This range can and does receive large amounts of snow accumulation in the mid to late fall. It is not uncommon for the snow to then be exposed to warmer wet weather. This has triggered debris torrents and large-scale pipe exposure due to erosion as recently as 2004. These events do put the pipeline at risk of damage.

44.0 Reference: Application, Tab 2, p. 20
TGVI RDDA, Royalty Payments, and Loan Repayments

On Tab 2, page 20 TGVI outlines the challenges of recovering the remaining RDDA, termination of royalty payments at the end of 2011, and repayment of interest free government loans.

44.1 Assuming in 2013 that the RDDA has been paid off, royalty payments have ended, long-term debt would be payable at 6.13%, average usage and contract demand remains the same as 2006 forecast for all customers, and any outstanding interest free government loans needs to be paid, would the cost of service in 2013 be higher or lower than the soft cap price level and by how much? Please elaborate on the analyses and state the assumptions. Assume in the analyses that gas commodity and electric energy costs remain the same in real terms as today and customer additions continue to be added.

Response:

Key Assumptions:

1. The base forecast used is the 2006/07 Revenue Requirement Application filed on July 20, 2005.
2. The average usage and contract demand remains the same as stated in 2006 forecast.
3. The inflation rate used is 3% for 2006 and 2007, and 2% for 2008 and beyond.
4. The RDDA has been paid off, royalty payments have ended, and the Special Direction Provision has ended before 2013.
5. The customer addition continues as filed (82,601 in 2005 vs. 111,900 in 2013).
6. The 2005 gas commodity price was updated to $7.98/GJ inclusive of Midstream costs to reflect August 10, 2005 strip. The royalty credit of $ 6.92/GJ (average price for 2005) is inflated at the above inflation rates. The 2013 gas commodity price is identical to 2005 price in real dollars.
7. The following electricity prices are assumed in 2005:
    a. Residential - $0.0605/KWh
    b. Small Commercial - $0.0688/KWh
    c. Large Commercial & Industrial - $0.0486/KWh

    The 2013 electricity rate is identical to 2005 rate in real dollars.
8. The West Texas intermediate oil price is assumed to be US$60/bbl in 2005. The 2013 oil price is identical to 2005 price in real dollars.
9. Currency Exchange rate used for the forecast period is US$0.83/C$.

10. Load term debt is payable at 6.13%.

11. The capital structure remains at 60% debt and 40% equity. The ROE is 9.04% as in the Revenue Requirement Application.

12. Rate Design Logic Assumptions:

    a. For the period through and including 2011, core rates are calculated by selecting the minimum of allocated unit cost and alternate fuel prices. The higher of the selected rate and the previous year rate is designated as the effective rate.

    b. In 2012 and beyond, the effective rate is set as the allocated unit cost (i.e. Revenue-to-Cost ratio = 1.00) for all customer classes. As a result, if rates were approved at that level, it may result in rates not being competitive with alternate fuels.

<u>Result:</u>

1. The Revenue Requirement of 2013 vs. 2005 is shown below. The 2013 Cost of Service is anticipated to be $36.5M (2005$) higher than in 2005.

	2013 (Nominal $)	2013 (2005$)	2005	Variance
	($000)	($000)	($000)	($000)
Total Cost of Service	$115,364	$96,559	$99,925	($3,366)
(excluding Cost of Gas)				$0
Cost of Gas	$130,056	$108,857	$97,346	$11,511
Gross Revenue Requirement	$245,420	$205,416	$197,271	$8,145
Less: Royalty Revenue	$0	$0	($44,125)	$44,125
Less: Miscellaneous Revenue	($566)	($474)	($285)	($189)
Add: RDDA Amortization	$0	$0	$15,584	($15,584)
Net Revenue Requirement	$244,854	$204,942	$168,445	$36,497

2. As described in the assumptions above, for the purposes of this analysis, the rates for each customer class for 2013 have been set to equal 100% of the allocated unit cost. Hence, Revenue-to-Cost ratios are 1.00 for all customer classes.

    - The residential rate is not competitive with electricity as the Gas-to-Electricity ratio is greater than 1.00. Other core customer class is competitive with electricity as the Gas-to-Electricity ratio is less than 1.00.

    - All customer classes are competitive with oil as their Gas-to-Oil ratios are less than 1.00.

	Allocated Cost	Volume	Allocated Unit Cost	Competitive Fuel		Effective Rate	Revenue / Cost	Gas / Oil	Gas / Electricity
				Oil	Electricity				
	($000)	(GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)			
Residential	$117,511	5,798	$20.27	$29.47	$18.07	$20.27	1.00	0.69	1.12
Other Core (Commercial)	$108,869	7,478	$14.56	$24.18	$16.13	$14.56	1.00	0.60	0.90
Transport	$18,474	21,446	$0.86	NA	NA	$0.86	1.00	NA	NA
Total	$244,854	34,722							

44.1.1 How would the scenario results change if the Joint Venture renews its long-term agreement and reduces its firm demand by 20%?

Response:

Key Assumption:

- The Joint Venture reduces its firm demand by 20% in 2012. It is assumed the Joint Venture annual demand is also reduced by 20%. All other forecast assumptions are the same as in the response to 41.1.

Result:

- The allocated cost before and after Joint Venture reducing its firm demand by 20% is shown below. As a result, the cost of service does not decrease. However, the costs allocated to the transportation customers are reduced by approximately $731K. These costs are shifted to the core customer classes, which is set out in the table below. The increased cost responsibility for core customers would result in a minor upward pressure on their rates.

2013	Allocated Cost		
	Before JV - 20%	After JV - 20%	Variance
	($000)	($000)	($000)
Residential	$117,511	$117,898	$386
Other Core (Commercial)	$108,869	$109,213	$344
Transport	$18,474	$17,743	($731)
Total	$244,854	$244,854	($0)

45.0 Reference: Application, Tab 2, pp. 20-21
TGVI Comparables

45.1 Please restate Table 2 using a similar format to Table 1 (page 4) and include Pacific Northern Gas and its subsidiary service areas (if different from the parent).

Response:

Please see Table 7 at Tab 2, page 51.

The two subsidiary areas of PNG would be:

	Allowed Common Equity Ratio (3)	Allowed Return at Forecast 5.25% Long Canada (2)	Weighted Equity Return Component (Col I x Col 2)
PNG-Tumbler Ridge	36%	9.40%	3.38%
PNG-FSJ/Dawson Creek	36%	9.15%	3.29%

45.2 Please provide for 2004, for these comparable utilities, the number of customers, delivery margin revenues, years of operation, sales volume, five year customer growth, and five year delivery margin growth.

Response:

	Delivery Margin Revenues	**Years of Operation**	**Customer Growth**	**Delivery Margin Growth**
AltaGas Utilities	$28.1 million	50	1.4%	3.7%
Enbridge Gas New Brunswick	$3.7 million	4	169% [1/]	N/A
Gazifère	$16.1 million	45	4.9%	2.7%
Heritage Gas	$67 thousand [2/]	1	N/A	N/A
Natural Resource Gas	$3.1 million	80	4.2%	-0-

Notes:

1/ 2001-2004.

2/ Total revenue.

45.3 Please identify and compare the risk factors for FortisBC and for TGVI that lead to the conclusion that TGVI faces higher business risks than FortisBC.

Response:

The principal reasons for concluding that TGVI is of higher risk than FortisBC are the fact that TGVI is building a new market from the ground up, in a very price competitive market, with an accumulated RDDA of $60 million to recover, an increasingly challenging objective in light of TGVI's soft cap pricing mechanism and rising commodity prices. While FortisBC is operating in a competitive market for space heating, it is a mature utility, is able to fully recover its revenue requirement from its existing load, and has a base load that has no competitive options.

46.0 Reference: Application, Tab 2, pp. 21-22
TGVI Recommended Common Equity Ratio and Risk Premium

On Tab 2, page 21 Ms. McShane states: "In my opinion, to equate TGVI to the benchmark low risk utility, an allowed common equity ratio of no less than 45-50% would be required (compared to the range of 35-40% for Terasen Gas). Terasen Gas is proposing a 40% common equity ratio for TGVI."

46.1 At the recommended 45-50% allowed common equity ratio there would be no incremental risk premium above the benchmark. Is this correct? If not, please clarify.

Response:

Yes, this is correct, based on the circumstances that existed at the time the Application was filed. However, if TGVI's competitive circumstances deteriorate in light of rising gas prices, or BC Hydro does not commit to firm transportation, raising the risk that the RDDA cannot be recovered, that conclusion will need to be revaluated.

46.2 On Tab 2, pages 21-22 Ms. McShane states: "I view the proposal as reasonable; however, the difference between the proposed 40% and the indicated range of 45-50% (mid-point of 47.5%) requires an incremental equity risk premium relative to the benchmark low risk utility return. Applying the same approach as detailed in Schedule 29 for Terasen Gas, the difference between the proposed 40% common equity ratio and a 47.5% common equity ratio warrants an incremental equity risk premium for TGVI relative to the benchmark low risk utility of 60-120 basis points (mid-point of 90 basis points). Thus, the 75 basis point incremental equity risk premium is reasonable."

46.2.1 Please provide the detailed calculation on how the 60-120 basis points are derived.

Response:

Please refer to Appendix 46.2.1

47.0 Reference: Application, Tab 2, p. 24

The testimony says that "a return that simply allows a utility to attract capital, irrespective of the cost, does not lead to the conclusion that it is compatible with the comparable returns standard.

47.1 Under the circumstances of the recent purchase of Terasen Inc. by Kinder Morgan, could it be said that the comparable earnings standard was met? Why or why not?

Response:

No. The purchase price for Terasen Inc. does not indicate that the comparable earnings standard for Terasen Gas has been met. Kinder Morgan is acquiring Terasen Inc., not Terasen Gas, the stand-alone gas distribution utility. Kinder Morgan's willingness to pay a premium over market value for Terasen Inc. appears to be tied in large part to its interest in the oil pipeline assets and their proximity to the oil sands region, whose future prospects have been recently enhanced by increases in world oil prices.

There is no separate purchase price for Terasen Gas that would allow the conclusion that Kinder Morgan views the returns of Terasen Gas as meeting the comparable earnings standard. Moreover, even when a stand-alone utility is purchased at a price in excess of book value, factors including tax benefits, synergies, future growth prospects, and the conclusion that future returns can be enhanced, will contribute to the price an acquirer is willing to pay. The willingness to pay a price in excess of book value does not mean that the acquirer views the current level of returns being earned at the utility level as meeting the comparable earnings standard.

48.0 Reference: Application Tab 2, p. 26 Overview of Approach to Estimating the Benchmark Return

The testimony of Kathleen McShane states that a basic economic principle establishes the expected relationship between market value and replacement cost which provides support for market prices in excess of original cost book value. Economic principles do not support that the market value of utility shares should be equal to book value.

48.1 Please explain if this economic principle, which is based on few barriers for entry and exit and equilibrium in the competitive marketplace, also applies to utility companies.

Response:

Yes, since regulation is intended to emulate the competitive model. The application of the principle to regulated utilities would recognize that ratepayers are consuming scarce resources, and the price that is paid for service should reflect the cost to replace the inputs consumed. Setting the price below replacement cost, in principle, incents customers to over-consume scarce resources.

48.2 One of the underlying assumptions that replacement cost should exceed the original cost book value of assets is the presence of inflation and the absence of significant technological advances.

48.2.1 Please explain how inflation is defined in the above statement, e.g. core CPI, CPI or another index?

Response:

In the referenced context, the term “inflation” does not refer to a particular index. It is intended to be interpreted as a generalized finding that price levels in the economy have increased over time, resulting in higher prices, in nominal terms, of replacing existing assets.

48.2.1.1 In addition to the CPI data in Tab 2 Schedule 6 please provide other indexes for measuring inflation such as the Industrial Product Price Indexes (Machinery and Equipment Price Indexes), Producer Price Index for Goods, Producer Price Index for Services.

Response:

Please refer to Appendix 48.2.1.1, which contains the following obtained from Statscan:

(1) Service Price Index, as measured by the Consulting Engineering Services (Total Engineering) Price Index, annually for 1989-2003.

(2) Raw Materials Price Index (Total Raw Materials), monthly from

January 1981-December 2003.

(3) Industry Prices Indices as follows:

Total, All Commodities, Monthly, December 1977-June 2005	Machinery & Equipment, second stage Monthly, January 1986-June 2005
Machinery & Equipment, Capital Equipment Monthly, January 1986-June 2005	Machinery & Equipment, Other Monthly, January 1986-June 2005

48.2.1.2 *Are the industrial and producer indices more relevant to the utility sector? Please comment on the level of inflation and deflation as measured by indices other than the CPI.*

Response:

A significant component of the cost of the utility's plant in service is labour, whether direct costs associated with installation or capitalized overhead. For example, approximately 54% of capital expenditures by Terasen Gas Inc. in 2004 were represented by direct or indirect labour. Because capital costs reflect a number of input costs, a broader inflation measure such as CPI is a more representative measure for the utility sector than narrow measures such as machinery and equipment or commodity price indices.

The levels of inflation as measured by the indices included in response to 48.2.1.1 compared to the CPI over similar periods (subject to the availability of data) are:

	CPI	**Industry Price Indexes**		**Raw Materials**	**Services**
		All	**Capital Equipment**		
1990-2003	2.2%	1.6%	1.4%	2.7%	1.8%
1981-2003	3.6%	2.4%	n/a	1.9%	n/a
1979-2004	4.0%	3.3%	n/a	n/a	n/a
1986-2004	2.6%	1.8%	1.7%	n/a	n/a

48.2.2 Please comment if significant technological advances have been made in the utility sector on equipment, e.g., lowered costs for smart meters, submarine cables, etc.?

Response:

As with any mainstream industry there have been technological advances in certain areas of the utility, although little has really changed in the way that gas is delivered from the source to the customer.

Transmission pipe, followed by pressure reducing stations, followed by distribution mains, services and a customer meter are essentially the same means of delivering gas to customers as they were forty years ago, albeit the techniques for installing and the materials are slowly evolving. Steel has been largely replaced by polyethylene (PE) in the distribution area; meters haven't changed substantially however there is a trend to smaller sets with more accurate measurement, sometimes with automated features; backhoes are still in use but in some cases have been replaced by mini-excavators and trenching equipment.

The computer hardware, software and telecommunications equipment has been the source for the most significant advancement. Cell phone equipment and coverage and mobile laptops are two examples of equipment that have made the industry more efficient.

From a Transmission perspective, technology has made some noticeable leaps. For example, technology advancements (pigging equipment) have now made it possible to conduct internal pipeline inspections that essentially provide data on pipeline integrity from inside the pipe. SCADA equipment (electronic data acquisition and control) is now routinely used to manage gas flows and gas control remotely.

The technology advances in the utility sector are not unique to natural gas utilities. Electric utilities will have made similar advances in their operations.

Notwithstanding the technological advances that have occurred, the delivered price of natural gas in British Columbia is less competitive with electricity than it was in the past.

48.3 To what extent is it possible that the market value of utility shares can still be expected to exceed their book value even without the presence of inflation and with technological advances (e.g. value of goodwill in mergers and acquisition)? Please explain.

Response:

In the absence of inflation and technological advances, factors that could cause the market value of utility shares to exceed book value include:

(1) The general levels of the market. Stocks tend to trade on a relative, rather than an absolute basis, so that the market as a whole is trading at a significant premium to book, utility shares may also trade above book value.

(2) The level of current earnings. If current earnings levels are higher than the "bare-bones" cost of attracting equity, the market value will likely exceed book value.

(3) Future growth prospects. Strong growth prospects will tend to push up the price investors are willing to pay.

(4) Other factors that could case price to exceed book include positive qualities associated with the firm's operations, including management and service quality.

48.4 Please comment on the key factors and principles that would cause the market value of an individual rate regulated utility to exceed its book value.

Response:

Please see response to BCUC IR No. 1, 48.3.

49.0 Reference: Application, Tab 2, p. 28

The testimony discusses the weight that some regulators have given to the multiple tests when recognizing the distinction between the capital attraction standard and the comparable earnings standard, citing some examples from Board decisions in 1991, 1992 and 1995, for example.

49.1 Please provide a similar discussion of the weight given the multiple tests in the most recent ROE and capital structure decisions of the respective Canadian regulatory boards.

Response:

In PU 19 (2003) for Newfoundland Power, the Board of Commissioners of Public Utilities stated that it will continue to rely primarily on the equity risk premium test with a view to establishing a risk-free rate plus an appropriate risk premium.

OEB Decision RP-2002-0158, dated January 2004 (Union Gas and Enbridge Gas Distribution), stated that comparable earnings and DCF should be given little or no weight, and that they would rely primarily on the equity risk premium test.

The AEUB Generic Cost of Capital Decision (July 2004) found the following:

(1) First, it determined the CAPM result.

(2) Second, it reviewed other forms of the equity risk premium test presented, concluded the results would generally support an ROE above the CAPM results, but concluded limited weight should be put on them.

(3) Third, it concluded no weight should be put on the DCF test.

(4) Fourth, it concluded no weight should be put on the comparable earnings test.

Then the AEUB looked at other indicators, including:

- Market-to-Book Ratios and Acquisition Premiums
- Income Trusts
- Return Awards for Other Canadian Utilities
- Return Awards for U.S. Utilities
- Alliance and Maritimes & Northeast Pipelines' ROEs
- Pension Returns Expectations.

The first two, the AEUB concluded, supported an ROE at or below the CAPM result; the last four would support an ROE at or above the CAPM result.

The Board also stated it gave no weight to the FERC incentive returns for electric transmission facilities or to other investment alternatives available to utility shareholders.

50.0 Reference: Application Tab 2, p. 30

Paragraph 'b.' on page 30 discusses the annual arithmetic and geometric returns for the TSE 300 and for bonds during the 1990-1994 period. Please provide, on a similar basis, the annual returns for low risk utilities.

Response:

50.0 The arithmetic and geometric average returns for the TSE Gas & Electric Index over 1990-1994 were 8.8% and 8.3%, respectively. For the S&P/TSX Utilities Index the corresponding averages were 8.3% and 8.1% respectively.

The 1990-1994 total returns for individual utilities (based on the annual average of monthly closing prices and the annual dividend paid) were:

	Averages	
	Arithmetic	Geometric
Canadian Utilities	10.4%	10.2%
Enbridge Inc.	2.9%	1.9%
Fortis	11.3%	11.1%
Terasen	6.5%	6.4%
TransAlta	8.2%	7.9%
TransCanada	6.5%	6.4%

51.0 Reference: Application Tab 2, p. 33

Paragraph 2 on page 33 states that the decline in the achieved equity market returns may have been interpreted as a reduction in the required (forward looking) equity market risk premium.

Does Ms. McShane accept that interpretation? If not please explain how that should be interpreted and why?

Response:

No. The low equity market returns that were achieved during 1990-1994 reflected the impact of a prolonged period of restructuring and recession. Achieved equity returns over a particular period reflect specific events that happened to occur as a result of circumstances unique to that period. The events of the recessionary period highlight the risk in the equity markets, while reducing the achieved risk premium. The fact that the incurrence of risk reduces the achieved risk premium underscores the care that must be taken in interpreting past risk premiums.

52.0 Reference: Application Tab 2, pp. 33, 61
Key Factors Determining the Level of Allowed Risk Premiums in the Mid-1990s

The testimony of Kathleen McShane states that at the time of determining the level of equity risk premiums, little recognition to alternative investment opportunities outside the Canadian market was given. It states that giving weight to the U.S. equity risk premium would have led to higher allowed utility equity risk premiums.

52.1 Please provide the latest forecast data for 30 year government bond yields for: (i) Japan; (ii) the United Kingdom; and (iii) Germany; and compare them to Canada and the U.S.

<u>Response:</u>

The only available consensus forecasts are for 10-year government bond yields. The August 8, 2005 10-year forecasts from Consensus Forecasts, *Consensus Economics*, are as follows.

	3-months Forward	12-months Forward
Japan	1.5%	1.7%
Germany	3.5%	3.8%
U.K.	4.4%	4.5%
Canada	4.2%	4.6%
U.S.	4.6%	5.0%

52.1.1 With the progress in the globalization of the financial marketplace since the mid-1990s, would Ms. McShane recommend giving weight to equity risk premiums to the above international government bonds yields going forward? If so, what weight should be assigned to the different international government bond yields.

<u>Response:</u>

No. The risk-free rate should still be determined using a Canadian-specific measure.

52.1.1.1 If recognition had been given to major alternative investment opportunities in the global market (Japan, Germany, the UK in addition to the U.S.) in the mid-1990s, what would have been, broadly speaking, the effects on the Canadian allowed utility equity risk premiums?

Response:

At the time, there would have been very little incremental impact of giving weight to data from countries other than the U.S. A relatively small proportion of the foreign equity investment was destined for countries other than the U.S. In 1994, total purchases by Canadians of foreign equities were $71.5 billion, of which 76% were U.S., 2.5% were U.K., 3.1% were other European Union countries, 4.5% were Japanese, 11% were "All Other Countries."

Ms. McShane can only speculate on what would have been the impact on the allowed utility risk premium if weight had been given to U.S. data. In 1999, The Régie de l'Energie gave an explicit 40% weighting to U.S. data, concluding that the market risk premium was 6.5%. By comparison, in 1994, the BCUC determined that the market risk premium was 4.5-5.0%; in 1999, it concluded that the market risk premium was 5.0%. Also in 1999, the Commission concluded that the relative risk adjustment for a benchmark low risk utility was 0.60. Thus, it is possible that giving weight to the U.S. data would have increased the allowed risk premium by 90 to 120 basis points, calculated as 0.60 [6.5% - (4.5-5.0%)].

53.0 Reference: Application Tab 2, p. 34

Paragraph 4 at the top of page 34 states that the mediocre performance of the overall Canadian equity market relative to that of utilities may have been perceived as an indication that utility investors were being overcompensated.

53.1 What is the time period being referred to when the Canadian equity market performance was mediocre relative to that of utilities?

Response:

The time period being referred to is 1990-1994, the same period discussed earlier at lines 804-806.

53.2 For the years referred to, please provide the comparative data that reflects the performance of utilities relative to the Canadian equity market.

Response:

The utility data are included in response to BCUC IR No. 1, 50.0. The corresponding overall equity market returns were 5.6% and 4.5% (arithmetic and geometric averages) as provided at Tab 2, lines 805-806.

54.0 Reference: Application Tab 2, p. 36
Changes in Economic and Capital Markets Since the Mid-1990s

The testimony of Kathleen McShane states that the spread between long-term Canadian A-rated utility bonds and 30-year Canada's averaged only 60 basis points from 1996-August 1998, despite the significant financing requirements of the Federal and Provincial Governments. The spreads then widened subsequent to the August 1998 crisis, peaking in late 2002 at close to 190 basis points. Recent spread for A-rated utility issues remains relatively high at approximately 120 basis points. The testimony concludes that the comparatively high spreads point to a perception by investors of an increased level of utility risk.

54.1 The explanation for the downward pressure on long-term government yields was the anticipated reduction in long-term government financing (Tab 2, page 35). The explanation for the decline in yields on long Canada bonds was that the investors' fear of inflation had abated (Tab 2, p.34). To what extent might these factors have played a stronger role in the changes in bond spreads relative to investors perceptions of the "increased level of utility risk"?

Response:

In the 1996-1998 period referenced, the government's financing requirements were of such a magnitude that issues of private borrowers would have had a tendency to be "crowded out". All other things equal, the result would have been a higher spread for a private issuer. As the government's financing requirements have declined, and there is more capacity in the market for private issuers, and more demand for high quality issues, the expectation would be that spreads today would be lower, not higher, than they were in 1996-1998. Nevertheless, it is possible that some of the prevailing premium reflects scarcity in the supply of government bonds.

With respect to the decline in government bond yields due to the fear of inflation abating, a similar decline would have occurred in utility bond yields, since inflation would impact their values similarly. Thus, that factor does not explain the change in spreads.

55.0 Reference: Application, Tab 2, p. 37

In the context of comment on the scarcity premium, the testimony says that sole reliance on a cost of equity methodology that tracks long-term government bond yields raises the risk that the true cost of equity will be underestimated.

55.1 Is this risk only present when a scarcity premium is evident? Why or why not? Would it otherwise be a risk of underestimation or rather a risk of inaccuracy?

Response:

No. The referenced comment was intended to speak solely to the impact of a scarcity premium on the risk premium. More generally, when the allowed return on equity tracks the long Canada yield by virtue of a formula, there will always be a risk that the results will underestimate or misspecify the cost of equity, since factors other than the change in long Canada yields may impact the overall and/or the market utility cost of equity.

55.2 Paragraph 3 states that "Since a utility's cost of debt, like its cost of equity, is determined by its business and financial risks, it should be expected that the utility cost of equity will track the utility cost of debt, all other things equal, more closely than it will track the Government of Canada bond yield."

Please confirm that a two-part ROE adjustment mechanism, in which one part is tied to government bond yields and one part is tied to a utility specific risk premium can address the concern raised in this paragraph. If not, please explain why not.

Response:

Ms. McShane disagrees with the above assertion. The utility-specific risk premium is intended to compensate for differential risks of a given utility, but it does not capture risk factors or changes in the capital markets that impact the cost of equity capital for the utility sector as a whole. Moreover, the "benchmark low risk utility" risk premium does not, by its very nature, include a utility-specific risk premium. Thus, any utility that is designated as the low risk benchmark utility (or to be equivalent to the benchmark) does not, by definition, have a utility-specific risk premium through which it can receive compensation for risk and capital market factors not reflected in the part of the automatic adjustment mechanism tied to government bond yields.

56.0 Reference: Application Tab 2, p. 40

Please expand on the statement that "Because the long-term returns of the various sectors are inconsistent with their relative risk, the achieved risk premiums may not accurately reflect what investors had expected." Please provide the data and analysis that support that statement.

Response:

Financial theory indicates that there is a positive relationship between risk and required return; the higher the risk, the higher the return investors expect and/or require. If, in retrospect, the achieved returns of the riskier sectors are lower than the returns of the less risky sectors, those results beg the question as to whether the market composite returns are a good measure of what investors expected in the past and would require or expect in the future.

Footnote 26 summarizes the long-term returns for the various sectors of the TSE Composite. The individual sector returns can be found in the table below. In addition, please see discussion in Appendix A, pages 6 and 7.

TSE Composite Compound Returns by Sector (1956-2003)

Sector	1956-2003
Metals/ Minerals	7.8%
Gold	9.5%
Oil and Gas	9.5%
Paper/Forest	7.1%
Average	**8.5%**

Sector	1956-2003
Consumer	11.3%
Industrial	7.2%
Real Estate	5.3%
Transportation	10.1%
Pipelines	11.7%
Utilities	11.0%
Comm./ Media	13.5%
Merchants	10.1%
Finance	12.4%
Management	10.8%
Average	**10.3%**

57.0 Reference: Application (Ex. B-1), Tab 2, p. 46

57.1 Please confirm that in March 2004 Terasen announced the discontinuance of its engagement with S&P.

Response:

That is correct.

57.2 Please provide copies of any letters to S&P and statements to other parties that describe the reasons for discontinuing its engagement.

Response:

Terasen advised S&P verbally of its intention to discontinue S&Ps engagement, and did not issue any letters to S&P regarding this. The following extract from Terasen's First Quarter 2004 MD&A is representative of Terasen's disclosure on this matter:

> After reassessing its relationship with Standard & Poor's, a division of The McGraw-Hill Companies (S&P), Terasen decided early in 2004 to discontinue the engagement of Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies (Canada) Corporation to provide credit ratings on the debt of Terasen and Terasen Gas. Terasen believes the credit ratings issued by Moody's and DBRS will be sufficient to service the requirements of creditors and maintain the Company's access to capital. S&P continues to provide an unsolicited rating on Terasen's outstanding debt based on publicly available information. As of March 31, 2004, Terasen's unsecured long-term debt was rated BBB- by S&P.

In verbal discussions with S&P and other parties, Terasen representatives indicated that the decision was made primarily as a result of a cost-benefit assessment. To initiate or maintain a credit rating relationship, an issuer must believe that the costs of soliciting credit ratings (primarily fees charged by the agency and management's time spent maintaining the relationship) will be less than the benefits of having credit ratings, whether in a lower cost of capital, enhanced access to capital, or a combination thereof. Terasen's assessment at the time was that the benefits of the S&P ratings did not exceed the costs of maintaining the rating relationship.

58.0 Reference: Application, Tab 2, pp. 48-49

58.1 Please file the DBRS, Terasen Gas Inc., June 21, 2005 report.

Response:

The requested report is attached as Appendix 58.1

58.2 Please file the Standard & Poor's April 18, 2005 report.

Response:

The requested report is attached as Appendix 58.2

58.3 Please file the CIBC World Markets Report, "Pipelines and Utilities: Time to Lighten Up", December 2001.

Response:

The requested report is attached as Appendix 58.3

58.4 Please file the RBC Capital Markets, August 15, 2003 Research Industry Comment, "It's the Grid, Silly".

Response:

The requested report is attached as Appendix 58.4

58.5 Please file all other DBRS, S&P and Moody's credit rating reports for both TGI and TGVI over the last 3 years.

Response:

Please refer to Appendix 58.5.

58.6 Please file all the financial analyst reports on Terasen Inc. in the year prior to the purchase by Kinder Morgan and all financial analyst reports since the purchase.

Response:

Please refer to Appendix 58.6.

59.0 Reference: Application Tab 2, p. 59 Risk-Adjusted Equity Market Risk Premium Test

The testimony of Kathleen McShane suggests that the U.S. equity market to be a relevant benchmark for estimating the equity risk premium. One of the two reasons is that:

> *"the U.S. economy and capital market, which is increasingly integrated with the Canadian economy and capital market, has historically been the largest recipient of Canadian investment funds outside of Canada, and is considered a broadly diversified global benchmark market."*

59.1 Please describe equity and bond market investors' views on U. S. and Canada's respective expected inflation rate, economic productivity and corporate profitability. Please provide copies of any reports or studies that you rely on to inform your answer.

Response:

The table below summarizes the consensus view of the 2006 values referenced in the question. The forecasts were taken from the August 8, 2005 *Consensus Forecasts*. A copy of the *Consensus Forecasts* is attached as Appendix 59.1

GDP	
U.S.	3.3
Canada	2.9
Pre-Tax Corporate Profits	
U.S.	5.7
Canada	5.2
CPI	
U.S.	2.5
Canada	2.0
Producer Prices	
U.S.	2.5
Canada	1.5
10-Year Bond Yields (12 months forward)	

U.S.	5.0
Canada	4.6
Productivity (Real Output per Employee) (Average for 2006-2017)	
U.S.	2.0
Canada	1.6

59.2 *Please comment whether the difference in fiscal health (e.g. size of budget deficit/surplus) between the U.S. and Canada would cause the long-term bond yields in U.S. and Canada to diverge.*

Response:

Yes, the relative fiscal health can cause the yields to diverge. The potential divergence between Canadian and U.S. yields is somewhat limited by the interdependence of the two economies.

60.0 Reference: Application Tab 2, p. 60 Risk-Adjusted Equity Market Risk Premium Test; Application Tab 2, Chart 1

Chart 1 demonstrates the decoupling between utility stocks and the S&P/TSX Composite between 1999 and mid-2002 period. Ms. McShane concludes in her testimony that this should not be interpreted as a change in the relative riskiness of utility shares but rather as a further indication of the weakness of beta as the sole measure of the relative equity return requirement.

60.1 Was there a change in the absolute risk of the utility shares during the period between 1998 and mid-2002? If so, please describe the magnitude and reasons for the change.

Response:

Yes, the standard deviations of price changes increased, as shown on Schedule 15. The five-year standard deviation of the utilities sector ending 2001 is over 50% higher than the five-year standard deviations ending 1997. The entire market was more volatile during the 1998 to 2002 period, reflecting the impact of the market crisis in 1998 and the market boom and bust that occurred between 1998 and 2000.

60.2 Please provide the average price earning ratios for June 30th and Dec 31st from 1999 to 2002 for the 10 major sectors and for the S&P/TSX and comment if there were changes in relative risk of the utility shares to the market.

Response:

The requested data are not available. The TSE did not "backcast" the P/E ratios when it created the 10 major sectors in April 2002. Table 9 on page 68 of Tab 2 indicates that the risk of the utilities sector relative to the market and the individual major sectors, as measured by relative standard deviations did not change materially.

61.0 Reference: Application, Tab 2, p. 62
Superiority of Arithmetic Averages

On Tab 2, page 62 Ms. McShane quotes from Dimson, Marsh, and Staunton:

"The present values are respectively $1.25/1.015 = $1.22…"

61.1 Should the '1.015' be instead '1.025'? Please confirm.

Response:

It is confirmed.

62.0 Reference: Application, Tab 2, p. 66

62.1 Please expound upon the rationale or methodology for the 6.0 to 6.5% estimate of the equity market risk premium.

<u>Response:</u>

The development of the 6.0-6.5% market risk premium is contained in lines 1577-1787, with further quantitative support found in Appendix A, pages 11-13.

The analysis starts with the "raw" market risk premiums from Canada and the U.S., which range from 4.5-6.2% on a geometric basis to 5.3-7.0% on an arithmetic basis. The consideration of U.K. risk premiums (due to the recent increase in portfolio equity investment flows between Canadian investors and the U.K.) of 5.6% to 6.0%, on a geometric and arithmetic average basis, respectively, provides support to the mid-point of the Canada/U.S. range. The conclusion that arithmetic averages are more relevant in developing a forward-looking cost of equity estimate puts the emphasis on the upper end of the range, i.e., 5.3-7.0%.

The "raw" historic results indicate a risk premium in the 5.5% to 6.0% range, giving primary weight to the Canadian data and to the arithmetic averages.. Although no precise weights were applied, a 70%/30% split between Canadian and U.S. data would be reasonable recognizing that the total foreign exposure of the typical pension plan is about 25%; the foreign exposure of the publicly-traded equity component of the typical large fund is closer to 40-50%. At 70%/30% split is consistent with the 5.5-6.0% range based on "raw" historic results.

The "raw" results, as discussed at pages 64-65 of Tab 2, do not recognize the underlying divergent trends in the equity market returns as compared to the bond returns. The separate analysis of the two components of the risk premium, the equity market return and the bond return, indicates that a reasonable estimate of expected value of the Canadian equity market returns is 11.5-12.5%, compared to a forecast of long Canada bond returns equal to the forecast yield of 5.25%. Comparing the forecast long Canada yield of 5.25% to the expected value of the equity market returns, the estimated market risk premium is 6.75%. The estimated forward-looking risk premium is thus approximately 5.75-6.75%, narrowed to mid-range, or 6.0-6.5%.

62.2 Please indicate and comment on the relative weight given to Canadian versus US data in obtaining the 6.0 to 6.5% estimate of the equity market risk premium.

<u>Response:</u>

The estimated market risk premium was not based on precise weightings of Canadian and U.S. data in arriving at the estimated market risk premium. However, one can infer weights as follows. The lower end of the initial range (5.75%) reflects approximately 70% weight to Canadian data and 30% weight to U.S. data. The upper end of the range (6.75%) is based solely on Canadian data, using a similar analysis of U.S. data as a check. With equal weight to both the "raw" historic and forward-looking estimates of equity and bond returns, the net weight to U.S. data would be about 15%

63.0 Reference: Application, Tab 2, pp. 67-78 and Schedule 15

To measure the relative market volatility of Canadian utility stocks, the testimony compares the standard deviations of the Utilities Index to the standard deviations of the S&P/TSX Index as well as to the mean and median standard deviations of 10 major Sector Indices.

63.1 With respect to the comparison of the Utilities Index to the 10 major Sector Indices, which comparison is more appropriate, the mean or the median, and why?

Response:

The median is likely to be a more accurate estimate of the central tendency when there are outliers whose value will skew the mean.

63.2 What utilities comprise the Utilities Index?

Response:

The Utilities sector is currently comprised of TransAlta Corporation (24.76%), Terasen Inc. (22.17%), Canadian Utilities (14.54%), Fortis Inc. (14.18%), Emera Inc. (13.15%) and ATCO Ltd. (11.19%) (relative weights in parentheses). From 2002 to early 2004, the sector also included TransCanada and Enbridge Inc.

63.3 Please provide the standard deviations for each of the utilities in the Utilities Index.

Response:

Please refer to Appendix 63.3

64.0 Reference: Application, Tab 2, p. 69

64.1 Please provide the data and sources for the regressions used to obtain the beta estimates summarized in Table 10.

<u>Response:</u>

64.1 The requested data can be found in Appendix 64.1 for the following:

- Canadian Utilities
- Emera
- Enbridge
- Fortis
- Terasen
- TransCanada
- TSE Utility Index
- TSX Utilities

64.2 For each of the estimates in Table 10, please provide a plot of the data used in the regressions.

<u>Response:</u>

Please see response to 64.1.

64.3 For each of the estimates in Table 10, please provide a plot of the residuals against the independent variable and a plot of the residuals against time.

<u>Response:</u>

Please see response to 64.1.

65.0 Reference: Application, Tab 2, p. 71

For each of the regression results presented on page 71:

65.1 Please provide the data and sources.

Response:

Please see Appendix 65.1.

65.2 Please provide a plot of the data.

Response:

Please see Appendix 65.2.

65.3 Please provide a plot of the residuals against the independent variables and a plot of the residuals against time.

Response:

Please see Appendix 65.3.

65.4 Please provide a simple linear regression of Monthly TSE Gas/Electric Return against Monthly Long Canada Bond Return. Please include data plots of then nature requested in the 2 questions immediately above.

Response:

Please see Appendix 65.4.

65.5 Please provide a corresponding analysis to the two regressions presented in the testimony and to the third requested above, that expands the analysis time frame through 2004 but separately includes and excludes the "Nortel effect".

Response:

The requested data can be found in Appendix 65.5

66.0 Reference: Application, Tab 2, p. 73

The testimony says that:

> *Based on the preceding analysis of standard deviations of market returns and betas, in my opinion, the relative risk adjustment for a benchmark low risk utility is approximately 0.65.*

66.1 Please explain in greater detail how and why the relative risk adjustment methodology reported in Section IV.C.3.c is directly applicable to a benchmark low risk utility.

<u>Response:</u>

The relative risk adjustment for a benchmark low risk utility was developed from the two principal measures of market risk, standard deviations and betas. The data employed were for the indices of utilities (Equity S&P/TSX Utilities Index and the TSE Gas/Electric Index), and for individual publicly-traded utilities. The relative standard deviations of the utilities indicate a relative risk adjustment for a Canadian utility in the range of 0.60-0.70. With respect to betas, the most relevant estimates are those that reflect relatively recent market data, but that exclude the impact of the market "boom and bust" and the Nortel effect, that is, betas that terminate prior to 1999, or do not commence until mid-2002.

The adjusted beta estimates for the individual Canadian utilities and the utility indices for five-year periods ending 1993-1998 and for mid-2002 to the end of 2004, similar to the standard deviations, support a relative risk adjustment of 0.60-0.70.

The relative risk measures that were developed for the individual publicly-traded Canadian utilities and the utility indices serve as a proxy for the relative risk adjustment for a low risk benchmark utility. There are a very limited number of publicly-traded Canadian utilities, but those that are publicly-traded are parents of utilities that would qualify as relatively low risk (e.g., TCPL, the ATCO Utilities, Enbridge Gas, Enbridge Pipeline, Newfoundland Light & Power). The betas for the parent companies and for the utility indices that comprise the parent companies are the best available proxy for the betas for a benchmark low risk utility.

67.0 Reference: Application, Tab 2, p. 73

In Section IV.C.3.d the testimony says that:

> *At an equity market risk premium of 6.0 to 6.5% and a relative risk adjustment of 0.65, the indicated benchmark utility equity risk premium is 4.0%.*

67.1 Was the term "low-risk" deliberately excluded from the description of "benchmark utility"?

Response:

No.

67.2 If so, why? How should "benchmark utility" then be understood in this context?

Response:

Please see response to BCUC IR No. 1, 67.1.

68.0 Reference: Application, Tab 2, pp. 74-75 and Statistical Exhibits, Schedule 16

The testimony says that:

> *The historic equity risk premiums for both Canadian and U.S. utilities support an expected equity risk premium estimate for a benchmark Canadian utility in the range of 4.25-5.0% or approximately 4.75%.*

68.1 How exactly was this range determined?

Response:

The bottom end of the range represents the Canadian risk premiums, with primary weight given to the arithmetic averages. The top end of the range represents the combined U.S. electric and gas utility risk premiums, with primary weight given to the arithmetic averages.

68.2 Please provide the data used in the tables and a working spreadsheet for the calculations in Schedule 16.

Response:

Please refer to Appendix 68.2.

68.3 Please indicate and comment on the relative weight given to Canadian versus US data in obtaining the 4.25-5.0% estimate of an expected equity risk premium for a benchmark Canadian utility.

Response:

As suggested by the response to BCUC IR No. 1, 68.1, approximately equal weight was given to the Canadian and U.S. results in arriving at the range. The past experience in both countries is a relevant consideration to investors' future expectations for utility returns.

68.4 Was the term "low-risk" deliberately excluded from the description of "benchmark utility"?

Response:

No.

68.5 If so, why? How should "benchmark utility" then be understood in this context?

Response:

Please see response to BCUC IR No. 1, 68.4.

69.0 Reference: Application, Tab 2, p. 73, Use of Adjusted Betas

On Tab 2, page 73, Table 12 shows Canadian Utility adjusted betas. The source indicates the figures are from Schedules 11 and 14.

69.1 Table 12 uses five-year betas from 1993 to 1998 with Nortel and then makes a change in methodology and calculates 30-month betas from 7/2002 to 12/2004 without Nortel.

69.1.1 Is this an accurate assessment of Table 12? If not, please rephrase the statement so that it is accurate.

Response:

Table 12 reflects betas both before and after the period (approximately 2000 through mid-2002) during which Nortel had an extraordinary impact on the S&P/TSX Composite (and its predecessor, the TSE 300). Therefore, to present betas exclusive of this “Nortel effect”, the calculation of betas encompassing the 2000 to mid-2002 period must be made using data from which the impact of Nortel is mitigated. As such, it is a change in methodology, but one required to attempt to calculate a volatility measure that is somewhat meaningful.

69.1.2 Please elaborate on the beta methodology used to calculate Schedules 11 and 14. Are they based on daily, weekly, or monthly returns? How would the results change if the returns were calculated on these other time intervals?

Response:

The betas in Schedules 11 and 14 are based on monthly price changes against the monthly price change of the S&P/TSX Composite. We do not have the data to calculate the betas on a daily or weekly basis for the periods in question.

69.1.3 Is the five-year beta the financial industry standard when calculating betas? Please elaborate.

Response:

A five year beta is common but is not necessarily standard. For instance, *Value Line* requires a minimum of only 2 years of data; Bloomberg requires a minimum of 3 years.

69.1.4 Please re-calculate Schedule 11 using five-year betas from 1993 to 2004 based on the S&P/TSX Capped Composite Index. Append at the last column for each item the average beta calculated for the whole period.

Response:

Please refer to Appendix 69.1.4

69.2 Tab 2, Schedule 12 provides Betas for Regulated Canadian Utilities (excluding Nortel) from 2000 to 2004. The table shows mean and median betas of the six utilities ranges from a high of 0.60 to a low of 0.35. The S&P/TSX Utilities adjusted beta shows a high of 0.56 to a low of 0.30.

69.2.1 How do these results in Schedule 12 reconcile with Table 12 that shows Individual Canadian Utilities (Median) of 0.64 and 0.61? Explain the apparent differences.

Response:

None of the betas on Table 12 are taken from Schedule 12. Table 12 is sourced as Schedules 11 and 14. The betas on Schedule 12 are 5-year betas excluding Nortel ending in 2000-2004. The five-year betas on Table 12 are averages of betas ending in 1993 through 1998.

69.2.2 How do these results in Schedule 12 reconcile with Table 12 which shows the S&P/TSX Utilities Index of 0.73 and 0.70? Explain the apparent differences.

Response:

Please see response to 69.2.1.

70.0 Reference: Application, Tab 2, p. 74
Benchmark Utility Equity Risk Premium

On Tab 2, page 74 Ms. McShane states: "I estimated the equity market risk premium at a long Canada yield of 5.25%, at approximately 6.0-6.5%."

70.1 Please provide the supporting calculation to yield the 6.0-6.5%.

Response:

Please see response to BCUC IR No.1, 62.1.

70.2 Please comment on the "survivorship bias" of market returns using historical data? Would the equity risk premium be higher or lower due to "survivorship bias"? Why? What adjustment, if any, was used to correct for survivorship data?

Response:

Ms. McShane has made no adjustment for survivorship bias. The term survivorship bias refers to the claim that survival of an equity market imparts a bias to *ex post* (historic) returns. The survivorship bias claim, which is referred to in the preamble to BCUC IR No. 1, 90.7.2, has been made with respect to the U.S. equity market. The survivorship bias argument is based on the proposition that U.S. returns reflect the fact that the economy has been spared the adverse impact of major disruptions caused such catastrophic events as hyper-inflation, major political turmoil, expropriation or war.

The suspicion that a survivorship bias exists in U.S. data was raised by Philippe Jorion and William N. Goetzmann, because their analysis indicated that U.S. market returns were higher than for other markets. (As an introduction to their analysis, Jorion and Goetzmann noted that most estimates of the long-term expected return on capital are derived from U.S. data only.) It is to the analysis of Jorion and Goetzmann that Copeland, Koller and Murrin (referenced in the preamble to BCUC IR No. 1, 90.7.2) refer in making a downward adjustment of 1.5 to 2.0 percentage points to the historic U.S. equity risk premium.

While Copeland, Koller and Murrin adjust the U.S. historic market risk premium by 1.5 to 2.0 percentage points for survivorship bias, based on their interpretation of the Goetzmann and Jorion analysis, the authors of the analysis themselves estimated survivorship biases in the range of 25 to 70 basis points (Philippe Jorion and William N. Goetzmann, "Global Stock Markets in the Twentieth Century", Journal of Finance, June 1999, pp. 953-979).

In Ms. McShane's view, the very relevance of the survivorship bias argument must be questioned in the context of a North American equity market analysis. Essentially, what the survivorship bias argument is saying is that the past returns in the U.S. must be discounted because they don't reflect the impact (or "risks") of catastrophic events that lead to economic upheaval. While there are likely to be future circumstances of economic or capital market instability in North America (such as the global capital market crisis of 1998), the risks of major upheaval are relative minor compared to many other countries.

Thus, the need to make a survivorship adjustment to U.S. data is questionable in principle; additionally, it would be applicable only to the U.S. market data. As indicated in Tab 2, Schedule 8, Canadian equity market returns have lagged U.S. returns by 1% on both a geometric and arithmetic average basis. Since the lower Canadian returns are given the preponderance of the weight in Ms. McShane's estimated the equity market risk premium, there is no need to make an adjustment for survivorship bias, since, implicitly, the relative weightings act as a discount to the U.S. data.

71.0 Reference: Application, Tab 2, p. 75

71.1 Please explain further why the time period 1993-2004 was selected so as to be subsequent to Open Access implemented via FERC Order 636.

<u>Response:</u>

The Federal Energy Regulatory Commission (FERC) instituted Order 636 in 1992. The Order required pipeline operators to unbundle transportation and storage services, and provide open access to their distribution networks. As a result distribution companies took over the merchant function previously provided by pipelines. Order 636 represented a fundamental change in natural gas distribution operations and, therefore, data prior to the Order may not be strictly comparable to subsequent data.

71.2 What was the impact of Open Access on utility risk and how did that affect the cost of equity compared to the period prior to FERC Order 636?

<u>Response:</u>

The transfer of the merchant function to the distributors represents an increase in risk. All other things equal, the cost of equity would increase; however, the industry change coincides with a period of declining interest rates, which would make it difficult to segregate the two effects. That fact is further support for beginning the analysis in 1993.

71.3 Please provide the data in a working copy of the DCF model used.

<u>Response:</u>

The data are provided in response to BCUC IR NO. 1, 76.1.

71.4 *Please summarize the commonly understood limitations of the DCF model with respect to model inputs and explain the degree to which your analysis overcomes these limitations.*

Response:

The limitations of the DCF model with respect to inputs center on whether the growth component used in the model represents a valid estimate of investors' growth expectations. I have mitigated that limitation in the direct application of the DCF test by:

(1) Using a sample of sufficient size to avoid "measurement error". The larger the sample, the more confidence the analyst has that the sample results are representative of the cost of equity. As noted in a widely utilized finance textbook:

> Remember, [a company's] cost of equity is not its personal property. In well-functioning capital markets investors capitalize the dividends of all securities in [the company's] risk class at exactly the same rate. But any estimate of [the cost of equity] for a single common stock is noisy and subject to error. <u>Good practice does not put too much weight on single-company cost-of-equity estimates. It collects samples of similar companies, estimates [the cost of equity] for each, and takes an average. The average gives a more reliable benchmark for decision making</u>. (Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance, Sixth Edition, Boston, MA: Irwin McGraw Hill, 2000, p. 69 (emphasis added)).

(2) Using various measures of growth;

(3) Using both constant growth and two-stage models; and,

(4) Testing the growth rates for systematic bias.

71.5 *Please provide data and analysis for the period 1947-2004 in a working copy of the model. If data is not available from 1947 please provide the data and analysis to the earliest subsequent period.*

Response:

Please see Appendix 71.5. Complete data are only available from December 1985. Inclusion of the 1985 to 1992 data does not produce any meaningful results.

The equation found at lines 2103-2105 of Tab 2, when derived using data back to 1985 is:

Equity Risk Premium = 4.8379 - 0.079 (30-Year Treasury yield)

t-statistic = -2.08

R2 = 1.9%

72.0 Reference: Application, Tab 2, p. 76

72.1 On what basis does the testimony conclude that "First, there are an insufficient number of forward-looking estimates of long-term growth rates for Canadian utilities that would permit the creation of a consistent series of DCF costs of equity and corresponding risk premiums from Canadian data."

Response:

Appendix 72.1 contains the history of the I/B/E/S consensus forecasts of long-term growth for the six publicly traded Canadian utilities on Schedule 12. The file shows that there has been at most one analyst's long-term forecast for Canadian Utilities from 1993-2004, and at most two forecasts for Emera. For Terasen, there have recently been three, but none until 1999. Fortis has recently had two, but virtually none prior to 1998.

72.2 Please provide all available forward-looking estimates of long-term growth rates for Canadian utilities, including for those utilities listed in Schedule 12 if available.

Response:

Please see response to BCUC IR No. 1, 72.1.

72.3 Please compare and discuss the implications of the general differences in the beta estimates of the LDCs in the DCF model sample summarized in Schedule 17 to the beta estimates of the Canadian utilities summarized in Schedules 12 and 14.

Response:

The betas on Schedules 17 and 18 represent the betas reported by *Value Line*. These betas are calculated using weekly prices and the NYSE Composite Index and then adjusted using the formula 0.35 (market mean of 1.0) + 0.67 (company "raw" beta).

If, instead, the betas were calculated in a manner similar to the Canadian utility betas, that is, on the basis of monthly prices, and in relation to the S&P 500, the raw betas would be very similar to the Canadian utility betas found on Schedule 11.

Please see Appendix 72.3.

72.4 On what basis does the testimony conclude that "Fourth, the selected U.S. LDCs are of relatively low business risk, on average, of a similar level to that of an average risk investor-owned Canadian utility." Please provide any data or analysis that supports this statement.

Response:

As indicated on Schedule 17 the average S&P business profile score is "3", similar to those assigned to Canadian utilities. The average S&P debt rating is A+, higher than the typical debt ratings for Canadian utilities by either DBRS or S&P. The betas, when calculated in a similar manner are also close.

73.0 Reference: Application, Tab 2, p. 76
DCF-Based Equity Risk Premium Test

On Tab 2, page 76 Ms. McShane states: "…U.S. and Canadian utilities are reasonable proxies for one another, particularly in today's global capital market."

73.1 The following passages are from Stowe, Robinson, Pinto and Mcleavey, "Analysis of Equity Investment Valuation", 2002, p. 237.

"Clearly, to perform a relative value analysis, an analyst must use comparable companies and underlying financial data prepared using comparable methods. Using relative valuation methods in an international setting is difficult. Comparing companies across borders frequently involves accounting differences, cultural differences, economic differences, and resulting differences in risk and growth opportunities."

"Although international accounting standards are beginning to converge, significant differences across borders still exist, making comparisons difficult. Even if harmonization of accounting principles is achieved, the need to adjust accounting data for comparability will always remain."

73.1.1 How has Ms. McShane addressed the challenges outlined in the passages above?

Response:

The comments referenced span all countries. The differences between Canadian and U.S. capital markets and the economy do not lead to a level of difficulty in evaluation and comparison that requires a significant challenge.

73.1.2 Would these comparability challenges affect the Equity Risk Premium Test, DCF-based Risk Premium Test and Comparable Earnings Test that rely on U.S. data?

Response:

Ms. McShane does not believe that the differences between Canada and the U.S. are material enough to create challenges to the application of the tests using U.S. data.

74.0 Reference: Application, Tab 2, pp. 77-78

74.1 Please provide support for the statement that "the DCF test has traditionally been the principal model relied on by U.S. regulators".

Response:

Support for this statement is found in the attached article "In Defense of the 'Gold Standard'" published in *Public Utilities Fortnightly* in May 2003. In the article, the author concludes that "it is hard to foresee abandoning the DCF as the gold standard relied upon so heavily by U.S. commissions and utilities for the past couple of decades. Please see Appendix 74.1

74.2 Please elaborate on how the conclusion that "the allowed returns should not in aggregate represent either an upwardly or downwardly biased measure of the utility cost of equity" follows from the premise that "different analysts and regulators rely on different DCF models and measures of growth expectations".

Response:

Investment analysts' growth forecasts have been criticized for being too optimistic. However, when U.S. regulators set allowed returns based on the DCF model, they do not necessarily focus on these forecasts in deciding what the appropriate growth component is. Rather, they may rely on historic growth rates in determining what the best estimate of investors' growth is. Reliance on historic growth in recent years as a measure of investors' long-term expectations would tend to underestimate investor expectations.

When the DCF cost of equity estimates are based on a broad range of growth estimates – as regulators' decisions are likely to reflect (comprising a range of inputs from cost of capital experts), there is no reason to believe that the aggregate results would entail upwardly biased estimates of growth.

74.3 The testimony compares the results of the DCF-based risk premium model from 1993-2004 to the average allowed return for U.S gas LDCs from 1993-2004. Please provide an estimate of the actual returns for U.S gas LDCs from 1993-2004.

Response:

The actual returns for the consolidated operations of the LDCs are contained in Appendix 74.3.

75.0 Reference: Application, Tab 2, p. 78

75.1 Please provide a copy of the report by Regulatory Research Associates: Regulatory Focus: Major Rate Case Decisions, January 1990 to December 2004.

Response:

Please see the summary pages of the source documents in Appendix 75.1. The report itself is a proprietary document and the underlying data are not to be copied and distributed.

76.0 Reference: Application, Tab 2, pp. 78-79

For each of the regression results presented on pages 78 and 79:

76.1 Please provide the data and sources.

Response:

76.1 The requested information is found in Appendix 76.1. The monthly price data for the LDCs is from Standard& Poor's Research Insight. The long term treasury series is from the Federal Reserve and is consistent with that presented in Tab 2, Schedule 7, page 1 of 2. The Moody's data is Moody's Credit Perspectives.

76.2 Please provide a plot of the data.

Response:

Please see Appendix 76.2.

76.3 Please provide a plot of the residuals against the independent variables and a plot of the residuals against time.

Response:

Please see Appendix 76.3.

76.4 Please provide a simple linear regression of the LDC Risk Premium against the Spread variable. Please include data plots of the nature requested in the 2 questions immediately above.

Response:

Please see Appendix 76.4.

76.5 Please provide the source data for the 120 basis point spread referred to in line 2133 on page 79.

Response:

Please see Appendix 76.5

76.6 Please show the calculation for the indicated utility risk premium of 4.3 % referred to in line 2135 on page 79.

Response:

The calculation underlying the 4.3% is as follows: 4.3 = 5.3 -.37 x 5.25 + .81 x 1.2

77.0 Reference: Application, Tab 2, pp. 85-87

77.1 How is "Canadian benchmark utility" defined in the context of selecting a sample of relatively low risk U.S. gas and electric utilities as a proxy for it in the DCF model?

Response:

The definition of a Canadian benchmark utility is the same as set forth in Section II. The selection of the low risk U.S. utilities was intended to produce a sample that serves as a proxy for the low risk Canadian benchmark utility as defined in Section II.

77.2 Please confirm that the sample of low risk U.S. gas and electric utilities referred to on page 85 are those listed in Schedules 19-21.

Response:

It is confirmed.

77.3 Please compare and discuss the implications of the general differences in the beta estimates of the LDCs in the DCF model sample summarized in Schedule 19 to the beta estimates of the Canadian utilities summarized in Schedules 12 and 14.

Response:

Please see response to BCUC IR No. 1, 72.3.

77.4 Please provide the I/B/E/S and Value Line growth forecasts used as the basis for the growth forecasts in Schedules 20 and 21.

Response:

The I/B/E/S growth rates are directly downloaded into Excel from a proprietary data base. The data base provides only the consensus growth rate for each company, i.e., the value that appears in the growth column on Schedule 20.

The *Value Line* growth forecast is also the single value for each company that appears on Schedule 21.

78.0 Reference: Application, Tab 2, p. 88

The testimony reports the results of the constant growth and two-stage DCF models, taking as an average of the two a "bare-bones" return on equity of approximately 9.25%.

78.1 In your view, which model is more applicable in the context of TGI and its Application, and why?

<u>Response:</u>

In Ms. McShane's opinion both have equal value; the DCF model comprises cash flows expected, in theory, into perpetuity, while the forecasts of growth are only for five-years. Thus, a two-stage, or multiple-stage, model recognizes that growth is likely to change over the life of the security, trending to an equilibrium level in the long-run. On the other hand, investors may not forecast beyond five years, thus implicitly building in an unchanged (from the five-year forecast) growth rate in pricing equities.

79.0 Reference: Application, Tab 2, p. 89

The testimony says:

> *In principle, for a market-derived cost of equity to produce a return compatible with the premise that regulation is a surrogate for competition, the cost of equity should be adjusted to reflect the replacement cost/book value ratio.*

79.1 Please report on whether any Canadian regulatory boards have adopted this principle beyond allowing for a financial flexibility premium. Please provide decision references as applicable.

Response:

Ms. McShane is not aware of any Canadian regulator who has either considered or adopted this principle.

80.0 Reference: Application Tab 2, p. 89 The DCF Test and the Fair Return on Equity

The testimony of Kathleen McShane states that there have been moderate to relatively high levels of inflation over the past two business cycles.

80.1 Please describe in detail the time periods of the two business cycles and the average annual inflation rates during those two periods.

Response:

Business cycles can be measured from peak-to-peak, trough-to-trough, or point-to-point. The last two rough-to-trough cycles were approximately 1983-1999 and 1992-2001, where 2001 represents the most recent business cycle downturn.

Alternatively, the most recent point-to-point cycle would be approximately 1993-2004, reflecting an “upswing” to “upswing”; the corresponding prior cycle would comprise approximately 1985-1992.

The average rates of inflation over these cycles were:

	CPI	GDP Deflator
1983-1991	4.3%	3.6%
1992-2001	1.6	1.4
1985-1992	4.1	3.4
1993-2004	1.8	1.8

81.0 Reference: Application, Tab 2, p. 90

81.1 Please discuss what you understand to be the limitations of the Comparable Earnings test and how your analysis accounts for these limitations, if at all.

Response:

Ms. McShane considers the limitations of the comparable earnings test to be primarily that there are judgments that need to be made in the selection of comparables, the determination of whether the resulting sample is comparable to a benchmark low risk utility, the selection of time period over which the earnings are measured, and whether the reported accounting earnings are an accurate representation of the “true” earnings of the companies.

Ms. McShane has dealt with the application issues as follows:

(a) In the selection, she has focused on selection criteria that are independent measures of risk (e.g., debt ratings). She has eliminated companies whose returns might be viewed as “too high”, and thus indicative of market power. She has selected a large sample of low risk U.S. industrials as a check, given the relatively small number of Canadian companies;

(b) With respect to whether the samples are of comparable risk, she has compared the relative risk measures of both the utilities and industrials, and recommended a focus on the lower end of the range of the industrials’ returns for purposes of establishing a fair return for a benchmark low risk utility. The focus on the lower end is a conservative recognition that the utilities and industrials may not be viewed as having precisely the same level of risk;

(c) With respect to the period chosen, Ms. McShane has ensured that the returns were measured over an entire business cycle, ensured that the major economic indicators during that cycle that would be key to levels of future profitability (inflation, economic growth) were similar to what is forecast over the next cycle; and considered the trends in the returns of the samples over the past cycle to ensure that the cycle average returns are a good proxy for the future; and,

(d) With respect to accounting returns, while it is possible for management to manage reported earnings, a focus on dividend-paying stocks (dividends can only be paid out of earnings), and a cycle average level, these potential application issues are mitigated. Further, by focusing on median values for the sample (rather than the mean), and by eliminating high earners, the impact of any outliers on the measured returns of the sample is mitigated.

81.2 Please discuss the findings of Canadian regulatory boards in recent ROE and capital structure decisions on the applicability of the Comparable Earnings test in a Canadian context.

Response:

The two recent decisions of Canadian regulators in which the comparable earnings test is discussed are referenced in response to BCUC IR NO. 1, 36.2. In Decision RP-2002-0158, the OEB decided the comparable earnings test should be given little or no weight. The EUB placed no weight on the comparable earnings test.

82.0 Reference: Application, Tab 2, p. 94; Appendix D; Statistical Exhibits, Schedule 23

The testimony says that "to recognize the industrials' marginally higher risk, the comparable earnings test, applied to a benchmark Canadian utility, should be interpreted as indicating a return of no less than 13.0%."

82.1 Does this statement suggest an unlikely level of precision in the comparable earnings test when considering, for example, the sample screening process, the assessment of comparative risks on balance across Canadian industrials, and the averaging of returns across the sample? Why or why not?

Response:

No. The referenced sentence needs to be considered in conjunction with page 94, lines 2528-2530, where it is stated that the returns of the low risk industrials were in the range of 13.0-13.5%. An alternative way of stating the conclusion would be that the comparable earnings test, applied to a benchmark Canadian utility, lies at the lower end of the range of 13.0-13.5%. Placing the return at the lower end of the range recognizes that the utilities may be viewed as marginally lower risk than the industrials.

82.2 If the results need to be assessed in this light, how comparable is the sample to begin with? For example, please contrast this view with the statement on page 1 in Appendix D that "the comparable earnings test is based on the premise that industrials' higher business risks are offset by a more conservative capital structure"?

Response:

Please see response to BCUC IR No. 1, 82.1.

82.3 Please expand upon the premise that industrials' higher business risks are offset by a more conservative capital structure by comparing the relatively high equity ratios (average 66.1%) of the industrials listed in Schedule 23 in the context of the DBRS ratings reported in the same table. How should the comparability of industrials with debt ratings of A(-)/A(low) or higher and equity ratios greater than 40% in nearly all instances be interpreted in this context?

Response:

Total risk is a function of both business and financial risk. One proxy for financial risk is the capital structure. The higher the debt ratio, the higher the financial risk. The fact that the industrials are able to achieve debt ratings – which reflect both business and financial risk – in the same rating category as the utilities is evidence that the industrials' higher business risks are offset by their lower financial risks.

83.0 Reference: Application, Tab 2, p. 98

The testimony says that:

> *Unfortunately, it is the 100% sliding scale at low levels of interest rates rather than the 80% sliding scale at higher (above 6%) levels of interest rates that is more likely to result in inadequate returns and capital attraction difficulties.*

83.1 Please document any evidence that demonstrates that the 100% sliding scale at low levels of interest rates has resulted in capital attraction difficulties.

Response:

While there is no evidence that, to date, the 100% sliding scale has resulted in capital attraction difficulties, the results of the formula have already been highlighted as being low relative to the BC utilities' peers' (see the DBRS report for Terasen Gas filed in response to BCUC IR No. 1, 58.1). If interest rates are lower than those used late last year to determine ROE for 2005,, the 100% sliding scale will pressure coverage ratios and ratings. Moreover, as interest rates increasingly decline below 6%, the competitive disadvantage of the B.C. utilities relative to their peers becomes more pronounced. To illustrate, at a 6% long Canada yield, the benchmark low risk utility return in B.C. is 9.50%; the generic cost of capital ROE in Alberta is 9.84%, a gap of 34 basis points in favour of the Alberta utilities. At a 4% long Canada yield, the corresponding allowed ROE's are 7.5% and 8.34%, a gap of 84 basis points in favour of the Alberta utilities. Further, there is no offsetting advantage to the B.C. utilities as interest rates rise. At an 8% long Canada yield, the B.C. low risk utility benchmark return is 11.1%, compared to the generic cost of capital ROE of 11.34% in Alberta, 24 basis points in favour of the Alberta utilities. In sum, not only are the B.C. utilities disadvantaged at all levels of interest rates, they are increasingly at a competitive disadvantage for capital as interest rates fall.

84.0 Reference: Application, Tab 2, pp. 97-100

The testimony points to the linear relationship between the utility DCF cost of equity and long-term government bond yields as implying that the utility cost of equity is less sensitive to changes in government bond yields than implied by the Commission's current automatic adjustment formula.

84.1 Based on the results of the regression presented in Section IV.C.4.b, to what degree are you satisfied that the linear model is the best fit of the data generally, and in particular at low levels of interest rates?

Response:

Based on tests using other models (see response to BCUC IR No. 1, 84.3), Ms. McShane believes the linear model is as good as the others tested. Please note that the time period over which the analysis was conducted was one of relatively low interest rates.

84.2 Please comment on the relevance of the DCF model results with two independent variables in the context of the testimony on the sliding scale.

Response:

The automatic adjustment formulas that are currently in use in Canada are based on changes in a single variable, the long Canada yield. However, there are factors other than the long Canada yield that actually explain changes in the cost of equity. Accounting for them in the analysis, as was done with the utility bond spread, helps establish more accurately what the relationship between long Canada's and the utility risk premium is.

84.3 Please provide additional regressions to demonstrate the sensitivity of your conclusions to a non-linear relationship between the utility DCF cost of equity and long-term government bond yields.

Response:

Ms. McShane tested both a hyperbola and a parabola.

The equations for the hyperbola were:

ERP = $0.16 + 23.99 \left(\frac{1}{TY}\right)$

4.7% = $0.16 + 23.99 \left(\frac{1}{5.25\%}\right)$

t-statistic = 11.2%

R^2 = 47%

ERP = $0.68 + 13.84 \left(\frac{1}{TY}\right)$ + .82 (spread)

4.3% = $0.68 + 13.84 \left(\frac{1}{5.25\%}\right)$ + .82 (1.2%)

t-statistics = 7.2% 10.1%

R^2 = 69%

The equations for the parabola were:

ERP = 9.01 – 0.93 (TY) + 0.02 (TY^2)

4.7% = 9.01 + 0.93 (5.25%) + 0.02 ($5.25\%^2$)

t-statistics = -1.14 0.33

R^2 = 48%

ERP = 9.48 – 1.78 (TY) + 0.11 (TY^2) + .84 (spread)

4.3% = 9.48 - 1.78 (5.25%) + 0.11 ($5.25\%^2$) + .84 (1.2%)

t-statistics = -2.80 2.23 9.90

R^2 = 69%

The predicted values and regression statistics are not materially different from the linear models.

84.4 Please provide a summary of the market to book ratios for TGI from 1999 to the present and a corresponding summary of interest rates over the same period.

Response:

Please see Appendix 84.4.

84.5 Please provide all data and working DCF models for the analysis discussed in the four questions immediately above.

Response:

The requested information can be found in Appendix 84.5

85.0 Reference: Application Tab 2, Appendix A; Statistical Exhibits, Schedule 5

For the utilities listed on page 2 of Schedule 5 please provide a table showing the equity thickness for each year beginning in 1998.

Response:

The history of the allowed equity ratios is as follows:

AltaLink: set at 34% for 2003; increased to 35% for 2005

ATCO Electric:

Transmission: set in 2004 generic cost of capital decision for

2004-2005 at 33% plus 6% preferred shares; first stand-alone decision set for 2003 at 32%

Distribution: set in 2004 generic cost of capital decision for

2004-2005 at 37% plus 6.9% preferred shares; first stand-alone decision set for 2003 at 35%

FortisAlberta: 40% for 2001-2003; set at 37% for 2004 and 2005

FortisBC: settled at 40% in 1995; 40% confirmed in 2005

Newfoundland Power: cap set at 45% in 1998 and reconfirmed in 2003; also has 1.4% preferred shares

Nova Scotia Power: 2002: set at 35% (with permission to move up to 40%), plus 9.2% preferred shares

2005: set at 37.5% (reiterated permission to move up to 40%), plus 9.2% preferred shares

<u>Gas Distributors</u>

ATCO Gas: 37% for 2001-2004; 38% set in generic cost of capital

decision for 2005, plus 6.9% preferred shares

Enbridge Gas: has been 35% for at least 10 years, plus approximately 3-4% preferred shares

Gaz Metro: has been 38.5% since at least 1999, plus 9.5% preferred shares

Pacific Northern Gas: has been 36% since at least 1999, plus 3.7% preferred shares.

Terasen Gas:	has been 33% since at least 1994. TGI's regulated capital structure formerly had 7.3% preferred shares which were redeemed as a result of the 1998-2000 negotiated settlement
Union Gas:	has been 35% since at least 1999, plus approximately 3-4% of preferred shares

Gas Pipelines

Alberta Natural Gas:	set at 30% in 1995
Foothills:	set at 30% in 1995
TransCanada Pipelines:	set at 30% in 1995, plus 9.1% of preferred share, increased to 33% in 2002 and to 36% in 2005
TransQuebec & Maritimes:	set at 30% in 1995
Westcoast Energy:	35% for combined mainline and processing plants in 1995; 30% for mainline between 1998 and 2003; settled at 31% for 2004 and 2005

86.0 Reference: Application Tab 2, Appendix A; Statistical Exhibits, Schedule 10

The testimony of Kathleen McShane gives the example that the Commission's current formula, which for interest rates below 6%, changes the allowed ROE by 100% of the change in long Canada yields. This formula is premised on perfect correlation between the required equity return and the risk-free rate.

86.1 Would the removal of the assumption of perfect correlation between the return on the market and the risk-free rate in the formula remove this disadvantage of CAPM?

Response:

The CAPM assumes that there is no correlation between the risk-free rate and the market return, while the Commission's formula at interest rates below 6% assumes perfect (1 to 1) correlation. The disadvantage in the CAPM lies in trying to apply it while simultaneously being faithful to that assumption. There is a tendency to think of the CAPM as:

Equity Return Stock = Risk-Free Rate + Beta (Market Risk Premium)

Thus, the typical application of the CAPM adds the risk-free rate to an estimated long-run average market risk premium. This approach effectively causes the CAPM result to be highly correlated with the risk-free rate. As a result, the typical application of the CAPM violates the zero correlation assumption.

A more precise statement of the CAPM formula is:

Equity Return Stock = Risk-Free Rate + Beta (Equity Return Market – Risk-Free Rate)

If the CAPM were applied in this manner, that is, the expected market return, rather than the market risk premium, is estimated, the violation of the assumption of zero correlation can theoretically be avoided, since the expected market return can be determined independent of the risk-free rate.

Removing the assumption of perfect correlation by applying the CAPM in this manner mitigates somewhat this disadvantage of the CAPM; the problem remains, however, in trying to estimate the market return at a given point in time without relying on the risk-free rate as the point of departure.

86.2 The testimony states that long-term government bond yields are not risk-free because they are subject to interest rate risk. Please comment on the extent that the equity market in general, and the utility shares in particular, are sensitive to interest rate risk.

Response:

The market in general is sensitive to interest rates; different sectors of the market will exhibit different sensitivities depending in large part on how much exposure their profitability has to interest rate changes. Utilities and financials are particularly sensitive to interest rate changes (see, for example, Tab 2, lines 1907 to 1923).

86.3 Please explain if the countercyclical commodities (e.g., gold) have been removed from the regression analyses used to produce the coefficients on beta as shown in Table A-1 and Table A-2.

Response:

No, they were not removed.

86.3.1 What are the standard errors for the coefficients on beta as shown in Table A-1 and Table A-2.

Response:

The standard errors for the individual Sector betas and the standard errors for the beta coefficients of the regression between the Sector betas and the sector returns can be found in Appendix 86.3.1.

86.4 Please explain why all the as for the 10 sectors in the S&P/TSX for different periods are positive (Tab 2, Schedule 10) whereas the betas for the S&P/TSX are negative.

Response:

The betas in Schedule 10 reflect the covariance between the individual sectors and the market. The betas are positive, because in each case, the sector moved in the same direction as the market. The coefficients in Tables A-1 and A-2 represent the relationship between the betas of the individual sectors and their corresponding returns. Tables A-1 and A-2 indicate that there is no relationship between the level of the betas of the sectors (i.e., those shown on Schedule 10) and the sector returns, also shown on Schedule 10.

86.4.1 Please provide the standard errors of betas in the table.

Response:

Please see Appendix 86.3.1

87.0 Reference: Application, Tab 2, Appendix A, pp. 8-9; Use of Arithmetic Averages to Estimate the Equity Market Risk Premium

On Tab 2, Appendix A, page 9 Ms. McShane states:

> *"The graphs for both Canada and the U.S. suggest that each year's actual risk premium has been random, that is not serially correlated with the preceding year's risk premium."*

87.1 Is Ms. McShane aware of the Fama and French 1988 study "Permanent and Temporary Components of Stock Prices", Journal of Political Economy 96, pp. 246-273 which found mean reversion (negative serial correlation) in stock market prices at longer horizons? Please comment on the finding. If available, please provide a copy of this Fama and French study.

<u>Response:</u>

Yes. A summary of the findings is as follows:

(a) The data series tested was over the 1926-85 period; Fama and French state that sub-period results indicate that the strong negative correlation may be largely due to the first fifteen years.

(b) Fama and French conclude that the stock price behavior has a random component and a predictable component. The autocorrelations become negative at two-year horizons, reach minimum-values at 3-5 year horizons, then move back toward zero for longer-term horizons. The results of the statistical analysis suggest that the random component of stock returns dominate at short term horizons, and begin to dominate again as the horizon lengthens.

In interpreting this article and its implications for estimating the equity risk premium, the results suggest that early years of data – years not included in Ms. McShane's analysis – may be largely responsible for the empirical findings. Further, it also suggests that at the longest horizons, autocorrelation is near 0.0 (i.e., returns year-to-year are random) supporting reliance on the arithmetic average to estimate the future risk premium.

The Fama and French analysis focused on the market equity return; Ms. McShane tested the year-to-year risk premiums for serial correlation (i.e., autocorrelation), and found that it was minimal (see page 9 of Appendix A).

A copy of the requested article is attached as Appendix 87.1.

87.2 Is Ms. McShane aware of the paper from James Poterba and Lawrence Summers "Mean Reversion in Stock Prices", Journal of Financial Economics, Vol. 22, pp. 27-59, (1988)? If available, please provide of copy of this Poterba and Summers paper. If the variance for the long-horizon is lower than the short-horizon when compared to the random walk assumption, would this imply that the annual arithmetic mean would overstate the return for the long-horizon?

Response:

Yes, Ms. McShane is aware of the paper. A copy is attached as Appendix 87.2. Ms. McShane accepts that equity market returns may not follow a pure random walk, since demographic changes and business cycles are likely to produce patterns in returns (up and down), which can lead to the longer-term variances being lower than predicted by a pure random walk. She does not accept, however, that the findings in this, or other studies, leads to abandoning the arithmetic average as the principal means of estimating the expected value of the equity risk premium.

The Poterba and Summers paper reports their analysis for mean reversion of stock prices. As part of their analysis, they look at variance ratios, which compared the actual variance over certain investment periods to what the variance is predicted to be if the returns followed a random walk. The results of the analysis suggested mean reversion, that is, the actual variance in returns over the investment horizons was less than that predicted by a pure random walk. In other words, the study suggested high returns tend to be followed by low returns.

The findings of Poterba and Summers are part of the body of evidence on mean reversion, which, as indicated in response to BCUC IR No. 1, 87.4, remains controversial. Like the Fama French study, the authors report a significant impact of the first ten years of the data. Given the statistical frailty of the findings, the fact that others have come to opposing conclusions, and the suggestion of "mean reversion" *per se* does not tell us how long mean reversion will take or to what level returns may revert, the paper itself does not lead to the conclusion that the arithmetic average overstates the expected value for the long-term horizon.

Further, investors may have capital committed over the long-term, but they will constantly be evaluating to what alternatives they should allocate funds, with their decisions based on relatively short-term considerations. For example, in a market upswing, investors are likely to reallocate funds from defensive to growth stocks, or from fixed income securities to equities. In that context, the expected value of returns over a short-term horizon is key.

Thus, the arithmetic average remains the superior input into the estimation of the risk premium. Unlike the geometric average, the arithmetic average incorporates compensation for risk, i.e., the high probability that the investor's actual return will differ from the expected value. Please note that the fact that Ms. McShane gave preponderant weight to the arithmetic average does not mean that geometric averages were not also taken into account.

87.3 If the stock markets were mean reverting over a longer period could this mean that periods of relatively high returns are followed by periods of relatively low returns and vice versa? Please elaborate and its implications to the risk premium.

Response:

Yes, if stocks are mean reverting, periods of high returns are likely to be followed by periods of low returns. A pattern of high and low returns is consistent with the existence of economic cycles, and with changes in demographics, with their corresponding savings/spending patterns.

However, the term mean reversion does not mean that returns will trend toward a particular value, simply that high returns will be followed by low returns and vice versa. First, there is uncertainty what the true long-term mean of returns is. There is also uncertainty whether there is a long-term average return (as contrasted with a time-varying average), since changes in demographics and investor behavior can alter expected and actual returns. Moreover, there is uncertainty regarding how long and at what level high and low returns will persist, and whether an investor, given his investment horizon, will achieve the expected return.

87.4 If negative serial correlation is present on stock returns would this indicate that the arithmetic average would overstate the premium?

Response:

If there is compelling evidence that there is a high degree serial correlation that allows the investor to better predict the expected value of his equity portfolio, the arithmetic average would overstate the expected value of equity market returns. The response to BCUC IR No. 1, 87.1 indicates that the evidence of Fama and French does not rise to that level. The existence of mean reversion in equity returns is still contradictory, and the empirical evidence relatively weak. Ibbotson Associates, "*Stocks, Bonds, Bills and Inflation, Valuation Edition, 2005 Yearbook*", reports that the serial correlation on Large Company Stock Total Returns is 0.03, to which they assigned the interpretation "Random".

87.5 If returns are not normal independently and identically distributed would the arithmetic average be appropriate?

Response:

Sole reliance on the arithmetic average is premised on the returns being IID. Tests for serial correlation are tests to determine if the returns are IID. Please see response to BCUC IR No. 1, 87.4 for a discussion of serial correlation.

88.0 Reference: Application, Appendix D

88.1 Please provide the data used to screen the sample of Canadian industrials under each criteria.

Response:

Please see Appendix 88.1.

88.2 Please provide the average return on equity at each step in the screening process of comparable Canadian industrials. So for example, report the initial average ROE of the sample and then report the average at each step where the sample is paired down. Please report multiple changes at each step separately as applicable; for example, the plus 1 standard deviation and minus 1 standard deviation criteria.

Response:

Please see Appendix 88.1.

88.3 Please answer the two questions immediately above for the selection of U.S. industrials.

Response:

Please see Appendix 88.3.

89.0 Reference: Application, Tab 2, Statistical Exhibits, Schedule 14 Regulated Canadian Utilities

89.1 Please list all the other publicly traded Canadian Utilities not shown in Schedule 14.

Response:

The only other publicly-traded Canadian utility is Pacific Northern Gas.

89.2 Please provide for these other Canadian Utilities data similar in format to Schedules 14, 23, and 24.

Response:

The requested data for Schedules 23 and 24 are included in the response to BCUC IR NO. 1, 90.4.

90.0 Reference: Application, Tab 2, Appendix D, pp. 1-2;
Application, Tab 2, Statistical Exhibits, Schedules 23 and 24
Selection of Canadian Industrials

On Tab 2, page 17 Ms. McShane states:

> *"The selection process starts with the recognition that industrials are generally exposed to higher business risk, but lower financial risk, than an average risk Canadian utility."*

90.1 When applying the comparable earnings test why are Canadian industrials chosen as the first stock screen? Considering the relatively smaller number of companies in Canada than the U.S., would the first step of including all Canadian stocks be more appropriate?

Response:

The initial screening was limited to the GICs Codes indicated in Appendix D to eliminate sectors that are in a different risk class than utilities (e.g., high tech stocks, resource-based firms) and whose accounting practices render them dissimilar (financials). In that regard, it is neither necessary nor appropriate to begin with all firms or stocks.

90.2 Please explain the rationale why financials are excluded from your stock analysis? Would the inclusion of financials be appropriate in the comparable earnings test? How would the results change if Financials were included in the sample?

Response:

Financials are excluded primarily because they are capitalized in a totally different manner, and their earned returns on equity, which for banks is a very small component of the capitalization, would not be a useful proxy for utilities.

Appendix 90.2 provides the relevant data for the financial stocks currently included in the S&P/TSX Composite. The returns for the entire group of financials that might qualify for inclusion in the sample were:

	1993-2004
Average	13.4%
Median	14.2%
Average of Medians	15.0%

Since corresponding averages and medians of the selected sample were in the 13.0-13.5% range, inclusion of the returns for financials would produce a higher average return.

90.3 Schedule 23 and 24 shows the results of the screened 17 companies.

90.3.1 Please provide for each company the following historical data from 1993 to present: revenues, net income, earnings per share, dividends per share, price-earnings ratio, and price-book ratio. Split adjust the per share data, if required.

Response:

The requested data can be found in Appendix 90.3.1

90.3.2 For the 17 companies and Terasen Inc. please provide the present market capitalization.

Response:

The requested data can be found in Appendix 90.3.2

90.4 Please provide tables similar to Schedule 23 and 24 for all publicly traded utilities and pipelines in Canada including Terasen Inc.

Response:

The requested data are attached as Appendix 90.4. Please note that the data for PNG, as requested in BCUC IR NO. 1, 89.2 are included in this Appendix.

90.5 In the 1994 ROE hearing Dr. Sherwin and Ms. McShane applied the comparable earnings test to a sample of 26 companies which they judged to be of similar risk to low risk, high grade utilities.

90.5.1 Please provide the stock screen methodology used to select the 1994 sample of 26 companies. Please explain any differences from the past methodology to the current methodology.

Response:

The information in the selection methodology in the 1994 sample is included in response to response to BCUC IR No. 1, 90.5.2.

The major differences with the current selection are as follows:

In 1994, the initial screen was limited to companies within certain SIC codes. The identification system has since changed to GICS codes, so these are now being used, with the objective of covering the same industries.

Also in 1994, companies which paid no dividends over the period of analysis, or had cut their dividends more than 25% were eliminated. The dividend screen in this case is less stringent, eliminating companies that had zero dividends in any year during the period.

In 1994, the selection criteria included beta, market standard deviations, coefficients of variation of returns and coefficients of variation of earnings before interest and taxes. The latter two were criticized as being biased toward selecting high earnings firms, and have been replaced with independent criteria: betas, debt ratings, and stock rankings.

90.5.2 For these 26 companies also provide a copy of the schedules and information that was filed at that proceeding.

Response:

The requested information can be found in Appendix 90.5.2.

90.5.3 For these 26 companies (or successor companies) please provide current information on those companies similar to Schedules 23 and 24. For those companies that are no longer trading on the stock exchange please explain what happened to those companies.

Response:

The requested information can be found in Appendix 90.5.3.

90.5.4 In the 1994 sample which companies that are still trading but are not included in the 2005 sample? Please explain why.

Response:

The companies that are still trading and were in the 1994 sample but not the current sample, along with the reasons for their exclusion are:

Corby Distilleries	Excluded because ROE was more than one standard deviation above the sample average
Gendis	Is included in GICS 40 (Financials)
Imperial Oil	Is included in GICS 10 (Energy)
Northern Telecom	Is included in GICS 45 (Information Technology)
Rothman's	Excluded because ROE was more than one

	standard deviation above the sample average
Shell Canada	Is included in GICS 10 (Energy)

90.5.5 For companies in the 2005 sample that were not in the 1994 sample please explain why they did not make the 1994 sample.

Response:

Ms. McShane has not retained the 1994 workpapers required to make that analysis. A number of the companies in the 2005 sample did not have sufficient data in the database at that time (Empire, Linamar, Metro, TransContinental).

90.6 In the 1999 ROE hearing, Ms. McShane applied the comparable earnings test to a sample of 20 companies that she judged to be of similar risk to low risk, high grade utilities.

90.6.1 Please provide the stock screen methodology used to select the 1999 sample of 20 companies. Please explain any differences from the 1994 methodology to the 1999 and current methods.

Response:

Please see response to BCUC IR No. 1, 90.6.2. The sample selection methodology for the 1999 sample was the same as for the 1994 sample, so the same differences with the 2005 sample selection methodology apply.

90.6.2 For these 20 companies also provide a copy of the schedules and information that was filed at that proceeding.

Response:

The requested information can be found in Appendix 90.6.2.

90.6.3 For these 20 companies (or successor companies) please provide current information on those companies similar to Schedules 23 and 24. For those companies that are no longer trading on the stock exchange please explain what happened to those companies.

Response:

The requested information can be found in Appendix 90.6.3.

90.6.4 In the 1999 sample which companies that are still trading but are not included in the 2005 sample? Please explain why.

Response:

The companies that are still trading and were in the 1999 sample but not the current sample, along with the reasons for their exclusion are:

Andres Wines	Ranked “Higher Risk” by CBS
CCL Industries	Included in GICS 15 (Materials, which includes mining, forest products)
Corby Distilleries	Excluded because ROE was more than one standard deviation above the sample average
Dover Industries	No S&P, DBRS or CBS ratings
Imperial Oil	Is included in GICS 10 (Energy)
Shell Canada	Is included in GICS 10 (Energy)
Winpack	Ranked “Higher Risk” by CBS

90.6.5 For companies in the 2005 sample that were not in the 1999 sample please explain why they did not make the 1999 sample.

Response:

Ms. McShane has not retained the 1999 workpapers necessary to make that determination.

90.7 When screening for the sample industrial companies, please comment on the survivorship bias and its affect on ROE.

Response:

Survivorship bias refers to the potential for over-estimation of expected returns from past returns when the past returns used in the analysis are those of a market that has succeeded, e.g. experienced no extended trading interruptions due to such factors as war, or natural disasters.

In the context of the comparable earnings test, the purpose of the selection exercise is to arrive at a sample of low risk industrials whose returns exhibit relative stability; the purpose is not to measure the returns of the universe of companies. Hence, survivorship bias has no impact on the rates of return for this sample.

90.7.1 Has Ms. McShane corrected for survivorship bias in the 17 sample companies? If so, what is the survivorship correction? If not, please correct for survivorship bias and explain the methodology used.

Response:

A comparison of the earnings of the 1994, 1999 and 2005 samples does not indicate any survivorship bias.

90.7.2 Is Ms. McShane aware of a Copeland, Koller, and Murrin (2000) report that recommended a downward adjustment of 1.5 percent to 2.0 percent for survivorship bias in the S&P 500 Index, using arithmetic mean estimates? Please comment on that recommendation.

Response:

Yes. However, the reference in the question was to U.S. equity market returns in the context of measuring the equity market risk premium, not in the context of applying the comparable earnings test. Please see response to 90.7.1 for a discussion of survivorship bias.

91.0 Reference: Application, Tab 2, Appendix D, p. 3;
Application, Tab 2, Statistical Exhibits, Schedules 23 and 24
Relative Risk Comparison

On Tab 2, Appendix D, page 3 Ms. McShane states:

> *"Comparisons of the industrials' and utilities' bond ratings and stock ratings indicate that they are in a similar risk class."*
>
> *"The median adjusted betas for the industrials were 0.48 and 0.56 for the five year periods ending 2003 and 2004 respectively (see Schedule 23), compared to my estimate of the relative risk adjustment factor for a benchmark utility of 0.65."*
>
> *"The estimate of a normal cycle average level of returns for low risk Canadian industrials is in the approximate range of 13.0-13.5%. Since the level of investment risk faced by the industrials is marginally higher than that of an average risk benchmark Canadian utility, a fair return for the latter based on the comparable earnings test is no less than 13.0%."*

91.1 Larger sample sizes result in a more robust return estimate. What is the optimal sample to meet this objective? By having 17 companies in the sample what is the consequence of not meeting the optimal sample size. What is the standard deviation of the return on equity for the mean and median shown in Schedule 24?

<u>Response:</u>

The optimal sample size depends on the size of the universe. In the comparable earnings test, Ms. McShane is not performing a random sampling from a universe of low risk companies. Rather, she is selecting all of the companies that meet criteria designed to ensure that the companies are indeed low risk. The potential consequence of too small a sample of companies that are indeed low risk and comparable to a low risk benchmark would be to inaccurately estimate the mean returns of the low risk universe.

In assessing whether there are sufficient companies in the comparable earnings sample, it should be noted that the entire universe of publicly-traded utilities in Canada is six. Further, the deeper U.S. market allowed the selection of a much larger sample (188) of low risk companies, whose returns can be used as a check on the reasonableness of the Canadian sample results.

The standard deviation around the 1993-2004 average of the individual Canadian companies is 3.8%.

91.2 What is the 'average risk benchmark Canadian utility'? Is that the results from Schedule 11 or is it the theoretical benchmark utility? Please elaborate.

Response:

The word "average" should be "low", that is, it is the theoretical low risk benchmark utility.

91.3 Does Ms. McShane consider the stock screening methodology and the resulting 17 companies to be a representative sample of a typical low risk Canadian industrial stock without any bias on business risk or returns?

Response:

Yes.

92.0 Reference: Application, Statistical Exhibits, Schedule 3

S&P bond ratings appear to be generally lower than DBRS bond ratings for the major Canadian gas and electric utilities listed.

92.1 In your view, what explains this?

Response:

In its 1998 publication entitled "Credit Ratings in Canada: DBRS Ratings Compared to Other Rating Agencies", DBRS gave six reasons that its ratings tended to be higher those of S&P:

1) Less penalty for size.
2) Better knowledge of Canadian companies.
3) Treatment of the sovereign rating principle.
4) Technical factors treatment of holding companies.
5) Specific industry biases.
6) Unsolicited ratings not generally done by DBRS.

At the time of their report, DBRS placed its ratings at .23 rating categories higher for 115 common ratings, with the largest variance occurring in the natural resources area. In particular, it was determined that S&P rated the oils consistently lower than any other rating agency. In total, DBRS estimated that 79% of the total difference in the S&P and DBRS ratings is explained by rating variances in the natural resource area.

93.0 Reference: Application, Statistical Exhibits, Schedule 27

93.1 Please provide the monthly data behind Schedule 27, broken down by the six Canadian utilities listed.

Response:

Please see Appendix 93.1.

94.0 Reference: Application, Statistical Exhibits, Schedule 29

94.1 Please confirm whether the formula and resulting calculation in Step 2 of Theory 2 in Schedule 29 is correct. Please provide updated figures if the calculation is incorrect.

Response:

It is confirmed.

94.2 Please redo the analysis in Schedule 29 using TGI's current embedded long term cost of debt and the Commission's current benchmark low-risk ROE.

Response:

Using the 2005 approved embedded cost rate of 7.255% and the 2005 benchmark ROE of 9.03% at a 37.5% common equity ratio, the ROE at a 33% equity ratio would be:

Theory 1: 9.6%

Theory 2: 9.23%

If, instead of the embedded debt cost, the current cost of 6.35% (as per Schedule 29) were used, the results at a 33% common equity ratio would be:

Theory 1: 9.7%

Theory 2: 9.34%