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August 21, 2012

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. ("FEI")

Application for Approval for Approval of Rate Treatment of Expenditures under the Greenhouse Gas Reductions (Clean Energy) Regulation ("GGRR") and Prudency Review of Incentives under the 2010 – 2011 Commercial NGV Demonstration Program (the "Application")

Attached please find an Application by FEI to the British Columbia Utilities Commission ("BCUC" or the "Commission") seeking approval of the following:

- deferral accounts and the accounting and rate treatment methodology for the three prescribed undertakings established by the GGRR; and
- that past natural gas vehicle (NGV) incentive expenditures totaling $5.6 million (the "2010-2011 Incentives") were prudently incurred and can be recovered through rates from FEI's non-bypass natural gas customers.

This submission contains two parts. The first part, which is discussed in sections 3 through 6, pertains to the accounting and rate treatment methodology under the GGRR. The second part discussed in section 7 relates to the prudency of the 2010-2011 Incentives.

FEI proposes a Streamlined Review Process ("SRP") pursuant to Commission Order No. G-37-12 to review this Application. The use of the SRP is an appropriate path for this submission as the information and approvals sought related to accounting and rate recovery treatment of expenditures are generic in nature. Rate recovery applications are a common regulatory practice and well established by precedent, a consideration which favors the SRP. The expedited information flow under the SRP is also important, as FEI plans to execute contracts with successful applicants under its Natural Gas for Transportation Incentive Program before the end of October of 2012. Clarity on this Application is required before FEI will proceed with agreements for incentive awards. FEI respectfully requests a Commission decision on this Application within this timeframe.

Request for Confidentiality

FEI is providing the live spreadsheet model contained in Appendix Q on a confidential basis. The information contained in the live spreadsheet model results from the investment of considerable internal and external expertise and resources including time, effort and expense, in the development of these financial models on behalf of all rate-paying customers. The models were developed for FEI and are proprietary to FEI on behalf of customers. FEI is concerned that public disclosure and availability could allow others to use or adapt these complex models freely, at the expense of FEI's customers.

If you require further information or have any questions regarding this submission, please contact Shawn Hill at (604) 592-7840.

Yours very truly,

FORTISBC ENERGY INC.

Original signed by: Shawn Hill

For: Diane Roy

Attachments

cc (email only): Registered Parties to the following proceedings:

- FEI CNG-LNG Service Application
- FEU 2012-2013 RRA
- FEI EEC NGV Incentive Review
- AES Inquiry

FORTISBC ENERGY INC.

Application for Approval of Rate Treatment of Expenditures under the Greenhouse Gas Reductions (Clean Energy) Regulation, and

Prudency Review of Incentives under the 2010 – 2011 Commercial NGV Demonstration Program

Volume 1 - Application

August 21, 2012

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1 EXECUTIVE SUMMARY

This Application consists of two parts. The first part (Sections 3 through 6) addresses the recovery in natural gas rates of expenditures made under the Greenhouse Gas Reduction (Clean Energy) Regulation (the “GGRR” or the “Regulation). FortisBC Energy Inc. (“FEI”) is seeking prospective approval from the British Columbia Utilities Commission (“BCUC” or the “Commission”) for the manner in which the GGRR expenditures will be treated for regulatory accounting purposes and the resulting recovery in rates.

The second part (Section 7) describes how the $5.6 million for vehicle incentives provided in 2010 and 2011 as part of FEI’s Commercial Natural Gas Vehicle (“NGV”) Demonstration Program were prudently incurred and therefore recoverable through rates.

1.1 The Context of the Greenhouse Gas Reduction (Clean Energy) Regulation and the Clean Energy Act

Section 3 outlines the provincial and regulatory context of the GGRR and the legal framework that established the *Clean Energy Act* (“CEA”)[1], and Section 4 provides a description of the GGRR. On May 14, 2012 the government of British Columbia (the “government”) enacted the GGRR that signals the government’s desire to promote the use of natural gas as a transportation fuel.[2] The GGRR enables public utilities to pursue programs or expenditures that advance these objectives of the government for medium and heavy duty fleet vehicles, buses and marine vessels. The Regulation establishes three prescribed undertakings under section 18 of the CEA which, in summary, permit a public utility to:

1. provide grants or zero-interest loans (and related expenditures) of up to $62 million in total for the purchase of eligible vehicles[3] operating in British Columbia;
2. make expenditures of up to $12 million to own and operate Compressed Natural Gas (“CNG”) fueling stations and infrastructure; and
3. make expenditures of up to $30.5 million to own and operate Liquefied Natural Gas (“LNG”) fueling stations and infrastructure.

The Regulation is in effect until March 31, 2017, and sets out a number of requirements for each of the prescribed undertakings which are described in detail later in this Application. FEI has begun to develop natural gas for transportation (“NGT”) initiatives under the prescribed

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1 The Clean Energy Act is attached as Appendix V. Section 18 is the portion of the Clean Energy Act that is directly applicable to this Application, and is referenced as section 18 throughout the Application.

2 Please refer to Appendix A for the Government of British Columbia News Release and Appendix B for the Greenhouse Gas Reduction (Clean Energy) Regulation.

3 Eligible vehicles include new medium and heavy duty trucks, transit buses and school buses, as well as the retrofit of marine vehicles.

undertakings and intends to continue pursuing the beneficial programs and expenditures authorized for public utilities by the GGRR.

CEA sections 18 (2) and (3) set limits on the Commission's jurisdiction over prescribed undertaking expenditures by a public utility. CEA section 18 (2) requires the Commission to permit a public utility carrying out a prescribed undertaking to recover sufficient revenues to recover the costs of the prescribed undertaking. CEA section 18 (3) states that, "the commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking".

1.2 The Proposed Rate Recovery Treatment

The first objective of this Application as described in Section 5 is to establish the manner in which these prescribed undertaking expenditures will be recovered in natural gas rates within the constraints established by the GGRR and sections 18 (2) and (3) of the CEA. The accounting treatment accommodates the current period where the approved 2012 and 2013 Revenue Requirement Application ("RRA") has established rates for this period and future RRAs.

Section 6 of this Application describes FEI's proposed NGT Incentive and CNG/LNG fueling station programs that it will be undertaking as prescribed undertakings under the GGRR. The expected results of these initiatives are outlined in Appendix J.

1.3 Past Vehicle Incentives Provided in 2010 and 2011 are Prudent Expenditures

In Section 7 of the Application, FEI explains why the $5.6 million in incentives provided in 2010 and 2011 as part of FEI's Commercial NGV Demonstration Program were in the public interest, were prudent, and are in direct alignment with the incentives under Prescribed Undertaking 1 of the GGRR.[4] FEI proposes that the $5.6 million in expenditures be considered within the maximum limit of $62 million that is available under Prescribed Undertaking 1.

1.4 Streamlined Review Process

Commission Order No. G-37-12 outlined the policy, guidelines and procedures for the Streamlined Review Process. The order describes the three factors that are evaluated when determining if an application is suited to the Streamlined Review Process procedure.

The first factor considers whether the application or portions of the application are contentious. FEI believes that this Application is not contentious due to the fact that many stakeholders have

[4] In this Application, FEI uses the name "prescribed undertaking 1" to refer to the prescribed undertaking established by section 2(1) of the GGRR. FEI refers to the prescribed undertakings established by sections 2(2) and 2(3) of the GGRR as "prescribed undertaking 2" and "prescribed undertaking 3" respectively.

been supportive of FEI's efforts to date to offer NGT solutions to customers, including the Commercial NGV Demonstration Program. Matters similar to the proposed accounting and rate treatment of GGRR incentives have been dealt with in past proceedings before the Commission such as revenue requirements applications or the FEI/FEVI 2008 Energy Efficiency and Conservation ("EEC") Application. This Application is similar in its purpose and methodology, and therefore no contentious issues are anticipated.

The second factor determines whether the application poses policy issues for which there is no Commission precedent. This Application is the result of communications with the provincial government, and is consistent with government policy.

The third factor considers the number of participants that may wish to participate in the Streamlined Review Process, as too large a number of participants could preclude an effective process. FEI does not anticipate a large number of potential participants. Appendix E includes letters from various parties who have a direct interest in natural gas transportation initiatives, and these letters demonstrate widespread support for these types of initiatives. Also, information sessions regarding the details of the natural gas transportation incentives, conducted in May 2012, also demonstrated significant interest and support for the incentive funding program.

1.5 Conclusion

The two major components of the Application are supported by the GGRR and the CEA which also provides direction to the Commission. Therefore FEI requests that this Application be reviewed under the Streamlined Review Process. There is direct alignment between FEI's Commercial NGV Demonstration Program and Prescribed Undertaking 1 of the GGRR. In addition, FEI's accounting treatment proposals maintain the integrity of the GGRR and should be approved.

2 PURPOSE OF APPLICATION AND APPROVALS SOUGHT

As outlined in Section 5, in this Application FEI seeks approval of the following two deferral accounts:

1. A non-rate base deferral account (the "NGT Incentives Account") attracting AFUDC to capture: (a) all grants and costs, including a portion of application costs, related to Prescribed Undertaking 1 for the period until December 31, 2013; and (b) to capture the 2010-2011 Incentives in the amount of $5.6 million. This account is to be transferred to rate base, effective January 1, 2014, and will continue to capture the actual incentives granted under Prescribed Undertaking 1 and will be amortized over a 10 year period into the delivery rates of all non-bypass natural gas customers; and

2. A non-rate base deferral account attracting AFUDC (the "Fueling Station Variance Account") to capture the total revenue surplus or deficiency pertaining to fueling station facility costs that have not been forecast in rates, as well as the administration and application costs, for the prescribed undertakings established under sections 2(2) and 2(3) of the GGRR. This account is to be transferred to rate base effective January 1, 2014, with an amortization period of three years into the delivery rates of all non- bypass natural gas customers.

FEI is also seeking approval from the Commission of the accounting and rate treatment methodology to be applied to these deferral accounts and the related expenditures associated with the three prescribed undertakings identified in the GGRR for the current period of the 2012-2013 RRA and for future years as described in Section 5 of this Application. The methodology entails recovering program costs from all non-bypass FEI customers. This is an appropriate methodology because all non-bypass customers receive benefits through lower delivery rates and reduced GHG emissions and the program is consistent with government policy.

FEI is also seeking orders that:

1. The incentive grants distributed in 2010 and 2011 that total $5.6 million as outlined in Section 7 of the Application were prudently incurred expenditures and are recoverable through rates from FEI's non-bypass natural gas customers; and
2. The $5.6 million in previously issued incentives will be subject to the accounting and rate treatment that FEI has proposed in Section 5 of the Application.

As further explained in Section 7 of the Application, FEI will commit to treat the $5.6 million in previously issued expenditures as part of the $62 million in the prescribed undertaking established under section 2(1) of the GGRR.

A Draft Form of Order setting out the detailed approvals sought has been included as Appendix Z. As set out in the Draft Form of Order, the approvals sought by FEI in this Application are pursuant to sections 59-61 and 90 of the *Utilities Commission Act*.

PART I – RATE TREATMENT OF EXPENDITURES UNDER GGRR

3 BACKGROUND AND CONTEXT

This Application is a response to the GGRR which was enacted on May 14, 2012, pursuant to sections 18 and 35 of the CEA. In this Section, FEI describes the background and context that have led to the enactment of the GGRR. This Section is organized as follows:

- Section 3.1 describes the relevant provincial legislative and policy context that led to the enactment of the GGRR;
- Section 3.2 describes the regulatory context that led to the enactment of the GGRR; and
- Section 3.3 describes the legal framework that is established by the CEA and which governs the Commission's treatment and regulation of expenditures incurred by FEI as a result of the GGRR.

The following Sections are included to provide a high level overview of the relevant background and context within which this Application has been brought forward. Details of the GGRR and the incentives that it authorizes as prescribed undertakings are discussed in Section 4.

3.1 Provincial Legislative Context

The Provincial Government has enacted a number of pieces of legislation that support energy efficiency and conservation and the use of clean and renewable energy sources, including the use of natural gas as a preferred energy source in the transportation sector. The provincial government's 2007 BC Energy Plan[5] (the "BC Energy Plan") recognized that transportation is a major contributor to greenhouse gas ("GHG") emissions and other air quality issues in BC, and that the use of conventional transportation fuels such as gasoline, diesel and propane contribute approximately 39% to BC's GHG emissions.

The BC Energy Plan set out strategies for reducing GHG emissions in various sectors, including strategies related to displacing conventional fuel in transportation vehicles, which is the largest source of GHG emissions in BC. The BC Energy Plan endorsed natural gas as a preferable alternative to conventional fuels, stating "natural gas burns cleaner than either gasoline or propane, resulting in less air pollution."[6]

On April 18, 2010, the Provincial Government enacted the *Clean Energy Act*. One of the key features of the *CEA* is the establishment of a number of legislated provincial energy objectives.[7]

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5 Please refer to Appendix S
6 BC Energy Plan, Page 19
7 *CEA*, s. 2.

A number of the established energy objectives encourage and support the expansion of natural gas as a preferable fuel alternative for transportation. The use of natural gas as a fuel for transportation promotes the development of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources, reduces BC GHG emissions, encourages individuals to switch to lower GHG emission fuel sources, encourages communities to reduce GHG emissions and use energy efficiently, and encourages economic development and the creation and retention of jobs.[8]

The CEA also provides that the Lieutenant Governor in Council can enact "prescribed undertakings" that are intended to encourage public utilities to pursue certain GHG reducing initiatives. These are discussed further below.

On February 3, 2012, the provincial government released "Liquefied Natural Gas – A Strategy for B.C.'s Newest Industry". This initiative highlighted the importance of Liquefied Natural Gas ("LNG") as a primary source of clean energy, and pledged support for development of LNG into a significant source of revenue and job growth.

Together, these policies recognize the positive environmental and economic impacts of natural gas, and encourage the expansion of natural gas as a preferred transportation fuel source.

3.2 Regulatory Context – FEI's Involvement in Natural Gas for Transportation ("NGT")

3.2.1 NGT APPLICATION AND GENERAL TERMS AND CONDITIONS SECTION 12B

NGT service involves FEI owning and operating fueling assets, and charging the customer a rate that is based on the cost of service associated with those fueling assets. On December 1, 2010 FEI sought approval of General Terms and Conditions ("GT&Cs") to offer Compressed Natural Gas and Liquefied Natural Gas fueling service (the "NGT Application") and approval of a CNG Service Agreement with Waste Management (the "WM Agreement"). The proposed GT&Cs Section 12B were designed to facilitate the development of CNG and LNG refueling stations that would be installed, owned and operated by FEI.

On July 19, 2011, the Commission issued Order No. G-128-11 in response to the NGT Application.[9] The Commission approved the WM Agreement, but required amendments to Section 12B of the GT&Cs proposed in the NGT Application. On September 28, 2011, FEI filed revised GT&Cs in accordance with the directives outlined in Order No. G-128-11 and the accompanying Reasons for Decision. Following discussions with Commission staff, FEI filed

[8] B.C. Energy Objectives, section 2 (d), (g), (h), (i), and (k) of the CEA
[9] Please refer to Appendix C.

further amendments to the revised GT&Cs on February 6, 2012. On February 7, 2012, the Commission issued Order No. G-14-12 approving the revised Section 12B of the GT&Cs[10].

Since filing the NGT Application in 2010, adoption of natural gas as a heavy duty transportation fuel has increased. Historic barriers to adoption include a lack of refueling infrastructure, a lack of proven engine technology and a cost premium associated with NGVs relative to conventionally-fueled vehicles. In recent years, natural gas engine manufacturers such as Westport Innovations and Cummins-Westport have introduced proven equipment to the heavy duty market. The NGT Application established infrastructure solutions for return-to-base fleets which is a key strategy that has opened up the commercial NGT market. The GGRR (discussed in detail in Section 4) further assists in overcoming some of these barriers, including the cost premium between diesel/gasoline powered vehicles and comparable NGVs and the development of CNG and LNG fueling infrastructure.

3.2.2 NGV Incentive Review (Commission Order No. G-145-11)

One of the significant barriers to the adoption of natural gas as a transportation fuel has been the capital cost premium of natural gas vehicles compared to diesel-equivalent vehicles. To address this issue and to encourage the adoption of natural gas as a transportation fuel, in 2010 FEI developed an incentive program called the Commercial NGV Demonstration Program.[11] The intention of this program was to provide EEC incentive payments that would cover up to 100% of the incremental cost of the NGVs relative to comparable diesel vehicles. Under this program, FEI provided Energy Efficiency and Conservation ("EEC") incentive funding to four commercial return-to-base fleet customers in 2010 and 2011: Waste Management, Vedder Transport, Kelowna School District and the City of Surrey. The total amount provided to these four customers under the NGV Demonstration Program was $5.6 million. FEI's proposed treatment of the incentive funding provided to Waste Management, Vedder Transport, Kelowna School District and the City of Surrey is discussed in Section 7.

In Commission Order No. G-6-11 issued on January 14, 2011, the Commission raised a concern with respect to the use of EEC incentives for NGV. FEI addressed this issue in the FEI and FortisBC Energy (Vancouver Island) Inc. ("FEVI") 2010 EEC Annual Report (Section 10) and also made requests in the covering letter that the issue raised by the Commission be resolved.[12] In response, the Commission initiated a regulatory process called the "NGV Incentive Review" by Commission Letter L-30-11 dated April 18, 2011. On August 15, 2011, following the NGV Incentive Review, the Commission issued Order No. G-145-11 (the "NGV Incentive Decision").[13] The NGV Incentive Decision determined that the NGV incentives did not meet the definition of a "Demand Side Measure" under the CEA. Accordingly, the Commission disallowed use of the EEC program to fund NGV incentives. Following the NGV Incentive

[10] Please refer to Appendix D.
[11] FEU's 2010 EEC Annual Report, section 10 at page 175.
[12] Please refer to Appendix E for excerpts of the 2010 EEC Annual Report.
[13] Please refer to Appendix F.

Decision, FEI's planned NGT projects were put on hold,[14] and FEI commenced discussions with the government about the possibility of establishing NGV incentives as prescribed undertakings under the CEA. The result of those discussions was the GGRR, which is described briefly in Section 3.3 and in further detail in the Section 4.

3.3 Legal Framework for this Application

The purpose of this Application is to establish the rate structures and rate design that will facilitate the recovery of FEI's costs incurred with respect to three prescribed undertakings that have been established by regulation under section 18 of the CEA. In this Section, FEI discusses the legal framework within which this Application has been made.

Section 18 of the CEA establishes the concept of a "prescribed undertaking" for the purposes of the CEA as follows:

> *"18 (1) In this section, "prescribed undertaking" means a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia."*

Section 35 of the CEA provides that the Lieutenant Governor in Council (the "LGIC") can enact regulations:

> *"… for the purposes of the definition of "prescribed undertaking" in section 18, prescribing classes of projects, programs, contracts or expenditures that encourage*
>
> > *…*
> >
> > *(ii) the use of natural gas, hydrogen or electricity in vehicles, and the construction and operation of infrastructure for natural gas or hydrogen fueling or electricity charging."*

If the LGIC enacts a regulation that establishes a prescribed undertaking, then there are significant implications for how the Commission regulates the activities that are carried out by a public utility as prescribed undertakings. The first implication pertains to rate setting in relation to prescribed undertakings, and is set out in section 18(2) of the CEA as follows:

> *"(2) In setting rates under the Utilities Commission Act for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking."*

The second implication, which is of a more general nature, is set out in section 18(3) of the CEA as follows:

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[14] Other than the four projects for which incentives had already been provided.

> *"(3) The commission must not exercise a power under the Utilities Commission Act in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking."*

In response to the discontinuation of EEC incentives for NGV, FEI made proposals to the provincial government for an alternative incentive program to be established under section 18 of the CEA. The government responded to FEI's proposals by issuing the GGRR pursuant to sections 18 and 35 of the CEA on May 14, 2012. Details of the GGRR and the incentives that it authorizes as prescribed undertakings are discussed in Section 4.

In response to the GGRR and to encourage the further development of natural gas as a transportation fuel, FEI has developed a program which provides incentives to encourage parties in the heavy-duty transportation sector to convert all or portions of their vehicle fleets to natural gas. As set out above, the effect of the GGRR is that the Commission must set rates that allow FEI to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking. As authorized by the GGRR, FEI intends to provide $62 million of funding prior to March 31, 2017. This incentive will offset a portion of the incremental costs of fuel conversion, and decrease the number of high emissions vehicles that operate today. This incentive program is discussed further in Section 6.

As described above, section 18(2) of the CEA requires the Commission to set rates that allow FEI to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertakings. The purpose of this Application is to establish the rate structures and rate design that will facilitate the recovery of FEI's costs incurred with respect to the prescribed undertakings set out in the GGRR as contemplated under section 18(2) of the CEA.

4 THE GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

This Section provides a description of the Regulation. A full copy of the Regulation and the government's accompanying News Release is found in Appendices A and B.

4.1 General Features of the GGRR

The adoption of natural gas as a transportation fuel has the potential to produce a number of benefits, including a reduction in GHG emissions and air contaminants, an economic payback to the citizens of BC and load building benefits to all natural gas utility customers, among other complementary benefits. The objective of the Regulation is to enable public utilities to engage in programs and expenditures that seek to replace diesel and gasoline powered vehicles in the heavy duty truck sector and replace diesel and bunker fuel powered vehicles in the marine transportation sectors with lower-emitting natural gas-fueled vehicles, so that sufficient natural gas load is developed to support a CNG/LNG fueling station infrastructure. This regulation is expected to result in a cost effective way to lower GHG emissions across the Province and help offset declining natural gas load with additional throughput volume which results in more cost-effective and efficient utilization of the natural gas distribution system.

The Regulation is enacted pursuant to sections 18 and 35 (n) of the *Clean Energy Act*. The CEA defines a "prescribed undertaking" as follows:

> *""prescribed undertaking" means a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia."*

The Regulation applies generally to public utilities. It consists of a set of definitions used in the Regulation, followed by three sections, each of which defines a major program area or "prescribed undertaking". The prescribed undertakings permit a public utility, at its discretion, to:

- provide grants or interest free loans for the purchase of eligible CNG/LNG vehicles;
- construct and operate or purchase and operate CNG fuelling stations; and
- construct and operate or purchase and operate LNG fuelling stations.

For each of these three program areas, the Regulation defines a spending cap. In total, expenditures under the Regulation are capped at $104.5 million if all three components are included. Each prescribed undertaking is independent of the others, such that under-spending in one prescribed undertaking is not transferable to the others. Table 4-1 below provides a breakdown of the expenditure caps for each of the three prescribed undertakings established by the GGRR, and the specific cost categories and associated expenditure caps within each prescribed undertaking.

Table 4-1: Greenhouse Gas Reduction (Clean Energy) Regulation

	Notes	$ Millions
Prescribed Undertaking 1 - Grants and Loans for Eligible Vehicles	• Total expenditures of the undertaking are not to exceed $62 million.	
"Specified Vehicles" (medium and heavy duty trucks, transit buses and school buses)	• Underspending of other Prescribed Undertaking 1 category caps can be shifted to increase available grants for the "specified vehicle" category.	43.9
Marine Vehicles	• Category expenditures not to exceed $11 million in the undertaking period.	11.0
Administration, marketing, training and education	• Category expenditures not to exceed $3.1 million in the undertaking period.	3.1
Safety practices and maintenance facilities	• Category expenditures not to exceed $4 million in the undertaking period.	4.0
Subtotal - Prescribed Undertaking 1		**62.0**
Prescribed Undertaking 2 - CNG Fueling Stations	• Total expenditures, including administration and marketing, are not to exceed $12 million.	
Expenditures on CNG stations	• Average expenditure on CNG stations not to exceed $1.1 M per station in any year.	11.76
Administration and marketing	• Category expenditures not to exceed $0.24 million in the undertaking period.	0.24
Subtotal - Prescribed Undertaking 2		**12.0**
Prescribed Undertaking 3 - LNG Fueling Stations	• Total expenditures, including administration and marketing, are not to exceed $30.5 million.	
Expenditures on LNG stations	• Expenditures on an LNG stations not to exceed $2.75 million per station.	26.25
Administration and marketing	• Category expenditures not to exceed $0.25 million in the undertaking period.	0.25
Tanker Truck Load-out Facilities	• Category expenditures not to exceed $4.0 million in the undertaking period.	4.0
Subtotal - Prescribed Undertaking 3		**30.5**
Total GGRR Expenditures		**104.5**

The Regulation will be repealed on April 1, 2017, as confirmed by the Ministry of Energy and Mines in their letter dated June 8, 2012[15]. As discussed in the letter, prescribed undertaking expenditures incurred prior to that date, and the related revenues and contractual commitments, continue to be recoverable in natural gas rates for the remainder of the applicable depreciation or amortization period, or contract terms. Expenditures made, or contracts entered into, pursuant to a prescribed undertaking are prudent expenditures and the prudency continues for the life of the assets or contracts, as the case may be. Details of the rate recovery treatment that FEI is seeking are provided in Section 5 of the Application.

Any public utility in the Province is eligible to carry out the prescribed undertakings set out in the Regulation, in terms of both types of expenditures in the prescribed undertakings and the expenditure limits. In addition to FEI, this may include FEVI, FortisBC Energy (Whistler) Inc. Pacific Northern Gas Ltd, Pacific Northern Gas (N.E.) Ltd., FortisBC Inc. (Electric) and BC Hydro and Power Authority. Carrying out the prescribed undertakings is optional so each public utility can elect to participate in any, all or none of the programs or expenditures allowed under the prescribed undertakings.

4.2 Prescribed Undertaking 1: Incentives or Zero Interest Loans for Eligible Vehicles

Section 2(1) of the GGRR establishes a class of grants or interest free loans for the purchase of eligible CNG/LNG vehicles as a prescribed undertaking for the purposes of section 18 of the CEA. Section 2(1) provides as follows:

> *"(1) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:*
>
> *(a) the public utility provides, through an open and competitive application process,*
>
> *(i) grants or zero-interest loans to persons in British Columbia for the purchase of an eligible vehicle to be operated in British Columbia, or*
>
> *(ii) grants to persons in British Columbia*
>
> *(A) to implement safety practices, or*
>
> *(B) to improve maintenance facilities*
>
> *to meet safety guidelines for operating and maintaining an eligible vehicle;*
>
> *(b) a grant or zero-interest loan for an eligible vehicle do not, in a year of the undertaking, exceed the percentage difference as indicated in the following table:*

[15] Please see Appendix P – Letter from Ministry of Energy and Mines ("Ministry"), June 8, 2012, at page 4.

	Year of Undertaking					
	1	*2*	*3*	*4*	*5*	*6*
Percentage difference between the cost of the eligible vehicle and the cost of a comparable vehicle that uses gasoline or diesel	*100*	*80*	*70*	*60*	*50*	*40*

(c) total expenditures on the undertaking during the undertaking period, including expenditures on administration, marketing, training and education, do not exceed $62 million, and

(i) expenditures on the undertaking during the undertaking period on marine vehicles do not exceed $11 million, and

(ii) expenditures on the undertaking during the undertaking period

(A) on administration, marketing, training and education do not exceed $3.1 million, and

(B) on grants referred to in paragraph (a) (ii) do not exceed $4 million;"

The GGRR defines "eligible vehicle" as either a "specified vehicle" or "marine vehicle" that uses CNG or LNG as a primary fuel source. The "specified vehicles" include medium duty trucks (in the 5,360 kg to 11,793 kg weight rating), heavy duty trucks (weight rating greater than 11,793 kg), school buses and transit buses with power trains and fuel systems that have not been modified after manufacture (i.e. the vehicles must be factory built to use either CNG or LNG). Typical vehicles in the weight categories identified would include waste haulage trucks, school buses, transit buses and Class 8 tractor-trailers. The requirement that an eligible vehicle be factory-built does not apply to marine vehicles.

The Regulation permits a public utility to spend up to $62 million, in total, prior to April 1, 2017 for this prescribed undertaking. Included in this $62 million are a number of subcategories, as summarized in Table 4-1. The first subcategory of disbursements during the program period is for marine vehicles, and is not to exceed $11 million. In addition, there is a subcategory of expenditures that include administration, marketing, training and education that are not to exceed $3.1 million in the undertaking period. A third subcategory of grants to implement safety practices or to improve maintenance facilities required to satisfy safety guidelines for the operation and maintenance of natural gas-fuelled vehicles is also available and capped at $4 million in the undertaking period. However, if the funding for these subcategories has not been totally applied, then any amounts remaining can be redirected to additional grants or zero interest loans for "specified vehicles" subject to the overall cap remaining at $62 million.

As discussed in Section 7 of the Application FEI proposes to include $5.6 million of vehicle incentives granted prior to the enactment of the GGRR within the $62 million expenditure envelope of the prescribed undertaking and to apply the same rate treatment to these earlier expenditures. The basis for these proposals is that the $5.6 million granted under the Commercial NGV Demonstration Program[16] were prudent expenditures that have the same purpose and intent as, and are consistent with, the vehicle incentive expenditures prescribed in the GGRR.

The limits for grants or zero interest loans are based on percentage differences between the cost of the eligible vehicle and a comparable vehicle using gasoline or diesel fuel, starting initially at 100%. In the next year of the undertaking the support is limited to 80% of the cost differential. Every year thereafter the percentage difference drops by 10% so that by year 6, the differential is 40% as shown in the table (above) in section 2 (1) (b) of the Regulation.

It is at the discretion of the utility whether a grant or an interest free loan is provided, and at this time FEI intends to provide grants for the purchase of a CNG/LNG eligible. The rationale for providing grants as opposed to interest free loans is discussed in Section 5.2.3. Applications will be judged on a competitive evaluation process based on specified criteria. As experience is gained during the prescribed undertaking period, FEI may make modifications to its programs, including the offering of interest-free loans in particular circumstances, if FEI believes that would be beneficial.

4.3 Prescribed Undertaking 2: CNG Stations

Section 2(2) of the GGRR establishes a class of CNG fueling stations as a prescribed undertaking for the purposes of section 18 of the CEA. Section 2(2) provides as follows:

> *"(1) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:*
>
> *(a) the public utility*
>
> *(i) constructs and operates, or*
>
> *(ii) purchases and operates,*
>
> *one or more compressed natural gas fuelling stations, including storage, compression and dispensing equipment and facilities, within the service territory of the public utility for the purposes of providing compressed natural gas fuel and fuelling services to owners of vehicles that operate on compressed natural gas;*
>
> *(b) total expenditures on the undertaking during the undertaking period, including expenditures on administration and marketing, do not exceed $12 million, and*
>
> *(i) the average expenditure on stations, in any year of the undertaking, does not exceed $1.1 million per station, and*
>
> *(ii) expenditures, during the undertaking period, on administration and marketing do not exceed $240 000;*

[16] These incentives were previously reviewed in the context of the FEI-FEVI 2010 EEC Natural Gas Vehicle Incentive Review (BCUC Order G-145-11 and Decision dated August 15, 2011) in which the Commission disallowed these incentives as EEC expenditures.

(c) at least 80% of the energy provided at each station during the undertaking period is provided to one or more persons under a take-or-pay agreement with a minimum term of 5 years."

The total spending cap for this prescribed undertaking is $12 million; however, the average spending per station in any year is not to exceed $1.1 million. Administration and marketing costs are not to exceed $240 thousand during the undertaking period.

The BCUC will continue to approve the rate for each station under the appropriate tariff provisions such as GT&Cs Section 12B (as modified to accommodate prescribed undertaking CNG stations). In addition, FEI has the option to apply to the Commission for a Certificate of Public Convenience and Necessity ("CPCN") and approval of a rate level for a CNG fueling station outside of the Regulation and limitations of the prescribed undertaking and without invoking or affecting the average station cost annual threshold of $1.1 million as a "prescribed undertaking" in the Regulation.

The prescribed undertaking requires that at least 80% of the energy provided at each station during the undertaking period is provided to one or more persons under a take-or-pay agreement with a minimum term of 5 years. This provision means that stations with less than full cost recovery still qualify as prescribed undertaking expenditures. While FEI intends to pursue contractual arrangements for CNG stations that involve full cost recovery, there may be circumstances in which this is not the case. Section 18(2) of the CEA provides that the Commission must set rates that allow a public utility to recover the costs of prescribed undertaking stations even if the revenues from the station customer(s) do not recover all the costs.

4.4 Prescribed Undertaking 3: LNG Stations (including truck load out)

Section 2(3) of the GGRR establishes a class of LNG fueling stations as a prescribed undertaking for the purposes of section 18 of the CEA. Section 2(3) provides as follows:

"(1) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility

(i) constructs and operates, or

(ii) purchases and operates

one or more tanker truck load-outs or liquefied natural gas fuelling stations for the purposes of providing within British Columbia liquefied natural gas fuel and fuelling services to owners of vehicles that operate on liquefied natural gas;

(b) total expenditures on the undertaking during the undertaking period, including expenditures on administration and marketing, do not exceed $30.5 million, and

(i) in any year of the 'undertaking period an expenditure on a station does not exceed $2.75 million, and

(ii) expenditures during the undertaking period on a tanker truck load-out do not exceed $4 million, and on administration and marketing do not exceed $250 000;

(c) at least 80% of the energy provided at each station during the undertaking period is provided to one or more persons under a take-or-pay agreement with a minimum term of 5 years."

This prescribed undertaking includes equipment for transferring liquefied natural gas from a storage tank to a liquefied natural gas trailer. Additional expenditures under this cap include costs for administration and marketing that are not to exceed $250 thousand during the undertaking period. The station costs are limited to $2.75 million while truck load-out is capped at $4 million.

The expenditures on each LNG station are limited to $2.75 million, which is not an average amount over a number of stations but a finite cap per station. However, FEI has the same option as with CNG stations – to make an application to the BCUC for a CPCN and approval of the rate level under the GT&Cs Section 12B tariff outside of the prescribed undertaking. In this case, the project would not invoke the total or per station funding limits of the prescribed undertaking.

The prescribed undertaking requires at least 80% of the energy provided at each station during the undertaking period is provided to one or more persons under a take-or-pay agreement with a minimum term of 5 years. The discussion above for CNG stations applies equally for LNG stations under the third prescribed undertaking. Although FEI intends to pursue full cost recovery from LNG station customers, the prescribed undertaking allows for contracts with less than full cost recovery to meet the requirements of the prescribed undertaking. Section 18(2) of the CEA provides that the Commission must set rates that allow a public utility to recover the costs of prescribed undertaking stations even if the revenues from the station customer(s) do not recover all the costs.

4.5 Reporting Requirements

As set out in sections 18 (4) and (5) of the CEA, a utility must report on the prescribed undertakings to the Minister of Energy and Mines (the "Minister"). The Minister establishes the reporting requirements, both in terms of timing and the information required. It is expected that the Minister will require regular reporting on the programs being offered to review the results and determine if any changes are required. The timing and form of reporting requirements is still to be determined.

5 PROPOSED TREATMENT OF PRESCRIBED UNDERTAKING COSTS AND RECOVERY IN RATES

In this Section FEI sets out its proposed treatment for costs incurred in respect of the prescribed undertakings and the recovery of those prescribed undertakings in FEI's revenue requirements and rates. The Section is organized in the same sequence as the three prescribed undertakings within the Regulation. FEI is seeking approval of the ratemaking principles and rate recovery concepts described below rather than specific year-to-year expenditure amounts allocated under the prescribed undertakings. The reasons for this approach are that the prescribed undertakings are optional for a public utility, and there is some latitude within the scope of the prescribed undertakings to move expenditures between years and among categories.[17] This flexibility is essential, as this is still a relatively new program, and FEI needs to be able to respond to the changes and developments in the market.

As a result, FEI is only seeking approval at this time of the generic regulatory accounting and rate recovery treatment for these expenditures. FEI will provide information in future revenue requirement applications to support the recovery of future prescribed undertaking expenditures.

5.1 Rate Recovery Considerations

As set out above, the legal framework for this Application is section 18 (2) of the CEA, which requires the Commission to "set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking". Section 18(3) of the CEA is also relevant, as it provides that "the commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent a public utility referred to in section (2) from carrying out a prescribed undertaking".

FEI interprets section 18(2) of the CEA to mean that rates must be set in such a way that the utility is not only allowed to recover its costs, but also that rates are to be established so that there is fair and reasonable compensation for the utility including a return on its investments in rate base. A fair return on rate base is required under section 59 of the *Utilities Commission Act*.

Costs incurred by FEI as prescribed undertakings will be incremental expenditures to the levels of deferral, capital and operating and maintenance expenses approved for the 2012-2013 RRA in the Commission's Decision dated May 11, 2012 and Order G-44-12. The expenditures set out in the GGRR dated May 14, 2012, were not included in the 2012-2013 RRA requests.

[17] Discussed in more detail in Section 4. For example, the prescribed undertaking for vehicle incentives specifies an overall cap on spending in the undertaking period of $62 million but yearly spending limits are not specified. Further, if the spending in a subcategory, such as incentives for marine vessels, is below the allowed cap of $11 million, the under-spending can be deployed in providing additional incentives for eligible trucks and buses, subject to the overall cap of $62 million.

5.2 Prescribed Undertaking 1- Vehicle Incentives or Zero Interest Loans

5.2.1 OVERVIEW

Prescribed undertaking 1 is made up of grants or zero interest loans to eligible trucks and buses, expenditures on administration, marketing, training and education, and grants to implement safety practices or to improve maintenance facilities. FEI will include a portion of the regulatory costs of this Application as an administrative expense of prescribed undertaking 1. Total expenditures for Prescribed Undertaking 1 in the undertaking period are not to exceed $62 million.

FEI has considered alternative accounting and rate recovery methodologies that recover costs from all non-bypass customers, and concluded that the appropriate treatment for all expenditures under this prescribed undertaking is to include them in a rate base deferral account and amortize the expenditures in delivery rates of all non-bypass customers over a ten-year period. This methodology was approved and utilized for the EEC expenditures, and remains appropriate for NGT Incentive Program expenditures. While the rate base deferral and ten-year amortization are the key principles, there are several circumstances that require minor or temporary adjustments to this treatment; these are discussed below.

5.2.2 DEFERRAL ACCOUNT AND ACCOUNTING TREATMENT

FEI's revenue requirements for 2012 and 2013 were approved by BCUC Order G-44-12. As described above, these revenue requirements did not include any forecast of expenditures related to the prescribed undertaking incentives or recoveries of them for the simple reason that the GGRR was enacted long after the 2012-2013 RRA was filed. Therefore, FEI proposes that all costs, including a portion of the Application costs as described in Section 5.3.4, related to the prescribed undertaking for the period up to December 31, 2013, be captured in a non-rate base deferral account, the "NGT Incentives Account", (attracting Allowance for Funds Used During Construction ("AFUDC")). The accumulated balance on a net of tax basis would attract AFUDC and would then be incorporated into rate base effective January 1, 2014, and amortized over a ten-year period in the delivery rates of all non-bypass natural gas customers.[18] Once transferred to rate base, this account will continue to capture the actual incentives granted under Prescribed Undertaking 1 with annual additions to the account amortized over a ten year period into the delivery rates of all non-bypass natural gas customers

For future revenue requirement applications, FEI proposes to include a forecast of the rate base deferral account (opening balance, new expenditures and amortization) and related cost-of-service impacts in the annual revenue requirements.

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[18] As required by BCUC Order No. G-44-12, the prior vehicle incentives expenditures of $5.6 million are currently captured in a non-rate base account within FEI (the "NGV Incentives" account). Upon receiving approval for the requested treatment of the $5.6 million (as discussed in Section 7 of the Application) FEI will transfer the balance in the "NGV Incentives" account to the new non-rate base account.

5.2.3 COSTS RECOVERED FROM ALL NON-BYPASS NATURAL GAS CUSTOMERS

FEI believes that it is appropriate to recover the costs of Prescribed Undertaking 1 from all non-bypass natural gas customers because non-bypass customers will benefit directly from the additional throughput on the distribution system.

It is evident that all non-bypass customers benefit from the new natural gas load added by NGT customers since the largely-fixed natural gas delivery costs are spread over a greater volume and therefore the total share of the revenue requirements that must be collected from other non-bypass customers is lowered. The greater throughput on the system results in lower delivery rates than would otherwise be the case. When the costs and throughput benefits of the prescribed undertakings are considered, delivery rates are forecast to decrease by approximately 5.6 per cent by 2030.[19] An estimate of the potential benefits that will accrue to natural gas ratepayers over time from the vehicle incentives program is provided in Appendix J.

Other significant benefits to non-bypass customers include a reduction in GHG emissions and air contaminants. GHG emissions from the transportation sector largely originate in the Lower Mainland and nearby regions, thus the cost recovery of Prescribed Undertaking 1 from non-bypass natural gas customers (within FEI) is reasonable. FEI's service territory includes the Lower Mainland and represents approximately 850,000 customers.

FEI has received suggestions from stakeholders in the GGRR development process that the incentives should be recovered from the parties that receive them, out of their fuel cost savings. FEI believes that requiring recovery of incentives from only the parties that receive them would be an obstacle to carrying out the prescribed undertaking as this treatment would, in FEI's estimation, reduce interest in the program and limit the ability to attract fleets to natural gas as a transportation fuel.

This is evidenced by the uptake in the purchase of natural gas transportation only once incentive funding was provided to companies such as Vedder and Waste Management. Even though interest rates and commodity costs are at their lowest levels in many years, there has been little interest in the purchase of natural gas fueled vehicles, regardless of the associated fuel savings. These vehicles were purchased only once incentive funding was granted.

Requiring recipients to repay their incentives through rates would, in effect, turn a grant into a loan and eliminate the permissible option in the prescribed undertaking of providing grants. Requiring the recipients to repay their incentives would also be contrary to established practices in other areas such as with the FEU's EEC programs. For example, a residential customer that receives an EEC incentive to purchase more efficient equipment to reduce their gas use is not required to repay the incentive. If EEC programs were structured that way there would be little

[19] Please refer to Appendix G and Appendix J for a detailed discussion on the forecast delivery rate impact of the prescribed undertakings and ensuing growth under the planned growth scenario (Scenario 1). Please also refer to Appendix H and Appendix J for a detailed discussion on the forecast delivery rate impact of the prescribed undertakings under a lower growth scenario (Scenario 2).

or no uptake by customers. Section 6 of this Application describes the use of grants under FEI's NGT Incentive Program.

5.2.4 Amortization Period

FEI considers a ten year amortization period to be an appropriate time frame for amortization as this approximates the expected life of the CNG/LNG vehicles as well as the period over which the benefits of the program are experienced[20]. This meets the ratemaking and accounting objective of matching costs and benefits and in turn achieves the concept of intergenerational equity. The costs of the programs should be matched against the benefits that are derived which would not be the case if the costs of the program are simply expensed in a single year. In that scenario, current customers would bear the expense and future customers would reap the benefits. In addition to matching costs and benefits, the proposed approach also avoids the rate volatility that would occur with an expensing approach.

5.2.5 Summary

In summary, the proposed approach allows FEI to earn a fair return on its investments in carrying out the prescribed undertaking, appropriately matches costs and benefits, and avoids rate volatility for customers.

5.3 Prescribed Undertakings 2 and 3 - CNG and LNG Fueling Stations

5.3.1 Introduction

Prescribed Undertakings 2 and 3 are made up of capital expenditures on stations, administration and marketing expenditures, and in the case of LNG Fueling Stations, truck load-out equipment. For both CNG and LNG Stations, at least 80% of the energy provided at each station during the undertaking period is to be provided under a take or pay agreement with a minimum term of 5 years. Total expenditures for Prescribed Undertaking 2 (CNG Fueling Stations) in the undertaking period are not to exceed $12 million. Total expenditures for Prescribed Undertaking 3 (LNG Fueling Stations) in the undertaking period are not to exceed $30.5 million.

The specific approval sought by FEI in respect of Prescribed Undertakings 2 and 3 is focussed on the accounting and rate treatment methodology to be applied during the period for the approved 2012 – 2013 RRA and in future revenue requirement applications beyond this period.

Prescribed undertakings 2 and 3 support the development of CNG and LNG fueling infrastructure. These two prescribed undertakings signal government's strong support for the

[20] The benefits to other natural gas customers of increased throughput from NGV load may well continue beyond the end of the vehicle life without the need for additional incentives as operators replace their first natural gas-fuelled vehicles with new natural gas-fuelled vehicles.

expansion of NGT fueling infrastructure and in turn complement Prescribed Undertaking 1 which is designed to drive an increase in the adoption of natural gas as a fuel source in the heavy duty and return-to-base fleet sector. The costs for fueling stations that are developed as prescribed undertakings will be determined in the same manner as the costs for fueling stations that are developed under GT&Cs Section 12B. However, with regard to rates and revenues from the stations, the GGRR permits less than full cost recovery. These issues and the rate recovery treatment for NGT stations are discussed in further detail below.

The Commission's decisions on several matters in current proceedings may have a bearing on the treatment of FEI's fueling stations. In the AES Inquiry the Commission has been considering the FEU's involvement in NGT initiatives and specifically how the GGRR affects the determinations to be made on FEI's NGT initiatives. Also, on June 15, 2012, FEI filed a variance and reconsideration application with respect to some of the Commission's determinations in the BFI Canada Inc. Decision (Order No. C-6-12) (the "BFI Reconsideration")[21]. The BFI Reconsideration seeks, among other things, a reconsideration of the Panel's determination that FEI's CNG fueling service activities and LNG fueling service activities each be placed in a separate class of service from the natural gas class of service. Although the outcomes of these processes are not known at this time, FEI will discuss its intended treatment of CNG fueling stations and make any adjustments necessary to accommodate the Commission's final determinations on the items discussed above and other NGT-related matters.

5.3.2 FEI INTENDS TO DEVELOP PRESCRIBED UNDERTAKINGS 2 AND 3 IN ACCORDANCE WITH GT&CS SECTION 12B

Over the past several years FEI has developed and sought Commission approval for several fuelling station projects under the approved Section 12B of the GT&Cs. As noted in Section 3, FEI applied in its December 2010 NGT Application for the GT&Cs for the provision of CNG and LNG fueling service, and ultimately, after incorporating changes required by BCUC Order G-128-11 to the Commission's satisfaction, received approval for GT&Cs Section 12B.

GT&Cs Section 12B sets out a variety of terms and conditions that lead to full cost recovery from the CNG or LNG fueling service customer, including rates being based on the actual capital and O&M costs, an allowance for overhead and marketing costs, taxes and any other costs. The customer must agree to repay any undepreciated capital costs or comparable buyout arrangements if the service contract is not renewed at the end of the initial term. BCUC Order G-128-11 also approved depreciation rates to be employed for CNG and LNG station equipment. The costs and revenues from the fueling stations developed under GT&Cs Section 12B to date have either been included in the approved 2012-2013 Revenue Requirements or are subject to deferral account treatment that will allow net excesses or shortfalls to be refunded or charged appropriately in future RRAs.

[21] Please see Appendix X

FEI intends to own and operate CNG and LNG fueling stations for natural gas customers in a manner that ensures that all FEI customers benefit from the increased system throughput resulting from NGT volumes. FEI intends to establish rates for these services on the basis of the principle reflected in GT&Cs Section 12B; that the costs of providing CNG or LNG Fueling Service should be recovered from the CNG or LNG Fueling Service customer. However the GGRR sets out a minimum threshold that 80% of the energy at a CNG or LNG station must be under a take or pay arrangement with a minimum 5 year term. Therefore natural gas ratepayers may in some cases be at risk for the revenues associated with up to 20% of the energy if the CNG or LNG station customer rates under the take-or-pay contract(s) do not meet the full cost of service.

In all cases FEI will determine the forecast and actual costs for CNG and LNG stations (capital, O&M, overhead and other costs) in keeping with the provisions of GT&C Section 12B and any directives of the Commission with respect to the costs applicable to CNG and LNG stations. These are the costs that will be used to determine the full-cost recovery rates that would be applicable to CNG and LNG stations as per GT&Cs Section 12B. FEI expects that the established rates for prescribed undertakings for CNG and LNG stations will in most instances reflect the full cost recovery principles since FEI intends to establish these full cost recovery contracts to the extent possible.

5.3.3 TREATMENT OF EXPENDITURES IN FUTURE REVENUE REQUIREMENT APPLICATIONS

In its revenue requirements applications FEI will include the forecast rate base and cost of service and revenue recoveries for all CNG and LNG fueling stations that are complete and in service as well as those that are expected with reasonable certainty (such as a contractual commitment) to come into service during the test period.

FEI will maintain records on the CNG and LNG stations that will allow for each station to be tracked separately. This will facilitate the required reporting to the Minister to be done on the prescribed undertaking expenditures and will also enable the provision of appropriate detailed information to the Commission for rate setting purposes in revenue requirements applications or applications with respect to rates for individual stations. For example, it will be possible to provide separate reporting and forecasting for all fueling stations under the prescribed undertaking versus those stations that have been applied for in the normal course (i.e. under GT&Cs Section 12B).

5.3.4 DEFERRAL ACCOUNT AND ACCOUNTING TREATMENT

In this Application, FEI is seeking approval for one new deferral account with respect to CNG and LNG stations as discussed below.

FEI's revenue requirements for 2012 and 2013 have already been approved by BCUC Order G-44-12 and these revenue requirements did not include any CNG or LNG fueling station facilities other than Waste Management CNG, Kelowna School District CNG, City of Surrey CNG, and Vedder LNG fueling stations. The 2012-2013 RRA forecasts did not include any further fueling stations in 2012 and 2013. As a result, FEI proposes to capture the total revenue surplus or deficiency pertaining to these un-forecast fueling station facilities in a non-rate base deferral account (attracting AFUDC), the "Fueling Stations Variance Account". The total revenue surplus or deficiency is the net of the total recoveries and the cost of service of the fueling stations, where total recoveries is defined as the summation of fueling station, tanker transportation and delivery margin recoveries.

This account will also capture the administration allowances for fueling stations as provided for in the prescribed undertakings. FEI will record the actual administrative costs incurred in this account, up to a maximum in the undertaking period of $240 thousand for CNG stations and $250 thousand for LNG stations, for a total maximum addition to the deferral account of $490 thousand. FEI will include the costs pertaining to this Application within the administrative cost allowances of the prescribed undertakings. That is, a portion of the Application costs will also be captured in the administrative cost allowance of Prescribed Undertaking 1. Application costs include legal fees, intervener and participant funding, Commission costs, required public notifications and miscellaneous stationery and supplies costs.

The accumulated balance on a net-of-tax basis would attract AFUDC and would then be incorporated into rate base and amortized in the cost of service when the non-bypass natural gas delivery rates are reset. As noted above, FEI will maintain records on the CNG and LNG stations that will allow for each station to be tracked separately, including its contribution to this deferral account. FEI proposes an amortization period of three years for this account, to align with the timeframe of the regulation.[22]

In addition, FEI will maintain the use of the Commission approved CNG and LNG Recoveries deferral account for recoveries received from fueling station customers attributable to throughput over and above the minimum contract demand. These recoveries will be amortized over a one year period in the delivery rates of non-bypass natural gas customers. This account will apply to all fueling stations, regardless of whether they are constructed as prescribed undertakings or under GT&Cs Section 12B.

5.4 Conclusion

As described above FEI has proposed regulatory accounting and rate recovery treatment for expenditures in each of the GGRR prescribed undertakings that:

- reflects an appropriate sharing of the costs and benefits that arise from the expenditures, both among customers and over time;

[22] That is, if rates are reset in 2014, amortization of this account will have been completed by the end of 2017 aligned with the final year that FEI will provide incentives under the Regulation

- is consistent with established regulatory practice in British Columbia;
- is consistent with Commission Order No. G-128-11;
- is reflective of the requirements and conditions of the GGRR and provides FEI with a suitable regulatory framework for carrying out the prescribed undertakings in an effective and efficient manner; and
- is consistent with FEI's opportunity to earn a fair and reasonable return on its investment in the prescribed undertaking expenditures.

As such FEI requests Commission approval of the proposed regulatory accounting and rate recovery treatment for the prescribed undertakings expenditures as set out above.

6 PROPOSED PROGRAMS UNDER THE PRESCRIBED UNDERTAKINGS

Sections 18(2) and 18(3) of the CEA, read together, indicate that the Commission's role in relation to prescribed undertaking expenditures incurred by a public utility is limited. In FEI's view, the Commission's role in relation to prescribed undertakings is limited to setting rates that allow the public utility to collect sufficient revenue to recover its costs incurred with respect to the prescribed undertaking. As a result, aside from the approvals relating to accounting and rate treatment of prescribed undertaking expenditures authorized by the GGRR, FEI is not seeking (nor is it required to seek) approvals in relation to the programs that will be designed and implemented to carry out the prescribed undertakings. With this context in mind, in this Section FEI provides an overview of the programs through which it intends to carry out the prescribed undertakings established under the GGRR. The overview provided is for background information only.

6.1 Prescribed Undertaking 1: Grants or Zero-Interest Loans for Eligible Vehicles

6.1.1 FEI'S NGT INCENTIVE PROGRAM

Prescribed Undertaking 1 of the Regulation authorizes FEI to provide up to $62 million in incentive funding to help offset the cost differential between an eligible natural gas vehicle and comparable diesel or gasoline vehicle.

In 2012, FEI intends to issue grants up to the equivalent of 80% of the cost differential between a natural gas and equivalent diesel vehicle through its NGT Incentive Program. In each subsequent year of the program, incentive funding of the cost differentials will decrease by 10%. Details of the NGT Incentive Program, including the number and types of vehicles that are forecast to receive funding, are provided in Appendix J. At this time, FEI intends to hold one call to fund projects for the 2012 period, and at least one call process per year in subsequent years. The overall program design, terms and conditions, and evaluation criteria will be assessed in conjunction with the annual reports to the Minister in order to make any adjustments for the next funding period.

All applicants wishing to apply for incentive funding must submit an application to FEI before the application deadline in each year. The application will include pertinent company details, as well as the price differential between their NGVs and equivalent diesel vehicle.

After the application deadline for each call process, all funding requests will be evaluated using a pre-established assessment model. The use of this model will ensure that evaluations are carried out consistently and fairly among all applicants. A fairness advisor has been selected to oversee the incentive funding process. The application approval process is conducted in stages, and includes three main categories. Each category is comprised of a set of criteria that are assigned scores based on the extent to which the criteria are met, and these criteria are weighted to ensure the goals of the program are met. See Appendix I for further discussion of these criteria.

6.1.2 BREAKDOWN OF FUNDING

The following table summarizes the funds already provided in 2010/2011, as well as the funds anticipated to be awarded or spent in the remainder of the program:

Table 6-1: Breakdown of Incentive Funding 2010/2011-2016

NGT Incentive Program Funding Summary	2010/2011	2012	2013	2014	2015	2016	Total
Incentive Funding by Category							
Trucks	$ 5.2	$ 6.3	$ 7.0	$ 6.4	$ 6.3	$ 6.8	$ 38.1
Buses	$ 0.4	$ 1.6	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 5.8
Marine	$ -	$ -	$ 3.5	$ 3.0	$ 2.5	$ 2.0	$ 11.0
Safety and Maintenance	$ -	$ 0.2	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 4.0
Administration, Marketing, Training & Education	$ -	$ 0.3	$ 1.0	$ 0.9	$ 0.6	$ 0.3	$ 3.1
Total	**$ 5.6**	**$ 8.3**	**$ 13.4**	**$ 12.3**	**$ 11.4**	**$ 11.0**	**$ 62.0**

Although it is anticipated that funds will be allocated as shown within these categories, the actual funding is dependent on the types of applications that are received. Any funds not spent within a particular category are available to be used in other categories within Prescribed Undertaking 1, subject to any specified limits for the categories[23]. For instance, in the event that no funds are requested for marine projects, these funds will be re-directed to other activities as needed to ensure that the maximum benefit for this program is achieved. In addition, the Regulation does not specify limits on the yearly spending so the actual spending by year will most likely vary from that presented in the table.

6.2 Prescribed Undertaking 2: CNG Fueling Stations

Expenditures under the second and third prescribed undertakings for CNG Stations and LNG Stations will occur based on the demand from customers for FEI to provide these services. It is expected a number of the recipients of vehicle incentives will also contract to take fueling service from FEI but there is no requirement to do so. CNG or LNG customers are free to build their own stations or contract for fueling service with parties other than FEI

As described in Section 4.3, up to $12 million in total expenditures is permitted for CNG fueling stations over the undertaking period. FEI may elect to submit its rate applications for CNG stations under Prescribed Undertaking 2 or through the established GT&Cs Section 12B. Rate applications would require Commission approval under either scenario.

[23] As established through discussions with the Ministry. Total spending limits for each category are detailed in Section 4.2.

Please refer to Appendix J for FEI's forecast of the number of stations over the undertaking period.

6.3 Prescribed Undertaking 3: LNG Fueling Stations and Truck Load-out Facilities

Section 4.4 discusses the utility's authorization to spend up to $30.5 million in total expenditures for LNG fueling stations (including a truck load out) over the undertaking period. As with CNG fueling station projects, FEI has the option to submit a CPCN and approval of the rate level under GT&Cs Section 12B outside of the prescribed undertaking.

Please refer to Appendix J for FEI's forecast of the number of stations over the undertaking period.

PART II

7 PRUDENCE OF PAST INCENTIVES

7.1 Introduction

In 2010 and early 2011, FEI issued approximately $5.6 million in natural gas vehicle incentives to four different fleet owners under an EEC program called the Commercial NGV Demonstration Program. On April 18, 2011, the Commission commenced a proceeding to review the Company's eligibility to use EEC funds to provide NGV incentives called the "NGV Incentive Review". At the conclusion of the NGV Incentive Review, the Commission determined that FEI did not have approval to use EEC monies to provide incentives for NGVs. However, the Commission noted that the question of the prudence of these expenditures had not been thoroughly canvassed in the NGV Incentive Review, and stated that it would entertain additional submissions on this issue at a later date.[24] This part of the Application contains FEI's further submissions on the prudence of the $5.6 million in previously awarded NGV incentives (the "2010-2011 NGV Incentives").

The $5.6 million in natural gas vehicle incentives provided to fleet owners in 2010 and 2011 were prudent expenditures in the circumstances, and FEI should be permitted to recover those expenditures through rates charged to all non-bypass natural gas customers. The Commission's consideration of prudence should account for the anticipated benefits, which are explained in detail in this Section, and should recognize the Company's good faith belief that the expenditures had been previously approved as part of the EEC portfolio.

The policy rationale supporting the 2010-2011 NGV Incentives is consistent with the policy rationale underpinning Prescribed Undertaking 1. As a result, the order sought by FEI in respect of the 2010-2011 NGV Incentives (that they were prudently incurred) does not extend to seeking approval for future expenditures of a similar nature outside the scope of Prescribed Undertaking 1. In the event that the Commission approves the recovery of some or all of the 2010-2011 NGV Incentives, FEI will commit to reduce the amount of incentives dispensed under Prescribed Undertaking 1 by the amount of the 2010-2011 NGV Incentives approved for recovery. Therefore, the total amount of vehicle incentives that can be dispensed in 2012 and onwards as a result of this Application (inclusive of the amount of 2010-2011 NGV Incentives if approved) will not exceed the Prescribed Undertaking 1 maximum of $62 million.

This Section is organized as follows:

- Section 7.2 describes the development of FEI's NGT initiatives that preceded and led to the expenditures of $5.6 million being issued;

[24] EEC Incentive Decision, August 15, 2011 (Order G-145-11), p. 17.

- Section 7.3 provides details of the $5.6 million in incentives that were issued to the four fleet owners in 2010 and 2011;
- Section 7.4. describes the Commission's decision that followed the NGV Incentive Review;
- Section 7.5 describes why the 2010-2011 NGV Incentives described in Section 7.3 were prudent based on:
  - FEI's good faith belief that it had approval to issue the expenditures;
  - the government policy and legislation in effect at the time the expenditures were made;
  - the immediate load benefits to FEI customers that were anticipated as a result of issuing the incentives;
  - the longer term load benefits to FEI customers that were anticipated as a result of issuing the incentives;
  - the GHG benefits that were anticipated as a result of issuing the incentives;
  - the stakeholder support, and in particular customer support, for the expenditures;
  - the Total Resource Cost ("TRC") test results of each of the four expenditures; and
  - complementary benefits.
- Section 7.6 describes the volume additions from the 2010-2011 NGV Incentives that were provided; and
- Section 7.7 describes how the prior incentives granted are consistent with the provisions of the GGRR and Prescribed Undertaking 1, which supports the proposed financial treatment and recovery of the $5.6 million.

The specific orders sought by FEI in respect of the 2010-2011 NGV Incentives are set out in the Draft Order attached to this Application as Appendix Z.

7.2 FEI's Development of its NGT Initiative

The FEU began developing the current natural gas for transportation initiatives in 2008. The initiatives were prompted by rapidly changing government policy, such as the 2007 BC Energy Plan, and declining natural gas use in the Province; total FEU demand volumes are forecast to decrease by 4.1% from 2007 to 2013[25]. In 2008 FEI began to search for ways to increase system load. FEI believed that the expansion of the NGT market presented a prudent solution

[25] FEU Common Rates, Amalgamation and Rate Design Application, Page 54-55.

to counteract this decline. The FEU's interest in pursuing NGT was discussed in the FEI-FEVI 2008 Long Term Resource Plan (the "2008 LTRP"), along with some concurrent discussion in the 2008 EEC proceeding which overlapped with the 2008 LTRP. The 2008 LTRP identified potential benefits in the heavy duty and return-to-base fleet sectors for the environment, for NGT customers and for natural gas ratepayers. The sections of the 2008 LTRP relating to the NGT initiatives are attached as Appendix L. Excerpts from the 2008 EEC proceeding relating to the NGV initiatives and NGV Incentive Decision are attached as Appendix Y.

NGT proposals were included in the FEI and FEVI 2010-2011 RRAs, in the FEU 2010 LTRP, and in the 2010 EEC Annual Report. The sections of the FEI and FEVI 2010-2011 RRA relating to the NGT initiatives are attached as Appendix N. The sections of the 2010 LTRP Application relating to the NGT initiatives are attached as Appendix M. The sections of the 2010 EEC Annual Report relating to the NGT initiatives are attached as Appendix E.

On December 1, 2010, FEI applied to the Commission for approval of a draft agreement which it had made with Waste Management of Canada Corporation for compression and dispensing service for CNG Service. It also applied for acceptance of the expenditures required to provide the service as well as approval of General Terms and Conditions for use in future contracts, for both CNG and LNG customers. The Commission's decision in this proceeding was issued on July 19, 2011. Excerpts from FEI's NGT Application are attached as Appendix O.

7.3 The 2010-2011 NGV Incentives

In 2010 and 2011 FEI began an incentive program for heavy duty and return-to-base fleets under the Company's Energy Efficiency and Conservation programs. This program was called the Commercial NGV Demonstration Program. In this Section, FEI provides a description of each of the incentives that were provided under the Commercial NGV Demonstration Program.

The four incentives that were committed are summarized in Table 7-1 below, and described in further detail in the following subsections. Please note the data in Table 7-1 is current as of May 10, 2011.

Table 7-1: Commercial NGV Demonstration Program – 2010/2011 Incentives Committed26

Customer Receiving NGV Incentive	Incentive Amount Committed ($)	Date of Agreement for EEC Incentive Funding (MM/DD/YYYY)	Estimated Fuel Savings to Customer ($)	Customer Estimated Avoided Diesel (L)	Customer Estimated GHG Reductions (tonnes)	Estimated Revenue to FortisBC Energy ($)	Total Resource Cost (TRC) Test Ratio
City of Surrey	$ 26,700	9/15/2010	$ 18,566	34,000	13	$ 5,611	1.7
Kelowna School District	$ 363,286	3/17/2011	$ 17,587	95,436	120	$ 21,888	1.1
Waste Management	$ 803,560	12/3/2010	$ 202,651	468,000	214	$ 38,728	1.4
Vedder Transport	$ 4,393,300	12/10/2010	$ 1,877,989	3,582,850	3,754	$ 548,460	1.4
Total	$ 5,586,846		$ 2,116,793	4,180,286	4,100	$ 614,687	

Source: 2011 NGV Incentive Review, Exhibit B-1, BCUC IR 1.7.2 (Totals added)

As required by the terms and conditions under the NGV Commercial Demonstration Program, FEI issued 50 percent of each funding amount when the customer provided FEI with evidence of a purchase order for their NGVs. FEI issued a subsequent payment of the remaining 50 percent of the funding amount upon receipt of evidence satisfactory to FEI that the vehicles were placed into regular service by the customer.

As indicated in Table 7-1, each customer provided FEI with an estimate of their diesel fuel displaced. This value (in diesel litres and GJ) was input into the TRC test for each participant, along with the incentive amount indicated in the Table. The calculation of the TRC for the Innovative Technologies Program Area including each NGV customer was provided in the NGV Incentive Review as a live spreadsheet and is attached as Appendix Q.[27]

The calculation of the GHG emission reductions is based on a fuel pathway lifecycle assessment tool called the GHGenius model.[28] FEI has detailed the underlying assumptions and inputs of these calculations in various proceedings, including the NGT Application.[29] Please refer to Appendix R for a summary of the GHG emission reductions for each of the four fleets under the Commercial NGV Demonstration Program..

In the following Sections, FEI has also explained the "Estimated Revenue to FortisBC Energy" column and expressed the calculation as delivery margin benefits.

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[26] A total of $26,700 in incentive funding was committed to the City of Surrey, however only $13,350 was provided, as detailed in Section 7.3.1.

[27] Please refer to NGV Incentive Review, BCSEA IR 1.1 which shows a live spreadsheet of the 2010 Innovative Technologies Program Area which includes the Commercial NGV Demonstration Program.

[28] GHGenius model 3.18, www.ghgenius.com.

[29] NGT (CNG-LNG) Application, Exhibit B-8, BCSEA IR 2.14.1.

7.3.1 CITY OF SURREY ($13,350)

On September 15, 2010, FEI committed to provide $26,700 of incentive funding to the City of Surrey ("Surrey").[30] The first 50 per cent ($13,350) of funds were issued to Surrey on September 30, 2010. Surrey used the funds to purchase one residential CNG garbage truck. Surrey did not submit any documentation to confirm their vehicle entered regular service within the 2010-2011 time frame, thus FEI did not issue a second payment.

Based on a fuel consumption estimate of 34,000 diesel litres by Surrey, FEI estimated the CNG garbage truck would create additional load of 1,538 GJs of natural gas per year. A delivery margin benefit estimate of $5,611 per year was calculated assuming delivery service under Rate Schedule 6 (at the 2011 rate of $3.648 per GJ).

Surrey purchased their CNG garbage truck to evaluate the benefits of NGVs on a pilot basis. Surrey has historically operated a private CNG fueling station on their property and did not require CNG service and did not contract with FEI for fueling service. FEI understands that Surrey's assessment led to the Request for Proposals ("RFP") issued in June of 2011 which mandated the use of CNG vehicles for waste haulage service. BFI Canada ("BFI") was announced as the successful RFP proponent in December of 2011. BFI subsequently sought and contracted for CNG service (through a take-or-pay volume commitment) with FEI to fuel a fleet of CNG garbage trucks purchased to serve Surrey.

7.3.2 KELOWNA SCHOOL DISTRICT ($363,286)

FEI entered into an agreement with Central Okanagan School District No. 23 ("Kelowna School District" or "KSD") on March 17, 2011 to provide $363,286 of incentive funding.[31] KSD used the funds to purchase 11 CNG school buses. The first incentive payment was issued to KSD on April 15, 2011 and the second on July 29, 2011.

Based on a fuel consumption estimate of 95,436 diesel litres by KSD, FEI estimated the CNG school buses would create additional load of 6,000 GJs of natural gas per year. A delivery margin benefit estimate of $21,888 per year was calculated assuming delivery service under Rate Schedule 6 (at the 2011 delivery rate of $3.648 per GJ).

FEI entered into an agreement with KSD on February 8, 2012 to provide CNG service to KSD for a period of 15 years. This agreement sets a take-or-pay volume of 5,000 GJs per year. FEI intends to submit an application for approval of a fueling rate to service KSD in the coming months.

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[30] This incentive amount was 100 percent of the incremental cost differential between a CNG garbage truck and a diesel equivalent garbage truck.

[31] This incentive amount was 78 percent of the incremental cost differential between a CNG school bus and a diesel equivalent school bus.

7.3.3 WASTE MANAGEMENT ($803,560)

FEI entered into an agreement with Waste Management ("WM") on December 3, 2010 to provide incentive funding for the purchase of CNG garbage trucks by WM. Pursuant to Commission Order No. G-6-11, the original agreement was amended on February 17, 2011. The incentive amount (not exceeding $55,000 per vehicle for 20 vehicles) in the agreement was greater than the amount actually paid by FEI. FEI contributed $803,560 (or approximately $40,178 per vehicle).[32] FEI issued payments to WM on December 15, 2010 and April 15, 2011.

Based on a fuel consumption estimate of 468,000 diesel litres by WM, FEI estimated the CNG garbage trucks would create additional load of 21,140 GJs of natural gas per year. A delivery margin benefit estimate of $38,728 per year was calculated assuming delivery service under Rate Schedule 25 (at the 2011 delivery rate of $0.645 per GJ plus $15.554 per GJ demand charge)[33]. Over the past year, WM's fleet has consumed approximately 30,000 GJs, surpassing this estimate and creating additional benefits for FEI's natural gas ratepayers.

FEI originally entered into a fueling service agreement with WM on December 3, 2010. Pursuant to Commission Order No. G-6-11, this agreement was amended (in an agreement separate from the incentive funding agreement) on February 17, 2011. The take-or-pay minimum is 1,583 GJs per month (18,996 per year) for a period of 10 years. WM began fueling their fleet of 20 CNG vehicles in March of 2011.[34]

7.3.4 VEDDER TRANSPORT ($4,393,300)

FEI entered into an agreement with Vedder Transport ("Vedder") on December 10, 2010 to provide $4,393,300 of incentive funding.[35] Vedder used this funding to purchase 50 LNG fuelled tractors. FEI issued payments to Vedder on December 24, 2010 (when Vedder placed its purchase order for the LNG vehicles) and subsequent payments throughout 2011 and 2012 (accrued in 2011) as the LNG vehicles were gradually placed into regular service.

Based on a fuel consumption estimate of 3.6 million diesel litres by Vedder, FEI estimated the LNG tractors would create additional load of 138,500 GJs of natural gas per year. The revenue estimate of $548,460 per year was calculated assuming delivery service under Rate Schedule 16 (at the 2011 rate of $3.96 per GJ).[36] At that point in time, the delivery margin benefit would be approximately $263,261 (assuming 52 per cent O&M cost under Rate Schedule 16 for incremental LNG production).

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32 This incentive amount was 100 percent of the incremental cost differential between a CNG garbage truck and a diesel equivalent garbage truck.
33 Calculation also referenced in the NGT Application proceeding BCUC IR 1.5.3.
34 Final CNG fueling service rate for WM was approved on July 19, 2011 in Commission Order No. G-128-11.
35 This incentive amount was 100 percent of the incremental cost differential between a LNG tractor and a diesel equivalent tractor.
36 Calculation methodology also referenced in the NGT Application proceeding BCUC IR 3.16.1.

Vedder has gradually increased its consumption as vehicles have been placed into service, but at this time Vedder expects its fleet will consume nearly 175,000 GJs per year, which would surpass the original estimate.

FEI entered into an LNG service agreement with Vedder for use of a temporary fueling station on May 12, 2011. On March 2, 2012 FEI entered into a permanent fueling station agreement with Vedder for a period of 10 years and a take-or-pay minimum of 140,000 GJs per year. This agreement is presently before the Commission for approval of an interim fueling rate and CPCN.

7.3.5 INCENTIVE FUNDING BENEFITS

FEI non-bypass customers have and will continue to benefit from the $5.6 million in incentive funding that was provided to the four fleet owners in 2010 and 2011. The details of the benefits, such as decreased GHG emissions and increased delivery margin revenues, are detailed above. The additional load added to FEI's system from these four projects is the equivalent of adding 1,858 residential customers to FEI's system. To provide context, FEI anticipates approximately 6,500 residential customer additions in 2012 in the course of normal operations[37].

Table 7-2 summarizes the equivalent residential customer additions based on the increased load provided for the four fleets discussed above:

Table 7-2: Residential Customer Addition Equivalent by Contract

Fleet Operator	Additional Annual Load (GJs)	Residential Customer Addition Equivalent
City of Surrey	1538	17
Kelowna School District	6000	67
Waste Management	21140	235
Vedder	138500	1539
Total	**167178**	**1858**

These load additions are anticipated to provide a present value delivery rate benefit of $1.2 million by 2030 for FEI's non-bypass customers[38].

7.3.6 SUMMARY

FEI's use of EEC funds for NGVs was done in a manner which sought to achieve benefits for FEI rate payers from decreased GHG emissions, increased delivery margin revenues and

[37] 2012 Common Rates, Amalgamation and Rate Design Application, Page 58
[38] See Appendix W. These calculations assume the vehicles awarded the $5.6 million are replaced at the end of the vehicle life without the need for further incentives.

development of the natural gas for transportation market. FEI acted in good faith throughout and sought to operate within what it understood the EEC framework to be. The initiatives within the Commercial NGV Demonstration were among the strongest within its EEC portfolio and met the Commission-approved TRC test.[39] Although the NGV Incentive Review determined these EEC expenditures did not meet demand-side measure definition in the *Clean Energy Act*, the positive TRC test results indicate these expenditures continue to provide a benefit to ratepayers.

The load addition estimates from 2011 are approximately 167,000 GJs per year, or the equivalent of adding 1,858 new residential customers.[40] This calculates to an overall revenue estimate of $614,687 per year and a delivery margin benefit estimate of $328,901 per year.

7.4 The 2011 NGV Incentive Review

On April 18, 2011, the Commission commenced the NGV Incentive Review, which considered the following three questions:

1. Was it appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program 2009 Report (filed March 31, 2010)?
2. If the scope of the Innovative Technologies program was appropriately changed, does the associated NGV purchase incentive funding become: (a) a Commission-approved expenditure; or (b) an approved EEC expenditure; or (c) an expenditure eligible for cost recovery from rate payers in whole or in part?
3. If NGV purchase incentive funding is found to be inappropriately included in the Innovative Technologies program, should incentive payments already made by the Companies be eligible for cost recovery from rate payers in whole or in part?

The Commission's decision in the NGV Incentive Review was issued on August 15, 2011 (the "EEC Incentive Decision"). With respect to the first question, the Commission decided that FEI did not have approval to use EEC monies to provide incentives for NGVs. As a result, the Commission did not address the second question.

With respect to the third question, FEI took the position in the NGV Incentive Review that regardless of whether the expenditures at issue were previously approved as EEC expenditures, they had been prudently incurred, they were in the public interest, and therefore they should be approved and FEI should be permitted to recover the expenditure amounts through rates. With respect to this issue, the Commission determined that it was unable to determine whether the expenditures should be recoverable from ratepayers. However, the

[39] EEC 2010 Annual Report, at page 182, table 10-2 shows a TRC of 1.4 for the NGV Demonstration Program and an overall portfolio TRC of 1.2 for the Innovative Technologies Program Area for 2010.
[40] Reflects an average residential use rate of 90 GJ across the FortisBC Energy Utilities.

Commission did not make a finding with respect to whether the expenditures that had been previously made were (or were not) prudent. The Commission stated:

> *"However, the Commission Panel also notes that the issue of prudency may involve additional and/or different considerations from those relating solely to the public interest, and that the issue of prudency is relevant and has not been thoroughly canvassed. The Commission Panel is therefore prepared to entertain additional submissions on the issue of prudency in respect of some or all of the expenditures in issue. Any submissions should be premised on the findings already made by the Panel."*[41]

This Section of the Application is FEI's response to the Commission's invitation for further consideration of the prudence of the expenditures. Exhibits filed in the NGV Incentive Review are attached as Appendix K.

7.5 The 2010-2011 NGV Incentives Were Prudent Expenditures

7.5.1 Introduction

The following Sections describe the facts known to FEI at the time the four incentives were issued that supported FEI's decisions to issue the funds. The key factors considered at the time included:

- FEI's good faith belief that it had approval to issue the expenditures;
- government policy and legislation in effect at the time the expenditures were made;
- immediate load benefits to FEI customers were anticipated as a result of issuing the incentives;
- longer term load benefits to FEI customers were anticipated as a result of issuing the incentives;
- GHG benefits were anticipated as a result of issuing the incentives;
- the stakeholder support, and in particular customer support, for the expenditures;
- TRC test results of each of the four expenditures; and
- complementary benefits.

These facts, which are outlined in detail below, establish that the $5.6 million in expenditures were prudently incurred costs.

[41] NGV Incentives Review Decision, August 15, 2011, p. 17.

7.5.2 FEI's Good Faith Belief That It Had Approval to Issue the Expenditures

When FEI issued the 2010-2011 NGV Incentives, it did so in good faith and on the basis of its belief that the approved EEC framework permitted it to do so.[42] In the course of the Incentive Review proceeding, FEI provided detailed evidence and submissions regarding its position that it had approval to issue the 2010-2011 NGV Incentives. The evidence and submissions provided by FEI in the NGV Incentive Review in support of its position have been included with this Application as Appendix K. FEI's position that it had approval was supported in the Final Submissions of other parties to the proceeding, including The Ministry of Energy and Mines, BC Sustainable Energy Association ("BCSEA"), and Commercial Energy Consumers Association of BC ("CEC").

BCSEA and CEC agreed with FEI's characterization of how the EEC framework was intended to operate. All three parties also stated their support of the Commercial NGV Incentive Program as being in the public interest.

7.5.3 Government Policy and Legislation

Over the time period that the FEU were developing and promoting the proposed NGT initiatives, provincial policy and legislation were evolving in ways that strongly supported FEI's provision of NGV incentives to fleet owners so as to encourage the development of the use of natural gas as fuel for transportation. In this Section, FEI describes these policy and legislative developments.

The 2007 BC Energy Plan recognized natural gas as a cleaner burning fuel to displace higher emitting diesel fuel and gasoline. The 2008 *Utilities Commission Amendment Act* ("2008 UCAA")[43] in Appendix T introduced, for the first time, a series of energy objectives for the Commission to consider in exercising its authority in certain types of regulatory proceedings. The 2008 UCAA energy objectives were supportive of using natural gas to displace conventional transportation fuel. In particular, the relevant objectives were:

> *"(a) to encourage public utilities to reduce greenhouse gas emissions;*
>
> *and*
>
> *(b) to encourage public utilities to use innovative energy technologies*
>
> > *(ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;"*

The enactment of the *Clean Energy Act* on June 3, 2010, further advanced the government's support for natural gas use in transportation. The CEA replaced the 2008 UCAA energy

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[42] When FEI brought forward its request in the 2010-2011 RRA for funding for the "Innovative Technologies" Program Area the program contemplated within that Program Area continue support for the deployment of forward-looking, low carbon technologies that are market ready and commercially available, but that have little or no market penetration in the BC marketplace.

[43] Bill 15 Utilities Commission Amendment Act (2008) received Royal Assent on May 1, 2008.

objectives with an enhanced set of sixteen energy objectives. In particular CEA energy objectives (d), (h) and (i) are supportive of natural gas for transportation.

> *"(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;*
>
> *(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;*
>
> *(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;"*

The CEA also includes sections 18 and 35 (n) which deal directly with natural gas being used in transportation to assist in achieving greenhouse gas emission reductions in the province. The government's April 28, 2010 news release issued by the Ministry on the CEA[44] in part 3 of the Backgrounder section listed the following among the goals of the CEA in the areas of environmental stewardship and GHG emission reductions.

> ***"Establishing programs** to encourage the use of high-efficiency equipment using clean electricity or natural gas for heating and hot water, and **to accelerate the deployment of natural gas and electric vehicles and fuelling infrastructure.**" [emphasis added]*

At the time the incentives were made (and at present) British Columbia's energy objectives supported the use of NGV incentives to promote NGVs in place of vehicles operated by traditional fuels in two important ways: First, objective (d) is "to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources". BC-developed engine technology can be used to permit the efficient use of natural gas in substitution for higher emitting diesel fuel. Second, objective (g) is "to reduce greenhouse gas emissions …" and objective (h) is "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia." Facilitating fleet conversion from diesel to natural gas reduces GHGs. The NGVs incented with the 2010-2011 NGV Incentives were expected (at the time) to produce between 20 - 30% fewer GHG emissions than their diesel counterparts. At the time, FEI estimated that the vehicles under the 2010-2011 NGV Incentives represented annual GHG savings of approximately 4,100 tonnes of CO2e per year, which is the equivalent to taking 800 passenger vehicles off the road.

The FEU believe that the FEU EEC NGV initiatives, including the $5.6 million of incentives that were granted, were strongly aligned with government policy and legislation for reducing greenhouse gas emissions in the transportation sector at the time they were made (and at present). The Companies expanded their efforts to develop NGT initiatives beginning in 2010 after the approval of the FEI and FEVI 2010-2011 RRA. The enactment of the CEA served to

[44] See Appendix U.

reinforce the direction that the Companies were taking. Each of the four incentive agreements was established after the June 3, 2010, enactment of the CEA (see Table 7-1 above).

7.5.4 IMMEDIATE LOAD BENEFITS WERE ANTICIPATED AS A RESULT OF ISSUING THE INCENTIVES

At the time they were made, the $5.6 million in expenditures were anticipated to result in immediate load building benefits that would accrue to all natural gas ratepayers. These benefits are described in this Section.

The 2010 LTRP reiterated the Companies' concern about declining throughput, attributable in part to declining use per customer rates, which adds to upward pressure on delivery rates and also represents a long-term stranding risk for the distribution system assets as a whole. At the time and at present, NGVs represented one of the best opportunities to mitigate the adverse delivery rate impact on existing customers flowing from this declining throughput. The addition of cost-effective NGV load on the FEI distribution system favourably affects customer delivery rates in two ways: First, delivery costs are shared over more GJs of natural gas, thus reducing the delivery charge per GJ; and second, adding NGV load is one of a few means available to FEI to combat declining throughput.

At the time that each of the incentives were provided to the fleet owners, FEI reasonably anticipated that the result would be immediate load building benefits (i.e. delivery margin) of the following magnitudes:

- City of Surrey Incentive: $5,611 per year;
- Kelowna School District Incentive: $21,888 per year;
- Waste Management Incentive: $38,142 per year; and
- Vedder Incentive: $263,261 per year (revenue of $548,460 less incremental O&M cost of LNG production).

The supporting calculations for each of the incentives were provided above in Sections 7.3.1 to 7.3.4. The additional load anticipated to result from these incentives, the equivalent of adding 1,858 residential customers, provided an immediate benefit by favourably affecting customer delivery rates.

7.5.5 LONGER TERM LOAD BENEFITS WERE ANTICIPATED AS A RESULT OF ISSUING THE INCENTIVES

At the time they were made, FEI reasonably anticipated that the $5.6 million in expenditures would result in longer term benefits by facilitating the development of the NGT market, which has significant long term benefits for natural gas customers.

In the NGV Incentive Review, FEI emphasized that the use of EEC NGV purchase incentives were a key element to enable the transition of the heavy duty transportation market from diesel fuel to natural gas.

> *Penetration of the natural gas market was estimated to by 30 PJs by 2030, or approximately 6% of the total heavy duty transportation market. The associated load building benefits to all rate payers from this level of penetration were estimated to be approximately $83 million per year. This provided evidence that there was direct benefit, and strong economic reasons why all customers should bear the cost of the EEC NGV purchase incentives.*

The Commission found that long term benefits had not been established by the FEU.[45] In particular, the Panel found that FEI's estimation of benefits was flawed in terms of:

- the absence of recognition of additional costs to provide LNG service;
- the assumed contribution from the sale of LNG; and
- the assumed cost of service for EEC incentive funding.

Although the Commission found that the specific dollar benefit of $83 million by 2030 had not been established, a significant long-term benefit remains when the conservative assumptions identified by the Commission are taken into account. Based on these conservative assumptions, the long term net benefit has been updated to a net benefit of approximately $45.4 million as identified in Appendix G, Schedule 1. This adjustment is based on a number of revisions, including the following:

- Revised natural gas demand forecasts;
- Revision to rate classes utilized in methodology;
- Forecast use rates have been adjusted at the CPI rate of approximately 2% per year;
- Incremental LNG capital costs have now been included in the forecast; and
- Revised incentive funding amounts, as well as revised time period for allocation of incentive.

In addition to the net benefit of $45.4 million by 2030, Appendix J details the additional annual volumes and associated delivery rate impacts that are anticipated as a result of the NGT Incentive Program. Additional demand volumes are anticipated to increase by approximately 25 PJs by 2030, which translates to a delivery rate decrease of 5.7 per cent for all FEI non-bypass customers.

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[45] EEC Incentive Decision, August 15, 2011, p. 17.

This highlights the FEI's finding that the NGT market represents a potentially significant source of load, that in the past has, and continues to warrant reasonable investments in order to capture and grow this market.

7.5.6 GHG BENEFITS WERE ANTICIPATED AS A RESULT OF ISSUING THE INCENTIVES

At the time they were made, the $5.6 million in expenditures were anticipated to provide immediate GHG benefits as follows:

- City of Surrey Incentive: 13 tonnes of CO2e emission reductions per year;
- Kelowna School District Incentive: 120 tonnes of CO2e emission reductions per year;
- Waste Management Incentive: 214 tonnes of CO2e emission reductions per year; and
- Vedder Incentive: 3,754 tonnes of CO2e emission reductions per year.

Collectively, the expenditures were anticipated to result in annual GHG savings of approximately 4,100 tonnes of CO2e per year, which is the equivalent to taking 800 passenger vehicles off the road.[46] Please refer to Appendix R for the detailed calculations.

FEI also reasonably anticipated that the $5.6 million in expenditures would result in longer term GHG benefits by facilitating the initial development of the NGT market in the heavy duty and return to base fleet sectors, which could result in significant GHG benefits over time. At the time, FEI forecast a cumulative total of approximately 865,000 tonnes of CO2e emission reductions by 2030, the equivalent of taking 165,000 passenger vehicles off the road.[47]

7.5.7 THE STAKEHOLDER SUPPORT THAT EXISTED AT THE TIME THE EXPENDITURES WERE MADE

The prudence of the $5.6 million in expenditures is also confirmed by the wide stakeholder support that FEI had for issuing the incentives.

As detailed in the 2010 EEC Annual Report, FEI requested feedback from its EEC Stakeholder Group regarding the use of EEC expenditures toward the NGV Commercial Demonstration Program. Five stakeholders – the BC Apartment Owners & Managers Association, BCSEA, City of Vancouver, CEC, and the Fraser Basin Council, submitted letters to FEI in support of the Company's approach to the funding approvals process and the appropriateness of using EEC expenditures for NGVs. These letters are included in Appendix E of this Application.

During the NGV Incentive Review, support was also confirmed by the Final Submissions of The Ministry of Energy and Mines, CEC and BCSEA, which are appended in Appendix K of this Application.

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46 Calculation based on US EPA Greenhouse Gas Equivalencies Calculator (2011).
47 NGT Application, Appendix A-1

7.5.8 TRC RESULTS OF EACH OF THE FOUR EXPENDITURES

The prudence of the $5.6 million in expenditures is also confirmed by the fact that each of the incentives issued had a TRC ratio greater than 1 (as determined prior to the issue of each incentive). Please refer to Appendix Q for a live spreadsheet of the TRC test results related to each expenditure issued.

The TRC test is a test that determines the ratio of benefits to costs of an incentive. A value greater than 1.0 is "cost effective". In the case of the incentives described in Section 7.3, the costs of each incentive were simply the amount provided, while the benefits for the purposes of the test were 1.4 at a program level. As set out above in Section 7.3, the TRC results for each of the four incentives were as follows:

- City of Surrey Incentive: 1.7;
- Kelowna School District Incentive: 1.1;
- Waste Management Incentive: 1.4; and
- Vedder Incentive: 1.4.

What these results demonstrate is that NGV initiatives result in a positive TRC at a program level (1.4 for the NGV Commercial Demonstration Program) and at a portfolio level (1.2 for Innovative Technologies Program Area).

7.5.9 COMPLEMENTARY BENEFITS

There were a number of complementary benefits anticipated by FEI at the time the incentives were issued that further support the prudence of the $5.6 million in expenditures:

- The development of further markets for BC's vast resources of natural gas will generate economic benefits from natural gas production, processing and transmission.
- The development of further markets for BC's vast resources of natural gas will generate economic benefits to the Provincial treasury in the form of increased production royalties.
- Lower costs of providing trucking services achieved from the reduction in fuel pricing, will help to improve the competitive position of products produced in BC.
- Lower costs of providing public transportation services (e.g. transit and/or school bus service) assists transit agencies and school districts in providing such services.
- A significant reduction in GHG emissions, which will benefit all citizens of BC.
- The expenditures support the development of natural gas transportation technology in BC.

7.5.10 CONCLUSION

The circumstances described in the preceding Sections 7.5.2 through 7.5.9 demonstrate that FEI's decisions in 2010 and 2011 to issue $5.6 million in incentive funding were prudent. Considered in aggregate, these various factors demonstrate that FEI had a reasonable and good faith belief that it had approval to issue the funds, and the anticipated benefits and overarching policy and legislative framework in effect at the time justified doing so. For these reasons, the 2010-2011 NGV Incentives were prudently incurred and recoverable through rates.

7.6 Volume Additions Resulting from 2010-2011 NGV Incentives Provided

The incentives provided in 2010-2011 to fleet owners have already generated firm load additions. In some cases, actual fuel consumption has exceeded the original fuel consumption estimates from Table 7-1, which calculated the TRC test results and delivery margin benefits. Current volumes from these four fleets are summarized below.

- City of Surrey's CNG garbage truck pilot has led to a firm contract demand with BFI for 60,000 GJs per year commencing in October of 2012 for a period of seven years.
- Over the 12 month period from August 2011 to July 2012, KSD consumed approximately 4,600 GJs, slightly below the original volume estimate of 6,000 GJs per year. FEI expects KSD's fuel consumption will increase once the take-or-pay commitment (of 5,000 GJs per year) in their fueling agreement becomes effective.
- Over the 12 month period from April 2011 to March 2012 WM consumed approximately 30,000 GJs, far exceeding the anticipated volume of 21,140 GJs per year.
- Since September 2011 Vedder has gradually placed its LNG vehicles into service. Over the period from September 2011 to June 2012 Vedder has consumed approximately 64,000 GJs. Fuel consumption in recent months suggests Vedder will surpass the original estimate of 138,500 GJs per year, and potentially exceed 175,000 GJs on an annual basis.[48]

All of these customers have take-or-pay contracts with FEI and thus are motivated to maintain their minimum level of fuel consumption.

FEI has not recalculated the TRC test results described in Section 7.5.8 based on these volumes, however any revised results would likely indicate a higher TRC number based on the evidence provided above. Furthermore, higher delivery margin benefits would result from these increased volumes.

[48] Vedder's fuel consumption for June 2012 was 15,143 GJ (all 50 LNG tractors in service).

7.7 The Prior Incentives Granted are consistent with the Provisions of the GGRR and Prescribed Undertaking 1

The $5.6 million of incentives issued under the Commercial NGV Demonstration Program are consistent with the intent of the GGRR and Prescribed Undertaking 1 in the following ways:

- The prior incentives were for grants for "eligible vehicles" as defined in the Regulation. The grants were provided to persons within British Columbia for vehicles to be operated within British Columbia and were anticipated to generate emission reductions, economic benefits, ratepayer benefits and provide initial "proof-of-concept" steps towards wider adoption of natural gas as a vehicle fuel among heavy duty and return-to-base fleets. The incentive awards included in the $5.6 million were for tractor-trailer units, waste haulage vehicles and school buses, all of which are among the specified eligible vehicles in the Regulation.
- The $5.6 million was provided for eligible vehicles within the prescribed undertaking limits. The incentive awards were for 100% (or less) of the vehicle price differentials between a natural gas vehicle and the comparable diesel or gasoline-fuelled vehicle. This complies with the Year 1 limit on incentive awards in Prescribed Undertaking 1.
- The $5.6 million of incentives were awarded through an open and competitive process. Considering that the Companies' NGT initiatives were at an earlier stage of development and the incentives program was being launched as a demonstration program, efforts were made to communicate the Commercial NGV Demonstration Program widely to attract suitable parties. Invitations to participate were sent out in April 2010 and ultimately provided to 27 different companies and organizations (or 40 individuals in total within the 27 organizations). The 27 organizations were selected because they had expressed interest in NGT during the Companies' marketing efforts or because they represented a significant interest in the sectors being targeted initially for adoption of natural gas in fleets. The Companies were willing to receive and evaluate proposals from parties other than the organizations originally invited to participate and did so in more than one case. In fact Vedder Transport, the first party in BC to adopt LNG as a commercial fleet fuel, was referred to FEI and the incentives program through contact with Westport Innovations.

7.8 Conclusion

The NGV incentives of $5.6 million provided in 2010 and 2011 were prudent expenditures and in the public interest. They generated throughput, represented an investment in promoting a much larger potential market, and were supported by the same policy considerations that underpin the prescribed undertaking expenditures for vehicle incentives in the GGRR. Given that the 2010-2011 NGV Incentives are similar in nature to those that will be issued under Prescribed Undertaking 1, FEI submits that a similar financial treatment is appropriate. FEI is intending to count any recoveries approved from the 2010-2011 NGV Incentives towards the

$62 million funding established by the GGRR for Prescribed Undertaking 1, such that, if the entire $5.6 million is approved, it will not spend more than $56.4 million in further funding. FEI submits that the outcome is fair, consistent with the interests of FEI's customers, and in line with government policy.

Appendix A

MINISTRY OF ENERGY AND MINES MAY 15, 2012 NEWS RELEASE

BRITISH COLUMBIA

NEWS RELEASE

For Immediate Release
2012ENER0057-000674
May 15, 2012

Ministry of Energy and Mines

Regulation fuels B.C.'s natural gas transportation sector

VICTORIA – The greenhouse gas reduction regulation will help diversify and increase the market for natural gas in British Columbia's transportation sector as well as deliver on our Natural Gas Strategy, announced Minister of Energy and Mines Rich Coleman.

This regulation allows utility companies to deliver natural gas transportation programs, including the opportunities to:

- Offer incentives to transportation fleets that would use natural gas, such as buses, trucks or ferries.
- Build, own and operate compressed natural gas fuelling stations or liquefied natural gas fuelling stations.
- Provide training and upgrades to maintenance facilities to safely maintain natural gas-powered vehicles.

These programs will increase options and opportunities for the transportation industry to use natural gas, a cheaper and cleaner option than traditional fuels like gasoline and diesel. By encouraging the use of natural gas, the Province is making use of one of B.C.'s natural resources. The use of natural gas in transportation supports economic development and new jobs at B.C.-based natural gas technology and services companies.

In developing this regulation, the Province consulted with about 20 organizations including utilities, fleet companies, communities, fuel suppliers and the natural gas vehicle industry. Promoting natural gas as a transportation fuel is a key action in British Columbia's Natural Gas Strategy.

Quotes:

Rich Coleman, Minister of Energy and Mines –

"It makes sense to develop a market for natural gas transportation here in B.C. by using our abundant natural gas reserves. This regulation will help us build on our global leadership in clean transportation, bringing new jobs and more economic opportunities to the province."

Blair Lekstrom, Minister of Transportation and Infrastructure –

"The use of natural gas will be a big part of the future for the transportation industry. We are encouraging the use of this made-in-B.C. resource, which can help cut transportation costs in half. We are already seeing trucking companies moving to natural gas, and it is a part of BC Ferries' long-term vision, as well. Natural gas is the transportation fuel choice of the future."

Pat Bell, Minister of Jobs, Tourism and Innovation –

"Our clean tech sector is a driving factor in the economic growth of British Columbia, generating $2.5 billion in revenue with a combined payroll estimated at $650 million. With this regulation, more companies will integrate B.C.'s world-leading natural gas technologies into their operations, increasing their competitiveness and driving innovation."

Terry Lake, Minister of Environment –

"By increasing the use of natural gas in fleets around the province we are making a clean transportation choice that reinforces our climate change leadership and reduces GHGs. The shift from vehicles that use costly, higher polluting diesel to those that use locally sourced natural gas is just another example of the many made-in-B.C. innovations that are part of our green economy."

Quick Facts:

- The regulation permits a utility to spend up to $62 million on vehicle and ferry incentives, up to $12 million on compressed natural gas fuelling stations and up to $30.5 million on liquefied natural gas stations, for a total of $104.5 million.
- The Province will require annual reporting on the programs being offered to review success and determine if any changes are required.
- Natural gas is 25 per cent to 40 per cent cheaper than gasoline and diesel.
- A natural gas-powered vehicle produces 20 per cent to 30 per cent fewer greenhouse gas emissions compared to a gasoline or diesel vehicle.
- British Columbia is home to world-leading natural gas vehicle industries, including engine and refuelling technology.
- The Province is offering incentives to provide up to $2,500 off the sticker price for qualifying compressed natural gas vehicles. This is being offered through the $14.3 million Clean Energy Vehicle Program, announced in November 2011.

Learn More:

- Find out more about B.C.'s Natural Gas Strategy at: http://www.gov.bc.ca/ener/natural_gas_strategy.html

Contact: Sandra Steilo
Ministry of Energy and Mines
250 952-0617

Connect with the Province of B.C. at: www.gov.bc.ca/connect

Appendix B

GREENHOUSE GAS REDUCTIONS (CLEAN ENERGY) REGULATION

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 295 *, Approved and Ordered* **MAY 14 2012**

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Greenhouse Gas Reduction (Clean Energy) Regulation is made.

DEPOSITED

May 15, 2012

B.C. REG. 102/2012

Minister of Energy and Mines and Minister Responsible for Housing

Mary McE

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Clean Energy Act*, S.B.C. 2010, c. 22, s. 35 (n)

Other:

April 2, 2012 R/847/2011/27

GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

Definitions

1 In this regulation:

"**Act**" means the *Clean Energy Act*;

"**eligible vehicle**" means

(a) a specified vehicle with a power train and fuel system that has not been modified after manufacture, and

(b) a marine vehicle

that uses, as a primary fuel source, compressed natural gas or liquefied natural gas;

"**heavy-duty vehicle**" means a truck or tractor-trailer with a manufacturer's gross vehicle weight rating of 11 793 kg or more;

"**medium-duty vehicle**" means a vehicle, including a waste-haulage truck, with a manufacturer's gross vehicle weight rating of more than 5 360 kg but less than 11 793 kg;

"**safety guidelines**" means safety guidelines adopted by the British Columbia Safety Authority;

"**specified vehicle**" means a heavy-duty vehicle, medium-duty vehicle, school bus or transit bus;

"**tanker truck load-out**" means equipment for transferring liquefied natural gas from a storage tank to a liquefied natural gas tank trailer;

"**undertaking period**" means the period that ends on March 31, 2017.

Prescribed undertakings

2 (1) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility provides, through an open and competitive application process,

(i) grants or zero-interest loans to persons in British Columbia for the purchase of an eligible vehicle to be operated in British Columbia, or

(ii) grants to persons in British Columbia

(A) to implement safety practices, or

(B) to improve maintenance facilities

to meet safety guidelines for operating and maintaining an eligible vehicle;

(b) a grant or zero-interest loan for an eligible vehicle do not, in a year of the undertaking, exceed the percentage difference as indicated in the following table:

	Year of Undertaking					
	1	2	3	4	5	6
Percentage of the difference between the cost of the eligible vehicle and the cost of a comparable vehicle that uses gasoline or diesel	100	80	70	60	50	40

(c) total expenditures on the undertaking during the undertaking period, including expenditures on administration, marketing, training and education, do not exceed $62 million, and

(i) expenditures on the undertaking during the undertaking period on marine vehicles do not exceed $11 million, and

(ii) expenditures on the undertaking during the undertaking period

(A) on administration, marketing, training and education do not exceed $3.1 million, and

(B) on grants referred to in paragraph (a) (ii) do not exceed $4 million;

(2) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility

(i) constructs and operates, or

(ii) purchases and operates,

one or more compressed natural gas fuelling stations, including storage, compression and dispensing equipment and facilities, within the service territory of the public utility for the purposes of providing compressed natural gas fuel and fuelling services to owners of vehicles that operate on compressed natural gas;

(b) total expenditures on the undertaking during the undertaking period, including expenditures on administration and marketing, do not exceed $12 million, and

(i) the average expenditure on stations, in any year of the undertaking, does not exceed $1.1 million per station, and

(ii) expenditures, during the undertaking period, on administration and marketing do not exceed $240 000;

(c) at least 80% of the energy provided at each station during the undertaking period is provided to one or more persons under a take-or-pay agreement with a minimum term of 5 years.

(3) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility

(i) constructs and operates, or

(ii) purchases and operates

one or more tanker truck load-outs or liquefied natural gas fuelling stations for the purposes of providing within British Columbia liquefied natural gas fuel and fuelling services to owners of vehicles that operate on liquefied natural gas;

(b) total expenditures on the undertaking during the undertaking period, including expenditures on administration and marketing, do not exceed $30.5 million, and

(i) in any year of the undertaking period an expenditure on a station does not exceed $2.75 million, and

(ii) expenditures during the undertaking period on a tanker truck load-out do not exceed $4 million, and on administration and marketing do not exceed $250 000;

(c) at least 80% of the energy provided at each station during the undertaking period is provided to one or more persons under a take-or-pay agreement with a minimum term of 5 years.

Expiry

3 This regulation is repealed on April 1, 2017.

Appendix C

NGT DECISION, COMMISSION ORDER NO. G-128-11

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-128-11

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
for Approval of a Service Agreement for Compressed Natural Gas Service
with Waste Management of Canada Corporation
and
General Terms and Conditions for
Compressed Natural Gas and Liquified Natural Gas Service

BEFORE: A. A. Rhodes, Panel Chair/Commissioner
D. A. Cote, Commissioner July 19, 2011
D. Morton, Commissioner

O R D E R

WHEREAS:

A. On December 1, 2010, FortisBC Energy Inc., formerly Terasen Gas Inc. (FEI), applied to the British Columbia Utilities Commission (Commission) for approval of a Service Agreement with Waste Management of Canada Corporation for compression and dispensing service for Compressed Natural Gas (the Waste Management Agreement), pursuant to sections 59 to 61 of the *Utilities Commission Act* (the Act);

B. FEI also applied for acceptance of the expenditures required to provide compression and dispensing service for Compressed Natural Gas under the Waste Management Agreement pursuant to section 44.2 of the Act;

C. FEI also applied for approval of General Terms and Conditions for compression and dispensing service for Compressed Natural Gas (CNG) Service and transportation, delivery, fuel storage and dispensing service for Liquified Natural Gas (LNG) Service for inclusion in future service agreements with customers pursuant to sections 59 to 61 of the Act, (collectively, the Application);

D. FEI sought an expedited process for approval of the Waste Management Agreement, requesting a permanent rate on or before January 14, 2011, or, alternatively, approval of an interim rate pursuant to section 89 of the Act on or before that date;

E. By Order G-181-10 dated December 6, 2010, the Commission established an expedited written hearing process for its consideration of the Waste Management Agreement, and established a written hearing process for the remainder of the Application;

…/2

F. By Order G-6-11 dated January 14, 2011, the Commission approved the Waste Management Agreement on an interim basis, subject to certain changes; and subject to an amended version being refiled with the Commission in standard Tariff Supplement form on a non-confidential basis;

G. On March 25, 2011, FEI submitted the amended Waste Management Agreement as Tariff Supplement J-1;

H. The Commission has considered the evidence and submissions of the parties and approves the interim Waste Management Agreement in final form as a Tariff Supplement. The Commission also accepts the expenditures on the facilities required to provide service under the Waste Management Agreement pursuant to section 44.2 of the Act but rejects the proposed General Terms and Conditions. The Commission will approve revised General Terms and Conditions which better provide for full cost recovery from the potential CNG/LNG customer, as set out in the Reasons for Decision which follow.

NOW THEREFORE pursuant to sections 44.2, 59-61, and 90 of the Act, and for the Reasons contained in Appendix A hereto, the Commission orders as follows:

1. The Waste Management Agreement as amended and refiled on March 25, 2011 as Tariff Supplement J-1, is approved in final form.

2. The expenditures required for FEI to provide compression and dispensing service for natural gas under the Waste Management Agreement, in the amount of $775,031 are accepted.

3. Approval of the proposed General Terms and Conditions for CNG Service and LNG Service is denied.

4. The Commission will approve revised General Terms and Conditions which, in addition to the proposed "Take or Pay" commitment, better reflect full cost recovery from the potential CNG/LNG customer, as more fully set out and explained in the Reasons for Decision attached hereto as Appendix A.

5. FEI shall comply with all directions of the Commission Panel in the Reasons for Decision attached hereto as Appendix A.

6. Subject to FEI filing revised General Terms and Conditions acceptable to the Commission, depreciation rates are approved in accordance with the following table:

Asset	Estimated Useful Life (years)	Depreciation Rate (%)
CNG Dispensing Equipment	20	5%
LNG Dispensing Equipment	20	5%
Foundations	20	5%
Pumps	10	10%
Dehydrator	20	5%

…/3

7. No amounts will be approved for capitalized overhead.

8. The following deferral accounts are approved:

   a. A non-rate base deferral account attracting AFUDC to capture the cost of the current application, including the cost of the Waste Management Application and to recover these costs from all non-by-pass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period. [Future individual application costs must be recovered from those customers.]

   b. A non-rate base deferral account attracting AFUDC to capture the O&M costs and the cost of service associated with the capital additions to the delivery system incurred and the CNG and LNG Service recoveries received prior to January 1, 2012 for contracts approved by the Commission, and to recover or refund the balance to all non-bypass customers by amortizing the balance through delivery rates commencing January 1, 2012 over a three year period.

   c. An ongoing rate base deferral account to capture incremental CNG and LNG recoveries received from actual volumes purchased in excess of minimum contract take or pay commitments to be refunded to all non-bypass customers by amortizing the balance through delivery rates over a one year period, commencing the following year, to be effective as of January 1, 2012 pursuant to sections 59 to 61 of the Act.

DATED at the City of Vancouver, in the Province of British Columbia, this 19th day of July, 2011.

BY ORDER

Original signed by:

A.A. Rhodes
Panel Chair/Commissioner

Attachments

IN THE MATTER OF

FORTISBC ENERGY INC.
AN APPLICATION FOR APPROVAL OF A SERVICE AGREEMENT
FOR COMPRESSED NATURAL GAS SERVICE
WITH WASTE MANAGEMENT OF CANADA CORPORATION
AND GENERAL TERMS AND CONDITIONS FOR COMPRESSED NATURAL GAS
AND LIQUEFIED NATURAL GAS SERVICE

REASONS FOR DECISION

JULY 19, 2011

BEFORE:

A.A. Rhodes, Panel Chair / Commissioner
D.A. Cote, Commissioner
D. Morton, Commissioner

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APPENDICES

EXECUTIVE SUMMARY

In December, 2010, FortisBC Energy Inc. (FEI) applied to the British Columbia Utilities Commission (Commission) for approval of "General Terms and Conditions" to allow it to offer Compressed Natural Gas (CNG) and Liquified Natural Gas (LNG) fuelling service to various potential customers with return to base fleets of buses, heavy duty and vocational trucks. Vehicles in these fleets are currently fuelled, for the most part, by diesel and would be converted, or replacement trucks purchased, to run on CNG or LNG. FEI proposes to negotiate individual agreements with customers to construct and operate a fuelling facility on their premises. Each agreement will reflect the proposed General Terms and Conditions, but may include additional provisions that reflect the specific terms that have been negotiated. While FEI proposes to recover most costs of the natural gas vehicle (NGV) fuelling infrastructure from new CNG/LNG customers, the Panel finds that there are still what could amount to substantial potential costs that are proposed to be recovered from existing ratepayers.

FEI also sought acceptance of the forecast expenditures it incurred to provide a fuelling station to Waste Management of Canada Corporation (Waste Management) and approval of the draft contract between those two parties. This contract (the Waste Management Agreement) is the first specific instance of a contract based on the proposed General Terms and Conditions. On January 14, 2011 the Commission agreed to approve the Waste Management Agreement on an interim basis provided certain changes were made and the amended agreement was filed on a non-confidential basis. The revised Waste Management Agreement was filed in final form as Tariff Supplement J-1 on March 25, 2011. The Commission Panel now approves the Waste Management Agreement as a Tariff Supplement. It also accepts the expenditures for FortisBC Energy Inc. to construct the fuelling facilities at Waste Management's premises.

The Panel finds that if the NGV market can be developed as described in FEI's application, benefits would accrue to FEI's new NGV customers, its existing ratepayers and the residents of British Columbia, not to mention FEI itself. These benefits arise from the lower cost of natural gas as a fuel when compared to diesel or gasoline; the increased throughput of natural gas on the FEI system due to the additional consumption of the truck fleet, other things equal, and the reduction in Green House Gas (GHG) emissions from the use of natural gas as compared to diesel or gasoline. However, the Panel finds that there are significant risks associated with this venture, including, but not limited to, the uncertainty surrounding the future price spread between natural gas and oil, and the apparent need for ongoing incentive funding to subsidize the higher cost of natural gas engines. These two factors, among others, had both contributed to the collapse of a previous NGV market in BC in which the Applicant had been involved.

Further, the Panel finds that a CNG/LNG fuelling infrastructure has no natural monopoly characteristics and the service offerings applied for would not be subject to regulation, unless the services were being provided by an organization that is already a regulated public utility.

Thus, the Panel finds that, given the risks involved and the potential presence of unregulated competition in the NGV market, it is neither in the public interest nor fair and just that FEI's existing ratepayers subsidize the NGV fuelling facilities. The Panel is of the view that the major beneficiaries of this proposed project are the potential new customers in the transportation sector, who are GHG emitters, FEI itself, which will make a return on the fuelling station infrastructure, and the residents of the province as a whole, who will enjoy reduced GHG emissions. FEI's existing ratepayers, on the other hand, may enjoy some reduction to the delivery charge they are required to pay due to increased throughput on the system, other things equal, but are not otherwise beneficiaries to the same extent, although they are being asked to shoulder the risks, should the project be unsuccessful. Accordingly, the Panel rejects the proposed General Terms and

Conditions as too general and failing to ensure that the actual cost of service is collected from the customer, as fully as possible. The Panel will approve revised General Terms and Conditions which reflect a greater recovery of the total actual cost of service as outlined in these Reasons for Decision.

1.0 INTRODUCTION

On December 1, 2010 FortisBC Energy Inc., formerly Terasen Gas Inc., applied to the Commission for, among other things, expedited approval of an executory contract to provide natural gas compression and dispensing services to Waste Management of Canada Corporation (the Waste Management Agreement). This was approved for as a Tariff Supplement pursuant to sections 59-61 of the *Utilities Commission Act*, R.S.B.C. 1996, c.473, as amended, for its fleet of return-to-base natural gas vehicles (NGVs).

The Waste Management Agreement was approved on an interim basis on January 14, 2011 (subject to certain amendments and the requirement it be filed on a non-confidential basis), to allow for a closer examination of the business model and any implications which could arise as a result of its approval.

In this Application, FEI also seeks the following:

- permanent approval of the now final Waste Management Agreement as a Tariff Supplement pursuant to sections 59 to 61 of the *Utilities Commission Act* (alternatively, *UCA* or the *Act*).
- acceptance of the expenditures it made on the facilities required to provide the natural gas compression and dispensing services to Waste Management under s. 44.2 of the *Act*.
- approval of standard form "General Terms and Conditions" pursuant to sections 59-61 of the *Act* to allow FEI to offer natural gas vehicle services to other potential customers for:
    - compression and dispensing services for Compressed Natural Gas (CNG); and
    - transportation, delivery, fuel storage, and dispensing for Liquified Natural Gas (LNG).

FEI takes the position that the approvals sought in the Application will benefit existing customers by enabling the addition of cost-effective load to the natural gas distribution system. However, it acknowledges that ratepayers should bear little or no risk and be "kept whole". It submits that the "take or pay" provision, which is a cornerstone of the business model, "ensures that the customer carries the bulk of the cost and risk associated with the investment." (Exhibit B-1, pp. 11, 13)

2.0 SPECIFIC ORDERS SOUGHT

FEI seeks the following specific approvals:

1. An Order approving the Waste Management Agreement pursuant to sections 59-61 of the *Act*.
2. An Order accepting the estimated expenditures (in the amount of $737,944) for the Waste Management project pursuant to s. 44.2 of the *Act*.

3. An Order approving an amendment to FortisBC Energy's "General Terms and Conditions," specifically, the addition of a new section 12B relating to CNG and LNG Service.

4. An Order approving:

   a. Depreciation rates applicable to NGV refuelling assets as per the following table:

Asset	Estimated Useful Life (years)	Depreciation Rate (%)
CNG Dispensing Equipment	20	5%
LNG Dispensing Equipment	20	5%
Foundations	20	5%
Pumps	10	10%
Dehydrator	20	5%
Capitalized Overhead	Average	2.7%

   b. A non-rate base deferral account attracting an Allowance for Funds Used During Construction (AFUDC) to capture the NGV Fuelling Service Application costs incurred in 2010 and 2011 and to recover these costs from all non-by-pass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period.

   c. A non-rate base deferral account attracting AFUDC to capture the operating and maintenance costs and the cost of service associated with the capital additions to the delivery system incurred and the CNG and LNG Service recoveries received prior to January 1, 2012, and to recover or refund the balance to all non-bypass customers by amortizing the balance through delivery rates commencing January 1, 2012 over a three year period.

   d. An ongoing rate base deferral account to capture incremental CNG and LNG recoveries received from actual volumes purchased in excess of minimum contract take or pay commitments to be refunded to all non-bypass customers by amortizing the balance through delivery rates over a one year period, commencing the following year, to be effective as of January 1, 2012 pursuant to sections 59 to 61 of the *Act*.

(Application, pp. 57, 70-71)

3.0 PROCEDURAL BACKGROUND

The Application was heard by way of a two stage written hearing process, to allow the application for approval of the Waste Management Agreement to proceed on an expedited basis. Three rounds of Information Requests in total were conducted. A number of the Information Requests were also sought to be held confidential. Some responses were refiled on a non-confidential basis. Where possible, the Commission Panel makes reference only to non-confidential information. However, in some instances, reference to confidential information cannot be avoided. The Commission Panel has attempted to ensure that reference has not been made to information which might be considered "commercially sensitive."

The following parties intervened: B.C. Sustainable Energy Association (BCSEA), B.C. Old Age Pensioners' Organization (BCOAPO) and the Commercial Energy Consumers (CEC). The hearing concluded with the filing of FEI's Reply Submissions on April 12, 2011.

4.0 HISTORICAL BACKGROUND

FEI, through one or more predecessor companies, has previously been involved in the NGV market. It was initially successful in penetrating the light duty vehicle market some decades ago when it established a public CNG fuelling network as a regulated offering. However, this network proved to be unsustainable when market conditions changed. (Exhibit B-1, p. 8)

More specifically, during the mid 1980s to 1990s FEI installed, owned and maintained CNG compression facilities at numerous sites as a regulated offering. At that time, FEI's focus was on public fuelling stations where the retail companies which hosted the CNG fuelling stations were charged a postage stamp rate. Vehicles utilizing the service were primarily high-mileage light duty converted vehicles.

In 1991, in BC, there were over 30 NGV fuelling stations to serve over 7,000 NGVs. Consumption of natural gas by the transportation sector peaked in 1992. At that time there was a wide price differential between natural gas and gasoline, supporting the market. FEI reports that by 1997 there were 52 fuelling stations (owned and operated either by its predecessor company or a third party provider) within its service territory, with an annual load of 627,000 GJ. By the late 1990s car manufacturers had started manufacturing NGVs and these vehicles became more prevalent than converted vehicles. (Exhibit B-1, p. 9)

On December 15, 1999, FEI, then Terasen, applied to the Commission for permission to sell its NGV utility assets to a wholly-owned non-regulated subsidiary, now known as Clean Energy. At that time, Terasen had compression and dispensing equipment located at 19 sites with a net book value of $4.1 million. The compression and dispensing service had been losing money and was being supported by other customer classes. The sale of the equipment, effective January 1, 2000, resulted in a loss of $2.13 million which was to be amortized over ten years and borne by ratepayers. The $2.13 million charge represented just over 50% of the net book value of the assets. (Exhibit B-6, BCUC IR 2.6.1) FEI takes the position that it formed the "separate, non-regulated company in order to have greater flexibility to grow the NGV market and own and operate natural gas fuelling stations across North America." (BCUC Order G-143-99; Exhibit A-2-4; Exhibit B-1, p. 9)

FEI sold what remained of its interest in Clean Energy in 2005. (Exhibit B-6, BCUC IR 2.29.2) At this point in time, "...the light-duty NGV market has almost completely eroded in B.C." Service has historically been provided by FEI to the transportation sector primarily under Rate Schedule 6. Rate Schedule 6 also offers up to $10,000 in incentive funding for the purchase of a factory-built NGV or the conversion of a conventionally-fuelled vehicle to natural gas. Rate Schedule 25 is also available for the provision of natural gas to large general accounts. This rate schedule had one customer, being Coast Mountain Bus Company, at the time the Application was prepared. (Exhibit B-1, Appendix A-2, pp. 8, 11-12; Appendix C, Rate Schedule 6)

FEI attributes the decline in consumption of natural gas by light duty vehicles over the last decade to a number of factors including:

- The price spread between natural gas and conventional fuels narrowed in the period between 2001-2003 to the point where there was no longer a sufficient economic incentive to switch to natural gas, given the difference in capital costs for the two options;
- Circa 2004 car manufacturers withdrew NGV offerings of pickup trucks and vans from the market;

- The cost of engine conversions increased from $3,000 (early 1990s) to $7,000 to $10,000 (now);
- A Natural Resource Canada matching grant program incentive for vehicle conversions was discontinued in 2006;
- Hybrid vehicles were introduced and competed with passenger and light duty vehicle market segments; and
- With load loss, stations closed and fuelling became less convenient.

(Exhibit B-1, pp. 9-10)

5.0 MARKET CONDITIONS, GOVERNMENT POLICY AND THE NEED TO KICKSTART THE NGV MARKET

Vehicles fuelled by natural gas, either in CNG or LNG form, although less energy efficient than their diesel counterparts, produce less Green House Gas (GHG) emissions. (Exhibit B-8, BCSEA IR 2.3.1) FEI advises that studies have shown conventional CNG has a net carbon intensity which is lower than that of reformulated gasoline and 28% less than that of ultra-low sulphur diesel; and that LNG provides a comparable reduction. (Exhibit B-1, p. 37) Thus, FEI argues that the displacement of vehicles currently fuelled by gasoline or diesel with vehicles fuelled by natural gas would result in significant reductions in GHGs in British Columbia. However, natural gas is not without GHG emissions. [A Gigajoule (GJ) of natural gas produces in the range of .05069 tonnes of GHGs, as per Terasen Gas Inc. 2010-2011 Revenue Requirements Application, Response to BCUC IR 1.22.1] In the case of Waste Management, FEI estimates that its fleet of twenty heavy duty vehicles would create 921.6 tonnes of carbon per year when run on diesel as compared to 708.2 tonnes of carbon per year when run on CNG, a saving of 213.4 tonnes per year, based on an analysis using GHG emissions per kilometres travelled for the two fuels. (Exhibit B-8, BCSEA IR 2.3.1)

FEI maintains that this reduction in GHG emissions can assist the province in meeting some of the objectives of the 2007 Energy Plan and the *Clean Energy Act* and notes that the Energy Plan identified the transportation sector as "a major contributor to climate change and air quality problems." (Exhibit B-1, pp. 35-36) FEI also notes that the Low Carbon Fuel Requirements Regulation mandates a 10% reduction in carbon intensity of motor fuels in BC by 2020.

FEI submits that in spite of the recent near collapse of the market for NGVs, there is currently a significant upside potential to this same market. Specifically, it forecasts that by 2030, there is the potential for 30 Petajoules (PJs) of natural gas energy use for buses, medium and heavy duty trucks; and an additional 6 PJs of demand for passenger vehicles. (Exhibit B-1, p. 23) [This compares to the total amount of natural gas delivered in the FEI system in 2010 of approximately 200 PJs]. FEI cites a number of factors that may contribute to the growth in demand for NGV over the next 10 to 20 years, including:

- Natural Gas price advantage over diesel which translates to operating cost savings;
- Competitive advantage of natural gas over diesel due to environmental benefits, including ownership and value of carbon credits;
- Availability of fuelling infrastructure; and

- Incentive funding that will reduce the incremental cost of manufactured NGV vehicles over diesel/gasoline powered vehicles.

(Exhibit B-1, pp. 25-33)

FEI submits that market indications are that natural gas is likely to retain its price advantage over diesel for the foreseeable future. (FEI Final Submissions, para. 35) FEI recognizes, however, that "predicting market share for alternative energy technologies is extremely difficult and highly subjective. Historically, projections for rapid adoption rates have proved to be wildly optimistic." (FEI Response to BCUC IR 2.68.3 from 2010-2011 RRA Application filed as Exhibit A2-6)

FEI is hoping to "kickstart" the potential market for natural gas vehicles with a regulated CNG compression and dispensing service and a storage and dispensing service for LNG. It maintains that because it is in the business of delivering energy to customers in a useable form these services are natural extensions of its existing service to customers. It further states that extension tests and policies are used to ensure that new customers pay the cost of service. (Exhibit B-1, p. 19)

FEI argues that the NGV business model being proposed is different from its previous venture, in that it targets return-to-base fleets of buses, heavy duty and vocational trucks which can be manufactured to use natural gas (as opposed to requiring conversion) and are available in British Columbia. It further argues that although the target market is smaller, there is less risk of changing market conditions. (Exhibit B-1, p. 10) These fleets of vehicles will serve as "anchor tenants" for the customized fuelling stations which FEI will build and own on the customer's premises. The vehicles can be fuelled on their return to their base each evening, giving FEI what amounts to a committed "captive audience."

FEI is proposing a rate design that is based on the cost of service. Once the market is more mature, FEI states that it may consider other rate designs and business models. It submits that the approach being put forward in this Application "will allow for the safe, economic and timely development of additional NGV projects to ensure that demand for NGV and supply of NGV Services are re-introduced in a sustainable manner." (Exhibit B-1, p. 20)

6.0 PROPOSED BUSINESS MODEL

6.1. CNG Service Description

FEI's target market for the CNG service offering will be buses and heavy duty or vocational trucks that are return-to-base fleets which are of sufficient size to be readily served by original equipment manufacturers' (OEM) product. In providing its service offering, FEI has identified three required steps in what it describes as the CNG value chain or model. The first step is the physical delivery of the natural gas supply to the customer. Once delivered, the second step is the process of compressing and storing natural gas at high pressure to be ready for delivery to the vehicle's storage tank. Accordingly, FEI will build customized, private stations designed to support the particular customer's return-to-base fleet with the capability of pressurizing fuel at up to 3,600 pounds per square inch (psi). The third step in the chain involves the actual dispensing of the CNG to the vehicle. FEI states that the cost of owning and maintaining the station for compression and dispensing will be part of the cost of service (COS) and the customer will be responsible for paying a per GJ charge which includes these costs.

With this model FEI states it will be positioned to offer the complete CNG service offering to potential customers. This will involve the following:

- Execution of a service agreement with the customer for compression and fuelling services;
- Investment in any required meter and main extensions and provision of the gas supply; and
- Installation and maintenance of the compression, pressure storage and dispensing equipment.

It is FEI's plan to own and maintain the private station equipment which includes gas compressors, gas dehydrators, high pressure storage tanks and fuel dispensers. Fuel dispensers may be either of the "fast-fill" type [as used in the case of BC Transit] which can fuel a vehicle in 2-3 minutes, or a time-fill setup which can be used to refuel a vehicle overnight, or a combination of the two. (Exhibit B-1, pp. 14-16)

6.2 LNG Service Description

LNG is natural gas which has been cooled to -160 degrees Celsius and must be stored on vehicles and in stations at this low temperature if it is to remain in a liquid state. FEI states that this fuel, because of its density, is particularly well-suited for vehicles like highway tractors with high daily mileage requirements. Like CNG, the value chain for LNG involves a number of steps. The first of these is the production and initial storage of LNG which is currently done at FEI's Tilbury bulk LNG storage facility. The second step in the chain involves the delivery of LNG for use in a customer's fuelling station since there is no piped infrastructure for LNG. FEI states that its proposed LNG service offering contemplates FEI owning and operating the transport and delivery process although it will allow customer delivery of the LNG where appropriate. The third step in the value chain involves the fuel storage and dispensing at the customer fuelling station - services which again FEI will provide.

As with the CNG model, FEI anticipates that it will be positioned to provide a complete LNG service offering to the customer. This will involve the following:

- Provision of LNG supply at Tilbury (where it is offered for bulk sale under Rate Schedule 16 – which is an interruptible service currently offered pursuant to a 5 year pilot project);
- Securing a service agreement with the customer for the LNG fuelling station (including cryogenic storage and dispensing);
- LNG transport from Tilbury to the customers' facility by transport truck, if required; and
- Investment in and maintenance of the storage and dispensing equipment.

For the LNG Service offering, it is FEI's intention to own and maintain the LNG tankers, cryogenic storage tanks which include secondary containment, the LNG vaporizer and pump and the dispenser equipment. As with the CNG offering, the model calls for the cost of owning and maintaining the station to be built into the COS charge which will be recovered from the customer on a per GJ basis. Where required, a separate delivery charge to cover transport and delivery of the LNG will be created. (Exhibit B-1, pp. 16-18)

6.3 Rate Schedules

FEI's business model is reflected in the rate structures for which it seeks approval. Essentially, there are two components:

1) the General Terms and Conditions for CNG and LNG Services; and
2) Customer-Specific contracts, which will be filed as Tariff Supplements.

In this Application, FEI is seeking Commission approval of standard form General Terms and Conditions which incorporate its proposed rate design for both CNG and LNG service pursuant to sections 59-61 of the *Utilities Commission Act,* which deal with rates. This proposed rate design "yields a customer-specific rate that will be incorporated into the applicable service agreement." (Exhibit B-1, p. 61)

FortisBC proposes that the General Terms & Conditions will have the following:

- a take or pay provision;
- provisions for full cost recovery from each customer; and
- stipulation of how the cost of service will be determined.

The General Terms and Conditions for which approval is sought are contained in Appendix B of the Application. They are an amendment to FEI's General Terms and Conditions by way of the addition of a section (section 12B) which relates to CNG and LNG Service. (Application, p. 11) Section 12B is very general and comprises little more than a single page. It is reproduced in its entirety in Appendix 1 of these Reasons for Decision.

Section 12B.3 deals with Cost of Service Recovery. This section states:

> "Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the forecast cost of service associated with the provision of CNG or LNG Service over the term of the Service Agreement, where the minimum contract demand is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station."

Section 12B.5 Costs states:

> "The total costs to be used in determining the forecast cost of service to be recovered from the Customer under the Service Agreement include, without limitation
>
> (a) the capital investment, including any associated labour, material, capitalized overhead and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission

(b) depreciation expense related to the capital assets associated with the vehicle fuelling station; and

(c) the incremental operating and maintenance expenses necessary to serve the Customers.

In addition to the costs identified, the cost of service recovery will include applicable property and incomes taxes and the appropriate return on rate base approved by the British Columbia Utilities Commission."

6.4 Cost of Service Model

FEI advises that, at a high level, the cost of service model captures all of the costs associated with providing service to a particular NGV customer, and uses those costs to generate a rate which recovers the cost of serving that specific NGV customer over the term of the agreement. (Exhibit B-1, pp. 11-12)

6.1.1 "Take or Pay" Commitment

Each customer-specific service agreement will contain a "take or pay" commitment which will require the customer to commit to purchase a specified volumetric fuel charge, calculated to recover the cost of service, whether or not such volume is actually required or consumed. However, if the customer takes more service than the amount committed to, an excess rate will be charged, which may be less than the "take or pay" rate. (Exhibit B-1, p. 12) FEI proposes to accumulate any additional revenues from quantities purchased in excess of the minimum committed "take or pay" volume in an ongoing rate base deferral account, commencing in 2012. (Exhibit B-1, p. 71)

6.1.2 Cost of Service Calculation

FEI proposes to base the cost of service calculation on the total forecast – as opposed to actual - costs to provide either CNG or LNG service which include:

- The capital cost of the fuelling station – including any associated labour, materials, capitalized overhead, less any contributions in aid of construction, grants etc. offsetting the full cost;
- Incremental operating and maintenance costs necessary to serve the customer;
- Depreciation expense related to the capital assets associated with the contract;
- Applicable property tax;
- Calculated income tax expense;
- Return on rate base at the then-current approved rate.

(Exhibit B-1, p. 55)

6.1.3 Capital Costs

FEI proposes to use forecast capital costs as an input into its cost of service calculation. It submits that its forecast costs have a high degree of accuracy for the following reasons:

- It has undertaken "detailed and comparative quotations";
- Its project engineering team is experienced;
- The fuelling station, which represents the largest component of a project's costs, can be procured by way of a fixed price contact.

The forecast capital costs also include capitalized overhead. Capitalized overhead is calculated as 14% of forecast gross operating and maintenance costs. (Exhibit B-1, p. 56)

6.1.4 Operating and Maintenance Costs

Forecast operating and maintenance (O&M) costs represent the incremental material and labour expenses associated with maintaining each fuelling station as well as the incremental administrative costs associated with each contract. FEI expects, however, that any administrative costs will be minimal, as most candidates for CNG or LNG service will be existing customers. O&M costs are estimated to be in the range of 4% to 6% of the capital costs for an LNG project. (Exhibit B-6, BCUC IR 2.10.2; 2.10.4) The gross forecast operating and maintenance costs will also be reduced by the 14% amount attributed to capitalized overhead.

FEI increases the net forecasted operating and maintenance expenses in its cost of service model by 2% per annum. (Exhibit B-1, p. 57) However, FEI also proposes that this escalation factor be open to negotiation with the individual customer. (Exhibit B-1, p. 61)

6.1.5 Depreciation and Amortization Expense

FEI proposes to use depreciation rates which, other than capitalized overhead, represent recovery of the cost of the asset over its estimated useful life, which is, for the most part, 20 years. (Exhibit B-1, p. 57) FEI proposes to amortize capitalized overhead at the rate of 2.7% per annum, which equates to a 37-year period.

The following table sets out the depreciation rates for which approval is requested:

TABLE 1
Useful Life and Resulting Depreciation Rates for CNG and LNG Fuelling Assets

Asset	Estimated Useful Life (years)	Depreciation Rate (%)
CNG Dispensing Equipment	20	5%
LNG Dispensing Equipment	20	5%
Foundations	20	5%
Pumps	10	10%
Dehydrator	20	5%
Capitalized Overhead	Average	2.7%

Source: Exhibit B-1, p. 57, Table 5-1

6.1.6 Property Taxes

As property taxes are site-specific, the property tax expense forecast will vary by project. The forecast property tax is an input to the cost of service calculation. (Exhibit B-1, p. 58)

6.1.7 Income Taxes

FEI also proposes to include forecast income taxes expense, calculated on an estimated actual taxes payable basis, in its cost of service calculation. (Exhibit B-1, p. 58)

6.1.8 Rate Base and Earned Return

FortisBC Energy's cost of service will also include an amount for the allowed return on the rate base associated with each CNG or LNG contract. (Exhibit B-1, pp. 60-61)

6.1.9 Contract Term

At a minimum, FortisBC proposes to match the contract term to the life of the initial fleet of NGVs. (Exhibit B-1, p. 55) The life of the vehicles in the projects which FortisBC is targeting ranges from five to ten years. (Exhibit B-1, p. 12)

7.0 ALIGNMENT WITH ENERGY POLICY

In reviewing an expenditure schedule for acceptance under section 44.2 of the *Utilities Commission Act*, (pursuant to which the expenditures on the fuelling station for Waste Management were filed, and others may be filed) the Commission is required to consider the applicable of British Columbia's energy objectives. In its Final Submission, FEI explains how its investments further these objectives.

FEI also asserts that the policy objectives introduced in "The BC Energy Plan A Vision for Clean Energy Leadership" (the 2007 BC Energy Plan) place a new focus on NGVs. (FEI Final Submissions, pp. 19-22)

FEI submits that any future cost-effective investment in fuelling stations for "return to base" fleet customers can similarly be expected to support British Columbia's energy objectives. FEI submits that "British Columbia's energy objectives apply to CPCN applications under section 45 of the *UCA* and applications brought under 44.2 (among other sections) which both relate to utility capital investments" and that this is "explicit recognition that Government intends public utilities to be investing in cost-effective initiatives and facilities that advance the legislated objectives." (FEI Final Submissions, p. 20)

FEI states that "On November 25, 2008 GHG interim targets were set by Ministerial Order as follows:

- 2012 – six per cent below 2007; and
- 2016 – eighteen per cent below 2007 levels"

and that reductions of at least 33% are required for the year 2020 and subsequent years. (Exhibit B-1, p. 38) These targets are reflected in Section 2(g) of the *Clean Energy Act*.

Given a 2007 estimated level of GHG emissions of 67.3 million tonnes (BC Provincial GHG Inventory Report, 2007; Exhibit B-1, p. 41), this amounts to required reductions of approximately 4 million, 12 million and 22 million tonnes in 2012, 2016 and 2020, respectively. FEI maintains that fuel switching for return to base fleets will help contribute to this required reduction. To this end, FEI estimates that if its "Reference Case," (which forecasts consumption of approximately 30 PJs (or 30 million GJs) of natural gas by trucks, buses and marine vessels which have switched away from conventional fuels to natural gas by 2030) comes to pass, there will be a reduction of 865,000 tonnes of GHGs emitted in the year 2030. However, much lower reductions are forecast for earlier years in the range of approximately 25,000, 70,000 and 180,000 tonnes for the years 2012, 2016 and 2020, respectively. (Exhibit B-1, Appendix A1, pp. 19, 27)

Commission Panel Discussion

As noted by FEI, the 2007 Energy Plan indicates that the single largest source of GHG emissions in B.C. is the transportation sector. This sector accounts for 39% of GHG emissions, as compared to 11% for the residential and commercial sector. FEI "believes that reducing GHG emissions in the transportation sector is necessary in order to realistically achieve the provincial government's stated objectives." (Exhibit B-1, pp. 41-42 citing 2007BC Energy Plan) FEI submits that the use of NGVs in BC will achieve large reductions in overall GHG emissions and this will help meet the Provincial government's GHG reduction targets.

FEI notes the comment in the 2007 Energy Plan that "natural gas burns cleaner than either gasoline or propane, resulting in less air pollution" in support of its proposition that "government policy generally places a new focus on NGVs". (FEI Final Submissions, p. 19) However, the Energy Plan also describes other transportation technologies, some considerably cleaner than natural gas and in fact went on to state in the next sentence that "[f]uel cell vehicles are propelled by electric motors powered by fuel cells, devices that produce electricity from hydrogen without combustion". It continued: "[c]ars that run on blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants. Electricity can provide an alternative to gasoline vehicles when used in hybrids and electric cars." (2007 BC Energy Plan, p. 19)

Further, the "policy actions" for addressing greenhouse gas emissions from transportation and increasing innovation as set out in the 2007 BC Energy Plan contemplated measures such as: the implementation of a 5% renewable fuel standard for diesel, support for the federal action of increasing the ethanol content in gasoline, and development of a leading hydrogen economy with a new, harmonized regulatory framework for hydrogen. (2007 BC Energy Plan, p. 20)

As well, the "key initiatives and recent announcements" in the 2007 BC Energy Plan in this area contemplated the promotion of hybrid vehicles through tax incentives and government purchases of hybrid vehicles exclusively. The 2007 BC Energy Plan also noted the Province's intention to reduce "diesel emissions through new financial incentives to help municipalities shift to hybrid vehicle fleets and retrofit diesel vehicles with cleaner technologies." (2007 BC Energy Plan, p. 21)

The Panel is of the view that the interest expressed in electricity and hydrogen as alternative fuels for the transportation sector in the 2007 BC Energy Plan introduces an additional element of risk to FEI's proposed NGV program, particularly as these alternative fuels tend to have a lower carbon footprint than natural gas and, when viewed in comparison, would align more closely with British Columbia's energy objectives.

In its closing submission, the BCSEA states that "...the evidence establishes that substituting CNG or LNG powered vehicles for diesel powered vehicles will significantly reduce GHG emissions in BC." (BCSEA Final Submission, p. 5) CEC submits that FEI has established that NGV applications for the target markets, switching from diesel to natural gas, would result in a reduced carbon footprint, and that FEI has also established that this is consistent with the BC energy objectives. (CEC Final Submission, p. 6) The BCOAPO is silent on the alignment of the NGV program with the Provincial Government's energy policy and its impact on GHG emissions.

The Panel accepts that fuel switching from diesel to natural gas will assist the province in meeting its energy objectives. However, we note that whether this contribution is considered "significant" is largely subjective.

While subsection 44.2 (5)(a) does indeed require the Commission to consider "the applicable of British Columbia's energy objectives," subsection 5(e) requires the Commission to consider the "interests of persons in British Columbia who receive or may receive service from the public utility."

The 2007 BC Energy Plan basically contemplates government initiatives and spending but otherwise provides little guidance on who should bear any specific costs associated with programs to reduce emissions.

There is a potential for some future guidance to be provided under the *Clean Energy Act*. Subsection 18(1) of that Act defines a "prescribed undertaking" as "a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia." Subsection 18(2) requires the Commission to set rates for a public utility that is carrying out a "prescribed undertaking" "that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking".
By subsection 35(n), the Lieutenant Governor in Council may make regulations... "(n) for the purposes of the definition of "prescribed undertaking" in section 18, prescribing classes of projects, programs, contracts or expenditures that encourage

(i)the use of

(A) electricity, or

(B) energy directly from a clean or renewable resource

instead of the use of other energy sources that produce higher greenhouse gas emissions, or

(ii) the use of natural gas, hydrogen or electricity in vehicles, and the construction and operation of infrastructure for natural gas or hydrogen fueling or electricity charging."

However, the Panel has not been referred to and is otherwise unaware of any regulations having been made to this point in time relating to "prescribed undertakings."

Accordingly, the Panel will examine the interests of FEI's existing ratepayers in considering the acceptability of NGV related expenditures under subsection 44.2(5).

As noted above, subsection 44.2(5)(e) requires the Commission to consider "the interests of persons in British Columbia who receive or may receive service from the public utility."

The Panel is of the view that not every expenditure that helps to meet an objective of the Energy Plan will necessarily be automatically eligible for acceptance under Section 44.2. Additional analysis is required to ensure that the expenditure is a reasonable use of limited funds and that better uses are not readily available. It is also important that proposed expenditures do not create too great of a burden on those who will be asked to foot the bill.

Further, in the Panel's view, it is important that, where there are different rate schedules in effect, the customer which benefits from the expenditure is responsible to "pay the freight". In this case, FEI's proposed NGV program targets a reduction in the GHG emissions of the transportation sector. Although many costs are borne directly by the NGV customers under the proposed Cost of Service model, cost overruns and unaccounted for costs are proposed to be borne by FEI's existing ratepayers. In addition, as discussed elsewhere in this decision, these existing ratepayers are proposed to shoulder the risk for what could amount to considerable additional costs should market conditions deteriorate, as they did in FEI's previous NGV venture.

The Panel questions whether it is in the interests of FEI's existing ratepayers to bear the costs or risks associated with reducing carbon emissions for the transportation sector when FEI ratepayers represent only a portion of the province's population and, generally speaking, are not directly responsible for those emissions. We are of the opinion that they should not. In our view, it is more appropriate that these costs be borne either by the owners of the vehicles, as they are the emitters, or by the people of the province as a whole, as they are the beneficiaries. Thus, in the Panel's view, expenditures undertaken to provide and operate infrastructure for fuelling NGVs are not sufficiently in the interests of FEI's existing ratepayers to satisfy the requirements of subsection 44.2(5)(e) as it relates to the interests of persons who take service from the public utility. The expenditures would, however, appear to be in the interests of those potential new customers who may receive CNG/LNG service from the utility.

Thus, the Panel agrees with FEI's approach that the ratepayers be "kept whole," and throughout this decision, we discuss the reasons for our agreement. **Consistent with this approach, the Panel finds that while the benefits of GHG emission reduction provides a justification for FEI's proposed NGV program, FEI's ratepayers must be insulated, to the greatest extent possible, from the costs and risks of the program.**

8.0 ISSUES ARISING

8.1 Introduction

In the view of the Commission Panel the Application raises several key issues. The first relates to the protection of the public interest in circumstances such as these, where a regulated utility is seeking to offer services which would otherwise not be subject to regulation.

Other issues which flow from the first include:

- Management of Risk
- Potential for Rate Discrimination
- Interpretation of Just and Reasonable Rates
- The Need for Confidentiality
- Adequacy of the Cost of Service Model and related Allocations

These issues all converge in the overarching concern of the Panel expressed throughout these Reasons, which is how best to insulate the existing ratepayer from various costs and risks and how to ensure that the costs and risks are actually borne by the parties who stand to benefit the most.

8.2 Regulated vs. Non-Regulated and the Public Interest

FEI has chosen to apply to the Commission to provide the new CNG and LNG fuelling services in its capacity as a regulated public utility. Given the definition of "petroleum industry" as including "the retail distribution of liquefied or compressed natural gas" and "public utility" as not including "a person not otherwise a public utility who is engaged in the petroleum industry..." in section 1 of the *Utilities Commission Act*, it is only because FEI is already "otherwise a public utility" that this new business is required to be regulated. FEI would be free to pursue this business through a non-regulated subsidiary and thereby avoid Commission oversight. Other companies, not otherwise public utilities, may enter the industry and will not be subject to regulation. In fact, FEI maintains that its CNG and LNG business models do not preclude a third party from offering the same services and that it supports other third party investment. (Exhibit B-1, pp. 16, 18) FEI states, however, that for its part, it "is interested in owning and operating NGV fuelling stations only through its regulated utility subsidiaries...in the manner proposed" in the Application. (Exhibit B-6, BCUC IR 2.29.1)

FEI also takes the position that once the Commission has approved a tariff offering for CNG and LNG service, such service becomes subject to the statutory framework relating to a utility's legal obligation to provide its service to the public, as set out in sections 28 to 30 of the *Act*. (Exhibit B-9, CEC IR 2.1.3)

Commission Panel Discussion

The Commission Panel acknowledges that the *Utilities Commission Act* does not prohibit FEI from providing CNG/LNG service offerings but that, unlike other potential market participants, if it does so, it will be subject to regulation. FEI is subject to regulation because it is otherwise a monopoly, and the regulatory framework exists to protect the public from monopolistic behaviour and the potential associated problems. (Atco Gas

Pipelines Ltd. v. Alberta (Energy Utilities Board), [2006] 1 S.C.R. 140, 2006, SCC4, para. 3) The Panel is of the view that in a case such as this one, the public interest requires that, if FEI is to provide CNG/LNG services in its capacity as a public utility, it must do so without utilizing any potential economic leverage which it may have as a result of its status as a monopoly distributor of natural gas.

The Commission Panel does not agree with FEI's position the "once Commission approval has been obtained for a tariff offering for CNG and LNG service" it will be under an obligation to provide this service to the public pursuant to section 28 of the *Act*. (Exhibit B-9, CEC IR 2.1.3) The Commission Panel is of the view that the obligation to serve stems from the nature of a monopoly provider of services with infrastructure which has natural monopoly characteristics such that a competitive market structure does not make economic sense. In the circumstances of this Application, the fuel dispensing service has no natural monopoly characteristics and could potentially be supplied by any number of competitors. As such, there is no corresponding requirement to recognize an obligation to serve such potential customers.

8.3 Risks

8.3.1 Parallels to Previous Natural Gas Program

As discussed earlier, FEI has, through a predecessor company, previously tried to establish a market for NGVs in British Columbia. However, the venture was ultimately not successful. The Panel will now examine the ways in which the current proposal is similar, and in what ways it differs, from the previous venture.

It is FEI's position that the current program has little in common with previous NGV initiatives. As previously described, this Application is based on a business model that targets return to base fleets of buses, heavy duty and vocational trucks. FEI submits that this "anchor tenant" model, although directed at a smaller target market, is less risky.

However, the Panel notes that FEI also owned and operated an NGV compression and dispensing facility for BC Transit. This facility was also constructed to serve a return-to-base fleet of heavy duty vehicles and was backed by a take or pay contract as is proposed here. FEI summarizes the main difference between the BC Transit case and the Waste Management case: "the BC Transit facility was a fast-fill design utilizing early CNG equipment technology, whereas the WM facility is time-fill facility using off the shelf proven CNG refuelling equipment." (Exhibit B-4, BCUC IR 1.11.1; 1.11.2)

One factor cited by FEI in the deterioration of the market for its previous NGV offering is an erosion of the cost differential between natural gas commodity prices and the price of conventional fuels, but that since 2000, the price differential has been re-established. FEI states that natural gas has historically had an advantage in price over other motor vehicle fuels and the lower operating cost savings result in savings for customers in spite of the higher cost of OEM NGVs or after-market conversions. Figure 3-1 in the Application outlines a historical comparison of the cost of CNG (including a $5/GJ compression charge and applicable rate riders) and diesel fuel. The figure shows that the CNG bundled rate over the ten year period commencing in 2000 would compare favourably with diesel over the entire period. Similar results are outlined in Figure 3-2 which depicts a comparison with gasoline. FEI further notes that as of the date of the Application, the advantage over diesel would be $.40/litre or 40 percent and submits that forward market prices indicate that natural gas is likely to maintain this price advantage for the foreseeable future. (Exhibit B-1, pp. 28-31)

Commission Panel Discussion

The Commission Panel acknowledges that the basis for this program and its operating fundamentals may be somewhat different from FEI's previous offering, but remains concerned that some of the factors which contributed to the lack of success with the initial NGV program remain at play with the current Application. For example, in the BC Transit case, the model was similar and the venture was not successful. As a result, the risk of stranded assets exists and with it the potential for additional costs, which FEI seeks to recover from its ratepayers.

As noted by FEI in the Application, the price of natural gas in 1992 was very favourable but this advantage eroded significantly by the early 2000's when "the price advantage of natural gas versus conventional fuels narrowed to the point where there was insufficient economic incentive to switch fuels given the differential in capital cost between the two options". (Exhibit B-1, p. 9) The Panel notes that the current price advantage related to natural gas has been affected by the current market surplus resulting from the exploitation of shale gas throughout North America. Whether this price advantage continues to be maintained over the next five to ten years remains an issue given potential for worldwide demand for LNG leading to the export of surplus natural gas in a liquefied state. We remain concerned that when initial service agreements, which FEI estimates to be 5 to 10 years (in line with the life of the vehicles), expire, the attractiveness of the programs may have diminished and customers may choose to pursue other alternatives. (Exhibit B-1, p. 12)

The Commission Panel is of the view that the primary reason this type of program will be attractive to prospective customers is because it offers a cost effective option to more traditional fuel alternatives. The current cost advantage enjoyed by CNG/LNG, is significant as FEI has pointed out. As a result, customers who choose to move forward with this program stand a very good chance of enjoying operating cost savings while also projecting a "greener" image due to the reduced emissions associated with NGVs. Of concern to the Commission Panel, as noted above, is the lack of certainty that the current price advantage of CNG/LNG versus conventional fuels will continue into the future. Additionally, the Panel is concerned about the potential for technology advancements which may provide a greener or more cost effective solution than that offered by CNG/LNG. For example, there may be increasing support for electric vehicles that are fuelled by energy generated from renewable hydro. In this regard, the Panel notes that the introduction of hybrid electric vehicles was cited by FEI as a factor in the decline of the NGV market in BC in the past ten years. (Exhibit B-1, p. 10)

8.3.2 Potential for Stranded Assets

For the purposes of the discussion in these Reasons, the Commission Panel considers a stranded asset to be an asset with a book value that exceeds its market value, in circumstances where the asset is no longer used or useful for utility purposes. The potential for stranded assets in the business model presented by FEI in this Application in particular, arises because of the differences in the time period covered by fleet operator service agreements (which FEI proposes to match to the life of the vehicle) and the asset life of the station infrastructure (which is estimated to be 20 years). As FEI has acknowledged, the risk associated with the expiry of the service agreement before recovery of the full capital cost of the station is one of under-recovery. Where a customer does not choose to use natural gas as its fuel beyond the initial term of a service agreement, 10 to 15 years of unrecovered costs could remain. Based on the average station infrastructure cost of $700,000 utilized in Figure 2-1 of the Application, this would amount to a potential for stranded asset costs ranging from $350,000 to $525,000 for each project depending on the period covered in the initial service agreement. (Exhibit B-1, pp. 12-13, 65)

FEI states that this recovery risk can be mitigated in a number of ways:

- Stations could be relocated to another project location resulting in an estimated recovery of 50 to 70 percent of the capital;
- Station assets could be sold into other jurisdictions [No cost mitigation estimates were provided for this instance]; and/or
- FEI could seek to negotiate contractual terms with customers to mitigate risk.

With respect to the last measure, the Waste Management Agreement contains a clause which stipulates that the customer must pay for any unrecovered amount if it chooses not to renew the Agreement (Exhibit B-1, Appendix D-1).

None of the Interveners expressed significant concern with respect to the risk of stranded assets. In reference to the Waste Management Agreement, BCSEA states that existing customers are provided significant protection against stranded asset risks with the 'take or pay' feature, bolstered by protection against unrecovered capital where a contract is not renewed. Additionally, it notes that the protection is greater than that provided by the Mains Extension test, which is applied in instances where there are customer driven extensions of the existing pipeline. (BCSEA Final Submission, p. 7) BCSEA makes no further comment with regard to stranded assets in its comments on the proposed General Terms and Conditions. BCOAPO notes that in its view the "risks of stranding assets are low" and the tolling proposal will provide "for fairly certain cost recovery." (BCOAPO Final Submission, p. 1) The CEC argues that the 'take or pay contracts', FEI's expectation that 50 to 70 percent of remaining capital costs can be recovered, and the potential for FEI to negotiate renewal or buyout terms provides a risk mitigation which significantly exceeds that available for other customer classes. The CEC concludes its comments on this issue by stating "the risks of stranded assets due to customers switching to other fuel sources exists across the FEI system and the risk for the proposed NGV assets is relatively low in comparison." (CEC Final Submission, pp. 3-4)

Commission Panel Determination

As noted earlier, the Panel remains concerned that there is a risk for stranded assets due to the potential for changing circumstances with respect to the use of natural gas as a transportation fuel. Further, the Panel is not convinced that FEI has made sufficient provisions within the proposed General Terms and Conditions to ensure the potential for stranded assets is adequately mitigated. We note that the 'take or pay' provision within the General Terms and Conditions ensures that the forecast cost of service over the term of the service agreement will be recovered. However, this provides no relief in the event that a customer decides not to renew after the initial 5 or 10 year term. FEI has stated that there are opportunities for it to recover 50 to 70 percent of the remaining unamortized capital in such instances. While the Panel will not dispute that the assets may still have useful life remaining, we do question whether the value would be realized in such instances. In the Panel's view the biggest threat to customer renewal is changing circumstances which may make CNG/LNG less attractive as a fuel source. This may be because of a change in the economics or through the introduction of new technology over the 5 or 10 year initial term period. In such instances the migration away from this solution would not likely be made by one customer but more likely by many and would apply to new customers as well. Thus, if such a change were to occur as it did with the previous NGV offering, it would be unreasonable to assume that reselling or relocating the assets would be certain or even likely. If resale or relocation did not occur, the cost proposed to be borne by existing ratepayers, as noted previously, would range between $350,000 and $525,000 per non renewing customer, based on average infrastructure costs of approximately $700,000.

As also noted earlier, in the case of the Waste Management Agreement, the 'take or pay' feature is bolstered by protection against unrecovered capital costs through a provision requiring Waste Management to purchase the fuelling station at its remaining undepreciated capital cost, if the contract is not renewed. However, FEI did not include such a provision in its proposed General Terms and Conditions, but stated that it can "... negotiate contractual terms that mitigate risk." (Exhibit B-1, p. 65) The Panel is of the view that, in the circumstances of this Application, a period of 5 to 10 years is a long time and, as evidenced by occurrences over the last few years, a great deal of change can occur over even a relatively short period of time. Failure to include provisions to protect against the risk of stranded assets would not be in the public interest. **Accordingly, the Commission Panel has determined that to be approved, the General Terms and Conditions must include a provision requiring the customer to pay any unrecovered capital in those cases where the initial contract is not renewed, or a similar provision that provides equivalent protection.** The Panel understands adding this provision may result in some potential customers being lost because they are not prepared to bear that risk. However, we also see no reason why the ratepayer should be required to do so either.

8.3.3 "Kick Starting" the Market

FEI submits that it should build the fuelling facilities to "kick-start" the market and that it is uniquely qualified to do so. FEI argues that the market for CNG in BC has stagnated in the past ten years or so, and that it must provide CNG/LNG service as a regulated entity to revitalize the market. It also states that it "is not aware of other businesses with the expertise and technical capability that have committed to developing the B.C. fuelling station market." (FEI Final Submissions, pp. 23-24)

Commission Panel Determination

In the Panel's view, while the lack of an experienced and committed CNG supplier may indeed be a reason for the decline in CNG use, FEI has provided a number of other factors, including an insufficient price spread between natural gas and conventional fuels, the introduction of hybrid electric vehicles and, significantly, the cost of engine conversion and the discontinuation of federal government incentive grants to support these conversions. (Exhibit B-1, p. 47, Appendix A-2, pp. 10-11) These last two reasons are underscored by the fact that FEI provided incentive funding to Waste Management to cover the entire incremental cost of purchasing 20 CNG fuelled vehicles over 20 diesel fuelled vehicles. The incentive funding was provided under the terms of a separate Contribution Agreement. (Exhibit B-1, p. 47; Exhibit B-8, BCSEA IR 2.27.2) FEI states that it "believes that incentive funding is important to achieving near-term opportunities...". (Exhibit B-1, Appendix A-1, p. 29) In fact, all three of FEI's demand scenarios assume the availability of incentive funding. FEI states that "if no incentive funding is available through government or other sources, NGV adoption under all three scenarios will be insignificant over the short and long term." (Exhibit B-11, BCUC IR 3.7.2)

Thus, the Panel notes the potential role of incentive funding in 'kick-starting' the market and is concerned that FEI has not established the potential existence of any market in the absence of such incentive funding. The Panel further notes that If it were the case that the market is dependent on incentive funding, from one source or another, then it introduces an additional element of risk into this service offering, in that incentive funding may not be sufficient or even available in the longer term.

Accordingly, while FEI may – or may not - be able to kick start the market, the Panel finds the evidence supporting FEI's assertion that it is uniquely qualified to do so is less than compelling. The Panel finds that there is a significant potential for risk in assuming the long term viability of this potential market and directs that ratepayers be insulated from this risk to the fullest extent possible.

8.4 Implications of Sections 59-62

8.4.1 Rate Discrimination

Section 59(2)(b) of the *UCA* states: *A public utility must not extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.* However, FEI argues that it needs considerable flexibility to negotiate terms of individual agreements that could extend beyond the proposed General Terms and Conditions. The Panel is concerned that this potential for significant variations in the terms of each custom service agreement could constitute a discriminatory extension of a privilege to a customer. For example, FEI states that the initial term of future contracts will vary. (Exhibit B-6, BCUC IR 2.3.1) FEI further admits that there will still be un-recovered costs at the end of the term unless the term is as long as the life of the underlying assets and that, in most cases, customers will expect a term only as long as the expected life of their vehicle assets. (Exhibit B-7, BCOAPO IR 2.1.1) In the case of Waste Management, FEI was able to negotiate a provision to ensure recovery of the undepreciated cost of the asset at the end of the initial contract term. If another customer did not agree to such a provision, the Panel questions whether both parties would have, in fact, been extended the same rule or privilege.

Commission Panel Determination

Given the General Terms and Conditions proposed and the negotiation process as described by FEI, there is a potential for a benefit or benefits being made available to one LNG/CNG customer but not another. **Therefore, the Panel finds that FEI's proposal, which provides for the potential to negotiate significant variations among different service agreements, is not acceptable.** The Panel favours a more structured approach to the General Terms and Conditions, which will result in a more standard form, leaving less to negotiate and consequently reducing the likelihood that an agreement will be discriminatory within the meaning of section 59(2)(b) of the *Act*.

8.4.2 Just, Reasonable and Fair Rates

Both the Waste Management Agreement and the proposed General Terms and Conditions are subject to approval under sections 59-61 of the *UCA*, which require that rates be not unjust or unreasonable or unduly discriminatory. Subsection 59(5) of the *Act* defines an unreasonable rate as one that is more than a fair and reasonable charge for service of the nature and quality provided by the utility, or is insufficient to yield a fair and reasonable compensation for the service provided by the utility. The Panel is concerned that the cost of service model as reflected in the proposed terms and conditions may not recover the full, actual cost of the services provided.

BCSEA argues that the Waste Management Agreement rate is just and reasonable because it is based on the cost of service and it is satisfied that there is no cross-subsidization by ratepayers. (BCSEA Final Submission, pp. 7-8) While the Panel agrees that a rate that is based on the cost of service could be just and reasonable, we are concerned that the General Terms and Conditions, as proposed by FEI, base the cost of service on forecast, as opposed such costs. (Exhibit B-6, BCUC IR 2.1.1) Actual costs may differ from forecast costs due to elements as cost overruns during construction. Further, higher inflation rates or taxes than originally anticipated, and potential increases to the utility's allowed rate of return will not be recovered from the customer. In addition, as discussed above, depending upon the term of the contract with the LNG /CNG customer, the cost of service as proposed by FEI, may not recover all of the potential costs to FEI of providing the service. The proposed cost of service model also does not include any costs relating to marketing of the program. While some of these costs may not be significant, there is a potential, under certain market scenarios, for some to be consequential. Thus, the Panel is concerned that there is a potential for cross-subsidization by ratepayers.

Commission Panel Determination

CEC argues that it is just and reasonable to recover only forecast costs and that the Mains Extension test supports this approach. (CEC Final Submission, p. 8) However, the Panel questions this comparison. In Exhibit B-9, CEC IR 2.8.1 FEI asserts that existing customers share in the costs of extending the system for a Mains Extension <u>because</u> they see benefit from additional load (emphasis added). The Panel does not agree with this characterization and does not consider Mains Extensions to be an appropriate basis of comparison. While additional load and the resulting potential for lower delivery rates may indeed be a benefit of a Mains Extension to existing ratepayers, it is not the reason for the cost sharing. The purpose of a Mains Extension is to connect new customers to the system, thereby extending the distribution system. A Mains Extension within the service area of a regulated utility can only be undertaken by that utility. Generally speaking all ratepayers – including the new ratepayers who will receive the service – will be required to share in the costs of the extension, as they share in all of the costs related to the operation of the distribution system. In cases where the connection costs are excessive, a utility may recover some of the costs from the new ratepayers through a "contribution in aid of construction." It is appropriate to share costs in this fashion since all ratepayers get connected to the utility at one time or another, so all receive the same benefit.

A CNG or LNG refuelling facility is not an extension of the distribution system. Most existing ratepayers do not require a return to base CNG or LNG refuelling facility. With the cost of service model, CNG /LNG customers do not share in all the costs of the distribution system beyond those recovered under the applicable Rate Schedule, but only in the incremental cost of providing their CNG /LNG service. Further, as noted earlier, the construction and operation of CNG /LNG fuelling facilities are not required to be regulated, unless they are provided by a [regulated] public utility. If a CNG station, for example, were provided by an unregulated entity, there would be no requirement, or need, for existing ratepayers to share the cost of providing the facilities, yet they would still benefit from increased throughput in FEI's distribution system. The Panel does not agree that existing ratepayers should share the costs just because FEI is providing the fuelling facilities.

The Panel finds that FEI has failed to provide a convincing argument that it is just and reasonable that existing ratepayers should subsidize the costs of the refuelling facilities. We believe that there should be as little potential for cross-subsidization as it is possible to achieve. In its submission, FEI endorses this approach when it describes its cost of service model: "At a high level, it captures all of the costs associated with providing service to an NGV customer, and uses these costs to generate a rate that recovers the cost of service from the NGV customer over the term of the service agreement. The intent is to keep other natural gas customers whole." (Exhibit B-1, p. 11) However, as discussed, the Panel is concerned about the effect of unbudgeted costs, cost overruns and other factors that could require ratepayer subsidization. The Panel therefore requires that, to the extent possible, none of the actual costs of the CNG/LNG service offerings be recovered from existing ratepayers. Any General Terms and Conditions must therefore include additional assurance that the total actual cost of the refuelling facility will be recovered from the CNG/LNG customer to the extent possible.

8.5 Confidentiality

In Order G-6-11 dated January 14, 2011 the Commission Panel approved the Waste Management Agreement as a Tariff Supplement on an interim basis and subject to certain conditions, including the condition that if the Waste Management Agreement was to be amended in accordance with the Commission's determinations and refiled, the Agreement was to be refiled on a non-confidential basis.

On February 25, 2011 FEI refiled the amended and restated Waste Management Agreement as Tariff Supplement J-1 on a non-confidential basis.

In its Reasons for Decision in support of the January 14, 2011 Order (Order G-6-11) the Commission Panel noted that section 62 of the *Act,* requires that: "A public utility must keep a copy of the schedules filed open to and available for public inspection under commission rules." The Panel noted at that time that: "...because transparency is a fundamental principle of sound regulation, the Commission requires public utilities to publically file all approved rates, rate schedules and tariff supplements unless there are very unusual circumstances."

In its Reply Submission (at p. 2) FEI endorses the rationale behind the Commission's decision that the public interest will generally favour the publication of rate schedules, but notes the support received from the CEC on the issue of confidentiality .

CEC submits that individual customer information does not need to be made public in the oversight process. It submits that important regulatory information could be separated from individual information and that adequate aggregate information with ranges could be made available. CEC submits that "disclosure of individual contract provisions may not be necessary or even sensible in order to protect FEI's commercial ability to negotiate terms." (CEC Submission, p. 12)

BCSEA notes that "both public access to public utilities' rate schedules and the protection of legitimate claims of confidentiality are important, and potentially conflicting interests." (BCSEA Submission, p. 9)

Commission Panel Determination

The Commission Panel remains of the view that there is no compelling reason why new customer-specific rate schedules should not be in the public domain, especially if each contract is designed to recover costs in a just and fair manner. The Panel does not support the need for confidentiality to allow FEI to negotiate different commercial terms with different customers, as suggested by the CEC.

Exhibit A2-9 is an example of a Tariff Supplement which relates to a particular individual customer. The Commission Panel believes that rate schedules should continue to be public documents to ensure openness and transparency and the absence of any form of discrimination in rates. However, the Panel acknowledges the possible need to protect commercially sensitive information in certain exceptional cases and notes that FEI has the ability to apply to the Commission in the event there are extenuating circumstances which may relate to a particular customer.

8.6 Cost of Service Calculation

The Commission Panel agrees with FEI that public interest considerations support the inclusion of terms and conditions which ensure the cost of the facilities will be recovered from the customer. This is critical to the Panel's review, consideration and potential approval of any General Terms and Conditions for future contracts.

8.6.1 Capital Cost Recovery

As noted in Section 5.1.3 of this decision, FEI proposes to use the forecast capital cost of the fuelling station as an input to the Cost of Service Model, including the "take or pay" provision. In its proposed model, any overruns would be recovered from existing ratepayers, absent a finding of imprudence. (Exhibit B-6, BCUC IR 2.1.9; 2.1.10)

FEI argues that customers want CNG and LNG rates that are known with certainty at the time a contract is entered and that this will necessarily precede the construction of the facility. (Exhibit B-6, IR BCUC 2.1.8) FEI further states that "the forecast cost of service is likely to be reasonably accurate," and the "bulk of the rate [being] composed of [capital and O&M] costs that can be estimated with a relatively high degree of certainty." (Exhibit B-6, BCUC IR. 2.1.1, 2.1.11)

Commission Panel Discussion

Given that FEI proposes to recover any cost overruns from general ratepayers, as noted above, the Panel is concerned with the use of forecast, as opposed to actual capital costs. For example, when the refuelling station for BC Transit was constructed in 1991, the actual cost exceeded the forecast cost by a factor of 75%. (Exhibit B-6, BCUC 2.1.6) In the case of Waste Management, actual construction costs exceeded forecast by approximately $37,000, a factor of 5%. (Exhibit B-11, BCUC IR 3.1.2)

In the Panel's view, the importance of using actual as opposed to forecast capital costs is further underlined by the fact that, at least for LNG, FEI has, at a high level, estimated the operating costs of the fuelling station based on the forecast capital cost. To the extent that the forecast capital cost is incorrect, this divergence will be magnified as the basis for the calculation of estimated operating costs will also be inaccurate. (Exhibit B-6, BCUC IR 2.10.2)

The provision of a fuelling station at a customer's premises is not, in the Panel's view, a typical utility project. Rather, such a project is essentially a custom construction project for an individual customer. In this regard, the Panel notes that FEI also contracted to provide other "associated" construction work to Waste Management under a separate agreement on a cost plus basis with an estimated margin of approximately $115,000. (Exhibit B-3, BCUC Confidential IR 1.9.1; Exhibit B-11, BCUC IR 3.1.4)

Accordingly, the Panel directs that FEI and use the actual construction costs in the calculation of the cost of service in any revised General Terms and Conditions. This could mean that the determination of the rate perhaps cannot be finalized until after construction is completed. Alternatively, hiring a third party construction company to provide the service on a fixed price basis would serve to provide the customer with certainty for the cost at the outset. In any event, as FEI has noted, since the forecast cost is assumed to be reasonably accurate, in the Panel's view the use of actual costs should not introduce an unacceptable level of uncertainty at the time the contact is being negotiated.

8.6.2 Operating and Maintenance Costs

Operating and maintenance cost forecasts for CNG are based on estimates of the material and labour costs associated with maintaining the fuelling station, and any additional administrative expenses associated with the service agreement. (Exhibit B-1, p. 56) In the case of LNG, FEI provided a high level estimate for O&M costs equivalent to 2% of the capital cost of the fuelling system. However, FEI now states that subsequent discussions with the manufacturer suggest that a range of 3%-6% is likely to be more reasonable. (Exhibit B-6, BCUC IR 2.10.2) The Panel notes that the amount for O&M that will be charged to the CNG/LNG customer is actually lower, as FEI proposes to take 14% of gross O&M to include in "capitalized overhead," to be recovered over a 37 year period. Once again, FEI proposes that any underestimate be recovered from all non-bypass customers. (Exhibit B-4, BCUC IR 1.9.6)

Commission Panel Determination

The Panel is concerned that FEI is proposing to recover estimated operating and maintenance expenses as opposed to actual. While FEI will gain experience as the program progresses, the risk of cost overruns remains, particularly in the early stages of the program, and particularly in the case of LNG, where there is less experience to draw upon. Ideally, FEI would charge its NGV customers the actual operating and maintenance costs incurred. **The Panel directs FEI to consider modifications to the General Terms and Conditions that will ensure that the operating and maintenance costs recovered from the customer are as close as possible to the actual operating and maintenance costs incurred.**

The Panel discusses the issue of capitalized overhead further in Section 8.6.4 below.

8.6.3 Escalation Factor

FEI proposes that that a 2% per annum escalation factor be applied to inflate O&M costs during the contract term. (Exhibit B-1, p. 57) The Panel notes that, in the case of the Waste Management Agreement, this escalation factor was only applicable to the first ten year term of the contract, and not to subsequent terms.

Commission Panel Determination

The Panel is concerned that, over the time periods contemplated in the Application, this escalation factor could become unrealistic. **FEI is therefore directed to include an escalation factor equal to the value of the British Columbia Consumer Price Index for all items, as produced by BC Stats on a monthly basis in any revised General Terms and Conditions.**

8.6.4 Depreciation and Amortization Expense

FEI proposes to depreciate the capital assets making up the fuelling station over either 10 or 20 years, which is consistent with the expected life of a fuelling station, being 20 years, with the exception of "capitalized overhead," which it proposes to depreciate in accordance with its average rates, or 2.7%. However the use of 2.7% will mean that the depreciation period will exceed the contract term such that this amount will not be fully recovered from the customer (absent an extension of the contract by the customer beyond the useful life of the other assets) putting other ratepayers potentially at risk for unrecovered costs. In the case of the Waste Management Agreement, FEI acknowledges that "the total present value of the free cash flow is negative because the depreciation period of the capitalized overhead is longer than the 20 year period.

That is, the full recovery of the capitalized overhead does not occur within the 20 year period." (Exhibit B-4, BCUC 1.24.1)

FEI has also excluded any provision for negative salvage value from its depreciation rate calculation and proposes to apply any removal costs to income in the year in which they are incurred. (Exhibit B-4, BCUC IR 1.22.2) In the circumstances of the CNG/LNG service offerings, these costs, which are directly associated with the service offering to the individual customer, would fall to be borne by rate payers.

Commission Panel Determination

The Commission Panel is again concerned that this cost recovery model does not adequately recover the full cost of the service from the customer over the unique timeframe associated with these projects and therefore directs FEI to include 100% of the operating and maintenance costs in the cost of service calculation and to include zero percent of gross operating and maintenance costs as capitalized overhead for CNG/LNG projects in any revised General Terms and Conditions. The Panel further directs FEI to include the estimated net negative salvage value in the cost of service calculation in any revised General Terms and Conditions.

8.6.5 Other Costs

The Commission Panel notes that there are a number of other costs on which FEI has been silent in its cost of service model. These include overhead and marketing costs related to the NGV programs and an allowance for any increase to FEI's allowed rate of return or cost of debt. For example, FEI has a full-time salesperson assigned to its NGV program. (Exhibit B-11, BCUC IR 3.5.2)

Commission Panel and Determination

As discussed throughout these Reasons for Decision, the Commission Panel requires that to be approved, any General Terms and Conditions must include a cost of service calculation which reflects the actual full cost of service, including the cost of establishing, maintaining and promoting the program, as closely as possible. **The Commission Panel therefore directs that any revised General Terms and Conditions contain a provision whereby FEI will estimate the overhead and marketing expenses which relate to the CNG/LNG program and the expected CNG/LNG sales volume and allocate those costs in a reasonable manner among CNG/LNG customers going forward.**

8.7 Contract Term

The cost of service model generally recovers the cost of providing service to a particular customer, over the term of its individual contract. However, unless the contact term matches the useful life of the fuelling station assets (20 years), there will be an asset remaining which may or may not be useful, and for which the cost has not been recovered, and therefore has the potential for being stranded. As noted earlier, in the case of Waste Management, FEI was able to negotiate a term requiring Waste Management to purchase the fuelling station for its un-depreciated capital cost if Waste Management chose not to proceed with the second ten year tem of the Agreement. This provision serves to a large extent to protect against this risk. (Exhibit B-1, p. 65)

Commission Panel Determination

As discussed in section 8.3.2 of these Reasons, the Commission Panel is of the view that a contractual term which serves to ensure that the customer pay the full cost of the fuelling station over its twenty year life is essential to mitigating the risk of stranded assets. **Accordingly, the Panel directs FEI to include a provision similar to that employed in the Waste Management Agreement, or some other equivalent provision which will result in the customer paying the full cost of the fuelling station during the term of the contract in any revised General Terms and Conditions.**

8.8 Carbon Credits

Treatment of any potential carbon credits which may be available from the NGV service offering remains unresolved at this time. FEI confirms that there may be additional value in monetizing GHG emission reductions as offsets in the event that there is a "suitable protocol" for switching from a higher carbon fuel to a lower carbon fuel. FEI advises that current industry practice in this area would see the benefit of the GHG reductions being attributed to the end user which is reducing its carbon footprint. However, FEI believes it unlikely that it would be cost effective to undertake validating and verifying emission reductions for an individual project. FEI proposes to consider including a term that it is entitled to any GHG emission credits in its future negotiations, in the event there are multiple projects supporting third party validation and verification on an aggregate basis. (Exhibit B-1, p. 34)

Commission Panel Determination

The Panel is of the view that carbon has a value and that value should be determined and recognized. **The Panel therefore directs FEI to quantify the GHG reductions and potential for carbon credits in future applications and describe any steps that have been taken by the parties to monetize those potential benefits.**

8.9 Competition

While this new business may or may not be a natural extension of FEI's existing regulated business, as argued by FEI at page 19 of the Application, the retail distribution of liquefied or compressed natural gas has no natural monopoly characteristics. Accordingly, non-regulated entities are free to enter this marketplace. This is a significantly different situation than that faced by FEI in the regulated distribution of natural gas to consumers and businesses.

Commission Panel Discussion

Given that FEI may be in competition with other non-regulated businesses, the Commission Panel is concerned about the potential for cross subsidization by FEI's existing ratepayers. The Panel considers that the public interest would not be served by effectively providing FEI with a competitive advantage over other potential participants in the industry by allowing FEI to subsidize the costs of what would otherwise be an unregulated service, with existing ratepayer money. This again supports the Panel's determination that, to the extent possible, the full cost of CNG and LNG service is to be recovered from the CNG and LNG customers, respectively.

9.0 COMMISSION PANEL DECISION

9.1 General Terms and Conditions

The Panel is persuaded that benefits will accrue to FEI, FEI's NGV customers, its ratepayers and the people of British Columbia if the NGV market can be kick-started. FEI's NGV customers could potentially save a significant amount on their fuel costs and its ratepayers may enjoy some rate stability or even a reduction in terms of delivery charges, other things being equal, if the load building that is forecast can be realized in the longer term. In addition, residents of the province will benefit from GHG reductions if diesel and gasoline vehicles switch to natural gas as a fuel. Further, a potential exists for these GHG reductions to be monetized by FEI's NGV customers. Accordingly, the Panel finds the benefits outlined in this Application to be generally in the public interest.

However, given the history of FEI's prior unsuccessful attempt to promote CNG as a transportation fuel, based in part on the behaviour of the relative market prices for diesel and natural gas, the Commission Panel finds that existing ratepayers should bear minimum risk in the service offerings proposed in this Application. In the Panel's view, the public interest will not be protected without strong measures in place to ensure that the proposed CNG or LNG customer pays for the full associated cost of service. Elsewhere in this decision, we have discussed the General Terms and Conditions as proposed by FEI. While FEI states that it supports the concept of cost recovery, we have found that the actual proposed General Terms and Conditions do not, in fact, recover all, or a even a sufficient proportion of the costs of the CNG /LNG offerings from the customers of those offerings to make the Application, as filed, in the public interest.

Therefore, the Commission Panel rejects the General Terms and Conditions, as proposed. The Commission Panel would be prepared, however, to approve revised General Terms and Conditions which better reflect full cost recovery from the CNG/LNG customer, as outlined in the Reasons above. In particular, the Panel invites FEI to file revised General Terms and Conditions which, in addition to the "Take or Pay" commitment, require that the rates charged to customers:

- Use actual construction costs as opposed to forecast costs;
- Fully recover the capital cost of the fuelling station (including estimated negative salvage value) within the term of the contract or include provisions requiring the customer to purchase the equipment for its undepreciated capital cost;
- Ensure that actual operating and maintenance costs are recovered as fully as possible;
- Inflate operating and maintenance costs by the regional CPI annually;
- Reflect no amount for capitalized overhead such that all operating and maintenance costs are recovered from the CNG/LNG customer over the term of the contract; and
- Provide an allowance for overhead and marketing to be recovered from the CNG/LNG customer.

9.2 Future Reporting Requirements

The Commission Panel is also concerned that the twenty year time horizon for the CNG assets is a lengthy time and FEI's proposed business model is therefore subject to the considerable uncertainty inherent in predictions of market forces a long time out. **Accordingly, the Panel directs FEI to keep the costs and**

revenues associated with the Waste Management Agreement and any other offerings separate and distinct and to monitor such offerings during a two year test period and provide a report by March 31, 2013. The scope of the report should include the topics listed in Appendix 2.

9.3 Waste Management Agreement

The Waste Management Agreement, for which interim approval was granted, is a concrete example of an application of the proposed General Terms and Conditions. The contract was approved on an interim basis only, to allow for a more thorough review of the context and the issues arising.

The Waste Management Agreement includes an additional provision which is intended to ensure that Waste Management pays the cost of the new service and the capital asset necessary to provide it. However, FEI suggests that some of these provisions may not be universally acceptable to potential new customers and therefore should be open for negotiation.

For example, in addition to the "take or pay" provision which is central to the business model and which purportedly ensures recovery of the cost of service over the term of the contract, the Waste Management Agreement covers a twenty year time period, coinciding with the expected life of the fuelling station. (The Agreement comprises an initial term of ten years, and a renewal term of a further ten years with a provision requiring Waste Management to purchase the fuelling station (for roughly its undepreciated capital cost) if Waste Management elects not to proceed with the second term). This provision is not reflected in the proposed General Terms and Conditions.

There are also real potential costs which may or may not be recovered from Waste Management. For example, as discussed earlier, the actual construction costs for the Waste Management facility exceeded the forecast cost used in the cost of service calculation. As well, for example, any increases in operating costs beyond those accounted for by the escalation factor, and increases to taxes and FEI's allowed ROE will also not be captured, and therefore will not be recovered from this customer.

Commission Panel Determination

The Commission Panel approves the Waste Management Agreement, filed as Tariff Supplement J-1 on March 25, 2011, in final form. Although the Panel remains concerned with the potential for increased costs which are not recoverable from Waste Management, this contract is in effect and because it is unique, the level of risk is, for the most part, acceptable in that it is identifiable and quantifiable and can be limited to this contract only. The Panel therefore approves this Agreement on an exception basis only. The Panel addressed the risks which it has identified as unacceptable for future contacts in its consideration of the proposed General Terms and Conditions.

9.4 Expenditures on Waste Management Fuelling Station

As noted above, FEI is also seeking acceptance of its expenditures on the Waste Management fuelling station and related facilities pursuant to s. 44.2 of the *Act*. By subsection 44.2(5) the Commission is required to consider a number of items. Of relevance to this Application are:

(a) the applicable of British Columbia's energy objectives;

(b) the most recent long term resource plan filed under s. 44.1...; and

(c) The interests of persons in British Columbia who receive or may receive service from the public utility.

British Columbia's energy objectives are set out in the *Clean Energy Act* SBC 2010 c. 22 s. 1. FEI submits that the energy objectives which apply to this Application are:

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(g) to reduce BC greenhouse gas emissions...;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to encourage economic development and the creation and retention of jobs.

(Application, p. 45)

Commission Panel Determination

With respect to energy objective (d), in the Commission Panel's view the promotion of innovative technologies refers only to those "that support energy conservation and efficiency and the use of clean or renewable resources". The promotion of natural gas in place of diesel as a fuel, although reducing carbon emissions, does not, in the Panel's view, necessarily support energy conservation and/or energy efficiency. In terms of "energy efficiency" the Panel specifically notes that natural gas is in fact less efficient as a fuel than diesel by a factor ranging from 10% to 20 % and that in its calculations, FEI used a figure of 17% for efficiency loss. (Exhibit B-1, pp. 50-51; Exhibit B-8, BCSEA IR 2.3.1) Further, the term "clean or renewable resource" is defined in the *Clean Energy Act* and does not include natural gas. Therefore, the Panel finds that this particular objective is not applicable to the circumstances of this Application.

The Panel does accept, however, that the use of natural gas as a fuel will result in fewer carbon and other emissions than the diesel which it replaces and the Application is therefore consistent with the energy objectives which relate to the reduction of greenhouse gas emissions. FEI estimates that the Waste Management project, which involves the replacement of 20 diesel vehicles with vehicles which consume natural gas, will result in a 214 tonne reduction of greenhouse gas emissions per year. The Panel further accepts that there may be some economic development benefits in that certain component manufacturers for NGVs are located in British Columbia.

FEI submits that its 2010 Long Term Resource Plan discussed the impacts of the service offerings applied for "at a high level" but that this Application contains more detailed information. (Exhibit B-1, p. 5) The Panel agrees that the information provided in the LTRP was at an extremely high level and therefore finds that the Application is not inconsistent with FortisBC Energy's most recent Long Term Resource Plan.

FEI, as noted above, submits that the expenditures are in the interests of persons in British Columbia who receive or may receive service from it in that the Waste Management fuelling facility will add cost-effective load to its system, thereby reducing delivery costs, other things equal, for its existing ratepayers, while providing the new customers with economic benefits through reduced operating costs. FEI states that the "typical payback period for a heavy duty fleet operator switching from diesel to CNG is approximately four to six years." (Exhibit B-1, pp. 1, 29-30, 50, 63)

The Panel accepts that the addition of cost effective load may benefit existing ratepayers, *other things equal* but reiterates that, in its view, existing ratepayers are not the main beneficiaries of the expenditures necessary for this project. Further, other things may not remain equal and to the extent that the increased load creates the need for additional infrastructure, this may not be the case. As well, the benefits to new CNG/LNG customers are dependent to a large extent on the continued price differential as between natural gas and diesel. Finally, the benefits attributable to existing ratepayers from the addition of cost-effective load are not dependent upon FEI undertaking the projects, but would flow in any event if the projects were undertaken by other market participants.

FEI also submits that the expenditures are in the public interest because the cost of the facilities is to be recovered from Waste Management over the term of the Waste Management Agreement. (Exhibit B-1, p. 1) As discussed throughout these Reasons, this factor is critical. The Panel's approval of the Waste Management Agreement is predicated on the fact that, in the Panel's view, the Agreement does accomplish cost recovery from the customer to a significant extent. **The Commission Panel therefore accepts the expenditures on the Waste Management fuelling station and related facilities pursuant to section 44.2 of the *Utilities Commission Act.***

10.0 FORTISBC ENERGY CNG AND LNG SERVICES – SUMMARY OF DETERMINATIONS

1. The Waste Management Agreement, as amended and refiled on March 25, 2011 as Tariff Supplement J-1, is approved in final form.

2. The expenditures made to provide the Waste Management fuelling station and related facilities in the final amount of $775,031 are accepted pursuant to s. 44.2 of the *Act*.

3. Approval of FEI's proposed General Terms and Conditions, specifically, the addition of a new section 12B relating to CNG and LNG Service, is denied.

4. The Commission Panel will approve revised General Terms and Conditions which, in addition to the proposed "Take or Pay" commitment, better reflect full cost recovery from the potential CNG/LNG customer, as described herein;

5. Subject to FEI filing revised General Terms and Conditions acceptable to the Commission, depreciation rates are approved in accordance with the following table:

Asset	Estimated Useful Life (years)	Depreciation Rate (%)
CNG Dispensing Equipment	20	5%
LNG Dispensing Equipment	20	5%
Foundations	20	5%
Pumps	10	10%
Dehydrator	20	5%

No amounts will be approved for capitalized overhead.

The following deferral accounts are approved:

a. A non-rate base deferral account attracting AFUDC to capture the cost of the current application, including the cost of the Waste Management Application and to recover these costs from all non-by-pass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period. [Future individual application costs must be recovered from those customers.]

b. A non-rate base deferral account attracting AFUDC to capture the O&M costs and the cost of service associated with the capital additions to the delivery system incurred and the CNG and LNG Service recoveries received prior to January 1, 2012 for contracts approved by the Commission, and to recover or refund the balance to all non-bypass customers by amortizing the balance through delivery rates commencing January 1, 2012 over a three year period.

c. An ongoing rate base deferral account to capture incremental CNG and LNG recoveries received from actual volumes purchased in excess of minimum contract take or pay commitments to be refunded to all non-bypass customers by amortizing the balance through delivery rates over a one year period, commencing the following year, to be effective as of January 1, 2012 pursuant to sections 59 to 61 of the Act.

FEI Proposed General Terms and Conditions – Section 12B

12B. Vehicle Fueling Stations

12B.1 **Compression and Dispensing Service for Compressed Natural Gas (CNG) Fueling and Fuel Storage and Dispensing Service for Liquefied Natural Gas (LNG) Fueling** - Terasen Gas will make extensions to the Terasen Gas System and provide CNG and LNG Services to vehicles in accordance with the provisions of this section.

CNG or LNG Service will be provided under the terms and conditions of a Service Agreement between Terasen Gas and the Customer. The CNG and LNG Services are described below:

CNG Service will typically consist of:

- installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer /dehydrator, high pressure storage, dispensing equipment; and
- dispensing of compressed natural gas.

LNG Service will typically consist of:

- transport and delivery of the LNG from TGI's LNG facilities to the Customer premise by LNG tankers;
- installing and maintaining a LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and
- dispensing of liquefied natural gas.

12B.2 **Ownership** - All CNG and LNG fueling stations will remain the property of Terasen Gas.

12B.3 **Cost of Service Recovery** – Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the forecast cost of service associated with provision of CNG or LNG Service over the term of the Service Agreement, where the minimum contract demand is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station.

12B.5 **Costs** - The total costs to be used in determining the forecast cost of service to be recovered from the Customer under the Service Agreement include, without limitation

(a) the capital investment, including any associated labour, material, capitalized overhead and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(c) depreciation expense related to the capital assets associated with the vehicle fueling station; and

(d) the incremental operating and maintenance expenses necessary to serve the Customers.

In addition to the costs identified, the cost of service recovery will include applicable property and incomes taxes and the appropriate return on rate base as approved by the British Columbia Utilities Commission.

Scope of Two Year Test Period Report on CNG LNG Service

The reporting period for the purposes of the report shall be fiscal 2011 and 2012 and the report shall be filed with the Commission by March 31, 2013.

The scope of the review and the report shall include the following:

1) CNG LNG Service to date
   a) Provide a List of CNG LNG Service Tariff Supplements executed with details regarding name of customer, location of refuelling station, number of vehicles in fleet, take-or-pay quantities, volumes delivered, rate, term of contract, capital costs, and operating and maintenance costs
   b) For each CNG LNG Agreement, provide a comparison of actual and forecast capital costs, revenues and expenses by month for CNG LNG Service for 2011 and 2012
   c) Quantify costs and benefits for other ratepayers for 2011 and 2012
2) Cost of Service
   a) Provide updates to the cost of service model inputs and explain any changes
   b) Provide rate base, depreciation/amortization and deferral account continuity schedules
3) Updated CNG LNG Market Forecasts for 5, 10, 15 and 20 years out
   a) Forecast CNG LNG Service market share
   b) Forecast annual CNG LNG Service volumes
   c) Forecast CNG LNG Service costs and revenue
4) Nature and Evolution of CNG LNG Service Agreements Executed To Date.

   In particular, provide details regarding:
   a) Range and types of terms incorporated in agreements negotiated to date
   b) Describe trends in standard terms of CNG LNG Agreements
   c) Feasibility of implementing Pro Forma Tariffs for CNG LNG Service
5) Deferral Account Update
   a) Report details of costs for all deferral accounts related to CNG LNG Service
   b) Describe any approved changes to such deferral accounts
   c) Describe any proposed changes to deferral accounts
6) Current Status of NGV sector in British Columbia
   a) Address the ongoing need for FEI to "kickstart" the return–to-base fleet NGV sector
   b) Identify remaining barriers to NGV uptake
   c) Discuss ongoing need for economic incentives
   d) Identify any technological threats (e.g. switching to electric hybrids)

e) Identify extent to which NGV refuelling stations are provided by suppliers other than FEI (number of stations, quantities, number and type of vehicles)

7) Natural Gas /Diesel Price Forecasts

a) Provide update on natural gas supply and pricing

b) Provide update on diesel/ natural gas price differentials

8) LNG Supply

a) Provide update on LNG supply availability and reliability of supply for LNG Service customers

b) Provide update on status of Rate Schedule 16 (e.g. approval of pilot, rate changes, volume restrictions)

c) Comment on any need to expand Tilbury (timing, cost and nature of any required expansion)

d) LNG tanker truck service (rate, cost, need for additional tankers, extent to which service is provided by FEI)

e) Impact of LNG Service on LNG Peaking reliability, availability and cost of service for other ratepayers

f) Role of Mt Hayes Facility in supply of LNG to LNG Service customers

9) LNG Standards and Codes

a) Provide an update on status of development of LNG Codes and Standards

b) Describe impact of new /revised codes on facility design and operation

c) Provided estimate of any cost impact related to changes in standards and codes

10) Update of Fully Allocated Cost of Service

a) Provide revenues and load factors for the rate classes relevant to CNG LNG Service (e.g. CNG LNG Service, Rate Schedule 16, Rate 25)

b) Provide estimates of the cost of serving new CNG LNG Service customers with a description of methodology

c) Compare revenue to cost ratios for all rate classes as compared to earlier years before implementation of CNG LNG Service

11) Ownership of Carbon Credits

a) Describe current status on treatment of carbon credits associated with CNG LNG Service

b) Provide update on FEI role in supporting third party validation and verification

c) Provide update on current cost/value of carbon

12) Incentive Funding

a) Status of incentive funding for NGVs

b) Amount of funding awarded for NGVs

c) Ongoing need for incentive funding in NGV sector

d) Identification of other potential or existing suppliers of incentive funding

13) Government policy impacting NGV sector

a) Provincial policy impacts

b) Federal policy impacts

c) Municipal policy impacts

14) NGV Regulations

a) Identify any government regulations related to CNG LNG Service

b) Describe the impact of the regulations on CNG LNG Service and the NGV market

Appendix D

FEI GT&C SECTION 12B

ALANNA GILLIS
ACTING COMMISSION SECRETARY
Commission.Secretary@bcuc.com
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BRITISH COLUMBIA UTILITIES COMMISSION

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Log No. 39013

VIA EMAIL
gas.regulatory.affairs@fortisbc.com

March 2, 2012

Ms. Diane Roy
Director, Regulatory Affairs
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc.
Revised Section 12B General Terms and Conditions

Further to your letter dated February 6, 2012, submitting the above noted amended Tariff pages in accordance with Order G-14-12, we enclose one duly executed set of tariff pages accepted for filing effective February 7, 2012.

Yours truly,

Alanna Gillis

cms
Enclosure

12B. Vehicle Fueling Stations

12B.1 **Compression and Dispensing Service for Compressed Natural Gas (CNG) Fueling and Fuel Storage and Dispensing Service for Liquefied Natural Gas (LNG) Fueling –** FortisBC Energy will provide CNG and LNG Services to vehicles in accordance with the provisions of this section.

CNG or LNG Service will be provided under the terms and conditions of a Service Agreement between FortisBC Energy and the Customer. The Service Agreement must comply with the provisions of this Section of the General Terms and Conditions.

The CNG and LNG Services are described below:

CNG Service will typically consist of:

(a) installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer /dehydrator, high pressure storage, dispensing equipment; and

(b) dispensing of compressed natural gas.

LNG Service will typically consist of:

(a) transport and delivery of the LNG from FortisBC Energy's LNG facilities to the Customer premises by LNG tankers, the service charge for which will be determined pursuant to Rate Schedule 16;

(b) installing and maintaining an LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and

(c) dispensing of liquefied natural gas.

12B.2 **Ownership** - All CNG and LNG fueling stations, temporary or permanent, will remain the property of FortisBC Energy, regardless of whether they are located on the customer's property. The ownership includes all components of the fueling stations.

12B.3 **Cost of Service Recovery** - Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the cost of service associated with provision of CNG or LNG Service over the term of the Service Agreement, as calculated pursuant to section 12B.4, where the minimum contract demand stipulated in the Service Agreement is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station.

12B.4 **Calculation of Cost of Service** – The total costs to be used in determining the cost of service to be recovered from the Customer under the Service Agreement include, without limitation

(a) the actual capital investment in the fueling station including any associated labour, material, and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) depreciation and net negative salvage rates and expense related to the capital assets associated with the vehicle fueling station;

(c) all operating and maintenance expenses, with no adjustment for capitalized overhead, necessary to serve the Customer , escalated annually by British Columbia CPI inflation rates as published by BC Stats monthly; and

(d) an allowance for overhead and marketing costs relating to developing NGV Fueling Station Agreements to be recovered from the Customer.

In addition to the costs identified, the cost of service recovery will include applicable property and incomes taxes and the appropriate return on rate base as approved by the British Columbia Utilities Commission for FortisBC Energy.

12B.5 **Customer's Obligation at the Expiration of Initial Term of the Service Agreement** - If, at the expiry of the initial term of an executed Service Agreement, the Customer does not wish to renew the Service Agreement, the Customer can terminate the Service Agreement provided the Customer agrees to pay any unrecovered capital costs (including the positive or negative salvage value) associated with the fueling stations, or agrees to similar provisions that permit recovery from the Customer of the remaining un-depreciated capital costs of the fueling station. Examples of such provisions include, but are not limited to, adjusting the contract rate or adjusting the contract term.

Appendix E

EXCERPTS FROM THE 2010 EEC ANNUAL REPORT

Diane Roy
Director, Regulatory Affairs Gas
FortisBC Energy Inc.

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March 31, 2011

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. ("FEI") and FortisBC Energy (Vancouver Island) Inc. ("FEVI") (collectively the "Companies")
Energy Efficiency and Conservation Program - 2010 Annual Report

British Columbia Utilities Commission (the "Commission") Decision dated April 16, 2009 and Order No. G-36-09 Compliance Filing

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On April 16, 2009, the Commission issued its Decision and Order No. G-36-09 ("Decision") on the Companies' Energy Efficiency and Conservation ("EEC") Application approving funding for FEI and FEVI for 2009 and 2010 programs.

In the Decision, the Companies were directed to file annual EEC report on all of the EEC initiatives and activities, expenditures, and results by the end of the first quarter following year-end.

Further funding for 2010-2011 was approved for each of the Companies in their respective 2010-2011 Revenue Requirements Application ("RRA") Negotiated Settlement Agreements approved by the Commission on November 26, 2009 for FEI by Order No. G-141-09 and FEVI by Order No. G-140-09.

Pursuant to the Decision, the Companies enclose their second annual report, the EEC Annual Report for 2010 (the "Report"). The Companies respectfully request that the Commission review the majority of the Report and raise any associated inquiries in the regulatory process that will be established for the Companies' upcoming Revenue Requirements Application, which will be filed with the Commission by May 2011. The Companies will file the Report as part of its RRA; therefore, the Companies believe that it is most efficient to consolidate the review of the 2010 EEC activity in the same process where the Companies will be seeking further funding for 2012-2013, as there is bound to be overlap in the substance of any inquiries.

The only exception to this approach to reviewing the Report is with respect to the use of EEC funds to provide an incentive to the customer to offset the cost of buying a natural gas vehicle (e.g. truck) versus the standard diesel or gasoline option. The information with regard to EEC funds being used for Natural Gas Vehicles ("NGV") is contained in the section of the Report relating to Innovative Technologies Program Area funding (Section 10.2). The

Companies wish to have this addressed at the earliest possible date for the reasons discussed below.

In the Decision accompanying Order No. G-6-11, dated January 14, 2011, relating to the interim approval of a Compressed Natural Gas service agreement with Waste Management, the Commission raised an issue about the Companies' provision of incentive funding for NGV initiatives. The Companies are of the view that NGVs are a part of the approved incentive funding for the innovative technologies program area, and the use of incentive funding for NGVs meets the requirements established by the Commission to ensure EEC funding is cost-effective. However, it has been necessary for the Companies to hold up new EEC incentive funding for NGV pending clarification of this issue. It is important that the Companies and the Commission reach concurrence on this issue in a timely manner, so that we can move forward on new projects that provide benefits to existing natural gas customers and fleet owners while helping to meet the energy objectives of the provincial government.

The Report (at page 201) provides additional explanation that was not available in the record of the NGV application proceeding as to why the Companies believe they have acted according to past Commission decisions. In this regard:

- We have made specific reference to past decisions, and have explained how the incentive funding was subjected to a transparent review process to ensure its cost-effectiveness.

- We have also obtained input from stakeholders involved in the EEC review process established to oversee the use of EEC funding that were aware of, and endorse, the use of incentive funding for NGVs. When this issue was discussed at the most recent EEC stakeholder group meeting (March 15, 2011), a number of participants at the meeting again verbally expressed support for the Companies' position and a desire for the Companies to proceed with cost-effective funding for NGV. Members of the EEC stakeholder working group and customer groups have since provided letters contained within the Report supporting the Companies' position that EEC funds for NGV have been used appropriately, within the established guidelines (Please see letters of support included in Appendix F).

It is the hope of the Companies that, with the benefit of this additional information, the Commission will be able to quickly provide confirmation of the Companies' compliance with past orders without additional process. Alternatively, if the Commission is unable to provide this confirmation, the Companies respectfully request that the Commission provide its concurrence for the Companies to proceed with EEC incentive funding to customers to offset the incremental cost of buying an NGV over a standard gasoline or diesel vehicle. The Companies respectfully submit that this concurrence to proceed could also be provided without additional process since the benefits of EEC incentive funding for NGV are clear, accord with Commission-approved EEC principles, exceed the Commission-approved tests for evaluating EEC funding, and have the support of stakeholders.

If you have any questions regarding this submission in general please contact the undersigned or Sarah Smith, Manager, Energy Efficiency and Conservation at (604) 592-7528. For NGV related questions, please contact Mark Grist, Manager, Business Development at (604) 592-7874.

Yours very truly,

FORTISBC ENERGY INC.
FORTISBC ENERGY (VANCOUVER ISLAND) INC.

Original signed by:

Diane Roy

Attachments

cc (email only): EEC Stakeholder Group

Innovative Technologies Program Area for both 2010 and 2011 is positive and meets the Commission's directives in Order No. 141-09 for innovative technologies to have a weighted TRC score of 1.0 or more on a portfolio level.

10.2 Funding for NGV Initiatives

10.2.1 DEFINITION

NGVs represent an important element of the Innovative Technology Program Area, and the favourable TRC of NGV related incentives has contributed in a large measure to the favourable TRC of the overall Innovative Technology portfolio. This Section specifically deals with the Commission's recent comments regarding whether FEI has approval to proceed with NGV related programs. It provides additional information regarding why the Companies believe that they are compliant with past Commission orders, and also provides further information about the benefits associated with the funding which have contributed to stakeholder support for these initiatives. It is the hope of the Companies that the Commission will be able to quickly provide confirmation of the Companies' compliance with past orders without additional process. Alternatively, if the Commission is unable to provide this confirmation, the Companies respectfully request that the Commission provide its concurrence for the Companies to proceed with EEC incentive funding to customers to offset the incremental cost of buying an NGV over a standard gasoline or diesel vehicle. The Companies respectfully submit that this concurrence to proceed could also be provided without additional process since the benefits of EEC incentive funding for NGV are clear, accord with Commission-approved EEC principles, exceed the Commission-approved tests for evaluating EEC funding, and have the support of stakeholders.

This section is organized as follows:

- The Companies first set out the Commission's comments that gave rise to this issue, and provide their views as to why this matter is most appropriately resolved in the context of this Report; and
- The Companies then outline the key elements of past decisions that support the Companies' actions to date, and support the continued use of cost effective NGV incentives.

10.2.2 COMMISSION'S COMMENTS ON FUNDING FOR NGVS AND NEED FOR QUICK RESOLUTION

On January 14, 2011, the Commission released its Order No. G-6-11 and decision ("Interim Decision"), which approved a CNG Fueling Station Installation and Operating Agreement between FEI and Waste Management of Canada Corporation on an interim basis, subject to certain conditions. In this Interim Decision, the Commission raised a potential issue with respect to the use of EEC incentives for NGV vehicle reimbursement. The Commission's Interim Decision, Appendix A, page 5, stated:

> *"The Commission Panel is not presently persuaded that Terasen has Commission approval for the incentive grant to Waste Management that is described under Vehicle Reimbursement in the WM Agreement. Directive 2 of Order G-36-09 explicitly rejected expenditures for Natural Gas Vehicles. The Negotiated Settlement approved by Order G-141-09 approved Rate Schedule 26 – NGV Transportation Service and marketing costs in support of NGV. Terasen withdrew its other requests related to NGV. Rate Schedules 6 and 26 provide for NGV incentive grants, but it seems unlikely that Waste Management will use these Rate Schedules. Therefore, the Commission Panel believes that Terasen is at risk of not being able to recover incentive payments to Waste Management in its rates."*

As FEI outlined in its response to BCUC CONFIDENTIAL IR 1.4.1, contained in the Application for Approval for a Service Agreement for Compressed Natural Gas Service and for Approval of General Terms and Conditions for Compressed Natural Gas Liquefied Natural Gas Service, dated December 20, 2010, that TGI intended "to continue meeting its reporting commitments by reporting in the next annual EEC report on the WM funding, and any matters relating to TGI's use of EEC funding should be addressed at that time…". The Commission did not have the benefit of a complete background and analysis when it made its comments regarding EEC funding for NGVs, and recognized that "the incentive payments are outside the scope of the review of the WM Agreement"56 in its Interim Decision.

What follows below is our commitment to provide all information related to why we believe we have acted within the guidelines and approvals of past regulatory decisions related to EEC, specifically to the use of EEC incentives for NGVs. The information included in this Report adds to the information available on the record in the proceeding where the Commission made its comment about EEC funding. As such, there is now a complete record on which the Commission can determine this issue.

The Companies submit that this Report is the most appropriate forum to seek concurrence on this issue, rather than deferring the matter to the upcoming revenue requirements application, for four reasons:

1. The first expenditures from the EEC funding envelope for NGV occurred in 2010, to which this Report speaks. The individual spend by program areas is contained within this Report along with the individual and portfolio level TRC to which EEC incentives for NGV contribute.
2. The EEC Annual Report was established to ensure the Companies are operating within the guidelines and approvals established in Order No. G-36-09 and sequence Orders G-140-09 and 141-09.
3. The Companies have put further EEC incentive awards for NGVs on hold until the uncertainty is resolved. Prolonged delays in resolving this matter will likely delay the delivery rate benefits obtained by existing non-bypass customers associated with building cost-effective load, delay the benefits achieved by new NGV customers from reduced

[56] Order No. G-6-11 Appendix A page 5.

transportation costs, and delay GHG emissions reductions in BC. These delays could potentially derail NGV initiatives (and its associated benefits) completely if fleet operators adopt conventional or viable alternative technologies.

4. The Companies' position for why we believe we have approvals to use EEC funds for NGVs is contained below and this makes for an efficient and less costly process to resolve this issue for all parties involved.

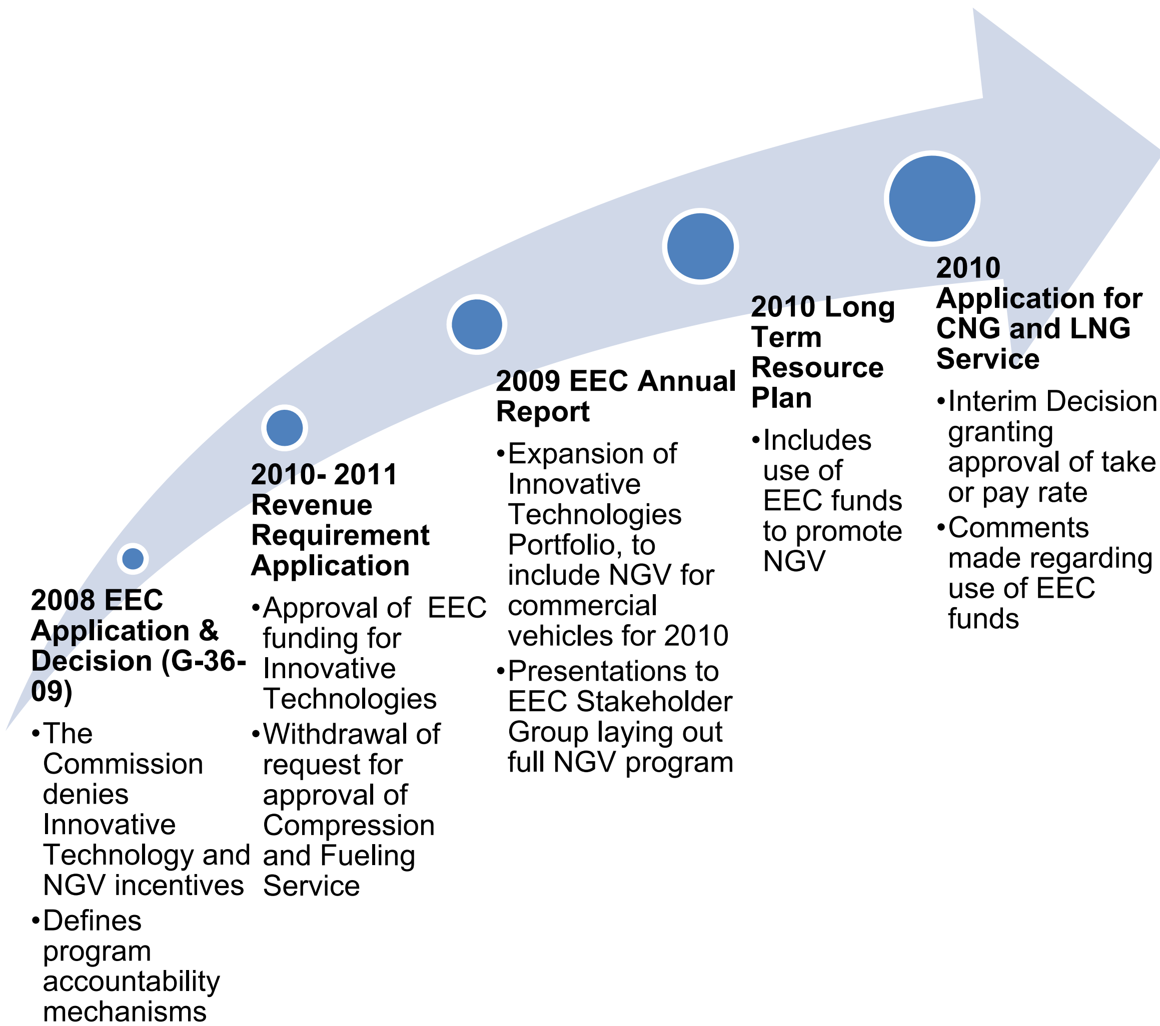
The Companies have support from key stakeholders for the quick resolution of this uncertainty resulting from the Commission's interim order on Waste Management, and the re-initiation of NGV incentive programs. As a result of a recent EEC Stakeholder Group held March 15, 2011, FEI has received letters from multiple members of the Stakeholders Group supporting FEI has followed the established process in the use of EEC funding (Please see Appendix F for copies of these letters). The Companies thus submit that the necessary information is now available to address this issue in a meaningful way.

10.2.3 RELEVANT COMMISSION APPROVALS

There have been a number of regulatory events that led up to the Companies providing NGV funding. In this section the Companies outline the key aspects of past Commission orders that support NGV funding. As explained in detail below, FEI believes that the use of Innovative Technologies Program Area EEC funding for NGV initiatives is consistent with previous Commission decisions (Orders G-36-09, G-141-09, and G-140-09), and that FEI has been open and transparent with stakeholders about EEC activities and expenditures, including the use of EEC incentives for NGV.

The following diagram summarizes the sequence of regulatory proceedings and events that touch on EEC funding.

Figure 10-1: Timeline of Regulatory Proceedings Related to EEC Funds and NGV



Each of these regulatory events and how they impact the Companies' use of EEC funds for NGVs is discussed in detail in the remainder of this Section, which is structured as follows:

1. EEC Application and Decision (Order No. G-36-09, dated April 16, 2009)
   a) Rejecting EEC funding for the Innovative Technology Portfolio, including Natural Gas Vehicles
   b) Recognizing and establishing principles applicable for developing further programs within the Innovative Technologies Program Area, including that
      i. Programs on a portfolio level must meet an established threshold

ii. Innovative Technologies Program Area brings forward the benefit of lower GHG emissions by promoting low carbon technologies

c) Setting up mechanisms for introducing new programs and making refinements to existing programs through the Commission approved accountability and oversight measures, including

i. Stakeholder Input and Reporting
ii. The Company's ability to transfer funds between program areas within the EEC funding envelope.

2. The 2010/2011 Revenue Requirements Application ("RRA") and Negotiated Settlement Agreement ("NSA") (Order No. G-141-09 and G-140-09, dated November 26, 2009)

a) Two Distinct Proposals Presented in the 2010/2011 RRAs for EEC and NGV fuelling station infrastructure, and the one that was withdrawn in the NSA did not relate to EEC

- Items 11 and 12 of the NSA for FEI are for EEC initiatives and programs. Items 6 and 7 of the NSA for FEVI are for EEC initiatives and programs

- Item 14 of the NSA for FEI, which the Commission has alluded to in its recent Decision accompanying Order No. G-6-11 as having been withdrawn, is NGV for fuelling and transportation service (delivery on the FEI system), not EEC funds for NGV. Also, item 9 of the NSA for FEVI is NGV for fuelling and transportation service (delivery on the FEI system), not EEC funds for NGV.

i. Increased EEC Funding Approvals for 2010 and 2011, including Innovative Technology and Industrial Programs and Innovative Technology programs are to be evaluated as a separate portfolio

ii. Withdrawal of NGV Rate Offering, not related to EEC funds

3. Adhering to the principles and framework established by Commission Decisions with regard to the use of EEC funds for NGVs

a) Favourable TRC Ratio
b) GHG emissions reductions benefits
c) Broad support from EEC Stakeholder Group Consultation
d) Openness and transparency in the 2009 EEC Annual Report and 2010 Long Term Resource Plan

Each of these topic areas are discussed in detail below.

10.2.3.1 EEC Application and Decision

The Companies filed an EEC Application on May 28, 2008. On April 16, 2009, the Commission issued Commission Order No. G-36-09 (the "EEC Decision"). While the specific request for

Innovative Technology funding was denied, the Decision established important principles and framework as to how FEI should evaluate EEC programs (primarily the TRC test, on a portfolio basis), and established a specific regulatory mechanism for overseeing the Company's use of EEC funding (the EEC stakeholder committee). These approvals become important later in the chronology, as the NGV funding meets the approved test for evaluating EEC funding, and the use of EEC funding for incentives was presented to, vetted by, and generally supported by, the stakeholder committee as confirmed by the letters of support filed with this Report.

10.2.3.1.1 Rejection of the Innovative Technology Portfolio Including Natural Gas Vehicles

In the EEC Application, funding for NGV initiatives was sought under the umbrella of "Innovative Technologies, NGV and Measurement", because all these programs aim "to foster and further the deployment of forward-looking low carbon technologies" (Page 69 of the EEC Application). In the EEC Decision, the Commission rejected funding for the Innovative Technology, NGV and Measurement Program Area based on "insufficient evidence" at that time. In particular, the EEC Decision (on Page 26) states:

> *…Terasen acknowledges that further refinement of this program is required and indicates uncertainty as to whether an effective program can be developed over the funding timeframe. The Commission Panel finds that there is insufficient evidence with respect to the nature and scope of the proposed program, and accordingly rejects the Innovative Technologies, NGV and Measurement program expenditures at this time. Terasen may wish to bring forward projects in this program area for consideration as they become more fully developed.*

Thus, although the Commission rejected the funding "at this time," it did not reject the possibilities that NGV programs be developed. Additionally, there are two other relevant parts of the EEC Decision, discussed in the following paragraphs: (1) the approval of the TRC test for evaluating programs by adopting the portfolio approach, and (2) the EEC stakeholder group being established as the means of efficiently reviewing EEC program spending.

10.2.3.1.2 Recognition and Establishment of Certain Principles

The Commission granted a number of other approvals, significant among which for the current issue was the approval of a method for evaluating EEC initiatives. The EEC incentives for NGVs meet the approved tests.

10.2.3.1.2.1 TRC Meets the Established Threshold

FEI assesses all EEC funding according to the framework established in the EEC Decision, which involves, among other things, the application of TRC test, which measures the cost-effectiveness of the EEC programs.

The Commission discussed the application of a TRC at page 34 of the EEC Decision:

The Commission Panel also takes note of the DSM Regulation which will apply to Terasen as of June 01, 2009 requiring the Commission to use, in addition to any other test it considers appropriate, the TRC test in determining whether a demand-side measure is cost-effective. While the DSM Regulation is not in effect for the purposes of this EEC Decision, the Commission Panel does consider the TRC test to be appropriate and adequate for the purposes of this Application and accepts it as such.

Furthermore, the Commission accepted a portfolio level approach when considering the TRC ratio. That is, all EEC programs, on an overall combined level, rather than on individual initiatives or programs, should achieve a portfolio TRC level of 1.0 or greater.

Thus, the cost effectiveness of EEC expenditure is evaluated as a whole, on the portfolio level, which must have a TRC test of one or greater.

Please refer to Table 10-2 which shows the TRC for the Innovative Technologies portfolio as a whole including the Commercial NGV Demonstration program for 2010.

10.2.3.1.2.2 GHG Emissions Reduction by Promoting Fuel Switching From Higher Carbon Fuel to a Lower Carbon Fuel

In the EEC Application, FEI and FEVI had applied for approval of funding to encourage the adoption of natural gas as a fuel instead of both higher carbon fuels and electricity in the residential sector. The Commission accepted the former, and rejected the latter. As per page 18 of the EEC Decision:

The Commission Panel accepts EEC expenditures directed at fuel switching from fossil fuels with a higher carbon content than that of natural gas.

We acknowledge that fuel switching was addressed in the EEC Application in the context of the residential sector, and that this statement did not represent Commission approval to pursue fuel switching in the transportation sector. (The Companies submit that the approval to do so came later, following upon the Commission's approval of the 2010-2011 Revenue Requirements Application Negotiated Settlement Agreement.) However, this recognition of the benefits of high to low carbon fuel switching speaks to the Companies' rationale for pursuing NGV incentives. Not only does using NGV technologies in the transportation section move customers from higher carbon fuel such as diesel to low carbon natural gas, but also the principles underlying the fuel switching and underlying all the Innovative Technologies Program Area are consistent – reduction of the GHG emissions. Please refer to Section 10.2.3.3.2, which outlines the GHG emissions reduction in 2010 from providing EEC incentives to NGVs.

Since the EEC Decision was issued, Government enacted the *Clean Energy Act ("CEA").* Reducing GHG emissions in BC is one of the main objectives of the provincial government, as outlined in the *CEA*. In fact, the *CEA* includes as one of "British Columbia's energy objectives"

GHG emissions reduction by high-to-low carbon fuel switching, which is directly applicable to NGVs.[57]

This, too, speaks to FEI's rationale for looking to the transportation sector as a potential target for EEC incentives.

10.2.3.1.3 Commission Approved Accountability Mechanisms for Introducing New Programs, and Refining Existing programs

The EEC Decision also included approvals of mechanisms that would ensure accountability for EEC expenditures. The approval for accountability mechanisms is more efficient than the Companies seeking Commission approvals each time funding was redirected, while, similar to the approval of inter and intra program area funding transfers, providing flexibility to the Companies in managing and developing EEC programs.

These approvals are important in the current context, not because they approved spending on NGV incentives, but because the Companies followed this framework once funding for Innovative Technologies incentives was approved in the 2010-2011 RRA NSA. By following this framework, the Companies have kept stakeholders fully apprised of our intentions regarding NGV incentives, and stakeholders have had input in to how it was done.

10.2.3.1.3.1 Stakeholder Input and Reporting

In the EEC Application, the Companies proposed accountability mechanisms for managing the funds approved for EEC programs. Specifically, the EEC Decision, at page 41, summarizes what was proposed:

> *In this Application the Companies have recognized the need for accountability for the funds approved for EEC programs. First, any funds not spent will not be charged to the regulatory asset deferral account. Second, the Companies intend to monitor the portfolio TRC on a monthly basis, and have proposed to file an Annual EEC Report with the Commission by the end of the first quarter every year. The Report will detail program activity, expenditures, and cost-benefit results for the previous year, as well as describe program activity and provide forecasts for the upcoming year. Third, in the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing a broad cross section of stakeholders identified in the Application. Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress and <u>obtain stakeholder input on new programs and refinements to existing programs</u>. [Emphasis added]*

Interveners supported this funding approach, as stated on page 41 of the EEC Decision:

> *BCSEA-BCSC states that they: ". . . support this [funding] approach, noting that the proposed accountability mechanisms are designed to be more effective and efficient than*

[57] Clean Energy Act, section 2, "British Columbia's energy objectives"

> *having on-going Commission involvement in decision-making within the portfolio during the Funding Period" and "BCSEA-SCBC acknowledge and support the additional accountability mechanisms proposed by Terasen in [Terasen Argument] paragraph 112." (BCSEA-SCBC Argument, pp. 5, 20)*

The Commission accepted these accountability mechanisms on page 42 of the EEC Decision:

> *The Commission Panel accepts Terasen's accountability undertakings, and considers that, while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted, TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.*

Once the 2010-2011 RRA NSA was in place, with its recognition of funding for Innovative Technologies, the Companies employed the accountability mechanisms approved in the EEC Decision for Innovative Technologies in the same manner as with all other EEC spending. For the Commercial NGV Demonstration program, the EEC Stakeholder Group was consulted on three occasions, as outlined below in Section 10.2.3.3.2.1.

10.2.3.1.3.2 Flexibility to Manage Funds for Approved Program Areas

With accountability mechanisms in place, FEI believes that the Companies should be provided the flexibility in managing the approved funds to further achieve efficiency. In the EEC Application, the Companies state:[58]

> *…that it is most efficient for the Commission to approve the overall expenditure level, by utility, for the Funding Period, rather than approving the funding by program area, or by individual program initiative. <u>This approach will allow the Companies' to respond quickly to changes within initiatives and to new opportunities that might arise.</u> For example, if a particular initiative within the commercial energy efficiency program area has a higher than expected number of participants, and a strong cost-benefit ratio, the Companies would like to have the ability to shift funds from another, underutilized program area to that commercial energy efficiency initiative, without coming back to the Commission for approval to do so. Not only will this allow the Companies' to respond quickly to opportunities, <u>it will also reduce the Companies' administrative burden related to EEC activity, and both the speed of response and reduced administrative burden will increase the value to customers of the Companies' EEC activity.</u>*
> [Emphasis Added]

The EEC expenditures approved in the EEC Decision are part of a funding envelope to develop and implement programs that conform to meeting the portfolio TRC of one or greater than one, and FEI has the ability to transfer funds to where it makes the most sense provided it can be

[58] EEC Application, at pages 50 and 51

justified after the fact in a Report. FEI requires the flexibility to move funds to programs like the EEC expenditures for natural gas vehicles so that programs can be designed and implemented efficiently within an approved funding envelope. The measure for determining whether or not the expenditure was made appropriately is the TRC test, and FEI's reporting obligations permit the regular assessment of FEI's expenditures. The Commission addressed reporting obligations on page 42 of the EEC Decision, and expressly anticipated that shift in funding within the overall approved envelope would be allowed provided that such a transfer is transparent and supported with reasons:

> *Commission Panel directs that the annual EEC Report include the following:*
>
> *• TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.*
>
> *• <u>any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be</u>.* [Emphasis Added]
>
> *• data for fuel switching programs should be tracked in a manner which allows for reporting types of fuels replaced by natural gas, including estimated GHG impacts.*

While this direction does not authorize spending outside of Commission-approved Program Areas, it does speak to the use of funds within those approved areas being managed by the Companies, with accountability to the EEC Stakeholder Group regarding the funding decisions as part of the annual reporting. Once the 2010-2011 RRA NSA was in place, with its recognition of funding for Innovative Technologies, FEI proceeded to design incentive programs and used EEC incentives in line with the approved tests. The oversight of those decisions occurred in the context of the EEC Stakeholder Group, in the same manner as with all other EEC spending. For the Commercial NGV Demonstration program, the EEC Stakeholder Group was consulted on three occasions, as outlined below in Section 10.2.3.3.2.1.

As described in the Evaluation Strategy of the Commercial NGV Demonstration program (in Section 10.1.5.2), fuel consumption data will be tracked and reviewed annually to determine fuel switching benefits and program roll-out approaches. This data will be used to calculate and monitor the estimated GHG emission reduction benefits.

10.2.3.1.4 <u>Summary: Providing EEC Incentives to Natural Gas Vehicles is Consistent with the Principles Contained in the EEC Decision</u>

While the EEC Decision rejected specific funding for the Innovative Technologies Program Area, the Decision establishes certain principles and provides framework for the Company to consider when developing and bringing forward programs in this Program Area. Specifically, the Commission:

- Recognized the benefits of high to low carbon fuel switching in the residential context;

- Adopted the use of TRC test on a portfolio level to assess the cost-effectiveness of the EEC programs;
- Approved the proposed accountability mechanisms to oversee the use of funds for approved Program Areas, including annual report to the Commission and consultation with Stakeholder groups, for development of new programs and refinement to existing programs; and
- Accorded the Companies flexibility to manage the funds subject to the accountability mechanisms.

Following the approval of the EEC funding for Innovative Technologies Program Area in the 2010-2011 Revenue Requirement Application proceeding, the Company developed the NGV programs using EEC funding consistent with these principles and the framework.

10.2.3.2 2010-2011 Revenue Requirements Application and Negotiated Settlement Agreements

Subsequent to Commission's Order No. G-36-09 in which the Commission left it open to the Companies to propose Innovative Technology programs, FEI and FEVI sought increased EEC funding approval to add specific programs under Innovative Technologies and Industrial Program Area in their respective 2010-2011 Revenue Requirements Applications. As discussed below, the settlement agreements that resolved these Revenue Requirements Applications included Innovative Technology funding envelope based on the Companies' proposal.

In several responses to Information Requests issued in the Revenue Requirements Applications regarding NGVs, the Companies expressed its intent to use different sources of incentive funding to overcome the high fleet conversion costs and limited number of OEM vehicles, including grants already available and "all available funding opportunities", a reference to using EEC funding that had been proposed. For example, in response to BCUC IR 1.34.2 in the RRA proceeding, FEI stated:

> *TGI intends to meet the other potential obstacles by providing grants, and ensuring that all available funding opportunities are used.*

Both applications were subject to Negotiated Settlement Agreements. On November 26, 2009, the Commission released Order No. G-141-09 and G-140-09 approving NSAs for FEI and FEVI respectively. Thus, the total funding envelope for EEC increased with these two decisions; however, the underlying principle contained in Order No. G-36-09 must be adhered to in order to make use of these funds.

The Commission's approved the NSA's included the approval of EEC funding for Innovative Technologies for FEI and FEVI for 2010 and 2011. These approvals are explicitly described in Items 11 and 12 in the FEI's NSA and Items 6 and 7 in the FEVI's NSA.

Associated with these approvals, both NSAs state that:

> *…the Innovative Technologies Programs will be managed by [the Companies] as a separate segment of the overall portfolio to have a weighted average Total Resource*

Cost ("TRC") of 1.0 or more. [The Companies] will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

The last sentence suggests that the Companies will continue to work with the EEC stakeholders to develop or refine programs/applications to achieve the established TRC threshold. This conforms to the principle and framework provided under the EEC Decision. NGV incentives, because of having a TRC well above 1.0, make a significant contribution to ensuring that the Innovative Technologies portfolio maintains a portfolio TRC greater than 1.0.

10.2.3.2.1 <u>Two Distinct proposals presented in the 2010-2011 RRA for EEC Funding and NGV Rate Offerings</u>

In its Reasons for Decision, accompanying Order No. G-6-11, the Commission commented that in the 2010-2011 RRA proceedings, the Companies "withdrew its other requests related to NGV" besides incentive grants under Rate Schedules 6 and 26.[59] The Companies respectfully submit that the Commission's comments reflect that it mixes two distinct issues addressed in separate sections of the NSAs: EEC funding and NGV rate offerings. The NSA granted express approval of the EEC funding requests.

In their respective Revenue Requirement Applications, the Companies made two distinct requests for approval: (1) EEC funding for Innovative Technologies Program Area, and (2) NGV Rate Offerings. For instance, in FEI's RRA (dated June 15, 2009 at page 227), FEI submitted six separate proposals in the context of its EEC and Alternative Energy Solutions initiatives. Two of these distinct proposals are:

" 1. Increase EEC funding for 2010 over the currently-approved EEC funding to add interruptible Industrial customer programs and Innovative Technologies programs to the EEC portfolio, with all funding subject to the same financial treatment as approved in the EEC Decision;

5. Approval of Tariffs for Rate Schedule 6C – Natural Gas Compression and Refuelling Service and Rate Schedule 26 – Natural Gas Vehicle Transportation Service, and subsequently the cancellation of Rate Schedule 6A – General Service – Vehicle Refuelling Service."

Item 5 listed above pertains to "Natural Gas Vehicle Rate Offerings", which FEI further described in its 2010-2011 RRA.[60] Specifically, FEI sought approval of Rate Schedule 6C – Compression and Refuelling Service, Rate Schedule 26 – NGV Transportation Service, and their supporting activities - Compression Service ("CS") test parameters and a NGV non-rate base deferral account. The requests for EEC funding and for natural gas vehicle rate offers are independent of each other in the context of the RRA.

[59] Order No. G-6-11, at page 5.
[60] FEI 2010-2011 RRA at pages 238 to 249.

10.2.3.2.1.1 EEC Funding Increase Request

The EEC funding request was approved in FEI's NSA, as Item 11 and Item 12 for FEI's NSA as Items 6 and 7. For example, Item 11 of the NSA is outlined here:

> ***<u>11. Energy Efficiency and Conservation ("EEC") Funding for 2010</u>***
>
> *The Parties agree as follows in respect of the EEC funding sought by TGI for 2010:*
>
> *(a) TGI will reallocate from residential and commercial EEC programs an additional $1.6 million from the amount approved for 2010 in the EEC Decision[61] to low income and rental housing programs. This brings the total for low income and rental housing programs to $2.4 million for 2010.*
>
> *(b) EEC funding for industrial interruptible programs for 2010 will be $435,000, which is the amount requested by TGI in the Application.*
>
> *(c) <u>EEC funding for innovative technologies will be $2.3 million for 2010, which is the amount requested by TGI in the Application.</u>*
>
> *(d) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). <u>However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee</u>.* [Emphasis added.]

Thus, the Innovative Technology funding was approved.

10.2.3.2.1.2 Withdrawal of NGV Rate Offering Request

With respect to natural gas vehicle rate offerings for FEI, Rate Schedule 26 was approved as filed; however, the other items related to the NGV Rate Offerings were subsequently withdrawn. To reach a settlement on requests in the RRA as a whole, FEI withdrew its request for NGV Rate Offerings, as described in the excerpt below. However, this was treated as distinct from the approval of EEC funding.

Relating to FEI, Item 14 from Page 10 of the NSA approved in Order No. G-141-09 states:

> ***14. Natural Gas for Vehicles ("NGV")***
>
> *The Commission Issue No. 2 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:*

[61] Decision and Order No. G-36-09 dated April 16, 2009 in the TGI-TGVI Energy Efficiency and Conservation Application

"Natural Gas Vehicles ("NGV") – if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?"

The Parties agree:

(a) NGV Rate Schedule 26 - NGV Transportation Service should be approved as filed.

(b) The marketing costs in support of NGV that are included in the revenue requirements Application are appropriately recoverable in 2010 and 2011 rates.

(c) Upon acceptance of this Agreement by the Commission, TGI withdraws its request in this Application for the following:

i. <u>Rate Schedule 6C NGV Compression and Refueling Service and 6A NGV</u>

<u>Refueling Service; and</u>

<u>ii. the Compression Service ("CS") Test; and</u>

<u>iii. NGV non-rate base deferral account.</u>

The Parties acknowledge that these requests are being withdrawn by TGI to facilitate a settlement on other issues presented in this Application. The Parties agree that TGI's withdrawal of its requests regarding NGV is without prejudice to TGI's right to bring forward similar requests in 2010 or 2011 or otherwise in the future. The Parties acknowledge that TGI intends to develop this area of business and that TGI anticipates it will bring forward applications on NGV projects to the Commission on a case-by-case basis during the term of this Agreement and in future years. The Parties agree that TGI is at liberty to do so. [Emphasis added.]

Thus, what was withdrawn by FEI only related to natural gas vehicle rate offerings (compression and fueling service). However, the use of EEC funds for NGVs was not withdrawn as part of the NSA; FEI was given express approval to pursue initiatives targeted at Innovative Technologies. When developing the Innovative Technologies programs, which the Companies believe that NGVs are to be part of, and have expressly stated so in 2008 EEC Application and the 2009 EEC Annual Report, the Companies would still have to adhere to the principles contained in Order No. G-36-09 as outlined above to use EEC funds for NGVs.

FEI has also received support for this interpretation of the NSA from a member of the EEC Stakeholder Group who was also a registered intervener during the RRA proceeding. In a March 22, 2011 letter[62] to FEI, the Commercial Energy Consumers Association of BC ("CEC") stated the following:

…The CEC is precluded (as a consequence of confidentiality provisions) from discussing the specific content of discussion in a Negotiated Settlement Process ("NSP") but may disclose its own positions at any time. The CEC believes that its sign off with respect to the RRA NSA carried the weight of its support for FEI providing funding for its NGV

[62] Please see Appendix F for a copy of the letter from CEC

initiatives. Specifically the CEC believes that item 14 of the NSA supports the fuelling and transportation services to be provided and that item 11 of the NSA supports the funding envelope for the Innovative technologies for 2010-2011.

The Companies agree with CEC's characterization of the agreement.

10.2.3.3 The Companies Have Adhered to the Principles Established By Commission Decisions with regard to the use of EEC funds for Natural Gas Vehicles

The Companies' use of the EEC funding for the Innovative Technologies Program Area to develop NGV programs, subsequent to the RRA NSAs, has met the principles and framework established in the EEC Decision and further developed in the NSAs approved by Commission Orders G-141-09 and G-140-09, as described in Section 10.2.3.1.3 in terms of evaluation, oversight and accountability. The factors relevant to the evaluation, oversight and accountability are discussed below.

10.2.3.3.1 Favourable TRC Ratio

Pursuant to the approved NSAs, the Companies must manage the Innovative Technologies Program Area as a separate segment of the overall portfolio and the TRC ratio for this segment must have a weighted average TRC of 1.0 or more.

The Innovative Technologies Program Area described in this Report has met this threshold with a weighted average TRC of 1.2. As summarized earlier, see Table 10-10 below for the Innovative Technologies Program Area TRC for 2010.

Table 10-10: Innovative Technologies Program Area TRC for 2010

Program	TRC	
	FEI	FEVI
Solar Water Heating PSECA Program	0.2	0.3
Commercial NGV Demonstration Program	1.4	-
Total	1.2	

The Commercial NGV Demonstration program has made a significant contribution to ensuring that the overall TRC for the Innovative Technologies portfolio has exceeded 1.0.

10.2.3.3.2 GHG Emissions Reductions Benefits

As the Commission recognized, the Innovative Technologies programs can be effective tools for achieving GHG emission reductions. Similar to the residential fuel-switching program, the Companies have tracked and demonstrated that the Commercial NGV Demonstration program creates GHG emissions reduction benefits. The NGVs incented in the 2010 Innovative

Technologies Program Area are expected to produce between 20 - 30% fewer GHG emissions than their diesel counterparts.[63] At this time, FEI estimates that the vehicles under the 2010 program expenditures represent annual GHG savings of approximately 4,100 tonnes of CO2e per year, which is the equivalent to taking 800 passenger vehicles off the road.[64] As these NGVs enter regular operations FEI will track and monitor fuel consumption and distance traveled, which is used to calculate GHG emissions.

10.2.3.3.2.1 Broad Support from EEC Stakeholder Group Consultation

As stated above, one of the key principles developed through the EEC Decisions and the subsequent approved NSAs is the accountability mechanism that allows for oversight by the stakeholder groups. In accordance with this principle, an EEC Stakeholder Group was formed in December of 2009 (Please see Section 12: EEC Stakeholder Group Activities). The members of the EEC Stakeholder Group were solicited through regulatory stakeholders (those that have historically intervened in the Companies' regulatory proceedings), from industry groups with whom the Companies interact, and from key contacts from the Companies' Energy Solution and Community Relations departments. Additionally, the Companies have also done the following:

- On March 11, 2010, the proposed Innovative Technologies portfolio was presented to the EEC Stakeholders meeting (Please see Appendix H for a copy of this presentation and a copy of the attendees list). In particular, at the meeting, the Companies provided estimates of funds to be applied to various Innovative Technologies Program Area, including NGVs (see slides 5 and 6). The meeting also achieved several important goals, such as:[65]
  a) Providing an opportunity to discuss details of how the weighted average TRC is applied to the Innovative Technologies portfolio.
  b) Allowing the EEC stakeholder group to discuss proposed Innovative Technologies program portfolio and program costs.
  c) Introducing the group to the feedback mechanism that affords them an opportunity to voice any concerns on the approach to Innovative Technologies, and to provide ongoing dialogue.
- Following the March 11, 2010 meeting, all members of the Stakeholder Group were contacted to provide FEI and FEVI with feedback. The goal was to ensure any concerns they may have with the practical application of the weighted average TRC or with the portfolio of proposed activity for Innovative Technologies have been brought forward and noted. The Companies did not receive any opposition from the Stakeholder Group through its request for feedback.

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[63] Based on BC emissions factors from Natural Resources Canada's GHGenius model 3.18 available at www.ghgenius.com
[64] Calculation based on US EPA Greenhouse Gas Equivalencies Calculator
[65] See page 114 of the EEC 2009 Annual Report

- On November 24, 2010, the EEC Stakeholder Group was further informed of the Commercial NGV Demonstration program through a 17-page presentation that focused exclusively on this topic. (Please see Appendix H for a copy of this presentation and a copy of the meeting minutes and attendees list).
- On March 15, 2011, the EEC Stakeholder Group was informed that the Companies are seeking confirmation from the Commission regarding the use of EEC funding for NGVs. (Please see Appendix H for a copy of this presentation and a copy of the EEC Stakeholder Group membership list). The timeline of regulatory proceedings,[66] as outlined in this section, was presented to the Group and several participants voiced their support for the Companies, and voiced their opinion that the Companies have been transparent on this matter and that the uncertainty should be removed as soon as possible to allow further funding to proceed.

The Companies asked those parties that spoke to this issue during the stakeholder group to provide a written comment for inclusion in this Report. FEI received letters in support of our approach to the funding approvals process from the following Stakeholder Groups:

a) BC Apartment Owners & Managers Association ("BCAOMA")
b) BC Sustainable Energy Association ("BCSEA")[67]
c) City of Vancouver ("COV")
d) Commercial Energy Consumers Association of BC ("CEC")
e) Fraser Basin Council ("Fraser Basin")

FEI has included these letters in Appendix F. Although all members of the EEC stakeholder group have been invited to comment, FEI has not received any specific letter of opposition to date.

Below, FEI has provided excerpts from these letters directed to FEI from Stakeholder Groups who attended these sessions:

From the BCAOMA letter:

> *The BCAOMA participated in stakeholder review sessions organized by FortisBC and had the opportunity to review and comment on the planned use of incentives to encourage the adoption of NGVs. During the November 24, 2010 session FortisBC provided a detailed presentation on the NGV program for BC, including the proposed use of EEC funding under the Innovative Technologies program. This presentation was favourably received by the stakeholder group. The BCAOMA believes that this consultation process meets the "Accountability Measures" defined in the Commission EEC Approval Decision G-36-09 and supports FortisBC's view that it has the necessary approvals to proceed with the NGV incentive program.*

[66] See Figure 10-1 in Section 10.2.3
[67] The BCSEA only attended the March 15, 2011 meeting. The other parties who provided letters attended both 2010 Stakeholder Group meetings.

From the BCSEA letter:

> *…as an active participant in the 2009 Energy Efficiency and Conservation Application of Terasen Gas, and a current member of FortisBC's EEC Stakeholder Group, the BC Sustainable Energy Association supports the use of FortisBC's EEC program to incent the purchase of heavy duty NGVs in place of diesel powered vehicles where cost effective, primarily because of the greenhouse gas emissions reductions benefits.*

From the COV letter:

> *We confirm that two stakeholder review sessions were held in 2010 (March and November) and that NGV programs were presented and discussed at these sessions. The City of Vancouver supports the continuation of the program to provide NGV incentives for heavy duty vehicle applications as adoption of NGVs in these markets provides GHG reductions and fuel cost savings to operators of NGVs.*

From the CEC letter:

> *The CEC would characterize the FEI approach with respect to its NGV initiatives as having been and continuing to be nothing but open and transparent. The CEC believes that FEI has worked diligently to build understanding and support for its NGV initiatives. The CEC has directly been involved in the regulatory processes, in which the CEC believed that FEI was being provided the CEC support and consent to both pursue these NGV initiatives and to fund these initiatives from EEC funds.*

From the Fraser Basin Council letter:

> *Through our involvement in the EEC Stakeholder group over the past two years, we have been informed of Fortis BC's ongoing plans to provide incentives for natural gas vehicles (NGVs) ... We are supportive of this effort by Fortis BC to provide incentives for NGV purchase...We also know that incentives are required to assist in overcoming the barrier of increased capital cost for NGVs.*

The Companies agree with the views expressed in these letters with respect to our approach to the funding approvals process.

10.2.3.3.3 Openness and Transparency of Innovative Technologies funding for NGVs in the 2009 EEC Annual Report and the 2010 Long Term Resource Plan

The Companies have been transparent about the use of Innovative Technologies Program Area funding for NGVs in two of its recent regulatory filings and proceedings.

Firstly, the 2009 EEC Annual Report, filed on March 31, 2010, states the Innovative Technologies Program Area includes NGVs. The suggested framework of the Innovative Technologies Program Area was described on Page 115:

> *TGI and TGVI restructured the existing portfolio list of Innovative Technologies to include Solar Thermal Hot Water, <u>NGV for Commercial Vehicles</u>, Hydronic and Combination Space Heating Systems, Residential GSHP and Commercial and Industrial GSHP Systems. <u>TGI and TGVI will treat NGV fuel switching from diesel as part of or normal course of EEC activities</u>. [Emphasis Added]*

Secondly, the 2010 Long Term Resource Plan ("LTRP"), filed on July 15, 2010, describes the Companies' plan to pursue NGV initiatives utilizing incentive funding from the Innovative Technologies Program Area.

The following is an excerpt from page 61 of the 2010 LTRP:

> *Since the Innovative Technologies portfolio was formulated, TGI has made progress with some of the technologies, particularly to support implementation of NGV technology.*
>
> *…TGI has initiated a pilot incentive program to encourage operators of heavy duty fleets such as garbage trucks and waste haulers to switch to natural gas from higher-carbon diesel. TGI has received expressions of interest from the City of Vancouver, City of Surrey, City of Port Coquitlam, and other third party partner* to use the EEC *funding to purchase new natural gas vehicles for garbage collection and transfer operations.*
>
> *Under the provisions of the pilot program, the fleet operators would be reimbursed for the incremental cost of the NGVs over conventional vehicles.*

No issues about the proposed use of EEC incentive funding for NGVs were raised in information requests filed in the LTRP.

As a result of the transparency of the Companies' NGV initiatives during 2009 and 2010, the support of stakeholders, and the fact that there were no issues raised during the LTRP information requests, the Companies were, with respect, surprised when the issue was raised by the Commission in the context of our Application for approval of the WM Agreement. The Companies are hopeful that the uncertainty can now be resolved.

10.2.4 SUMMARY

NGVs represent an important element of the Innovative Technologies Program Area, and the favourable TRC of NGV related incentives has contributed to a large measure to the favourable TRC of the overall Innovative Technologies Program Area portfolio. The Companies understand the Commission's desire to ensure that EEC funding is undertaken appropriately, and we have thus endeavoured to provide a more complete picture than was available to the Commission in the context of considering the Waste Management agreement as to why the Companies' initiatives are compliant with past Commission orders. Even if the Commission is unable to provide this confirmation, the Companies respectfully request that the Commission acknowledge the benefits of the Commercial NGV Demonstration program and the broad stakeholder support, and provide its concurrence for the Companies to proceed.

Appendix F

LETTERS OF SUPPORT

CEC
British Columbia

March 22, 2011

Mr. Mark Grist,
FortisBC Energy Inc.
Manager Business Development
16705 Fraser Highway
Surrey B.C. V4N 0E8

Dear Mr. Grist,

The Commercial Energy Consumers ("CEC") Association of BC is writing to you at this point in time to communicate its views with respect to the provision of FortisBC Energy Inc. ("FEI") Energy Efficiency and Conservation ("EEC") funds to support the transition of diesel oil fuelled transportation markets to natural gas fuelled transportation, particularly for the trucking component of the transportation market.

The CEC has supported the provision of FEI's EEC funds to transforming the transportation market and continues to support FEI in allocating EEC funds to this purpose for one very simple reason; it is in the interest of FEI's customers, the ratepayers. The CEC believes all ratepayers and specifically the commercial ratepayers will benefit significantly from investing in the transformation of this market. The CEC has been supportive of FEI in moving to capture this opportunity for its customers and critical whenever the movement to capture this opportunity is moving too slowly or not being planned aggressively enough.

The CEC is putting forward this position to FEI because at the stakeholder workshop, held to discuss EEC programs, we were informed of issues arising from the recent interim decision of the BC Utilities Commission ("BCUC") with respect to the Waste Management contracts and initiative being undertaken by FEI. We understand from FEI that it is interested in stakeholder's views with respect to these initiatives and that FEI might like to include these views in its submissions to the Commission relative to its planned filing with the BCUC of FEI's 2010 Report on its EEC Programs.

We understand that the Commission's recent decision may have created some uncertainty with respect to FEI providing funds to support the Waste Management initiatives and potentially with respect to advancing the transformation of the trucking transportation markets in general. The CEC would like to see this uncertainty resolved as soon as possible. The CEC would therefore support a reconsideration of the decision leading to the uncertainty or any plan to have clarification and certainty returned to the FEI transportation market transformation initiatives. We understand that FEI believes that the best opportunity to seek the required certainty would be found in BCUC regulatory process considering the issues in conjunction with the FEI 2010 EEC Report. The CEC would therefore support any initiative by FEI or the BCUC to consider the funding issues as part of the FEI 2010 EEC Report filing.

509-1190 Melville Street, Vancouver, BC V6E 3W1
T: 604-568-4904 F: 604-568-4595

The CEC has been an active participant in the original FEI EEC application made in 2008, has been an active participant in the 2010-2011 FEI Revenue Requirements Application (“RRA”) regulatory process, including being a signatory to the Negotiated Settlement Agreement (“NSA”) arising from that process, is involved in the current BCUC regulatory process considering the approval criteria for Natural Gas for Vehicles (“NGV”) initiatives and the CEC has attended all of the EEC stakeholder workshops held since FEI instituted these consultation processes in 2009. As a consequence the CEC believes that it is reasonably informed with respect to the issues involved.

Over the course of these various regulatory proceedings the CEC has come to understand the attractiveness of the FEI NGV Programs for all customers and specifically for the CEC commercial sector. The CEC would characterize the FEI approach with respect to its NGV initiatives as having been and continuing to be nothing but open and transparent. The CEC believes that FEI has worked diligently to build understanding and support for its NGV initiatives. The CEC has directly been involved in the regulatory processes, in which the CEC believed that FEI was being provided the CEC support and consent to both pursue these NGV initiatives and to fund these initiatives from EEC funds. The CEC is precluded (as a consequence of confidentiality provisions) from discussing the specific content of discussion in a Negotiated Settlement Process (“NSP”) but may disclose its own positions at any time. The CEC believes that its sign off with respect to the RRA NSA carried the weight of its support for FEI providing funding for its NGV initiatives. Specifically the CEC believes that item 14 of the NSA supports the fuelling and transportation services to be provided and that item 11 of the NSA supports the funding envelope for the Innovative technologies for 2010-2011. The CEC in stakeholder consultation both in group processes and in numerous other consultations FEI has provided the CEC the opportunity for input, has consistently voiced the view that the NGV opportunity needs to be pursued vigorously. The CEC notes that FEI has also been cautious to ensure that it is trying to pursue these opportunities prudently and has taken the time to do so in a number of ways. The CEC believes that the current uncertainty may arise as from a perspective on a technicality with regard to FEI’s ability to provide funding for the NGV programs. The CEC believes that substance should trump technicality, although the CEC with respect supports FEI’s efforts to review the issues.

In substance, the CEC believes that the FEI NGV initiatives have a positive Total Resource Cost (“TRC”) both independently and as part of the FEI EEC programs. The CEC believes that funding from the Innovative Technologies Program (“ITP”) exceeds a TRC of 1 when including the NGV funding. The CEC understands that the NGV initiatives result in environmental reduction of greenhouse gases emissions from transportation use of fuel. Where this can be done with a positive TRC the CEC is particularly supportive and has expressed strong support for this strategic direction of FEI.

The CEC understand that whether it is dealing with BC Hydro (“BCH”) Electricity Conservation and Efficiency (“ECE”) programs or the FEI EEC programs that the fundamental principle has not been to micro-manage every program and every component of the program for basic regulatory efficiency reasons. The CEC believes that FEI has the ability to make changes, refinements or even switches of specific funding activity from the submissions it makes with respect to EEC programs at any given point in time. The CEC believes that FEI can be held accountable for the prudence of its management in after the fact review processes enabled by the BCUC regulatory processes. The CEC believes that the TRC test accountability as well as the specific program reporting accountability and the frequent stakeholder consultation opportunities the CEC is engaged in provide an ample framework for ensuring that FEI is at risk and accountable for its decisions with respect to the prudent management of the EEC funds.

The CEC believes that it has sufficient access to regulatory processes to ensure that customer perspectives are incorporated into the BCUC's final decisions with respect to the public interest. In this case the CEC believes that the FEI NGV activities are substantially in the public interest and that prolonged uncertainty with respect to funding would be counterproductive to the best interest of the ratepayers.

The CEC supports the use of EEC funds for FEI's NGV programs specifically understanding that these funds are recovered through the delivery margin from ratepayers and not directly from specific rates charged to NGV users. The CEC supports this because tf the contribution it believes this program may provide to all customers as a strategic direction for FEI and its customers.

The CEC will support whatever process FEI or the BCUC take in regard to obtaining an early resolution of the uncertainties arising from the Waste Management interim decision and specifically the FEI initiative to have these issues considered as part of its 2010 EEC Report filing. The CEC will support and participate fully in any expedited process to achieve an early resolution to the uncertainty, because the CEC believes that commercialization initiatives need the nurturing of appropriate degrees of certainty to ensure that the benefits can be developed and captured for the FEI customers and specifically those the CEC represents.

Yours truly,

David Craig
Executive Director
Commercial Energy Consumers

DWC/amp

509-1190 Melville Street, Vancouver, BC V6E 3W1
T: 604-568-4904 F: 604-568-4595

BC Sustainable Energy ASSOCIATION

5 - 4217 Glanford Avenue
Victoria, BC Canada V8Z 4B9
(250) 744-2720
info@bcsea.org

21 March 2011

To:
Shawn Hill,
FortisBC
Vancouver, BC
By email: shawn.hill@fortisbc.com

Dear Shawn,

Re: FortisBC's Energy Efficiency and Conservation Plan Annual Report

This is to confirm that, as an active participant in the 2009 Energy Efficiency and Conservation Application of Terasen Gas, and a current member of FortisBC's EEC Stakeholder Group, the BC Sustainable Energy Association supports the use of FortisBC's EEC program to incent the purchase of heavy duty NGVs in place of diesel-powered vehicles where cost effective, primarily because of the greenhouse gas emissions reductions benefits. (BCSEA does not support incentives for fuel switching toward natural gas in the *passenger* vehicle sector, where hybrid and plug-in electric vehicles are on the cusp of achieving substantial market penetration.) BCSEA believes that using EEC monies in this instance is consistent with the objectives of the *Clean Energy Act* and other government policies on energy efficiency and greenhouse gas reductions.

Regards,

Thomas Hackney,
Vice-President for Policy

CITY OF VANCOUVER | 125 YEARS

OFFICE OF THE CITY MANAGER
Sustainability Group

March 22, 2011

Dave Bennett
Director Resource Planning & Market Development
FortisBC Energy Inc.
16705 Fraser Hwy
Surrey, BC
V4N 0E8

RE: EEC Funding of NGVs

Dear Mr. Bennett:

This letter is to confirm that The City of Vancouver has been a participant in stakeholder review sessions held by FortisBC regarding Energy Efficiency and Conservation (EEC) programs. We confirm that two stakeholder review sessions were held in 2010 (March and November) and that NGV programs were presented and discussed at these sessions. The City of Vancouver supports the continuation of the program to provide NGV incentives for heavy duty vehicle applications as adoption of NGVs in these markets provides GHG reductions and fuel cost savings to operators of NGVs.

Sincerely yours,

Sean Pander
Assistant Director, Sustainability Group
City of Vancouver

City of Vancouver, Office of the City Manager
453 West 12th Avenue
Vancouver, British Columbia V5Y 1V4 Canada
tel: 604.871.6542 *fax:* 604.673.8169
website: vancouver.ca

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Mark Grist
Manager, Business Development
Fortis BC Energy Inc.
16705 Fraser Hwy
Surrey, BC
V4N 0E8

Re: Letter of Support - Stakeholder Review of FortisBC EEC Programs

Dear Mr. Grist:

Further to our discussions at the EEC Stakeholder meeting held on March 15, 2010, the BC Apartment Owners & Managers Association (BCAOMA) would like to express its support for the use of Energy Efficiency & Conservation program incentives to encourage the use of Natural Gas Vehicles within BC's heavy duty transportation markets. The BCAOMA participated in stakeholder review sessions organized by FortisBC and had the opportunity to review and comment on the planned use of incentives to encourage the adoption of NGVs. During the November 24, 2010 session FortisBC provided a detailed presentation on the NGV program for BC, including the proposed use of EEC funding under the Innovative Technologies program. This presentation was favourably received by the stakeholder group. The BCAOMA believes that this consultation process meets the "Accountability Measures" defined in the Commission EEC Approval Decision G-36-09 and supports FortisBC's view that it has the necessary approvals to proceed with the NGV incentive program. The BCAOMA support this program as it has significant potential to reduce GHG emissions in the transportation sector while providing delivery rate revenues that will benefit all users of the FortisBC system.

Sincerely yours,

Marg Gordon
Chief Executive Officer
BC Apartment Owners and Managers Association

BC APARTMENT OWNERS AND MANAGERS ASSOCIATION
203–1847 WEST BROADWAY, VANCOUVER, BC V6J 1Y6
PHONE: 604.733.9440 | FAX: 604.733.9420 | TOLL FREE IN BC: 1.877.700.9440

Fraser Basin Council

March 23, 2011

Mark Grist
Manager, Business Development
Fortis BC
16705 Fraser Highway
Surrey, B.C. V4N 0E8

Dear Mark,

I am writing in followup to the meeting of Fortis BC Energy Efficiency and Conservation Stakeholder Meeting on March 15, 2011.

The Fraser Basin Council is a non-profit organization with a mandate of advancing sustainability in British Columbia, with a focus on the Fraser River watershed. We participate in the Fortis BC EEC Stakeholder sessions, as one of our strategic priorities in action on climate change and air quality.

Over the past six years, one component of FBC's climate change work has been to engage public and private sector vehicle fleets on emissions reduction activities, as a key leadership area in the transportation sector. This includes the delivery of a national green rating system – E3 Fleet – that provides third-party green certification of vehicle fleets. We have over 100 members in the program across Canada. We are technology and fuel neutral, and work with leading fleets to implement a variety of practices that reduce emissions and fuel costs.

Through our involvement in the EEC Stakeholder group over the past two years, we have been informed of Fortis BC's ongoing plans to provide incentives for natural gas vehicles (NGVs) and interest in providing natural gas compression and refueling service. We are supportive of this effort by Fortis BC to provide incentives for NGV purchase, and are also supportive of Fortis BC providing natural gas compression and refueling service. We have noticed, based on recent unsolicited calls from fleets, that there is growing interest amongst the fleets that we work with in exploring the use of natural gas as one means for reducing emissions. We also know that incentives are required to assist in overcoming the barrier of increased capital cost for NGVs. In addition, our experience in working with fleets is that in many cases there is a need for third-parties such as Fortis BC who can provide refueling services.

Fraser Basin Council

If you have any questions, please do not hesitate to contact me at 604-488-5359 or via email at jvanderwal@fraserbasin.bc.ca.

Sincerely ,

Jim Vanderwal
Senior Manager

Appendix F

NGV INCENTIVE DECISION,
COMMISSION ORDER NO. G-145-11

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-145-11

SIXTH FLOOR, 900 HOWE STREET, BOX 250
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IN THE MATTER OF
The Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc.
Energy Efficiency and Conservation Program
Natural Gas Vehicle Incentives Review

BEFORE: A.A. Rhodes, Panel Chair /Commissioner
D.A. Cote, Commissioner
M.R. Harle, Commissioner

August 15, 2011

O R D E R

WHEREAS:

A. On March 31, 2011, FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. (FEI/FEVI, the Companies) submitted their Energy Efficiency and Conservation (EEC) Program 2010 Annual Report as a compliance filing in accordance with British Columbia Utilities Commission (Commission) Order G-36-09. In the cover letter to the Report, FEI/FEVI request the Commission address the Companies' use of EEC funds as incentives for Natural Gas Vehicles (NGVs) at the earliest possible date;

B. On April 18, 2011, the Commission issued Letter L-30-11 which indicated the Commission would initiate a regulatory process to review and determine the appropriateness of the Companies' use of EEC funds as NGV incentives (the Review Proceeding). The following specific questions were posed:

1. Was it appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program-2009 Report (filed March 31, 2010)?

2. If the scope of the Innovative Technologies program was appropriately changed, does the associated NGV purchase funding become:

   a. a Commission-approved expenditure; or
   b. an approved EEC expenditure; or
   c. an expenditure eligible for cost recovery from ratepayers in whole or in part?

3. If NGV purchase incentive funding is found to be inappropriately included in the Innovative Technologies program, should incentive payments already made by the Companies be eligible for cost recovery from ratepayers in whole or in part?

C. By Order G-70-11 dated April 20, 2011, the Commission established a Regulatory Timetable for the written hearing of the Review Proceeding;

…/2

D. On June 3, 2011, following its receipt and review of the submissions of the Companies and Interveners, the Commission Panel sought further submissions from the parties on the additional issue of:

- the ability and appropriateness of the utility moving EEC funds among programs that meet the definition of "demand-side measure" in the *Utilities Commission Act* and programs that do not

and established an amended Regulatory Timetable for that purpose;

E. The written process for the Review Proceeding concluded with the filing of the Companies' Reply Submission on June 16, 2011;

F. The Commission Panel has reviewed the evidence and submissions of the Parties.

NOW THEREFORE for the Reasons attached hereto as Appendix A**,** the Commission:

1. Determines that, in answer to Question 1, it was not appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program–2009 Report (filed March 31, 2010). It further determines that the NGV program is not a demand-side measure within the meaning of the *Clean Energy* and *Utilities Commission Acts*.

2. Directs that FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. are to include only those expenditures meeting the definition of "demand-side measure" as found in the *Clean Energy* and *Utilities Commission Acts*, as determined by the Commission Panel in the attached Reasons for Decision, in the Energy Efficiency and Conservation category. Programs which do not meet the definition are to be kept separate. This applies as well to any funding for "technology innovation programs".

3. Provides FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. and Interveners the opportunity to file further submissions on the issue of the prudency of the NGV incentive expenditures, given the findings of the Commission Panel as set out in the Reasons attached hereto as Appendix A, in accordance with a timetable to be arranged.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2011.

BY ORDER

Original signed by:

A.A. Rhodes
Panel Chair/Commissioner

Attachment

IN THE MATTER OF

FORTISBC ENERGY INC./
FORTISBC ENERGY (VANCOUVER ISLAND) INC.
ENERGY EFFICIENCY AND CONSERVATION
NATURAL GAS VEHICLE INCENTIVE REVIEW

REASONS FOR DECISION

August 15, 2010

BEFORE:

A.A. Rhodes, Panel Chair / Commissioner
D.A. Cote, Commissioner
M.R. Harle, Commissioner

TABLE OF CONTENTS

PAGE NO.

1.0 INTRODUCTION

FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. (the Companies) are related regulated public utilities engaged primarily in the distribution of natural gas through the provision of sales and transportation services to over 900,000 residential and commercial customers in over 100 communities in British Columbia, including Vancouver Island.

The Companies have recently significantly increased their spending of "Energy Efficiency and Conservation" funds (which are provided by ratepayers) to finance programs in the area of Natural Gas Vehicles (NGVs). This spending relates to the provision of incentive payments to select large customers to assist them to purchase Natural Gas Vehicles in lieu of vehicles fuelled by diesel.

This Review Proceeding was initiated to assess the appropriateness of this activity, in light of the history set out below.

Specifically, this Review Proceeding was initiated on April 18, 2011 to examine three questions:

1. Was it appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program- 2009 Report (filed March 31, 2010)?

2. If the scope of the Innovative Technologies program was appropriately changed, does the associated NGV purchase incentive funding become: (a) a Commission-approved expenditure; or (b) an approved EEC expenditure; or (c) an expenditure eligible for cost recovery from rate payers in whole or in part?

3. If NGV purchase incentive funding is found to be inappropriately included in the Innovative Technologies program, should incentive payments already made by the Companies be eligible for cost recovery from rate payers in whole or in part?

(Commission Letter L-30-11; FEI/FEVI EEC Natural Gas Vehicle Incentive Review Proceeding; Exhibit A-1)

2.0 BACKGROUND

The Companies have had programs in place relating to demand-side management and the promotion of energy efficiency for a number of years. Traditionally, expenditures for these programs have been assessed as part of the Revenue Requirements Applications. The Companies' demand-side management activity was relatively constant from the late 1990s to 2007, involving total expenditures for both incentives and non-incentive expenses for both Companies of less than $5.0 million per year over that time period.

2.1 Energy Efficiency and Conservation Programs Application

In May of 2008, the Companies filed their "Energy Efficiency and Conservation Programs" Application which sought approval of increased expenditures (of $56.6 million for both Companies for three years) in support of an expanded energy efficiency and conservation (EEC) strategy. The Companies also sought to increase the amortization period for incremental EEC expenditures to 20 years [from 3 years for FortisBC Energy Inc. (FEI) and 1 year for FortisBC Energy (Vancouver Island) Inc. (FEVI)].

One area of proposed expansion in the EEC Application was "Innovative Technologies, NGV and Measurement Program Area" which requested a total of $3.0 Million. The projects described in "NGV- Natural Gas Vehicle projects" included "utilizing liquefied natural gas in heavy-duty vehicle applications or utilizing renewable or hydrogen in combination with natural gas in specific transportation applications". The notion of providing vehicle grants to customers not otherwise eligible for grants under Rate Schedule 6 through a vehicle grant fund was also raised. Other NGV projects identified in this section included: Hydrogen/Compressed Natural Gas blended projects (HCNG) and Biogas vehicles. (Exhibit A2-2, Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. EEC Application, pp. 14-15; 75-76)

In its Decision on the EEC Application of April 16, 2009, (the EEC Decision) the Commission Panel rejected all proposed expenditures in this area. It found that "Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies to reduce or replace natural gas consumption and related GHG emissions". It also noted the acknowledgement of FEI that further refinement of the program was required and found that there was insufficient evidence as to the nature and scope of the proposed program. The Panel commented that FEI might wish to bring forward projects in this program area for consideration as they become more fully developed. (Exhibit A2-3, EEC Decision, p. 26)

2.2 2010-2011 Revenue Requirements Application

On June 15, 2009 FEI filed its 2010-2011 Revenue Requirements Application.

The Table of Contents and Headings within that Application are clear in their classification of Natural Gas Vehicle offerings within "Alternative Energy Solutions", as separate and distinct from "Energy Efficiency and Conservation Programs" under which "Innovative Technologies" were shown as a subsection of "Industrial Energy Efficiency". (Exhibit A2-4, Terasen Gas Inc. 2010-2011 Revenue Requirements Application, p. iii)

The technologies described in the "Innovative Technologies" subsection were:

- Hydronic Based Heating Systems
- Integrated Energy Systems (or Combinations Systems)
- Solar Thermal
- Ground Source Heat Pumps

(Exhibit B-1, BCUC IR 1.6.2)

The 2010-2011 RRA was determined by way of a Negotiated Settlement Process.

2.2.1 Negotiated Settlement Agreement

The Negotiated Settlement Agreement which was approved by Commission Order G-141-09 dated November 26, 2009, states the following with respect to Natural Gas Vehicles:

"14. Natural Gas for Vehicles ("NGV")

The Commission Issue No. 2 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

"Natural Gas Vehicles ("NGV") – if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?"

The Parties agree:

(a) NGV Rate Schedule 26 – NGV Transportation Service should be approved as filed.

(b) The marketing costs in support of NGV that are included in the revenue requirements Application are appropriately recoverable in 2010 and 2011 rates.

(c) Upon acceptance of this Agreement by the Commission, TGI withdraws its request in this Application for the following:

i. Rate Schedule 6C NGV Compression and Refueling Service and 6A NGV Refueling Service; and
ii. the Compression Service ("CS") Test; and
iii. NGV non-rate base deferral account.

The Parties acknowledge that these requests are being withdrawn by TGI to facilitate a settlement on other issues presented in this Application. The Parties agree that TGI's withdrawal of its requests regarding NGV is without prejudice to TGI's right to bring forward similar requests in 2010 or 2011 or otherwise in the future. The Parties acknowledge that TGI intends to develop this area of business and that TGI anticipates it will bring forward applications on NGV projects to the Commission on a case-by-case basis during the term of this Agreement and in future years. The Parties agree that TGI is at liberty to do so."

(Exhibit A2-5, Terasen Gas Inc. 2010-2011Revenue Requirements Application, Negotiated Settlement Agreement, p. 9)

2.3 Application for Approval of Service Agreement for Compressed Natural Gas

On December 01, 2010 FEI applied to the Commission for, *inter alia*, approval of a draft agreement which it had made with Waste Management of Canada Corporation for compression and dispensing service for Compressed Natural Gas. It also applied for acceptance of the expenditures required to provide the service as well as approval of General Terms and Conditions for use in future contracts, for both CNG and LNG customers. FEI specifically stated that it was "not seeking approvals for Energy Efficiency and Conservation (EEC) funding, O&M funding for NGV business development, or any costs that are intended to be recovered from existing natural gas customers". However, the Application did indicate that FEI had provided incentive funding to Waste Management to cover the incremental cost of purchasing 20 natural gas vehicles, as opposed to their diesel equivalents. This funding was in the approximate amount of $803,000 or slightly more than $40,000 per vehicle. (Application for Approval of Service Agreement for Compressed Natural Gas Exhibit B-1, p. 47; EEC Natural Gas Vehicle Incentive Review, Exhibit B-1, BCUC IR 1.7.2)

In its January 14, 2011 Reasons for Decision approving the Waste Management Agreement on an interim basis, the Commission Panel questioned whether FEI had approval to make the incentive payments to Waste Management outside those contemplated in existing Rate Schedules, given the explicit rejection of expenditures in that area in the EEC Decision as well as the withdrawal of requests relating to NGVs in the Negotiated Settlement Agreement (NSA).

2.4 Energy Efficiency and Conservation Programs 2010 Annual Report

During 2010 FEI committed a total of $5.587 million in incentives for NGVs. Future commitments are expected to amount to a further $3.78 million. (Future commitments are those where, *inter alia*, there has been an application by the customer, but no agreement with the customer has been signed.) (Exhibit B-1, BCUC IR 1.7.1; 1.7.1.1)

In their 2010 EEC Programs Annual Report, the Companies took the position that they had acted within the guidelines and approvals of past regulatory decisions for EEC funding for NGVs and sought Commission concurrence on the issue, in an expedited fashion, prior to the 2012-2013 Revenue Requirements Application. The Companies took the further position that the use of Innovative Technologies Program Area EEC funding for NGV initiatives is consistent with past Commission Orders. (2010 EEC Annual Report pp. 201-203)

It is not suggested that further stakeholder engagement or compliance reporting can alter the overall scope of an accepted expenditure schedule. As noted by the Companies, "[o]nly the Commission has the ability to accept EEC expenditures pursuant to section 44.2... For clarity, the stakeholder engagement process is a consultation exercise, not an approval process. The EEC Annual Report is a compliance reporting. Neither the mere consent of the EEC stakeholder group, nor the inclusion of information in a compliance report to the Commission, can alter the overall scope of an accepted expenditure schedule". (FEI and FEVI Final Submissions, pp. 5-6)

3.0 FEI/FEVI ENERGY EFFICIENCY AND CONSERVATION NATURAL GAS VEHICLE INCENTIVE REVIEW PROCEEDING

As noted previously, this Review Proceeding was initiated to examine three questions, the first of which is:

3.1 Question 1

Was it appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program- 2009 Report (filed March 31, 2010)?

The Companies submit that the inclusion of additional spending in the area of NGVs was properly within their discretion as contemplated by the framework established in the EEC Proceeding. That framework contemplated the Companies' ability to re-allocate funds among approved program areas within the overall portfolio. (FortisBC Energy Utilities Submission, pp. 6-9)

The Companies admit that the programs identified in the "Innovative Technologies" section of the 2010-2011 RRA did not include NGVs. They further admit that in another program area, [Alternative Energy Solutions], certain specific requests with respect to NGVs were approved, but the other remaining requests were withdrawn. Notwithstanding these admissions, the Companies submit that NGVs share the same fundamental objectives and characteristics as the other programs within the Innovative Technologies area such that the approval of the Innovative Technologies Program Area was the only approval necessary. (FortisBC Energy Utilities Submission, pp. 10-11)

The Companies further submit that the scope of the Innovative Technologies Program Area approved in the NSA must be viewed in context, which context includes the EEC Application where the Companies described potential areas of opportunity and a broad range of types of initiatives having the same underlying characteristics:

1) Promoting the efficient use of natural gas through sustainable design,

2) Not being a mainstream technology,

3) Offering the potential for at least a 10% GHG reduction benefit.

The BC Sustainable Energy Association (BCSEA) supports the Companies' position. The BCSEA submits that the Commission accepted an overall expenditure envelope for EEC funding in its April, 2009 EEC Decision and therefore contemplated that the Companies would have the ability to move funding among program areas without additional Commission involvement. It further submits that approval of "Innovative Technologies" as a program area in the 2010-2011 RRA NSA contemplated that new programs would be added. (BCSEA Final Submission, pp. 4-6) BCSEA further submits that the Commission's approval of the Companies' 2010-2011 RRA NSA, (where the program area for Innovative Technologies was approved, without reference to NGVs) did "not imply anything negative about NGV incentive funding." (BCSEA Final Submission, p. 6) Further discussion of NGVs was with stakeholders, which BSCEA considers appropriate. (BCSEA Final Submission, pp. 6-7)

The Commercial Energy Consumers Association of British Columbia (CEC) also supports the Companies' position. The CEC argues that the scope of the Innovative Technologies Program Area is defined by the objectives of the program as opposed to by a list of specific initiatives within it. It submits that the initial rejection of the Program Area in the EEC Decision was temporary and notes the invitation of the Commission Panel for FEI, which was "to bring forward projects in this program area for consideration as they become more fully developed." (CEC Final Submission, p. 2; EEC Decision, p. 26) The CEC further submits "that the [Companies] have not changed the scope of the Innovative Technologies Program Area but have added the NGV Incentives funding program to the suite of programs in the Innovative Technologies Program Area. (CEC Final Submission, p. 5) It argues that the Companies have shown the NGV Purchase Incentive Funding is cost-effective, which supports the contention that this funding is in the public interest. It recommends that the Commission find the addition of the NGV Incentive Funding program to the Innovative Technologies Program Area was appropriate and met the objectives of that Program Area as well as EEC objectives generally. (CEC Final Submission, p. 6)

Commission Panel Determination

The Commission Panel finds that the Companies did not have approval to use EEC monies to provide incentives for NGVs.

The Commission Panel notes at the outset that the EEC Decision specifically rejected the entire area of "Innovative Technologies, NGVs and Measurement".

Further, in the EEC application, although LNG in heavy-duty vehicle applications was mentioned, the Companies did not advance compressed natural gas vehicles as an "innovative technology", as is now suggested. Rather, at that time, the Companies noted that "[u]nlike conventional Compressed Natural Gas ("CNG") vehicles, new technology is emerging whereby hydrogen is blended at the pump with compressed natural gas...HCNG is one of the most promising near-term opportunities for utilizing hydrogen in vehicles and moving towards a more hydrogen driven economy. As hydrogen burns cleaner than natural gas, further emission reductions are gained and 10-20% GHG reductions over CNG can be achieved. Other HCNG initiatives may include fuel for trains, fleets and other vehicle applications." (EEC Application, Exhibit B-1, pp. 75-76)

As well, in the Commission Panel's discussion and subsequent rejection of this category of expenditure it indicated that "Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies *to reduce or replace natural gas consumption*..." but that there was insufficient evidence of the nature and scope of the proposed program to warrant approval. (emphasis added). (EEC Decision, p. 26)

In the subsequent 2010-2011 Revenue Requirements Application, NGVs were again brought forward, this time as part of "Alternative Energy Solutions". The Commission Panel specifically raised concerns about NGVs and requested that these concerns be addressed in the Negotiated Settlement Process. As a result, in the end, the NSA provided approval for two items, being new Rate Schedule 26 and recovery of what were described as "modest" marketing costs incurred in support of NGVs in 2010-2011 rates. The remaining items for which approval was sought, which included an NGV non rate base deferral account, were withdrawn.

New Rate Schedule 26, "NGV Transportation Service" which was approved as part of the NSA, included "Special Conditions" basically identical to the "Special Conditions" found in existing Rate Schedule 6 "Natural Gas Vehicle Service". These Special Conditions contemplate a maximum incentive payment for the purchase of or conversion to a heavy duty natural gas vehicle of $10,000.00 per vehicle. To the extent that it can be suggested that incentive grants were contemplated in that NSA, the amounts put forward were limited, and consistent with grant amounts already on offer.

The Compression Service Tariff, the request for approval of which was withdrawn as part of the NSA, contemplated capitalization of costs once a potential customer executed a contract for the provision of compression service, and deferral account treatment of those costs, as well as ongoing operating and maintenance costs related to the delivery of energy. (TGI 2010-2011 RRA Exhibit B- 4, BCUC IR 1.21.1)

The Commission Panel disagrees with the suggestion that approval of the Innovative Technologies Program area could in any way be considered approval of EEC funding for NGVs. In fact, in its answers to Information Requests in the 2010-2011 Revenue Requirements Application, FEI emphasized that its EEC requests were different than those relating to Alternative Energy Solutions. It stated that "...it is important to distinguish between the requests in this Application regarding EEC and those pertaining to Alternative Energy Solutions [under which approval was sought for NGVs]....EEC programs and expenditures primarily related to activities to reduce energy usage via incentives, education and audits etc. They do not include the ownership of alternative energy equipment." (TGI 2010-2011 RRA, Exhibit B- 4, BCUC IR 1.21.1) FEI further confirmed that "...Innovative Technologies are an EEC program (i.e. not one of the Alternative Energy Solutions) whereby customers will receive incentives for Hydronic Heating Systems, Integrated Energy Systems, Solar Thermal and Ground Source Heat Pumps." (TGI 2010-2011 RRA, Exhibit B-4, BCUC IR 1.23.1.2)

Moreover, in the Panel's view, the Innovative Technologies Area as set out in the 2010-2011 Revenue Requirements Application did not share the same characteristics as the NGV area, as is now suggested by FEI. The Innovative Technologies put forward included measures to reduce natural gas consumption, not increase it, as is the case for NGVs.

Even if it could be argued that it was open to move/add program areas with similar objectives etc., which argument is not accepted given the specific rejection of NGVs in both applications– and particularly given the express concern of the Commission Panel – the underlying characteristics are not the same.

The Panel does not accept that the Companies were justified in assuming that approval of the Innovative Technologies category was a green light to proceed with NGV initiatives. FEI confirmed in its November 13, 2009 letter to the Commission responding to staff's comments on the NSA that it had an existing NGV tariff and the amount of the marketing costs in the revenue requirements for 2010 and 2011 [which were accepted in the NSA] were "very modest". It also confirmed that "[*i]ssues relating to NGV have been deferred by the terms of the Settlement Agreement".* (emphasis added) In the Panel's view, this latter statement indicated that FEI was proposing to make a further application to the Commission prior to committing EEC funds to NGV initiatives.

However, no other applications concerning EEC funding for NGV initiatives were made. In that regard, the Commission Panel agrees with the Companies that the stakeholder engagement process is a consultation exercise, not an approval process and the EEC Annual Report is a compliance reporting such that "[n]either the mere consent of the EEC stakeholder group, nor the inclusion of information in a compliance report to the Commission, can alter the overall scope of an accepted expenditure schedule". (FEI and FEVI Final Submissions, pp. 5-6)

Accordingly, the Commission Panel answers Question 1 "Was it appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program- 2009 Report (filed March 31, 2010)?" in the negative.

3.2 Question 2

If the scope of the Innovative Technologies program was appropriately changed, does the associated NGV purchase incentive funding become: (a) a Commission-approved expenditure; or (b) an approved EEC expenditure; or (c) an expenditure eligible for cost recovery from rate payers in whole or in part?

It is not necessary to consider this question given the Panel's answer to Question 1.

3.3 Question 3

If NGV purchase incentive funding is found to be inappropriately included in the Innovative Technologies program, should incentive payments already made by the Companies be eligible for cost recovery from rate payers in whole or in part?

In response to Question 3, the Companies submit that the Commission must set rates so as to allow the utility to recover the forecast costs for the test period that the Commission reasonably considers will be prudently incurred. The Companies further submit that a finding that the NGV-related expenditures were not approved as part of the Innovative Technologies Program Area does not amount to a finding of imprudence, simply a finding that there has been no prior approval under s. 44.2 of the Act, which they argue is optional in any event. Finally, the Companies submit that, in the absence of a s. 44.2 acceptance, the prudence of the expenditure must still be determined, having reference to the costs and benefits associated with the activities. They submit that the NGV-related expenditures to date are in the public interest and the forecasted amortization expense associated with the expenditures should be eligible for recovery as a prudent expenditure.

3.4 Demand-side Measures

Given the above submissions on section 44.2 which states (in part):

> (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:
>
> > (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

(b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;...

(2) The commission may not consent under section 61 (2) to an amendment or a rescission of a rate schedule filed under section 61(1) [which requires public utilities to file schedules showing all rates] to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section [being expenditures on demand-side measures], unless

(a) The expenditure is the subject of a schedule filed and accepted under this section, or

(b) The amendment or rescission is for the purpose of setting an interim rate,

the Commission Panel requested additional submissions on the ability and appropriateness of the utility moving EEC funds among programs that meet the definition of "demand-side measure" in the *Utilities Commission Act* and programs that do not. (Exhibit A-6)

The definition of Demand-Side Measure is found in the *Clean Energy Act* SBC 2010 c.22 s. (1) (1) and means:

a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand,

but does not include

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate, measure, action or program prescribed.

The Companies take the position that the NGV Program meets the definition of "demand-side measure" in the Act. They state that the NGV Program was undertaken to "promote energy efficiency". The Companies submit that the term "promote energy efficiency" must be different than "conserve energy" and therefore the concept of "using the right fuel for the right activity" is relevant. The Companies submit that this broader concept includes a variety of perspectives such as system utilization, economics, and reduction of Greenhouse Gases.

FEI and FEVI further submit that because the definition of "demand-side measure" specifically excludes "programs which encourage a switch from one kind of energy to another such that the switch would *increase* GHG emissions in B.C." the fact that this fuel-switching activity has the effect of reducing GHG emissions may qualify it as a demand-side measure.

They also argue that "[t]he NGV Program is efficient from the perspective of the use of energy resources and delivery systems in the province. ... As the NGV demand is a relatively flat year-round load, it increases natural gas use in the lower demand summer period,..." thereby shifting the use of energy to periods of lower demand. (Exhibit B-4, FEI/FEVI Submission on Exhibit A-6, pp. 2-3)

The BCSEA agrees with the Companies that the NGV Incentives Program meets the definition of a "demand-side measure" on the basis that the Program is undertaken to "promote energy efficiency". It argues that the legislation does not require that such a program have the exclusive objective of conservation or energy efficiency and that there may be additional purposes. It also argues, as do FEI and FEVI, that, as the definition of "demand-side measure" does not specifically exclude fuel-switching programs that decrease GHG emissions, the legislation therefore contemplates DSM programs that can have GHG emissions benefits through fuel-switching. The BCSEA further takes the position that, as the reduction of GHG emissions is one of British Columbia's energy objectives, and the Commission must consider British Columbia's energy objectives in reviewing a demand-side measure expenditure, the fact that this program has a substantial purpose of reducing GHG emissions increases its desirability as a demand-side measure. It further argues that what is important is the evaluation of the merits of a DSM program, not whether it meets the definition of the same, and that an inclusive approach to the definition does no harm, whereas applying the definition so that it serves a "gate-keeping' function serves no policy purpose. The BCSEA further argues that if the NGV program was not eligible for public interest acceptance under section 44.2 of the *Utilities Commission Act* (as either a demand-side measure or possibly a capital expenditure), there would be a gap, and there would be "no obvious way for such a program to be proposed by a public utility and the expenditures accepted (or not) by the Commission". Finally, the BCSEA argues that it is important that all putative DSM programs be included in a DSM portfolio so that any benefits of a program in terms of maintaining a positive benefit-cost ratio not be lost.

The CEC supports the submissions of the BCSEA. It further supports the ability of the Companies to move EEC funds among programs in the interests of administrative efficiency. It confirms that, in its view, the risk of inappropriate or imprudent movement of funds between DSM and non-DSM programs is one the Company faces in subsequent prudency reviews and that ultimately, an improper or imprudent movement of funds will be a risk to the shareholder.

Commission Panel Determination

The Commission Panel finds that the NGV program is not a "demand-side measure" as defined in the *Clean Energy Act*.

Reduction in greenhouse gases, although a laudable goal, and a goal which is recognized in the *Clean Energy Act*, is not, in the Panel's view tantamount to "conservation" or "energy efficiency". The Commission Panel agrees with FEI that the terms "conservation" and "energy efficiency" must be accorded different meanings. However, in the Panel's view, on a plain meaning, the term "conservation" implies using less [energy], and "energy efficiency" is a similar but different concept which implies doing the same task, while using less energy. For example, to conserve energy a person might turn off a light or turn down his/her thermostat. To be energy efficient, that same person might switch to a light bulb which, although providing equivalent light, uses less energy to do so, or switch to a furnace which uses less energy to produce the same amount of heat. Reducing GHGs is not one of the objects of the definition of a demand-side measure, but will often flow as a natural and inevitable consequence when demand-side measures are taken.

This meaning is also consistent with the greater context of both the *Clean Energy Act* and the *Utilities Commission Act*.

As noted above, the goal of reducing greenhouse gas emissions is recognized in a number of the specific energy objectives contained in the *Clean Energy Act*. However, the objectives relating to the reduction of greenhouse gases are separate and distinct from those relating to demand-side measures. In the Panel's view, the legislature uses both terms and had it sought to include a measure designed to reduce greenhouse gases in its definition of demand-side measures it could and would have done so.

Further, under s. 44.1 of the *Utilities Commission Act* a public utility's long-term resource plan must be filed and must include an estimate of the demand it expects to serve absent demand-side measures and how it expects to reduce that demand by taking cost-effective demand-side measures. This underscores the fact that demand-side measures are directed at reducing energy consumption, not building load.

In terms of energy efficiency, natural gas is not more energy efficient than gasoline or diesel. It is, in fact, less efficient than diesel by a factor of 10-20%. FEI used a 17% fuel efficiency loss in its economic analysis relating to the conversion of vehicles in the Waste Management fleet, a related application. (Application for Approval of a Service Agreement for Compressed Natural Gas Service and for Approval of General Terms and Conditions for Compressed Natural Gas and Liquified Natural Gas Service Exhibit B-1, p. 50, FN 59; p. 51, FN 61; Exhibit B-8 BCSEA IR 2.3.1)

In the Panel's further view, the definition is clear that demand-side measures relate to the use of "energy" itself and not the infrastructure used to deliver it.

The Panel also does not agree with FEI/FEVI or the Interveners that the specific exclusion of “a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia” as set out in subsection (d) of the definition of “demand-side measure” can be interpreted to allow for the inclusion of an item which was never included in the definition in the first instance. In the Panel’s view, the definition of “demand side measure” does not mean anything other than what is set out in subsections (a), (b), and (c) of the definition. Rather, excluded items (d) and (e), add clarity but do not, by implication, extend the definition beyond the measures contemplated in items (a), (b), and (c).

In the Panel’s view, item (d) would be relevant to a program which met the definition of “demand-side measure” as set out in either items (a), (b), or (c) in the first instance, but which then fell afoul of the exclusions. For example, a program designed to have electricity consumers in British Columbia switch from purchasing electricity from BC Hydro to heat their houses to purchasing natural gas for the same purpose would “reduce the energy demand that a public utility [BC Hydro] must serve’, but would then be excluded from the definition due to the fact that it would increase greenhouse gas emissions in British Columbia. Conversely, a program designed to have natural gas consumers in British Columbia switch from purchasing natural gas to heat their houses to purchasing electricity for the same purpose would “reduce the energy demand that a public utility [the natural gas provider] must serve, and would also decrease GHG emissions such that the exclusion would not apply.

The NGV program also fails to meet items (b) and (c) of the definition of demand-side measures.

Item (b) contemplates a reduction in the demand a utility must serve, and the NGV program does the opposite.

Item (c) contemplates shifting the use of energy to periods of lower demand. The Commission Panel does not accept FEI’s argument that an increased load on the delivery system during the summer months can be viewed as “shift[ing] the use of energy to periods of lower demand”. In the Panel’s view, meaning must be given to the word “shift”, which contemplates an equivalent reduction in load during periods of higher demand. In the Panel’s view, this definition contemplates a measure such as “Time of Use” pricing, whereby people may be encouraged to, for example, run an appliance at night instead of during the day, when demand on the electricity system is greater.

The Panel, further, finds no merit in the BCSEA’s suggestion that whether a program falls within the definition of a “demand-side measure” is of less importance than the merits of a particular program and that the definition should not serve a “gate-keeping” function. In the Panel’s view, the definition of “demand-side measure” is of critical importance. The nature of an expenditure on a “demand-side measure” is unlike other expenditures a utility may make in that the expenditure is aimed at reducing the amount of product the utility sells, either generally, or during a particular time period. Expenditures on demand-side measures are therefore often accorded different treatment so as to incent the utility to make expenditures which do not serve to further its business. With respect to the BCSEA’s argument that unless the NGV Program could be considered either a demand-side measure or a capital expenditure there would be a “gap” in expenditure schedules put before the Commission, the Commission Panel notes the comment of the Companies that “[f]or capital expenditures under the CPCN threshold, and for O&M generally, it is less common to have section 44.2 approval than to proceed to a revenue requirements proceeding without one”. (Exhibit B-1 BCUC IR 1.9.1) In any event, the Panel does not find BCSEA’s arguments, which tend to simply extoll the virtues of the NGV Program, to be of particular assistance in determining the meaning of a “demand-side measure”.

The Panel therefore finds, for the reasons set out above, that the NGV Program, which is a load-building exercise, does not meet the definition of a “demand-side measure” as set out in the *Clean Energy Act* and used in the *Utilities Commission Act*.

3.5 Implications of Determination Regarding Demand-Side Measures

The Companies argue that the Commission’s acceptance of their “EEC funding envelope was made pursuant to s. 44.2 (a) which applies to “demand-side measures”” but that even if funds were spent on a program which was not a “demand-side measure”, this would only mean that there was no prior public interest approval, not that it was necessarily inappropriate for the expenditure to have been made. (FEI/FEVI Submission on Exhibit A-6, p. 5)

FEI/FEVI submit as well that section 44.2 acceptance is optional and that the Act does not prohibit utilities from engaging in EEC activities without prior approval from the Commission. They submit that "in the absence of a section 44.2 public interest determination, the Commission must assess the forecast amortization expenses relating to past NGV Program expenditures when setting rates for [the utilities]".

Commission Panel Determination

The Commission Panel does not agree with the Companies that in the absence of a section 44.2 acceptance of a demand-side measure expenditure the Commission must assess the forecast amortization expenses when setting rates. In the Panel's view, although filing an expenditure schedule with the Commission under section 44.2 is "optional" in that the word "may" is used [i.e. "[a] public utility *may* file with the commission an expenditure schedule..."], section 44.2 (2) suggests that if the utility is seeking to amend or rescind a rate schedule to recover expenditures referred to in subsection (1) (a) [i.e. expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule], other than on an interim basis, the Commission may not consent to the amendment or rescission unless the expenditure is the subject of a filed and accepted schedule. It is only expenditures on demand-side measures which require this prior approval, as the other types of contemplated expenditures are not subject to section 44.2(2). As noted above, in the Panel's view, expenditures on NGVs were never the subject of an accepted expenditure schedule.

However, the Commission Panel has determined that the NGV program expenditures are not demand-side measures, as defined in the *Clean Energy Act* (and carried over into the *Utilities Commission Act*). Therefore, section 44.2(2) does not apply.

3.6 Public Interest Considerations

FEI/FEVI further submit that regardless of whether the expenditures are demand-side measures, the expenditures were prudently incurred and are in the public interest and should be approved.

The Ministry of Energy and Mines - Electricity and Alternative Energy Division- intervened in support of the Companies' position and submits that the incentive grants are in the public interest.

It argues that the incentive grants are initiating a transformation of the heavy duty vehicle market in British Columbia and that such market transformation supports British Columbia's energy objectives of reducing greenhouse gas emissions and encouraging economic development and the creation and retention of jobs. The Ministry further submits that these expenditures are in the interests of the Companies' current and potential customers. The Ministry argues that the incentive grants benefit the owners of NGVs and must logically "exceed the considerable risk to fleet operations of adopting an alternative fuel..." The Ministry also adopts the Companies' position that there are long term benefits to all ratepayers through increased throughput and notes the Companies' [reference case scenario] estimate that they will achieve market penetration in the order of 30 Petajoules per year by 2030, which would provide an estimated benefit of approximately $83 million per year to all ratepayers. (Submissions of the Ministry of Energy and Mines, paras. 3, 12, 13)

The Ministry takes the position that "[a]s with most market transformation activities, some short term costs are necessary to facilitate long term benefits" and that "[s]haring of start-up costs across ratepayers is not new in the utility context." (Submissions of the Ministry of Energy and Mines, para. 14)

The Ministry also supports the model of providing incentive funding for the full incremental cost of NGVs initially, and subsequently ramping the funding down. It notes that "new technologies often have high perceived risks" due to lack of information regarding performance and concerns around the long term availability of supporting infrastructure. It further notes that "financial measures either by government or utilities can be an important tool for overcoming these barriers in the NGV market." (Submissions of the Ministry of Energy and Mines, para. 15)

The Ministry asserts that there is no other program in BC to provide incentives for heavy duty NGVs. It also expresses the view that the Companies are "filling a vital gap in the transition to widespread adoption of heavy duty NGVs". The Ministry further asserts that the Companies are best-positioned to design and run NGV incentive programs due to their familiarity with their customers' energy needs, their expertise in natural gas technology and their existing organizational capacity to run incentive programs. It submits that "the burden and opportunity of offering heavy duty NGV incentive grants should fall upon [the FortisBC Energy Utilities]." (Submissions of the Ministry of Energy and Mines, para. 16)

Commission Panel Discussion

The Commission Panel accepts that the NGV program provides benefits in that conversion of motor vehicle fleets from diesel to natural gas will reduce greenhouse gas emissions to some extent (as natural gas is not without greenhouse gas emissions) and that the reduction of greenhouse gas emissions is one of British Columbia's energy objectives. It also accepts that there may be other benefits in terms of promoting local technology and the creation of jobs.

However, it is also relevant that FortisBC Energy Inc. had approximately 830,000 customers at the time of its RRA in 2009. (Exhibit A2-4, Terasen Gas Inc. 2010-2011 Revenue Requirements Application, p. 1) FortisBC Energy (Vancouver Island) Inc. added a further approximately 100,000 customers. It is questionable whether this small customer base should fund initiatives which benefit a few select large potential customers engaged in the transportation sector, as well as all British Columbians generally through the reduction in GHG emissions. It is arguable that the funds collected from ratepayers could provide more direct benefits to those ratepayers by being used in conventional demand-side management programs which may allow those ratepayers to reduce their own consumption and, hence, their bills and which would also have the additional outcome of reducing GHGs.

3.7 Benefit to Ratepayers from Increased Throughput

The Ministry specifically notes the approximate $83 million annual savings for ratepayers which the Companies have estimated as a "long term benefit" if their "reference case scenario" market penetration comes to pass in 2030 [as expressed in 2030 dollars]. This figure has its source in the Companies' CNG/LNG Service Application, and is based on an annual volume from CNG/LNG sales to the transportation sector of approximately 29.5 million GJs of natural gas in the year 2030. The Companies described this saving: "increased throughput from the NGV fuel[l]ing service results in a favourable reduction in delivery rates for [FEI] existing natural gas customers, *all other things being equal*." (emphasis added) (CNG/LNG Application, Exhibit B-1, pp. 24-25; Appendix A-1, pp. 32-33)

In its Reasons for Decision rejecting the Companies' proposed General Terms and Conditions for CNG/LNG Service (as they failed to recover a sufficient proportion of the actual cost of CNG/LNG service from the CNG/LNG customer), the Commission Panel expressed concern as to the risks which were sought to be shouldered by FEI's existing ratepayers. These risks included the risk that there might not, in fact, be a market for CNG/LNG in the absence of incentive funding. The Panel also noted FEI's previous unsuccessful attempt to promote CNG as a transportation fuel, the costs of which were borne by its ratepayers. (CNG/LNG Application Reasons for Decision, p. 22, 30)

Aside from the uncertainty inherent in forecasts almost 20 years out, there is also considerable uncertainty surrounding the Companies' projections themselves and the "all other things being equal" assumption noted above.

3.7.1 Increased Throughput Benefit Calculation

Volume

For example, the estimates used in the projected sales of natural gas to the transportation sector of 29.5 million GJs are derived from the following projections [for the "reference case scenario"], by rate schedule:

Annual Natural Gas Volume (GJs)	Year 2030
Rate Schedule 6	4,201,500
Rate Schedule 16	18,680,000
Rate Schedule 25	6,668,000
Total	**29,549,500**

There is also an estimated impact to Rate Schedule 25 Demand Volume, estimated in 2030 to be 22,826 GJs. (Source: CNG/LNG Application, Exhibit B-1, Appendix A-1, p. 34)

Delivery Rates

The incremental margin for delivery rates is calculated based on the volumes above and the delivery rates set out below:

Delivery Rates	($/GJ)
Rate Schedule 6	$3.648
Rate Schedule 16	$3.89
Rate Schedule 25-Delivery	$0.645
Rate Schedule 25-Demand	$15.943

(Note: The Delivery Rates which FEI used for its calculations are the existing approved rates for consistency and comparability with 2011 NSA calculations.)
(Source: CNG/LNG Application, Exhibit B-1, Appendix A-1, p. 34)

Incremental Margin at Existing Rates – 2030

The Incremental Margin is then calculated by multiplying the forecast volumes of natural gas sales in 2030 for the "reference case scenario", for each rate schedule, by the delivery rate applicable to the rate schedule. The result is the total incremental margin from increased throughput.

Incremental Margin	
Rate Schedule 6	$15,327,072
Rate Schedule 16	$72,665,200
Rate Schedule 25-Delivery	$ 4,300,860
Rate Schedule 25-Demand	$ 364,074
Total Incremental Margin	**$92,657,206**

(Source: CNG/LNG Application, Exhibit B-1, Appendix A-1, p. 34)

Net Annual Cost of Service Benefit

This incremental revenue margin of $92,657,206 for 2030 is then reduced by the forecast cost of service of the EEC Incentive Funding (which is estimated to be $10,206,000 for 2030) to arrive at the Net Annual Cost of Service Benefit, which as noted above, is calculated to be approximately $83 million in 2030. (CNG/LNG Application, Exhibit B-1, Appendix A-1, p. 33)

3.7.1.1 Forecast Volumes of Natural Gas Sales

The forecast volumes for CNG/LNG sales in the amount of 29.5 million GJs must be considered in the context of the "all other things being equal" assumption.

Rate Schedule 6 has been in effect since November of 1996, a period of almost 15 years. It is applicable to the sale of natural gas for the purpose of compression and dispensing as a fuel for the operation of NGVs. (This schedule includes the offer of a grant for customers to purchase a factory built NGV or convert a vehicle to natural gas, to a maximum of $10,000 per vehicle for a heavy duty truck.) (CNG/LNG Application, Exhibit B-1, Appendix C) The forecast volume under Rate Schedule 6 (for CNG vehicles) is 4.2 million GJs.

Rate Schedule 25 is a natural gas transportation tariff. It also relates to CNG Service and adds a further 7 million GJs to the forecast sales of natural gas for use in NGVs running on CNG. (CNG/LNG Application, Exhibit B-1, p. 24, Appendix C) Rate Schedule 25 does not offer any grant money.

Sales of LNG under Rate Schedule 16 make up 78% of the total incremental margin from the sale of natural gas to the transportation market in 2030 under the reference case scenario. (CNG/LNG Application, Exhibit B-11, BCUC IR 3.22.1.1) Rate Schedule 16 is applicable to LNG sales and dispensing service from the FEI LNG facility at Tilbury. Rate Schedule 16 was approved by the Commission as a five year pilot in 2009. This Rate Schedule defines "LNG Service" as "the interruptible service of the liquefaction, storage and Dispensing of LNG ..." This Rate Schedule is "interruptible" because the total quantity of LNG available for sale must be limited in order to avoid any potential negative impact on core customers. The maximum quantity available for sale to all LNG transportation customers is 1,040 GJs (or one tanker load) per day. Any one customer may only take delivery of 50% of the available LNG capacity in one month. The Rate Schedule contemplates that, in the event there is insufficient capacity on the FEI system to accommodate the customer's request for LNG Service, FEI may interrupt, or curtail, the LNG Service under the Schedule. (CNG/LNG Application, Exhibit B-1, Appendix C; Terasen Gas Inc. Application for Rate Schedule 16, pp. 4, 18)

As noted above, the assumption for sales of LNG under Rate Schedule 16 by the year 2030 is 18.68 million GJs in a year. This number is approximately fifty times greater than the annualized maximum daily quantity of LNG available for sale [1,040 GJs/day x 365 days/year=379,600 GJs/year] from Tilbury. The magnitude of this difference brings into question the capacity of Tilbury to accommodate even a fraction of the estimated demand for LNG in 2030 and refutes the reasonableness of the assumption "all other things being equal".

The Commission Panel is concerned that no amounts were included in the projected costs for the CNG/LNG Service Offerings for any expenditures associated with additional facilities or equipment required to provide the assumed volume of LNG. Rather, FEI took the position that "it is premature to define the extent and nature of the incremental investments in LNG assets that may be required over the next 20 years as part of [its CNG/LNG] [A]pplication". (CNG/LNG Application, Exhibit B-11, BCUC IR 3.21.4) The Commission Panel is of the view that this position serves to undermine the credibility of the Companies and their estimate of $83 million in ratepayer benefits.

The Commission Panel notes that there is, however, a new LNG storage facility, Mt. Hayes, located on Vancouver Island, which can be used to provide some guidance into the order of magnitude of the potential investment required to support the estimated 18.67 million GJs of LNG required by the transportation sector by 2030.

The Mt. Hayes facility has a storage capacity of approximately 1.6 million GJs and a liquefaction rate of somewhere in the range of approximately 8,100 GJs per day, such that it takes approximately 200 days to fill the storage tank. The CPCN for this facility was granted, subject to certain conditions, on November 15, 2007. The P90 cost estimate for this facility, as applied for, was in the order of $200 million dollars. (Terasen Gas (Vancouver Island) Inc. CPCN Application to enter into a Storage and Delivery Agreement and Terasen Gas Inc. Application to enter into a Storage and Delivery Agreement for the Mt. Hayes LNG Storage Facility (Mt. Hayes CPCN Application) Decision pp. 14-15, 21; Mt. Hayes CPCN Application, Exhibit B-1, p. 14)

The Mt. Hayes facility was constructed to provide back-up supply and peak shaving capability for the combined FEI/FEVI distribution system. It was not designed to provide direct physical supply and to do so would require the construction of a truck loading facility. FEI advises that "[t]he addition of Mt. Hayes has increased LNG storage capacity in the system by 250% and production capacity by 140%". It argues that the addition of Mt. Hayes is a factor which may warrant increasing the 1040 GJ/day limit for sales of LNG under Rate Schedule 16 currently in effect at Tilbury. (CNG/LNG Application, Exhibit B-6, BCUC IR 2.19.4)

In any event, from an order of magnitude perspective, assuming a liquefaction rate of 8,100 GJs per day, or approximately 3 million GJs per year at Mt. Hayes, and assuming Mt. Hayes could be used for LNG transportation (which, as noted above, it was neither designed nor is equipped to do), the Companies would need access to facilities with five times the liquefaction capability as Mt. Hayes, to supply the estimated 18.68 million GJs of LNG consumption by the transportation sector estimated for 2030 in the “reference case” scenario. This is not to suggest that any particular number of facilities would necessarily actually be required to be constructed or that the cost of a particular facility would equate to that of Mt. Hayes. Rather, the suggestion is that there are significant additional infrastructure requirements associated with the assumed volume of LNG consumption in 2030, the costs of which have been excluded from the analysis.

3.7.1.2 Contribution of LNG Delivery Charge

The incremental contribution of the delivery charge for the sale of a GJ of LNG to the estimated $83 million benefit in reduced delivery costs for all ratepayers is also relevant and of concern. As noted above, FEI uses the rate of $3.89 per GJ as the incremental revenue from the sale of LNG. This number is multiplied by the forecast volume of LNG sales under Rate Schedule 16 in 2030 (i.e. 18,680,000 GJs) to calculate the estimated incremental margin of $72.665 million.

It is necessary to consider the inputs to the $3.89 delivery charge per GJ of LNG to assess the validity of this critical factor input.

The $3.89 rate for LNG was originally put forward in the 2009 Rate Schedule 16 Application.

The number is derived from the following components:

O&M Charge – Liquefaction, Storage and Dispensing	$1.95 per GJ
Capital Recovery	.97 per GJ
Transportation from Huntingdon to Tilbury	.73 per GJ
Peaking Arrangement Cost	.08 per GJ
Total Variable Charge	**$3.73 per GJ**

The $3.73 number was subsequently increased to **$3.89** in accordance with approved annual rate adjustments. (CNG/LNG Application, Exhibit B-6, BCUC IR 2.25.2)

However, as FEI explains, “[p]roduction of LNG at Tilbury will generate incremental O&M cost associated with increased production of LNG at Tilbury and this cost will partially offset the revenue benefit...this incremental cost is estimated at $1.95/GJ or 52% of the rate.” It is only the remaining [48%] which represents a contribution to existing costs and would provide a benefit to all ratepayers. (CNG/LNG Application, Exhibit B-6, BCUC IR 2.25.2)

Therefore, the estimated contribution of $72.665 million from LNG sales in 2030 is over-stated by a factor of more than 50%.

3.7.1.3 EEC Cost of Service

As also noted above, in order to arrive at the approximate $83 million benefit in 2030, the total incremental margin in the amount of $92.657 million is then reduced by the Cost of Service of the EEC incentive payments, which is estimated to be $10.206 million.

The EEC Cost of Service calculation, in simplified form, is based upon the EEC NGV incentive payments made, adjusted for income tax. The incentive payments, net of tax, are then accumulated in a rate base deferral account, and amortized over ten years.

The assumed Gross Additions of EEC Funding (in thousands of dollars) in intervals up to 2030 are set out below:

2011	2012	2015	2020	2025	2030
$1,100	$1,100	$2,816	$5,082	$7,062	$8,316

These additions, (net of taxes, and assuming a 10% amortization of the existing balance), result in a deferral account balance of approximately $33 million by 2030. This rate base deferral account is proposed to attract an earned return of 7.93% for FEI. (CNG/LNG Application, Exhibit B-1, Appendix A-1, p. 35)

The Cost of Service of the EEC Incentive Funding calculation is of concern in that the assumption regarding the "gross additions" of EEC funding, on which the cost of service impact is based, does not appear to align with the levels contemplated in this NGV Incentive Review.

In this NGV Incentive Review, as noted earlier, FEI's evidence is that it has spent or committed to a total of $9.367 million in incentives for NGVs for 2010 and 2011 - ($5.587 million spent in 2010 with a further expected $3.78 million in future commitments). The disparity between the assumed level of spending to calculate the cost of service (of no amount in 2010 and $1.1 million in each of 2011 and 2012) and the actual brings the usefulness of this aspect of the analysis into question as well.

Commission Panel Determination

In the Panel's view, the analysis provided by FEI to support the existence of a long term benefit to ratepayers from increased throughput on the distribution system is so flawed in terms of:

- the absence of any recognition of additional costs to provide LNG service
- the assumed contribution from the sale of LNG, and
- the assumed cost of service of the EEC incentive funding,

as outlined above, as to make the $83 million in 2030 (in 2030 dollars) result so speculative as to be deserving of no weight. **The Commission Panel finds that long term benefits to existing customers from increased throughput on the delivery system have not been established.**

As no long term monetary benefits to the Companies' existing ratepayers have been established, the Commission Panel is unable to conclude that the Companies' existing ratepayers should be contributing millions of dollars in funding to this initiative. The primary beneficiaries of the NGV incentive program are readily identifiable. They are the NGV customers who receive incentives to purchase NGVs and stand to reduce their operating costs and the Companies, which will deliver more natural gas and earn a return on the related infrastructure.

Commission Panel Determination on Recovery

Given the Panel's finding that the Companies had no prior approval to spend EEC monies on the Natural Gas Vehicle program, its finding that such expenditures are not "demand-side measures" within the meaning of the *Clean Energy Act* (and *Utilities Commission Act*), and its further finding that long term benefits to existing customers have not been established, the Commission Panel is unable to conclude that all of the expenditures in issue (totalling $9.367 million) were or will be prudently incurred and recoverable from ratepayers.

However, the Commission Panel also notes that the issue of prudency may involve additional and/or different considerations from those relating solely to the public interest, and that the issue of prudency is relevant and has not been thoroughly canvassed. The Commission Panel is therefore prepared to entertain additional submissions on the issue of prudency in respect of some or all of the expenditures in issue. Any submissions should be premised on the findings already made by the Panel.

The Panel recognizes that this Review Proceeding was initiated as a separate process to provide guidance on the issue of the provision of incentive funding for NGVs on an expedited basis. However, the Panel is concerned that the issue of prudency of the expenditures in issue has not been the subject of comprehensive submissions and is of the view that it would be fair to allow for this additional process. The Commission Panel can, however, provide some guidance on the treatment of EEC funds in the future.

4.0 EEC FRAMEWORK GOING FORWARD

The Companies have asked that the Commission provide clarification generally of the EEC process in the event that the addition of the new NGV program did not meet the Commission's intent. (FEI Final Submission, p. 10)

4.1 Separation of Demand-Side Measures Programs from other Proposed Programs

As noted earlier, and for the reasons outlined above, the Panel has determined that incentive payments for NGVs do not meet the definition of "demand-side measures" in the *Clean Energy Act*. In the Panel's view, it is important to distinguish between those programs which involve expenditures on measures which meet the definition of "demand-side measures" and others which do not. In the Panel's view these programs have different drivers and may not be amenable to the same treatment.

The Panel therefore directs that only programs or measures which meet the definition of demand-side measures, as outlined above, be included in the EEC category. Programs or measures which do not meet the strict definition should be categorized under a separate heading to avoid confusion and any expenditures, proposed or incurred, applied for separately from EEC programs or initiatives. The Panel is of the view that load-building activities should not necessarily be accorded the same treatment as is accorded demand-side measures and that this issue will need to be considered in depth. As this proceeding is limited in nature, a better forum would be the Revenue Requirements Application for 2012-2013 which was recently filed.

As well, for clarification, initiatives in Innovative Technologies or elsewhere which do not meet the definition of "technology innovation program" in the Demand Side Measures Regulation which states:

> ""technology innovation program" means a program
>
> (a) to develop a technology, a system of technologies, a building design or an industrial facility design that is
>
> (i) not commonly used in British Columbia, and
>
> (ii) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy,
>
> (b) to do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or
>
> (c) to gather information about a technology, a system of technologies, a building design or an industrial design referred to in paragraph (a).

should also be kept separate from those which do. Programs or initiatives which do not meet the definition of a technology innovation program can be included with other programs or initiatives which do not meet the definition of a "demand-side measure".

Appendix G

FINANCIAL SCHEDULES, SCENARIO 1 (EXPECTED CASE)

Appendix G
Financial Schedules – Scenario 1: Planned Growth
List of Schedules

Appendix G – Scenario 1: Planned Growth
Financial Assumptions

1) Scenario 1 Description

Market continues to expand after the expiration of the prescribed undertaking, LNG capital (Liquefaction and Storage equipment: $66M in 2011$) added to meet LNG demand in 2018, 2023, 2025,2027,2029,2030. Total CNG/LNG volumes projected to reach 25.3PJ by 2030. Capital cost based on high level estimates, further detailed study required. Rate 16 increased by $1/GJ in 2018 to pay for additional LNG facilities.

2) Rates & Capital Structure

FEI	2011	2012[1]	2013[1]	2014+
Rates				
ROE	9.50%	9.50%	9.50%	9.50%
Short Term Debt Rate	4.50%	2.50%	3.50%	3.50%
Long Term Debt Rate	6.95%	6.85%	6.87%	6.87%
Capital Structure				
Equity Ratio	40.00%	40.00%	40.00%	40.00%
STD Ratio	1.63%	1.93%	3.03%	3.03%
Ltd Ratio	58.37%	58.07%	56.97%	56.97%
Total	100.00%	100.00%	100.00%	100.00%
Note 1: 2012-13, BCUC Order No.G-44-12				

3) Income Tax Rate

2010	2011	2012+
28.5%	**26.5%**	**25.0%**

4) Incentive Award & Payout Schedule

<u>Vehicle & Marine</u>

Incentives are assumed to be awarded once per year. 25% of the incentive award paid out when initial terms of the contract have been met, remaining 75% is paid when CNG/LNG vehicles enter service, ranging from 6 to 12 months later. Incentives recorded in deferral account based on cash payment of incentives.

<u>Maintenance Upgrades & Safety</u>

Incentives are assumed to be awarded once per year. 25% of the incentive award paid out upon incentive award, balance of incentive is paid when work is completed ranging from 2 to 6 months later. Incentives recorded in deferral account based on cash payment of incentives.

Appendix G – Scenario 1: Planned Growth
Financial Assumptions (continued)

Administration, Marketing, Training and Education
Expenditures assumed to be evenly spread throughout the year.

Total Incentive Award Schedule

('000$)	2010/11	2012	2013	2014	2015	2016	Total
Vehicles	5,573	7,843	7,979	7,404	7,307	7,794	43,900
Marine Vessels		0	3,500	3,000	2,500	2,000	11,000
Admin, Marketing, Training & Education		300	1,000	900	600	300	3,100
Maintenance Upgrades & Safety		200	950	950	950	950	4,000
Total	5,573	8,343	13,429	12,254	11,357	11,044	62,000
Cumulative Incentives	5,573	13,916	27,345	39,599	50,956	62,000	

Total Incentive Payout (Cash Basis)

('000$)	2010/11	2012	2013	2014	2015	2016	2017	Total
Vehicles & Marine	5,573	1,961	8,752	11,210	10,255	9,804	7,345	43,900
Admin, Marketing, Training & Education		300	1,000	900	600	300	0	11,000
Maintenance Upgrades & Safety		50	922	950	950	1,128	0	4,000
Total	5,573	2,311	10,674	13,060	11,805	11,232	7,345	62,000
Cumulative Incentives	5,573	7,884	18,558	31,618	43,423	54,655	62,000	

5) Deferral Account & Amortization Period

Non Rate Base Deferral Account
The non rate base deferral account contains the following: 1) Incentive payouts (cash basis) prior to 2014. 2) Incremental margins (exclude margins already included in RRA 2012/13) prior to 2014. 3) Prior incentives ($5.573 million). AFUDC is calculated on incentive payouts from August 2012 to the end of 2013. AFUDC is calculated on prior incentives from the date of the first vehicle and marine incentive payment, forecasted to be Oct 1, 2012 to the end of 2013. The non rate base deferral account is transferred to a rate base deferral account beginning January 1, 2014 and amortized over 10 years.

Rate Base Deferral Account
Incentive payouts (cash basis) are added to a rate base deferral account for incentive payouts starting in 2014. Each annual addition to the rate base deferral account is amortized over 10 years in the following year. The non rate base deferral account is transferred to the rate base deferral account at the start of 2014 and amortized over 10 years.

Appendix G – Scenario 1: Planned Growth
Financial Assumptions (continued)

6) **FEI Total Delivery Margin**

	2012[1,3]	2013[1,3]	2014[2,3]+
FEI Total Delivery Margin	$575M	$577M	Increase at 2% per year

Note 1: 2012 & 2013 based on 2012-13 RRA G-44-12 Compliance Filing May 1, 2012
Note 2: Inflation based on high level long range planning assumptions
Note 3: FEI Delivery Margins do not include any impact of the prescribed undertaking expenditures

7) **FEI Delivery Rates**

FEI		2012[1]	2013[1]	2014[2]+
Rate 16[3]	$/GJ	4.05	4.11	Increase at 2%/year
Rate 23	$/GJ	2.44	2.62	Increase at 2%/year
Rate 25 Delivery	$/GJ	0.68	0.73	Increase at 2%/year
Rate 25 Demand	Demand $/Month /GJ of Daily Demand	16.82	18.06	Increase at 2%/year

Note 1: 2012 & 2013 approved
Note 2: Inflation based on high level long range planning assumptions
Note 3: $1/GJ added in 2018 to fund incremental LNG liquefaction and storage facilities for Scenario 1

8) **Rate 16 Delivery Rate less Incremental Cost of LNG**

		2012	2013	2014	2015	2016	2017	2018[2]+
Rate 16	$/GJ	4.05[1]	4.11[1]	4.19	4.28	4.36	4.45	2014+ Increase at BC CPI All Items, assumed to be 2% / year & Note 5
Incremental Cost of LNG[4]	$/GJ	0.80	0.82	0.92	1.01	1.00	0.98	Note 3:
Rate 16 – Incremental Cost of LNG	$/GJ	3.25	3.29	3.28	3.27	3.36	3.47	

Note 1: 2012 & 2013 approved
Note 2: BC CPI All Items based on high level long range planning assumptions
Note 3: Vary from $0.80 to $1.01 / GJ depending on LNG volumes and sources, increase at BC CPI All Items projected to be 2% / year
Note 4: Incremental Cost of LNG = Incremental O&M / Incremental volumes sold into the LNG market
Note 5: $1/GJ added in 2018 to fund incremental LNG liquefaction and storage facilities for Scenario 1

Appendix G – Scenario 1: Planned Growth
Financial Assumptions (continued)

9) **Incremental LNG Capital[1,5]**

	2011$M[3]	As Spent $M[4]
2018[2]	66	74
2023	66	84
2025	66	87
2027	66	91
2029	66	94
2030	66	96

Note 1: Scenario 1 only, incremental LNG capital added to meet increasing LNG demand
Note 2: In Service Nov 2017
Note 3: Capital costs are high level estimates, further detailed study required
Note 4: 2011$ estimates converted to 'As Spent'$ at 2% per year
Note 5: Incremental LNG capital includes liquefaction and storage facilities

Appendix G - Scenario 1: Planned Growth
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (2012 -2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, unless otherwise stated

Appendix G - Scenario 1: Planned Growth
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (2012 -2021)

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Annual NG Volume (TJ)	Sch 2, Line 8	178	458	917	1,416	2,032	2,882	3,407	4,027	4,760	5,626
2												
3	Discount Rate	2014 FEI After-Tax WACC	6.81%									
4	Discount Period (years)		1	2	3	4	5	6	7	8	9	10
5												
6	FEI Total Delivery Margin Projections $Millions	Note 1	575	577	588	600	612	624	637	649	662	676
7												
8	Net COS Benefit (Cost) to Existing Natural Gas Customers											
9	Annual Incremental Margin from additional NGT volume	Sch 2, Line 40, Note 2,4	538	1,284	2,662	4,044	5,958	8,690	12,964	15,628	18,842	22,719
10	Annual Incentive Funding COS	Sch 3, -Line 76			(3,488)	(5,471)	(7,181)	(9,175)	(17,316)	(17,640)	(18,117)	(18,783)
11	Net Annual COS Benefit (Cost) '000$	Line 9 + Line 10	538	1,284	(826)	(1,427)	(1,223)	(485)	(4,352)	(2,012)	725	3,937
12												
13	Approximate Annual FEI Delivery (Reduction) Increase, %	-Line 11 / (Line 6 x 1000), Note 3			0.14%	0.24%	0.20%	0.08%	0.68%	0.31%	(0.11)%	(0.58)%
14												
15	Present Value of Annual Net COS Benefit (Cost)	Line 11/(1+Line 3)^(Line 4)	504	1,126	(678)	(1,096)	(879)	(327)	(2,743)	(1,187)	401	2,036
16												
17	NPV of Net COS Benefit (Cost) '000$	Sum Line 15 2012 to year	504	1,629	952	(144)	(1,024)	(1,351)	(4,094)	(5,282)	(4,881)	(2,845)
18												
19	NPV of Net COS Benefit (Cost) 2012 to 2030 (19 Years)			66,147								

20 Note:

21 1: 2012, 2013 based on 2012-2013 RRA G-44-12 Compliance Filing May 1, 2012; 2014+ increase at 2%/year reflecting high level long range planning assumptions,

22 does not include any impact of the prescribed undertaking expenditures or prior incentives

23 2: 2012 & 2013 incremental margin added to non rate base deferral account in Schedule 3: Cost of Service Line 32

24 3: Cumulative FEI Delivery (Reduction) increase, FEI delivery margin does not include any impact of the prescribed undertaking expenditures or prior incentives

25 4: 2012 & 2013 includes some margin already included in the 2012/13 RRA

Appendix G - Scenario 1: Planned Growth
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (continued 2022 - 2030)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, unless otherwise stated

Appendix G - Scenario 1: Planned Growth
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (continued 2022 - 2030)

Line		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Annual NG Volume (TJ)	Sch 2, Line 8	6,650	7,861	9,291	10,982	12,981	15,344	18,136	21,437	25,338
2											
3	Discount Rate	2014 FEI After-Tax WACC									
4	Discount Period (years)		11	12	13	14	15	16	17	18	19
5											
6	FEI Total Delivery Margin Projections $Millions	Note 1	689	703	717	731	746	761	776	792	808
7											
8	Net COS Benefit (Cost) to Existing Natural Gas Customers										
9	Annual Incremental Margin from additional NGT volume	Sch 2, Line 40, Note 2,4	27,388	33,024	39,812	47,999	57,872	69,768	84,123	101,417	122,281
10	Annual Incentive Funding COS	Sch 3, -Line 76	(19,679)	(24,758)	(28,336)	(33,207)	(38,716)	(45,196)	(52,776)	(62,230)	(77,137)
11	Net Annual COS Benefit (Cost) '000$	Line 9 + Line 10	7,709	8,266	11,476	14,793	19,156	24,572	31,347	39,187	45,144
12											
13	Approximate Annual FEI Delivery (Reduction) Increase, %	-Line 11 / (Line 6 x 1000), Note 3	(1.12)%	(1.18)%	(1.60)%	(2.02)%	(2.57)%	(3.23)%	(4.04)%	(4.95)%	(5.59)%
14											
15	Present Value of Annual Net COS Benefit (Cost)	Line 11/(1+Line 3)^(Line 4)	3,733	3,747	4,871	5,878	7,126	8,557	10,220	11,961	12,900
16											
17	NPV of Net COS Benefit (Cost) '000$	Sum Line 15 2012 to year	888	4,635	9,506	15,384	22,509	31,066	41,286	53,247	66,147

18

19

20 Note:

21 1: 2012, 2013 based on 2012-2013 RRA G-44-12 Compliance Filing May 1, 2012; 2014+ increase at 2%/year reflecting high level long range planning assumptions,

22 does not include any impact of the prescribed undertaking expenditures or prior incentives

23 2: 2012 & 2013 incremental margin added to non rate base deferral account in Schedule 3: Cost of Service Line 32

24 3: Cumulative FEI Delivery (Reduction) increase, FEI delivery margin does not include any impact of the prescribed undertaking expenditures or prior incentives

25 4: 2012 & 2013 includes some margin already included in the 2012/13 RRA

Appendix G - Scenario 1: Planned Growth
Schedule 2, Part A: Benefits (2012-2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth
Schedule 2, Part A: Benefits (2012-2021)

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Annual NG Volume (TJ)											
2	Rate 16 not included in RRA 2012/13		12	183	698	1,036	1,482	2,103	2,486	2,938	3,473	4,105
3	Rate 16 included in RRA 2012/13	Note 8	139	139								
4	Rate 23 not included in RRA 2012/13		1	1	15	27	39	55	64	76	90	106
5	Rate 23 included in RRA 2012/13	Note 8	6	6								
6	Rate 25 not included in RRA 2012/13		2	110	204	353	512	725	857	1,012	1,197	1,415
7	Rate 25 included in RRA 2012/13	Note 8	19	19								
8	Total NG Volume (TJ)	Sum of Lines 2 to 7	178	458	917	1,416	2,032	2,882	3,407	4,027	4,760	5,626
9	Number of CNG Stations											
10	Rate 23		-	-	-	-	1	1	1	1	1	1
11	Rate 25		1	3	5	8	11	15	18	21	25	30
12	Number of LNG Stations		2	3	5	8	11	16	18	21	25	30
13	Estimated Impact to Rate 25 Demand Volume	Note 1, 4, 10	8	378	698	1,210	1,752	2,482	2,934	3,467	4,098	4,844
14	Estimated Impact to Rate 25 Demand Volume	Note 1, 5, 11	65	65								
15	Volumetric Delivery Rates ($/GJ)	Note 2										
16	Rate 16 (Net of incremental costs) Note 3 & 12	2012 & 2013 approved	3.25	3.29	3.28	3.27	3.36	3.47	4.54	4.63	4.72	4.81
17	Rate 23	2012 & 2013 approved	2.44	2.62	2.67	2.72	2.78	2.83	2.89	2.95	3.01	3.07
18	Rate 25	2012 & 2013 approved	0.68	0.73	0.75	0.76	0.78	0.79	0.81	0.82	0.84	0.86
19	Demand Rates	Note 2										
20	Rate 25 $/ Month / GJ of Daily Demand	2012 & 2013 approved	16.82	18.06	18.42	18.79	19.17	19.55	19.94	20.34	20.75	21.16
21	Basic & Admin Charge	Note 2, 7										
22	Rate 23 $/Month	2012 & 2013 approved	210.52	210.52	214.73	219.03	223.41	227.87	232.43	237.08	241.82	246.66
23	Rate 25 $/Month	2012 & 2013 approved	665.00	665.00	678.30	691.87	705.70	719.82	734.21	748.90	763.88	779.15
24	Rate 16 $/Month	Note 9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	Inflation Annual: Delivery/Demand/Basic	Long term planning assumptions			2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Appendix G - Scenario 1: Planned Growth
Schedule 1, Part B: Benefits (2012-2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth
Schedule 1, Part B: Benefits (2012-2021)

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	Incremental Margin '000$											
27	*Delivery*											
28	Rate 16 not included in RRA 2012/13	(Line 2 x Line 16)	37	604	2,288	3,386	4,988	7,291	11,277	13,596	16,391	19,762
29	Rate 16 included in RRA 2012/13	(Line 3 x Line 16)	450	456								
30	Rate 23 not included in RRA 2012/13	(Line 4 x Line 17)	2	2	41	72	107	155	186	225	271	326
31	Rate 23 included in RRA 2012/13	(Line 5 x Line 17)	15	16								
32	Rate 25 not included in RRA 2012/13	(Line 6 x Line 18)	2	81	152	269	397	573	691	834	1,005	1,212
33	Rate 25 included in RRA 2012/13	(Line 7 x Line 18)	13	14								
34	*Demand*											
35	Rate 25 not included in RRA 2012/13	(Line 13 x Line 20x12/1000)	2	82	154	273	403	582	702	846	1,020	1,230
36	Rate 25 included in RRA 2012/13	(Line 14 x Line 20x12/1000)	13	14								
37	*Basic Charges*											
38	Rate 23 + 25	Note 6	5	16	27	44	64	88	108	128	155	189
39	Rate 16		-	-	-	-	-	-	-	-	-	-
40	Total Incremental Margin	Sum of Lines 28 to 39	538	1,284	2,662	4,044	5,958	8,690	12,964	15,628	18,842	22,719
41	Cumulative Incremental Margin		538	1,822	4,484	8,528	14,487	23,177	36,140	51,768	70,610	93,330

42 Note:
43 1 Compression load is assumed to be consistent; therefore, the peak will not change in a winter month
44 2 Existing delivery / demand / basic & admin charges are approved 2012 and 2013 charges, 2014+ increase at 2% per year reflecting high level long range planning assumptions
45 3 Rate 16 reflects delivery rate minus incremental cost of LNG (incremental O&M / incremental volume sold into the LNG market), further detail included in this appendix,
46 Financial Assumptions, section 8
47 4 Rate 25 demand volumes not included in RRA 2012/13 filing
48 5 Rate 25 demand volumes included in RRA 2012/13 filing
49 6 (Line 10 x Line 22 x 12) /1000 x (2/3) + Line 11 x (Line 23 x 12) /1000x(2/3); Basic charges reduce by 1/3 to reflect that some existing accounts are already on R23/25
50 7 New CNG/LNG stations results in new Rate 23/25/16 accounts
51 8 Volumes related to prior incentives, included in 2012/13 RRA
52 9 There are no basic or admin charges for LNG Rate 16 accounts
53 10 Line 6 / 365 x 1.25 x 1000
54 11 Line 7 / 365 x 1.25 x 1000
55 12 Add $1/GJ in 2018 to fund incremental LNG liquefaction and storage

Appendix G - Scenario 1: Planned Growth
Schedule 2, Part A: Benefits (continued 2022-2030)
Appendix G - Scenario 1: Planned Growth
Schedule 2, Part A: Benefits (continued 2022-2030)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Annual NG Volume (TJ)										
2	Rate 16 not included in RRA 2012/13		4,852	5,736	6,779	8,013	9,472	11,196	13,233	15,642	18,488
3	Rate 16 included in RRA 2012/13	Note 8	-	-	-	-	-	-	-	-	-
4	Rate 23 not included in RRA 2012/13		126	149	176	208	246	290	343	406	480
5	Rate 23 included in RRA 2012/13	Note 8	-	-	-	-	-	-	-	-	-
6	Rate 25 not included in RRA 2012/13		1,672	1,976	2,336	2,761	3,264	3,858	4,560	5,390	6,371
7	Rate 25 included in RRA 2012/13	Note 8	-	-	-	-	-	-	-	-	-
8	Total NG Volume (TJ)	Sum of Lines 2 to 7	6,650	7,861	9,291	10,982	12,981	15,344	18,136	21,437	25,338
9	Number of CNG Stations										
10	Rate 23		1	1	2	2	2	2	2	2	2
11	Rate 25		35	42	49	58	69	81	97	114	136
12	Number of LNG Stations		35	41	49	58	68	80	95	112	133
13	Estimated Impact to Rate 25 Demand Volume	Note 1, 4, 10	5,726	6,768	8,000	9,456	11,177	13,211	15,616	18,458	21,817
14	Estimated Impact to Rate 25 Demand Volume	Note 1, 5, 11	-	-	-	-	-	-	-	-	-
15	Volumetric Delivery Rates ($/GJ)	Note 2									
16	Rate 16 (Net of incremental costs) Note 3 & 1	2012 & 2013 approved	4.91	5.01	5.11	5.21	5.31	5.42	5.53	5.64	5.75
17	Rate 23	2012 & 2013 approved	3.13	3.19	3.25	3.32	3.39	3.45	3.52	3.59	3.66
18	Rate 25	2012 & 2013 approved	0.87	0.89	0.91	0.93	0.95	0.96	0.98	1.00	1.02
19	Demand Rates										
20	Rate 25 $/ Month / GJ of Daily Demand	2012 & 2013 approved	21.59	22.02	22.46	22.91	23.37	23.83	24.31	24.80	25.29
21	Basic & Admin Charge	Note 2, 7									
22	Rate 23 $/Month	2012 & 2013 approved	251.59	256.62	261.76	266.99	272.33	277.78	283.33	289.00	294.78
23	Rate 25 $/Month	2012 & 2013 approved	794.74	810.63	826.84	843.38	860.25	877.45	895.00	912.90	931.16
24	Rate 16 $/Month	Note 9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	Inflation Annual: Delivery/Demand/Basic	Long term planning assumptions	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Appendix G - Scenario 1: Planned Growth

Schedule 2, Part B: Benefits (continued 2022-2030)

Market expands, additional LNG equipment (liquefaction and storage) added to meet demand

$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
26	Incremental Margin '000$										
27	*Delivery*										
28	Rate 16 not included in RRA 2012/13	(Line 2 x Line 16)	23,826	28,726	34,633	41,755	50,341	60,693	73,174	88,221	106,363
29	Rate 16 included in RRA 2012/13	(Line 3 x Line 16)	-	-	-	-	-	-	-	-	-
30	Rate 23 not included in RRA 2012/13	(Line 4 x Line 17)	394	475	572	690	832	1,003	1,209	1,457	1,757
31	Rate 23 included in RRA 2012/13	(Line 5 x Line 17)	-	-	-	-	-	-	-	-	-
32	Rate 25 not included in RRA 2012/13	(Line 6 x Line 18)	1,461	1,761	2,123	2,560	3,086	3,721	4,486	5,409	6,521
33	Rate 25 included in RRA 2012/13	(Line 7 x Line 18)	-	-	-	-	-	-	-	-	-
34	*Demand*										
35	Rate 25 not included in RRA 2012/13	(Line 13 x Line 20x12/1000)	1,483	1,788	2,156	2,599	3,134	3,778	4,556	5,492	6,622
36	Rate 25 included in RRA 2012/13	(Line 14 x Line 20x12/1000)	-	-	-	-	-	-	-	-	-
37	*Basic Charges*										
38	Rate 23 + 25	Note 6	225	274	328	396	479	573	699	837	1,018
39	Rate 16		-	-	-	-	-	-	-	-	-
40	Total Incremental Margin	Sum of Lines 28 to 39	27,388	33,024	39,812	47,999	57,872	69,768	84,123	101,417	122,281
41	Cumulative Incremental Margin		120,718	153,742	193,554	241,554	299,426	369,194	453,317	554,734	677,015

42 Note:

43 1 Compression load is assumed to be consistent; therefore, the peak will not change in a winter month

44 2 Existing delivery / demand / basic & admin charges are approved 2012 and 2013 charges, 2014+ increase at 2% per year reflecting high level long range planning assumptions

45 3 Rate 16 reflects delivery rate minus incremental cost of LNG (incremental O&M / incremental volume sold into the LNG market), further detail included in this appendix,

46 Financial Assumptions, section 8

47 4 Rate 25 demand volumes not included in RRA 2012/13 filing

48 5 Rate 25 demand volumes included in RRA 2012/13 filing

49 6 (Line 10 x Line 22 x 12) /1000 x (2/3) + Line 11 x (Line 23 x 12) /1000x(2/3); Basic charges reduce by 1/3 to reflect that some existing accounts are already on R23/25

50 7 New CNG/LNG stations results in new Rate 23/25/16 accounts

51 8 Volumes related to prior incentives, included in 2012/13 RRA

52 9 There are no basic or admin charges for LNG Rate 16 accounts

53 10 Line 6 / 365 x 1.25 x 1000

54 11 Line 7 / 365 x 1.25 x 1000

55 12 Add $1/GJ in 2018 to fund incremental LNG liquefaction and storage

Appendix G - Scenario 1: Planned Growth
Schedule 3, Part A: Cost of Service (2011-2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth
Schedule 3, Part A: Cost of Service (2011-2021)

		Reference	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Key Assumptions												
2	Rates												
3	ROE %	BCUC Order No. G-44-12	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
4	STD Rate %	BCUC Order No. G-44-12	4.50%	2.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
5	LTD Rate %	BCUC Order No. G-44-12	6.95%	6.85%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
6	Capital Structure												
7	Equity %	BCUC Order No. G-44-12	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
8	STD %	BCUC Order No. G-44-12	1.63%	1.93%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
9	LTD %	BCUC Order No. G-44-12	58.37%	58.07%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
10	Total %		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	Return on Rate Base %	Note 5	7.93%	7.83%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
12	WACC %	Note 6	6.84%	6.82%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%
13	Tax Rate %		26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
14	Incentive Award Schedule	Note 1											
15	Prior Vehicle Incentives	Note 10	5,573										
16	Vehicle & Marine		-	7,843	11,479	10,404	9,807	9,794	-				
17	Maintenance Upgrades & Safety		-	200	950	950	950	950	-				
18	Admin, Marketing, Train, Education		-	300	1,000	900	600	300	-				
19	Total Incentive Awards ($62000)	Sum of Lines 15 to 18	5,573	8,343	13,429	12,254	11,357	11,044	-				
20	Incentive Payouts (Cash Basis)	Note 1											
21	Prior Vehicle Incentives		5,573										
22	Vehicle & Marine	Note 1	-	1,961	8,752	11,210	10,255	9,804	7,345				
23	Maintenance Upgrades & Safety	Note 1		50	922	950	950	1,128	-				
24	Admin, Marketing, Train, Education	Note 1		300	1,000	900	600	300	-				
25	Total Incentive Payouts (Cash Basis)	Sum of Lines 21 to 24	5,573	2,311	10,674	13,060	11,805	11,232	7,345				

Appendix G - Scenario 1: Planned Growth
Schedule 3, Part B: Cost of Service (2011-2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

		Reference	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	Non Rate Base Deferral Account (NRBDA) Calculation												
27	Gross Additions	Line 25 (2011-2013)	5,573	2,311	10,674								
28	Tax	- Line 27 x Line 13	(1,477)	(578)	(2,668)	-	-	-	-	-	-	-	-
29	Net Additions	Line 27 + Line 28	4,097	1,733	8,005	-	-	-	-	-	-	-	-
30	Opening Deferral Account Balance	Previous Year, Line 34	-	4,097	5,851								
31	Net Additions	Line 29	4,097	1,733	8,005								
32	Incremental Margins pre 2014	Note 7	-	(36)	(588)								
33	AFUDC on Deferral Account pre 2014	Note 4, 11	-	58	585								
34	Closing Deferral Account Balance	Sum of Lines 30 to 33	4,097	5,851	13,853								
35	Rate Base Deferral Account Calculation												
36	Amortization Period (Years)		10										
37	Gross Additions	Line 25 (2014+)				13,060	11,805	11,232	7,345	-	-	-	-
38	Tax	- Line 37 x Line 13				(3,265)	(2,951)	(2,808)	(1,836)	-	-	-	-
39	Net Additions	Line 37 + Line 38				9,795	8,854	8,424	5,509	-	-	-	-
40	Annual Amortization of Net Addition	Line 39/10 years				980	885	842	551	-	-	-	-
41	Add NRBDA	Line 34, 2013 Closing & Note 2				13,853							
42	Annual Amortization of NRBDA	Line 41/10 years				1,385							
43	Opening Deferral Account Balance	Note 8				13,853	22,263	28,752	33,925	35,342	30,698	26,055	21,411
44	Net Additions	Line 39				9,795	8,854	8,424	5,509	-	-	-	-
45	Amortization: Net Additions	Sum of Line 40 & Note 9					(980)	(1,865)	(2,707)	(3,258)	(3,258)	(3,258)	(3,258)
46	Amortization: NRBDA	Line 42 over 10 years & Note 3				(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)
47	Closing Deferral Account Balance	Sum of Lines 43 to 46				22,263	28,752	33,925	35,342	30,698	26,055	21,411	16,768
48	Total Amortization	Line 45 + Line 46				(1,385)	(2,365)	(3,250)	(4,093)	(4,643)	(4,643)	(4,643)	(4,643)
49	Mid Year Rate Base	(Line 43 + Line 47)/2				18,058	25,508	31,339	34,634	33,020	28,377	23,733	19,090
50	Income Tax Expense												
51	Equity Earned Return	Line 60	-	-	-	686	969	1,191	1,316	1,255	1,078	902	725
52	Add: Amortization Expense	- Line 48	-	-	-	1,385	2,365	3,250	4,093	4,643	4,643	4,643	4,643
53	Taxable Income After Tax	Line 51 + Line 52	-	-	-	2,072	3,334	4,441	5,409	5,898	5,722	5,545	5,369
54	Taxable Income	Line 53 / (1 - Line 13)	-	-	-	2,762	4,446	5,921	7,212	7,864	7,629	7,394	7,159
55	Income Tax Expense	Line 54 x Line 13	-	-	-	691	1,111	1,480	1,803	1,966	1,907	1,848	1,790

Appendix G - Scenario 1: Planned Growth
Schedule 3, Part C: Cost of Service (2011-2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth
Schedule 3, Part C: Cost of Service (2011-2021)

		Reference	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
56	Earned Return												
57	Total Rate Base	Line 49				18,058	25,508	31,339	34,634	33,020	28,377	23,733	19,090
58	ROE Rate %	Line 3				9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
59	Equity Ratio %	Line 7				40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60	Equity Return	Line 57 x Line 58 x Line 59				686	969	1,191	1,316	1,255	1,078	902	725
61	Total Rate Base	Line 49				18,058	25,508	31,339	34,634	33,020	28,377	23,733	19,090
62	Short Term Debt Rate %	Line 4				3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
63	Short Term Debt Ratio %	Line 8				3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
64	Short Term Debt Component	Line 61 x Line 62 x Line 63				19	27	33	37	35	30	25	20
65	Total Rate Base	Line 49				18,058	25,508	31,339	34,634	33,020	28,377	23,733	19,090
66	Long Term Debt Rate %	Line 5				6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
67	Long Term Debt Ratio %	Line 9				56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
68	Long Term Debt Component	Line 65 x Line 66 x Line 67				707	998	1,227	1,356	1,292	1,111	929	747
69	Total Debt Component	Line 64 + Line 68				726	1,025	1,260	1,392	1,327	1,141	954	767
70	Total Earned Return	Line 60 + Line 69				1,412	1,995	2,451	2,708	2,582	2,219	1,856	1,493
71	Annual Cost of Service Impact of NGT Incentive Program												
72	Amortization Expense	- Line 48	-	-	-	1,385	2,365	3,250	4,093	4,643	4,643	4,643	4,643
73	Income Tax Expense	Line 55	-	-	-	691	1,111	1,480	1,803	1,966	1,907	1,848	1,790
74	Earned Return	Line 70	-	-	-	1,412	1,995	2,451	2,708	2,582	2,219	1,856	1,493
75	Upgrade LNG Capital COS	Note 12		-	-	-	-	-	571	8,125	8,870	9,769	10,857
76	Total Cost of Service	Sum of Lines 72 to 75	-	-	-	3,488	5,471	7,181	9,175	17,316	17,640	18,117	18,783

77 Note:
78 1: This appendix, Financial Assumptions, Section 4
79 2: Non rate base deferral account is transferred to the rate base deferral account at the start of 2014
80 3: Non rate base deferral account transferred to rate base deferral account in 2014 and amortized over 10 years starting in 2014
81 4: AFUDC calculated on prior incentives added to non rate base deferral account from the date (forecasted Oct 2012) of the first vehicle and marine incentive payment to end of 2013
82 5: Line 3 x Line 7 + Line 4 x Line 8 + Line 5 x Line 9
83 6: Line 3 x Line 7 + (Line 4 x Line 8 + Line 5 x Line 9) x (1 - Line 13)
84 7: Exclude volumes / margin already included in RRA 2012/2013; Schedule 2 Benefits: Line 28+ Line 30 + Line 32 + Line 35 + Line 38
85 8: 2014 Opening rate base deferral account equals 2013 closing non rate base deferral account of $13.853 Million, 2015 onwards previous year Line 47
86 9: Amortization of new additions in following year over 10 years
87 10: Prior incentive spending in 2011 includes 2010 amounts, totals $5.573 million
88 11: AFUDC calculated on incentives added to the non rate base deferral account from Aug 2012 to the end of 2013
89 12: Liquefaction and Storage capital added to meet increasing LNG demand, please see financial assumption, section 9 of this appendix for further detail

Appendix G - Scenario 1: Planned Growth
Schedule 3, Part A: Cost of Service (continued 2022-2030)

Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

		Reference			2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Key Assumptions	-											
2	Rates												
3	ROE %	BCUC Order No. G-44-12			9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
4	STD Rate %	BCUC Order No. G-44-12			3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
5	LTD Rate %	BCUC Order No. G-44-12			6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
6	Capital Structure				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
7	Equity %	BCUC Order No. G-44-12			40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
8	STD %	BCUC Order No. G-44-12			3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
9	LTD %	BCUC Order No. G-44-12			56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
10	Total %				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	Return on Rate Base %	Note 5			7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
12	WACC %	Note 6			6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%
13	Tax Rate %				25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
14	Incentive Award Schedule	Note 1			-	-	-	-	-	-	-	-	-
15	*Prior Vehicle Incentives*	Note 10			-	-	-	-	-	-	-	-	-
16	Vehicle & Marine				-	-	-	-	-	-	-	-	-
17	Maintenance Upgrades & Safety				-	-	-	-	-	-	-	-	-
18	Admin, Marketing, Train, Education				-	-	-	-	-	-	-	-	-
19	Total Incentive Awards ($62000)	Sum of Lines 15 to 18			-	-	-	-	-	-	-	-	-
20	*Incentive Payouts (Cash Basis)*	Note 1											
21	*Prior Vehicle Incentives*				-	-	-	-	-	-	-	-	-
22	Vehicle & Marine	Note 1			-	-	-	-	-	-	-	-	-
23	Maintenance Upgrades & Safety	Note 1			-	-	-	-	-	-	-	-	-
24	Admin, Marketing, Train, Education	Note 1			-	-	-	-	-	-	-	-	-
25	Total Incentive Payouts (Cash Basis)	Sum of Lines 21 to 24			-	-	-	-	-	-	-	-	-

Appendix G - Scenario 1: Planned Growth
Schedule 3, Part B: Cost of Service (continued 2022-2030)

Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
26	Non Rate Base Deferral Account (NRBDA)Calculation										
27	Gross Additions	Line 25 (2011-2013)	-	-	-	-	-	-	-	-	-
28	Tax	- Line 27 x Line 13	-	-	-	-	-	-	-	-	-
29	Net Additions	Line 27 + Line 28	-	-	-	-	-	-	-	-	-
30	Opening Deferral Account Balance	Previous Year, Line 34	-	-	-	-	-	-	-	-	-
31	Net Additions	Line 29	-	-	-	-	-	-	-	-	-
32	Incremental Margins pre 2014	Note 7	-	-	-	-	-	-	-	-	-
33	AFUDC on Deferral Account pre 2014	Note 4, 11	-	-	-	-	-	-	-	-	-
34	Closing Deferral Account Balance	Sum of Lines 30 to 33	-	-	-	-	-	-	-	-	-
35	Rate Base Deferral Account Calculation										
36	Amortization Period (Years)										
37	Gross Additions	Line 25 (2014+)	-	-	-	-	-	-	-	-	-
38	Tax	- Line 37 x Line 13	-	-	-	-	-	-	-	-	-
39	Net Additions	Line 37 + Line 38	-	-	-	-	-	-	-	-	-
40	Annual Amortization of Net Addition	Line 39/10 years	-	-	-	-	-	-	-	-	-
41	Add NRBDA	Line 34, 2013 Closing & Note 2	-	-	-	-	-	-	-	-	-
42	Annual Amortization of NRBDA	Line 41/10 years	-	-	-	-	-	-	-	-	-
43	Opening Deferral Account Balance	Note 8	16,768	12,125	7,481	4,223	1,944	551	0	0	0
44	Net Additions	Line 39	-	-	-	-	-	-	-	-	-
45	Amortization: Net Additions	Sum of Line 40 & Note 9	(3,258)	(3,258)	(3,258)	(2,279)	(1,393)	(551)	-	-	-
46	Amortization: NRBDA	Line 42 over 10 years & Note 3	(1,385)	(1,385)	-	-	-	-	-	-	-
47	Closing Deferral Account Balance	Sum of Lines 43 to 46	12,125	7,481	4,223	1,944	551	0	0	0	0
48	Total Amortization	Line 45 + Line 46	(4,643)	(4,643)	(3,258)	(2,279)	(1,393)	(551)	-	-	-
49	Mid Year Rate Base	(Line 43 + Line 47)/2	14,446	9,803	5,852	3,084	1,248	275	0	0	0
50	Income Tax Expense										
51	Equity Earned Return	Line 60	549	373	222	117	47	10	0	0	0
52	Add: Amortization Expense	- Line 48	4,643	4,643	3,258	2,279	1,393	551	-	-	-
53	Taxable Income After Tax	Line 51 + Line 52	5,192	5,016	3,481	2,396	1,441	561	0	0	0
54	Taxable Income	Line 53 / (1 - Line 13)	6,923	6,688	4,641	3,194	1,921	748	0	0	0
55	Income Tax Expense	Line 54 x Line 13	1,731	1,672	1,160	799	480	187	0	0	0

Appendix G - Scenario 1: Planned Growth
Schedule 3, Part C: Cost of Service (continued 2022-2030)

Market expands, additional LNG equipment (liquefaction and storage) added to meet demand

$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
56	Earned Return										
57	Total Rate Base	Line 49	14,446	9,803	5,852	3,084	1,248	275	0	0	0
58	ROE Rate %	Line 3	0	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
59	Equity Ratio %	Line 7	0	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60	Equity Return	Line 57 x Line 58 x Line 59	549	373	222	117	47	10	0	0	0
61	Total Rate Base	Line 49	14,446	9,803	5,852	3,084	1,248	275	0	0	0
62	Short Term Debt Rate %	Line 4	0	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
63	Short Term Debt Ratio %	Line 8	0	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
64	Short Term Debt Component	Line 61 x Line 62 x Line 63	15	10	6	3	1	0	0	0	0
65	Total Rate Base	Line 49	14,446	9,803	5,852	3,084	1,248	275	0	0	0
66	Long Term Debt Rate %	Line 5	0	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
67	Long Term Debt Ratio %	Line 9	1	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
68	Long Term Debt Component	Line 65 x Line 66 x Line 67	565	384	229	121	49	11	0	0	0
69	Total Debt Component	Line 64 + Line 68	581	394	235	124	50	11	0	0	0
70	Total Earned Return	Line 60 + Line 69	1,130	767	458	241	98	22	0	0	0
71	Annual Cost of Service Impact of NGT Incentive Program										
72	Amortization Expense	- Line 48	4,643	4,643	3,258	2,279	1,393	551	-	-	-
73	Income Tax Expense	Line 55	1,731	1,672	1,160	799	480	187	0	0	0
74	Earned Return	Line 70	1,130	767	458	241	98	22	0	0	0
75	Upgrade LNG Capital COS	Note 12	12,175	17,676	23,460	29,888	36,745	44,437	52,776	62,230	77,137
76	Total Cost of Service	Sum of Lines 72 to 75	19,679	24,758	28,336	33,207	38,716	45,196	52,776	62,230	77,137

77 Note:

78 1: This appendix, Financial Assumptions, Section 4

79 2: Non rate base deferral account is transferred to the rate base deferral account at the start of 2014

80 3: Non rate base deferral account transferred to rate base deferral account in 2014 and amortized over 10 years starting in 2014

81 4: AFUDC calculated on prior incentives added to non rate base deferral account from the date (forecasted Oct 2012) of the first vehicle and marine incentive payment to end of 2013

82 5: Line 3 x Line 7 + Line 4 x Line 8 + Line 5 x Line 9

83 6: Line 3 x Line 7 + (Line 4 x Line 8 + Line 5 x Line 9) x (1 - Line 13)

84 7: Exclude volumes / margin already included in RRA 2012/2013; Schedule 2 Benefits: Line 28+ Line 30 + Line 32 + Line 35 + Line 38

85 8: 2014 Opening rate base deferral account equals 2013 closing non rate base deferral account of $13.853 Million, 2015 onwards previous year Line 47

86 9: Amortization of new additions in following year over 10 years

87 10: Prior incentive spending in 2011 includes 2010 amounts, totals $5.573 million

88 11: AFUDC calculated on incentives added to the non rate base deferral account from Aug 2012 to the end of 2013

89 12: Liquefaction and Storage capital added to meet increasing LNG demand, please see financial assumption, section 9 of this appendix for further detail

Appendix H

FINANCIAL SCHEDULES, SCENARIO 2 (LOW GROWTH CASE)

Appendix H
Financial Schedules - Scenario 2: GGRR Load Growth Only
List of Schedules

Appendix H – Scenario 2: GGRR Load Growth Only
Financial Assumptions

1) **Scenario 2 Description**

Market does not expand further after incentives discontinued, CNG / LNG vehicles replaced at end of vehicle life and volumes maintained at 2.9PJ per year. No additional LNG capital required.

2) **Rates & Capital Structure**

FEI	2011	2012[1]	2013[1]	2014+
Rates				
ROE	9.50%	9.50%	9.50%	9.50%
Short Term Debt Rate	4.50%	2.50%	3.50%	3.50%
Long Term Debt Rate	6.95%	6.85%	6.87%	6.87%
Capital Structure				
Equity Ratio	40.00%	40.00%	40.00%	40.00%
Short Term Debt Ratio	1.63%	1.93%	3.03%	3.03%
Long Term Debt Ratio	58.37%	58.07%	56.97%	56.97%
Total	100.00%	100.00%	100.00%	100.00%
Note 1: 2012-13, BCUC Order No.G-44-12				

3) **Income Tax Rate**

2010	2011	2012+
28.5%	**26.5%**	**25.0%**

4) **Incentive Award & Payout Schedule**

<u>Vehicle & Marine</u>
Incentives are assumed to be awarded once per year. 25% of the incentive award paid out when initial terms of the contract have been met, remaining 75% is paid when CNG/LNG vehicles enter service, ranging from 6 to 12 months later. Incentives recorded in deferral account based on cash payment of incentives.

<u>Maintenance Upgrades & Safety</u>
Incentives are assumed to be awarded once per year. 25% of the incentive award paid out upon incentive award, balance of incentive is paid when work is completed ranging from 2 to 6 months later. Incentives recorded in deferral account based on cash payment of incentives.

Appendix H – Scenario 2: GGRR Load Growth Only
Financial Assumptions (continued)

Administration, Marketing, Training and Education

Expenditures assumed to be evenly spread throughout the year.

Total Incentive Award Schedule

('000$)	2010/11	2012	2013	2014	2015	2016	Total
Vehicles	5,573	7,843	7,979	7,404	7,307	7,794	43,900
Marine Vessels		0	3,500	3,000	2,500	2,000	11,000
Admin, Marketing, Training & Education		300	1,000	900	600	300	3,100
Maintenance Upgrades & Safety		200	950	950	950	950	4,000
Total	5,573	8,343	13,429	12,254	11,357	11,044	62,000
Cumulative Incentives	5,573	13,916	27,345	39,599	50,956	62,000	

Total Incentive Payout (Cash Basis)

('000$)	2010/11	2012	2013	2014	2015	2016	2017	Total
Vehicles & Marine	5,573	1,961	8,752	11,210	10,255	9,804	7,345	43,900
Admin, Marketing, Training & Education		300	1,000	900	600	300	0	11,000
Maintenance Upgrades & Safety		50	922	950	950	1,128	0	4,000
Total	5,573	2,311	10,674	13,060	11,805	11,232	7,345	62,000
Cumulative Incentives	5,573	7,884	18,558	31,618	43,423	54,655	62,000	

5) Deferral Account & Amortization Period

Non Rate Base Deferral Account

The non rate base deferral account contains the following: 1) Incentive payouts (cash basis) prior to 2014. 2) Incremental margins (exclude margins already included in RRA 2012/13) prior to 2014. 3) Prior incentives ($5.573 million). AFUDC is calculated on incentive payouts from August 2012 to the end of 2013. AFUDC is calculated on prior incentives from the date of the first vehicle and marine incentive payment, forecasted to be Oct 1, 2012 to the end of 2013. The non rate base deferral account is transferred to a rate base deferral account beginning January 1, 2014 and amortized over 10 years.

Rate Base Deferral Account

Incentive payouts (cash basis) are added to a rate base deferral account for incentive payouts starting in 2014. Each annual addition to the rate base deferral account is amortized over 10 years in the following year. The non rate base deferral account is transferred to the rate base deferral account at the start of 2014 and amortized over 10 years.

Appendix H – Scenario 2: GGRR Load Growth Only
Financial Assumptions (continued)

6) FEI Total Delivery Margin

	2012[1,3]	2013[1,3]	2014[2,3]+
FEI Total Delivery Margin	$575M	$577M	Increase at 2% per year
Note 1: 2012 & 2013 based on 2012-13 RRA G-44-12 Compliance Filing May 1, 2012 Note 2: Based on high level long range planning assumptions Note 3: FEI Delivery Margins do not include any impact of the prescribed undertaking expenditures			

7) FEI Delivery Rates

FEI		2012[1]	2013[1]	2014[2]+
Rate 16	$/GJ	4.05	4.11	Increase at 2%/year
Rate 23	$/GJ	2.44	2.62	Increase at 2%/year
Rate 25 Delivery	$/GJ	0.68	0.73	Increase at 2%/year
Rate 25 Demand	Demand $/Month /GJ of Daily Demand	16.82	18.06	Increase at 2%/year
Note 1: 2012 & 2013 approved Note 2: Based on high level long range planning assumptions				

8) Rate 16 Delivery Rate less Incremental Cost of LNG

		2012	2013	2014	2015	2016	2017	2018[2]+
Rate 16	$/GJ	4.05[1]	4.11[1]	4.19	4.28	4.36	4.45	2014+ Increase at BC CPI All Items, assumed to be 2% / year
Incremental Cost of LNG[4]	$/GJ	0.80	0.82	0.92	1.01	1.00	0.98	Note 3
Rate 16 – Incremental Cost of LNG	$/GJ	3.25	3.29	3.28	3.27	3.36	3.47	
Note 1: 2012 & 2013 approved Note 2: BC CPI All Items based on high level long range planning assumptions Note 3: Vary from $0.80 to $1.01 / GJ depending on LNG volumes and sources, increase at BC CPI All Items projected to be 2% / year Note 4: Incremental Cost of LNG = Incremental O&M / Incremental volumes sold into the LNG market								

Appendix H - Scenario 2: GGRR Load Growth Only
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (2012-2021)

Appendix H - Scenario 2: GGRR Load Growth Only
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (2012-2021)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, unless otherwise stated

		Reference	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1	Annual NG Volume (TJ)	Sch 2, Line 8	178	458	917	1,416	2,032	2,882	2,882	2,882	2,882	2,882
2												
3	Discount Rate	2014 FEI After-Tax WACC	6.81%									
4	Discount Period (years)		1	2	3	4	5	6	7	8	9	10
5												
6	FEI Total Delivery Margin Projections $Millions	Note 1	575	577	588	600	612	624	637	649	662	676
7												
8	Net COS Benefit (Cost) to Existing FEI Natural Gas Customers											
9	Annual Incremental Margin from additional NGT volumes	Sch 2, Line 40, Note 2,4	538	1,284	2,662	4,044	5,958	8,690	8,864	9,041	9,222	9,406
10	Annual Incentive Funding COS	Sch 3, -Line 75	-	-	(3,488)	(5,471)	(7,181)	(8,604)	(9,192)	(8,770)	(8,348)	(7,926)
11	Net Annual COS Benefit (Cost) '000$	Line 9 + Line 10	538	1,284	(826)	(1,427)	(1,223)	86	(328)	271	874	1,480
12												
13	Approximate Annual FEI Delivery / (Reduction) Increase, %	-Line 11 / (Line 6 x 1000), Note 3			0.14%	0.24%	0.20%	(0.01)%	0.05%	(0.04)%	(0.13)%	(0.22)%
14												
15	Present Value of Annual Net COS Benefit (Cost)	Line 11/(1+Line 3)^(Line 4)	504	1,126	(678)	(1,096)	(879)	58	(207)	160	483	766
16												
17	NPV of Net COS Benefit (Cost) '000$	Sum Line 15 2012 to year	504	1,629	952	(144)	(1,024)	(966)	(1,173)	(1,013)	(530)	235
18												
19	NPV of Net COS Benefit (Cost) 2012 to 2030 (19 Years)			24,020								

20 Note:
21 1: 2012, 2013 based on 2012-2013 RRA G-44-12 Compliance Filing May 1, 2012; 2014+ increase at 2%/year reflecting high level long range planning assumptions,
22 does not include any impact of the prescribed undertaking expenditures or prior incentives
23 2: 2012 & 2013 incremental margin added to non rate base deferral account in Schedule 3: Cost of Service Line 32
24 3: Cumulative FEI Delivery (Reduction) increase, FEI delivery margin does not include any impact of the prescribed undertaking expenditures or prior incentives
25 4: 2012 & 2013 includes some margin already included in the 2012/13 RRA

Appendix H - Scenario 2: GGRR Load Growth Only
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (continued 2022 - 2030)
Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, unless otherwise stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Annual NG Volume (TJ)	Sch 2, Line 8	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882
2											
3	Discount Rate	2014 FEI After-Tax WACC									
4	Discount Period (years)		11	12	13	14	15	16	17	18	19
5											
6	FEI Total Delivery Margin Projections $Millions	Note 1	689	703	717	731	746	761	776	792	808
7											
8	Net COS Benefit (Cost) to Existing FEI Natural Gas Customers										
9	Annual Incremental Margin from additional NGT volumes	Sch 2, Line 40, Note 2,4	9,594	9,786	9,982	10,181	10,385	10,593	10,805	11,021	11,241
10	Annual Incentive Funding COS	Sch 3, -Line 75	(7,504)	(7,082)	(4,876)	(3,318)	(1,971)	(760)	(0)	(0)	(0)
11	Net Annual COS Benefit (Cost) '000$	Line 9 + Line 10	2,090	2,704	5,106	6,863	8,414	9,833	10,805	11,021	11,241
12											
13	Approximate Annual FEI Delivery / (Reduction) Increase, %	-Line 11 / (Line 6 x 1000), Note 3	(0.30)%	(0.38)%	(0.71)%	(0.94)%	(1.13)%	(1.29)%	(1.39)%	(1.39)%	(1.39)%
14											
15	Present Value of Annual Net COS Benefit (Cost)	Line 11/(1+Line 3)^(Line 4)	1,012	1,226	2,167	2,727	3,130	3,424	3,523	3,364	3,212
16											
17	NPV of Net COS Benefit (Cost) '000$	Sum Line 15 2012 to year	1,248	2,473	4,640	7,367	10,497	13,922	17,444	20,808	24,020

18

19

20 Note:

21 1: 2012, 2013 based on 2012-2013 RRA G-44-12 Compliance Filing May 1, 2012; 2014+ increase at 2%/year reflecting high level long range planning assumptions,

22 does not include any impact of the prescribed undertaking expenditures or prior incentives

23 2: 2012 & 2013 incremental margin added to non rate base deferral account in Schedule 3: Cost of Service Line 32

24 3: Cumulative FEI Delivery (Reduction) increase, FEI delivery margin does not include any impact of the prescribed undertaking expenditures or prior incentives

25 4: 2012 & 2013 includes some margin already included in the 2012/13 RRA

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 2, Part A: Benefits (2012-2021)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Annual NG Volume (TJ)											
2	Rate 16 not included in RRA 2012/13		12	183	698	1,036	1,482	2,103	2,103	2,103	2,103	2,103
3	Rate 16 included in RRA 2012/13	Note 8	139	139								
4	Rate 23 not included in RRA 2012/13		1	1	15	27	39	55	55	55	55	55
5	Rate 23 included in RRA 2012/13	Note 8	6	6								
6	Rate 25 not included in RRA 2012/13		2	110	204	353	512	725	725	725	725	725
7	Rate 25 included in RRA 2012/13	Note 8	19	19								
8	Total NG Volume (TJ)	Sum of Lines 2 to 7	178	458	917	1,416	2,032	2,882	2,882	2,882	2,882	2,882
9	Number of CNG Stations											
10	Rate 23		-	-	-	-	1	1	1	1	1	1
11	Rate 25		1	3	5	8	11	15	15	15	15	15
12	Number of LNG Stations		2	3	5	8	11	16	18	21	25	30
13	Estimated Impact to Rate 25 Demand Volume	Note 1, 4, 10	8	378	698	1,210	1,752	2,482	2,482	2,482	2,482	2,482
14	Estimated Impact to Rate 25 Demand Volume	Note 1, 5, 11	65	65								
15	Volumetric Delivery Rates ($/GJ)	Note 2										
16	Rate 16 (Net of incremental costs) Note 3	2012 & 2013 approved	3.25	3.29	3.28	3.27	3.36	3.47	3.54	3.61	3.68	3.75
17	Rate 23	2012 & 2013 approved	2.44	2.62	2.67	2.72	2.78	2.83	2.89	2.95	3.01	3.07
18	Rate 25	2012 & 2013 approved	0.68	0.73	0.75	0.76	0.78	0.79	0.81	0.82	0.84	0.86
19	Demand Rates	Note 2										
20	Rate 25 $/ Month / GJ of Daily Demand	2012 & 2013 approved	16.82	18.06	18.42	18.79	19.17	19.55	19.94	20.34	20.75	21.16
21	Basic & Admin Charge	Note 2, 7										
22	Rate 23 $/Month	2012 & 2013 approved	210.52	210.52	214.73	219.03	223.41	227.87	232.43	237.08	241.82	246.66
23	Rate 25 $/Month	2012 & 2013 approved	665.00	665.00	678.30	691.87	705.70	719.82	734.21	748.90	763.88	779.15
24	Rate 16 $/Month	Note 9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	Inflation Annual: Delivery/Demand/Basic	Long term planning assumptions			2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 2, Part B: Benefits (2012-2021)

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 2, Part B: Benefits (2012-2021)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	Incremental Margin '000$											
27	*Delivery*											
28	Rate 16 not included in RRA 2012/13	(Line 2 x Line 16)	37	604	2,288	3,386	4,988	7,291	7,437	7,586	7,738	7,892
29	Rate 16 included in RRA 2012/13	(Line 3 x Line 16)	450	456								
30	Rate 23 not included in RRA 2012/13	(Line 4 x Line 17)	2	2	41	72	107	155	158	161	164	167
31	Rate 23 included in RRA 2012/13	(Line 5 x Line 17)	15	16								
32	Rate 25 not included in RRA 2012/13	(Line 6 x Line 18)	2	81	152	269	397	573	585	597	609	621
33	Rate 25 included in RRA 2012/13	(Line 7 x Line 18)	13	14								
34	*Demand*											
35	Rate 25 not included in RRA 2012/13	(Line 13xLine 20x12/1000)	2	82	154	273	403	582	594	606	618	630
36	Rate 25 included in RRA 2012/13	(Line 14xLine 20x12/1000)	13	14								
37	*Basic Charges*											
38	Rate 23 + 25	Note 6	5	16	27	44	64	88	90	92	94	95
39	Rate 16		-	-	-	-	-	-	-	-	-	-
40	Total Incremental Margin	Sum of Lines 28 to 39	538	1,284	2,662	4,044	5,958	8,690	8,864	9,041	9,222	9,406
41	Cumulative Incremental Margin		538	1,822	4,484	8,528	14,487	23,177	32,040	41,081	50,303	59,709

42 Note:
43 1 Compression load is assumed to be consistent; therefore, the peak will not change in a winter month
44 2 Existing delivery / demand / basic & admin charges are approved 2012 and 2013 charges, 2014+ increase at 2% per year reflecting high level long range planning assumptions
45 3 Rate 16 reflects delivery rate minus incremental cost of LNG (incremental O&M / incremental volume sold into the LNG market), further detail included in this appendix,
46 Financial Assumptions, section 8
47 4 Rate 25 demand volumes not included in RRA 2012/13 filing
48 5 Rate 25 demand volumes included in RRA 2012/13 filing
49 6 (Line 10 x Line 22 x 12) /1000 x (2/3) + (Line 11 x Line 23 x 12) /1000 x (2/3); Basic charges reduce by 1/3 to reflect that some existing accounts are already on R23/25
50 7 New CNG/LNG stations results in new Rate 23/25 accounts
51 8 Volumes related to prior incentives, included in 2012/13 RRA
52 9 There are no basic or admin charges for LNG Rate 16 accounts
53 10 Line 6 / 365 x 1.25 x 1000
54 11 Line 7 / 365 x 1.25 x 1000

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 2, Part A: Benefits (continued 2022-2030)
Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 2, Part A: Benefits (continued 2022-2030)
Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Annual NG Volume (TJ)										
2	Rate 16 not included in RRA 2012/13		2,103	2,103	2,103	2,103	2,103	2,103	2,103	2,103	2,103
3	Rate 16 included in RRA 2012/13	Note 8									
4	Rate 23 not included in RRA 2012/13		55	55	55	55	55	55	55	55	55
5	Rate 23 included in RRA 2012/13	Note 8									
6	Rate 25 not included in RRA 2012/13		725	725	725	725	725	725	725	725	725
7	Rate 25 included in RRA 2012/13	Note 8									
8	Total NG Volume (TJ)	Sum of Lines 2 to 7	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882
9	Number of CNG Stations										
10	Rate 23		-	-	-	1	1	1	1	1	1
11	Rate 25		3	5	8	11	15	15	15	15	15
12	Number of LNG Stations		3	5	8	11	16	18	21	25	30
13	Estimated Impact to Rate 25 Demand Volume[1,4]	Note 1, 4, 10	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482
14	Estimated Impact to Rate 25 Demand Volume[1,5]	Note 1, 5, 11									
15	Volumetric Delivery Rates ($/GJ)	Note 2									
16	Rate 16 (Net of incremental costs) Note 3	2012 & 2013 approved	3.83	3.90	3.98	4.06	4.14	4.23	4.31	4.40	4.48
17	Rate 23	2012 & 2013 approved	3.13	3.19	3.25	3.32	3.39	3.45	3.52	3.59	3.66
18	Rate 25	2012 & 2013 approved	0.87	0.89	0.91	0.93	0.95	0.96	0.98	1.00	1.02
19	Demand Rates										
20	Rate 25 $/ Month / GJ of Daily Demand	2012 & 2013 approved	21.59	22.02	22.46	22.91	23.37	23.83	24.31	24.80	25.29
21	Basic & Admin Charge	Note 2, 7									
22	Rate 23 $/Month	2012 & 2013 approved	251.59	256.62	261.76	266.99	272.33	277.78	283.33	289.00	294.78
23	Rate 25 $/Month	2012 & 2013 approved	794.74	810.63	826.84	843.38	860.25	877.45	895.00	912.90	931.16
24	Rate 16 $/Month	Note 9									
25	Inflation Annual: Delivery/Demand/Basic	Long term planning assumptions	0.02	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 2, Part B: Benefits (continued 2022-2030)
Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 2, Part B: Benefits (continued 2022-2030)

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
26	Incremental Margin '000$										
27	*Delivery*										
28	Rate 16 not included in RRA 2012/13	(Line 2 x Line 16)	8,050	8,211	8,375	8,543	8,714	8,888	9,066	9,247	9,432
29	Rate 16 included in RRA 2012/13	(Line 3 x Line 16)	-	-	-	-	-	-	-	-	-
30	Rate 23 not included in RRA 2012/13	(Line 4 x Line 17)	171	174	177	181	185	188	192	196	200
31	Rate 23 included in RRA 2012/13	(Line 5 x Line 17)	-	-	-	-	-	-	-	-	-
32	Rate 25 not included in RRA 2012/13	(Line 6 x Line 18)	633	646	659	672	685	699	713	727	742
33	Rate 25 included in RRA 2012/13	(Line 7 x Line 18)	-	-	-	-	-	-	-	-	-
34	*Demand*										
35	Rate 25 not included in RRA 2012/13	(Line 13xLine 20x12/1000)	643	656	669	682	696	710	724	738	753
36	Rate 25 included in RRA 2012/13	(Line 14xLine 20x12/1000)	-	-	-	-	-	-	-	-	-
37	*Basic Charges*										
38	Rate 23 + 25	Note 6	97	99	101	103	105	108	110	112	114
39	Rate 16		-	-	-	-	-	-	-	-	-
40	Total Incremental Margin	Sum of Lines 28 to 39	9,594	9,786	9,982	10,181	10,385	10,593	10,805	11,021	11,241
41	Cumulative Incremental Margin		69,303	79,089	89,071	99,252	109,637	120,230	131,035	142,055	153,297

42 Note:
43 1 Compression load is assumed to be consistent; therefore, the peak will not change in a winter month
44 2 Existing delivery / demand / basic & admin charges are approved 2012 and 2013 charges, 2014+ increase at 2% per year reflecting high level long range planning assumptions
45 3 Rate 16 reflects delivery rate minus incremental cost of LNG (incremental O&M / incremental volume sold into the LNG market), further detail included in this appendix,
46 Financial Assumptions, section 8
47 4 Rate 25 demand volumes not included in RRA 2012/13 filing
48 5 Rate 25 demand volumes included in RRA 2012/13 filing
49 6 (Line 10 x Line 22 x 12) /1000 x (2/3) + (Line 11 x Line 23 x 12) /1000 x (2/3); Basic charges reduce by 1/3 to reflect that some existing accounts are already on R23/25
50 7 New CNG/LNG stations results in new Rate 23/25 accounts
51 8 Volumes related to prior incentives, included in 2012/13 RRA
52 9 There are no basic or admin charges for LNG Rate 16 accounts
53 10 Line 6 / 365 x 1.25 x 1000
54 11 Line 7 / 365 x 1.25 x 1000

Appendix H - Scenario 2: GGRR Load Growth Only

Schedule 3, Part A: Cost of Service (2011-2021)

Appendix H - Scenario 2: GGRR Load Growth Only

Schedule 3, Part A: Cost of Service (2011-2021)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained

$000's, Unless Otherwise Stated

		Reference	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1	Key Assumptions												
2	Rates												
3	ROE %	BCUC Order No. G-44-12	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
4	STD Rate	BCUC Order No. G-44-12	4.50%	2.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
5	LTD Rate	BCUC Order No. G-44-12	6.95%	6.85%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
6	Capital Structure												
7	Equity	BCUC Order No. G-44-12	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
8	STD %	BCUC Order No. G-44-12	1.63%	1.93%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
9	LTD %	BCUC Order No. G-44-12	58.37%	58.07%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
10	Total %		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	Return on Rate Base	Note 5	7.93%	7.83%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
12	WACC	Note 6	6.84%	6.82%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%
13	Tax Rate		26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
14	Incentive Award Schedule	Note 1											
15	Prior Vehicle Incentives	Note 10	5,573										
16	Vehicle & Marine		-	7,843	11,479	10,404	9,807	9,794	-				
17	Maintenance Upgrades & Safety		-	200	950	950	950	950	-				
18	Admin, Marketing, Train, Education		-	300	1,000	900	600	300	-				
19	Total Incentive Awards ($62000)	Sum of Lines 15 to 18	5,573	8,343	13,429	12,254	11,357	11,044	-				
20	Incentive Payouts (Cash Basis)	Note 1											
21	Prior Vehicle Incentives		5,573										
22	Vehicle & Marine	Note 1	-	1,961	8,752	11,210	10,255	9,804	7,345				
23	Maintenance Upgrades & Safety	Note 1		50	922	950	950	1,128	-				
24	Admin, Marketing, Train, Education	Note 1		300	1,000	900	600	300	-				
25	Total Incentive Payouts (Cash Basis)	Sum of Lines 21 to 24	5,573	2,311	10,674	13,060	11,805	11,232	7,345				

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 3, Part B: Cost of Service (2012-2021)

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 3, Part B: Cost of Service (2012-2021)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	Non Rate Base Deferral Account (NRBDA) Calculation												
27	Gross Additions	Line 25 (2011-2013)	5,573	2,311	10,674								
28	Tax	- Line 27 x Line 13	(1,477)	(578)	(2,668)	-	-	-	-	-	-	-	-
29	Net Additions	Line 27 + Line 28	4,097	1,733	8,005	-	-	-	-	-	-	-	-
30	Opening Deferral Account Balance	Previous Year, Line 34	-	4,097	5,851								
31	Net Additions	Line 29	4,097	1,733	8,005								
32	Incremental Margins pre 2014	Note 7		(36)	(588)								
33	AFUDC on Deferral Account pre 2014	Note 4 , 11	-	58	585								
34	Closing Deferral Account Balance	Sum of Lines 30 to 33	4,097	5,851	13,853								
35	Rate Base Deferral Account Calculation												
36	Amortization Period (Years)		10										
37	Gross Additions	Line 25 (2014+)				13,060	11,805	11,232	7,345	-	-	-	-
38	Tax	- Line 37 x Line 13				(3,265)	(2,951)	(2,808)	(1,836)	-	-	-	-
39	Net Additions	Line 37 + Line 38				9,795	8,854	8,424	5,509	-	-	-	-
40	Annual Amortization of Net Addition	Line 39/10 years				980	885	842	551	-	-	-	-
41	Add NRBDA	Line 34, 2013 Closing & Note 2				13,853							
42	Annual Amortization of NRBDA	Line 41/10 years				1,385							
43	Opening Deferral Account Balance	Note 8				13,853	22,263	28,752	33,925	35,342	30,698	26,055	21,411
44	Net Additions	Line 39				9,795	8,854	8,424	5,509	-	-	-	-
45	Amortization: Net Additions	Sum of Line 40 & Note 9					(980)	(1,865)	(2,707)	(3,258)	(3,258)	(3,258)	(3,258)
46	Amortization: NRBDA	Line 42 over 10 years & Note 3				(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)
47	Closing Deferral Account Balance	Sum of Lines 43 to 46				22,263	28,752	33,925	35,342	30,698	26,055	21,411	16,768
48	Total Amortization	Line 45 + Line 46				(1,385)	(2,365)	(3,250)	(4,093)	(4,643)	(4,643)	(4,643)	(4,643)
49	Mid Year Rate Base	(Line 43 + Line 47)/2				18,058	25,508	31,339	34,634	33,020	28,377	23,733	19,090
50	Income Tax Expense												
51	Equity Earned Return	Line 60	-	-	-	686	969	1,191	1,316	1,255	1,078	902	725
52	Add: Amortization Expense	- Line 48	-	-	-	1,385	2,365	3,250	4,093	4,643	4,643	4,643	4,643
53	Taxable Income After Tax	Line 51 + Line 52	-	-	-	2,072	3,334	4,441	5,409	5,898	5,722	5,545	5,369
54	Taxable Income	Line 53 / (1 - Line 13)	-	-	-	2,762	4,446	5,921	7,212	7,864	7,629	7,394	7,159
55	Income Tax Expense	Line 54 x Line 13	-	-	-	691	1,111	1,480	1,803	1,966	1,907	1,848	1,790

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 3, Part C: Cost of Service (2012-2021)
Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 3, Part C: Cost of Service (2012-2021)
Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
56	Earned Return												
57	Total Rate Base	Line 49				18,058	25,508	31,339	34,634	33,020	28,377	23,733	19,090
58	ROE Rate %	Line 3				9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
59	Equity Ratio %	Line 7				40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60	Equity Return	Line 57 x Line 58 x Line 59				686	969	1,191	1,316	1,255	1,078	902	725
61	Total Rate Base	Line 49				18,058	25,508	31,339	34,634	33,020	28,377	23,733	19,090
62	Short Term Debt Rate %	Line 4				3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
63	Short Term Debt Ratio %	Line 8				3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
64	Short Term Debt Component	Line 61 x Line 62 x Line 63				19	27	33	37	35	30	25	20
65	Total Rate Base	Line 49				18,058	25,508	31,339	34,634	33,020	28,377	23,733	19,090
66	Long Term Debt Rate %	Line 5				6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
67	Long Term Debt Ratio %	Line 9				56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
68	Long Term Debt Component	Line 65 x Line 66 x Line 67				707	998	1,227	1,356	1,292	1,111	929	747
69	Total Debt Component	Line 64 + Line 68				726	1,025	1,260	1,392	1,327	1,141	954	767
70	Total Earned Return	Line 60 + Line 69				1,412	1,995	2,451	2,708	2,582	2,219	1,856	1,493
71	Annual Cost of Service Impact of NGT Incentive Program												
72	Amortization Expense	- Line 48	-	-	-	1,385	2,365	3,250	4,093	4,643	4,643	4,643	4,643
73	Income Tax Expense	Line 55	-	-	-	691	1,111	1,480	1,803	1,966	1,907	1,848	1,790
74	Earned Return	Line 70	-	-	-	1,412	1,995	2,451	2,708	2,582	2,219	1,856	1,493
75	Total Cost of Service	Sum of Lines 72 to 74	-	-	-	3,488	5,471	7,181	8,604	9,192	8,770	8,348	7,926

76 Note:
77 1: This appendix, Financial Assumptions, Section 4
78 2: Non rate base deferral account is transferred to the rate base deferral account at the start of 2014
79 3: Non rate base deferral account transferred to rate base deferral account in 2014 and amortized over 10 years starting in 2014
80 4: AFUDC calculated on prior incentives added to non rate base deferral account from the date (forecasted Oct 2012) of the first vehicle and marine incentive payment to end of 2013
81 5: Line 3 x Line 7 + Line 4 x Line 8 + Line 5 x Line 9
82 6: Line 3 x Line 7 + (Line 4 x Line 8 + Line 5 x Line 9) x (1 - Line 13)
83 7: Exclude volumes / margin already included in RRA 2012/2013; Schedule 2 Benefits: Line 28+ Line 30 + Line 32 + Line 35 + Line 38
84 8: 2014 Opening rate base deferral account equals 2013 closing non rate base deferral account of $13.853 Million, 2015 onwards previous year line 47
85 9: Amortization of new additions in following year over 10 years
86 10: Prior incentive spending in 2011 includes 2010 amounts, totals $5.573 million
87 11: AFUDC calculated on incentives added to the non rate base deferral account from Aug 2012 to the end of 2013

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 3, Part A: Cost of Service (continued 2022-2030)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained

$000's, Unless Otherwise Stated

		Reference	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
1	Key Assumptions	-									
2	Rates										
3	ROE %	BCUC Order No. G-44-12	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
4	STD Rate	BCUC Order No. G-44-12	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
5	LTD Rate	BCUC Order No. G-44-12	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
6	Capital Structure		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
7	Equity	BCUC Order No. G-44-12	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
8	STD %	BCUC Order No. G-44-12	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
9	LTD %	BCUC Order No. G-44-12	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
10	Total %		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	Return on Rate Base	Note 5	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
12	WACC	Note 6	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%
13	Tax Rate		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
14	Incentive Award Schedule	Note 1									
15	*Prior Vehicle Incentives*	Note 10	-	-	-	-	-	-	-	-	-
16	Vehicle & Marine		-	-	-	-	-	-	-	-	-
17	Maintenance Upgrades & Safety		-	-	-	-	-	-	-	-	-
18	Admin, Marketing, Train, Education		-	-	-	-	-	-	-	-	-
19	Total Incentive Awards ($62000)	Sum of Lines 15 to 18	-	-	-	-	-	-	-	-	-
20	*Incentive Payouts (Cash Basis)*	Note 1									
21	*Prior Vehicle Incentives*		-	-	-	-	-	-	-	-	-
22	Vehicle & Marine	Note 1	-	-	-	-	-	-	-	-	-
23	Maintenance Upgrades & Safety	Note 1	-	-	-	-	-	-	-	-	-
24	Admin, Marketing, Train, Education	Note 1	-	-	-	-	-	-	-	-	-
25	Total Incentive Payouts (Cash Basis)	Sum of Lines 21 to 24	-	-	-	-	-	-	-	-	-

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 3, Part B: Cost of Service (continued 2022-2030)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
26	Non Rate Base Deferral Account (NRBDA) Calculation										
27	Gross Additions	Line 25 (2011-2013)	-	-	-	-	-	-	-	-	-
28	Tax	- Line 27 x Line 13	-	-	-	-	-	-	-	-	-
29	Net Additions	Line 27 + Line 28	-	-	-	-	-	-	-	-	-
30	Opening Deferral Account Balance	Previous Year, Line 34	-	-	-	-	-	-	-	-	-
31	Net Additions	Line 29	-	-	-	-	-	-	-	-	-
32	Incremental Margins pre 2014	Note 7	-	-	-	-	-	-	-	-	-
33	AFUDC on Deferral Account pre 2014	Note 4 , 11	-	-	-	-	-	-	-	-	-
34	Closing Deferral Account Balance	Sum of Lines 30 to 33	-	-	-	-	-	-	-	-	-
35	Rate Base Deferral Account Calculation										
36	Amortization Period (Years)										
37	Gross Additions	Line 25 (2014+)	-	-	-	-	-	-	-	-	-
38	Tax	- Line 37 x Line 13	-	-	-	-	-	-	-	-	-
39	Net Additions	Line 37 + Line 38	-	-	-	-	-	-	-	-	-
40	Annual Amortization of Net Addition	Line 39/10 years	-	-	-	-	-	-	-	-	-
41	Add NRBDA	Line 34, 2013 Closing & Note 2	-	-	-	-	-	-	-	-	-
42	Annual Amortization of NRBDA	Line 41/10 years	-	-	-	-	-	-	-	-	-
43	Opening Deferral Account Balance	Note 8	16,768	12,125	7,481	4,223	1,944	551	0	0	0
44	Net Additions	Line 39	-	-	-	-	-	-	-	-	-
45	Amortization: Net Additions	Sum of Line 40 & Note 9	(3,258)	(3,258)	(3,258)	(2,279)	(1,393)	(551)	-	-	-
46	Amortization: NRBDA	Line 42 over 10 years & Note 3	(1,385)	(1,385)	-	-	-	-	-	-	-
47	Closing Deferral Account Balance	Sum of Lines 43 to 46	12,125	7,481	4,223	1,944	551	0	0	0	0
48	Total Amortization	Line 45 + Line 46	(4,643)	(4,643)	(3,258)	(2,279)	(1,393)	(551)	-	-	-
49	Mid Year Rate Base	(Line 43 + Line 47)/2	14,446	9,803	5,852	3,084	1,248	275	0	0	0
50	Income Tax Expense										
51	Equity Earned Return	Line 60	549	373	222	117	47	10	0	0	0
52	Add: Amortization Expense	- Line 48	4,643	4,643	3,258	2,279	1,393	551	-	-	-
53	Taxable Income After Tax	Line 51 + Line 52	5,192	5,016	3,481	2,396	1,441	561	0	0	0
54	Taxable Income	Line 53 / (1 - Line 13)	6,923	6,688	4,641	3,194	1,921	748	0	0	0
55	Income Tax Expense	Line 54 x Line 13	1,731	1,672	1,160	799	480	187	0	0	0

Appendix H - Scenario 2: GGRR Load Growth Only
Schedule 3, Part C: Cost of Service (continued 2022-2030)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained

$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
56	Earned Return										
57	Total Rate Base	Line 49	14,446	9,803	5,852	3,084	1,248	275	0	0	0
58	ROE Rate %	Line 3	0	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
59	Equity Ratio %	Line 7	0	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60	Equity Return	Line 57 x Line 58 x Line 59	549	373	222	117	47	10	0	0	0
61	Total Rate Base	Line 49	14,446	9,803	5,852	3,084	1,248	275	0	0	0
62	Short Term Debt Rate %	Line 4	0	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
63	Short Term Debt Ratio %	Line 8	0	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
64	Short Term Debt Component	Line 61 x Line 62 x Line 63	15	10	6	3	1	0	0	0	0
65	Total Rate Base	Line 49	14,446	9,803	5,852	3,084	1,248	275	0	0	0
66	Long Term Debt Rate %	Line 5	0	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
67	Long Term Debt Ratio %	Line 9	1	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
68	Long Term Debt Component	Line 65 x Line 66 x Line 67	565	384	229	121	49	11	0	0	0
69	Total Debt Component	Line 64 + Line 68	581	394	235	124	50	11	0	0	0
70	Total Earned Return	Line 60 + Line 69	1,130	767	458	241	98	22	0	0	0
71	Annual Cost of Service Impact of NGT Incentive Program										
72	Amortization Expense	- Line 48	4,643	4,643	3,258	2,279	1,393	551	-	-	-
73	Income Tax Expense	Line 55	1,731	1,672	1,160	799	480	187	0	0	0
74	Earned Return	Line 70	1,130	767	458	241	98	22	0	0	0
75	Total Cost of Service	Sum of Lines 72 to 74	7,504	7,082	4,876	3,318	1,971	760	0	0	0

76 Note:

77 1: This appendix, Financial Assumptions, Section 4

78 2: Non rate base deferral account is transferred to the rate base deferral account at the start of 2014

79 3: Non rate base deferral account transferred to rate base deferral account in 2014 and amortized over 10 years starting in 2014

80 4: AFUDC calculated on prior incentives added to non rate base deferral account from the date (forecasted Oct 2012) of the first vehicle and marine incentive payment to end of 2013

81 5: Line 3 x Line 7 + Line 4 x Line 8 + Line 5 x Line 9

82 6: Line 3 x Line 7 + (Line 4 x Line 8 + Line 5 x Line 9) x (1 - Line 13)

83 7: Exclude volumes / margin already included in RRA 2012/2013; Schedule 2 Benefits: Line 28+ Line 30 + Line 32 + Line 35 + Line 38

84 8: 2014 Opening rate base deferral account equals 2013 closing non rate base deferral account of $13.853 Million, 2015 onwards previous year line 47

85 9: Amortization of new additions in following year over 10 years

86 10: Prior incentive spending in 2011 includes 2010 amounts, totals $5.573 million

87 11: AFUDC calculated on incentives added to the non rate base deferral account from Aug 2012 to the end of 2013

Appendix I

SUMMARY OF FEI'S NGT INCENTIVE PROGRAM

APPENDIX I – SUMMARY OF FEI'S NGT INCENTIVE PROGRAM

This Appendix provides a brief summary of FEI's NGT Incentive Program that was launched in early June of 2012. This detail is provided for informational purposes and background only. Complete program documents including instructions to applicants, timelines, application form, draft contract and frequently asked questions are publicly available on FEI's external website at www.fortisbc.com/ngt. The following sections summarize a few key categories related to the NGT Incentive Program.

Incentive calculation

As discussed in Section 4 of the Application, incentives are based on percentage differences between the cost of the eligible vehicle and a comparable vehicle using conventional fuel. The percentage differential in the current round of funding is limited to 80%, and will be scaled downward by at least 10% in each subsequent year. The program only includes new original equipment manufactured ("OEM") vehicles. Engine conversions only apply to marine vessel projects that convert from diesel or heavy fuel oil to natural gas. Applicants are asked to provide this price differential on the application form based on quotations from their authorized dealer.

Staged evaluation criteria

FEI intends to evaluate projects under three categories main categories of criteria:

1. Fitness test and mandatory requirements.

2. Amount of funding per litre of diesel fuel displacement.

3. Overall fit with program objectives.

These are discussed in the sections below.

Fitness test and mandatory requirements

All applicants must satisfy the minimum requirements in this first category in order to continue on in the evaluation process. Companies which fail the safety standard assessment, or that have a poor financial rating, will be disqualified from the selection process.

The safety standards will be based on applicants' scores as measured by the Ministry of Transportation's National Safety Code Carrier Profile ("CP"), or an equivalent measure. The CP is a record of a company's on-road performance. The CP rates companies based on performance measures including the number of accidents, company and driver-related violations and audit results. Based on the score, each company is assigned a weighted rating based on the last three years of operation.

A financial assessment will be conducted for each company to ensure that funds are granted to companies with sound financial histories. A company's past financial performance is a reliable indicator of future financial performance, and a clean financial record will minimize the risk that funds will be provided to companies with the potential for default or insolvency.

The financial assessment will be conducted through Equifax, Canada's largest credit reporting agency. Equifax assigns a score to each company based on indicators such as payment history, number of derogatory items and the length of time the company has been in operation. A score is assigned based on each item in the credit analysis, and this score represents the overall risk associated with the company.

FEI also has other mandatory requirements which deem an applicant eligible for funding and consideration in the subsequent criteria. Briefly, these include:

- FEI's form of Contribution Agreement (legal contract), shall apply.
- Natural gas vehicles must be registered in and used primarily in British Columbia.
- The applicant must primarily fuel the NGVs using natural gas (CNG or LNG) delivered through FEI's natural gas distribution system.
- Payment of incentive awards under this program are subject to BCUC confirmation of cost recovery upon terms and conditions that are acceptable to FEI in its sole discretion. FEI expects to have clarification regarding the cost recovery treatment prior to the time frame for final execution of the Contribution Agreements.

Other terms and conditions can be viewed on FEI's external website. Based on the overall weighted score from this category, applicants may gain an advantage over their competitors which could impact their overall ranking and award.

Amount of Funding per Litre of Diesel Fuel Displacement

Each applicant will be assessed based on the dollar amount of funding per litre of diesel fuel displaced.

A measure called the Dollars per Diesel Litre Equivalent ("$/DLE") will be calculated for each company. Once the $/DLE has been calculated, the companies can be ranked accordingly and then be assigned a score relative to all other companies.

This is a key evaluation criteria, as it determines the level of benefit received for each dollar of funding granted. As it is an important factor in the funding decision, this measure will receive a higher weighting relative to other evaluation criteria.

Overall Fit With Program Objectives

The final category of the evaluation criteria considers the extent to which each applicant furthers the objectives of the GGRR. This category considers factors such as whether funded projects would increase geographical diversification of projects throughout BC, as well as the ability to expand corridor development. Construction of fueling stations along BC's busiest corridors plays a vital role in expanding the use of natural gas vehicles.

Applicant support and commitment to the program is also key to the success of the program. It is important that applicants demonstrate a commitment to continue to fuel their vehicles with natural gas for the life of the vehicle. In addition, the willingness to construct fueling stations, and also allow third-party access to those fueling stations, would provide a significant benefit to a number of fleets that may not otherwise have the capital or the opportunity to operate natural gas vehicles.

The program will also provide funding in a manner that strikes an optimum balance between LNG and CNG projects.

Fairness Advisor

In order to ensure the evaluation process and the provision of funds is conducted in a fair and objective manner, a Fairness Advisor has been appointed to oversee the incentive funding process. The Fairness Advisor is an independent consultant who will facilitate the evaluation of all applicants, and will substantiate that the process has been carried out diligently, impartially and in a non-discriminatory fashion.

The appointment of the Fairness Advisor will also serve to eliminate any potential or perceived bias from the process, and will ensure that the process has been carried out in a fair, open and transparent manner. To date, the Fairness Advisor has reviewed and provided comments on the program materials prior to the program launch which FEI has integrated into its program design.

As part of the transparency process, all awards will be made public and posted on the FEI website. The amount of funds awarded to successful applicants, along with the project details will be posted publicly on FEI's website once the applicants have been notified.

Marine Vehicles

Consistent with the Regulation, FEI has designed its program to consider applications from proponents in the marine sector. Marine applicants are requested to indicate the cost of engine conversion from conventional fuels to natural gas, in addition to similar requirements for trucking fleets. As noted in Section 4, expenditures during the program period for marine vehicles are not to exceed $11 million. At this time, FEI expects that market adoption will only fully develop when further LNG supply is made available through amendments to Rate Schedule 16 and the installation of a truck load out facility at Mt. Hayes.

Administration, Marketing, Training and Education

The expenditure allowance for $3.1 million in administration, marketing, training and education will enable FEI to administer its NGT Incentive Program and further promote natural gas as a transportation fuel. For example, this funding will capture the cost of public information sessions to educate prospective fleet owners on the program, as well as costs and fees to the Fairness Advisor.

Safety Practices and Maintenance Shop Upgrades

The Regulation also authorizes FEI to provide grants for safety and maintenance programs. An example would be a fleet, dealer or manufacturer who invests in incremental upgrades to its maintenance shop to service and accommodate natural gas vehicles. A typical large fleet operator could expect to incur a one-time cost ranging from $100,000 to $200,000 in incremental shop improvements.[1] Examples of safety modifications may include the addition of methane detectors and increased ventilation. Over the undertaking period FEI estimates it could fund between 15 and 25 shop improvements, assuming the range of costs above and the funding limit of $4 million.

[1] FEI understands the cost of the WM facility shop upgrade was approximately $160,000.

Appendix J

FORECAST RESULTS OF FEI INITIATIVES UNDER THE GGRR

APPENDIX J - FORECAST RESULTS OF FEI INITIATIVES UNDER THE GGRR

This Appendix discusses FEI's forecast of the results of carrying out the three prescribed undertakings of the GGRR. The forecast results are intended to provide reasonable estimates of the benefits and costs of the proposed incentive programs, and the expected rate impacts.

FEI also discusses the anticipated results of expenditures on CNG and LNG fueling stations (Prescribed Undertakings 2 and 3). It is anticipated that all, or nearly all, of the costs related to expenditures on CNG and LNG stations will be recovered through the rates charged to the station customers. FEI intends to pursue contracts for CNG and LNG stations that involve full cost recovery and expects that station contracts with less than full cost recovery (as permitted in Prescribed Undertakings 2 and 3) will be more of an exception than the norm.

Forecast Impacts of the NGT Incentive Program (Prescribed Undertaking 1)

NUMBER OF VEHICLES

It is the goal of the NGT Incentive Program funding to encourage as many fleet owners and operators as possible to adopt natural gas as a transportation fuel in the target sectors set out in the Regulation. The amount of incentive funding provided per vehicle is expected to be reduced in each year of the program, allowing more vehicles to receive funding as the program progresses.

The forecast of the number of NGT vehicle additions by vehicle type is summarized in Table 1 below and shows that, based on current assumptions, by 2017, approximately 1,460 vehicles are forecast to have adopted either CNG or LNG fueling as a result of this funding. Note that the vehicle additions are assumed to lag the incentive payments by one year.

Table 1: Number of Vehicles Anticipated to Receive Funding – 2012-2017[1]

CNG Vehicle Additions (1 yr lag from funding)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**TOTAL**
Vocational trucks	21	64	53	124	123	167	552
Transit/School Buses	11	40	30	37	47	63	228
LNG Vehicle Additions							
Class 8 tractors	54	69	110	95	138	208	674
Marine Vessels + Other Applications	0	0	1	1	1	1	4
Total Vehicle Additions	86	173	195	257	310	439	1460

1 2012 vehicle additions include Waste Management (20), City of Surrey (1), Kelowna School District (11), Vedder Transport (50) and Westport Research (4); for Westport Research, no incentives were provided but the volumes are included to forecast LNG demand).

EXPECTED INCENTIVES CAPS

The first prescribed undertaking in the GGRR permits a public utility to provide up to $62 million in incentive funding for eligible vehicles to help transition heavy-duty transportation vehicles from gasoline or diesel fuelled engines to lower emission natural gas-fuelled engines.

Table 2 below highlights the estimated cost premiums associated with natural gas-fuelled vocational trucks (such as waste hauling trucks), transit buses and Class 8 tractor trailer trucks, and the associated incentive caps per vehicle. The table assumes incentives are awarded at the percentage levels outlined in the Regulation.[2]

Table 2: Estimated Natural Gas Vehicle Premiums & Incentive Caps by Vehicle Type – 2012-2016[3]

Incentive Funding Level	Type of Fuel	2012 80%	2013 70%	2014 60%	2015 50%	2016 40%
NGV Premiums '000$						
Vocational Truck	**CNG**	39.0	36.5	34.1	31.7	29.2
Transit Bus	**CNG**	48.7	46.3	43.8	41.4	39.0
Class 8 Tractor	**LNG**	77.9	73.1	68.2	63.3	58.5
Proposed Incentive Caps Per Vehicle '000$						
Vocational Truck	**CNG**	31.2	25.6	20.5	15.8	11.7
Transit Bus	**CNG**	39.0	32.4	26.3	20.7	15.6
Class 8 Tractor	**LNG**	62.4	51.1	40.9	31.7	23.4

The first section of the table above indicates that as the program progresses, the cost premiums associated with natural gas vehicles are anticipated to decrease. In general, costs tend to be high during the introduction phase of any product. As the product is adopted, and the technology evolves, production costs are projected to fall.

The second section of the table summarizes the proposed maximum level of incentive funding to be granted to applicants based on the percentages set out in the Regulation. It is anticipated that there will be a larger number of applicants requesting funding as natural gas engines become more common. In order to comply with the Regulation and to maximize the number of vehicles and fleets adopting natural gas as a vehicle fuel, funding of the differentials will be limited to 80% in 2012 and will decrease by 10% annually so that funds are available to an increasingly greater number of vehicles each year.

TOTAL INCENTIVES BY VEHICLE TYPE

The table below summarizes the total amount of incentive funding forecast to be provided under Prescribed Undertaking 1:

[2] FEI has discretion to award less than this percentage based on the uptake of the program and the actual price differential. As FEI completes each funding round, the actual price differential (as indicated by proposals from applicants) and related incentive caps will be adjusted accordingly.

[3] NGV Premiums are based on FEI's experience and discussions with fleets and dealers. FEI will assess the reasonableness of these price differentials once it receives complete proposals in its first round of incentive funding.

Table 3: Total Dollars of Incentive Funding By Vehicle Type – 2011-2016[4],[5]

Incentives Funding (000's)		2010/2011		2012		2013		2014		2015		2016	Total
Vehicles		5,573	$	7,843	$	7,979	$	7,404	$	7,307	$	7,794	43,900
Marine		-	$	-	$	3,500	$	3,000	$	2,500	$	2,000	11,000
Admin & Education		-	$	300	$	1,000	$	900	$	600	$	300	3,100
Safety & Maintenance		-	$	200	$	950	$	950	$	950	$	950	4,000
Total Incentives	$	5,573	$	8,343	$	13,429	$	12,254	$	11,357	$	11,044	
Cumulative Incentives	$	5,573	$	13,916	$	27,345	$	39,599	$	50,956	$	62,000	

Although incentives will be provided to both CNG and LNG projects, it is expected that LNG fuelled vehicles will account for the majority of the incentives granted. This is due to two factors: the cost premium for an LNG vehicle is higher than for a CNG vehicle, as demonstrated by Table 3 above; and LNG vehicles tend to travel greater distances on an annual basis consuming more natural gas. Overall this results in more efficient use of funding for LNG vehicles on a dollar per GJ of throughput basis, further maximizing the cost benefits of natural gas vehicles.

Marine vessels are expected to account for a significant portion of the funding, with the commencement of funding forecast to occur in 2013. Due to the size and unique requirements of this type of vehicle, and the establishment of LNG supply as described in Section 7.5, more lead time and additional infrastructure may be required before marine vessels will be able to utilize natural gas fuel.

Natural Gas Volumes Added as a Result of Incentive Funding

Total volumes on the FEI system have dropped by approximately 15 TJs since 2003 when compared to the forecast total demand for 2012 and 2013.[6] This is due in large part to reduced consumption by existing customers (due to the replacement of older furnaces and other energy efficiency measures), and also fewer new customers being added to the system.

The addition of volumes that would result from this NGT incentive funding program will increase the system load and ultimately lower delivery rates for FEI customers relative to what they would otherwise be. The table below provides a conservative estimate of the additional volumes that will be added to the system (irrespective of the fueling station provider) as a result of this incentive funding. There is a one year lag period built into the forecast, to account for the time between the granting of the incentives and the time those vehicles are in operation. Vehicles funded in year 'n' are shown as load additions in year 'n+1'.

4 The total dollars of incentive funding per year is equal to the number of vehicle additions for the subsequent calendar year (as shown in Table 1), multiplied by the proposed incentive cap per type of vehicle as shown in Table 2. For example, the 2012 incentives of $7.8 million is equal to 2013 vehicle additions x 2012 proposed incentive caps

5 To the extent that funds allocated to Safety & Maintenance and Administration expenses are not used they will be diverted to fund additional vehicles as discussed in the Application. The use of these funds will be evaluated annually.

6 Exhibit B-1, FEU 2012 and 2013 Revenue Requirement Application, Figure 4.4-9, Page 98

Table 4: Incremental Demand Volumes by Vehicle Type – 2012-2017[7]

Total Vehicle Demand Volumes (000's)	2012	2013	2014	2015	2016	2017
CNG Vehicle Demand GJ						
Vocational trucks	22	85	138	262	385	552
Transit/School Buses	6	51	81	118	165	228
Total CNG Vehicle Demand GJ	28	136	219	380	550	779
LNG Vehicle Demand						
Class 8 tractors	150	322	598	836	1,182	1,703
Marine Vessels + Other Applications	0	0	100	200	300	400
Total LNG Vehicle Demand	150	322	698	1,036	1,482	2,103
Total NGT Demand GJ	**178**	**458**	**917**	**1,416**	**2,032**	**2,882**

Revenue Requirement and Rate Impacts Related to Incentive Funding

FEI anticipates that the number of natural gas fueled vehicles will increase in the marketplace, largely as a result of this incentive funding program. The additional volume that results from the program will lead to lower delivery rates for all non-bypass FEI customers in the long run.

The anticipated rate impact of carrying out Prescribed Undertaking 1 is a cumulative rate decrease of approximately 5.6% by 2030 and is described in Scenario 1 below.[8] This impact considers both the costs of the undertaking as well as the benefits associated with the additional throughput.

Analysis for an alternative lower growth scenario is presented as Scenario 2. Scenario 2 presents rate impacts based on the assumption of load growth occurring only from the incentives granted under this program and results in a cumulative rate decrease of approximately 1.4% by 2030.

Each of the scenarios discusses the forecasted demand volumes, as well as the delivery rate impacts under each scenario.

SCENARIO 1 (PLANNED GROWTH CASE): MARKET EXPANDS, VOLUMES INCREASE TO MEET DEMAND

Scenario 1 is based on the anticipated outcome of the NGT Incentive Program, which is market expansion, and a subsequent increase in demand volumes. It is expected that natural gas transportation vehicles will increase in the marketplace due to the cost-effectiveness of the vehicles, their increasing presence in the marketplace and the availability of a larger number of fueling stations. Additional LNG liquefaction and storage assets are added in late 2017 to meet increasing LNG demand starting in 2018.

[7] This forecast assumes the following:
1) Average fuel consumption of 1,000 GJs per year for CNG vehicles, 2,500 GJs per year for LNG vehicles, and 100,000 GJs per year for marine vehicles; and
2) NGVs under the program remain in operation for their expected vehicle life.

[8] The delivery rate impacts for both scenarios assume that all vehicles are fueled by CNG or LNG from FEI's distribution system and LNG facilities.

The following table outlines the annual projected NGT load resulting from the NGT Incentive funding from 2014 – 2030.

Table 5: Scenario 1 Demand Volumes (TJ) 2014-2030

TJ	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Volume Annual	917	1,416	2,032	2,882	3,407	4,027	4,760	5,626	6,650
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
Volume Annual	7,861	9,291	10,982	12,981	15,344	18,136	21,437	25,338	

Table 5 shows that demand volumes will increase as a result of the incentive funding program. This is in line with the forecast outcome, where the number of natural gas transportation vehicles in the market will increase, coupled with a corresponding increase in consumption.

The increase in volumes will positively impact delivery rates for all customers. An increased load on FEI's system will lead to decreasing rates for all customers, as fixed costs are spread over a larger number of customers. Table 6 summarizes the forecast approximate cumulative delivery rate impacts for FEI non-bypass customers. Cumulative rate impacts have been calculated by dividing the annual impact of the NGT Incentive Program by the FEI delivery margin independent of any Incentive Program influences.

Table 6: Scenario 1 Cumulative Delivery Rate Impacts (%) 2014-2030

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Impact	0.14%	0.24%	0.20%	0.08%	0.68%	0.31%	(0.11)%	(0.58)%	(1.12)%
	2023	2024	2025	2026	2027	2028	2029	2030	
Rate Impact	(1.18)%	(1.60)%	(2.02)%	(2.57)%	(3.23)%	(4.04)%	(4.95)%	(5.59)%	

Table 6 shows that delivery rate impacts fluctuate slightly in the first few years of the program because incremental volumes are not yet great enough to offset the costs of incentives and the administration of the NGT Incentive Program, as well as the costs of additional LNG liquefaction and storage forecast to occur in 2017. However, FEI customers will start to realize the benefit of the incentive funding program in 2020. By 2020, delivery rates are forecast to decrease by 0.11% as a result of this program, and will continue to decrease after that point as volumes increase. Detailed rate impact tables have been included in Appendix G, Schedule 1.

SCENARIO 2 (LOAD GROWTH FROM GGRR INCENTIVES ONLY): MARKET EXPANDS DURING INCENTIVE REWARD PERIOD, VOLUMES STABILIZE

FEI has also analyzed the volume and rate impacts for a scenario in which customers do not continue to purchase additional natural-gas powered vehicles upon expiration of the incentive funding program in 2017 (Scenario 2). Although it is expected that natural gas transportation vehicles will increase in the marketplace, there is the possibility that without incentive funding, firms will not purchase additional natural gas fueled vehicles, regardless of the fuel cost savings that can be achieved.

Scenario 2 is based on the assumption that although no additional vehicles will be purchased, existing vehicles purchased as part of this program will be replaced at the end of their life cycle. Therefore, volumes will remain steady once the incentive funds have been fully disbursed.

Table 7 outlines the annual projected NGT load resulting from the NGT Incentive Program from 2014 – 2030 under this scenario.

Table 7: Scenario 2 Demand Volumes (TJs) 2014-2030

TJ	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Volume Annual	917	1,416	2,032	2,882	2,882	2,882	2,882	2,882	2,882
Volume Annual	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882	

Table 7 highlights the steady increase in demand volumes until 2017, when the funding program has ended. From that point onwards, volumes will remain at 2017 levels. Although volumes will remain steady, this program will continue to have a positive effect on delivery rates. The table below summarizes the forecast approximate cumulative delivery rate impacts for FEI non-bypass customers.

Table 8: Scenario 2 Cumulative Delivery Rate Impacts (%) 2014-2030

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Impact	0.14%	0.24%	0.20%	(0.01)%	0.05%	(0.04)%	(0.13)%	(0.22)%	(0.30)%
	2023	2024	2025	2026	2027	2028	2029	2030	
Rate Impact	(0.38)%	(0.71)%	(0.94)%	(1.13)%	(1.29)%	(1.39)%	(1.39)%	(1.39)%	

Table 8 highlights that the incentive funding program has a peak rate increase of 0.24% in 2015 and FEI customers' rates are forecast to start to decrease in the 2017 to 2019 period. Delivery rates are forecast to continue to fall in this scenario, but at a slower pace than in Scenario 1. This is due to the continued decrease in amortization and income tax expenses. Detailed rate impact tables have been included in Appendix H, Schedule 1.

Although this scenario is not likely to occur, it serves to emphasize the benefits that will accrue to all FEI customers, even in a scenario where there is no uptake in demand volumes upon completion of the program.

Expected CNG and LNG Station Additions

Due to the multiple options available for NGT customers to obtain fueling service, FEI cannot forecast with a high degree of precision the number of CNG or LNG stations that will be brought forward as prescribed undertaking expenditures. FEI plans to seek the required approvals in the future as part of a separate application process for each fueling station, whether prescribed undertaking or otherwise.

As the NGT Incentive Program is anticipated to increase the number of natural gas vehicles by 1,460 in 2017, it is clear that fueling station infrastructure to accommodate these vehicles will also need to increase. Table 9 below summarizes the anticipated number of annual fueling station additions from 2012-2017 that would be needed to serve the forecast load as shown in Table 4. The table presents the total number of fueling stations, not necessarily those that will be funded through the NGT Incentive Program. These stations may be constructed privately, through another public utility offering incentives under this Regulation, or by FEI, either through the Regulation or under FEI's GT&C 12B.

Table 9: Fueling Station Additions 2012-2017

Fueling Station Additions	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
CNG Stations	1	3	5	8	12	16
LNG Stations	1	3	5	7	10	15
Total Number of Stations	**2**	**6**	**10**	**15**	**22**	**31**

Fueling service can be contracted from FEI, a private supplier or through a third-party contract with the owner of a fueling station. If an applicant would like to construct a fueling station on their own property, FEI would own, build, construct and maintain the station.

The specific rates for each station will vary depending on each individual applicant's costs and requirements for the fueling station. Fueling station applications will be submitted once the need for additional stations has been identified.

Summary

It is anticipated that the number of natural gas fueled vehicles will increase throughout the incentive funding period, and that this growth will be sustained well beyond the end of the Program in 2017, as NGT vehicles provide substantial cost savings relative to vehicles that are powered by alternative fuels.

The Program will provide benefits not only to NGT customers who are granted incentive funding under the Program, but to FEI customers in general through the increased throughput of natural gas on the delivery system. As well, BC residents as a whole will see benefits through the reduced amount of GHG emissions that are expected to result from transportation vehicles transitioning from their existing fuel to CNG or LNG.

Appendix K

NGV INCENTIVE REVIEW PROCEEDING EXHIBITS

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May 12, 2011
File No.: 240148.00595/14797

ELECTRONIC FILING

British Columbia Utilities Commission
6th floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Erica Hamilton
Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. and Fortis Energy (Vancouver Island) Inc.
(the "FortisBC Energy Utilities")
Energy Efficiency and Conservation Program Natural Gas Vehicles Incentive

We enclose for filing in the above proceeding the electronic version of the Final Submissions on behalf of FortisBC Energy Utilities.

Twenty hard copies of the Final Submissions will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[original signed by Matthew Ghikas]

Matthew Ghikas

MTG/fxm
Enc

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF the *Utilities Commission Act,*
R.S.B.C. 1996, Chapter 473 (the "*Act*")

and
FortisBC Energy Inc. and
FortisBC Energy (Vancouver Island) Inc.
(the "FortisBC Energy Utilities")

ENERGY EFFICIENCY AND CONSERVATION PROGRAM

NATURAL GAS VEHICLE INCENTIVES

Final Submissions of the FortisBC Energy Utilities

May 12, 2011

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PART ONE: INTRODUCTION AND OVERVIEW

A. INTRODUCTION

1. The FortisBC Energy Utilities (the "FEU" or the "Companies") have engaged in significant Energy Efficiency and Conservation ("EEC") initiatives since 2009, following the Commission's acceptance pursuant to section 44.2 of the *Utilities Commission Act* ("UCA") of expenditure schedules for expanded EEC funding in the 2008 FEVI and FEI EEC Application ("EEC Application"). The Commission accepted an expenditure schedule for further funding, including for a new Innovative Technologies Program Area, as part of the Negotiated Settlement Agreement ("NSA") in the FEI and FEVI 2010-2011 Revenue Requirements Applications ("RRA").[1] The FEU initiated EEC program activity related to Natural Gas Vehicles ("NGV") following the Commission's order approving the 2010-2011 RRA, in response to market developments. The Companies have committed significant funding to the NGV program to encourage market transformation, and have begun to see results. Planned funding is on hold pending the resolution of this process, and it very important to the objective of market transformation that the program be put back on track.[2]

2. Based on the Commission's comments in the NGV Application Interim (Waste Management) Decision ("NGV Decision"), the three questions set out in Letter L-30-11, and drawing inferences from the Commission's IRs, the FEU understand the Commission's issue to be specific to NGVs, and not with respect to how the EEC framework operates generally. In particular, the Commission's letter expresses the view that NGV was "an initiative that was specifically excluded in prior Decisions and Orders (G-36-09, G-140-09 and G-141-09)". The root of the issue in this proceeding is that the FEU did not consider NGVs to be "an initiative that was specifically excluded in prior Decisions and Orders (G-36-09, G-140-09 and G-141-09)"; rather, the FEU considered that these new activities fell within the scope of the Innovative Technologies Program Area that had been approved in the 2010-2011 RRA. The FEU

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1 In November 2009, in the orders approving the 2010-2011 RRA Negotiated Settlement Agreements for each of the Companies, FEI received approval for the Innovative Technologies Program Area, based on a budget of $2.334 million in 2010 and $4.669 million for 2011, for a total budget of $7.003 million. FEVI's budget was $478,000 in 2010 and $958,000 for 2011, for a total budget of $1.435 million.

2 FEI has committed a total of $5.587 million to date. These incentives were committed during 2010. The future commitments that are on hold are $3.780 million. BCUC 1.7.1 and 1.7.1.1.

considered the addition of an NGV program to the Innovative Technologies Program Area to be no different from the number of new programs that the FEU have introduced within most of the approved Program Areas with the objective of optimizing the EEC portfolio as a whole. The NGV program activity met the objectives of the Innovative Technologies Program Area as a whole. The Companies would never have spent EEC funding on NGV initiatives had they realized there was any residual doubt regarding the scope of the Innovative Technologies Program Area. It is in the Companies' best interest to have unequivocal prior public interest determinations covering all EEC activities. The magnitude of EEC expenditures is too significant for the Companies to defer the issue of whether certain EEC activities are in the public interest until a future revenue requirement proceeding, in which the FEU are applying for rates that include forecast amortization expense for past expenditures. As such, the present uncertainty regarding NGV expenditures has necessitated the current freeze on the initiatives.[3] At this time, the Companies continue to engage in other non-NGV related programs developed since the EEC Application on the understanding that the Commission's concern relates to the NGV program alone. However, only express confirmation by the Commission in this process of the EEC framework generally can restore the necessary certainty for the Companies to pursue these non-NGV programs going forward.

3. The benefits of including NGV funding within the approved Innovative Technologies Program Area are well-established, and the rationale for stakeholders supporting those initiatives is clear. The NGV initiatives pursued to date are among the strongest initiatives in the overall EEC portfolio when assessed according to the Commission-approved Total Resource Cost ("TRC") test,[4] and high-to-low carbon fuel switching has environmental and other benefits. NGV load has a favourable delivery rate impact for existing customers. The FEU respectfully submit the NGV-related expenditures are in the public interest, and it makes sense for them to be included within the Innovative Technologies Program Area.[5] Stakeholders, including government, have confirmed their support for the NGV program in comment letters filed in this process.[6] If the Commission concludes that these expenditures are not currently covered by the existing approvals, a new determination ensuring that result is warranted.

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[3] BCUC 1.1.1, 1.7.1.

[4] Exhibit A2-1 p.182. Please refer to Table 10-2 or Table 10-10 of the 2010 EEC Report which shows the TRC for NGV programs (TRC 1.4) and the Innovative Technologies portfolio as a whole including the Commercial NGV Demonstration program for 2010.

[5] Exhibit A2-1 p. 213. Including the NGV initiatives as part of the Innovative Technologies Program Area is important because of the significant contribution the program makes to ensuring that the TRC for the Innovative Technologies Program Area is greater than 1.0, which is a requirement of the NSA.

[6] Exhibit A2-1 Appendix F (CEC, City of Vancouver, BCAOMA, Fraser Basin Council and BCSEA)

Acceptance of these expenditures will bring lasting benefits, achieve the intended effect of the NSA, be consistent with the desire of stakeholders, and resolve the uncertainty regarding the future of NGV-related funding.

B. OVERVIEW

4. The remainder of this Submission is organized as follows:

- Part Two addresses the regulatory framework governing EEC expenditures generally, and how the NGV-related programs fit within it;
- Part Three summarizes the evidence as to why NGV-related expenditures are in the public interest;
- Part Four provides specific answers to the questions posed by the Commission in Letter L-30-11; and
- Part Five is a conclusion, and includes the specific determinations sought.

PART TWO: THE EEC FRAMEWORK AND HOW NGV-RELATED ACTIVITY FITS WITHIN IT

A. INTRODUCTION

5. The three questions in Letter L-30-11 are generally directed at the effect of prior Commission orders in establishing parameters for EEC spending, the proper process to be followed in allocating previously accepted EEC funding to new initiatives, and how the current status of the Commission's orders affects the recoverability of NGV-related EEC funding. In this Part, the FEU addresses:

- The EEC framework approved in the EEC Decision;
- How NGV-related activity fits within it; and
- The implications of the issue regarding the scope of the approved Innovative Technologies Program Area for cost recovery of NGV-related EEC funds incurred to date.

The FEU submit that under the approved EEC framework the FEU retained the ability to develop NGV-related programs within the Innovative Technology Program Area, and to allocate Commission-accepted funding to the programs.

B. THE COMMISSION-APPROVED EEC FRAMEWORK

6. The FEU's position on NGV programs is rooted in the EEC framework approved in the EEC Decision, which is discussed below. The FEU submit that, in introducing NGV-related initiatives after the RRA, they were exercising a discretion contemplated in the EEC Application and EEC Decision to introduce new programs *within* the approved Innovative Technologies Program Area in order to optimize the portfolio. This same approach has been used in program development in several Program Areas to date.

(a) The 2008 EEC Decision Framework

7. The aspects of the Commission-approved framework that are relevant for the purposes of this process are depicted in the diagram below.[7]

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[7] BCUC 1.1.1.

Annual Funding Envelope

2010: Expenditure Schedule Accepted: $31.0 million (includes FEI+FEVI)
2011: Expenditure Schedule Accepted: $35.3 million (includes FEI+FEVI)

Program Areas

Scope of Expenditure Schedule Approval Defined by Expressly Approved Program Areas

Residential	Commercial	High Carbon Fuel Switching	Conservation for Affordable Housing	Innovative Technologies	Joint Initiatives	Industrial
(G-36-09, G-140-09, G-141-09)	(G-36-09, 140-09, G-141-09)	(G-36-09, G-140-09)	(G-140-09, G-141-09)	(G-140-09, G-141-09)	(G-36-09, G-140-09, G-141-09)	(G-36-09, G-141-09)

Programs or Initiatives

The FEU has flexibility to develop programs or initiatives within approved Program Areas and reports in the EEC Annual Report and EEC Stakeholder Committee meetings

Residential	Commercial	High Carbon Fuel Switching	Conservation for Affordable Housing	Innovative Technologies	Joint Initiatives	Industrial
ENERGY STAR® Heating System Upgrade	Spray N'Save 2010 Program*	Switch 'N' Shrink	REnEW*	Solar Water Heating PSECA Program	LiveSmart BC	Energy Audit Funding Agreement*
Furnace Service "TLC"*	Efficient Boiler Program		Energy Savings Kit*	Commercial NGV Demonstration Program*	Washer Rebates*	Heat Exchanger Program*
Domestic Hot Water Heaters	Light Commercial ENERGY STAR® Boiler Program		Ministry of Energy Low Income Partnership Grant	Solar Air Heating PSECA Program	City of Vancouver Weatherization*	
EnerChoice Fireplace	Efficient Commercial Water Heater Program			SolarBC Schools Incentive		
	Energy Assessment Program					
	PSECA Initiative*					
	Fireplace Timers Pilot*					
	Radiant Tube Heaters Pilot*					
	Spray N'Save Program*					
	Commercial Custom Design Program*					

*Indicates the program was added after the NSA (G-140-09, G-141-09)
This table does not show the Conversation Education and Outreach Program Area
Programs "in development" are not included in list of programs and initiatives

8. The key elements of the existing EEC framework, as reflected in the above diagram, are:

(a) Only the Commission has the ability to accept EEC expenditures pursuant to section 44.2. An EEC expenditure schedule accepted under section 44.2 is defined as

- a total funding envelope for EEC activity,

- comprised of Program Areas (e.g. Residential, Commercial and Innovative Technologies) that have been expressly accepted by the Commission.

(b) While the amount of the expenditure schedule reflects the sum of the Companies' budgets for the individual approved Program Areas, the FEU retain the flexibility to re-allocate funding within the overall portfolio with the objective of improving the benefits achieved by the overall EEC portfolio.

(c) While the budget for an accepted Program Area may reflect the sum of the Companies' budgets for individual programs or initiatives that are included within an approved Program Area, the FEU retain the flexibility to add, modify or discontinue programs within a Program Area and to re-allocate funding with the objective of improving the benefits of the overall EEC portfolio.

(d) The Company's engagement with stakeholders, and the EEC Annual Report must include reporting on the new programs or initiatives added and how the envelope of funding has been re-allocated among accepted Program Areas. For clarity, the stakeholder engagement is a consultation exercise, not an approval process. The EEC Annual Report is compliance reporting. Neither the mere consent of the EEC stakeholder group, nor the inclusion of information in a compliance report to the Commission, can alter the overall scope of an accepted expenditure schedule.

Below, the FEU elaborate on the scope of an expenditure schedule and the role of the stakeholder consultation and compliance reporting, as these matters are specifically impugned by the three questions posed in Letter L-30-11.

<u>Scope of an Expenditure Schedule</u>

9. The FEU submit that the outcome of the EEC Decision was that an EEC expenditure schedule accepted under section 44.2 is defined as a total funding envelope for EEC activity, comprised of Program Areas that have been expressly accepted by the Commission. This submission is based on the Companies' position in the 2008 EEC Application, and the resulting EEC Decision.

10. In the EEC Application, the Companies requested that the Commission approve the overall expenditure level, rather than approving the funding by program area, or by individual program initiative. The FEU explained this request as follows:[8]

> …that it is most efficient for the Commission to approve the overall expenditure level, by utility, for the Funding Period, rather than approving the funding by program area, or by individual program initiative. This approach will allow the Companies' to respond quickly to changes within initiatives and to new opportunities that might arise. For example, if a particular initiative within the commercial energy efficiency program area has a higher than expected number of participants, and a strong cost-benefit ratio, the Companies would like to have the ability to shift funds from another, underutilized program area to that commercial energy efficiency initiative, without coming back to the Commission for approval to do so. Not only will this allow the Companies' to respond quickly to opportunities, it will also reduce the Companies' administrative burden related to EEC activity, and both the speed of response and reduced administrative burden will increase the value to customers of the Companies' EEC activity. [Emphasis Added]

11. The Companies' EEC Application submission discussed FEU adding programs and reporting in consultation with stakeholders. The Companies' submission stated in part, in discussing reporting mechanisms:

> Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs. [Emphasis added.][9]

12. The EEC Decision expressly contemplated re-allocation of funding within the funding envelope: "Commission Panel directs that the annual EEC Report include the following…any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be."[10] It follows from this funding flexibility that the scope of an accepted EEC expenditure schedule is defined in relation to the total amount of the portfolio.

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8 Exhibit A2-2 EEC Application, at pages 50 and 51.

9 Exhibit A2-3 EEC Decision p. 41 .

10 Exhibit A2-3 EEC Decision, p.42.

13. The EEC Decision, at page 41, summarized what the FEU had proposed regarding accountability mechanisms, and the reference to the FEU adding programs has been underlined for emphasis:

> In this Application the Companies have recognized the need for accountability for the funds approved for EEC programs. First, any funds not spent will not be charged to the regulatory asset deferral account. Second, the Companies intend to monitor the portfolio TRC on a monthly basis, and have proposed to file an Annual EEC Report with the Commission by the end of the first quarter every year. The Report will detail program activity, expenditures, and cost-benefit results for the previous year, as well as describe program activity and provide forecasts for the upcoming year. Third, in the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing a broad cross section of stakeholders identified in the Application. Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs. [Emphasis added]

The Commission noted in the EEC Decision[11] that interveners supported this approach:

> BCSEA-BCSC states that they: ". . . support this approach, noting that the proposed accountability mechanisms are designed to be more effective and efficient than having on-going Commission involvement in decision-making within the portfolio during the Funding Period" and "BCSEA-SCBC acknowledge and support the additional accountability mechanisms proposed by Terasen in [Terasen Argument] paragraph 112." (BCSEA-SCBC Argument, pp. 5, 20) [Emphasis added.]

The Commission then accepted these accountability mechanisms stating:

> The Commission Panel accepts Terasen's accountability undertakings, and considers that, while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted, TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.[12]

14. The FEU respectfully submit that it was reasonable for the Companies to conclude based on these approvals that they had been given the flexibility to develop and fund

[11] Exhibit A2-2 EEC Decision, p.41.

[12] Exhibit A2-2 EEC Decision, p.42.

new programs within the accepted Program Areas, with the goal of maximizing the benefits achieved from the Program Area funding.

15. The corollary was that Program Areas under the approved framework must be defined by reference to the objectives they are achieving, or the customers they serve, and not as the sum of the specific initiatives enumerated in the section 44.2 application. In all Program Areas, programs that are added to the Program Area should support the general area of activity, be within Program Area scope, and support goals for that Program Area.[13] A process that would contemplate the Commission managing the EEC portfolio at the level of requiring approvals for individual programs that advanced the goals of existing Program Areas undermines the objective of administrative and regulatory efficiency. Based on that understanding, the FEU have added a variety of new programs within existing Program Areas.

Stakeholder Consultation and Compliance Reporting

16. The Commission's Letter L-30-11 refers to the FEU "chang[ing] the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program – 2009 Report".[14] For clarity, the FEU's position is that neither the mere consent of the EEC stakeholder group, nor the inclusion of information in a compliance report to the Commission, can alter the scope of an accepted expenditure schedule. The FEU's engagement with the EEC stakeholder group is a consultation exercise, and a means of ensuring that the stakeholders remain apprised of, and have an opportunity for input into, the FEU's EEC activities.[15] The Commission's jurisdiction to accept or extend the scope of an expenditure schedule under section 44.2 has not been (nor could it be) delegated to the stakeholder group. Compliance reporting is just that – reporting – and ensures transparency *vis a vis* the Commission.[16] If the NGV program is covered by an expenditure schedule – and the FEU submits that it is – it is by virtue of the inclusion of the Innovative Technologies Program Area in the approved NSA. This is discussed in section (d) below.

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[13] CEC 1.1.2.

[14] There are also Commission IRs, see for instance BCUC 1.3.1 and 1.3.2, that appear to misinterpret the FEU's evidence regarding these mechanisms.

[15] BCUC 1.3.1, 1.3.2, 1.3.3, 1.3.3.1, and CEC 1.1.4. The relevant evidence from the EEC Application is quoted in the response to BCUC 1.4.1. For instance, EEC Application BCUC 2.17.1 stated in part: "It is the Companies' intent to engage in a consultative process with stakeholders, rather than one in which stakeholders feel the need to direct the Companies one way or another." The relevant passages from the EEC Decision are set out in BCUC 1.4.3.

[16] BCUC 1.5.1-1.5.5. A representative of Commission Staff has been in attendance at the stakeholder meetings as well.

Resolving Present Uncertainty Regarding the EEC Framework and Other Program Areas

17. The FEU have acted in good faith throughout, and have sought to operate within what it understood the EEC framework to be. All decisions to add new EEC programs within established Program Areas have been transparent and supported by stakeholders. There seems to be broad agreement among stakeholders who have commented thus far regarding the EEC framework generally. If the FEU's actions with regard to the addition of new programs (including but not limited to the NGV program) have not met the Commission's intent, the Companies respectfully look to the Commission to provide the necessary clarification of the EEC framework generally in this process. The Company explained the difficulties with the present uncertainty regarding the EEC framework in the following terms:

> A change in how program development occurs within approved Program Areas so as to require individual approvals for each and every new program or change in programs would result in the administrative burden that the EEC framework was seeking to avoid. Also, the additional financial risk to the FEU that this would represent in respect of expenditures incurred to date, would necessarily cause a disruption in EEC activities pending such approvals, given that so many of the current programs have been introduced on the understanding that this was permissible. It is thus of critical importance to the FEU and customers to have the uncertainty as to the scope of the expenditure schedule approval determined in this process.[17]

The FEU submit that past program additions within accepted Program Areas should be endorsed in this process, and the EEC framework described in this Part should be confirmed as the approach going forward. Under the framework described in these Submissions, the FEU are accountable for how they spend EEC funding. Retaining flexibility at an operational level has worked well, as is evident from the broad consensus among stakeholders participating in the consultation processes as to the framework and direction being pursued by the FEU.[18]

(b) How NGV Program Fits Within Approved EEC Framework

18. The NGV-related activities are a discreet EEC program that shares the same fundamental objectives and characteristics as the other programs within the Innovative Technologies Program Area. The differences in the case of NGV were:

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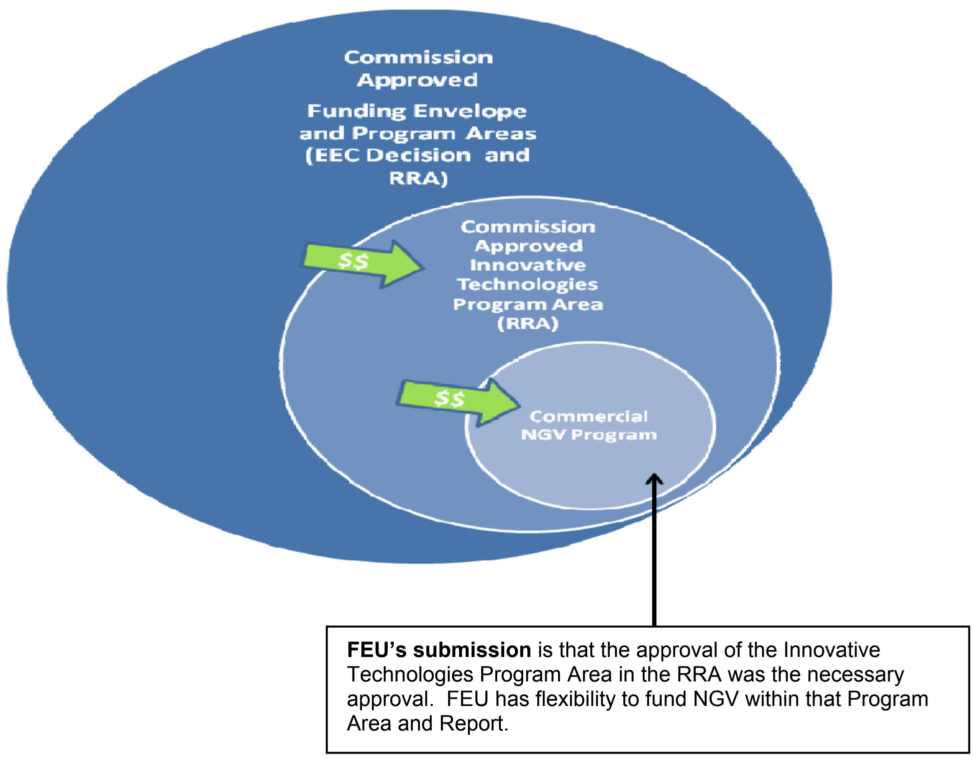
[17] BCUC 1.1.1.

[18] Exhibit A2-1 Appendix F.

- the NSA contemplated FEI withdrawing (in the Commission's words) "its other requests related to NGV";[19] and
- in the RRA evidence, the programs identified in the discussion of the Innovative Technologies Program Area did not include NGVs.

The FEU submit that these facts should not affect the status of the NGV program. NGV-related programs were introduced by the FEU within the *existing Commission-approved scope* of the Innovative Technologies Program Area and be treated as part of the existing expenditure schedule.

19. The FEU's submission as to how the NGV program fits within the overall framework approved in the EEC Decision is depicted in the diagram below:



This puts the new NGV program on the same footing as three solar-energy related programs that were explicitly identified in the RRA evidence as being included in the Innovative Technologies Program Area (see the EEC framework table earlier in this Submission).

20. The Commission's explanation in the NGV Decision for why it considered that the Companies were at risk focused on the rate schedules that the FEU had requested (and

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[19] Exhibit A2-10 Waste Management Decision, Appendix A, p.5, and Exhibit A2-1 page 213-215.

subsequently withdrew) in the RRA, rather than on the Companies' EEC request in that application:

> "The Commission Panel is not presently persuaded that Terasen has Commission approval for the incentive grant to Waste Management that is described under Vehicle Reimbursement in the WM Agreement. Directive 2 of Order G-36-09 explicitly rejected expenditures for Natural Gas Vehicles. The Negotiated Settlement approved by Order G-141-09 approved Rate Schedule 26 – NGV Transportation Service and marketing costs in support of NGV. Terasen withdrew its other requests related to NGV. Rate Schedules 6 and 26 provide for NGV incentive grants, but it seems unlikely that Waste Management will use these Rate Schedules. Therefore, the Commission Panel believes that Terasen is at risk of not being able to recover incentive payments to Waste Management in its rates."[20]

21. The requests in the RRA for EEC funding and NGV fueling service rate schedules were distinct requests, and were addressed in separate sections of the NSA.[21] As the FEU maintained in the NGV Application, NGV fueling service offerings and NGV-related EEC are distinct issues. The value of EEC expenditures is dependent neither on the approval of fueling service rate schedules, nor on fleets deciding to take CNG or LNG service from the Companies. The Commission accepted that position in the context of the NGV Decision, excluding discussion of EEC from the scope of that proceeding.[22] The FEU respectfully submit that the withdrawal of their request for CNG/LNG fuelling service rate schedules, per the NSA, was on a "without prejudice" basis as part of a comprehensive settlement, and should not have any bearing on the present issue. Rather, the focus should be on whether the approved Innovative Technologies Program Area was sufficiently broad to cover NGV-related programs.

22. In determining the intended scope of the Innovative Technologies Program Area agreed to in the NSA it is necessary to consider the overall context in which the parties to the NSA undertook their negotiations. That context includes the EEC Application. For instance:

- First, the evidence in the EEC Application was that the "Innovative Technologies, NGV and Measurement" (which was presented as a single Program Area)[23] was and is intended to support the deployment of forward-looking low carbon technologies, and technologies that are market ready and commercially

[20] Exhibit A2-10 NGV (Waste Management) Decision, Appendix A, p.5, and Exhibit A2-1 page 213-215.

[21] Exhibit A2-1 2010 EEC Report page 213-215.

[22] Exhibit A2-10 Waste Management Decision Appendix A p.5.

[23] This is evident in the way in which the Program Area was described in the Exhibit A2-2 (EEC Application): BCUC 1.2.1. It is also evident in the Exhibit A2-3 EEC Decision on p.26 where it discussed the Program Area.

available, but that have little or no market penetration in the BC marketplace.[24] NGV programs were an aspect of that Program Area. The evidence in this regard included:

> "This Section of the Application provides an overview of potential areas of opportunity for innovative technology investment that the Companies intend to pursue if the Application is approved. The information is divided into energy efficiency and fuel substitution activities, and by sector (Residential and Commercial). It should be noted that the initiatives listed in this Section do not include all the innovative technologies that the Companies may pursue, but rather provide an overview of the types of initiatives the Terasen Utilities intend to pursue, all having the same underlying characteristics:
>
> 1) Each promotes the efficient use of natural gas through sustainable design
>
> 2) None are currently a mainstream technology
>
> 3) Each offers the potential for at least a 10% GHG benefit.
>
> For all sectors, programs for fuel-substitution include plans that displace less efficient and dirtier fuels with natural gas or add cleaner renewable fuels to natural gas for further efficiency and GHG benefits."[25] [Emphasis added.]

And:

> "The initiatives listed in Section 6.9 of the Application do not include all the innovative technologies that the Companies may support, but rather provide an overview of the types of initiatives the Terasen Utilities are aiming to promote that all have the same underlying characteristics; 1) they promote the efficient use of natural gas through sustainable design 2) are not currently mainstream technology 3) offer at a minimum a GHG benefit."[26] [Emphasis added.]

- Second, as discussed above, the Companies' evidence in the EEC Application contemplated the Companies having flexibility at the program level to discontinue, modify and add new programs within an approved Program Area. The EEC Decision echoed the desire of the Companies and intervenors to

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[24] CEC 1.1.1.

[25] Exhibit A2-2 EEC Application p.69 (quoted in CEC 1.1.3).

[26] Exhibit A2-2 EEC Application, BCUC 1.36.2 (quoted in CEC 1.1.3).

ensure that the Companies had the necessary flexibility to manage the program efficiently, without the involvement of the Commission during the funding period.

- Third, in the EEC Decision, while the Commission rejected funding for the "Innovative Technology, NGV and Measurement" Program Area based on "insufficient evidence" it was receptive to the Company coming forward again in the future.[27]

23. When the FEU brought forward its request in the 2010-2011 RRA for funding for the "Innovative Technologies" Program Area the programs contemplated within that Program Area continued support the deployment of forward-looking, low carbon technologies that are market ready and commercially available, but that have little or no market penetration in the BC marketplace.[28] The FEU were, in effect, re-initiating the request that had been denied in the 2008 EEC Decision.

24. In hindsight, there are two elements of the FEU's request in the 2010-2011 RRA that have "muddied the waters" regarding the scope of the Program Area that was expressly approved in the NSA. First, the name of the Program Area changed, without any intention to make a substantive change to the scope of the Program Area.[29] Second, the FEU's description in the RRA filing of the Innovative Technologies Program Area focussed on a specific list of initiatives, rather than emphasizing the broader objectives of the Program Area as had been done to a greater extent in the EEC Application. The list set out in the RRA did not expressly include NGV. It was never the intent of the FEU to define Program Areas as the sum of their constituent parts listed in the RRA; the EEC Application and the EEC Decision had suggested otherwise. However, in retrospect, the description provided by the FEU in the RRA could reasonably be understood to have implied that approach.[30]

25. While the FEU take full responsibility for the way the evidence was presented in the RRA, there are several reasons why the FEU is confident that other parties that negotiated the NSA shared FEU's view regarding how the EEC framework was intended to operate:

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[27] Exhibit A2-3 EEC Decision, p.26.

[28] BCUC 1.1.1: "In developing those NGV-related programs within the Innovative Technologies Program Area, the Companies had in mind the broader definition of the program area used in the 2008 EEC Application which definition was more geared to the purpose being served by the programs, and not a specific list of programs."

[29] BCUC 1.2.1.

[30] BCUC 1.6.1.1, 1.6.1, 1.6.2, 1.6.3, 1.1.1.

(a) First, another key participant in the NSA has confirmed that this was their intention. In a March 22, 2011 letter[31] to FEI, the Commercial Energy Consumers Association of BC ("CEC") stated:

> …The CEC is precluded (as a consequence of confidentiality provisions) from discussing the specific content of discussion in a Negotiated Settlement Process ("NSP") but may disclose its own positions at any time. The CEC believes that its sign off with respect to the RRA NSA carried the weight of its support for FEI providing funding for its NGV initiatives. Specifically the CEC believes that item 14 of the NSA supports the fuelling and transportation services to be provided and that item 11 of the NSA supports the funding envelope for the Innovative technologies for 2010-2011.

(b) Second, the requirement in the NSA that "Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more" necessarily implied that the FEU would be introducing new programs, as the combined TRC of the programs expressly identified in the RRA was well below 1.0.[32]

(c) Third, NGV-related programs were discussed with stakeholders after the NSA and prior to implementation,[33] without any objection by representatives of stakeholders who had been present in the NSP. The following excerpt from the 2009 EEC Annual Report, filed on March 31, 2010 on Page 115 reflected the approach taken in the consultation: "TGI and TGVI restructured the existing portfolio list of Innovative Technologies to include Solar Thermal Hot Water, <u>NGV for Commercial Vehicles</u>, Hydronic and Combination Space Heating Systems, Residential GSHP and Commercial and Industrial GSHP Systems. <u>TGI and TGVI will treat NGV fuel switching from diesel as part of our normal course of EEC activities</u>." [Emphasis Added] Stakeholders involved in the consultation have confirmed that the FEU were transparent with respect to NGVs.[34]

(d) Fourth, it made sense that the Innovative Technology Program Area would be approached the same way as other Program Areas. The FEU were adding programs in other Program Areas consistent with the objectives of each Program Area. The NGV-related EEC expenditures advance the objective of Innovative Technologies generally: supporting the deployment of forward-looking, low carbon

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[31] Exhibit A2-1 Appendix F for a copy of the letter from CEC and others

[32] BCUC 1.1.1.

[33] Consultation on NGV took place on March 11, 2010, with a follow up request for input: Exhibit A2-10, 2010 Report, page 216-218. NGV was discussed in the LTRP filed in July 2010, with no objections from stakeholders: Exhibit A2-10 2010 EEC Report page 218-219. The first funding took place in September 2010: CEC 1.1.4.

[34] CEC 1.1.4, CEC 1.1.5, A2-1 2010 EEC Report Appendix F.

technologies that are market ready and commercially available, but that have little or no market penetration in the BC marketplace.[35]

26. In summary, the overall context supports a finding that NGV programs could be added within the Innovative Technologies Program Area.

C. IMPLICATIONS FOR COST RECOVERY

27. The second and third questions in Commission Letter L-30-11 give rise to issues relating to the legal implications of a section 44.2 order, which is the section pursuant to which the Commission has accepted the EEC expenditures. More specifically, they touch on the implications for FEU of a Commission determination that FEU (a) already have or (b) do not yet have, section 44.2 approval for NGV program expenditures. The Commission's determination of this point may have implications for the evidence supporting cost recovery in future revenue requirements applications, but does not determine the recoverability of the expenditures.

28. Before addressing cost recovery, the FEU feel it necessary given the tenor of some of the Commission IRs[36] to make the point that there is no provision in the UCA that prohibits a public utility from engaging in EEC activities without prior approval from the Commission. The funding requests included in the 2008 EEC Application and the 2010-2011 RRA were made pursuant to section 44.2 of the UCA. The section also contemplates that a request for acceptance can be made in respect of expenditures already incurred. Unlike a CPCN required under section 45 for plant extensions, section 44.2 approvals are optional; the section provides that a public utility "may" file an expenditure schedule. The acceptance of an expenditure schedule under 44.2 is thus not an authorization to undertake activity, rather it represents a determination that the expenditures in question are in the public interest. In the event that the Commission determines that the NGV program is outside of the expenditure schedule, this is not the same as the FEU having breached a Commission order.

29. In terms of cost recovery, the UCA requires that rates be set to recover the forecast costs for the test period that the Commission reasonably considers will be prudently incurred. A prior public interest approval of an expenditure schedule is evidence (to be cited by the applicant utility in the context of rate setting) that it was or will be prudent for the utility to

[35] CEC 1.1.1, CEC 1.1.3.

[36] A number of Commission Information Requests relate to whether or not FEI had "authority" or "approval" to engage in NGV-related EEC activities. For the reasons described in this paragraph, these terms are actually out of step with the legal nature of the section 44.2 approval, which is an optional public interest determination.

engage in the activities contemplated in an accepted schedule that have cost implications in the test period. However, a section 44.2 public interest determination is also not a precondition of future recovery of the accepted costs in rates. The fact that a public utility has not applied for, or has not received approval for, an EEC expenditure schedule prior to applying for rates that account for those forecast EEC expenditures does not make it imprudent to undertake the forecasted EEC activities.[37] The prudence of EEC expenditures must be determined with reference to the costs and benefits associated with the activities.[38] There is obvious overlap between a public interest determination and the prudence test; however, the FEU submit that the Commission would err by disallowing NGV-related expenditures on the basis of a finding that they fell outside a Commission-accepted Program Area.

30. That said, the matters raised in this proceeding are of great importance to the FEU because the Companies had intended only to spend EEC funding on programs that are backed by a public interest approval, as a means of forestalling any suggestion in future revenue requirements proceedings (when forecast amortization expense for past EEC expenditures is sought to be included in rates) that the types of expenditures undertaken were imprudent. The FEU are confident that it is prudent for the Companies to be pursuing NGV-related EEC expenditures for the reasons described in Part Three. These expenditures, if otherwise prudently incurred, should therefore be recoverable in future revenue requirements proceedings regardless of whether they are covered by a section 44.2 approval. Nevertheless, the magnitude of EEC investment is too great for the FEU to proceed with in the absence of a prior section 44.2 acceptance.[39] The FEU's decision to temporarily cease providing EEC funding for NGVs pending the determination of this proceeding is a reflection of this.[40] For similar reasons, the Companies also require clarity regarding the other non-NGV programs that they have introduced in consultation with stakeholders (see EEC framework table above).

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[37] For capital expenditures below the CPCN threshold, and for O&M generally, it is less common to have section 44.2 approval than to proceed to a revenue requirements proceeding without one. But there will be circumstances, and EEC is one of them expressly contemplated in the UCA, where obtaining the protection of an expenditure schedule only makes sense.

[38] Evidence that supports the inclusion of budgeted EEC expenditures in rates will include the Conservation Potential Review ("CPR"), which indicates the level of EEC activity that can be achieved cost-effectively. The Total Resource Cost ("TRC") test, which the Commission has endorsed as a test for evaluating EEC expenditures, is also evidence.

[39] BCUC 1.4.3.

[40] BCUC 1.7.2

D. SUMMARY

31. While the thrust of this proceeding is directed at determining the scope of the existing EEC expenditure schedules, and the implications for cost recovery of expenditures incurred to date, the FEU submit that an equally important outcome of this proceeding will be greater clarity regarding the EEC framework. The fact that the current proceeding is even necessary, speaks to the need for this additional clarity, as the FEU have at all times acted with the utmost good faith.[41] All stakeholders who have commented in this proceeding thus far accept that the FEU have acted in a transparent manner, more so than examining the FEU's good faith conduct to date.[42]

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[41] BCUC 4.2.1 and 5.3

[42] Exhibit A2-1 Appendix F and Section 10.2.3.3.2.1 pages 216-218.

PART THREE: NGV INCENTIVES ARE IN THE PUBLIC INTEREST

A. INTRODUCTION

32. The Commission, in Letter L-30-11, acknowledged that the replacement of diesel/gasoline fuelled commercial vehicles with NGVs "appears to align with the objectives of the *Clean Energy Act,* other environmentally focussed legislation and policies, and potential rate payer interests". These considerations all play a part in the public interest assessment, and demonstrate that cost-effective EEC initiatives aimed at NGVs are an appropriate component of an overall EEC portfolio. The FEU submit that the substantive merits of NGV-related programs should be the focus of this proceeding.

B. FACTORS CONSIDERED IN PUBLIC INTEREST ASSESSMENT

33. Section 44.2 involves a public interest assessment. Section 44.2(3) provides:

> (3) After reviewing an expenditures schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6) must
>
> (a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or
>
> (b) reject the schedule.

34. Section 44.2(5) sets out factors that the Commission must consider in making the public interest assessment. It provides in part:

> (5) In considering whether to accept an expenditure schedule filed by a public utility other than the authority, the commission must consider
>
> (a) the applicable of British Columbia's energy objectives,
>
> (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,
>
> …
>
> (d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and
>
> (e) the interests of persons in British Columbia who receive or may receive service from the public utility.

35. "British Columbia's energy objectives" are defined in s. 2 of the *Clean Energy Act* ("CEA") and apply to FEI as a public utility. The applicability of "British Columbia's energy objectives" to applications for approval of expenditure schedules under section 44.2 of the UCA, among other sections, speaks to Government's intention to use cost-effective investments by public utilities to help achieve targeted reductions of GHG emissions, greater energy efficiency, and other public policy goals.

C. NGV-RELATED EEC IS IN THE PUBLIC INTEREST

36. Each of paragraphs (a), (b), (d) and (e) of section 44.2(5) is relevant in the context of FEI's investment in NGV-related EEC programs. This section addresses each of those factors.

37. Item (a) requires consideration of "British Columbia's energy objectives". "British Columbia's energy objectives" support the use of NGV incentives to promote NGVs in place of vehicles operated by traditional fuels in two important ways:[43]

- First, objective (d) is "to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources". BC-developed engine technology can be used to permit the efficient use of natural gas in substitution for higher emitting diesel fuel.
- Second, objective (g) is "to reduce greenhouse gas emissions …" and objective (h) is "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia." Facilitating fleet conversion from diesel to natural gas will reduce GHGs. The NGVs incented in the 2010 Innovative Technologies Program Area are expected to produce between 20 - 30% fewer GHG emissions than their diesel counterparts. At this time, FEI estimates that the vehicles under the 2010 program expenditures represent annual GHG savings of approximately 4,100 tonnes of CO_2e per year, which is the equivalent to taking 800 passenger vehicles off the road.[44]

NGV-related EEC initiatives are not detrimental to any of the other "British Columbia's energy objectives".

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[43] Exhibit A2-2 EEC Application, p. 45.

[44] Exhibit A2-1 2010 EEC Report p.215-216.

38. Item (b) requires the Commission to consider FEI's most recent resource plan. The 2010 Terasen Utilities Long-Term Resource Plan ("LTRP"), reiterated the Companies' concern about declining throughput, attributable in part to declining use per customer rates, which increases upward pressure on delivery rates and also represents a long-term stranding risk for the distribution system assets as a whole. NGVs were discussed in the LTRP because they represent one of the best opportunities to mitigate the adverse delivery rate impact on existing customers flowing from this declining throughput. The addition of cost-effective NGV load on the FEI distribution system favourably affects customer delivery rates in two ways: First, delivery costs are shared over more GJs of natural gas, thus reducing the delivery charge per GJ; and second, adding NGV load is one of a few means available to FEI to combat declining throughput that, left unchecked, will continue to contribute to a higher cost of capital over time.[45] Given the state of the market, NGVs will not see uptake at this point without EEC. The NGV program is vital to market transformation.[46]

39. Item (d) is a reference to the TRC test. The NGV-related EEC initiatives are cost-effective when assessed on a portfolio basis using the TRC test.[47] The NGV programs to date, with a TRC of 1.4, have one of the highest program TRC ratios in the entire EEC portfolio.[48] NGV incentives, because of having a TRC well above 1.0, make a significant contribution to ensuring that the Innovative Technologies portfolio maintains a portfolio TRC greater than 1.0. This is illustrated in table 10-10, reproduced below:[49]

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45 BCUC 1.7.4.

46 BCUC 1.7.3. As described in that response, the amount of funding required to incent a particular fleet owner to adopt NGVs is anticipated to be reduced over time.

47 The Commission discussed the application of a TRC at page 34 of the Exhibit A2-3 EEC Decision: "The Commission Panel also takes note of the DSM Regulation which will apply to Terasen as of June 1, 2009 requiring the Commission to use, in addition to any other test it considers appropriate, the TRC test in determining whether a demand-side measure is cost-effective. While the DSM Regulation is not in effect for the purposes of this EEC Decision, the Commission Panel does consider the TRC test to be appropriate and adequate for the purposes of this Application and accepts it as such." Please refer to Table 10-2 of the 2010 EEC Report which shows the TRC for the Innovative Technologies portfolio as a whole including the Commercial NGV Demonstration program for 2010.

48 2010 EEC Report, Table 2.2, p.7 shows the TRC by Program Area for all Program Areas. NGV on its own has a TRC of 1.4, as specified in Table 10-10 of the 2010 EEC Report.

49 2010 EEC Annual Report, p.215. A further breakdown by project is included in BCUC 1.7.2.

Table 10-10: Innovative Technologies Program Area TRC for 2010

Program	TRC	
	FEI	FEVI
Solar Water Heating PSECA Program	0.2	0.3
Commercial NGV Demonstration Program	1.4	-
Total	1.2	

40. Section 44.2(5)(e) requires the Commission to assess the public interest from the perspective of both existing customers and potential customers of FEI. In addition to benefits to existing non-bypass customers addressed above, EEC funding also benefits the owner of NGVs. The benefits include: operating cost savings due to favourable natural gas costs relative to diesel and gasoline; reduced fuel cost volatility as compared to diesel and gasoline; and reduced GHG emissions.[50] The customer comments in support of the FEU providing incentives for NGVs, which are included with the 2010 EEC Report, underscore the benefits to customers.

41. Stakeholder comments, included in the 2010 EEC Report, support a determination that NGV programs are in the public interest.

42. Section 44.2 provides that the Commission must accept an expenditure schedule if it determines that the expenditures contemplated are in the public interest. If the Commission determines in this process that NGV programs align with the objectives of the *Clean Energy Act,* other environmentally focussed legislation and policies, and potential rate payer interests (which is suggested by the Commission's comments in Letter L-30-11), the FEU submit that the Commission would be required under section 44.2 to accept an expenditure schedule on application by the FEU. The FEU respectfully request that acceptance be extended to NGV programs in this process by defining the scope of the existing expenditure schedule to include NGV programs within the Innovative Technologies Program Area.

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[50] BCUC 1.7.4, 1.7.3.

PART FOUR: RESPONSE TO COMMISSION'S QUESTIONS

43. In specific response to the Commission's three questions:

1) Was it appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program – 2009 Report (filed March 31, 2010)?

- The Companies submit that they proceeded in good faith with NGV initiatives based on the belief that they were included within the scope of the Innovative Technologies Program Area approved in the 2010-2011 RRA NSA.
- The EEC Stakeholder Group is a consultation exercise, and does not have the power to expand the scope of an approved expenditure schedule. The EEC Report is a compliance report only, and the Companies would have had to make a specific application to change the scope of the accepted expenditure schedule.
- The Companies did not legally require the (optional) section 44.2 acceptance of NGV related expenditures to proceed with them, but the Companies would never have proceeded with those initiatives (due to financial risk) had they not believed that they were covered by the Commission's public interest determination.

2) If the scope of the Innovative Technologies program was appropriately changed, does the associated NGV purchase incentive funding become: a) a Commission-approved expenditure; or b) an approved EEC expenditure; or c) an expenditure eligible for cost recovery from rate payers in whole or part?

- The Companies cannot unilaterally, or with the consent of the stakeholder group, or by virtue of filing a compliance report, expand the scope of an expenditure schedule that has been accepted by the Commission. The answer to this question depends on how the "scope" of a Program Area is defined. As stated above, the NGV initiatives were discrete programs aimed at the same objectives as all other programs within the Innovative Technologies Program Area. The FEU believed that they were included within the scope of the accepted expenditure schedule because the scope is defined by reference to the objectives, not a pre-approved list of programs. The only way the "scope" could be considered to have changed is if "scope" is defined solely by reference to the list of programs explicitly referenced when seeking a prior section 44.2 order. This interpretation, if adopted, would have broader implications for the other new EEC programs introduced by the FEU.
- Cost recovery is addressed under issue three.

3) If NGV purchase incentive funding is found to be inappropriately included in the Innovative Technologies program, should incentive payments already made by the Companies be eligible for cost recovery from rate payers in whole or in part?

- The UCA requires that rates be set to recover the forecast costs for the test period that the Commission reasonably considers will be prudently incurred.
- A prior public interest determination in respect of an expenditure schedule is evidence in a rate-setting proceeding that it was prudent for the utility to engage in past activities contemplated in an accepted schedule (and thus assists in being able to recover in rates the forecast amortized cost of those activities occurring during the test period). However, a determination in this proceeding that the approved Innovative Technologies Program Area did not include NGV-related expenditures does not in any way mean that the activities were imprudent; rather, it just means that the FEU have not yet obtained an optional section 44.2 approval.
- For capital expenditures under the CPCN threshold, and for O&M generally, it is less common to have section 44.2 approval than to proceed to a revenue requirements proceeding without one. In the absence of a section 44.2 acceptance, the prudence of EEC expenditures must still be determined in the context of rate setting with reference to the costs and benefits associated with the activities.
- The FEU submit that the NGV-related expenditures to date, which have a relatively high TRC and confer delivery rate reductions (all else equal) and environmental benefits, are in the public interest. When the time comes to determine future rates, the forecasted amortization expense associated with NGV-related EEC expenditures are eligible for recovery as prudent expenditures.

PART FIVE: CONCLUSION AND ORDERS SOUGHT

44. The evidence demonstrates that the FEU have at all times acted in good faith in pursuing NGV-related EEC programs and other new programs within various existing Program Areas. While the focus of this proceeding is on the NGV program, this process has given rise to uncertainty regarding how the scope of an approved Program Area is to be defined, i.e. according to the underlying purpose and objective of the Program Area, or a pre-approved (by the Commission) list of programs. The ramifications of the current uncertainty extends to almost every Program Area, as the FEU have already introduced a number of new non-NGV programs in consultation with stakeholders, and are always seeking new opportunities to improve the portfolio. Further, the recently filed 2012-2013 RRA has sought EEC funding without the expectation of having to obtain specific prior Commission approval for individual programs. The FEU submit that the Commission should use this opportunity to provide greater clarity going forward as to the EEC framework in general, rather than dealing with the same issues in the RRA as well. The FEU submit that the framework as outlined in Part Two of these Submissions makes the most sense for all stakeholders going forward. The FEU respectfully request that the Commission make the following determinations in respect of the EEC framework generally:

(a) that non-NGV past program additions were within the scope of the expenditure schedule;

(b) that the EEC framework described in Part Two of these Submissions accurately reflects the approved EEC-framework; and

(c) that the EEC framework described in Part Two of these Submissions will continue to be the approach going forward.

These determinations will provide a strong basis for the Companies to proceed with EEC funding that is in the interests of all customers and the public generally.

45. The NGV-related expenditures, which were the intended focus of this process, are beneficial and enjoy broad stakeholder support. They support the objectives of Government set out in the *Clean Energy Act*. EEC funding for NGV are integral to market transformation. There are third parties that have spent considerable time and effort in the expectation that the FEU would be making more EEC funding available for NGV, and meeting those expectations by quickly restoring NGV programs is vital to avoid set backs in achieving the goal of market

transformation. In short, the evidence confirms that the NGV-related expenditures to date, and the planned expenditures for 2011, are in the public interest.

46. Section 44.2 contemplates the Commission accepting an expenditure schedule where the expenditures are in the public interest. The FEU respectfully request the following determinations to resolve the present uncertainty regarding NGV programs:

(a) The FEU's NGV programs are in the public interest; and

(b) NGV-related programs were already, or are now, within the scope of the currently approved expenditure schedule as part of the Innovative Technologies Program Area.[51]

47. The FEU appreciate the Commission's willingness to consider this matter on an expedited basis in recognition of the importance of these EEC initiatives for all stakeholders.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated: May 12, 2011

[original signed by Matthew Ghikas]
Matthew Ghikas
Counsel for FortisBC Energy Inc.

[51] Including the NGV initiatives as part of the Innovative Technologies Program Area is important because of the significant contribution the program makes to ensuring that the TRC for the Innovative Technologies Program Area is greater than 1.0, which is a requirement of the NSA.

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June 10, 2011

VIA ELECTRONIC MAIL

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

Attention: Erica M. Hamilton, Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc./FortisBC Energy (Vancouver Island) Inc. - Energy Efficiency and Conservation Natural Gas Vehicle Incentive Review ~ Project No. 3698633

We are counsel to the Commercial Energy Consumers Association of British Columbia (the “CEC”) with respect to the above-noted proceeding

The CEC has received and reviewed the comments filed on June 9, 2011 by Mr. William J. Andrews on behalf of the B.C. Sustainable Energy Association (“BCSEA”) with respect to the Commission’s letter of June 9, 2011. The CEC advises that it supports the contents of the BCSEA’s letter submission.

The CEC commented in its May 20, 2011 submission on the general concept of moving EEC funds among programs and in those submissions supported flexibility for FEI to manage and administer its EEC programs. The risk of inappropriate or imprudent movement of funds between DSM and non-DSM programs is one the Company faces in subsequent prudency reviews. The CEC encourages flexibility and the avoidance of micro management of this topic by the Commission in order to avoid administrative costs and inefficiency. Ultimately, an improper or imprudent movement of funds will be a risk to the shareholder.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,
OWEN BIRD LAW CORPORATION

Christopher P. Weafer
CPW/jlb
cc: CEC
cc: FortisBC
cc: Registered Interveners

BRITISH
COLUMBIA

June 10, 2011 **VIA EMAIL**

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Erica Hamilton, Commission Secretary

Dear Madam:

Re: FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. Natural Gas Vehicle Incentive Review

Pursuant to Commission Order G-103-11, I attach herewith the additional submissions of the Ministry of Energy and Mines (the "Ministry") with respect to the above-captioned proceeding.

Yours truly,

Paul Wieringa
Executive Director

Cc: FortisBC
All Registered Interveners

Ministry of Energy

Electricity and Alternative Energy Division

Mailing Address:
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BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

the *Utilities Commission Act,*

R.S.B.C. 1996, Chapter 473 (the "Act")

and

FortisBC Energy Inc. and

FortisBC Energy (Vancouver Island) Inc.

Energy Efficiency and Conservation Natural Gas Vehicle Incentive Review

ADDITIONAL SUBMISSIONS OF THE MINISTRY OF ENERGY AND MINES

1. These are the additional submissions of Her Majesty the Queen in Right of the Province of British Columbia, as represented by the Ministry of Energy and Mines ("the Ministry") concerning the FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. (together "the FortisBC Energy Utilities" or "FEU") Natural Gas Vehicle (NGV) Incentive Review, in response to order G-103-11.

2. By letter dated June 3, 2011 and order G-103-11, the BC Utilities Commission ("the Commission") has invited submissions to examine the following:

   > *The ability and appropriateness of the utility moving EEC funds among programs that meet the definition of "demand-side measure" in the Utilities Commission Act and programs that do not.*

3. The Ministry submits that the utility can and should move EEC funds among programs which meet the definition of demand-side measure (DSM) in the *Utilities Commission Act*, and those that do not, provided that:
   a. inclusion of the non-DSM program in the EEC portfolio, and
   b. expenditure on the non-DSM program,

   are both in the interests of ratepayers and the public.

4. The value of a portfolio approach and the ability to transfer funds within and between program areas has been discussed at length in this proceeding. The Ministry is of the

view that FEU's portfolio approach to EEC funds will allow the utility to most efficiently allocate funds and adapt to new opportunities as they arise.

5. FEU's NGV program, whether or not it is considered a demand-side measure, has many common characteristics with the other FEU EEC program areas which make it appropriate and desirable for it to be a part of the portfolio within which funds may be transferred. Common characteristics include an incentive structure aimed at influencing customer technology choices, an objective of achieving long term market transformation, the ability to evaluate cost effectiveness using a Total Resource Cost Test[1], and alignment with British Columbia's energy objectives. The NGV program also benefits from the additional accountability that comes from involvement of the EEC Advisory Committee. For these reasons, the Ministry submits that it is in the interests of ratepayers and the public to allow movement of EEC funds between NGV and other program areas.

6. The Ministry already outlined, in its submission of May 20, 1011, its argument that FEU's NGV program is in the interests of ratepayers and the public.

7. The Commission, when setting rates, has the opportunity to determine if expenditure on a program is prudent. It is the view of the Ministry that submissions made during this proceeding have shown that the $5.587 million in committed NGV incentive grants, and the $3.780 million in future 2011 commitments for commercial vehicles are prudent.

ALL OF WHICH IS RESPECTFULLY SUBMITTED,

Dated: June 10, 2011

Paul Wieringa
Executive Director, Alternative Energy
Ministry of Energy and Mines

[1] The 2001 California Standard Practice Manual states that the TRC can be applied to fuel substitution programs as "a measure of the economic efficiency of the total energy supply system". See p.18, http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

William J. Andrews

Barrister & Solicitor

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June 9, 2011

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC, V6Z 2N3
Attn: Ms. Alanna Gillis, Acting Commission Secretary

By Web Posting

Dear Madam:

Re: FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc.
Energy Efficiency and Conservation Program
Natural Gas Vehicle Incentives Review
BCUC Order G-103-11

This is on behalf of the intervenor B.C. Sustainable Energy Association in response to the Commission's June 3, 2011 letter to FEI and FEVI [Exhibit A-6] and Order G-103-11 amending the regulatory timetable to allow parties to provide submissions by June 10, 2011 regarding the following topic:

> 1) The ability and appropriateness of the utility moving EEC funds among programs that meet the definition of "demand-side measure" in the *Utilities Commission Act* and programs that do not.

The wording of the topic, in the context of this proceeding, raises the threshold question of whether the NGV Incentives Program meets the definition of DSM (which has been moved recently from the *Utilities Commission Act* (*UCA*) to the *Clean Energy Act* (*CEA*) This is a question of statutory interpretation of the *CEA* and the *UCA*, in particular the meaning of DSM as it is defined in *CEA* s.1(1) and used in *UCA* s.44.2 (expenditure schedules) and s.44.1 (long-term resource plans).

In brief, BCSEA's view is that the FortisBC Energy Utilities' (FEU's) Natural Gas Vehicles (NGV) Incentives Program does meet the definition of "demand-side measure" (DSM) in the *Clean Energy Act (CEA)*.[1]

CEA s.1(1) defines DSM as follows:

> **"demand-side measure"** means a rate, measure, action or program undertaken
>
> (a) to conserve energy or promote energy efficiency,
>
> (b) to reduce the energy demand a public utility must serve, or

[1] This view is implicit in BCSEA's May 20, 2011 submission that the FEU NGV Incentives program is within the FEU DSM expenditure schedule accepted by the Commission under s.44.2 of the *Utilities Commission Act*.

(c) to shift the use of energy to periods of lower demand,

but does not include

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate, measure, action or program prescribed;

The NGV Incentives Program is not undertaken to reduce the energy demand a public utility must serve or to shift the use of energy to periods of lower demand; so (b) and (c) do not apply. The NGV Incentives Program does not have as its main purpose encouragement of a switch from the use of one kind of energy to another such that the switch would *increase* greenhouse gas emissions in British Columbia; so (d) does not apply. Nor is the Program prescribed; so (e) does not apply. So the question is whether the FEU NGV Incentive Program is a program undertaken (a) "to conserve energy or promote energy efficiency" within the meaning of that phrase properly construed under the *CEA* and the *UCA*.

The NGV Incentives Program *is* undertaken to promote energy efficiency, and BCSEA submits that it therefore meets the definition of DSM. This is so even though the Program has additional objectives.[2] Seven reasons:

First, the definition of DSM does not state 'a program undertaken *exclusively* to conserve energy or promote energy efficiency." Had that been the Legislature's intention, it could have said so.

Second, the statutory regime contemplates that DSM programs may have additional purposes beyond energy conservation and efficiency. An example is the requirement in s.3 of the DSM Regulation, BC Reg., 326/2008, under the *UCA*, that a public utility's DSM plan portfolio is adequate for the purposes of section 44.1 (8) (c) only if it includes DSM aimed at low-income households, rental accommodations, school programs and post-secondary programs.

Third, the definition of DSM expressly excludes fuel switching programs that would *increase* GHG emissions, but does not exclude fuel switching programs (such as the NGV Incentives Program) that would *decrease* GHG emissions. Thus the legislation contemplates that DSM programs can have GHG emissions benefits through fuel switching, which description includes the NGV Incentives Program.

Fourth, the reduction of GHG emissions is one of the enumerated B.C. "energy objectives" listed in *CEA* s.2 which the Commission must consider in reviewing a DSM expenditure schedule under *UCA* s.44.1.[3] Therefore the fact that a program undertaken to promote energy efficiency also has a substantial purpose of reducing GHG emissions *adds* to the program's desirability as a DSM program, and could not reasonably be interpreted as a factor *disqualifying* the program from being a DSM program.

[2] The NGV Incentives Program has objectives including promoting energy efficiency, reducing GHG emissions within B.C., reducing average delivery costs to natural gas customers, reducing conventional air pollution and noise, and promoting B.C. innovative energy technology (i.e., heavy duty NGV engines).

[3] In reviewing a DSM expenditure schedule, the Commission must also consider a public utility's approved long-term resource plan, the review of which also requires consideration of the B.C. energy objectives, including reduction of GHG emissions in B.C.

Fifth, the structure of the statutory regime is such that the Commission's role regarding DSM programs (and rates, measures and actions) arises in the context of the Commission's review of a public utility's long-term resource plan under *UCA* s.44.1 and, at the utility's discretion, a DSM expenditure schedule under *UCA* s.44.2. Both of these functions involve a public interest test and a current and future ratepayers' interest test, supported by factors and requirements set out in the *UCA*, the *CEA* and the DSM Regulation. It is under s.44.1 and s.44.2 that the Commission evaluates the merits of a DSM program, not under the *CEA* s.1(1) definition of DSM. In other words, an inclusive approach to the definition of DSM does no harm. It is not as though a DSM program obtains some automatic regulatory benefit simply by meeting the definition of DSM. In the context of the existing statutory regime, no policy purpose would be achieved by giving the DSM definition a redundant 'gate-keeping' function.

Sixth, UCA s.44.2(1) provides for only three types of expenditure schedule: (a) DSM expenditures, (b) capital expenditures, and (c) energy acquisition expenditures. A program such as the NGV Incentives Program is not likely to be considered a capital expenditure, and it is certainly not an energy acquisition expenditure. An interpretation that made the Program ineligible for inclusion in a DSM expenditure schedule under UCA s.44.2(1)(a) would create a gap in which there would be no obvious way for such a program to be proposed by a public utility and the expenditures accepted (or not) by the Commission under s.44.2. That would thwart the purposes of the *CEA* and the *UCA* and is therefore not a reasonable interpretation of the statutes.

Seventh, because the DSM legal regime puts considerable weight on the benefit-cost attributes of the DSM portfolio as a whole it is important that all putative DSM programs (and rates, measures and actions) be included in the DSM portfolio. As it happens, the NGV Incentives Program has a strongly positive benefit-cost ratio. Therefore exclusion of the Program from the DSM portfolio would artificially reduce the benefit-cost ratio of the portfolio, perhaps to the point where other DSM programs (with relatively low benefit-cost ratios) would have to be eliminated from the portfolio. That outcome would run counter to the express legislative mandate for public utilities to expand their DSM programs.

In conclusion, BCSEA respectfully submits that the Commission should conclude that the FEU NGV Incentive Program is a demand-side measure as the term is defined in *CEA* s.1(1) and used in s.44.2 and s.44.1 of the *UCA*. For the Commission to hold otherwise would fly in the face of the statutory requirements and the B.C. energy objectives.

All the above is respectfully submitted.

Yours truly,

William J. Andrews

Barrister & Solicitor

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May 25, 2011
File No.: 240148.00595/14797

ELECTRONIC FILING

British Columbia Utilities Commission
6th floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Ms. Alanna Gillis,
Acting Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. and Fortis Energy (Vancouver Island) Inc.
(the "FortisBC Energy Utilities")
Energy Efficiency and Conservation Program Natural Gas Vehicles Incentive

We enclose for filing in the above proceeding the electronic version of the Reply Submissions on behalf of FortisBC Energy Utilities.

Twelve hard copies of the Reply Submissions will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[original signed by Matthew Ghikas]

Matthew Ghikas

MTG/fxm
Enc

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF the *Utilities Commission Act,*
R.S.B.C. 1996, Chapter 473 (the “*Act*”)

and
FortisBC Energy Inc. and
FortisBC Energy (Vancouver Island) Inc.
(the “FortisBC Energy Utilities”)

ENERGY EFFICIENCY AND CONSERVATION PROGRAM

NATURAL GAS VEHICLE INCENTIVES

Reply Submission of the FortisBC Energy Utilities

May 25, 2011

1. A number of stakeholders provided letters of support to the FortisBC Energy Utilities (the "FEU" or the "Companies"), which were included in evidence and have already been referenced in the Companies' Final Submission. This Reply Submission addresses the final submissions of the Commercial Energy Consumers Association of British Columbia ("CEC"), the Ministry of Energy and Mines ("Government"), and the B.C. Sustainable Energy Association ("BCSEA"). These three parties are supportive of the position articulated by the FEU.[1] In particular:

(a) Both customer groups that filed final submissions – BCSEA and CEC (Government did not speak to this issue) – agreed with the FEU's characterization of how the EEC framework was intended to operate.[2] They agreed that customers benefit from the FEU continuing to have flexibility to manage the EEC portfolio going forward.[3]

(b) Government, BCSEA and CEC all support NGV EEC as being in the public interest. Government, for instance, provided an extensive submission detailing how the actions taken to date have supported "British Columbia's energy objectives", and the importance of eliminating the uncertainty regarding EEC funding going forward. For the reasons articulated by the FEU, and reinforced by these intervenors, the NGV EEC funding meets the requirements under section 44.2.

The overwhelming support for these initiatives underscores the need to bring this process to a conclusion as soon as possible.

2. The CEC has articulated a practical concern regarding the potential for the Commission to be "drawn into micro managing the entire EEC activity".[4] BCSEA similarly stresses the benefits of flexibility in optimizing EEC funding.[5] The FEU agree that there are key administrative efficiencies inherent in the EEC approach that the Companies submit was approved in the original EEC Decision. Accountability for how the FEU manages expenditures included within an accepted expenditure schedule is well addressed through the requirement that only prudent forecast costs are recoverable in rates,[6] which as CEC notes[7] is an analysis undertaken at the time rates are set and not before.

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1 The FEU have focussed on the general thrust of the submissions, without taking issue with any minor nuances in wording.

2 CEC Submission, pp. 4-5; BCSEA Submission, pp. 4-6.

3 CEC Submission, p. 5; BCSEA Submission, p.4-6.

4 CEC Submission, p. 5.

5 BCSEA Submission, pp. 4-5.

6 Both CEC and BCSEA agree with the applicability of the prudence test: BCSEA Submission, p.8; CEC Submission, pp. 8-9.

7 CEC Submission, pp. 8-9.

3. BCSEA submits on pages 4-6 that the effect of the 2009 EEC Decision rejecting Innovative Technologies was to reduce the total approved envelope, and not to bar the activity or even exclude Innovative Technologies from the expenditure schedule, because the FEU were explicitly given flexibility over the portfolio spending. BCSEA's submission is analytically consistent with fact that the Commission's rate setting mandate involves fixing rates without dictating how the utility spends the resulting revenues.

4. The CEC has identified that the Commission's final order in the 2010-2011 RRA cited sections 59-61 of the Act, but not section 44.2, in the preamble to the list of orders. As the RRA and the NSA contemplated that the EEC funding approvals were being sought under section 44.2 of the Act, the rectification of the Order to include a reference to section 44.2 in the Order should be treated as a "housekeeping issue".

5. In conclusion, the FEU respectfully submit that the existing EEC framework, which preserves the Companies' flexibility to optimize the EEC portfolio, makes sense for all stakeholders. The EEC programs for NGV are in the public interest and are already, or alternatively should be, included within the scope of the currently accepted expenditure schedule as part of the Innovative Technologies Program Area. Once the uncertainty regarding the EEC framework and the NGV-related EEC programs has been resolved, the Companies expect to resume the NGV-EEC program for 2011 by extending funding to previously identified recipients and any newly identified vehicle fleets.

6. The FEU wish to reiterate that they appreciate the Commission's willingness to consider this matter on an expedited basis in recognition of the importance of the NGV-related and other EEC initiatives for all stakeholders.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated: May 25, 2011

[original signed by Matthew Ghikas]
Matthew Ghikas
Counsel for FortisBC Energy Inc.

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June 10, 2011
File No.: 240148.00595/14797

ELECTRONIC FILING

British Columbia Utilities Commission
6th floor, 900 Howe Street
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Attention: **Ms. Alanna Gillis**
Acting Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. and Fortis Energy (Vancouver Island) Inc.
(the "FortisBC Energy Utilities")
Energy Efficiency and Conservation Program Natural Gas Vehicles Incentive

We enclose for filing in the above proceeding the electronic version of the Submissions on behalf of FortisBC Energy Utilities on Exhibit A-6.

Twelve hard copies of the Submissions on Exhibit A-6 will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[original signed by Matthew Ghikas]

Matthew Ghikas

MTG/fxm
Enc

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF the *Utilities Commission Act,*

R.S.B.C. 1996, Chapter 473 (the "*Act*")

and

FortisBC Energy Inc. and

FortisBC Energy (Vancouver Island) Inc.

(the "FortisBC Energy Utilities")

ENERGY EFFICIENCY AND CONSERVATION PROGRAM

NATURAL GAS VEHICLE INCENTIVES

Submission of the FortisBC Energy Utilities on Exhibit A-6

June 10, 2011

Table of Contents

A. INTRODUCTION

1. This is the submission of FortisBC Energy Utilities (the "FEU") with respect to Exhibit A-6, in which the Commission requested submissions on the following:

> The ability and appropriateness of the utility moving EEC funds among programs that meet the definition of "demand-side measure" in the Utilities Commission Act and programs that do not.

2. In the context of this regulatory process regarding the use of incentive funding for Natural Gas Vehicles in the Commercial NGV Demonstration Program (the "NGV Program"), the implication of the statement above is that the NGV Program may not be a "demand-side measure". In this submission, FEU will first explain why the NGV Program is a demand-side measure within the meaning of the *Utilities Commission Act* ("UCA") and, second, will explain why the expenditures are recoverable as prudent expenditures regardless.

B. THE NGV INNOVATIVE TECHNOLOGIES PROGRAM IS A "DEMAND-SIDE MEASURE"

3. The FEU submit that the NGV Program meets the definition of "demand-side measure" in the UCA. The definition of "demand-side measure" in the UCA refers to the *Clean Energy Act* where the term is defined as follows:

> "Demand-side measure" means a rate, measure, action or program undertaken
>
> (a) to conserve energy or promote energy efficiency,
>
> (b) to reduce the energy demand a public utility must serve, or
>
> (c) to shift the use of energy to periods of lower demand,
>
> but does not include
>
> (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or
>
> (e) any rate, measure, action or program prescribed;

4. The NGV Program is undertaken to promote energy efficiency and thus falls into paragraph (a) of the above definition. The fact that the FEU's innovative technology programs "promote energy efficiency" is reflected in the scope of the Innovative Technologies Program Area itself, as defined in the 2008 Energy Efficiency and Conservation ("EEC") Application, which states:[1]

> It should be noted that the initiatives listed in this Section do not include all the innovative technologies that the Companies may pursue, but rather provide an overview of the types of initiatives the Terasen Utilities intend to pursue, <u>all having the same underlying characteristics</u>:
>
> <u>1) Each promotes the efficient use of natural gas through sustainable design</u>
>
> 2) None are currently a mainstream technology
>
> 3) Each offers the potential for at least a 10% GHG benefit.
>
> <u>For all sectors, programs for fuel-substitution include plans that displace less efficient and dirtier fuels with natural gas or add cleaner renewable fuels to natural gas for further efficiency and GHG benefits</u>. [Emphasis added.]

5. Notably, paragraph (a) of the definition of "demand-side measure" includes programs that "conserve energy" or "promote energy efficiency." Meaning must be ascribed to the words in the legislation so that the words are not redundant or meaningless. "Promoting energy efficiency" must therefore be given a meaning that is different than "conserve energy". One important way of understanding energy efficiency beyond conserving energy is through the concept of the use of the right fuel for the right activity. Using the right fuel for the right activity can be a more efficient or effective use of energy from a variety of perspectives, such as in a system utilization sense, an economic sense, or an environmental sense such as promoting greenhouse gas ("GHG") reduction. The NGV Program promotes energy efficiency in all these ways.

6. The NGV Program is energy efficient from the perspective of the use of energy resources and delivery systems in the province. Without incentives for natural gas vehicles ("NGV"), customers would not purchase NGVs, and NGV load on the natural gas system would

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[1] Exhibit B-3, CEC IR 1.1.3.

not occur; the transportation energy demands of these customers would have been met with diesel fuel. As the NGV demand is a relatively flat year-round load, it increases natural gas use in the lower demand summer period, resulting in an increased load factor and more efficient use of the natural gas delivery system overall.[2] The NGV Program thus accomplishes the objective identified in paragraph (c) of the definition of "demand-side measure": "to shift the use of energy to periods of lower demand." From the perspective of fleet owners, the use of natural gas is also more energy efficient in an economic sense.[3] In addition, the NGV Program promotes switching from high GHG-emitting forms of energy to natural gas as a transportation fuel.[4] This is more efficient as it results in the energy demand being met with less resulting GHG emissions. This objective is supported by British Columbia's energy objectives set out in section 2 of the *Clean Energy Act*.

7. The FEU's interpretation is supported by the Province's 2007 Energy Plan, which states on page 21:

> Promote Energy Efficiency and Alternative Energy
>
> It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province. [Emphasis added.]

8. Although not referring to NGV per se, the quote above demonstrates that promoting the switching to a lower GHG emitting source of energy is a way to promote energy efficiency. The users of energy in these situations may not be using *less* energy, but they are using energy more *efficiently* by using "the right fuel, for the right activity at the right time."

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[2] Since NGV load has a flat year-round profile and FEU's core load is heavily weighted towards winter space heating use, adding NGV load will increase the summer throughput as a percentage of the annual throughput. When this is coupled with the fact that winter-weighted core throughput is declining due to the impacts of FEU's EEC programs and other drivers of declining gas use, the impact of adding NGV load on system efficiency and load factors is magnified. (Exhibit B-1, BCUC IR 1.7.3, 1.7.4 and 1.2.2.1.)

[3] Exhibit B-1, BCUC IR 1.7.4.

[4] Exhibit B-1, BCUC IR 1.7.4.

9. The FEU have been clear with respect to the scope of their EEC activities. In the Terasen Utilities May 2008 Energy Efficiency and Conservation Application, the introduction states:[5]

> EEC Activity is a term that describes what has been referred to in previous Regulatory filings as Demand Side Management ("DSM") activity. "EEC" and "DSM" are used interchangeably throughout this document; both terms refer to activities undertaken by the Companies that have the goal of affecting customers' use of natural gas, either through conservation activity or through load-building/fuel switching activity. [Emphasis added.]

10. Load building and fuel switching activities are a recognized form of demand-side management in the industry.[6]

11. Fuel switching programs may be "demand-side measures" within the meaning of the definition in the *Clean Energy Act*. Paragraph (d) of the definition of "demand-side measure" states that the definition excludes programs which encourage a switch from one kind of energy to another such that the switch would *increase* GHG emissions in B.C. The definition thus contemplates that programs that encourage a switch that would *decrease* GHG emissions in the Province may be demand-side measures. The NGV Program is just such a program, as it adds load by encouraging the switch from other forms of energy, such as diesel, to natural gas, which reduces GHG emissions.

12. Moreover, the Commission has previously accepted other EEC expenditures directed at fuel switching from fossil fuels with higher carbon content than that of natural gas.[7] The FEU currently provide incentives for customers to install Energy Star and EnerChoice equipment and appliances where customers wish to switch to natural gas as the fuel of choice. On Vancouver Island, for example, there is a program to encourage switching from the use of oil to natural gas for home heating.[8] Similar to the NGV Program, these programs add load to

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[5] Exhibit B-1, BCUC IR 1.7.3.

[6] Terasen Utilities May 2008 Energy Efficiency and Conservation Application, Appendix 12, *California Standard Practice Manual DSM-7-02*, pages 2-4.

[7] In the Matter of Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Energy Efficiency and Conservation Application, Decision, dated April 16, 2009, at page 18.

[8] Ibid.

the system, reducing GHG emissions and resulting in a greater utilization of the distribution infrastructure.

13. The FEU therefore submit that the NGV Program is a "demand-side measure" within the meaning of the UCA and is similar to other EEC programs.

C. IMPLICATIONS IF NGV PROGRAM IS NOT A DEMAND-SIDE MEASURE

14. The FEU have made detailed submissions regarding the ability of the FEU to move EEC funds amongst program areas within the Commission-accepted EEC funding envelope.[9] The Commission's acceptance of the EEC funding envelope was made pursuant to section 44.2(a) of the UCA which applies to "demand-side measures". If the FEU were to expend funds in a program that was not a "demand-side measure," as defined in the *Clean Energy Act,* this would mean that the FEU did not have a prior public interest approval pursuant to section 44.2 for the expenditure of those funds. However, this does not mean that it was inappropriate for the FEU to expend those funds.

15. The FEU have addressed the implications for FEU of a Commission determination that FEU does not yet have section 44.2 approval for the NGV Program expenditures.[10] Those submissions are equally applicable if the NGV Program was not a "demand-side measure." As FEU have submitted, section 44.2 acceptance is optional and the UCA does not prohibit the FEU from engaging in EEC activities without prior approval from the Commission. In the absence of a section 44.2 public interest determination, the Commission must assess the forecast amortization expenses relating to past NGV Program expenditures when setting rates for the FEU. In fact, the NGV Program amortization expenses are currently included in the FEU's Revenue Requirements Application before the Commission, and the FEU are seeking that these costs be recovered in rates.

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[9] FEU Final Submissions, Part Two.

[10] FEU Final Submissions, Part Two (pp. 16-17).

16. The NGV Program has many benefits to customers, including keeping natural gas delivery rates low for the benefit of all users.[11] As explained in Part Three and Four of its Final Submissions, the FEU submit that the NGV Program expenditures are in the public interest, were prudently incurred, and should therefore be approved. These submissions apply whether or not the expenditures meet the definition of "demand-side measure."

D. CONCLUSION

17. The benefits of including NGV Program funding within the overall EEC portfolio are well-established, and the rationale for stakeholders - including customers and Government - supporting those initiatives is clear. The NGV Program initiatives pursued to date are among the strongest initiatives in the overall portfolio when assessed according to the Commission-approved Total Resource Cost ("TRC") test, and high-to-low carbon fuel switching has environmental and other benefits. The NGV Program promotes energy efficiency, adding relatively flat NGV load which results in a more efficient use of the natural gas delivery system and lower GHG emissions in the Province. The FEU respectfully submit the Commission should therefore conclude that the NGV Program is a demand-side measure within the meaning of the *UCA* and the *Clean Energy Act* and that the FEU are able to apply EEC funding to the NGV Program within the Commission-approved EEC expenditure schedule. In the alternative, the FEU submit that the Commission should nonetheless conclude the expenditures on the NGV Program were prudent and in the public interest and therefore eligible for recovery from ratepayers in rates to be set for the FEU.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated: June 10, 2011

[original signed by Matthew Ghikas]
Matthew Ghikas
Counsel for FortisBC Energy Inc.

[11] Exhibit B-1, BCUC IR 1.7.2 and 1.7.3.

Appendix L

EXCERPTS FROM THE 2008 LONG TERM RESOURCE PLAN

7 ALTERNATIVE ENERGY OPPORTUNITIES

The energy planning landscape and trends described in Chapter 2 – growing demand, increasing energy costs and concerns about carbon emissions – have led to renewed interest in a wide range of clean and efficient energy alternatives. Terasen Gas has been developing proposals and opportunities to use the infrastructure and existing resources it already has in place to develop a number of potential alternative energy initiatives. These initiatives are important steps in helping to meet the policies of the B.C. Energy Plan and other provincial and regional energy objectives and in improving the efficiency and optimization of energy infrastructure in B.C.

Although the proposed initiatives discussed in this Chapter do not form part of a traditional resource planning portfolio for Terasen Gas, they do respond to the changing planning environment. The opportunities and initiatives discussed below include both demand and supply side resources. Terasen Gas has chosen to discuss them separately from other resources due to the unique nature and early stages of their development. This discussion provides stakeholders with examples of the types of activities Terasen Gas is undertaking to ensure that natural gas is being used as the right fuel in the right applications to help meet Provincial energy and carbon emission objectives.

7.1 Natural Gas Clean Transportation Opportunities

The 2007 BC Energy Plan ("Energy Plan") sets out a strategy for reducing greenhouse gas emissions and reducing human impacts on the climate. Transportation is a major contributor to climate change and air quality concerns. The use of conventional transportation fuels such as gasoline, diesel, propane and bunker fuel oil accounts for about 39% of B.C.'s GHG emissions[22], the single largest source of greenhouse emissions in the province.

Given its economic and environmental benefits over traditional fuels, natural gas can play a significant role in helping meet the GHG goals set out in the BC Energy Plan 2007 and the air quality goals of the Ministry of Environment. Examples of current technologies and initiatives in other jurisdictions provide an indication of the benefits that can be achieved in B.C. Terasen Gas is working with others in the NGV industry to identify and develop important new NGV initiatives here in B.C. that will help reduce carbon emissions and pollution.

This section describes a number of both near-term and long-term opportunities for the adoption of natural gas vehicles ("NGV") within the transportation industry. Near-term opportunities are defined those where the:

1) technology is proven and commercially available;
2) transition to natural gas technology for the end user is economically and environmentally viable; and
3) technology is supported.

[22] BC Ministry of Environment – based on 2004 data

Terasen Gas has identified near-term opportunities to shift from conventional fuels to NGV technology in a wide range of transportation sector applications such as heavy-duty truck fleets, port materials handling equipment, bus fleets, refuse haulers and port electrification.

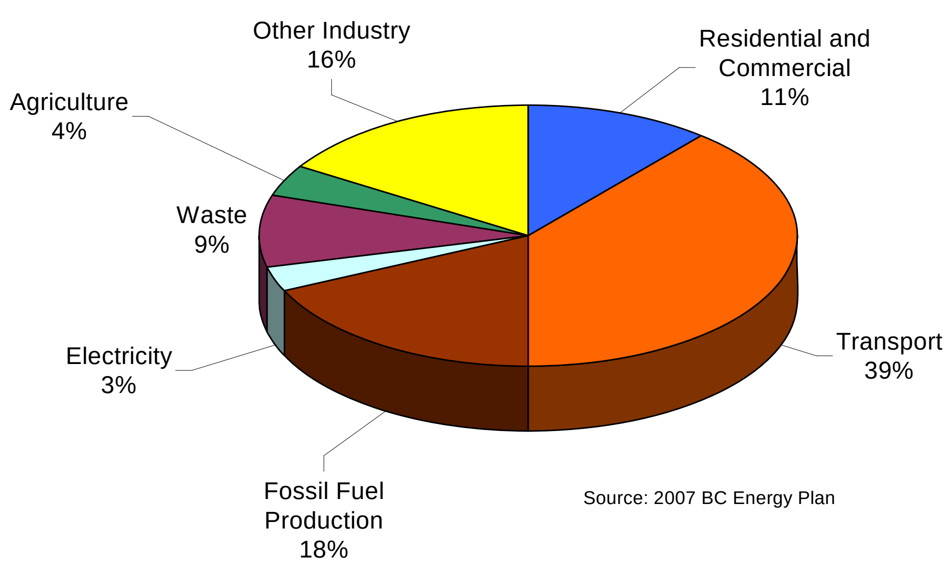
Long-term opportunities are those in which natural gas transportation technology exists, but is not yet commercially proven or available. Terasen Gas believes there are opportunities where natural gas technologies can be adopted in the transport sector for marine passenger vessels and in new light-duty return-to-home fleet or passenger vehicle technology.

The potential natural gas load growth discussed in these examples has not been included in the Terasen Gas demand forecasts due to the uncertainties that remain in capturing this market. As demonstration projects and first adopters in the province show success Terasen Gas expects that markets will begin to grow. As that occurs, Terasen Gas will endeavour to include load growth expectations from this market into its demand forecasts

Air Quality Benefits of Implementing NGV Technology

Figure 7-1 indicates that the single largest source of greenhouse gas in B.C. is the transport sector. Terasen Gas believes that this sector provides the greatest opportunity for greenhouse gas reductions.

Figure 7-1 B.C. Greenhouse Gas Emissions by Sector



Data from Natural Resources Canada indicates heavy-duty natural gas vehicles emit 15-30 % less GHG emissions than their diesel counterparts. Light-duty vehicles emit almost 30% less

GHG emissions compared to their gasoline equivalents. Natural gas vehicles also emit 50-80% less air quality contaminants such as NOx, SOx and particulate matter[23].

Economic Benefits of Implementing NGV Technology in BC

In terms of fuel costs, natural gas refueling prices at the pump in B.C. are currently up to 50% less than the gasoline equivalent[24]. The recently imposed carbon tax will also affect traditional petroleum fuels to a greater degree than natural gas. This operational cost savings can help to offset fleet conversion costs and in the long run can continue to provide operational efficiencies.

In terms of industry development, the Lower Mainland hosts a cluster of NGV technology expertise and businesses, including Terasen Gas, Westport Innovations, Cummins Westport, Clean Energy, Eco Fuels, MaxQuip, IMW Industries and Powertech Labs. Canadian companies are recognized worldwide as being leading providers of natural gas vehicle technologies and services. Implementing NGV technologies in B.C. will help to develop and support the long-term viability and health of this important industry. Figure 7-2 shows examples of natural gas fuel applications in heavy duty trucks and transit vehicles.

Figure 7-2 Examples of Natural Gas Fuel Technology in Heavy Duty Trucks

Class 8 LNG Truck

CNG Refuse Truck

CNG Articulated Bus

7.1.1 Near-Term Opportunities

7.1.1.1 Ports and Shipping Industry Applications

Heavy Duty Trucks

As a result of the new BC Energy Plan and specific goals in the Pacific Gateway Plan, the Ministry of Transportation ("MOT") and the Climate Change Secretariat are searching intensely for ways to clean up the emissions in British Columbia's Ports. Interest is growing in initiatives that are unfolding in California around truck and ship emissions as opportunities in British Columbia.

23 Emission comparisons cited here are available from NRCan GHGenius modeling software available at: http://www.oee.nrcan.gc.ca/transportation/tools/greenhouse-gas-info.cfm?attr=16

24 Based on March 26,2008 gasoline price of $1.20 /litre and CNG pump prices of $0.63 / GLE

San Pedro Bay Ports, operating in the Ports of Los Angeles and Long Beach, have developed an aggressive Clean Air Action Plan ("CAAP") which calls for the replacement of more than 16,000 old Class 8 diesel trucks with several thousand new trucks that operate using LNG fuel technology. The plan includes this and other clean fuel initiatives to meet specifications for reduced particulate matter ("PM") and nitrogen oxide ("NOx") emissions. This movement to cleaner LNG trucks, featuring LNG fuel systems developed and manufactured here in B.C. by Westport Innovations Inc., will result in significantly decreased greenhouse gasses, NOx and particulate emissions. Westport's LNG fuel system is the only alternative fuel technology currently qualified for financial support under the ports' clean truck program.
In the Port of Vancouver, Class 8 trucks are used for transporting containers to and from cargo ships to various hubs throughout the Lower Mainland for distribution throughout North America via rail or long-haul transport. The incremental cost of purchasing a Class 8 heavy-duty truck is approximately $75,000, however; the incremental cost can be offset by fuel savings and the environmental benefits.[25] The near-term business proposal for Class 8 heavy-duty trucks to operate on LNG is for short-haul point-to-point routes where a refueling station is located at one of the points. This is due to the infrastructure investment needed for refueling.

There are currently over 4,000 Class 8 trucks that frequent the Ports of Vancouver, 1,500 of these are regular visitors. Each truck uses approximately 2000 GJ / yr[26]. Terasen Gas believes that with government and industry support a market could be developed starting with a pilot project of 10 trucks, ramping up to 250 -500 trucks over the next 10 years with an estimated consumption is 500,000-1,000,000/GJ per year.

Materials Handling Equipment: Forklifts and Shunt Trucks

Most forklift fleets today use propane as an energy source; however, natural gas is a viable and cleaner alternative. Natural gas as CNG produces fewer emissions, is safer to handle, and is cheaper to operate. In the past five years over 1500 forklifts in the Province of Ontario have converted from propane to natural gas to capture fuel cost savings and air quality benefits[27].

A potential market exists in B.C. for the conversion of propane forklift and shunt trucks (container movers in shipping ports – see Figure 7-3) fleets to CNG. The conversion process includes converting the equipment to use CNG and installing compression and refuelling facilities at the customer premise. Third party vendors are available to provide both the conversion and compression services at either a capital cost to the customer or through a lease back program. By choosing a lease option, the customer will often see immediate savings. The customer may also be eligible for grants to help offset conversion costs. On average, third party vendors report a 15-40% savings on fuel costs for end users that have adopted CNG for their forklift fleets. Current Original Equipment Manufacture ("OEM") products are also available for both equipment types.

[25] U.S. DOE Alternative Fuel Price Report, October 2006.

[26] Information obtained through discussions with industry representatives.

[27] ibid

Figure 7-3 Shunt Truck

Terasen Gas estimates that a market opportunity exists for approximately 300-500 CNG forklifts and shunt trucks. On average each unit uses approximately 200 GJ/year, resulting in a market potential of approximately 60,000-100,000 GJ/year.

Focus on solutions

Natural Gas Fork Lifts

Terasen Gas with its technology partner FuelMaker is converting 100 forklifts from propane fuel to natural gas, for a trans-load shipping operator located in the Lower Mainland. On average a forklift consumes as much natural gas as a house or as much gas as two cars. Not only are forklifts cheaper to operate on natural gas than propane, but they produce well over 50% less smog and 90% less carbon monoxide, yielding great environmental, health, and safety benefits as most forklifts operate indoors.

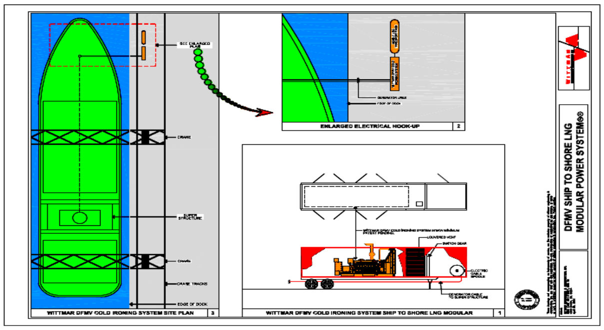
Cold Ironing

In 2004, the Greater Vancouver Regional District (now Metro Vancouver) identified that by 2006 marine activities would become the single largest producer of smog forming pollutants (NOx+SOx+VOC+PM2.5+NH3) in the Lower Fraser Valley.[28] By 2025, marine activities are anticipated to produce approximately three times more smog than light-duty vehicles.[29]

The primary contributor of air pollutants in British Columbia associated with marine activities occurs from ships while idling in port. When transport ships load and unload while in port - on average a two day process - they continue to burn their own fuel source, often bunker fuel, to run auxiliary engines and power electrical equipment such as navigation, ventilation, refrigeration, and other appliances. Providing shore power for ships (cold-ironing) is a possible solution to the emissions concerns resulting from marine activity. The Port of Oakland has recently completed testing, whereby generators that can run on either LNG or CNG to power the ships while in port. Figure 7-4 provides an illustration of the LNG cold-ironing process and a picture of the proof of concept demonstration at the Port of Oakland.

[28] http://www.portvancouver.com/the_port/docs/Air_Quality_Management_in_the_GVRD.pdf
[29] Ibid.

Figure 7-4 LNG Cold-Ironing Schematic and In-use Photo



Source: Clean Air Logix

Tests at the Port of Oakland indicate reductions of 94-100% in NOx, SOx, and PM10, and CO and CO2 reductions of 43% and 57% respectively, per 24 hour port call (see Table 7-1). This technology is now included in California regulations for shore power alternatives for ships.

Table 7-1 Pollutant Reductions: Port of Oakland - LNG Cold-Ironing

APL POLLUTION REDUCTION EFFORTS AND RESULTS

	Statistics for a 24 Hour Port Call in Oakland				
	2006	2007	LATE 2007		
Fuel Type	2.5% Sulfur Diesel	0.5% Sulfur Diesel	Wittmar DFMV Cold Ironing w/ RML	Reduction	%
NOx	1059 Pounds	1059 Pounds	56 Pounds	94.71	%
CO	79 Pounds	79 Pounds	34 Pounds	56.96	%
PM10	29 Pounds	15 Pounds	0.02 Pounds	99.93	%
SOx	358 Pounds	72 Pounds	0 Pounds	ELIMINATED	
CO2	42,651 Pounds	42,651 Pounds	24,430 Pounds	42.72	%
Fuel Consumption	1,906 Gallons of Diesel	1,906 Gallons of Diesel	2,813 Gallons of RML		

Source: Clean Air Logix, Port of Oakland, Proof of Concept

Terasen Gas continues to closely monitor the developments in California shore power initiatives. Terasen Gas believes that in the next five years there is a potential for three generators at the Port of Vancouver. The estimated consumption would be 300,000 GJ/ year for all three units.

7.1.1.2 Transit Buses

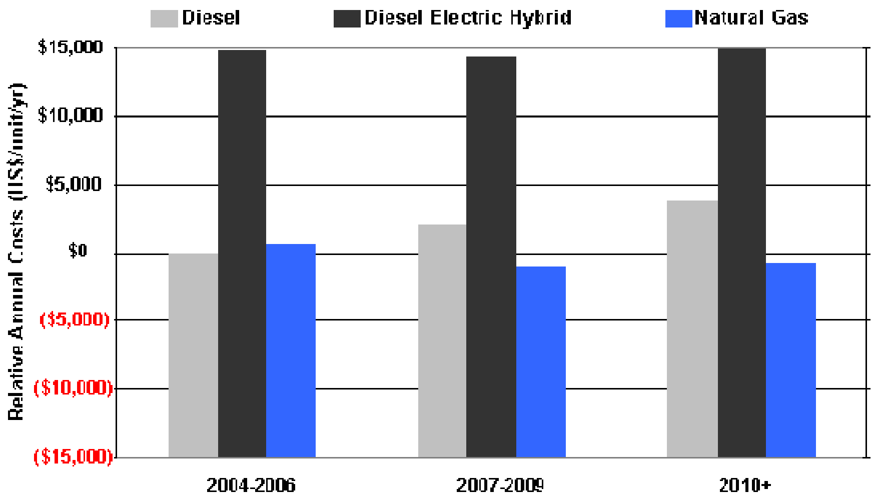
Commercially available OEM engines exist that allow transit buses to operate on CNG. Cummins Westport's ISLG 2007 natural gas engine is already certified to meet 2010 Environmental Protection Agency (EPA) and California Air Resources Board (CARB) emissions standards. This engine is the cleanest heavy-duty commercial technology available.

The incremental cost of purchasing a CNG powered bus over its diesel counterpart is approximately $50,000[30]. The incremental cost is offset by the environmental benefits and

[30] ibid

lower fuel costs. Figure 7-5 illustrates estimated annual capital and operating cost of CNG buses against diesel and diesel electric hybrid buses.

Figure 7-5 Annual Capital and Operating Costs



The City of Los Angeles has more than 2000 CNG buses, accounting for 94% of their total fleet. In B.C., there are currently 75 CNG buses, (4% of fleet) which operate out of the Port Coquitlam transit hub and are operated by Coast Mountain Bus Company. In January 2008, the Premier of British Columbia in conjunction with the Minister of Transportation announced a $14 billion transportation plan that called for 1500 new clean technology buses. CNG is among the five technologies being considered for this plan.

Given the current policy direction for clean transportation technology, Terasen Gas anticipates there are opportunities over the next seven years, for an additional 150 CNG buses. An additional 150 buses would result in a total of 300,000 GJ/year or 2,000 GJ per bus per year. The total estimated number of transit buses in B.C. greater than 2200.

7.1.1.3 Refuse Trucks

Refuse trucks operating on CNG use the same engine technologies as transit buses. The use characteristics of these vehicles are similar to that of bus fleets. As a result, the economic and environmental benefits of operating a refuse fleet on CNG are similar to those of operating bus fleets on CNG.

Smithtown, Long Island, NY, a suburb of New York City, has recently replaced its entire refuse fleet of 24 trucks to CNG. Smithtown has reported a significant reduction in operating costs, a

20% reduction in greenhouse gas emissions, quieter trucks operating in residential neighbourhoods, and improved breathing conditions for operators.[31]

The most significant challenge with adopting CNG is fleet portability. Many B.C. municipalities outsource their waste hauling contracts through a bid process with contract periods ranging for 3-5 years. If an operator loses a contract in an area after adopting a CNG fleet, it may be costly to move the refueling systems if they have to re-deploy their fleet to another jurisdiction.

With government incentives, and continued municipality commitment to reduce greenhouse gas emissions, this challenge can be overcome. Terasen Gas anticipates that one or two pilot projects can be developed to include approximately 25 CNG refuse trucks using approximately 35,000 GJ/yr or 1,400 GJ per truck per year.

7.1.2 Long-Term Opportunities

7.1.2.1 Light-Duty Fleet & Passenger Vehicles

The successful business model for light-duty fleet and passenger vehicles is similar to the model for heavy-duty trucks. Due to limited refueling infrastructure, vehicles must either operate as a return-to-home fleet with dedicated refueling or operate within an area with retail refueling infrastructure. A significant hurdle in pursuing return to home fleets is the lack of OEM vehicles available in Canada. Terasen Gas believes the majority of CNG fleets over the next 3-5 years will be as a result of converting existing gasoline vehicles to bi-fuel vehicles (run both on natural gas and gasoline).

Vehicles converted in B.C. are predominately converted using a standard EPA approved kit. Depending on the vehicle type, conversions cost approximately $4,000-$7,000[32], and customers are eligible for grants of up to $2500 under Terasen Gas' Rate Schedule 6. The cost of conversion can be offset by the reduced commodity cost of natural gas versus gasoline. Terasen Gas is not aware of any significant fleet conversions to CNG bi-fuel. However, if a lifecycle emission analysis approach similar to that adopted in California is adopted in B.C. there may be significant opportunity to develop a CNG vehicle market for couriers, taxis, delivery vehicles and other light-duty fleets.

Terasen Gas believes that any success in this CNG market segment would have to be driven by CNG OEM engine manufacturers. Terasen Gas is, however, closely following the recent successes of the natural gas powered Honda Civic GX in California and New York State, and is closely monitoring the OEM CNG vehicles manufactured in Europe.

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31 http://www.nytimes.com/2006/07/30/opinion/nyregionopinions/30LIunderwood.html?_r=1&ref=nyregionopinions&oref=slogin

32 ibid

7.1.2.2 Marine Passenger Vessels

Current technology exists to build ships that can operate on LNG instead of diesel. Given the current energy planning environment and emphasis on greenhouse gas reduction, Terasen Gas believes that in the long term an opportunity may arise to use LNG to operate passenger vessels in British Columbia. Terasen Gas efforts to make LNG available to truck fleets will provide valuable experience as the potential for operating fleet vessels in B.C. is more closely examined.

7.1.3 Standing Tariff for the Sale of LNG

To help open the market for LNG as a fleet fuel, Terasen Gas expects to apply for the approval of a standing tariff for the sale of LNG from its Tilbury LNG peakshaving facility within the coming year. Initially, the tariff would allow for up to 1040 GJ per day (11,700 gallons of LNG) to be sold to customers within the Terasen Gas service territory from the Tilbury facility. As the market for LNG in the fleet transportation sector grows, Terasen Gas will build the necessary infrastructure to support its growth. Infrastructure may include 50,000 to 80,000 gallon storage tanks at Tilbury to facilitate moderate growth and a new LNG facility at either the existing Tilbury site or an alternative location if the market demand justifies the investment.

7.1.4 Natural Gas Vehicle Grants

Under Rate Schedule 6, TGI offers promotional grants towards the cost to purchase factory-built natural gas vehicles, or the cost to convert vehicles to natural gas. The amount of the grant is up to $10/GJ, based on estimated consumption over a one year period, up to a maximum total grant by vehicle type as outlined in Table 7-2.

Table 7-2 Rate Schedule 6 Vehicle Grants

Vehicle Description	GVW (Pounds)	Maximum Grant
Light Duty	< 10,000	$ 2500
Medium Duty	< 17,000	$ 5,000
Heavy Duty	>17,000	$10,000

Terasen Gas may also fund Special Demonstration project grants for innovative applications of natural gas used in vehicles that can be used to demonstrate the technology and promote natural gas as a fuel source for the particular application. The total funds available under the Special Demonstration project grants are $100,000 per year.

7.2 Alternative Supply - Opportunities to Capture Energy from Waste

Terasen Gas' initiatives in alternative energy supplies support the 2007 BC Energy Plan objectives of energy conservation and efficiency, innovation to create clean and renewable energy, and developing leadership in clean energy generation. Terasen Gas is examining

Appendix M

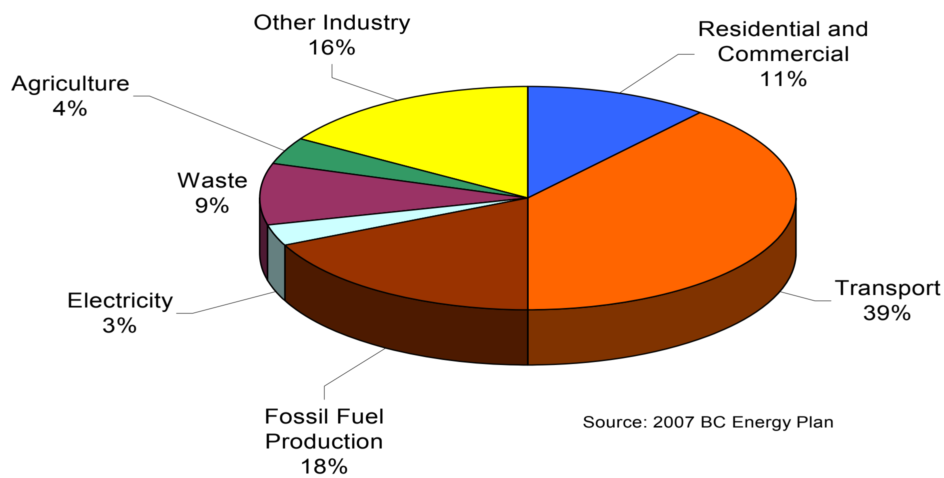
EXCERPTS FROM THE 2010 LONG TERM RESOURCE PLAN

3.1.2 NEW NATURAL GAS VEHICLE SOLUTIONS

The Terasen Utilities' customers are seeking integrated, low carbon energy solutions that can help them to manage their energy costs and minimize their carbon footprint. New and complete natural gas vehicle solutions are a vital opportunity for the Utilities to serve these needs and help reach the impressive GHG reduction targets legislated by the Province. This section provides background on NGV technology in B.C., identifies the need and availability of incentive funding for vehicle purchases to spur development NGV solutions, describes the strategy behind new solutions being developed by TGI and presents TGI's intention to bring forward a an application to the Commission for more complete transportation fuel service offerings.

The Utilities see the development of new NGV services, programs and markets as a key part of its low carbon strategy to help meet both the changing needs of our customers and the GHG reduction targets legislated by the Province. The transportation sector is responsible for more energy use and carbon emissions than any other sector (Figure 3-3). As such, it provides B.C.'s biggest opportunity to contribute to a global reduction of carbon emissions and other pollutants over the next 20 years. TGI is developing new NGV solutions that will capture this opportunity for emission reductions, as well as provide an important source of load growth on the Terasen Utilities systems to help optimize system throughput for the benefit of all customers.

Figure 3-3: B.C. Greenhouse Gas Emissions by Sector



Natural gas is a lower carbon alternative to conventional diesel and gasoline and can therefore play a much greater role in this sector than it has historically, improving emissions, reducing reliance on oil and supporting technology development in B.C. Using natural gas instead of conventional fuels reduces GHG and other emissions, such as oxides of nitrogen, sulphur oxides, carbon monoxide and particulate matter. Furthermore, using natural gas for transportation application significantly reduces the customers fuel cost. To capture this benefit, customers must make significant investments in vehicles and equipment that can use natural gas. Given the financial risks, customers are looking to the Terasen Utilities as a trusted partner that can be depended upon to deliver the energy they need for years to come. We believe that the greatest near-term potential to deliver these solutions is in the return-to-base, fleet vehicle market.

As described in Section 2, natural gas is well positioned to compete against conventional fuels which dominate the market for transportation. Low carbon transportation fuel requirements have been legislated, the fuel price advantage for natural gas over conventional diesel and gasoline has improved further, all levels of government are increasing their focus on reducing transportation related emissions and proven technology ready for commercial use is readily available. The Utilities believe that NGVs have a viable and important role to play in the B.C. transportation fuels.

- **Natural Gas Vehicles**

NGVs look like any other vehicle. The difference is NGVs operate on natural gas rather than the fuel we typically pump into our vehicles' tanks. Clean Energy Fuel Corp. offers the following summary:

"NGVs typically use one of two varieties of natural gas: Compressed Natural Gas (CNG) or Liquefied Natural Gas (LNG). CNG is the preferred fueling method for light to medium NGVs, Heavy-duty NGVs with weight and range requirements typically fuel up on LNG, which allows them to store more fuel on board with less tank weight. L/CNG stations can service both types of NGVs by converting LNG into CNG"[72]

In general terms, the benefits of NGVs are:

- Better for the environment, with significantly lower CO2 (carbon dioxide), NOx (nitrogen oxide) and greenhouse gas emissions than the majority of existing vehicles on the road today
- Lower fuel cost - 25 to 50 per cent less than the pump price for gasoline
- Lower maintenance costs - natural gas burns cleaner so engine parts stay cleaner
- A natural resource, produced here in B.C. and elsewhere in Canada

Data from Natural Resources Canada indicates heavy-duty NGVs emit 19-29 % less GHGs than their diesel counterparts. Light-duty vehicles emit almost 30% less GHGs compared to their gasoline equivalents. NGVs also emit 50-80% less air quality contaminants such as NOx, SOx and particulate matter[73].

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[72] http://www.cleanenergyfuels.com/ngvs_what.html
[73] Emission comparisons cited here are available from NRCan GHGenius modeling software available at: http://www.oee.nrcan.gc.ca/transportation/tools/greenhouse-gas-info.cfm?attr=16

The methodology adopted within the provincial regulation combines measures of the base carbon intensity of the fuel with measures of the efficiency of the engine technology that is used with the fuel. This results in an effective Carbon Intensity in use. CNG has a carbon intensity approximately 38% lower than gasoline and 28% lower than diesel. LNG's carbon intensity is roughly 43% lower than gasoline and 34% lower than diesel[74].

3.1.3 BACKGROUND ON NATURAL GAS VEHICLE SOLUTIONS IN B.C.

Historically, NGV programs in B.C. were focused on the passenger vehicle market through the development of public fueling stations. In 1997 there were 51 public fueling stations in operation in B.C. NGV sales peaked in 1999 reaching 609,000 GJ. Since then, this market has declined due primarily to:

- Lack of OEM vehicle availability - OEM manufacturers exited the market in the 2000/01 time period.
- Unreliable Conversion Technology - Vehicle conversions became more complex with the introduction of electronic engine controls and more sophisticated pollution abatement technologies. After-market conversion technologies had challenges providing reliable vehicle solutions.
- Lack of Support from Fuel Vendors – NGV station providers focused efforts on development of markets in other jurisdictions such as the U.S. market.
- Passenger Vehicle Market Focus – The focus on passenger vehicle markets is more difficult to support as it relies on the development of public fueling infrastructure.
- Modest Price Advantage – In the early part of the decade the pricing advantage of CNG was more modest that it is at present.

Currently, TGI continues to offer NGV Service and modest levels of vehicle incentive grants through Rate Schedule 6. TGI also received approval for the sale of LNG under Rate Schedule 16, Interruptible Liquefied Natural Gas and Dispensing Service[75], effective June 15th, 2009. This rate schedule provides assurance of supply and cost certainty to fleet vehicle and LNG refueling station owner-operators, initiating the development of a new NGV market. LNG sales originate from the Tilbury LNG storage facility in Delta, complementing its existing usage.

[74] Low Carbon Fuel Requirements Regulation Intentions Paper for Consultation http://www.empr.gov.bc.ca/EEC/Strategy/BCECE/Documents/LCFRR%20Intentions%20Paper%20Final.pdf
[75] BCUC Order No. G-65-09

Terasen's Environmental Leadership in Action: NGV Fleets

Terasen has incorporated using NGVs for company's fleet vehicles as NGVs, such that fuel savings and the most optimal emissions profile for the company is attained.

Terasen leases or purchases vehicles equipped to operate on natural gas fuel by the original equipment manufacturer if available. Otherwise, Terasen converts units to operate and run on natural gas using aftermarket conversion kits.

- **New Incentive Funding**

Vehicle funding to help offset the incremental capital cost of NGVs is a critical driver that motivates customers to adopt natural gas as a transportation fuel. The Terasen Utilities received approval for $2.3 million in 2010 and $4.7 million in 2011 for Innovative Technologies to advance emerging technologies. Since the Innovative Technologies portfolio was formulated, TGI has made progress with some of the technologies, particularly to support implementation of NGV technology. For more information on the Utilities' Innovative Technologies portfolio, see Section 5.

TGI has initiated a pilot incentive program to encourage operators of heavy duty fleets such as garbage trucks and waste haulers to switch to natural gas from higher-carbon diesel. TGI has received expressions of interest from the City of Vancouver, City of Surrey, City of Port Coquitlam, and other third party partner. to use the EEC funding to purchase new natural gas vehicles for garbage collection and transfer operations. Under the provisions of the pilot program, the fleet operators would be reimbursed for the incremental cost of the NGVs over conventional vehicles. TGI expects to assist with funding the adoption of 16 and 32 heavy duty diesel trucks in 2010 and 2011 respectively.

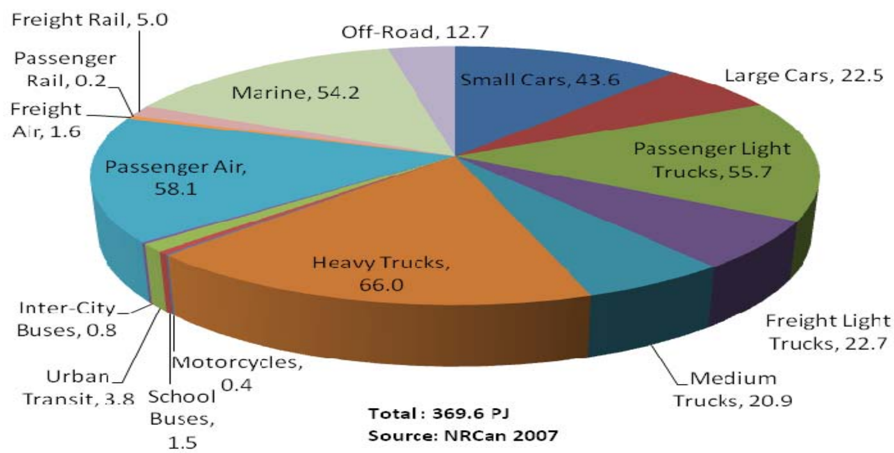
This penetration is based on current cost estimates, allocated funding levels and expression of interest from prospective customers. It should be noted that in the absence of such funding, these operators were not able to commit to NGVs. The higher initial capital cost of NGVs is a significant barrier to adoption in transportation markets but once this is overcome the operator will receive the benefits of lower operating costs and reduced emissions. The success of the initial offering of this program demonstrates there is a strong correlation between incentives and adoption and awareness for emerging technologies. Terasen Utilities believes that the need for such incentives will decline as NGVs gain greater share of the market and the capital cost premium for NGVs declines with volume.

3.1.4 TERASEN UTILITIES NGV STRATEGY

- **Target Market**

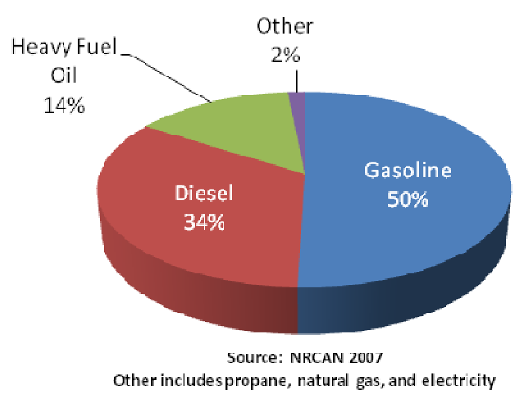
The Terasen Utilities believe the near-term opportunities for natural gas in the transportation sector in B.C. are in the return-to-home applications where commercial fueling technology exists for industrial use vehicles such as light, medium and heavy trucks, waste haulers, as well as bus fleets. Long-term opportunities may exist in marine passenger vessels and in new light-duty passenger vehicle technology. The total transportation sector fuel usage was 370 PJ in 2007 as shown by category in Figure 3-4. Of this total, the target markets that TGI has identified make up 290 PJ. TGI expects natural gas demand from its new NGV solutions to grow to 30 PJ or 6.5% of this total market by 2030. NGV target market segments and demand scenarios are discussed further in Section 4.3.

Figure 3-4: Total B.C. Transportation Market Sector Energy Use by Category (PJ)



The target market can also be broken down by fuel type as shown in Figure 3-5. Gasoline represents 50% of the target market and is consumed primarily in the passenger car and light duty truck segments. Diesel fuel is consumed primarily in the heavy duty and vocational trucking segments. Nearly two-thirds of TGI's NGV growth targets are focused on the high mileage, heavy duty truck segment, where diesel fuel occupies 100% of the market.

Figure 3-5: Terasen Utilities NGV Target Market by Fuel Type



➢ Vehicle Availability

Heavy duty, vocational fleets (ie. garbage trucks), and transit buses can be serviced and supported through an existing dealer network. OEM product offerings exist in the heavy duty segment from manufacturers such as Kenworth and Peterbilt, in the transit segment from New

Flyer, and in the vocational truck market from Crane Carrier, Autocar, Freightliner, and Mack. The light duty and medium truck segments are more challenging. At present the approach being utilized within the TGI fleet is to purchase OEM equipment that is factory prepared and certified to be "NGV Ready" for subsequent conversion by qualified aftermarket conversion suppliers. This approach is presently offered by Ford on a variety of truck and van models. General Motors has also announced a return to providing OEM Natural Gas ready vehicles.[76] Additionally, the marine segment has OEM manufacturer availability from Rolls Royce and Wartsilla.

- **Focus on Commercial and Fleet Vehicles**

TGI aims to concentrate on commercial and fleet vehicles that operate out of a single location, or between a limited number of points. A constrained service area makes the refueling investment more manageable. The medium and heavy duty truck segments, as well as transit buses consume high amounts of fuel. Specific consumption level expectations are described in Section 4.3.

The business strategy should focus on fleet vehicles that can be economically served by a minimal number of fueling stations. This implies a focus on "return home" fleet vehicles and vehicles that operate between a limited number of destinations (e.g. ferries or long haul trucks that travel from point to point.

- **Fueling – A Complete Offering**

A successful development strategy will need to provide a complete offering to the fleet customer. TGI's strategy will require extension of the service offering to provide fueling station assets and services. For CNG applications, a compression, storage and dispensing service needs to be added. For LNG applications, a local storage and dispensing service needs to be added. TGI has been exploring this market place for some time now and to date, no other businesses are stepping forward to fulfil this role in B.C..

The task of establishing fueling infrastructure is not trivial and requires experience and expertise with respect to compressed gas facilities and/or cryogenic fuels facilities. The provision of these services is consistent with TGI's role as a trusted supplier of energy products and services and should be part of our service offering.

As discussed above, provision of fueling services is a key element of TGI's new NGV strategy. We propose the addition of services for both CNG and LNG fueling stations.

- CNG - Compression, high pressure storage, dispensing and metering assets
- LNG - Cryogenic storage, dispensing and metering

[76] Oilweek magazine June 2010: http://www.oilweek.com/articles.asp?ID=732

The assets provided for each station are different but the service and proposed rate model are the same.

By providing commercial fleet customers with an offering that is readily comparable to their existing fuel products (ie. gasoline, diesel), the benefits of NGVs may be easier for customers to understand. For commercial fleet customers, this means providing a single bill from a single vendor which includes all service up to the point where fuel is delivered into the tank.

TGI is presently exploring project proposals with the City of Port Coquitlam and another third party interest. These projects involve heavy duty vocational trucks that run on CNG. The aforementioned parties communicated to TGI that trucks would use approximately 1100 GJ/unit/year over an average total distance of 40,000 kilometers per vehicle per year.

In 2009, TGI, Westport Innovations, and IMW Industries combined with Wastech Services Ltd. for a pilot project where solid waste was transported using heavy duty LNG garbage trucks, from Greater Vancouver to the Cache Creek landfill[77]. The results of the study concluded that the NGV trucks would consume up to 9,500 GJ/unit/year over an average total distance of 389,000 kilometers per vehicle per year. TGI is also exploring a potential project with the City of Vancouver's fleet of waste transfer vehicles. These vehicles consume approximately 1,500 GJ per year operating approximately 80,000 kms per year. It is expected that fleets with high mileage are more likely to convert to LNG operation as the operating cost savings will be greater for these fleets. Given the range of potential fuel consumption and the propensity for LNG customers to be high mileage applications, TGI believes that 2,500 GJ/truck/year is a reasonable estimate for average heavy duty vehicle fuel consumption.

3.1.5 CONCLUSIONS AND NEXT STEPS FOR NEW NGV SOLUTIONS

TGI's new NGV initiatives can provide substantial GHG and other emission reductions from the largest emitting sector in B.C. The transportation markets we are targeting (light, medium and heavy duty trucks, transit, marine fleets and potentially rail) emit almost 50% of transportation related emissions in B.C. These initiatives can help our customers manage their costs and carbon footprints, and help meet the Province's emission reduction targets. Our low carbon fuel strategy targets return-to-base fleet vehicles for CNG solutions where fueling infrastructure economics make sense and vehicle ranges can match fuel capacity. Transport industry fleets with large engines present LNG solution opportunities where larger fuel capacities are needed for heavy duty or longer haul operations. Marine and rail fleets offer future LNG fueling opportunities.

The Terasen Utilities have a role to play in removing the barriers that will enable the development of an NGV industry in B.C., which will help new customers reduce their GHG emissions in a cost effective manner, while providing benefits to existing customers by

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[77] http://www.wastech.ca/uploads/media%20material/090507_Wastech_LNG_mediapkg.pdf

improving the utilization of the existing natural gas infrastructure. The Utilities expect to grow demand in its NGV target market to 30 PJ annually by 2030. NGV solutions must be complete solutions, however, and provide the customer with service that allows them to directly fuel their vehicles and equipment without the need for them to supplement a portion of the service, or risk the unwillingness to participate in this important opportunity.

TGI intends to bring forward an application to the Commission in the summer of 2010 for approval of more complete transportation fuel service offerings. That application will include the requirement for and appropriate treatment of CNG and LNG fueling infrastructure being sought from the Utilities by existing and potential future customers. Extension of a more complete NGV service to the TGVI and TGW service territories is contemplated at a later date pending future unbundling of gas delivery rates for these utilities.

More Opportunities for Compressed Natural Gas:
Napa Valley Wine Train Example

The Napa Valley Wine Train started a program for the experimental conversion of a Napa Valley Wine Train Alco locomotive to 60% natural gas and 40% diesel fuel mixture. In 1999 the conversion became permanent. A total conversion of locomotive 73 was completed and it was put into service using 100% Compressed Natural Gas on in 2008.

Source: http://winetrain.com/about/our-train

3.1.6 CARBON NEUTRAL BIOMETHANE OFFERING

Biogas is a readily available supply of renewable gas from landfills, sewage treatment plants, food waste, and agricultural operations. Established technology exists that can be used to upgrade biogas to biomethane, which has characteristics that make biomethane a reliable and safe substitute for natural gas. Moreover, biomethane is a renewable fuel. The production and consumption of biomethane is considered carbon neutral. The use of this carbon neutral fuel in place of a carbon positive fuel such as natural gas results in a net reduction of GHG emissions as well as other environmental and economic benefits for potential biogas producers throughout the province. This offering to customers promotes government's energy policy objectives

Appendix N

EXCERPTS FROM THE 2010-2011 REVENUE REQUIREMENTS APPLICATION

3. Energy Efficiency and Conservation and Alternative Energy Solutions

To remain a viable energy provider TGI must be able to offer complete energy solutions representing our base natural gas business in combination with both EEC programs and alternative energy solutions. TGI is well positioned to work with customers and communities to provide complete energy solutions and is committed to doing so.

Terasen Gas' proposal for 2010 and 2011 is:

1. Increase EEC funding for 2010 over the currently-approved EEC funding to add interruptible Industrial customer programs and Innovative Technologies programs to the EEC portfolio, with all funding subject to the same financial treatment as approved in the EEC Decision;
2. Reallocate funding from the amount approved in the EEC Decision for 2010 to low income and rental housing programs;
3. Extend funding for 2011 for the entire EEC portfolio consisting of the above and currently-approved EEC program areas, with all funding being subject to the same financial treatment as approved in the EEC Decision;
4. Recovery in a deferral account of the revenues and ongoing O&M and the related expenditure of capital related to investment in energy solutions in NGV and alternative energy.
5. Approval of Tariffs for Rate Schedule 6C – Natural Gas Compression and Refuelling Service and Rate Schedule 26 – Natural Gas Vehicle Transportation Service, and subsequently the cancellation of Rate Schedule 6A – General Service – Vehicle Refuelling Service.
6. Approval of the economic models for evaluating new community energy solutions, and the proposed streamlined regulatory processes for approval of individual projects.

The approvals sought are reasonable and prudent and should be approved.

a) Energy Efficiency and Conservation Programs

The proposed increase in funding to support EEC programs for Interruptible Industrial customers as well as funding for specific Innovative Technology programs is consistent with the Commission's EEC Decision. The EEC funding sought for 2011, which matches the level of 2010 EEC forecast spending, will permit the ongoing funding in program areas approved in the EEC Decision. We believe that the requested EEC funding is prudent and in the interests of customers

On May 28, 2008, TGI and TGVI filed their EEC Programs Application, for funding of EEC programs for the 2008-2010 period. The application requested approval for a total of $56.6 million (for both TGI and TGVI collectively), capital treatment and amortization period of 20 years, and a portfolio methodology for evaluating the costs and benefits of the overall EEC portfolio. On April 16, 2009, TGI and TGVI received

BCUC Order No. G-36-09 which approved funding in aggregate of $41.5 million ($34.4 million for TGI and $7.1 million for TGVI), capital treatment of all expenditures with an amortization period of 10 years, and approval of a portfolio approach to evaluating the costs and benefits of the overall EEC portfolio. The Companies did not receive approval for expenditures for innovative technologies and the Companies were directed to bring forward projects in this program area for consideration as the projects become more fully developed. The Companies were directed to commence a planning process for the development of an Industrial EEC program and file a report with the Commission within 90 days of the Decision. The Company proposes that this reporting requirement is satisfied with the Industrial EEC information included in this filing. The Companies were also directed to proceed with a Joint Initiative relating to Affordable Housing and the Commission encouraged Terasen Gas to consider re-allocating funding from other approved areas of its overall spending as may be suitable.

Table C-3-1 shows the breakdown of approved 2008-2010 funding by regulated entity and the expected timing of expenditures for 2009 and 2010.

Table C-3-1: EEC Approved Funding for 2008-2010

	2008		2009		2010	Total
	O & M	Deferral	O & M	Deferral (Forecast)	Deferral	
TGI ('000s) Programs as per EEC	$ 1,740	$ 744	$ 1,624	$ 7,258	23,075	**$ 34,441**
TGVI ('000s) Programs as per EEC	$ 452	$ -	$ 497	$ 1,379	$ 4,726	**$ 7,054**

We are seeking approval for funding in 2011 for program areas outlined in the EEC Application and already approved by the Commission for 2010, with the reallocation of some of these funds to low income and rental housing programs as described below. TGVI will be seeking approval for similar EEC expenditures in its revenue requirements application to be filed later this month. We are also seeking approval of funding for 2010 and 2011 for Interruptible Industrial programs as well as funding for specific programs under Innovative Technologies. For TGI in 2010, these new programs add $2.8 million to the amount approved by BCUC Order No. G-36-09. An additional $6.5 million for 2011 is being sought for Interruptible Industrial programs and Innovative Technologies. This spending is outlined in the table below. The funding for EEC activities represents a placeholder for total dollar amounts that can be used to delivery programs to the benefit of customers. This funding envelope represents the total amount of dollars that would be spent by the Company on EEC activities for 2010 and 2011. However, over time, only the actual spend on EEC activities will be charged to the EEC deferral account and ultimately reflected in customers delivery rates.

Table C-3-2: EEC Funding Sought for 2010 and 2011

	2008		2009		2010	2011
	O & M	Deferral	O & M	Deferral (Forecast)	Deferral	Deferral
TGI ('000s) Programs as per EEC	$ 1,740	$ 744	$ 1,624	$ 7,258	23,075	$23,075
Interruptible Industrial					$ 435	$ 1,875
Innovative Technologies					$ 2,334	$ 4,669
TGI Total					**$ 25,845**	**$29,619**

The basis for the funding requests is outlined in the following sections.

(1) 2011 EEC PROGRAMS

As noted, Terasen Gas wishes to extend to 2011 the programs approved by the Commission in Order No. G-36-09 for the three year period 2008-2010. The expenditures for 2011 are set to match the forecast expenditures for 2010. The breakdown of the programs and cost are the same as that approved in the EEC Application Decision, as outlined in the table below.

Table C-3-3: EEC Program Breakdown and Cost for 2011

2011 Program Area Description		**Budget Amount (000)**		
		Incentives	**Non-incentive Costs**	**Total**
Residential	Energy Efficiency	$2,818	$1,257	$4,075
Commercial	Energy Efficiency	$10,471	$4,292	$14,763
Residential	Joint Initiatives	$1,010	$337	$1,346
Residential	Conservation Education and Outreach	$0	$1,445	$1,445
Commercial	Conservation Education and Outreach	$0	$1,445	$1,445
Total		$14,299	$8,776	$23,075

We believe that these programs and expenditures are consistent with the approvals already received for the years 2008-2010 and therefore should be approved by the Commission. The basis for the funding in these areas was outlined extensively in the EEC Application. In support of this request TGI relies on information and appendices filed in the EEC Application that have been identified and included in Appendix G-1.[148] This information includes the Conservation Potential Review ("CPR") and the Habart

148 Included in Appendix G-1, included the TGI's 2008 EEC Application and Appendices 1, 9, 10, 11 and 12

report used to refine the results of the CPR. The evidence demonstrates the benefits of extending funding for a further year.

TGI will use the same portfolio approach and same financial treatment as that approved in BCUC Order No. G-36-09 to assess TGI's EEC expenditures. The portfolio approach allows flexibility in allowing the Company to redirect dollars from one program area to another as long the TRC test for the portfolio as a whole is 1.0 or greater. In this case, the portfolio under consideration would include all EEC programs, i.e. the previously-approved funding as well as the proposed new funding.

(2) RE-ALLOCATION TO LOW INCOME PROGRAMS AND RENTAL HOUSING

Of the EEC funding approved for 2010 and requested for 2011, TGI will allocate a minimum of $800 thousand to conservation for the low income and rental housing sector, with the potential for an additional re-allocation. The minimum proposed amount of $800 thousand for EEC activity for the low income and rental housing sector is based upon the annual proposed expenditure in the Joint Initiatives program area of Terasen Gas' EEC Application, and approved in BCUC Order No. G-36-09. We are in the process of implementing EEC programming for the low income and rental housing sector for the 2009 - 2010 period. As such we believe we will be able to increase the funding toward the low income and rental sector above $800 thousand. It is our intention to re-allocate an additional $1.6 million in funds from both the Residential and Commercial programs outlined above to low income and rental programs in each of 2010 and 2011.

(3) INDUSTRIAL ENERGY EFFICIENCY

This Application sets out our plan for the development of industrial programs including a revised Manufacturing and Industrial Conservation Potential Review ('CPR"), stakeholder meetings, program development and lastly funding requests. As such, it addresses the following Commission directives in BCUC Order No. G-36-09:

> *"The Commission Panel takes note of the MEMPR Letter of Comment, and directs Terasen to commence the planning process for the development of an industrial EE program and to file a report outlining the process contemplated and scheduling of the development plan with the Commission for review within 90 days of this Decision. The matters addressed in the report should include those raised by MEMPR in Exhibit C4-1."*

Exhibit C1-4 (not C4-1) from the MEMPR broadly states that it notes the absence of an industrial energy efficiency program and that this may result in missed opportunities for energy reduction. The MEMPR goes on to further state that:

> *"Ministry submits that the Commission include in its final determination on the Application:*
> 1. *A requirement for the Companies to refine the CPR for the manufacturing sector at the earliest opportunity.*
>   a. *Include the Companies' largest manufacturing accounts in the CPR.*
>   b. *Identify and develop specific DSM measures for the manufacturing sector.*
> 2. *The Commission should establish a timeline for the Companies to submit for approval a supplemental application for manufacturing sector DSM measures."*

With respect to the development of EEC programs for manufacturing sector, it is important to note that the approvals received via BCUC Order No. G-36-09 actually do include funding for industrial customers. The funding approved so titled "Commercial" customers includes those customers in sales Rate Schedules 2, 3, 4, 5, 6, and transportation Rate Schedules 23 and 25. Of these, TGI considers Rate Schedules 4, 5, 6, 23 and 25 to represent primarily large commercial and industrial customers[149][150]. Therefore the only customers who do not currently have access to any funding, and for which additional funding is required, are those in the Interruptible Rate Schedules 7, 22 and 27. For customers in Rate Schedules 4, 5, 23 and 25, there is currently sufficient funding available, but TGI needs to further develop manufacturing process load programs for customers in Rate Schedules 4, 5, 23 and 25.

Key in developing industrial and manufacturing programs for customers served under Rate Schedules 4, 5, 23 and 25 as well as interruptible Rate Schedules 7, 22 and 27 is that since the time of both the Conservation Potential Review - Manufacturing Sector Report ("Manufacturing CPR") (commissioned in 2006) and the EEC Application, the industrial sector has significantly changed in scope and scale (this is further referenced in Part III, Section C, Tab 4). Primarily, volumes have decreased in the industrial sector as a result of changes in the marketplace, fuel switching alternatives and changes in economic drivers. For example the Manufacturing CPR identified a number of opportunities in the forestry and greenhouse sector. Since the time of the Manufacturing CPR, forestry has significantly declined with many operations either closed, idled and in a number of cases, in bankruptcy proceedings. Those that are operational may have difficulty raising capital for asset expenditures or have already taken steps to become efficient and that has partly led to their resilience. Similarly, nearly all greenhouses have

[149] Note that in Rate Schedule 23 and 25, customers represented include heavy industry, strata corporations, institutions. This is covered in greater detail in Section 5 of this application.

[150] Note that the programs described in the EEC Application do not include programs for industrial process energy efficiency programs for these rate schedules.

installed wood waste systems used as their primary energy source. Gas has been used only as a backup; although due to recent low gas prices and increases in wood waste prices and lack of wood waste, we have seen an increase in gas use as a primary fuel. As a result of these changes there may not be as significant an opportunity for gas related EEC programs for these industrial groups.

To ensure that TGI provides programs that meet the customer's needs, TGI needs to better understand the economic and environmental drivers of this diverse group of customers. TGI proposes the following process for the design and implementation of a program to develop both programs for firm industrial customers served under Rate Schedules 4, 5, 23 and 25 as well as programs and funding for interruptible customers served under Rate Schedules 7, 22, and 27.

(a) Stakeholder Consultation

Stakeholder input is crucial to the development of any industrial EEC program due to the relatively small number of customers on industrial rates and the potential for the relatively large incentives needed to spur activity in the industrial sector negatively impacting rates for non-participants. TGI convened a workshop with industrial customers, the MEMPR and other stakeholders on May 19, 2009. Through this workshop and comments received from participants, it became apparent that TGI must do more work to develop programs to meet EEC needs of this group of customers. There was support for additional funding and programs and energy efficiency audits. However, participants and TGI acknowledged:

- TGI does not have experience with developing industrial programs, and will require further time to develop suitable programs; and
- Incentives and programs may have to be unique to either the industrial group or in many cases the individual customer.

We will convene further industry specific workshops, and customer meetings concurrent with the RRA process. The input gathered in the additional meetings and workshops will be invaluable in developing industrial EEC programs.

(b) Update to 2006 Manufacturing Sector Report in Terasen Gas CPR

TGI will commission an update to the 2006 Manufacturing CPR. It has now been three years since the last Manufacturing CPR, and the market has changed significantly since the report was originally received by the Company in May 2006. An updated report will give the Company a very high-level indication of the size and nature of EEC opportunities in this sector. The findings will be then be validated with the MEMPR Industrial DSM Stakeholder Group.

(c) Initial High-Level Budget

The budget below represents TGI's initial, high-level estimate of the expenditures that will be required to support EEC activity for the interruptible industrial sector for 2010 and 2011. It includes funding for: activity related to the workshops and customer meetings; an additional staff member with expertise in the Industrial and Manufacturing Sector; and, a series of in-depth energy savings potential studies, or mini-CPRS, with individual customers in the food processing, manufacturing and forest products sectors in 2010. Collectively the workshops, meetings with individual customers, updated Manufacturing CPR and audits in 2010 will provide data for evaluating the provision of incentives budgeted for 2011. TGI expects that the learnings from programs in 2010 and 2011 will help form the basis for expanded programs in the period 2012 forward.

Table C-3-4: TGI's High-Level Budget of the Expenditures Required to Support EEC Activity for the Interruptible Industrial Sector for 2010 and 2011

Industrial EEC	
Preliminary Budget for RRA	
2010	
Item	**Budget Amount**
Stakeholder Activity	$5,000
Additional position to administer Industrial DSM Program	$120,000
Consultant Update to 2006 Manufacturing CPR	$100,000
Energy Savings Potential Studies	
Food Processing Sector (3)	$60,000
Manufacturing Sector (3)	$60,000
Forest Products Sector (3)	$90,000
Total Year 1	**$435,000**
2011	
Item	**Budget Amount**
Stakeholder Activity	$5,000
Additional position to administer Industrial DSM Program	$120,000
Incentives	
Food Processing Sector (1)	$500,000
Manufacturing Sector (1)	$250,000
Forest Products Sector (1)	$1,000,000
Total Year 2	**$1,875,000**

TGI will continue to provide leadership developing expanded EEC programs. We believe that the process for determining programs described above is prudent and will result in appropriate industrial energy efficiency program needs. The funding request is reasonable and necessary to initiate a successful suite of industrial programs in the manner directed by the Commission. We respectfully request that the Commission approve the above noted funding for industrial EEC.

(d) Innovative Technologies

In its April 16, 2009 decision on TGI and TGVI Energy Efficiency and Conservation Application, the BCUC stated that:

> *"The Commission Panel considers that Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies to reduce or replace natural gas consumption and related GHG emissions."*

The BCUC further stated that:

> *"The Commission Panel finds that there is insufficient evidence with respect to the nature and scope of the proposed program, and accordingly rejects the Innovative Technologies, NGV and Measurement program expenditures at this time. Terasen may wish to bring forward projects in this program area for consideration as they become more fully developed."*

TGI has since evaluated the market and need for innovative technologies. This Section of the Application provides an overview of EEC initiatives we intend to pursue through the use of innovative technologies. TGI's proposed programs are in the interests of customers and therefore should be approved.

(e) Residential and Small Commercial

Hydronic Based Heating Systems - Hydronic heating systems use liquid (water with corrosion inhibitors) to distribute energy for space and domestic hot water heating through a supply and return closed-loop piping system.

The flexible nature of this system ensures that the energy input can be changed with changes in technology and public policy, thus promoting a more sustainable energy design. An old low efficiency boiler can be upgraded to a high efficiency condensing boiler. Later the customer installing the boiler may be able to obtain energy from a district energy heating system, biomass, ground or solar energy sources. By utilizing this hydronic based heating systems for space and domestic hot water heating, an owner will be in a position to replace or supplement one type of energy source with another source as technology advances.

Given existing technologies, upgrading from a low efficiency boiler to a high efficiency boiler could result in a 20-30 per cent reduction in a residential customer's natural gas consumption. For the average family home this alone would be equivalent to 725 to 900 Kg of CO2e/yr. Similar reductions of 20-30 per cent in natural gas consumption in the small commercial sector could be achieved when upgrading from a low efficiency boiler to a high efficient boiler.

The cost on average for hydronic underfloor system materials is estimated to be about $4,000, not including the cost of the boiler. The average cost of hydronic baseboard materials is estimated to be approximately $2,000, again not including the cost of the boiler. In order to promote a sustainable energy design, the Companies will provide incentives up to 25 per cent of cost of the hydronic under floor piping materials (oxygen barrier tubing) to a maximum of $1,000 and hydronic baseboard materials up to 25 per cent and a maximum of $500. For 2010 spending will equal $778 thousand and for 2011 spending will equal $1.6 million for a two year total of $2.3 million.

Integrated Energy Systems (or Combination Systems) - Integrated Energy or Combination Systems are defined as a single appliance supplying both space and domestic hot water ("DHW") heating. Combo heating systems can be cost effective and increase the operating efficiency of tank-style water heaters by reducing their normal standby energy losses. The hot water tank can be connected to a fan coil to provide forced air heating, and the fan coils can be upgraded to provide air conditioning as well. Combo systems can also be connected to in-floor tubing to provide in-floor radiant heat.

TGI is already encouraging efficient boilers in new construction with heat exchangers through the existing Efficient Boiler Program, although the smallest boiler is 300,000 Btu/hour, thus excluding residential boilers from this program. There is a possibility that more high efficient hot water tanks could be utilized in combo systems.

Standard gas hot water tanks are about 60 per cent efficient. Improving the energy efficiency of domestic hot water heating to above 90 per cent efficiency will reduce GHG emissions.

A program to fund high efficiency (condensing) hot water tanks used for space and domestic hot water heating would help to drive demand for high efficiency gas hot water tanks. Right now these types of tanks cost approximately $3,000-$3,500 compared to $450-750 for a standard gas hot water tank. Installation costs would be comparable for both tanks. Instantaneous or tankless systems can be used for this application as well. Given that the average single family dwelling annually consumes 25 GJs of gas for domestic hot water, moving from 60 per cent to 90 per cent efficiency would produce savings of about 8.3 GJs per household per year. This could equate to a reduction of about 400 kilograms/year of CO2e. We will provide incentives up to 25 per cent of total cost of condensing hot water tanks to a maximum of $1000. This will equate to incentives of $518 thousand for 2010 and $1 million for 2011 for a total o f$1.5 million for the RRA period.

Solar thermal - A subset of hydronic heating systems, solar thermal systems also use water or glycol heated by the sun, with the thermal energy used for space and domestic hot water heating. Solar thermal space and water heating is usually supplemental to existing systems and reduces the use of the primary energy source used in the system.

Solar thermal space heating is cost prohibitive today and adds approximately $30,000 to the cost of construction for an average new single family detached home. Solar thermal domestic water heating at present costs about $8,000 for an average home and can be used as a supplement to the existing hot water tank to supply roughly half of the yearly water heating energy requirements.

Any solar energy usage results in GHG savings for that part of the load that it displaces. As a result, GHG production can be reduced by about 50 per cent.

The average household uses approximately 25 GJ/year for domestic water heating. If there was an annual reduction in gas usage of 12.5 GJ/year, that would reduce household greenhouse gas production by approximately 600 kilograms/year of CO2e.

We will provide incentives of $1,000 towards a solar thermal hot water system so long as natural gas is used to provide the balance of energy for the system. This will equate to incentives of $518 thousand for 2010 and $1 million for 2011 for a total of $1.5 million for the RRA period.

Ground Source Heat Pumps ("GSHP") - A GSHP uses the earth or ground water or both as the sources of heat in the winter, and as the "sink" for heat removed from the building in the summer. Heat is extracted from the earth with a liquid, such as ground water or an antifreeze solution, upgraded by a heat pump, and transferred to indoor air via a heat exchanger. During summer months, the process is reversed as heat is extracted from indoor air and transferred to the earth through the ground water or antifreeze solution.

GSHP systems are available for use with both forced-air and hydronic heating systems. They can also be designed and installed to provide heating only, heating with "passive" cooling, or heating with "active" cooling. Passive-cooling systems provide cooling by pumping cool water or antifreeze through the system without using the heat pump to assist the process.

GSHP systems are more costly than gas or electric systems and can add upwards of $10,000 to $20,000 to the cost for average new home construction. GSHP can be used as the primary source of energy to heat a building; however they do require a back-up source of energy such as a gas fired boiler.

The average household uses approximately 53 GJ/year for space heating. With a GSHP combined with a natural gas boiler for back-up there could be annual reduction in gas usage of 35 GJ/year per installation, which would reduce household greenhouse gas production by approximately 1.6 tonnes per year.

We will provide incentives of $1,000 towards the installation of GSHP pre-piping and provisions for the future installation of the heat exchanger. This will equate to incentives of $518 thousand for 2010 and $1 million for 2011 for a total of $1.5 million for the RRA period. To be eligible for incentives the installation must meet also meet the following criterion:

The GSHP must be backed up with a natural gas boiler for new construction and for retrofit installations. The GSHP system uses either a closed loop (i.e. under-ground piping) or an open loop (i.e. well, if the water source is suitable). The system equipment, design and installation meets CSA Standards

We believe that it is the utilities responsibility to continue and expand its energy efficiency and conservation programs available to customers. We believe that the programs detailed in these sections are in the interest of customers and should be approved.

b) Alternative Energy Solutions

The second part of TGI’s strategy for meeting evolving customer needs and government policy is to pursue new alternatives to augment and enhance our core gas business. Natural gas will remain a foundational source of energy for the foreseeable future.[151] The pursuit of the new Tariff offerings

[151] Please see TGI’s most recent Resource Plan, at www.terasengas.com

identified in this section for NGV compression and transportation service, as well as investment in biogas recovery, geothermal, solar thermal and district heating, is a prudent response to the challenges being faced by traditional natural gas service. We believe that it is in the best interest of both existing and new customers that TGI offer these alternative energy solutions, with the program, development and sales costs of these activities recovered as part of the revenue requirement.

The following sections report on TGI's specific opportunities that we intend to pursue, propose a regulatory model to assess each opportunity, and comment on other alternative energy solutions TGI intends to pursue in the future.

(1) NATURAL GAS VEHICLES ("NGV") RATE OFFERINGS

With the reduction of natural gas use as a result of energy policy, industrial, commercial and residential use, natural gas vehicles are one of the main areas where there is potential for volume growth. The growth of NGV benefits existing customers by adding natural gas customers with high load factors[152] to the TGI system. Government policy also supports NGV as a cleaner alternative to fuels like diesel, gasoline and propane. Natural Gas as an alternative is the cleanest burning fossil fuel as it has the fewest carbon molecules on the atom.

On June 8, 2009, TGI received BCUC Order No. G-65-09 which approved Rate Schedule 16 – Interruptible Liquefied Natural Gas Sales and Dispensing Service. To further support and grow the NGV market TGI proposes two new rate schedules:

1. Rate Schedule 6C – Natural Gas Compression and Refuelling Service
2. Rate Schedule 26 – Natural Gas Vehicle Transportation Service

These service offerings are targeted mainly at fleet customers that have return-to-home vehicle fleets, where refueling can occur at the end of each day. The Compression and Refueling Service contemplates that TGI will construct the necessary facilities for a fleet, and the customer would be charged a postage stamp rate of $5/GJ for compressed natural gas. The rate is designed to recover the cost of compression over a reasonable period of time, while ensuring that the service remains competitive with alternative fuel choices. Customers can combine compression service with a delivery service through either a sales or transportation Rate Schedule. The transportation service proposed under Rate Schedule 26 is the same delivery service as that currently provided under Rate Schedule 6, except that customers would have the option of purchasing the commodity from a marketer. TGI's proposal overcomes the potential

[152] Adding customers with a high load factor is advantageous as they increase the efficient use of the pipeline system therefore reducing costs to all other customers.

obstacle to adoption arising from the capital cost of compression and delivery facilities. Other potential hurdles to take-up exist, notably fleet conversion costs and availability of natural gas vehicles. We nonetheless believe that by offering compression and NGV transportation service, with the associated grants already available from Terasen Gas, customers will be more likely to embrace NGV as part of their fleet operations.

Below, we discuss the drivers behind this rate offering, the opportunity presented, followed by a discussion of how the proposed Rates were designed.

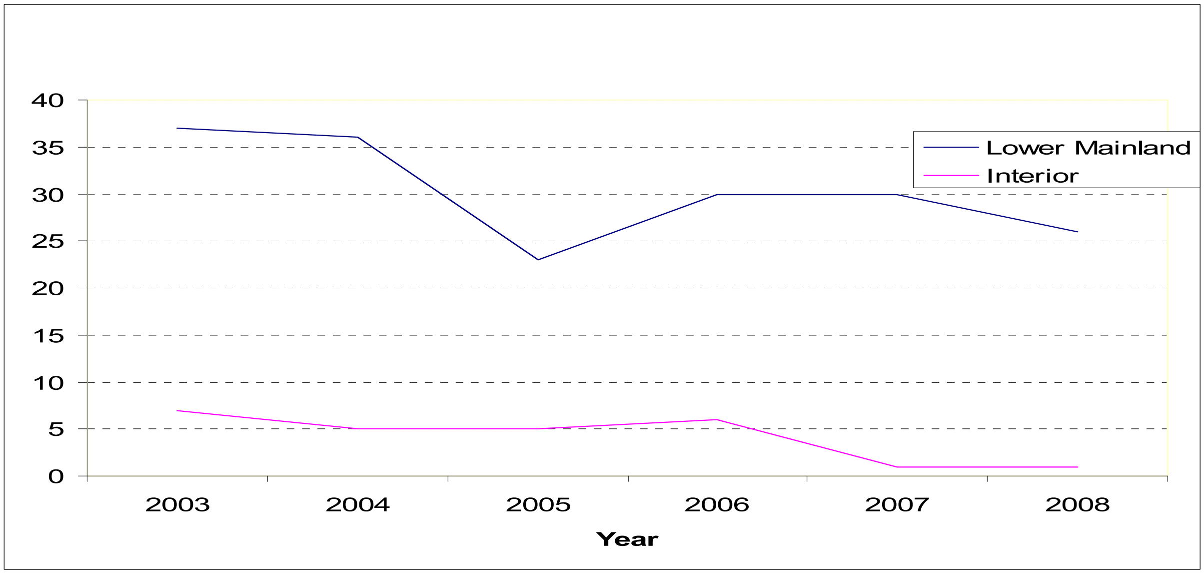
(a) Overcoming Market Obstacles

The number of Rate Schedule 6 – Natural Gas Vehicle Service customers has declined from 2003 to 2008. This decline is primarily due to the limited number of Original Equipment Manufacture ("OEM") vehicles, the limited presence of a third party compression provider, limited infrastructure to support re-fuelling, no concerted sales effort to educate customers about CNG as an option for fuelling, the cost of conversions and no clear policy direction encouraging lower emissions. Consumers in the BC market may still be cautious of using natural gas vehicles, due to the history behind natural gas vehicles in the 1990's. Some BC residents recall purchasing or converting vehicles only to experience vehicles that did not operate as proposed, and fueling stations that closed or were moved. In addition, North American auto makers stopped making the few OEM vehicles that were previously offered. However, with the change in policy, and a wider interest in using vehicles that are more efficient and reduce emissions, natural gas vehicles have an opportunity to make a resurgence. In addition, CNG technology has evolved significantly since early 2000's and this technology is just beginning to be showcased here in BC. IMW Inc now produces compression equipment in its Abbotsford manufacturing facility and Westport Innovations Inc. of Vancouver designs and in partnership with Cummins Westport Inc. manufactures heavy duty natural gas engines. Together, along with support from provincial energy policy, we believe we can deliver a made in BC solution to overcome the hurdles noted above.

(b) Decline in NGV Service Customers

Figure C-3-1 below presents the number customers served under Rate Schedule 6 – Natural Gas Vehicle Service between 2003 to 2008.

Figure C-3-1: Rate Schedule 6 Customers (2003 to 2008)



Gas Consumption (GJ's)						
For Year Ended	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Lower Mainland	261,115	232,242	160,414	113,970	94,204	79,902
Interior	20,527	20,036	23,095	23,571	16,552	10,704
Total Consumption	281,642	252,278	183,508	137,540	110,756	90,606

Although a decline in Rate Schedule 6 customers and volume has been observed from 2003 to 2008 we see an opportunity for future growth in this market. Customers are seeking ways to reduce their energy costs and meet carbon reduction targets, heavy duty OEM vehicles are available locally through Westport Innovations Inc., compressors are manufactured locally by IMW industries, government policy aligns with an increase in NGV usage, and increased sales efforts by NGV parties are all contributing to increased interest in NGV usage. [153]

(c) Market Opportunity and Potential

The Wesport White Paper[154] discusses the economic and environmental benefits of NGVs. The paper notes that not only does using NGV reduce GHG emissions, they also can reduce the cost of fuel for

153 Above figures do not include NGV volumes consumed under other rate schedules such as Rate Schedule 25. Currently, customers who do not wish to resell natural gas and who do not receive NGV grants may receive service under any other rate schedule for which they meet the applicability requirements. It is for this reason that we wish to provide a transportation option for customers who wish to resell gas and for whom also wish to receive NGV grants. Rate Schedule 26 will offer this alternative.

154 See Appendix G-2 for a copy of Westport White Paper

customers. The paper further states that there are over 17,000 heavy duty trucks, 103,000 medium duty trucks and 1,400 transit buses in BC. We see this as an opportunity to increase natural gas load on our system, meet customer needs and align with government policy direction.

(i) Return-to-Home Fleets

The main drawbacks currently with NGV are lack of re-fuelling infrastructure and limited travel distance due to the need for compression tanks on the vehicle. We believe a bundled natural gas supply, options for transportation NGV service, and compression and refueling service will be more attractive to new and existing customers and promote the growth of the CNG market. The opportunity is greatest for fleet vehicle operators with "short haul, return to home" fleets. As noted in the Westport Paper, these include transit buses, and heavy and medium duty trucking fleets, and also school bus and forklift fleets.

All of these market segments offer opportunities for the transportation sector to use natural gas as a fuel source that is cleaner, cheaper, and is in great abundance in the Province. Additionally, these markets are also an ideal target market for biogas as a supply source, which would enable transportation customers to be net zero emitters. Further details of these market segments are presented in the Westport Paper and below.

(ii) School Buses

Many communities in the US (mostly in California) use natural gas buses to transport children to and from school. The greatest advantage of the natural gas bus to this segment is the "cleaner burning" nature of the fuel, as well as the fact that the buses are so quiet.

(iii) Forklifts

There are a significant number of industrial companies in the province that have anywhere from 10-100 forklifts on site running continually in a given day. As opposed to buses which must be OEM delivered vehicles, to provide natural gas vehicle service to a forklift, the propane forklift must simply be converted (a straightforward process costing approximately $3,500 CAD per vehicle). Compression is then provide on-site for refueling purposes. CNG has significant advantages over propane, namely air quality improvement in warehouses leading to healthier work conditions, and lower GHG emissions. In addition customers may see fuel cost savings when switching from propane to natural gas.

(iv) Compression and Refueling Service

Currently, natural gas compression and refueling service is available at 14 public stations in the Lower Mainland, in additional there are private stations owned by business and municipalities. In TGI's opinion, the main hindrance to new entrants into the commercial compression market is the up-front capital required. We believe that in order for the NGV market to grow, we must play a pivotal role by providing compression service to customers who do not wish to own and operate their own compression service. Below, we discuss the types of compression that TGI would make available under its proposed Compression Rate, and more detail about the derivation of the Rate.

(a) Types of Compression

There are two categories of compression and refueling equipment available, slow-fill (or time fill) and fast-fill. TGI would be in a position to offer either service.

The typical application for slow fill is a return to home fleet, such as delivery trucks of forklifts, where drivers connect the vehicles overnight to the fueling infrastructure. Fueling tends to take about 8-10 hours and vehicles are fully fueled by morning and ready for use. Fast-fill compression, as the name implies, fuels in a much faster time frame; although the speed of fueling requires a higher price tag, a greater reliance on "redundancy," and maintenance. The following table summarizes the two categories:

Table C-3-5: Summary of Slow Fill and Fast Fill

Slow Fill	Gas is compressed and dispensed slowly directly to vehicles' onboard storage tank. Lower cost station investment. Best for fleets that return to central lot and sit idle overnight or for extended periods.
Fast-fill	Similar to liquid fueling station, same fill rates and times. A MUST for public access. Also good for larger fleets where fueling turn-around time is short.

The type of refueling required on a specific site is dependent upon the individual customer's needs and as such differ greatly from installation to installation. Often there may be a combination of natural gas refueling options such as fast and slow fill depending on customers' operational requirements.

(b) Proposed Compression and Refueling Service Rate

TGI intends to purchase, own, install and operate the compression and refueling equipment necessary to provide compression service to customers. In addition the Company will also maintain the equipment either using internal resources or securing services from external service providers. We propose a postage stamp, volumetric charge of $5.00 per GJ for the compression and refueling service, which would be in addition to delivery and commodity charges. The volumetric charge creates an appropriate incentive in terms of conservation and demand side management. In addition, this rate structure is how vehicles are currently served with other fuels such as gasoline and diesel. TGI arrived at the $5.00 per GJ charge through a two-prong approach of economic alternative analysis and cost of service analysis. In order for compressed natural gas to be competitive, the bundled cost of natural gas compression, delivery and commodity must be significantly lower than the alternative fuel; that being gasoline, diesel or propane. Due to the incremental capital cost of a natural gas vehicle, a lower bundled charge for both natural gas and refueling service will allow for a payback period that, depending upon vehicle type and usage, can be anywhere from 1-10 years. If there is no payback, the only incentive for customers to use natural gas is reduced emissions; this alone is generally not enough to encourage a customer to use natural gas. Secondly, to be competitive, the rate must be one that is similar in structure to rates customers pay for other fuels. Gasoline, diesel and propane are sold using a strictly volumetric rate. As such a compression and refueling rate must not only be competitive but should also be volumetric in nature. When combined with the current delivery and commodity charge, bundled NGV service (Rate Schedule 6 charges plus the proposed compression and refueling charge) equals:

$0.59/Diesel Litre Equivalent (“DLE”)
$0.37/Propane Litre Equivalent (“PLE”)
$0.47/Gasoline Litre Equivalent (“GLE”)

These rates are competitive with the present costs of propane, gasoline and diesel are shown in the table below:

Table C-3-6: MJ Ervin Pump Price Survey – Retail Vancouver Pump Price

Propane	Diesel	Gasoline
53.4/L	91.1/L	106.9/L

Below are three graphs showing the relative competitiveness if TGI had a $5.00/GJ compression and refueling rate (bundled with the delivery and commodity rates effective January 1 of each year) as compared to the retail rates for propane, gasoline and diesel:

Figure C-3-2: Propane vs. Natural Gas (PLE)

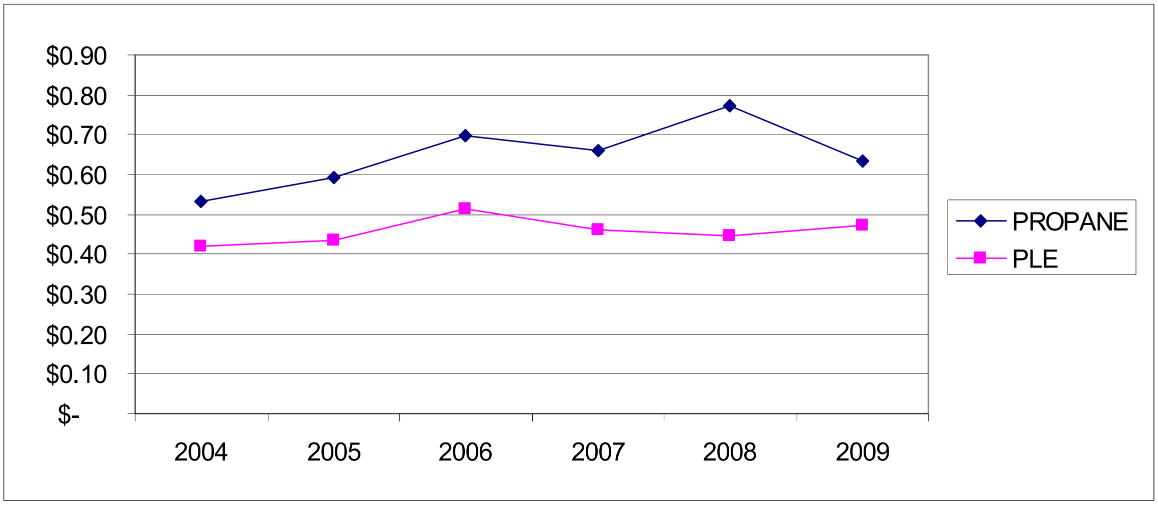


Figure C-3-3: Diesel vs. Natural Gas (DLE)

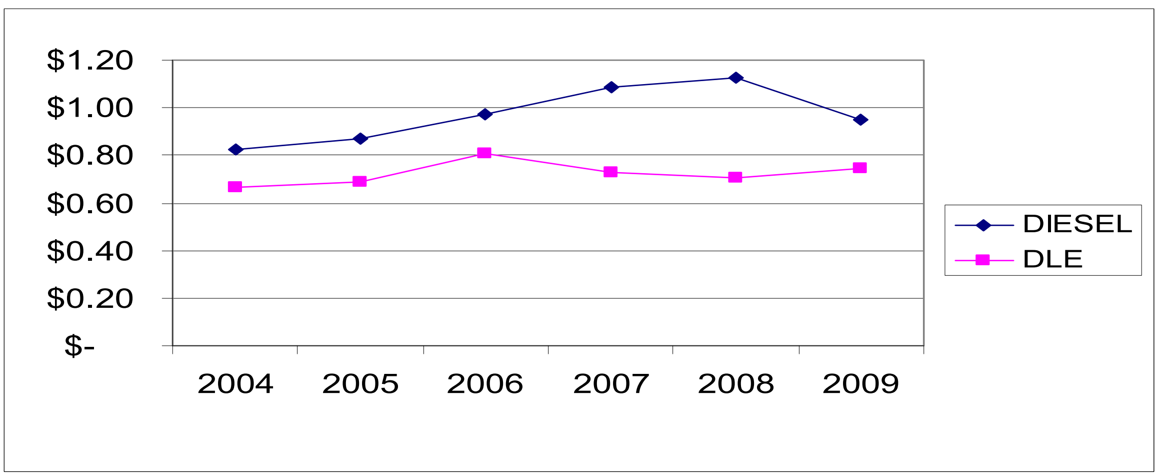
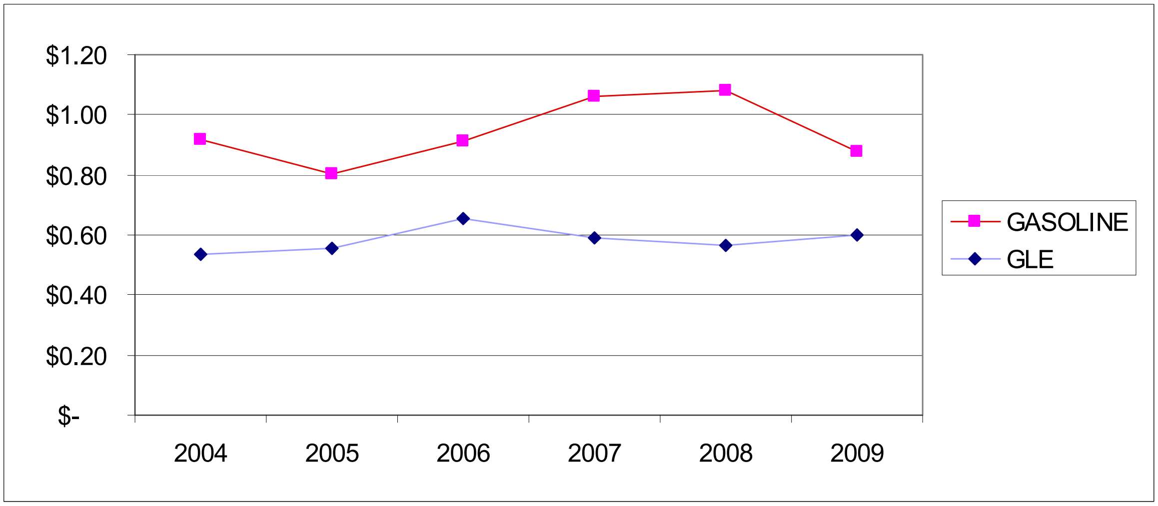


Figure C-3-4: Gasoline vs. Natural Gas (GLE)



The second prong of the approach to arriving at a postage stamp rate for the compression and refueling service is a cost of service ("COS") analysis. For the COS analysis, TGI assumed a 5-year scenario consisting of various costs (capital and O&M) and demand (vehicles and consumption). TGI arrived at the capital costs and demand forecasts by using its projected sales targets for compression service. The capital and operational costs were provided by compression equipment providers. Demand was based upon what we believe is a reasonable target for fleet vehicle additions. The analysis was based on matching the capital investment or the capital cost of the compressor equipment, along with the other COS components including O&M, depreciation, and taxes, with the short-term demand (5-year, the same time frame as a traditional MX Test) for Compression and Refueling Service. The result of the analysis was a compression and refueling rate of approximately $5.00 per GJ. The tables below outline the capital costs and resulting COS including the volume assumptions.

Table C-3-7: 5-Year Capital Additions Assumptions

	Year 1	Year 2	Year 3	Year 4	Year 5
Capital Additions ('000)	$ 238	$ 294	$ 399	$ 35	$ 873

Table C-3-8: Cost of Service Summary

NGV Station										
Cost of Service Summary ($Thousands)										
Calendar Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Nominal "000$	1	2	3	4	5	6	7	8	9	10
Equipment Options										
Total Operating & Maintenance	14	39	75	76	135	138	141	144	146	149
Depreciation	4	14	27	35	53	70	70	70	70	70
Income Tax	(7)	(19)	(29)	(29)	(41)	(48)	(31)	(17)	(7)	2
Property Tax	0	0	0	0	0	0	0	0	0	0
Debt Expense	5	17	32	41	61	80	77	74	71	68
Return on Equity	4	12	22	28	42	54	52	50	48	46
Total Annual Cost ('000$)	20	62	127	152	250	294	308	320	328	335
Annual Demand (GJ)	1,800	8,400	16,000	36,600	62,200	70,000	70,000	70,000	70,000	70,000
Annual Toll ($/GJ)	11.27	7.42	7.91	4.14	4.02	4.19	4.41	4.57	4.69	4.78
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
	11	12	13	14	15	16	17	18	19	20
Equipment Options (Continued)										
Total Operating & Maintenance	152	155	159	162	165	168	172	175	179	182
Depreciation	70	70	70	70	70	70	70	70	70	70
Income Tax	9	14	18	21	23	25	26	27	27	28
Property Tax	0	0	0	0	0	0	0	0	0	0
Debt Expense	65	61	58	55	52	49	46	43	40	37
Return on Equity	44	42	40	38	36	33	31	29	27	25
Total Annual Cost ('000$)	339	342	344	345	346	346	345	344	343	342
Annual Demand (GJ)	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Annual Toll ($/GJ)	4.84	4.89	4.92	4.93	4.94	4.94	4.93	4.92	4.90	4.88
Level Toll - 20 Years										
2009 - 2028, $/GJ $4.77										

A $5.00 per GJ compression and refueling rate will ensure that forecast revenues match or exceed the cost of service.

We believe the proposed compression and refueling rate is appropriate as the rate was derived using the best possible information on capital costs, usage rates, and O&M. In addition, the resultant rate will be competitive with diesel, propane and gasoline.

(v) Economic Test

For each application for Compression and Refueling Service, the Company proposes that the potential compression customer pass an economic test to assess the economic feasibility or profitability of the capital investment. In this case a compression customer would typically be a fleet operator on whose property the compression equipment would be located. An economic test would take into account the vehicles and associated expected volumes, and the revenue ($5.00/GJ) generated from those volumes. This would be compared against the costs for installation and operation of the compressor. The Company proposes to use a modified MX test, referred to in this Application as the Compression and Refueling Service ("CS") Test, which is described below. We believe this approach will ensure that existing customers are not subsidizing the Compression and Refueling Service, while at the same time ensuring that TGI is able to connect as many compression customers as possible. By adding new economic NGV customers to the TGI system, the existing system is used more efficiently and as a result the revenues from NGV delivery service will help to keep rates lower for all customers.

The CS Test, similar to the MX Test, is a twenty year discounted cash flow analysis which compares the present value ("PV") of cash inflows to the PV of the cash outflows from a proposed investment in compression and refueling equipment. The cash inflows used in the CS Test are the revenues from rates and fees paid by the customer or customers served by the compressor, as per the proposed Rate Schedule 6C, and do not include the Rate Schedule 6 delivery charges, commodity cost recovery charge or midstream cost recovery charge. The cash outflows are the estimated annual costs for the Company to install and operate the compression system in the first five years of the service including capital costs for materials and installation of the compressor and associated equipment, on-going operating and maintenance costs and upstream system improvement costs.

Again, similar to the MX Test, the CS Test is used to determine a PI that represents a ratio of the PV of expected revenues to the PV of expected costs. We propose to use CS Test parameters which are reflective of a compression and refueling service. The parameters are presented below:

Table C-3-9: CS Test Parameters

Parameter Name	TGI 2009 MX Test Parameters	Proposed CS Test Parameters	Comments for CS Test Parameters
Application Fee - New	$85	Case-specific	Not applicable if gas service received through Rate Schedule 6. Applicable to all other rate schedules to measure volume through compression equipment.
Application Fee - Existing	$25	N/A	Not applicable.
Change of Service Frequency	5	N/A	Not applicable.
Overhead Rate	32.0%	Case-specific	Based on cost of compression equipment.
CCA Class 1	6.0%	20.0%	NGV compression and fueling equiment are Class 8.
Project Life	20	20	Same
Discount Rate	4.20%	4.20%	Same
Fixed SI	N/A	N/A	Same. Not applicable.
Variable SI	$0.16	N/A	Not applicable. Included in MX Test for other rate schedules (i.e. Rate Schedule 6).
Income Tax Rate	30.0%	30.0%	Same
Income Tax Surcharge	N/A	N/A	Same. Not applicable.
Property Tax Rate	1.85%	N/A	Not applicable. Compression equipment similar to station.
Working Capital Rate	0.50%	0.50%	Same
Demand Charge	Rate dependant	N/A	Not applicable.
Fixed O&M	Rate dependant	Case-specific	Based on the model/size of compression equipment
Variable O&M	N/A	N/A	Same. Not applicable.
In Lieu Rate	Rate dependant	N/A	Not applicable. NGV revenues are exempt from property tax.
Fixed Margin	Rate dependant	N/A	Not applicable.
Variable Charge	Rate dependant	$ 5.00	Propose $5.00/GJ Compression Rate

The economic test will be based on the $5.00 per GJ compression and refueling rate presented above. Due to the small number of compressors expected in the early years of this service offering, we propose an individual PI of 1.0 rather than 0.8 used for individual main extensions. This will ensure that, based upon forecast consumption, new compression service customers will recover the costs associated with serving them. Therefore, if the PI is less than 1.0, the customer will be required to provide an upfront contribution in aid of installation as compensation for the revenue shortfall.

We believe the CS Test will ensure that existing customers are not harmed by customers under the Compression and Refueling Service, while at the same time ensuring that TGI is able to connect as many compression customers as possible.

(vi) Capital Additions and Revenue – Forecast and Treatment

Although the interest in this market has increased as a result of the BC Energy Policy and increased customer awareness of natural gas as a vehicle fuel, sales cycles are typically quite long. Customers must first be comfortable with the merits of natural gas vehicles and then they must then be prepared to either purchase OEM vehicles or convert existing vehicles. Once this commitment has been reached, only then can TGI contract to install compression service. As such, TGI sees modest growth over the two year period of the revenue requirement. Sales targets for capital investment, customers and volume are shown below.

Table C-3-10: Sales Targets for Capital Investment, Customers and Volume

2010						
Vehicle	**Capital Investment Potential**	**# of Vehicles**	**Annual GJ**	**1/2 Year GJ Volume**		**TOTAL GJ's**
School Bus	125,000	2	300	150		300
Fork Lift	100,000	10	200	100		1,000
Garbage hauler	250,000	2	1,000	500		1,000
P/U (Mixed Use)	150,000	5	200	100		500
	$ 625,000					**2,800**
2011						
Vehicle	**Capital Investment Potential**	**# of Vehicles**	**GJ**	**1/2 Year GJ Volume**		**TOTAL GJ's**
School Bus	250,000	4	300	150		600
Fork Lift	300,000	60	200	100		6,000
Garbage hauler	450,000	4	1,000	500		2,000
P/U (Mixed Use)	500,000	10	200	100		1,000
	$ 1,500,000					**9,600**

Note that the forecast capital additions are based on an estimate of the success of our sales efforts.

As TGI attaches compression customers we will incur ongoing O&M costs for the repair and maintenance of the compression equipment. These O&M costs are dependent upon not only the quantity of capital installed but also the type of equipment installed to serve specific customers. The O&M costs incurred in respect of each customer are appropriately accounted for as part of the CS Test.

As the sales cycle is long, the nature of customer acquisition uncertain, the timeline of capital expenditures undetermined and associated O&M expenses unknown, TGI is forecasting zero capital additions, O&M expenditures and revenues in this area for the purpose of the RRA. As such, TGI believes it is prudent and therefore proposes that revenues, ongoing O&M and capital attributed to additions in 2010/11 be recorded in a non-rate base deferral account for the period of the RRA. In this manner, existing customers' rates will not be impacted in 2010 and 2011 by capital and O&M expenditures, and associated revenues that are too uncertain to forecast at this time.

(vii) Approvals Sought

We request Commission approvals of Rate Schedule 6C - Natural Gas Compression and Refueling Service and Rate Schedule 26 – Natural Gas Vehicle Transportation Service which are included as Appendix J. If Rate Schedule 6C - Compression and Refueling Service (Appendix J-6) is approved, we also seek approval to cancel Rate Schedule 6A – General Service – Vehicle Refueling Service (Appendix J-5), as it will become redundant. We request approval of the deferral treatment of compression equipment costs and expenses. The Transportation Service and the Compression and Refueling Service, as proposed in this Section of the RRA, complements the existing NGV service and results in a comprehensive natural gas fuel service across the value chain which offers customers solutions in managing transportation costs and reducing GHG emissions. The rate proposals also benefit existing customers through the more efficient use of our delivery infrastructure.

As indicated above, we are seeking approval to record in a deferral account the revenues and O&M and capital expenditures associated with NGV and the service provided. In this manner, existing customers will not pay for capital costs, and associated revenues that are uncertain over the RRA Period.

(d) Biogas

The development of biogas upgrading and recovery projects represents an opportunity to recover useful energy from waste, to displace other consumption of fossil fuels such as diesel, to complement the use of natural gas, and to reduce greenhouse gas emissions. Biogas upgrading was identified in TGI's 2008 Resource Plan as a potential new supply resource for the Company to assist in meeting the goals of the

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TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

10. Inclusion of SCP Capacity in MCRA

The Parties agree that TGI will continue for 2010 and 2011 to include in the MCRA the $3.6 million representing the annual cost of Southern Crossing Pipeline (SCP) capacity, because the benefits and use of the SCP capacity are used by Core Market Customers (Rate Schedules 1-7).

11. Energy Efficiency and Conservation ("EEC") Funding for 2010

The Parties agree as follows in respect of the EEC funding sought by TGI for 2010:

(a) TGI will reallocate from residential and commercial EEC programs an additional $1.6 million from the amount approved for 2010 in the EEC Decision[5] to low income and rental housing programs. This brings the total for low income and rental housing programs to $2.4 million for 2010.

(b) EEC funding for industrial interruptible programs for 2010 will be $435,000, which is the amount requested by TGI in the Application.

(c) EEC funding for innovative technologies will be $2.3 million for 2010, which is the amount requested by TGI in the Application.

(d) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

12. EEC Funding for 2011

12.1 The Parties agree as follows in respect of the EEC funding sought by TGI for 2011:

(a) EEC funding for residential and commercial programs for 2011 will be $23.075 million, which is the amount requested by TGI in the Application.

(b) TGI will reallocate from 2011 residential and commercial EEC funding ($23.075M for 2011) an additional $1.6 million (from the $0.8 million included in the Application) to low income and rental housing programs. This brings the total for low income and rental housing programs to $2.4 million for 2011.

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[5] Decision and Order No. G-36-09 dated April 16, 2009 in the TGI-TGVI Energy Efficiency and Conservation Application

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DATED THURSDAY, NOVEMBER 5

(c) EEC funding for industrial interruptible programs will be $1.875 million for 2011, which is the amount requested by TGI in the Application.

(d) EEC funding for innovative technologies will be $4.669 million for 2011, which is the amount requested by TGI in the Application.

(e) All agreed to EEC expenditures will be considered and evaluated within the existing EEC portfolio, and will be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

(f) TGI will report to the Commission on industrial interruptible and innovative technology programs as part of TGI's annual report on EEC activities required under the EEC Decision.

The Parties offer the following rationale for the agreed upon 2011 EEC funding.

All Parties agree that it is important to maintain EEC funding levels in 2011 to allow customers to have continued access to EEC programs and incentives. The residential and commercial EEC programs relating to the $23.075 million funding in 2011 on a portfolio basis in aggregate have a TRC of one or more. This means that, from a resource perspective and on a portfolio basis, these programs are expected to yield favourable results for customers. The predictability and continuity of these programs on a sustained basis is critical to their overall success.

Issue No. 1 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "EEC Program – TGI is to provide results of programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding."

There are practical difficulties associated with the approach identified by the Commission Panel. They include the following:

- As per the EEC Decision (Order No. G-36-09), TGI will be reporting 2009 activities and results by no later than March 31, 2010. This report will also outline the forecasted activities and programs for 2010. Recognizing the timing of the recent EEC Decision and its current implementation in the Fall of 2009, the EEC Report for 2009 results will give the Commission and stakeholders another check point to validate the level of spend for 2011. However, there is expected to be very little additional information on the results of programs available in March 2010 than exists presently and is included in the evidentiary record of this proceeding. TGI's

EEC programs only completed start up phase in the Fall of 2009. It typically takes longer than 6-8 months to achieve momentum with EEC programs. There will be no information available in March 2010 on results for industrial programs or programs relating to innovative technologies initiated in 2010 as a result of this Agreement. The information that the Commission Panel appears to desire will be more likely included in TGI's 2010 results report to be filed in March 2011.

- Employees responsible for the programs at TGI, whose salaries are funded from EEC funding, will face the prospect of losing their jobs in 2011. This could lead to employee retention issues. Employee turnover issues may disrupt the program implementation progress and potentially be more costly if EEC activity is ceased and later resumed.

- Programs will need to begin winding down in advance of 2011 if the 2011 funding is not approved. For example, programs will need to have an end date of December 31, 2010 which may not yield positive results since programs will be winding up in the middle of the heating season.

12.2 The Parties agree that the Commission may sever Section 12.1 (a) and (b) above from this Agreement, with the remainder of this Agreement remaining in force and effect. If the Commission severs Section 12.1 (a) and (b), then the Parties agree that the following provisions take effect:

(a) The Residential and Commercial EEC programs totaling $23.075 million in 2011 will be removed from the EEC expenditure forecast and the revenue requirements for 2011. (If 12.2 takes effect, the financial schedules in Part IV of this Agreement and the revenue requirements resulting from this Agreement will be revised to reflect this).

(b) The Parties agree that the first annual report on EEC Activities, which was due to be filed on March 31, 2010 pursuant to Order No. G-36-09, can be filed on or before June 30, 2010. Concurrent with that report, TGI will file an application with the anticipation of a decision within 120 days after filing. The application will include requests for:

i. approval of the above EEC funding for 2011;

ii. approval of the same financial treatment approved in the EEC Decision; and

iii. approval for the continuation of the portfolio approach and assessment methodology as approved in the EEC Decision.

13. Alternative Energy Solutions

Alternative Energy Solutions ("AES") means Geo-exchange, Solar-thermal and District Energy Systems as those terms are described in the Application.

3. Energy Efficiency and Conservation and Alternative Energy Solutions

a) Introduction

In order to remain a viable energy provider TGVI must be able to offer complete energy solutions comprised of our base natural gas business in combination with both EEC programs and alternative energy solutions. TGVI is well positioned to work with customers and communities to provide complete energy solutions and is committed to doing so.

TGVI's proposal for 2010 and 2011 is:

1. Increase EEC funding for 2010 over the currently-approved EEC funding, for Innovative Technologies programs, with all funding being subject to the same financial treatment as approved in the EEC Decision;
2. Reallocate funding from the amount approved in the EEC Decision to low income and rental housing programs;
3. Extend funding for the above and currently-approved EEC programs for 2011, with all funding being subject to the same financial treatment as approved in the EEC Decision;
4. Recovery in a deferral account of the revenues and ongoing O&M and the related expenditure of capital for the investment in energy solutions in NGV and alternative energy;
5. Approval of Tariffs for NGV Service and Natural Gas Compression and Refueling Service; and
6. Approval of the economic models for evaluating new community energy solutions, and the proposed streamlined regulatory processes for approval of individual projects.

TGVI believes that the approvals sought are reasonable and prudent and should be approved.

(a) Energy Efficiency and Conservation Programs

The proposed increase in funding to support EEC programs funding for specific Innovative Technology programs is consistent with the Commission's EEC Decision. The EEC funding sought for 2011, which matches the level of 2010 EEC forecast spending, will permit the ongoing funding in program areas approved in the EEC Decision with added Innovative Technology funding and a reallocation of funds to programs directed at low income customers and rental properties. We believe that the requested EEC funding is prudent and in the interests of customers.

On May 28, 2008, TGI and TGVI filed their EEC Programs Application, for funding of EEC programs for the 2008-2010 period. The application requested approval for a total of $56.6 million (for both TGI and TGVI collectively), deferral treatment and amortization period of 20 years, and a portfolio methodology for evaluating the costs and benefits of the overall EEC portfolio. On April 16, 2009, the Commission issued Order No. G-36-09. It approved EEC funding in aggregate of $41.5 million ($34.4 million for TGI and $7.1 million for TGVI), deferral treatment of all expenditures with an amortization period of 10 years, and approval of a portfolio approach to evaluating the costs and benefits of the overall EEC portfolio. The Companies did not receive approval for expenditures for innovative technologies and the Companies were directed to bring forward projects in this program area for consideration as the projects become more fully developed. The Companies were directed to commence a planning process for the development of an Industrial EEC program and file a report with the Commission within 90 days of the Decision. The Companies were also directed to proceed with a Joint Initiative relating to Affordable Housing and the Commission encouraged TGI to consider re-allocating funding from other approved areas of its overall spending as may be suitable.

Table C-3-1 shows the breakdown of approved 2008-2010 funding by regulated entity and the expected timing of expenditures for 2009 and 2010.

Table C-3-1: EEC Approved Funding for 2008-2010

	2008		2009		2010	Total
	O & M	Deferral	O & M	Deferral (Forecast)	Deferral	
TGI ('000s) Programs as per EEC	$ 1,740	$ 744	$ 1,624	$ 7,258	23,075	**$ 34,441**
TGVI ('000s) Programs as per EEC	$ 452	$ -	$ 497	$ 1,379	$ 4,726	**$ 7,054**

We are seeking approval for funding in 2011 for program areas outlined in the EEC Application and already approved by the Commission for 2010, with the reallocation of some of these funds to low income and rental housing programs as described below. We are also seeking approval of funding for 2010 and 2011 for specific programs under Innovative Technologies. TGI, in its RRA filing of June 15, 2009, responded to the direction to commence planning for an Industrial EEC Program. TGVI is not proposing any Industrial EEC programs for this RRA[156]. For TGVI in 2010, these new programs add

[156] As noted in the Companies EEC Application, there are only three transmission customers who are not eligible to receive direct EEC funding: Squamish, BC Hydro ICP, and VIGJV. Of these, Squamish end use customers are eligible for EEC funding directly from TGI, and BC Hydro is a utility that can provide its own energy efficiency

$478,000 to the EEC funding approved by BCUC Order No. G-36-09. An additional $956,000 for 2011 is being sought for Innovative Technologies. This spending is outlined in the table below. The funding for EEC activities represents a placeholder for total dollar amounts that can be used to deliver programs to the benefit of customers. This funding envelope represents the total amount of dollars that would be spent by the Company on EEC activities for 2010 and 2011. However, over time, only the actual spend on EEC activities will be charged to the EEC deferral account and ultimately reflected in customers delivery rates.

Table C-3-2: EEC Funding Sought for 2010 and 2011

	2008		2009		2010	2011
	O & M	Deferral	O & M	Deferral (Forecast)	Deferral	Deferral
TGVI ('000s) Programs as per EEC	$ 452	$ -	$ 497	$ 1,379	$ 4,726	$ 4,726
Innovative Technologies					$ 478	$ 956
TGVI Total					**$ 5,204**	**$ 5,683**

The basis for the funding requests is outlined in the following sections.

(i) 2011 EEC Programs

As noted, TGVI wishes to extend the programs approved by the Commission in Order No. G-36-09, for the three year period 2008-2010, to 2011. The expenditures for 2011 are set to match the forecast expenditures for 2010. The breakdown of the programs and cost are the same as that approved in the EEC Application Decision, as outlined in the table below.

funding. We do not propose any Industrial EEC funding for the VIGJV as the VIGJV is on a contract rate, therefore any EEC funding would have to be funded by core customers only.

Table C-3-3: EEC Program Breakdown and Cost for 2011

2011 Program Area Description		Budget Amount (000)		
		Incentives	Non-incentive Costs	Total
Residential	Energy Efficiency	$388	$109	$497
Commercial	Energy Efficiency	$1,393	$376	$1,769
Residential	Joint Initiatives	$226	$75	$302
Residential	High-Carbon Fuel Conversion	$1,132	$377	$1,510
Residential	Conservation Education and Outreach	$0	$324	$324
Commercial	Conservation Education and Outreach	$0	$324	$324
Total		$3,140	$1,586	$4,726

We believe that these programs and expenditures are consistent with the approvals already received for the years 2008-2010 and therefore should be approved by the Commission. The basis for the funding in these areas was outlined extensively in the EEC Application. In support of this request TGVI relies on information and appendices filed in the EEC Application that have been identified and included in Appendix G-1. This information includes the Conservation Potential Review ("CPR") and the Habart report used to refine the results of the CPR. The evidence demonstrates the benefits of extending funding for a further year.

TGVI will use the same portfolio approach and same financial treatment as that approved in BCUC Order No. G-36-09 to assess TGVI's EEC expenditures. The portfolio approach allows flexibility in allowing the Company to redirect dollars from one program area to another as long the TRC test for the portfolio as a whole is 1.0 or greater. In this case, the portfolio under consideration would include all EEC programs, (i.e. the previously-approved funding as well as the proposed new funding).

(ii) Re-Allocation to Low Income Programs and Rental Housing

Of the EEC funding approved for 2010 and requested for 2011, TGVI will allocate a minimum of $200,000 to conservation for the low income and rental housing sector, with the potential for an additional re-allocation. The minimum proposed amount of $200,000 for EEC activity for the low income and rental housing sector is based upon the annual proposed expenditure in the Joint Initiatives program area of the EEC Application, and approved in BCUC Order No. G-36-09. We are in the process of implementing EEC programming for the low income and rental housing sector for the 2009 - 2010 period. As such we believe we will be able to increase the funding toward the low income and rental sector above $200,000. It is our intention to re-allocate an additional $400,000 in funds from both the Residential and Commercial programs outlined above to low income and rental programs in each of 2010 and 2011.

(iii) Innovative Technologies

In its April 16, 2009, Decision on TGI and TGVI Energy Efficiency and Conservation Application, the BCUC stated that (at p. 26):

> *"The Commission Panel considers that Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies to reduce or replace natural gas consumption and related GHG emissions."*

The BCUC further stated that (at p. 26):

> *"The Commission Panel finds that there is insufficient evidence with respect to the nature and scope of the proposed program, and accordingly rejects the Innovative Technologies, NGV and Measurement program expenditures at this time. Terasen may wish to bring forward projects in this program area for consideration as they become more fully developed."*

TGVI has since evaluated the market and need for innovative technologies. This Section of the Application provides an overview of EEC initiatives we intend to pursue through the use of innovative technologies. TGVI's proposed programs are in the interests of customers and therefore should be approved.

(a) Residential and Small Commercial

Hydronic Based Heating Systems - Hydronic heating systems use liquid (water with corrosion inhibitors) to distribute energy for space and domestic hot water heating through a supply and return closed-loop piping system.

The flexible nature of this system ensures that the energy input can be changed with changes in technology and public policy, thus promoting a more sustainable energy design. An old low efficiency boiler can be upgraded to a high efficiency condensing boiler. Later the customer installing the boiler may be able to obtain energy from a district energy heating system, biomass, ground or solar energy sources. By utilizing hydronic based heating systems for space and domestic hot water heating, an owner will be in a position to replace or supplement one type of energy source with another source as technology advances.

Given existing technologies, upgrading from a low efficiency boiler to a high efficiency boiler can result in a 20-30 per cent reduction in a residential customer's natural gas consumption. For the average family home this alone would be equivalent to 725 to 900 Kg of CO_2e/yr. Similar reductions of 20-30 per cent in natural gas consumption in the small commercial sector could be achieved when upgrading from a low efficiency boiler to a high efficiency boiler.

The cost on average for hydronic underfloor system materials is estimated to be about $4,000, not including the cost of the boiler. The average cost of hydronic baseboard materials is estimated to be approximately $2,000, again not including the cost of the boiler. In order to promote a sustainable energy design, the Companies will provide incentives up to 25 per cent of cost of the hydronic underfloor piping materials (oxygen barrier tubing) to a maximum of $1,000 and hydronic baseboard materials up to 25 per cent and a maximum of $500. For 2010 and 2011 the spending forecast is $159,000 and $319,000 respectively for a two year total of $478,000.

Integrated Energy Systems (or Combination Systems) - Integrated Energy or Combination Systems are defined as a single appliance supplying both space and domestic hot water ("DHW") heating. Combo heating systems can be cost effective and increase the operating efficiency of tank-style water heaters by reducing their normal standby energy losses. The hot water tank can be connected to a fan coil to provide forced air heating, and the fan coils can be upgraded to provide air conditioning as well. Combo systems can also be connected to in-floor tubing to provide in-floor radiant heat.

TGVI is already encouraging efficient boilers in new construction with heat exchangers through the existing Efficient Boiler Program, although the smallest boiler is 300,000 Btu/hour, thus excluding residential boilers from this program. There is a possibility that more high efficient hot water tanks could be utilized in combo systems.

Standard gas hot water tanks are about 60 per cent efficient. Improving the energy efficiency of domestic hot water heating to above 90 per cent efficiency will reduce GHG emissions.

A program to fund high efficiency (condensing) hot water tanks used for space and domestic hot water heating would help to drive demand for high efficiency gas hot water tanks. Right now these types of tanks cost approximately $3,000-$3,500 compared to $450-750 for a standard gas hot water tank.

Installation costs would be comparable for both tanks. Instantaneous or tankless systems can be used for this application as well. Given that the average single family dwelling annually consumes 25 GJs of gas for domestic hot water, moving from 60 per cent to 90 per cent efficiency would produce savings of about 8.3 GJs per household per year. This would equate to a reduction of about 400 kilograms/year of CO2. We will provide incentives up to 25 per cent of total cost of condensing hot water tanks to a maximum of $1,000. This is expected to result in incentive payments of $106,000 for 2010 and $213,000 for 2011 for a total of $319,000 for the forecast period.

Solar thermal - A subset of hydronic heating systems, solar thermal systems also use water or glycol heated by the sun, with the thermal energy used for space and domestic hot water heating. Solar thermal space and water heating is usually supplemental to existing systems and reduces the use of the primary energy source used in the system.

Solar thermal space heating is cost prohibitive today and adds approximately $30,000 to the cost of construction for an average new single family detached home. Solar thermal domestic water heating at present costs about $8,000 for an average home and can be used as a supplement to the existing hot water tank to supply roughly half of the yearly water heating energy requirements.

Any solar energy usage results in GHG savings for that part of the load that it displaces. As a result, GHG production can be reduced by about 50 per cent.

The average household uses approximately 25 GJ/year for domestic water heating. If there was an annual reduction in gas usage of 12.5 GJ/year, that would reduce household GHG production by approximately 600 kilograms/year of CO2.

TGVI proposes to provide incentives of $1,000 towards a solar thermal hot water system as long as natural gas is used to provide the balance of energy for the system. This is expected to result in incentive payments of $106,000 for 2010 and $213,000 for 2011 for a total of $319,000 for the RRA period.

Ground Source Heat Pumps - A Ground Source Heat Pump ("GSHP") uses the earth or ground water or both as the sources of heat in the winter, and as the "sink" for heat removed from the building in the summer. Heat is extracted from the earth with a liquid, such as ground water or an antifreeze solution, upgraded by a heat pump, and transferred to indoor air via a heat exchanger. During summer months, the process is reversed as heat is extracted from indoor air and transferred to the earth through the ground water or antifreeze solution.

GSHP systems are available for use with both forced-air and hydronic heating systems. They can also be designed and installed to provide heating only, heating with "passive" cooling, or heating with "active" cooling. Heating-only systems do not provide cooling. Passive-cooling systems provide cooling by pumping cool water or antifreeze through the system without using the heat pump to assist the process, while in active cooling systems the heat pump assists the process.

GSHP systems are more costly than gas or electric systems and can add upwards of $10,000 to $20,000 to the cost for average new home construction. GSHP can be used as the primary source of energy to heat a building; however they do require a back-up source of energy such as a gas fired boiler.

The average household uses approximately 53 GJ/year for space heating. With a GSHP combined with a natural gas boiler for back-up there could be annual reduction in gas usage of 35 GJ/year per installation, which would reduce household greenhouse gas production by approximately 1.6 tonnes per year.

We will provide incentives of $1,000 towards the installation of GSHP pre-piping and provisions for the future installation of the heat exchanger. This will equate to incentives of $106,000 for 2010 and $213,000 for 2011 for a total of $319,000 for the RRA period. To be eligible for incentives the installation must meet also meet the following criterion:

- The GSHP must be backed up with a natural gas boiler for new construction and for retrofit installations.
- The GSHP system uses either a closed loop, i.e. under-ground piping, or an open loop, i.e. a well, if the water source is suitable.
- The system equipment, design and installation meets CSA Standards.

We believe that, at this time, it is the utility's responsibility to continue and expand the cost-effective energy efficiency and conservation programs available to customers. We believe that the programs detailed in these sections are in the interest of customers and should be approved.

(b) Alternative Energy Solutions

The second part of TGVI's strategy for meeting evolving customer needs and government policy is to pursue new alternatives to meet the energy needs of our customers, as a means of augmenting and enhancing our core gas business. Natural gas will remain a foundational source of energy for the foreseeable future.[157] The pursuit of the new tariff offerings identified in this section for NGV, as well as investment in biogas recovery, geothermal, solar thermal and district heating, is a prudent response to the challenges being faced by traditional natural gas service. We believe that it is in the best interest of both existing and new customers that TGVI offer these alternative energy solutions, with the program, development and sales costs of these activities recovered as part of the revenue requirement.

The following sections report on TGVI's specific opportunities, propose a regulatory model to assess each opportunity, and comment on other alternative energy solutions TGVI intends to pursue in the future.

(i) Natural Gas Vehicles (NGV) Rate Offerings

With the reduction of natural gas use as a result of energy policy in industrial, commercial and residential use, natural gas vehicles are one of the main areas where there is potential for volume growth. The growth of NGV benefits existing customers by adding natural gas customers with high load factors[158] to the TGVI system. Government policy also supports NGV as a cleaner alternative to fuels like diesel, gasoline and propane. Natural Gas as an alternative is the cleanest burning fossil fuel as it has the fewest carbon molecules on the atom. TGVI proposes two new rate schedules to support and grow the NGV market: NGV Service; and Natural Gas Compression and Refuelling Service ("Compression and Refueling Service"). These service offerings are targeted mainly at fleet customers that have return-to-home vehicle fleets, where refueling can occur at the end of each day.

Currently, NGV customers can purchase natural gas under all Rate Schedules, however residential customers are unlikely to use such a service due to the cost of individual compressors. Service is available to private fleet operators who do not re-sell gas, do not receive grants, and who wish to own and operate their own compression facilities. TGVI proposes two new NGV rates that target other potential NGV customers and that may be taken in conjunction with the existing commercial rate schedules.

157 Please see TGI's most recent Resource Plan, at www.terasengas.com.
158 Adding customers with a high load factor is advantageous as they increase the efficient use of the pipeline system, therefore reducing costs to all other customers.

- Compression and Refueling Service: Fleet customers who do not re-sell gas and who do not receive grants, but who wish to receive Compression and Refuelling Service from TGVI will purchase both commercial service and Compression and Refuelling Service from TGVI. The Compression and Refueling Service contemplates that TGVI will construct the necessary facilities for a fleet, and the customer would be charged a postage stamp rate of $5 per GJ for compressed natural gas. The rate is designed to recover the cost of compression over a reasonable period of time, while ensuring that the service remains competitive with alternative fuel choices.
- NGV Service: Customers that plan on re-selling gas and/or who have received grants for NGV purchase or conversion will purchase natural gas under a commercial rate schedule, so long as rate schedule minimum volume requirements are met, and must also purchase NGV Service. The NGV Service offers promotional or incentive grants towards the cost to purchase a factory built natural gas vehicle or the cost to convert a vehicle to natural gas. It is similar to TGI's Rate Schedule 6 – Natural Gas Vehicle Service in this regard. The $2.25 per GJ rate is designed to amortize the grant over a five year term. If the compression facilities are to be owned by TGVI, then the customer would also take Compression and Refuelling Service.

TGVI's proposed rate offerings overcome the potential obstacle to adoption arising from from the capital cost of compression and delivery facilities. Other potential hurdles to take-up exist, notably fleet conversion costs and availability of natural gas vehicles. We nonetheless believe that by offering NGV Service and Compression and Refueling Service, customers will be more likely to embrace NGV as part of their fleet operations.

Below, we discuss the drivers behind this rate offering, the opportunity presented, followed by a discussion of how the proposed Rates were designed.

(a) Overcoming Market Obstacles

In 1997, TGVI applied for and received approval to establish an NGV rate for public refueling, and at that time TGVI was also providing grants for vehicle conversions. The Commission, by Order No. G-48-97 approved a NGV Rate Schedule offering natural gas delivery for NGV at $5.00/GJ and grants up to $500 per vehicle. Three Mohawk stations, one in each of Victoria, Courtney and Nanaimo, subsequently began offering NGV service. In the 2000-2002 TGVI RRA, by Order No. G-6-00 TGVI agreed to review its NGV programs and pursue NGV on a declining, selected basis". Since that time TGVI has not actively pursued an NGV program. Currently there is only one Mohawk station still providing NGV service. With the change in provincial energy policy, and a wider interest in using vehicles that are more efficient and reduce emissions, natural gas vehicles have an opportunity to make a resurgence. Compressed Natural Gas ("CNG") technology has evolved significantly since early 2000's and this technology is just beginning to be showcased here in BC. IMW Inc. now produces compression equipment in its Abbotsford manufacturing facility and Westport Innovations Inc. of Vancouver designs and in partnership with Cummins Westport Inc. manufactures heavy duty natural gas engines. Together, along with support from provincial energy policy, we believe we can deliver a "made in BC" solution to that meets both customer needs and government policy.

(b) Market Opportunity and Potential

The Westport White Paper[159] discusses the economic and environmental benefits of NGVs. The paper notes that not only does using NGV reduce GHG emissions, it also reduces the cost of fuel for customers. The paper further states that there are over 17,000 heavy duty trucks, 103,000 medium duty trucks and 1400 transit buses in BC. We see this as an opportunity to increase natural gas load on our system, meet customer needs and align with government policy direction.

(i) Return-to-Home Fleets

The main drawbacks currently with NGV are lack of re-fuelling infrastructure and limited travel distance due to the need for compression tanks on the vehicle. We believe a bundled natural gas supply, and compression and refueling service will be more attractive to new and existing customers and promote the growth of the CNG market. The opportunity is greatest for fleet vehicle operators with "short haul, return to home" fleets. As noted in the Westport White Paper, these include transit buses and fleets of heavy and medium duty trucks, school buses and forklifts.

All of these market segments offer opportunities for the transportation sector to use natural gas as a fuel source that is cleaner, cheaper, and is in great abundance in the Province. Additionally, these markets are also an ideal target market for biogas as a supply source, which would enable transportation customers to be net zero emitters. Further details of these market segments are presented in the Westport White Paper and below.

(ii) School Buses

Many communities in the US (mostly in California) use natural gas buses to transport children to and from school. The greatest advantage of the natural gas bus to this segment is the "cleaner burning" nature of the fuel, as well as the fact that the buses are so quiet.

159 See Appendix G-2 for a copy of Westport White Paper.

(iii) Forklifts

There are a significant number of industrial companies in the province that have anywhere from 10-100 forklifts on site running continually in a given day. As opposed to buses which must be OEM delivered vehicles, to provide natural gas vehicle service to a forklift, the propane forklift must simply be converted (a straightforward process costing approximately $3,500 CAD per vehicle). Compression is then provided on-site for refueling purposes. CNG has significant advantages over propane, namely air quality improvement in warehouses leading to healthier work conditions, and lower GHG emissions. In addition customers may see fuel cost savings when switching from propane to natural gas.

(c) Proposed NGV Service and Rate

TGVI intends to offer NGV Service to customers. NGV Service is primarily a mechanism to provide grants for vehicle purchase or conversion and to allow customers to re-sell compressed natural gas. Customers who either wish to receive grants (such as a private fleet operator who will have compression facilities installed on their property) and/or customers who wish to have a refueling station (with or without TGVI Compression and Refuelling Service) and re-sell compressed natural gas would be required to take service under a commercial rate schedule in combination with NGV Service. NGV Service customers would sign a NGV Service Agreement and would pay a charge (outlined below) for NGV Service. From an end use customer perspective, this charge would be similar to a rate rider on a commercial rate schedule. As noted previously, customers can combine NGV Service with Compression and Refuelling Service.

Customers who wish to receive NGV Service are eligible for vehicle grants similar to grants available to customers of TGI under Rate Schedule 6. The amount of the grant would not exceed $10 per GJ, based on estimated consumption over a one year period, up to a maximum total grant by vehicle type as listed in the table below:

Table C-3-4: NGV Incentive Grants

NGV Incentive Grants		
Vehicle Description	GVW (#)	Maximum Grant
Light Duty	< 10,000	$2,500
Medium Duty	< 17,000	$5,000
Heavy Duty	> 17,000	$10,000

We propose a postage stamp, volumetric charge of $2.25 per GJ for the NGV service, which would be in addition to charges in the commercial rate schedule for delivery and commodity. TGVI arrived at the NGV Service rate of $2.25 per GJ by calculating a discounted levelized rate for grants made at $10 per GJ of estimated consumption of the vehicle. The grants would be accounted for on a net-of-tax basis and amortized over a five year term (the same treatment as in TGI). The incremental annual cost of service for the period is discounted by the utility's weighted average cost of capital and converted into a levelized unit rate per GJ by dividing the present value of the cost of service by an equivalent value of the GJ delivered to the customer. The cost of service for a $2,000 NGV grant is below to illustrate the derivation of the Levelized Rate.

Table C-3-5: Levelized Rate of $2.25/GJ for a $2,000 NGV Grant

Particulars		2010 1	2011 2	2012 3	2013 4	2014 5	2015 6
Mid-Year Rate Base		$ 644	$ 1,144	$ 858	$ 572	$ 286	$ 72
Return on Rate Base		6.864%					
Cost of Service							
Amortization Expense		$ 143	$ 286	$ 286	$ 286	$ 286	$ 143
Income Tax Expense		66	118	106	102	99	49
Earned Return		44	84	63	42	21	5
Total Cost of Service	$1,791.40	$ 254	$ 489	$ 455	$ 430	$ 406	$ 197
Sales Volume (GJ)	796.60	100	200	200	200	200	100
Proposed Levelized Rate / GJ	$ 2.25						
Income Tax Expense							
Equity Return		$ 24	$ 42	$ 31	$ 21	$ 10	$ 3
Amortization Expense		143	286	286	286	286	143
Taxable Income After Tax		$ 167	$ 328	$ 317	$ 307	$ 296	$ 146
Taxable Income		$ 233	$ 446	$ 423	$ 409	$ 395	$ 194
Current Income Tax Rate		28.50%	26.50%	25.00%	25.00%	25.00%	25.00%
Income Tax Expense		$ 66	$ 118	$ 106	$ 102	$ 99	$ 49
Deferred Charge							
NGV Grant							
Opening		$ -	1,287	1,001	715	429	143
Addition		2,000					
Tax Offset		(570)					
Amortization		(143)	(286)	(286)	(286)	(286)	(143)
Closing Balance		1,287	1,001	715	429	143	-

We believe that the rate of $2.25 is appropriate and that the NGV Service Rate Schedule should be approved.

(d) Compression and Refueling Service

Currently, natural gas compression and refueling service is available at one public station in the Victoria, and one municipal station (accessible only to municipal fleet vehicles). These are legacy customers served under existing rate schedules. In TGVI's opinion, the main hindrance to new entrants into the commercial compression market is the up front capital required. We believe that in order for the NGV market to grow, we must play a pivotal role by providing compression service to customers who do not wish to own and operate their own compression service. Below, we discuss the types of compression that TGVI would make available under its proposed Compression and Refueling Service, and more detail about the derivation of the rate.

(i) Types of Compression

There are two categories of compression and refueling equipment available, slow-fill (or time fill) and fast-fill. TGVI would be in a position to offer either service.

The typical application for slow fill is a return to home fleet, such as delivery trucks of forklifts, where drivers connect the vehicles overnight to the fueling infrastructure. Fueling tends to take about 8-10 hours and vehicles are fully fueled by morning and ready for use. Fast-fill compression, as the name implies, fuels in a much faster time frame. The speed of fueling, however, requires a higher price tag, a greater reliance on "redundancy," and maintenance. The following table summarizes the two categories:

Table C-3-6: Summary of Slow Fill and Fast Fill

Slow Fill	• Gas is compressed and dispensed slowly directly to vehicles' onboard storage tank. • Lower cost station investment. • Best for fleets that return to central lot and sit idle overnight or for extended periods.
Fast-fill	• Similar to liquid fueling station, same fill rates and times. • A MUST for public access. • Also good for larger fleets where fueling turn-around time is short.

The type of refueling required on a specific site is dependent upon the individual customer needs and as such differ greatly from installation to installation. Often there may be a combination of natural gas refueling options such as fast and slow fill depending on customer's operational requirements.

(ii) Proposed Compression and Refueling Service Rate

TGVI intends to purchase, own install and operate the compression and refueling equipment necessary to provide compression service to customers. In addition, the Company will maintain the equipment either using internal resources or securing services from external service providers. We propose a postage stamp, volumetric charge of $5.00 per GJ for the compression and refueling service, which would be in addition to delivery and commodity charges. The volumetric charge creates an appropriate incentive in terms of conservation and demand side management.

TGVI arrived at the $5.00 per GJ charge through a two-prong approach of economic alternative analysis and cost of service analysis. In order for compressed natural gas to be competitive, the bundled cost of natural gas compression, delivery and commodity must be significantly lower than the alternative fuel; that being either gasoline, diesel or propane. Due to the incremental capital cost of a natural gas vehicle, a lower bundled charge for both natural gas and refueling service will allow for a payback period that, depending upon vehicle type and usage, can be anywhere from 1-10 years. If there is no payback, the only incentive for customers to use natural gas is reduced emissions. This alone is generally not enough to encourage a customer to use natural gas. Secondly, to be competitive, the rate must be one that is similar in structure to rates customers pay for other fuels. Gasoline, diesel and propane are sold using a strictly volumetric rate. As such a compression and refueling rate must not only be competitive but should also be volumetric in nature.

Below are three graphs showing the relative competitiveness if TGVI had a $5.00/GJ Compression and Refueling rate (bundled with the delivery and commodity rates effective January 1 of each year), and the competitiveness of Compression and Refuelling with NGV Service (bundled with the delivery and commodity rates effective January 1 of each year) as compared to the retail rates for propane, gasoline and diesel:

Figure C-3-1: Propane vs. Natural Gas (PLE)

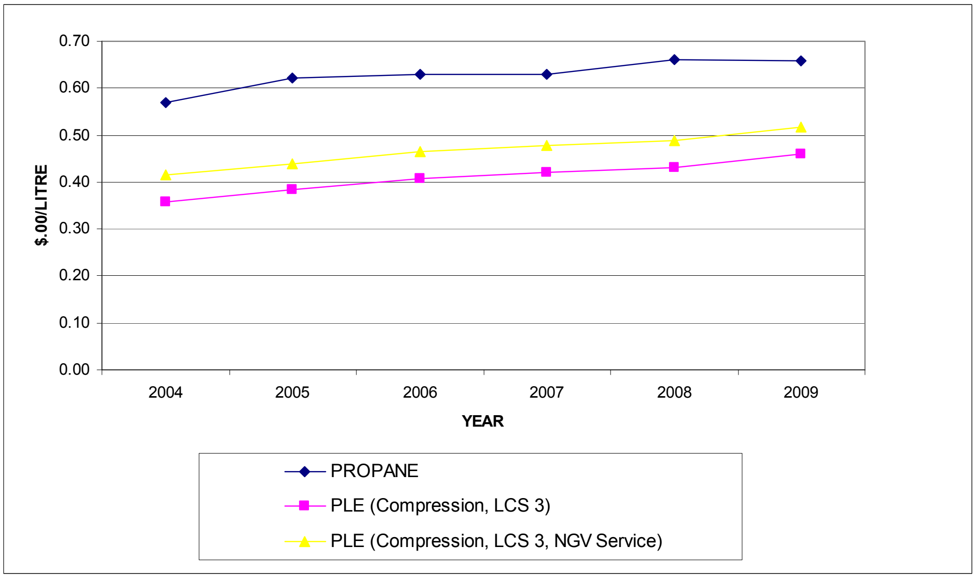


Figure C-3-2: Diesel vs. Natural Gas (DLE)

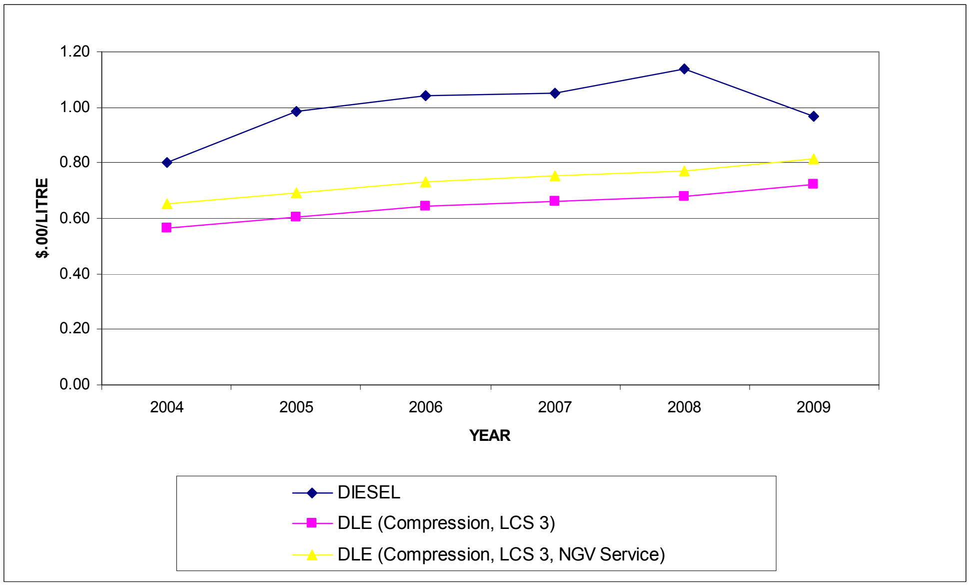
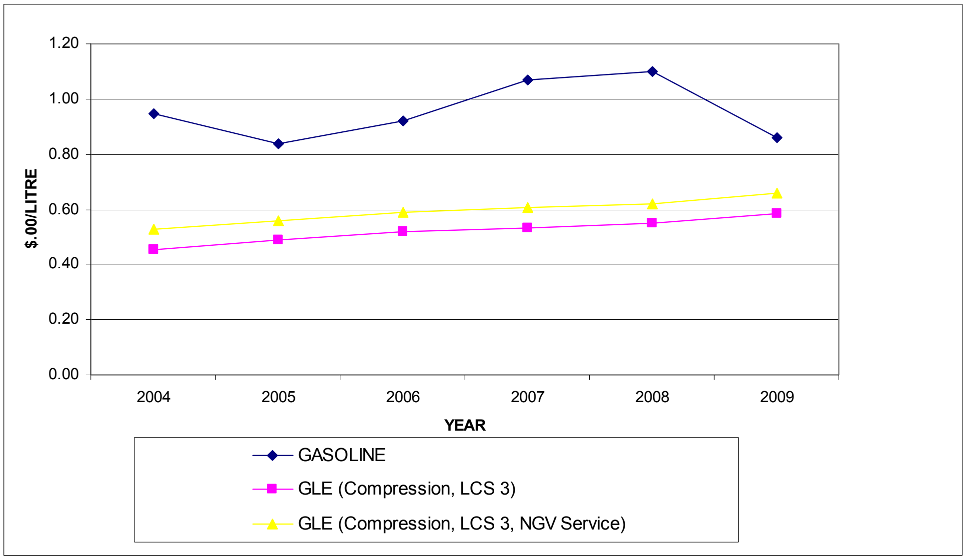


Figure C-3-3: Gasoline vs. Natural Gas (GLE)



The second prong of the approach to arriving at a postage stamp rate for the compression and refueling service is a cost of service ("COS") analysis. For the COS analysis, TGVI assumed a 5-year scenario consisting of various costs (capital and O&M) and demand (vehicles and consumption). TGVI arrived at the capital costs and demand forecasts by using its projected sales targets for compression service. The capital and operational costs were provided by compression equipment providers. Demand was based upon what we believe is a reasonable target for fleet vehicle additions. The analysis was based on matching the capital investment or the capital cost of the compressor equipment, along with the other COS components including O&M, depreciation, and taxes, with the short-term demand (5-year, the same time frame as a traditional MX Test) for Compression and Refuelling Service. The result of the analysis was a compression and refueling rate of approximately $5.00 per GJ. The tables below outline the capital costs and resulting COS including the volume assumptions.

Table C-3-7: 5-Year Capital Additions Assumptions

	Year 1	Year 2	Year 3	Year 4	Year 5
Capital Additions ('000)	$ 238	$ 294	$ 399	$ 35	$ 873

Table C-3-8: Cost of Service Summary

Total Cost Summary										
Evaluation of Equipment Options										
Name of Equipment Option										
Calendar Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Nominal "000$	1	2	3	4	5	6	7	8	9	10
Equipment Options										
Total Operating & Maintenance	14	39	75	76	135	138	141	144	146	149
Depreciation	4	14	27	35	53	70	70	70	70	70
Income Tax	(6)	(18)	(27)	(27)	(38)	(44)	(27)	(13)	(3)	6
Property Tax	0	0	0	0	0	0	0	0	0	0
Debt Expense	4	12	23	30	45	58	56	54	51	49
Return on Equity	4	14	27	34	51	67	64	62	59	57
Total Annual Cost ('000$)	20	62	125	149	246	289	304	315	324	331
Annual Demand (GJ)	1,800	8,400	16,000	36,600	62,200	70,000	70,000	70,000	70,000	70,000
Annual Toll ($/GJ)	11.14	7.33	7.80	4.07	3.96	4.13	4.34	4.51	4.63	4.72
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
	11	12	13	14	15	16	17	18	19	20
Equipment Options (Continued)										
Total Operating & Maintenance	152	155	159	162	165	168	172	175	179	182
Depreciation	70	70	70	70	70	70	70	70	70	70
Income Tax	12	17	21	24	26	27	29	29	30	30
Property Tax	0	0	0	0	0	0	0	0	0	0
Debt Expense	47	45	43	40	38	36	34	31	29	27
Return on Equity	54	52	49	46	44	41	39	36	34	31
Total Annual Cost ('000$)	335	339	341	342	343	343	342	342	341	340
Annual Demand (GJ)	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Annual Toll ($/GJ)	4.79	4.84	4.87	4.89	4.89	4.90	4.89	4.88	4.87	4.85
Level Toll - 20 Years										
2009 - 2028, $/GJ $4.72										

A $5.00 per GJ compression and refueling rate will ensure that forecast revenues match or exceed the cost of service.

We believe the proposed compression and refueling rate is appropriate as the rate was derived based on a cost of service analysis using the best available information, including capital costs, usage rates, and O&M. In addition, the resultant Commercial Service with Compression and Refuelling Service, and a Commercial Service combined with NGV Service and Compression and Refuelling Service, will be competitive with diesel, propane and gasoline.

(ii) Economic Test

For each application for Compression and Refueling Service, the Company proposes that the potential compression customer pass an economic test to assess the economic feasibility or profitability of the capital investment. A compression customer would typically be a fleet operator on whose property the compression equipment would be located. An economic test would take into account the vehicles and associated expected volumes, and the revenue ($5.00/GJ) generated from those volumes. This would be compared against the costs for installation and operation of the compressor. The Company proposes to use a modified MX test, referred to in this Application as the Compression and Refueling Service ("CS") Test, which is described below. We believe this approach will ensure that existing customers are not subsidizing the Compression and Refueling Service, while at the same time ensuring that TGVI is able to connect as many compression customers as possible. By adding new economic NGV customers to the TGVI system, the existing system is used more efficiently and as a result the revenues from NGV delivery service will help to keep rates lower for all customers.

The CS Test, similar to the MX Test, is a twenty year discounted cash flow analysis which compares the present value ("PV") of cash inflows to the PV of the cash outflows from a proposed investment in compression and refueling equipment. The cash inflows used in the CS Test are the revenues from rates and fees paid by the customer or customers served by the compressor, as per the proposed NGV Compression and Refueling Service, and do not include the NGV Service charges, or Commercial Service. The cash outflows are the estimated annual costs for the Company to install and operate the compression system in the first five years of the service including capital costs for materials and installation of the compressor and associated equipment, on-going operating and maintenance costs and upstream system improvement costs.

Similar to the MX Test, the CS Test is used to determine a PI that represents a ratio of the PV of expected revenues to the PV of expected costs. We propose to use CS Test parameters which are reflective of a compression and refueling service. The parameters are presented below:

Table C-3-9: CS Test Parameters

Parameter Name	TGVI 2009 MX Test Parameters	Proposed CS Test Parameters	Comments for CS Test Parameters
Application Fee - New	$85	N/A	Not applicable. Account created under gas service or NGV service.
Application Fee - Existing	$25	N/A	Not applicable. Existing account under separate Rate Schedule.
Change of Service Frequency	5	N/A	Not applicable.
Overhead Rate	32.0%	Case-specific	Based on cost of compression equipment.
CCA Class 1	6.0%	20.0%	NGV compression and fueling equiment are Class 8.
Project Life	20	20	Same
Discount Rate	4.30%	4.30%	Same
Fixed SI	N/A	N/A	Same. Not applicable.
Variable SI	$0.15	N/A	Not applicable. Included in MX Test for other rate schedules.
Income Tax Rate	30.0%	30.0%	Same
Income Tax Surcharge	N/A	N/A	Same. Not applicable.
Property Tax Rate	1.71%	N/A	Not applicable. Compression equipment similar to station.
Working Capital Rate	0.50%	0.50%	Same
Demand Charge	Rate dependant	N/A	Not applicable.
Fixed O&M	Rate dependant	Case-specific	Based on the model/size of compression equipment
Variable O&M	N/A	N/A	Same. Not applicable.
In Lieu Rate	Rate dependant	N/A	Not applicable. NGV revenues are exempt from property tax.
Fixed Margin	Rate dependant	N/A	Not applicable.
Variable Charge	Rate dependant	$ 5.00	Propose $5.00/GJ Compression Rate

The economic test will be based on the $5.00 per GJ compression and refueling rate presented above. Due to the small number of compressors expected in the early years of this service offering, we propose an individual PI of 1.0 rather than 0.8 used for individual main extensions. This will ensure that, based upon forecast consumption, new compression service customers will recover the costs associated with serving them. Therefore, if the PI is less than 1.0, the customer will be required to provide an upfront contribution in aid of installation as compensation for the revenue shortfall.

We believe the CS Test will ensure that existing customers are not harmed by customers under the Compression and Refueling Service, while at the same time ensuring that TGVI is able to connect as many compression customers as possible.

(iii) Capital Additions and Revenue – Forecast and Treatment

Although the interest in this market has increased as a result of the BC Energy Policy and increased customer awareness of natural gas as a vehicle fuel, sales cycles are typically quite long. Customers must first be comfortable with the merits of natural gas vehicles and then they must be prepared to either purchase OEM vehicles or convert existing vehicles. Once this commitment has been reached, only then can TGVI contract to install compression service. As a pilot program, we foresee only limited growth over the two year period of the revenue requirement.

As TGVI attaches compression customers we will incur ongoing O&M costs for the repair and maintenance of the compression equipment. These O&M costs are dependent upon not only the quantity of capital installed but also the type of equipment installed to serve specific customers. The O&M costs incurred in respect of each customer are appropriately accounted for as part of the CS Test.

As the sales cycle is long, the nature of customer acquisition uncertain, the timeline of capital expenditures undetermined and associated O&M expenses unknown, TGVI believes it is prudent and therefore proposes that revenues, ongoing O&M and capital attributed to additions in 2010/11 be recorded in a non-rate base deferral account, attracting AFUDC for the period of the RRA. TGVI is forecasting zero capital additions in this area for the purpose of the RRA.

(iv) Approvals Sought

We request Commission approvals of Natural Gas Vehicle Service and Compression and Refueling Service rate schedules which are included as Appendix J-4 and J-5.

As presented in Part III, Section C, Tab 8, we request approval of the deferral treatment of NGV Conversion Grants.

We also request approval of the deferral treatment of compression equipment costs and expenses. As indicated above, we are seeking approval to recover in a deferral account the revenues and O&M and capital related to NGV and the service provided. In this manner, existing customers will not pay for capital costs, and associated revenues that are uncertain.

(c) Biogas

The development of biogas upgrading and recovery projects represents an opportunity to recover useful energy from waste, to displace other consumption of fossil fuels such as diesel, to complement the use of natural gas, and to reduce greenhouse gas emissions. Biogas upgrading was identified in TGVI's 2008 Resource Plan as a potential new supply resource for the Company to assist in meeting the goals of the 2007 BC Energy Plan[160] and the legislated "government's energy objectives". Biogas represents an

[160] Biogas upgrading was identified in TGVI's 2008 Resource Plan as a potential new supply resource for the Company to assist in meeting the goals of the 2007 BC Energy Plan and the legislated "government's energy

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TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

PART II – AGREED CHANGES FROM THE APPLICATION

5. Use Per Customer Rates

The Parties agree that the use per customer rates will be as set out in the Application.

6. Energy Efficiency and Conservation ("EEC") Funding for 2010

The Parties agree as follows in respect of the EEC funding sought by TGVI for 2010:

(a) TGVI will reallocate from residential and commercial EEC programs an additional $0.4 million from the amount approved for 2010 in the EEC Decision[2] to low income and rental housing programs. This brings the total for low income and rental housing programs to $0.6 million for 2010 (currently at $0.2 million).

(b) EEC funding for innovative technologies will be $0.478 million for 2010, which is the amount requested by TGVI in the Application.

(c) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 438, Item 15). However, Innovative Technology programs will be managed by TGVI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. TGVI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

7. EEC Funding for 2011

7.1 The Parties agree as follows in respect of the EEC funding sought by TGVI for 2011:

(a) EEC funding for residential and commercial programs for 2011 will be $4.726 million, which is the amount requested by TGVI in the Application.

(b) TGVI will reallocate from 2011 residential and commercial EEC funding ($4.726 million for 2011) an additional $0.4 million to low income and rental housing programs. This brings the total for low income and rental housing programs to $0.6 million for 2011.

(c) EEC funding for innovative technologies will be $0.956 million for 2011, which is the amount requested by TGVI in the Application.

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2 Decision and Order No. G-36-09 dated April 16, 2009 in the TGI-TGVI Energy Efficiency and Conservation Application.

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DATED THURSDAY, NOVEMBER 5

(d) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 438, Item 15). However, Innovative Technology programs will be managed by TGVI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more. TGVI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

(e) TGVI will report to the Commission on innovative technology programs as part of TGVI's annual report on EEC activities required under the EEC Decision.

The Parties offer the following rationale for the agreed upon 2011 EEC funding.

All Parties agree that it is important to maintain EEC funding levels in 2011 to allow customers to have continued access to EEC programs and incentives. The residential and commercial EEC programs relating to the $4.726 million funding in 2011 on a portfolio basis in aggregate have a TRC of one or more. This means that, from a resource perspective and on a portfolio basis, these programs are expected to yield favourable results for customers. The predictability and continuity of these programs on a sustained basis is critical to their overall success.

Issue No. 1 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "EEC Program – TGVI is to provide results of programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding."

There are practical difficulties associated with the approach identified by the Commission Panel. They include the following:

- As per the EEC Decision (Order No. G-36-09), TGVI will be reporting 2009 activities and results by no later than March 31, 2010. This report will also outline the forecasted activities and programs for 2010. Recognizing the timing of the recent EEC Decision and its current implementation in the Fall of 2009, the EEC Report for 2009 results will give the Commission and stakeholders another check point to validate the level of spend for 2011. However, there is expected to be very little additional information on the results of programs available in March 2010 than exists presently and is included in the evidentiary record of this proceeding. TGVI's EEC programs only completed start up phase in the Fall of 2009. It typically takes longer than 6-8 months to achieve momentum with EEC programs. There will be no information available in March 2010 on results for programs relating to innovative technologies initiated in 2010 as a result of this Agreement. The information that the Commission Panel appears to desire will be more likely included in TGVI's 2010 results report to be filed in March 2011.

- Employees responsible for the programs at TGVI, whose salaries are funded from EEC funding, will face the prospect of losing their jobs in 2011. This could lead to employee retention issues. Employee turnover issues may disrupt the program implementation progress and potentially be more costly if EEC activity is ceased and later resumed.

- Programs will need to begin winding down in advance of 2011 if the 2011 funding is not approved. For example, programs will need to have an end date of December 31, 2010 which may not yield positive results since programs will be winding up in the middle of the heating season.

7.2 The Parties agree that the Commission may sever Section 7.1 (a) and (b) above from this Agreement, with the remainder of this Agreement remaining in force and effect. If the Commission severs Section 7.1 (a) and (b), then the Parties agree that the following provisions take effect:

(a) The Residential and Commercial EEC programs totaling $4.726 million in 2011 will be removed from the EEC expenditure forecast and the revenue requirements for 2011. (If 7.2 takes effect, the financial schedules in Part IV of this Agreement and the cost of service/revenue requirements resulting from this Agreement will be revised to reflect this).

(b) The Parties agree that the first annual report on EEC Activities, which was due to be filed on March 31, 2010 pursuant to Order No. G-36-09, will instead be filed on or before June 30, 2010. Concurrent with that report, TGVI will file an application with the anticipation of a decision within 120 days after filing. The application will include requests for:

i. approval of the above EEC funding for 2011;

ii. approval of the same financial treatment approved in the EEC Decision; and

iii. approval for the continuation of the portfolio approach and assessment methodology as approved in the EEC Decision.

8. Alternative Energy Solutions

Alternative Energy Solutions ("AES") means Geo-exchange, Solar-thermal and District Energy Systems as those terms are described in the Application.

The forecast costs of pursuing AES projects in the TGVI service area were included in the Shared Services cost pool, which is allocated pursuant to the Shared Services Agreement among TGI, TGVI and TGW. The costs related to AES projects that would otherwise have been allocated to TGVI have been allocated to TGI's New Energy Solutions Deferral Account pursuant to the Settlement Agreement for the TGI 2010 and 2011 Revenue Requirements. Accordingly, TGVI withdraws its requests for relief in the Application relating to AES. The Parties acknowledge that TGI will be pursuing AES projects within the TGVI

Appendix O

EXCERPTS FROM THE NGT APPLICATION

3 PROPOSED SERVICE OFFERING BENEFICIAL TO CUSTOMERS AND SUPPORTS ENERGY OBJECTIVES

As discussed in Section 2 of this Application, offering LNG and CNG Services requires some investment in fueling infrastructure, the cost of which is to be recovered through contractual rates charged to the NGV customer. TGI's investment in infrastructure backed by a long-term "take-or-pay" contract generates immediate and direct benefits not only for the NGV customer but also for existing natural gas customers and British Columbians generally. Over the longer term, TGI's involvement as a market participant promotes the efficient development of natural gas as a transportation fuel,and will help stimulate the market, which does not appear to be gaining any traction without TGI's involvement, while continuing to accommodate other companies that may wish to offer the same service.

This section discusses three key reasons why it is in the public interest for TGI to invest in the necessary fueling infrastructure where the investment is backed by a multi-year "take or pay" contract. In particular:

1. Section 3.1 discusses how the addition of natural gas transportation load associated with a new NGV contract provides an immediate benefit to existing and new gas customers through lower delivery rates all else equal. Over time, the addition of NGV load has the potential to be a significant benefit to existing and future natural gas customers, which are being faced with declining load from traditional end uses.
2. Section 3.2 discusses how potential NGV customers benefit from accessing natural gas in a usable form from TGI in addition to other potential NGV providers. These benefits include:
    a) NGV customers can enjoy a fuel price differential compared to diesel or gasoline;
    b) Natural gas experiences more price stability; and
    c) Customers can reduce their carbon footprint.
3. Section 3.3 outlines how TGI's investment in fueling facilities that will enable a fleet to be converted to NGV supports government policy and, specifically, British Columbia's energy objectives. Federal, provincial, regional, and municipal governments are increasingly focused on addressing climate change and pollution. Governments at all levels are adopting policies in favour of lower carbon energy forms as a key part of the solution to help achieve these goals.

The proposed rate structures, which contemplate investment in projects backed by "take-or-pay" service agreements, generate immediate benefits for existing natural gas customers and stand on their own regardless of how successful TGI is in developing the NGV market in the long-term.

3.1 Existing Customers Benefit From Increased Throughput

NGVs represent a currently untapped customer segment that can add high load-factor throughput to make better use of the existing TGI infrastructure. Terasen Gas customers will achieve lower delivery rate benefits, all else being equal, as a result of the increased throughput on the system that is attributable to the NGV fueling service. As with any instance where cost effective load is added, each “take-or-pay” service agreement incorporates rates that recover the cost of providing service and thus confers a direct benefit on existing and future natural gas customers. While individual agreements will not, in isolation, result in material changes in delivery rates, TGI believes that there is significant market potential for NGVs in British Columbia (see Appendix A) and thus significant possible future benefits for existing and future natural gas customers.

In this Section, TGI:

- Explains how the addition of cost-effective load reduces delivery rates, all else being equal;
- Puts the WM Agreement into perspective in terms of the amount of load it is adding to the system for the benefit of all customers; and
- Provides some information about the potential benefit in terms of reduced delivery rates that could be achieved over time by adding NGV load.

3.1.1 ADDITION OF COST EFFECTIVE LOAD REDUCES DELIVERY RATES

As with any instance where cost-effective load is added, each “take-or-pay” service agreement incorporating rates that recover the cost of providing service confers a direct benefit on existing and future customers. The Company has been experiencing a trend towards lower use per customer in recent years, which results in upward pressure on delivery rates, all other things being equal. This occurs by virtue of the fact that the revenue requirement is shared over fewer GJs of throughput. NGV load will serve to mitigate some of the delivery rate pressure that existing customers may face in years to come as natural gas demand for heating declines. Moreover, NGV load tends to be more year-round in nature than low load factor space heating, which is the dominant contributor to demand in the residential and commercial customer segments. TGI has developed the cost of service model and rate structures to ensure that NGV load is cost-effective and thus beneficial to existing and future customers.

3.1.2 WM AGREEMENT IN PERSPECTIVE

Although individual agreements with an NGV customer will not, in isolation, result in material changes in delivery rates, it is useful to put these agreements in the context of how the added load compares in terms of residential customer additions. As an illustration, the WM Agreement described in detail in Section 4 is expected to add approximately 21,000 GJ of load per year, with Waste Management paying for the incremental cost of service.

The addition of 21,000 GJ per year is the equivalent of TGI adding 221 average Lower Mainland residential customers (assuming residential use rates of 95 GJ / yr). One natural gas garbage truck, for example, is akin to adding 10 of these average residential customers. In 2009, the Terasen Utilities will add just over 8,000 residential customers representing approximately 760,000 GJs[12]. The annual load under the WM Agreement alone will represent 3% of the residential load added in 2009. Put another way, TGI would need only 36 NGV stations with the same "take-or-pay" demand as the WM Agreement to add, on an annual basis, the equivalent residential load added in all of 2009. These figures illustrate why it is important for TGI to provide a service offering for NGVs that will help to add load.

3.1.3 POTENTIAL DELIVERY RATE BENEFIT OVER TIME

TGI has performed an analysis of the long-term potential NGV market in B.C. and the impact various demand scenarios could have on rates (all other things being equal). The impact under each scenario will be further discussed.

TGI's demand forecasts for NGV were addressed in the 2010 LTRP, and the Company is including them in this context only to illustrate how added NGV load can translate into benefits for existing and future customers. The Company believes that since the proposed rate structures contemplate investments backed by "take-or-pay" commitments from customers that will cover the incremental cost of service, it is unnecessary for the purposes of this Application to assess the reliability of the long-term demand forecasts.

3.1.3.1 Demand Forecast Scenarios

As detailed in Appendix A-1 Demand Forecast as well as the Terasen Utilities 2010 Long Term Resource Plan[13], Terasen Gas forecasts that by 2030 there is market potential for:[14]

- 30 PJ of total energy use under the Reference Case which targets Buses and Medium and Heavy Duty Trucks;
- 13 PJ of total energy use under the Low Growth scenario targeting only Heavy Duty Trucks; and
- 36 PJ of total energy use under the Reference Case Plus Passenger Growth scenario.

30 PJ of natural gas demand for transportation represents about 6.5% of the Company's target transportation market (458 PJ) in 2030.[15] For illustration purposes, TGI will use those demand forecasts for calculating the potential favourable impact on delivery rates associated with NGV

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12 Assuming a Lower Mainland residential use rate of 95 GJs / year

13 In addition to the information filed previously in the Terasen Utilities 2010 Long Term Resource Plan, TGI has expanded upon the previously-filed data to include a NGV station and station capital forecast.

14 Scenario forecasts are expressed as rounded totals. Please see Appendix A-1 for actual data.

15 Estimation based on the assumption that the current target market size grows at approximately 2% per year, equal to rate of GDP growth, based on current 5 year B.C. Ministry of Finance GDP forecast. See Appendix A-1 for the detailed analysis.

load. It should be noted, however, that the portion of the NGV market that is targeted by the proposed CNG and LNG Services is only a subset of this demand. NGV offerings would ultimately have to extend beyond the proposed offering to capture the full extent of the demand forecast.

3.1.3.2 Methodology for Calculating the Favourable Impact on Delivery Rates

Terasen Gas has used the projected increases in natural gas system load for each of the three scenarios (Reference Case, Low Growth, and Reference Case plus Passenger) as identified in Appendix A to calculate the impact to revenue requirements and the corresponding impact to Terasen Gas delivery rates under each scenario.[16] To determine the incremental revenue requirement benefit, Terasen Gas multiplied the volumes in each of the three scenarios by the approved 2011 volumetric delivery rates for three rate schedules. Each of the target market categories described in Appendix A are listed below in Table 3-1 and were assigned to an existing TGI Rate Schedule.[17]

The revenue requirement benefit represents the increase in delivery margin from the incremental volumes associated with the NGV fueling service and is offset by the cost of service of the forecast EEC innovative technologies funding attributable to NGV fueling service. As the incremental cost of service for adding an NGV customer (e.g. dispensing infrastructure) is paid by the NGV customer, this is not a factor in the calculations.

The table below demonstrates the annual benefit that existing gas customers experience in each of the three scenarios.

Table 3-1: All Customers Benefit from Increased Throughput

Impact to Existing Natural Gas Customers: NGV Refuelling Service	2012	2015	2020	2025	2030
Forecast Revenue Requirement Reduction (Increase), $000's					
Reference Case	384	2,285	12,501	39,829	82,451
Low Growth	308	730	5,059	15,865	33,377
Plus Passenger	421	2,650	17,973	50,773	104,339
Approximate Annual Delivery Rate (Decrease) Increase, %					
Reference Case	-0.07%	-0.42%	-2.31%	-7.36%	-15.24%
Low Growth	-0.06%	-0.14%	-0.94%	-2.93%	-6.17%
Plus Passenger	-0.08%	-0.49%	-3.32%	-9.38%	-19.29%

[16] Please see Appendix A-1 for the detailed analysis. The analysis excludes current transportation load in 2010 of 211,939 GJ from each scenario.

[17] Please see Appendix A-1 for the detailed analysis. In general, Transportation Rate Schedules have the following definitions:
Rate Schedule 6 (NGV Vehicle Service) – CNG service, no minimum GJ
Rate Schedule 16 (LNG Sales and Dispensing Service) – sale of LNG, maximum of 1,040 GJ/day
Rate Schedule 25 (General Firm Transportation Service) – CNG service, greater than or equal to 6,000 GJ per month. While other Transportation Rate Schedules exist (22, 23, 26, and 27) this analysis only considers the three for simplicity.

The results are consistent in all three demand forecast scenarios: increased throughput from the NGV fueling service results in a favorable reduction in delivery rates for Terasen Gas existing natural gas customers, all other things being equal. Under the Reference Case, existing natural gas customers benefit with a significant 15.2% reduction, or $82.5 million, in delivery rates in 2030. In today's dollars, this is an approximate revenue requirement reduction of $22.0 million.

Terasen Gas believes that the Reference Case scenario is the most likely of the three NGV demand scenarios developed, as it is based on the current positive external opportunity for increased adoption of NGV solutions as described above. This scenario is based on the best possible information available today on expected vehicle growth in the defined target segments, continued incentive funding expectations, favourable natural gas prices and availability of fueling infrastructure. The assumptions underlying this scenario are:

1. Adoption of NGV solutions over the long-term across all the identified target market segments except passenger cars;[18]
2. Incentive funding[19] will continue to be a driver to reduce the initial incremental capital cost across the entire target market segments excluding passenger cars;
3. In the later years, there is increased adoption and uptake of NGVs from the success of the initial pilot projects;
4. Public policy will continue to support the use of natural gas as a transportation fuel to meet climate action legislative targets;
5. Natural gas commodity prices will continue to maintain or increase its advantage against conventional fuel types as more shale gas comes online;
6. Economies of scale from OEM vehicle manufacturers and station manufacturers will help push the initial capital costs for natural gas fuelled equipment down over the longer term;
7. Availability of targeted fueling infrastructure supports the expected demand and uptake;
8. OEM vehicles and improvements in conversion technology are available across light duty and medium duty vehicles.

The Reference Case forecasts a demand of 34,540 NGVs by the end of 2030, which would require an estimated 405 stations to provide fueling service. Of those stations, 143 would provide LNG service and the remaining 262 CNG service.[20] The composition of NGVs is shown Appendix A, and a summary of the station infrastructure is shown in Table 3-2.

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[18] Passenger vehicles are not pursued as a near-term target by Terasen Gas due to their low fuel consumption and limited fueling infrastructure, and thus a limited economic incentive to switch from gasoline to natural gas.

[19] From Terasen Gas EEC Innovative Technologies and potential government sources.

[20] Please see Appendix A-1, Section 2.2.1 for the fuel type consumption assumptions for each vehicle category

Table 3-2: Reference Case demand for 405 total fueling stations by 2030

Category	Total Number of New Stations - Reference Case				
	2011	2015	2020	2025	2030
Light Duty Trucks (CNG)	-	5	51	91	158
Medium Duty Trucks (CNG)	-	1	8	20	25
Heavy Vocational Trucks (CNG)	1	4	17	41	61
Heavy Duty Trucks (LNG)	1	7	30	68	118
Buses (CNG)	1	4	12	15	20
Marine Vessels (LNG)	-	1	4	13	23
Cumulative Total:	3	23	122	248	405

Note: Does not include existing public or private stations in B.C.

The delivery rate benefit associated with NGV fueling service will serve to mitigate some of the delivery rate pressure that existing customers may face in years to come as a result of natural gas demand declines. Furthermore, increasing NGV load offers additional benefits to the natural gas system as NGV load tends to be more year-round in nature than low load factor space heating which is the dominant contributor to demand in the residential and commercial customer segments. TGI's near-term target market that could be served by an anchor tenant model is a subset of this demand forecast, therefore TGI would seek Commission approval to pursue other business models to serve NGV demand should the demand for other models materialize.

3.1.4 CONCLUSION

The changing nature of market conditions for NGV solutions in B.C. has opened up an important new target customer segment for Terasen Gas. However, significant NGV adoption is unlikely to occur in the province unless adequate station infrastructure is provided. Terasen Gas can serve a sub-set of NGV demand on a low-risk basis whereby the NGV customer pays on a "take-or-pay" basis for the incremental cost of service associated with installing a fueling station. The proposed WM Agreement is an illustration of this approach. Any future initiatives to expand the Company's basis for serving NGVs beyond the proposed "take-or-pay" contractual model would be submitted to the Commission for consideration. Ultimately, all TGI customers will benefit from lower delivery rates as a result of the increased throughput on the system that is attributable to the CNG and LNG Services proposed in this Application.

3.2 Benefit to NGV Customers

In the previous Section, TGI explained the benefits of additional NGV load for all existing and future customers through reduced delivery rates, all else equal. The proposed offerings also directly benefit potential NGV customers. Potential customers in the transportation industry that are able to adopt NGV technology can achieve some important benefits, including:

- Operating cost savings;
- Reduced fuel cost volatility as compared to diesel and gasoline; and
- Reduced GHG emissions.

The unavailability of fueling infrastructure and a secure supply of CNG or LNG currently represents an obstacle to customers' adoption of NGV technology. TGI, by providing access to fueling infrastructure and a secure supply of CNG or LNG pursuant to the proposed rate offerings, removes that obstacle.

In this Section, TGI will address the three key benefits, identified above, that potential customers such as Waste Management will see as a result of TGI's CNG and LNG Service offering.

3.2.1 OPERATING COST SAVINGS

Terasen Gas has performed an analysis of the up front cost of NGVs (either OEM NGVs or after market conversions) and the savings in operating costs associated with NGVs over time. The results of that analysis demonstrate that the adoption of NGVs can be beneficial to the customer. TGI discusses the elements of its analysis below.

3.2.1.1 Cost of NGVs to Customer

At present, OEM NGVs command a price premium over their conventional fuelled equivalents. The below Table 3-4 shows this price differential of each target market segment. In general, this premium is recovered over time through the fuel savings of natural gas. Depending on fuel consumption, a typical payback would be between 4-6 years for heavy-duty trucks. The table also shows today's approximate cost of engine conversion (using after market conversion kits) for use in Light and Medium Duty vehicles. This cost has increased significantly from the $2,000 - $3,000 per installation in the late 1990s.[21]

[21] Based on conversations with conversion specialist Excel Fuels Installations. Prices do not include incentive funding, grants, or subsidies.

Table 3-4: NGVs Price Premium over Conventional Vehicles

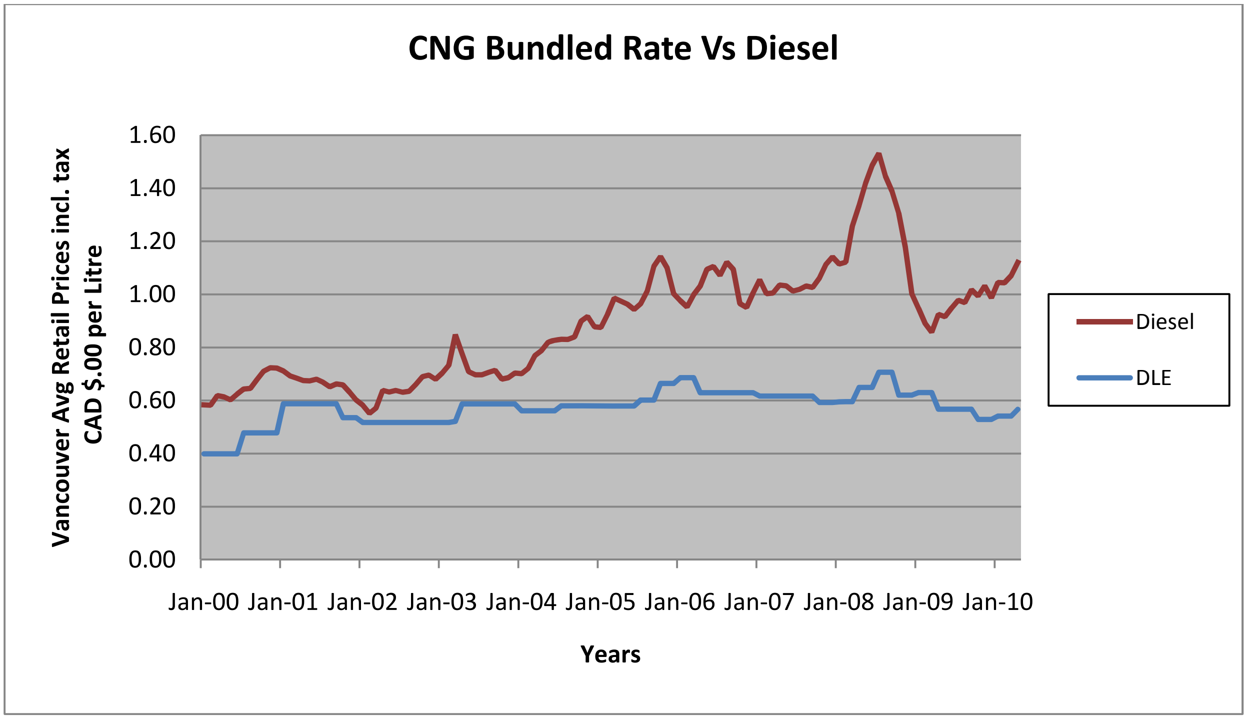
	Conventional Vehicle			Natural Gas Vehicle			NGV
Vehicle Category	**Product**	**Fuel Type**	**MSRP**	**Product**	**Fuel Type**	**MSRP**	**Price Premium**
Passenger Car	Honda Civic	gasoline	$20,820	Honda Civic GX	CNG	$29,600	$8,780
Light Duty Vehicle	engine conversion	diesel	-	engine conversion	CNG	$5,000 to $7,000	$5,000 to $7,000
Medium Duty Vehicle	engine conversion	diesel	-	engine conversion	CNG	$8,000 to $10,000	$8,000 to $10,000
Heavy Duty Vehicle	vocational truck	diesel	$250,000	vocational truck ISL - G	CNG	$305,000	$55,000
Heavy Duty Vehicle	tri-drive tractor	diesel	$145,000	tri-drive tractor GX	LNG	$223,000	$78,000
Transit Bus	New Flyer	diesel	$435,000	New Flyer CNG	CNG	$504,000	$69,000

3.2.1.2 Pricing Comparisons Between Fuels

Natural gas has historically enjoyed a pricing advantage over other motor vehicle fuels (diesel and gasoline). The operating cost savings attributable to the favourable price differential between natural gas and other motor vehicle fuels create the opportunity for overall savings for customers, despite the relatively higher cost of OEM NGVs and after market conversions. As an illustration, TGI explains in this section the magnitude of the differential between CNG and diesel, and CNG and gasoline, in previous years, and how that would have translated into savings for customers. The market indications show that natural gas is likely to retain its price advantage over incumbent fuels for the foreseeable future, meaning that this opportunity for customers to benefit will continue to exist provided the appropriate NGV fueling infrastructure is in place to serve these customers.

Figure 3-1 below illustrates the advantage of natural gas over diesel over the past 10 years. In the period between 2001 and 2003 the gap narrowed to the point where it became difficult to pay back the incremental cost of the NGVs. Since 2005, however, the gap has widened.

Figure 3-1: Proposed Offering Would Have Historically Beaten Diesel on Price



Notes:

- Average pump prices for low sulphur diesel in Vancouver include all applicable taxes. Terasen Gas CNG prices include $5 per GJ compression charge and applicable Rate Riders.
- CNG pricing is based on Rate Schedule 6 historical pricing with an additional $5/GJ to cover the costs associated with compression and dispensing the fuel.
- CNG pricing is converted to Diesel Litre Equivalent basis for ease of comparison to diesel. The conversion is based on energy content values published in the NRCan GHGenius model[22]. (Diesel at 38.653 MJ/litre – yields conversion factor of 25.9)

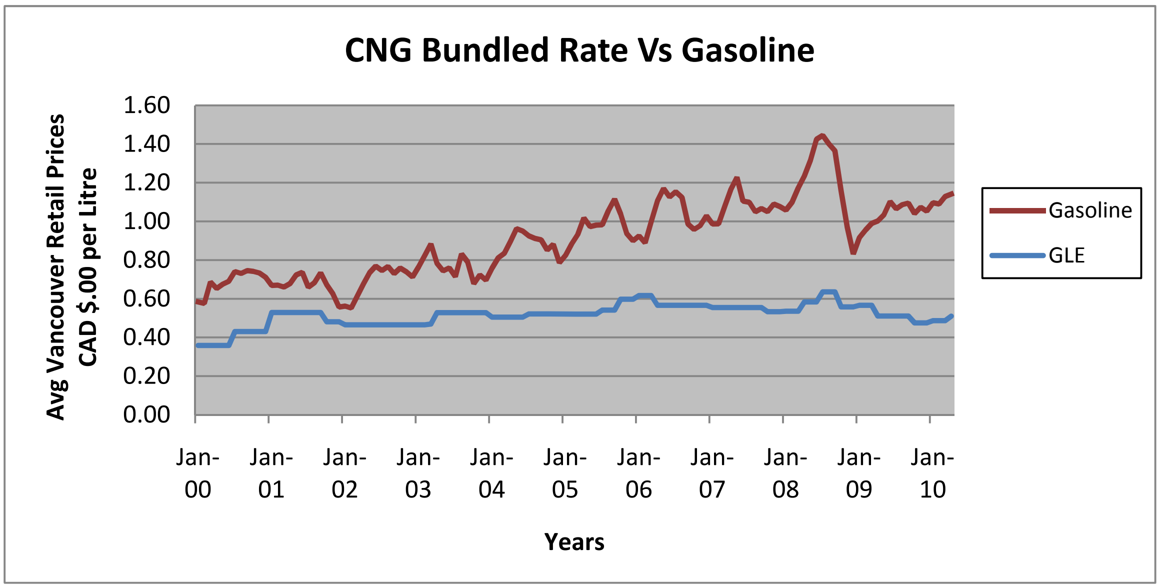
The graph shown above in Figure 3-1 demonstrates that a CNG offering as proposed in this Application, if priced at approximately $5/GJ, would have consistently been less expensive than diesel for the entire preceding decade. The $5/GJ is an approximation based on a high-level analysis of the cost of service of many large NGV projects.[23] Such an offering would currently have a price advantage over diesel of approximately $0.40/litre, or 40% as of the date of the filing of this Application. These fuel savings can offset the upfront price premium for NGVs (see Table 3-4) over time. The typical payback for a heavy duty fleet operator switching from diesel

[22] http://www.ghgenius.ca/downloads.php
[23] Terasen Gas has selected $5/GJ based on historic diesel fuel consumption and fueling station capital cost estimates provided by large fleet operators in BC. The proposed rate structure is described in Section 2 of this Application.

to CNG is approximately four to six years. The combined price advantage and stability is something that Terasen Gas believes would be very attractive to fleet managers.

TGI's near-term focus is commercial, return-to-base, heavy duty fleet vehicles which operate on diesel. Since there are a number of return-to-base fleets which also run light duty vehicles on gasoline, a comparison of CNG versus gasoline is also included. Figure 3-2 below illustrates the advantage of natural gas over gasoline over the past 10 years. In the period between 2001 and 2003 the gap narrowed to the point where it became difficult to pay back the incremental cost of the NGVs. Since 2005, however the gap has widened.

Figure 3-2: Proposed Offering Would Have Historically Beaten Gasoline on Price



Notes:

- Average pump prices for regular unleaded gasoline in Vancouver include all applicable taxes. Terasen Gas CNG prices include $5 per GJ compression charge and applicable Rate Riders.
- CNG pricing is based on Rate Schedule 6 historical pricing with an additional $5/GJ to cover the costs associated with compression and dispensing the fuel.
- CNG pricing is converted to Gasoline Litre Equivalent basis for ease of comparison to diesel. The conversion is based on energy content values published in the NRCan GHGenius model[24]. (Gasoline at 34.686 MJ/litre – yields conversion factor of 28.8)

The graph shown above in Figure 3-2 demonstrates that a CNG Service offering as proposed in this Application, if priced at approximately $5/GJ, would have consistently been less expensive than gasoline for the entire preceding decade. Such an offering would currently have a price advantage over gasoline of approximately $0.60/litre, or 55% as of the date of the filing of this Application, even more significant than the price advantage of natural gas over diesel. The

[24] ibid

typical payback period for light duty NGVs is generally longer than heavy duty NGVs. This is one reason why light duty vehicles are not part of TGI's near-term target market.[25] The combined price advantage and stability is something that Terasen Gas believes would be very attractive to fleet managers.

3.2.1.3 Natural Gas Likely to Maintain Price Advantage Over Diesel Oil

The market indications, as reflected in the forward market prices, show that natural gas is likely to retain its price advantage over incumbent fuels for the foreseeable future, meaning that the payback period remains favourable for the adoption of NGV in place of diesel.

Historically natural gas prices have been heavily influenced by oil prices due to the short term substitutability of crude oil products, such as fuel oil, with natural gas for industrial and commercial processes and electricity generation. As illustrated in Figure 3-3[26], price fluctuations in crude oil prices can have major impacts on natural gas prices regardless of the fundamental supply and demand factors that underpin gas prices. This was observed during mid-2008 when crude oil rallied to over $145 US per barrel by July, pulling up natural gas prices to almost $14 US/MMBtu. Prior to this time, natural gas prices were typically bounded by fuel oil as the ceiling and heating oil as the floor, and breakouts from this range were seldom. During the hurricane season of 2005, hurricanes Katrina and Rita disrupted natural gas production in the Gulf of Mexico to such an extent that natural gas prices temporarily rose above heating oil prices.

Since the collapse of oil prices after mid 2008, natural gas prices have disconnected from oil and related oil product prices. Natural gas prices have traded below those of fuel oil and the ratio of natural gas to oil prices has widened from the historical average of about ten to one to about twenty to one. The reason for this disconnection lies with the supply and demand balances for natural gas and crude oil. Natural gas is based on supply and demand factors in North America. Currently, natural gas prices are the lowest in many years due to weakened industrial demand due to the recent recession and strong production from unconventional (especially shale gas) supplies. Crude oil, on the other hand, is a globally traded commodity, and prices are dependent on international supply and demand factors. Currently, the crude oil supply and demand balance is tight, meaning that demand is strong relative to available supply. Strong economic growth from China and India has increased the demand for oil in recent years. Furthermore, geopolitical events affecting global crude oil supply have created a risk premium associated with crude oil, somewhat inflated prices. Examples of geopolitical risks include disruptions by Nigerian militants on pipeline infrastructure, tensions between Iran and the U.S. over Iran's nuclear program and conflicts between North and South Korea. Furthermore, the Organization of Petroleum Exporting Countries' ("OPEC") influence on supply and oil prices is also significant. OPEC has indicated that its preference is for crude oil prices to remain near

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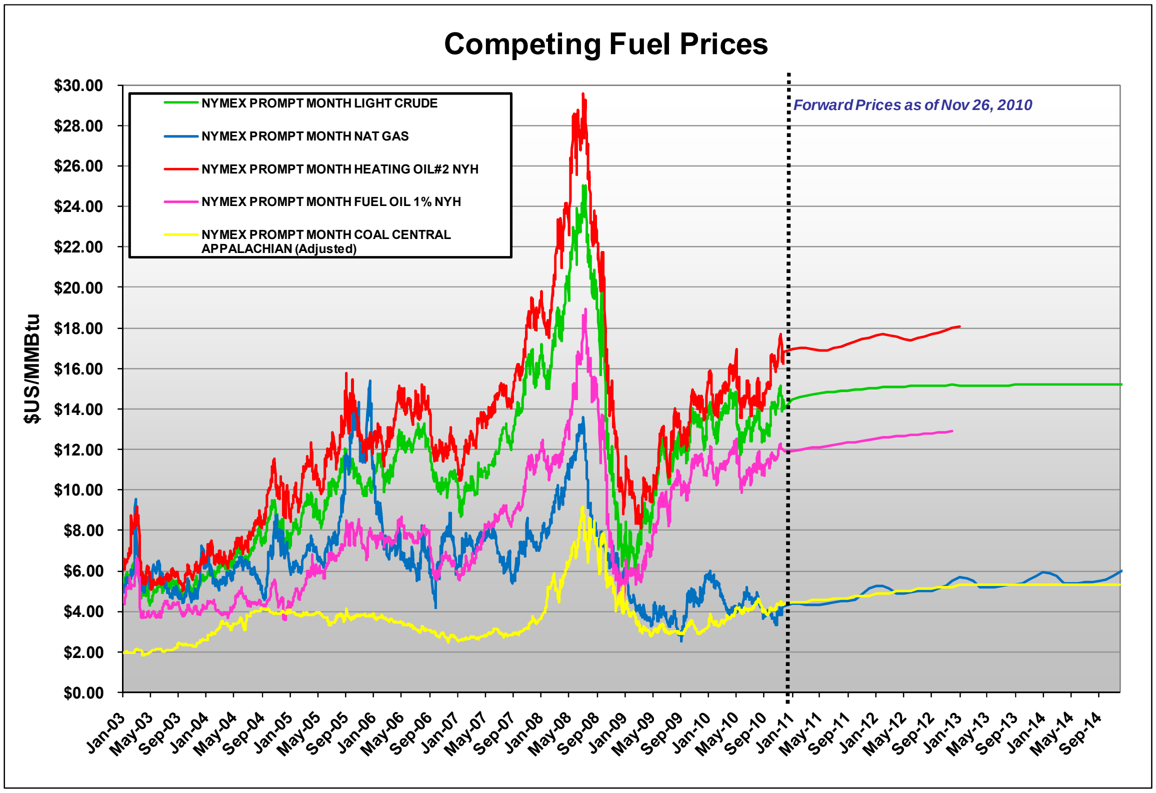
[25] Please see Appendix A-1 for additional details
[26] As presented on page 19 of the Terasen Utilities 2010 Long Term Resource Plan

$80 US per barrel. Any significant deviations in crude oil prices from this level are likely to be met with supply adjustments by OPEC.

Consequently, with depressed natural gas prices, the price of coal is becoming increasingly relevant by acting as the floor for natural gas prices due to the ability of many power generators to switch between coal and gas fired electric generation.

Figure 3-3: Historic and Settled Future Commodity Prices – Oil and Natural Gas



As can be seen from the above graphs in Figure 3-1, Figure 3-2 and Figure 3-3, the market indications, as reflected by forward prices, show that natural gas is likely to retain its price advantage over incumbent fuels for the foreseeable future. Natural gas production declines in 2011 in response to low gas prices, recovery in industrial demand, growth in power generation demand and stricter environmental regulations placed on coal-fired generation going forward may lead to higher gas prices in the future. Furthermore, because of these factors, the natural gas supply and demand balance may be tighter in the future than it is currently and periods of price spikes due to supply disruptions or weather events may occur. However, because of the different supply and demand factors that influence natural gas and oil prices, natural gas is likely to retain its price advantage, on average, over oil and related product prices for the foreseeable future.

3.2.2 REGULATED PRICE OF CNG AND LNG IS LIKELY TO BE LESS VOLATILE THAN PRICE OF DIESEL OR GASOLINE

The second key benefit associated with NGV service offered by TGI is that it tends to be subject to less price volatility than diesel or gasoline. Although the underlying volatility of natural gas , oil and gasoline made similar, how these prices get reflect to customers may be somewhat different. For example, the NGV service relates to the fact that the regulated commodity and delivery rates under Rate Schedule 6 are set on a quarterly and annual basis, whereas diesel and gasoline are priced according to constant fluctuation more akin to a spot market. For fleet operators, a fixed fueling charge[27] such as $5 / GJ contributes to a smoother, more predictable net fuel price on a diesel litre equivalent basis.[28]

3.2.3 COMPETITIVE ADVANTAGE DUE TO ENVIRONMENTAL BENEFITS

There will be businesses that wish to employ measures to reduce their carbon footprint as a matter of principle. TGI's service offerings provide an option for these customers. Further, the reduced carbon output associated with CNG and LNG relative to diesel may also create competitive advantages that complement the fuel cost savings outlined above.

Businesses may be able to capitalize on the reduced carbon footprint for marketing purposes. An increasing number of municipalities and businesses have introduced procurement policies which favour clean air standards for garbage trucks and refuse haulers. Fleet operators running NGVs may hold a significant advantage in winning competitive bid contracts due to the GHG savings associated with NGVs.[29]

On that same note, other organizations may be interested in the reduced GHG emissions for their fleet in order to reduce their carbon footprint for compliance purposes, such as a public service organizations or municipalities that have signed on to be carbon neutral.

3.2.3.1 Ownership and Value of Carbon Credits

There may be additional value in monetizing GHG emission reductions as offsets should there be a suitable protocol for fuel switching from a higher carbon fuel such as diesel to natural gas. Current industry practice would see the benefit of the GHG emission reductions be attributed to the customer whose carbon footprint is being reduced, which, in this case, would be the end user. It is unlikely that validating and verifying emission reductions on an individual project basis would be cost effective for participating customers. Therefore, TGI may consider negotiating in future NGV agreements that Terasen Gas is entitled to any GHG emission

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27 Fueling charge would typically escalate at 2% per year over the term of the service agreement. Please refer to Section 2 of this Application for more details.

28 The Company's response to BCUC IRs 1.11.1 and 1.11.2 in the 2010 Long Term Resource Plan proceeding contained additional detailed analysis of this price relationship.

29 One large fleet operator, Waste Management stated "clients that want us to associate with us if we undertake these kinds of green initiatives. It's a competitive differentiator for us." http://www.vancouversun.com/news/Waste+Management+converting+garbage+trucks+from+diesel+natural/3590341/story.html#ixzz15ffJ5LPU

reductions as a result of the provision of the proposed NGV service offerings or EEC incentives for NGVs. Therefore, if multiple projects qualify, TGI could undertake, on an aggregate basis, third party validation and verification and the establishment of accepted protocols for these projects. Treatment of any carbon credits resulting from TGI's proposed NGV service offering or EEC NGV initiatives has not been resolved at this time.

3.2.4 SUMMARY

In summary, the expansion of NGV service offerings will be beneficial to potential NGV customers. The economic advantage of natural gas over conventional fuels is large and growing. Natural gas market fundamentals support the continuation of this economic advantage. The volatility of natural gas pricing under Rate Schedule 6 is less than gasoline or diesel pricing. The fact that NGV is a lower carbon alternative to diesel may create further competitive advantage for NGV operators that complement the fuel cost savings. These advantages all speak to the suitability of the Company providing an alternative that will permit more BC fleets to adopt NGV.

3.3 Proposed NGV Services Support B.C.'s Energy Objectives

The Company's proposed CNG and LNG Services require some investment in facilities, the cost of which is recovered in the contractual rates charged to the NGV customers using the facilities. In this Application, which is the first of such investments, TGI is seeking a section 44.2 "public interest" approval for the expenditures associated with the WM Agreement. The Commission, in considering the section 44.2 approval that the Company is seeking in respect of the Waste Management facilities, must consider "British Columbia's energy objectives" as defined by the *Clean Energy Act ("CEA")*. Other government policy provides context as well. TGI's investment to facilitate the WM Agreement supports British Columbia's energy objectives and government policy generally, primarily by promoting the adoption of NGVs and facilitating a reduction in Waste Management's GHG emissions[30]. TGI's future investments in refueling stations for NGV fleet customers will similarly support legislated energy objectives and government policy.

This Section addresses:

- Government policy impacting the transportation sector;
- The GHG emissions associated with the transportation sector; and

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[30] GHGs are gases that, once dissipated into the atmosphere, trap infrared radiation from the sun that has been reflected from the earth's surface. In effect, the gases act like a greenhouse – hence the name. Ultimately too much GHG emission may contribute to a warmer planet and climate change. For the purpose of this Application, the most relevant GHGs are carbon dioxide (CO_2) and nitrous oxides (NO_x), which are emitted from combustion of transportation fuels.

- How TGI's investment in the facilities required to provide CNG Service to Waste Management promotes British Columbia's energy objectives.

3.3.1 GOVERNMENT POLICY IMPACTING THE TRANSPORTATION SECTOR

Federal, provincial, regional, and municipal governments are increasingly focused on addressing climate change and pollution. Governments at all levels are adopting policies favouring low-carbon energy as a key part of the solution to help achieve these goals. This Section discusses government's policy, objectives and direction at each level of government.

3.3.1.1 British Columbia Provincial Government

The provincial government has continually demonstrated interest in the implementation of more environmentally-friendly and efficient use of energy. In recent years the focus has been primarily on GHG emissions. As discussed in more detail in subsection 3.3.2 of this application, displacement of vehicles fueled by gasoline and diesel by NGVs would result in significant reduction of GHG emissions in British Columbia, as well as a reduction in other forms of pollution caused by the combustion of gasoline and diesel. The following sub-sections detail the specific provincial government actions that support, and are supported by, the Company's efforts to help displace conventionally fuelled vehicles with NGVs.

3.3.1.1.1 2007 Energy Plan

The framework for provincial energy policy is the 2007 BC Energy Plan[31]. The policies set out in the 2007 BC Energy Plan have been given effect in several pieces of legislation, including the recently passed CEA that sets out "British Columbia's energy objectives" applicable to the regulation of public utilities.[32]

The 2007 BC Energy Plan built on the 2002 Energy Plan,[33] which had focused on low electricity rates, energy security, private sector involvement in new electricity development, and environmental responsibility. The 2007 BC Energy Plan committed British Columbia to addressing climate change by harnessing clean and renewable energy to reduce overall GHG emissions, and to a renewed focus on the efficient use of energy sources. Recently, the provincial government's commitment to reducing GHG emissions and increasing the development of clean energy were re-affirmed in the February 9th, 2010 Speech from the Throne and through the passing of the *CEA*.

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[31] "Energy Plan 2007: A Vision for Clean Energy Leadership". http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan.pdf

[32] S.B.C. 2010, c. 22. A copy of the First Reading version of the *Clean Energy Act* is available at: http://www.leg.bc.ca/39th2nd/1st_read/gov17-1.htm
At the time of filing this Application this was the only version of the *Clean Energy Act* available on the Legislature's website.

[33] "Energy Plan 2002: Energy For Our Future: A Plan for BC". http://www.llbc.leg.bc.ca/public/pubdocs/bcdocs/357957/

The 2007 Energy Plan identified the transportation sector as "a major contributor to climate change and air quality problems". The 2007 Energy Plan went on to observe that, based on current practices, "The fuel we use to travel around the province accounts for about 40 per cent of British Columbia's greenhouse gas emissions". This statement not only observes a problem, but helps identify the solution: displacing incumbent fuels with cleaner-burning fuels in the transportation sector presents the greatest opportunity by volume for a reduction in province-wide GHG emissions. The 2007 Energy Plan went on to note that "The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California's tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards", a clear statement of direction that the British Columbia provincial government is serious about not just encouraging, but demanding that the transportation sector move to cleaner options. An example of a preferred cleaner option was then identified in the 2007 Energy Plan with the statement "Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution." Finally, the provincial government encouraged the use of new and innovative solutions by stating that "British Columbia will focus on research and development, demonstration projects, and marketing strategies to promote British Columbia's technologies to the world."

The Provincial Government has given effect to policies set out in the 2007 BC Energy Plan in legislation. Several examples follow.

3.3.1.1.2 Renewable Portfolio Standards

Renewable Portfolio Standards are requirements that any given supply, or portfolio, of a energy must be composed of a standard minimum amount of energy from a sustainable source. An example of the adoption of a Renewable Portfolio Standard by the British Columbia Provincial Government was the 2008 introduction of the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*.[34] This act created the legal structure required to impose an escalating minimum percentage of renewable fuel in gasoline and diesel sold within the province. As of January 1, 2010, the renewable component required is 5%, and the Carbon Tax applicable to gasoline and diesel has been reduced proportionately to reflect the reduced non-renewable component of these fuels.[35]

The LCFRR mandates a 10% reduction in the carbon intensity of motor vehicle fuels used in B.C. The required reductions are phased in over time with the 10% reduction required by 2020.

Natural gas is a low carbon intensity motor vehicle fuel. The methodology adopted within the provincial regulation combines measures of the base carbon intensity of the fuel with measures of the efficiency of the engine technology that is used with the fuel. This results in an effective carbon intensity in use. Selected values for various fuels are presented in Table 3-5 below:

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[34] S.B.C. 2008, c. 16.
[35] Renewable Fuels Notice – Carbon Tax. http://www.sbr.gov.bc.ca/documents_library/notices/Renewable_Fuels_Notice_Carbon_Tax.pdf

Table 3-5: Natural Gas is Less Carbon Intensive Than Conventional Fuels

Fuel	Base Carbon Intensity (gms CO_2e /MJ)	Engine Efficiency Factor	Adjusted Carbon Efficiency (gms CO_2e /MJ)
Gasoline	90.56	1.0	90.56
Ultra Low Sulphur Diesel	93.56	1.2	77.97
CNG	62.16	1.1	56.51
CNG (Digester Gas)	-3.25	1.1	-2.95
LNG	61.69	1.2	51.41
LNG (Digester Gas)	-3.25	1.2	-2.71

Source: LCFRR Intentions Paper[36]

Some key points to note:

- Conventional CNG has a net carbon intensity value that is 38% lower than reformulated gasoline and 28% lower than ultra-low sulphur diesel.
- Conventional LNG has comparable reductions in net carbon intensity

Emerging sources of Biomethane such as CNG from anaerobic digesters is fully carbon neutral, and potentially even carbon negative.

3.3.1.1.3 Greenhouse Gas Reductions Targets Act

The *Greenhouse Gas Reduction Targets Act* ("GGRTA"), enacted in 2007, mandates reductions of provincial GHG emissions of thirty-three percent by 2020 and eighty percent by 2050 using 2007 as the baseline.[37] The GGRTA also requires all departments of the provincial government to become GHG neutral by 2010.

In recent years, BC's provincial government and municipalities have taken steps to develop targets and action plans to support reductions in GHG emissions. The actions of Canada's federal government, while not (yet) reflected in formal policy or legislation, reinforce this focus on cutting GHG emissions through reducing consumption of carbon based fuels. All levels of government recognize that GHG emissions reduction is a pressing need, which gives rise to an increased focus on energy policy and energy issues. The BC Government has established aggressive goals for GHG emission reductions. Figure 3-4 shows the emission reduction targets for B.C. in 2020[38].

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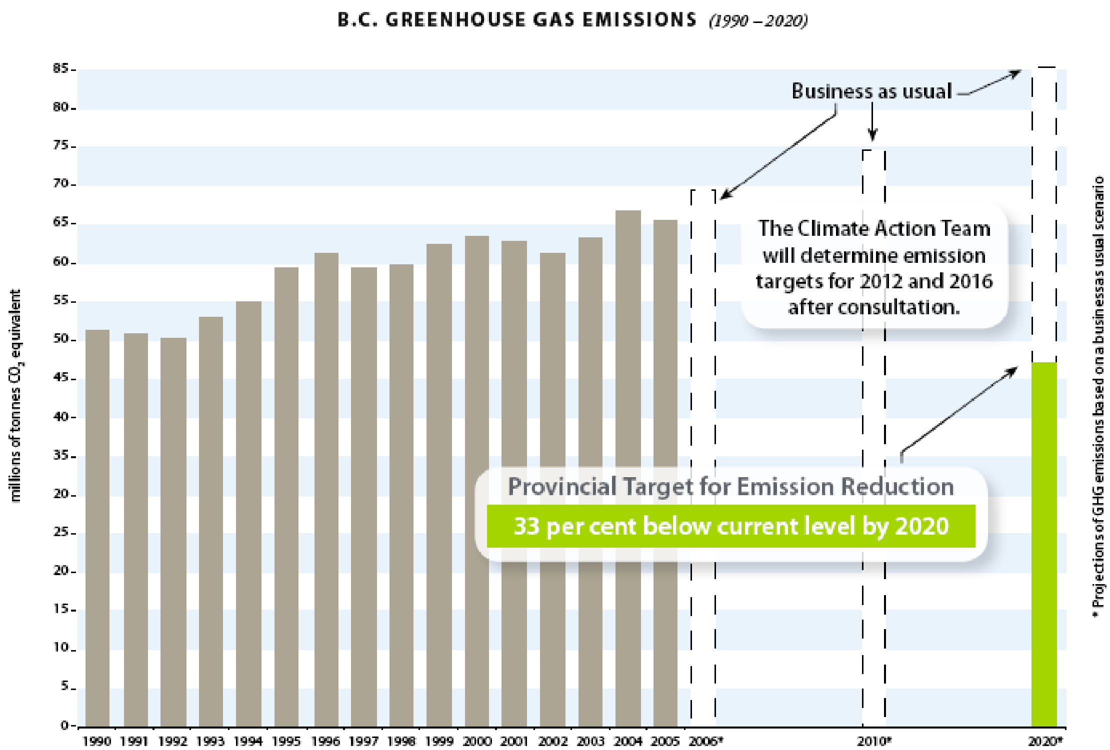
[36] LCRFF Intentions Paper http://www.empr.gov.bc.ca/EEC/Strategy/BCECE/Documents/LCFRR%20Intentions%20Paper%20Final.pdf
[37] S.B.C. 2007, c. 42
[38] BC Ministry of Energy, Mines and Petroleum Resources 2009

Figure 3-4: B.C. GHG Emissions from 1990 to 2020



The Province passed Bill 44 (2007 Greenhouse Gas Reduction Target Act) in the 3rd Session of the 2007 Legislative Session. Part 1 of Bill 44 outlines BC GHG emission targets levels as being:

> *"By 2020 and for each subsequent calendar year, BC greenhouse gas emissions will be at least 33% less than the level of those emissions in 2007; and by 2050 and for each subsequent year, BC greenhouse gas emissions will be at least 80% less than the level of those emissions in 2007."*[39]

On November 25, 2008 GHG interim targets were set by Ministerial Order as follows:

- 2012 – six per cent below 2007; and
- 2016 – eighteen per cent below 2007 levels.

[39] This means that GHG's emissions within BC must be reduced by 33% from 2007 levels by 2020. This may come in the form of a physical reduction or purchasing an offset that qualifies under the regulations.

3.3.1.1.4 Carbon Tax Act

The Carbon Tax Act, passed in 2008, further signaled the provincial government's commitment to the reduction of GHG emissions.[40] As stated on the British Columbia

Ministry of Finance website, the purpose of the carbon tax "*is to ensure that a consistent long term price signal is provided to consumers so that they continue to make the choices required to reduce their fossil fuel use and emissions*."[41] The level of the carbon tax varies according to the carbon intensity of the fuel. The implementation of this tax therefore encourages the use of natural gas over gasoline and diesel through a lower rate of taxation.

3.3.1.1.5 Utilities Commission Act and Clean Energy Act

The *UCA* requires the Commission to ensure that utilities undertake efficiency and conservation measures in their operations, and to consider the British Columbia's energy objectives (as defined in the *CEA*, in specified approval processes. TGI details later in this Section how the investment in NGV fueling infrastructure to serve fleets supports British Columbia's energy objectives.

3.3.1.1.6 Natural Gas Road Tax Exemption

The British Columbia Provincial Government has explicitly encouraged the use of NGVs in the treatment of road taxes. Motor fuel tax is not applied to the natural gas used to power NGVs[42]. This explicit endorsement through subsidization of the use of natural gas as a vehicle fuel is further evidence of the government's support for NGVs, and how the aims of this application are supportive of government policy and energy objectives.

3.3.1.2 Municipal Governments in British Columbia

Local governments have responded to the provincial policy initiatives in respect of GHG reduction. On September 26, 2007, sixty-two communities across the province announced that they had signed on to the B.C. Climate Action Charter, committing to become carbon neutral by 2012.[43] By the end of 2009, 176 municipalities in B.C. (out of 188 in total) had signed the Climate Action Charter. Replacing conventionally-fueled fleet vehicles with NGVs provide municipalities an opportunity to achieve significant GHG emissions reductions.

3.3.1.3 Canadian Federal Government

Like the British Columbia provincial government, the Canadian federal government has shown increasing concern for GHG emissions, the use of renewable energy and the efficient use of energy. Examples of this concern have been demonstrated in recent environmental legislation

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[40] S.B.C. 2008, c. 40.
[41] British Columbia Ministry of Finance: Myths and Facts About The Carbon Tax http://www.fin.gov.bc.ca/tbs/tp/climate/A6.htm
[42] http://www.sbr.gov.bc.ca/documents_library/bulletins/mft-ct_005.pdf Page 7 of 12
[43] http://www.cd.gov.bc.ca/ministry/whatsnew/climate_action_charter_update.htm

and throne speeches. Specific support of the increased use of NGVs has been building within the federal government, and is discussed below.

3.3.1.3.1 Marbek Report – Study of Opportunities for Natural Gas in the Transportation Sector

In 2009 the Fuels Policy and Programs division of Natural Resources Canada ("NRCan") commissioned Marbek, an environmental consulting firm, to produce a study[44] examining the potential benefits of and market size for increased usage of NGVs in Canada. The report found that not only was there a significant market opportunity for increased utilization of NGVs in Canada, but federal government encouragement of this market transformation could produce substantial environmental benefits including but not limited to substantial reduction of GHG emissions.

3.3.1.3.2 Natural Resources Canada ("NRCAN") Working Group

As a follow up to the Marbek study, NRCan launched a roundtable forum for potential participants in the NGV industry and other interested parties to determine what steps can be taken to encourage the adoption of NGVs in Canada. This working group was announced in March of 2010[45].

3.3.1.4 Summary of Government Policy

Governments at all levels are adopting policies in favour of low-carbon energy as a key part of the solution to help achieve their GHG emission reduction goals. The proposals in this Application are both consistent with and adherent to these policy directives, and allow Terasen Gas to be a part of the solution to these environmental challenges.

3.3.2 TRANSPORTATION SECTOR GHG EMISSIONS

Government policy relating to the reduction of GHG emissions in the Province presents a significant challenge to retaining and attracting customers who consume natural gas to produce heat. However, at the same time the policy supports the use of natural gas as a fuel in the transportation sector, which has lower associated GHG emissions than gasoline or diesel. In this Section, Terasen Gas discusses the GHG emissions that are associated with the transportation sector.

What makes B.C. unique relative to other jurisdictions regarding the output of GHG is the sources of these emissions. BC has only 2 per cent of its GHG emissions coming from the electricity sector, while at the same time producing fossil fuel (primarily natural gas) which creates additional emissions in BC. About 17% of BC GHG emissions come from the direct consumption of natural gas. This creates some challenges for BC in meeting its stated goals

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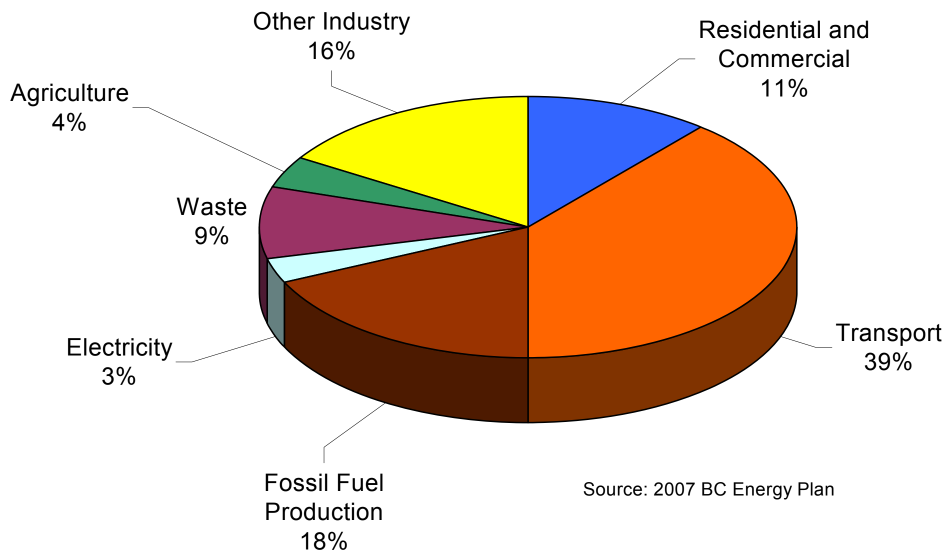
[44] "Study of Opportunities for Natural Gas in the Transportation Sector", March 2010 http://www.cngva.org/media/4302/marbek_ngv_final_report-april_2010.pdf

[45] Further description of the working group can be found on the NRCAN website at http://www.nrcan-rncan.gc.ca/com/consultation/concon-eng.php

with economic and market ready customer solutions. The use of natural gas in NGV is a solution that meets these criteria for customers.

Figure 3-5 below indicates that the single largest source of greenhouse gas in B.C. is the transport sector. Terasen Gas believes that reducing GHG emissions in the transportation sector is necessary in order to realistically achieve the provincial government's stated objectives.

Figure 3-5: B.C. Greenhouse Gas Emissions by Sector[46]



According to the 2007 BC Energy Plan, overall emissions of GHGs in BC as of 2007 was estimated at 67 million tonnes.[47] The BC Provincial GHG Inventory Report indicates that BC's transportation sector produced over 25 million tonnes ("Mt") of this total.[48] Figure 3-6 below breaks down the 25 million tones of GHG emissions from the transportation sector by each segment.

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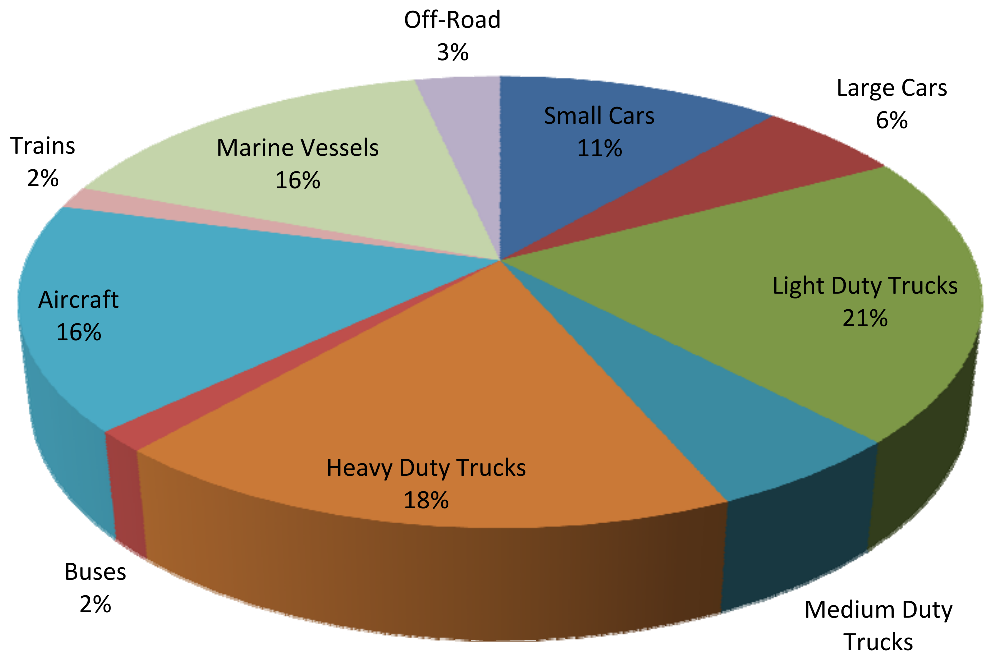
[46] 2007 BC Energy Plan – A Vision for Clean Energy Leadership, http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan.pdf
[47] BC Provincial GHG Inventory Report 2007. http://www.env.gov.bc.ca/cas/mitigation/ghg_inventory/pdf/pir-2007-full-report.pdf
[48] Natural Resources Canada, Office of Energy Efficiency, 2007: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/trends_tran_bct.cfm

Figure 3-6: Trucking segments represent nearly 44% of B.C.'s transportation GHG emissions



Source: NRCan 2007

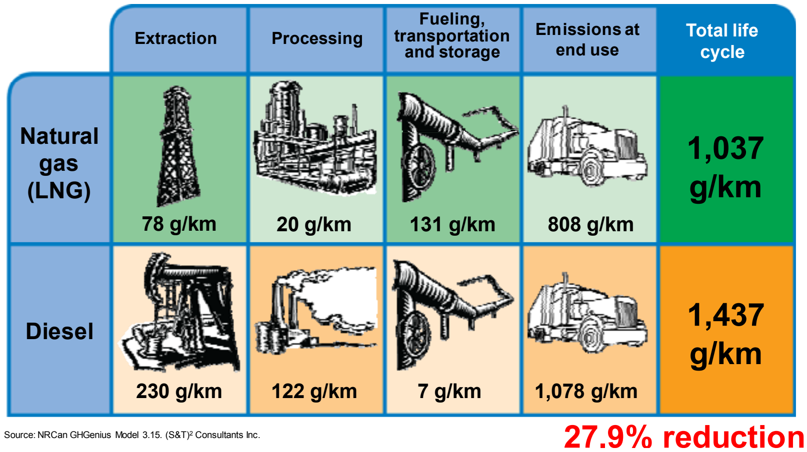
The above graph illustrates that the trucking segments (light trucks, medium truck and heavy trucks) makes up approximately 44% (or 11.4 Mt) of the total transportation emissions profile, or 17% of all GHG emissions in the province.

Data from NRCan indicates heavy duty NGV's emit 23 - 27% less GHG emissions than their diesel counterparts;[49] therefore adoption of NGVs in the trucking sector would have a significant impact on overall GHG emissions in BC.

For example, Figure 3-7 illustrates the GHG emission reduction on a lifecycle or "wells-to-wheels" approach of LNG versus diesel. This considers not only vehicle operation, but fuel stock production, processing, transport and storage.

[49] Based on BC emissions factors from Natural Resources Canada's GHGenius model 3.18 available at www.ghgenius.com

Figure 3-7: Lifecycle GHG Benefit – Westport GX-Equipped Truck – BC 2010



Source: Natural Resources Canada - *GHGenius 3.18*

Vehicle assembly, transport and materials add small incremental emissions to the lifecycle analysis, resulting in a 26.8% overall reduction. Using the same lifecycle model, the emission benefits from a vocational garbage truck running on CNG is approximately 23.2%. A light duty vehicle switching from gasoline to CNG creates a reduction of 25.6%.

Public and government interest in the environmental impact of fuel consumption, particularly as it relates to GHG emissions, should be beneficial to the growth in use of natural gas as a vehicle fuel because:

- Natural gas burns cleaner than conventional fuels and generates fewer air contaminants such as oxides of nitrogen, sulphur oxides, carbon monoxide and particulate matter. In general this means that natural gas engines require less post combustion treatment to meet emissions requirements.
- As discussed in the preceding section, natural gas is a low carbon fuel that creates far fewer greenhouse gas emissions.

In conjunction with vehicle operators, Terasen Gas has developed detailed estimates of GHG emissions reductions that will be achieved for the trucks that are most commonly used in the trucking segments. As the emissions data are reported in grams per km travelled, overall GHG emissions reductions depend on the number of vehicles operating on natural gas and the annual distance travelled by such vehicles. The results of these models indicate that GHG reductions ranging from 10 to 126 tonnes per vehicle per year are achievable by switching to natural gas.

If successful in achieving a 30 PJ market penetration, which is 6.5% of the target market, the use of NGVs should deliver 865,000 tonnes of GHG emissions reductions. Thus the use of NGVs in BC will achieve large reductions in overall GHG emissions and this will help meet

British Columbia's targets as set out in legislation, as discussed in further detail in subsection 3.3.1.1.3 of this Application.

3.3.3 TGI'S INVESTMENT SUPPORTS BRITISH COLUMBIA'S ENERGY OBJECTIVES

The Commission must consider "British Columbia's energy objectives", specified in the *Clean Energy Act*, in determining TGI's application pursuant to section 44.2 for approval of expenditures for the cost of the facilities required to provide service to Waste Management under the WM Agreement. These legislated policy objectives contemplate public utilities being engaged in achieving government policy through utility investments (sections 44.2 and 45) and supply acquisition (section 71).

A number of the "British Columbia's energy objectives", quoted below, support this Application:[50]

> (d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;
>
> (g) to reduce BC greenhouse gas emissions
>
> > (i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,
> >
> > (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,
> >
> > (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,
> >
> > (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and
> >
> > (v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;
>
> (h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;
>
> (i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;
>
> (k) to encourage economic development and the creation and retention of jobs;

In Table 3-6 below,, TGI summarizes how investment in NGV refueling facilities backed by "take-or-pay" contracts like the WM Agreement supports each of the above objectives.

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[50] S.B.C. 2010, c. 22. A copy of the First Reading version of the *Clean Energy Act* is available at: http://www.leg.bc.ca/39th2nd/3rd_read/gov17-3.htm

Table 3-6: Service Agreement Support BC Energy Objectives

British Columbia's Energy Objective	How Proposed Service Offering Supports Energy Objective
(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources	Use of low-carbon CNG and LNG engine technology developed and manufactured by BC-based Westport Innovations.
(g) to reduce BC greenhouse gas emissions…	Low-carbon NGVs in WM Agreement result in 23% fewer emissions than diesel equivalent vehicles.
(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia	WM Agreement facilitates Waste Management fuel switching from diesel to CNG. This results in approximately 214 fewer tonnes of CO2e per year.
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently	Waste Management is replacing high-carbon, diesel emitting waste haulers - which operate in Lower Mainland communities - with low-carbon NGVs.
(k) encourage economic development and the creation and retention of jobs	Supports economic development and job creation for BC-based NGV engine manufacturer Westport Innovations, CNG station manufacturer IMW industries, and various engine conversion installers.

The proposed services are not detrimental to any of the other British Columbia's energy objectives.

3.3.4 CONCLUSION

The *Clean Energy Act* and government policy generally places a new focus on NGVs, laying the groundwork for increase in utilization of this technology in British Columbia. As British Columbia's energy objectives are applicable in the context of the regulation of public utilities, these amendments speak to the government's objective of involving public utilities in the targeted reduction of GHG emissions through the efficient development of cleaner uses of energy, such as displacing incumbent fuels with NGVs. The Company's proposed investment in the facilities to provide service to Waste Management under the WM Agreement supports British Columbia's energy objectives and government policy. TGI believes that the expenditure in support of providing service to Waste Management is in the public interest and should be approved pursuant to section 44.2 of the Act.

Appendix P

MINISTRY OF ENERGY AND MINES LETTER ON GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION DATED JUNE 8, 2012

BRITISH COLUMBIA
Ministry of Energy and Mines

June 8, 2012

Via E-Mail
Commission.Secretary@bcuc.com

Ms. Alanna Gillis
Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Gillis:

Re: An Inquiry into FortisBC Energy Inc. Project No. 3698635/Order G-95-11 Regarding the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives (AES Inquiry) - Timetable to Receive Comments on the Greenhouse Gas Reduction (Clean Energy) Regulation

Her Majesty the Queen in Right of the Province of British Columbia, as represented by the Ministry of Energy and Mines (the Ministry), as a registered intervener in the AES Inquiry makes the following submissions in reply to the submissions of other interveners in the matter set out in the Commission's letter dated May 17, 2012. These submissions pertain to the implications of the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012 (the "Regulation") for the AES Inquiry.

The undertakings prescribed in the Regulation define those in respect of which public utilities are entitled to cost recovery pursuant to section 18 of the *Clean Energy Act*. The news release accompanying the announcement of the Regulation on May 15, 2012 identified a number of benefits of the prescribed undertakings:

- reducing greenhouse gas emissions in the transportation sector in B.C.;
- diversifying markets in B.C. for natural gas, a B.C.-based resource, and supporting the Natural Gas Strategy;
- providing a cleaner burning, lower cost alternative to diesel fuel for fleets and marine vessels; and
- fostering economic development, jobs and innovation in the province.

The Ministry submits that the Regulation provides the opportunity for public utilities to promote natural gas as transportation fuel in the heavy duty vehicle and marine sectors to achieve these benefits. The Ministry also submits that the analysis of public utility incentives for natural gas vehicles, which supported the development of the Regulation, demonstrated that the prescribed undertakings defined in the Regulation would provide a net benefit to all of the public utility's natural gas ratepayers.

Does Section 18 and the Regulation apply to non-regulated entities of a public utility?

The Coalition for Renewable Natural Gas and Clean Energy Fuels suggest that the entity carrying out a prescribed undertaking need not be a "public utility", and that it could be a non-regulated subsidiary of the public utility.[1,2]

Section 18 of the *Clean Energy Act,* and the Regulation, apply only to public utilities. Section 18 provides, in part:

> (2) In setting rates under the *Utilities Commission Act* **for a public utility carrying out a prescribed undertaking**, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking.
>
> (3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would **directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking**.
>
> (4) A public utility referred to in subsection (2) must submit to the minister, on the minister's request, a report respecting the prescribed undertaking.
>
> (5) A report to be submitted under subsection (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies. [Emphasis added.]

The opening words to subsections 2(1)(2) and (3) of the Regulation also provide that the Regulation applies only to public utilities. Finally, subsection 2(1) of the *Clean Energy Act* provides that:

> (2) Words and expressions used but not defined in this Act or the regulations, unless the context otherwise requires, have the same meanings as in the *Utilities Commission Act.*

[1] Coalition for Renewable Natural Gas, June 1, 2012 submission, page 2

[2] Clean Energy Fuels, June 1, 2012 Submission, page 2

Commission Oversight

Ferus LNG suggests that the Regulation does not materially affect the question of "how" the commission should regulate the prescribed undertakings.[3] Ferus LNG also notes that, "the Regulation also clearly requires that the Commission be responsible for setting out the basic terms and conditions for any loans or other incentives that may be provided by FortisBC to the owners of "eligible vehicles"".[4] Similarly, Clean Energy Fuels notes that, "it is imperative for the commission to implement a standard, completely objective formula or methodology for determining how NGV incentives are awarded."[5] Clean Energy Fuels, in referencing section 18 (3) of the *Clean Energy Act*, notes that, "only 'prevention' of the prescribed undertaking is barred, however, anything less than prevention would therefore, be within the commission's discretion."[6]

In response to the assertion made by Ferus LNG on page 14 of its submission, the Ministry submits that there is nothing in the Regulation, and in particular s. 2(1), that would give the commission the ability to set the competitive process or methodology for allocating grants or loans that may be provided by a public utility for the purchase of eligible vehicles.

Section 18 of the *Clean Energy Act*, along with the Regulation, also changes the commission's role with regard to activities or expenditures that are prescribed undertakings. Section 18 makes it clear that the commission is obliged to "set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking." The Ministry submits that this provision removes commission discretion concerning the recovery of costs incurred with respect to prescribed undertakings. The Regulation has now prescribed certain undertakings, and thereby given effect to section 18. Section 18 also provides that "the commission must not exercise a power under the Utilities Commission Act in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking".

Grants or Zero-Interest Loans

Clean Energy Fuels argues that the formula for providing loans or grants should not take into consideration whether the applicant is in the utility's service territory, and that this would "corrupt the intent of the *Clean Energy Act* and the Regulation".[7] Similarly, Ferus LNG argues that Government is requiring, in prescribing grants or loans to be provided to persons in British Columbia for an eligible vehicle to be operated in British Columbia, that "incentives are clearly not limited to FortisBC service sectors."[8] The Ministry submits that the Regulation is permissive in this regard. The public utility, through its

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[3] Ferus LNG, June 1, 2012 Submission, page 13
[4] Ferus LNG, June 1, 2012 Submission, page 14
[5] Clean Energy Fuels, June 1, 2012 Submission, page 5
[6] Clean Energy Fuels, June 1, 2012 Submission, page 3
[7] Clean Energy Fuels, June 1 2012 Submission, page 5
[8] Ferus LNG, June 1, 2012 Submission, page 4

open and competitive process for providing grants or zero-interest loans, may limit the provision of its ratepayer-funded loans or grants to those in its service territory to ensure its ratepayers also receive the benefits from these investments. Provision of such loans or grants would remain within the undertaking prescribed in the Regulation.

Prescribed Undertakings are Optional

Ferus LNG argues that the public utility cannot both engage in projects that are "prescribed undertakings" and bring forward similar projects outside of the "prescribed undertaking" format.[9] The Ministry submits that the Regulation imposes no such restriction. A public utility continues to be able to make expenditures or initiate programs similar to those that are prescribed undertakings, but that fall outside of one or more of the limits defined in the prescribed undertakings; for example, a LNG fuelling station that does not meet the per station expenditure limit. Such expenditures or programs would simply not be "prescribed undertakings", and would be dealt with through other established mechanisms under the *Utilities Commission Act* or otherwise.

April 1, 2017 Repeal Date

Ferus LNG notes that some fuelling station projects developed throughout the undertaking period may only be considered prescribed undertakings for "only a few years or even months"[10]. While the Regulation is repealed as of April 1, 2017, the Ministry submits that, for a contract (1) falling within an undertaking prescribed in the Regulation, and (2) having an end date after April 1, 2017, costs during the "undertaking period" prescribed in the Regulation remain recoverable under s. 18.

All of which is respectfully submitted,

Paul Wieringa
Executive Director
Electricity and Alternative Energy Division

cc: Registered Interveners as per Distribution List

[9] Ferus LNG, June 1 2012 Submission, page 12
[10] Ferus LNG, June 1 2012 Submission, page 11

Appendix Q

INNOVATIVE TECHNOLOGIES PROGRAM TRC TEST RESULTS

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

FILED CONFIDENTIALLY

(accessible by opening the Attachments Tab in Adobe)

Appendix R

SUMMARY OF GREENHOUSE GAS EMISSIONS REDUCTION

APPENDIX R - GREENHOUSE GAS ("GHG") EMISSION REDUCTIONS CALCULATIONS

FEI has adopted the GHGenius model to calculate the lifecycle emission reductions for the vehicles referenced in Section 7 of the Application. GHGenius version 3.18 is available for download at the following link: http://www.ghgenius.ca/downloads.php

The calculations in this Appendix are current as of the time EEC expenditures occurred. FEI's GHG methodology was detailed in the NGT Application proceeding in response to BCSEA IR 2.14.1 on February 10, 2011.

The GHGenius model

Developed for Natural Resources Canada, the GHGenius model has been used by the BC Government to develop a carbon intensity baseline for its Low Carbon Fuel Requirements Regulation.[1] FEI believes GHGenius to be the most appropriate tool for determining lifecycle emission impacts in B.C., rather than GREET (as cited in the ANL Report in the question) or other models developed for use in other jurisdictions. GHGenius also complies with ISO standards for determining lifecycle emissions. Additional information on the model history of GHGenius can be accessed at the following link:
http://www.ghgenius.ca/about.php

CNG Vehicles

The CNG vehicles have been analyzed using the GHGenius version 3.18. GHGenius is a similar lifecycle assessment tool to the GREET model, but contains more fuel pathways specific to Canada. FEI used the default GHGenius 3.18 model, with the exception of the following assumption:

- Regional Default set to "BC".

The lifecycle emissions results (1477 gCO2e/km for diesel and 1135 gCO2e/km for CNG) were referenced from "Table 57d. Heavy Duty ICE Vehicles" on the Lifecycle Results tab.

Fleet Emissions

To calculate the total fleet emissions of each CNG vehicle, the results of 1477 gCO2e/km for diesel and 1135 gCO2e/km for CNG were each divided by 1,000,000 to convert into tonnes of CO2e per km.

The following tables provide a detailed calculation of each CNG fleet's total emissions.

1 Low Carbon Fuel Requirements Regulation Intentions Paper for Consultation. http://www.empr.gov.bc.ca/EEC/Strategy/BCECE/Documents/LCFRR%20Intentions%20Paper%20Final.pdf

Table 1: City of Surrey GHG emission reductions

City of Surrey	GHGenius v3.18 Emissions	X	Average Annual Kms Traveled	=	Emissions Per Truck (tCO2e)	X	Number of Trucks	=	Emissions Per Fleet (tCO2e)
Diesel (t/km)	0.00147701		36,700		54.2		1		54.2
CNG (t/km)	0.00113471		36,700		41.6		1		41.6
Emissions Reduction (tCO2e):					**12.6**				**12.6**

Table 2: Kelowna School District GHG emission reductions

Kelowna School District	GHGenius v3.18 Emissions	X	Average Annual Kms Traveled	=	Emissions Per Bus (tCO2e)	X	Number of Buses	=	Emissions Per Fleet (tCO2e)
Diesel (t/km)	0.00147701		32,000		47.3		11		519.9
CNG (t/km)	0.00113471		32,000		36.3		11		399.4
Emissions Reduction (tCO2e):					**11.0**				**120.5**

Table 3: Waste Management GHG emission reductions

Waste Management	GHGenius v3.18 Emissions	X	Average Annual Kms Traveled	=	Emissions Per Truck (tCO2e)	X	Number of Trucks	=	Emissions Per Fleet (tCO2e)
Diesel (t/km)	0.00147701		31,200		46.1		20		921.7
CNG (t/km)	0.00113471		31,200		35.4		20		708.1
Emissions Reduction (tCO2e):					**10.7**				**213.6**

LNG Vehicles

The LNG vehicles for Vedder have been analyzed using the GHGenius version 3.18. FEI used the default GHGenius 3.18 model, with the exception of the following assumptions:

- Regional Default set to “BC”, and
- Input fuel type set to “LNG”.

The lifecycle emissions results (1477 gCO2e/km for diesel and 1082 gCO2e/km for LNG) were referenced from “Table 57d. Heavy Duty ICE Vehicles” on the Lifecycle Results tab.

Fleet Emissions

To calculate the total fleet emissions of each project, the results of 1477 gCO2e/km for diesel and 1082 gCO2e/km for LNG were each divided by 1,000,000 to convert into tonnes of CO2e per km.

The following table provides a detailed calculation of Vedder's total fleet emissions.

Table 4: Vedder Transport GHG emission reductions

Vedder Transport	GHGenius v3.18 Emissions	X	Average Annual Kms Traveled	=	Emissions Per Tractor (tCO2e)	X	Number of Tractors	=	Emissions Per Fleet (tCO2e)
Diesel (t/km)	0.00147701		190,000		280.6		50		14,031.6
LNG (t/km)	0.00108189		190,000		205.6		50		10,278.0
Emissions Reduction (tCO2e):					**75.1**				**3,753.6**

Appendix S

2007 BC ENERGY PLAN

The BC Energy Plan

A Vision for Clean Energy Leadership

BRITISH COLUMBIA
The Best Place on Earth

TABLE OF CONTENTS

MESSAGE FROM THE PREMIER

The BC Energy Plan: A Vision for Clean Energy Leadership is British Columbia's plan to make our province energy self-sufficient while taking responsibility for our natural environment and climate. The world has turned its attention to the critical issue of global warming. This plan sets ambitious targets. We will pursue them relentlessly as we build a brighter future for B.C.

The BC Energy Plan sets out a strategy for reducing our greenhouse gas emissions and commits to unprecedented investments in alternative technology based on the work that was undertaken by the Alternative Energy Task Force. Most importantly, this plan outlines the steps that all of us – including industry, environmental agencies, communities and citizens – must take to reach these goals for conservation, energy efficiency and clean energy so we can arrest the growth of greenhouse gases and reduce human impacts on the climate.

As stewards of this province, we have a responsibility to manage our natural resources in a way that ensures they both meet our needs today and the needs of our children and grandchildren. We will all have to think and act differently as we develop innovative and sustainable solutions to secure a clean and reliable energy supply for all British Columbians.

Our plan will make B.C. energy self-sufficient by 2016. To do this, we must maximize our conservation efforts. Conservation will reduce pressure on our energy supply and result in real savings for those who use less energy. Individual actions that reduce our own everyday energy consumption will make the difference between success and failure. For industry, conservation can lead to an effective, productive and significant competitive advantage. For communities, it can lead to healthier neighbourhoods and lifestyles for all of us.

We are looking at how we can use clean alternative energy sources, including bioenergy, geothermal, fuel cells, water-powered electricity, solar and wind to meet our province's energy needs. With each of these new options comes the opportunity for new job creation in areas such as research, development, and production of innovative energy and conservation solutions. The combination of renewable alternative energy sources and conservation will allow us to pursue our potential to become a net exporter of clean, renewable energy to our Pacific neighbours.

Just as the government's energy vision of 40 years ago led to massive benefits for our province, so will our decisions today. **The BC Energy Plan** will ensure a secure, reliable, and affordable energy supply for all British Columbians for years to come.

Premier Gordon Campbell

MESSAGE FROM THE MINISTER

The BC Energy Plan: A Vision for Clean Energy Leadership is a made-in-B.C. solution to the common global challenge of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way. In the next decade government will balance the opportunities and increased prosperity available from our natural resources while leading the world in sustainable environmental management.

This energy plan puts us in a leadership role that will see the province move to eliminating or offsetting greenhouse gas emissions for all new projects in the growing electricity sector, end flaring from oil and gas producing wells, and put in place a plan to make B.C. electricity self-sufficient by 2016.

In developing this plan, the government met with key stakeholders, environmental non-government organizations, First Nations, industry representatives and others. In all, more than 100 meetings were held with a wide range of parties to gather ideas and feedback on new policy actions and strategies now contained in **The BC Energy Plan**.

By building on the strong successes of Energy Plan 2002, this energy plan will provide secure, affordable energy for British Columbia. Today, we reaffirm our commitment to public ownership of our BC Hydro assets while broadening our supply of available energy.

We look towards British Columbia's leading edge industries to help develop new, greener generation technologies with the support of the new **Innovative Clean Energy Fund**. We're planning for tomorrow, today. Our energy industry creates jobs for British Columbians, supports important services for our families, and will play an important role in the decade of economic growth and environmental sustainability that lies ahead.

The Ministry of Energy, Mines and Petroleum Resources is responding to challenges and opportunities by delivering innovative, sustainable ways to develop British Columbia's energy resources.

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

THE BC ENERGY PLAN HIGHLIGHTS

In 2002, the Government of British Columbia launched an ambitious plan to invigorate the province's energy sector. Energy for Our Future: A Plan for BC was built around four cornerstones: low electricity rates and public ownership of BC Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility with no nuclear power sources. Today, our challenges include a growing energy demand, higher prices, climate change and the need for environmental sustainability. **The BC Energy Plan: A Vision for Clean Energy Leadership** builds on the successes of the government's 2002 plan and moves forward with new policies to meet the challenges and opportunities ahead.

- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **No nuclear power.**
- **Best coalbed gas practices in North America.**
- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**

Environmental Leadership

The BC Energy Plan puts British Columbia at the forefront of environmental and economic leadership by focusing on our key natural strengths and our competitive advantages of clean and renewable sources of energy. The plan further strengthens our environmental leadership through the following key policy actions:

- **Zero greenhouse gas emissions from coal fired electricity generation.**
- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**

British Columbia's current electricity supply resources are 90 per cent clean and new electricity generation plants will have zero net greenhouse gas emissions.

A Strong Commitment to Energy Conservation and Efficiency

Conservation is integral to meeting British Columbia's future energy needs. **The BC Energy Plan** sets ambitious conservation targets to reduce the growth in electricity used within the province. British Columbia will:

- **Set an ambitious target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Implement energy efficient building standards by 2010.**

Current per household electricity consumption for BC Hydro customers is about 10,000 Kwh per year. Achieving this conservation target will see electricity use per household decline to approximately 9,000 Kwh per year by 2020.

Energy Security

The Government of British Columbia is taking action to ensure that the energy needs of British Columbians continue to be met now and into the future. As part of ensuring our energy security, **The BC Energy Plan** sets the following key policy actions:

- **Maintain public ownership of BC Hydro and the BC Transmission Corporation.**
- **Maintain our competitive electricity rate advantage.**
- **Achieve electricity self-sufficiency by 2016.**
- **Make small power part of the solution through a set purchase price for electricity generated from projects up to 10 megawatts.**
- **Explore value-added opportunities in the oil and gas industry by examining the viability of a new petroleum refinery and petrochemical industry.**
- **Be among the most competitive oil and gas jurisdictions in North America.**
- **BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known.**

Investing in Innovation

British Columbia has a proven track record in bringing ideas and innovation to the energy sector. From our leadership and experience in harnessing our hydro resources to produce electricity, to our groundbreaking work in hydrogen and fuel cell technology, British Columbia has always met its future energy challenges by developing new, improved and sustainable solutions. To support future innovation and to help bridge the gap experienced in bringing innovations through the pre-commercial stage to market, government will:

- **Establish an Innovative Clean Energy Fund of $25 million.**
- **Implement the BC Bioenergy Strategy to take full advantage of B.C.'s abundant sources of renewable energy.**
- **Generate electricity from mountain pine beetle wood by turning wood waste into energy.**

POLICY ACTIONS

COMMITMENT TO CONSERVATION

- **Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.**
- **Encourage utilities to pursue cost effective and competitive demand side management opportunities.**
- **Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.**

Ambitious Energy Conservation and Efficiency Targets

The more energy that is conserved, the fewer new sources of supply we will require in the future. That is why British Columbia is setting new conservation targets to reduce growth in electricity demand.

Inefficient use of energy leads to higher costs and many environmental and security of supply problems.

Conservation Target

The BC Energy Plan sets an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020. This will require building on the "culture of conservation" that British Columbians have embraced in recent years.

The plan confirms action on the part of government to complement these conservation targets by working closely with BC Hydro and other utilities to research, develop, and implement best practices in conservation and energy efficiency and to increase public awareness. In addition, the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management programs. Utilities are also encouraged to explore and develop rate designs to encourage efficiency, conservation and the development of renewable energy.

Future energy efficiency and conservation initiatives will include:

- Continuing to remove barriers that prevent customers from reducing their consumption.
- Building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume.
- Exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times.
- Employing new rate structures to help customers implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices.
- Advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

The average household uses about 10,000 kilowatt-hours of electricity per year.

Implement Energy Efficiency Standards for Buildings by 2010

British Columbia implemented *Energy Efficient Buildings: A Plan for BC* in 2005 to address specific barriers to energy efficiency in our building stock through a number of voluntary policy and market measures. This plan has seen a variety of successes including smart metering pilot projects, energy performance measurement and labelling, and increased use of Energy Star appliances. In 2005, B.C. received a two year, $11 million federal contribution from the Climate Change Opportunities Envelope to support implementation of this plan.

Working together industry, local governments, other stakeholders and the provincial government will determine and implement cost effective energy efficiency standards for new buildings by 2010. Regulated standards for buildings are a central component of energy efficiency programs in leading jurisdictions throughout the world.

The BC Energy Plan supports reducing consumption by raising awareness and enhancing the efforts of utilities, local governments and building industry partners in British Columbia toward conservation and energy efficiency.

Aggressive Public Sector Building Plan

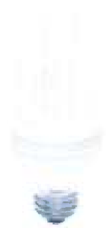
The design and retrofit of buildings and their surrounding landscapes offer us an important means to achieve our goal of making the government of British Columbia carbon neutral by 2010, and promoting Pacific Green universities, colleges, hospitals, schools, prisons, ferries, ports and airports.

British Columbia communities are already recognized leaders in innovative design practices. We know how to build smarter, faster and smaller. We know how to increase densities, reduce building costs and create new positive benefits for our environment. We know how to improve air quality, reduce energy consumption and make wise use of other resources, and how to make our landscapes and buildings healthy places for living, working and learning. We know how to make it affordable.

Government will set the following ambitious goals for all publicly funded buildings and landscapes and ask the Climate Action Team to determine the most credible, aggressive and economically viable options for achieving them:

- Require integrated environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
- Supply green, healthy workspaces for all public service employees.
- Capture the productivity benefits for people who live and work in publicly funded buildings such as reduced illnesses, less absenteeism, and a better learning environment.
- Aim not only for the lowest impact, but also for restoration of the ecological features of the surrounding landscapes.

Gigawatt = 1,000,000 kilowatts
Kilowatt = amount of power to light ten 100-watt incandescent light bulbs.



Community Action on Energy Efficiency

British Columbia is working in partnership with local governments to encourage energy conservation at the community level through the Community Action on Energy Efficiency Program. The program promotes energy efficiency and community energy planning projects, providing direct policy and technical support to local governments through a partnership with the Fraser Basin Council. A total of 29 communities are participating in the program and this plan calls for an increase in the level of participation and expansion of the program to include transportation actions. The Community Action on Energy Efficiency Program is a collaboration among the provincial ministries of Energy, Mines and Petroleum Resources, Environment, and Community Services, Natural Resources Canada, the Fraser Basin Council, Community Energy Association, BC Hydro, FortisBC, Terasen Gas, and the Union of BC Municipalities.

Leading the Way to a Future with Green Buildings and Green Cities

British Columbia has taken a leadership role in the development of green buildings. Through the Green Buildings BC Program, the province is working to reduce the environmental impact of government buildings by increasing energy and water efficiency and reducing greenhouse gas emissions. Through this program, and the Energy Efficient Buildings Strategy that establishes energy efficiency targets for all types of buildings, the province is inviting businesses, local governments and all British Columbians to do their part to increase energy efficiency and reduce greenhouse gas emissions.

The Green Cities Project sets a number of strategies to make our communities greener, healthier and more vibrant places to live. British Columbia communities are already recognized leaders in innovative sustainability practices, and the Green Cities Project will provide them with additional resources to improve air quality, reduce energy consumption and encourage British Columbians to get out and enjoy the outdoors. With the Green Cities Project, the provincial government will:

- Provide $10 million a year over four years for the new LocalMotion Fund, which will cost share capital projects on a 50/50 basis with municipal governments to build bike paths, walkways, greenways and improve accessibility for people with disabilities.
- Establish a new Green City Awards program to encourage the development and exchange of best practices by communities, with the awards presented annually at the Union of British Columbia Municipalities convention.
- Set new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.
- Commit to making new investments in expanded rapid transit, support for fuel cell vehicles and other innovations.

Industrial Energy Efficiency Program

Government will establish an Industrial Energy Efficiency Program for British Columbia to address challenges and issues faced by the B.C. industrial sector and support the Canada wide industrial energy efficiency initiatives. The program will encourage industry driven investments in energy efficient technologies and processes; reduce emissions and greenhouse gases; promote self generation of power; and reduce funding barriers that discourage energy efficiency in the industrial sector. Some specific strategies include developing a results based pilot program with industry to improve energy efficiency and reduce overall power consumption and promote the generation of renewable energy within the industrial sector.

The 2010 Olympic and Paralympics Games: Sustainability in Action

In 2010 Vancouver and Whistler will host the Winter Olympic and Paralympic Games. The 2010 Olympic Games are the first that have been organized based on the principles of sustainability.

All new buildings for the Olympics will be designed and built to conserve both water and materials, minimize waste, maximize air quality, protect surrounding areas and continue to provide environmental and community benefits over their lifetimes. Existing venues will be upgraded to showcase energy conservation and efficiency and demonstrate the use of alternative heating/cooling technologies. Wherever possible, renewable energy sources such as wind, solar, micro hydro, and geothermal energy will be used to power and heat all Games facilities.

Transportation for the 2010 Games will be based on public transit. This system – which will tie event tickets to transit use – will help reduce traffic congestion, minimize local air pollution and limit greenhouse gas emissions.

POLICY ACTIONS

BUILDING STANDARDS, COMMUNITY ACTION AND INDUSTRIAL EFFICIENCY

- **Implement Energy Efficiency Standards for Buildings by 2010.**
- **Undertake a pilot project for energy performance labelling of homes and buildings in coordination with local and federal governments, First Nations and industry associations.**
- **New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.**
- **Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.**
- **Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.**

British Columbia benefits from the public ownership of BC Hydro and the BC Transmission Corporation.

POLICY ACTIONS

SELF-SUFFICIENCY BY 2016

- **Ensure self-sufficiency to meet electricity needs, including "insurance."**
- **Establish a standing offer for clean electricity projects up to 10 megawatts.**
- **The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.**
- **Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.**
- **Ensure that the province remains consistent with North American transmission reliability standards.**

Electricity Security

Electricity, while often taken for granted, is the lifeblood of our modern economy and key to our entire way of life. Fortunately, British Columbia has been blessed with an abundant supply of clean, affordable and renewable electricity. But today, as British Columbia's population has grown, so too has our demand for electricity. We are now dependent on other jurisdictions for up to 10 per cent of our electricity supply. BC Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years.

We must address this ever increasing demand to maintain our secure supply of electricity and the competitive advantage in electricity rates that all British Columbians have enjoyed for the last 20 years. There are no simple solutions or answers. We have an obligation to future generations to chart a course that will ensure a secure, environmentally and socially responsible electricity supply.

To close this electricity gap, and for our province to become electricity self-sufficient, will require an innovative electricity industry and the real commitment of all British Columbians to conservation and energy efficiency.

The New Relationship and Electricity

The Government of British Columbia is working with First Nations to restore, revitalize and strengthen First Nations communities. The goal is to build strong and healthy relationships with First Nations people guided by the principles of trust and collaboration. First Nations share many of the concerns of other British Columbians in how the development of energy resources may impact as well as benefit their communities. In addition, First Nations have concerns with regard to the recognition and respect of Aboriginal rights and title.

By focusing on building partnerships between First Nations, industry and government, tangible social and economic benefits will flow to First Nations communities across the province and assist in eliminating the gap between First Nations people and other British Columbians.

Government is working every day to ensure that energy resource management includes First Nations' interests, knowledge and values. By continuing to engage First Nations in energy related issues, we have the opportunity to share information and look for opportunities to facilitate First Nations' employment and participation in the electricity sectors to ensure that First Nations people benefit from the continued growth and development of British Columbia's resources. **The BC Energy Plan** provides British Columbia with a blueprint for facing the many energy challenges and opportunities that lay ahead. It provides an opportunity to build on First Nations success stories such as:

- First Nations involvement in independent power projects, such as the Squamish First Nation's participation in the Furry Creek and Ashlu hydro projects.

- Almost $4 million will flow to approximately 10 First Nations communities across British Columbia to support the implementation of Community Energy Action Plans as part of the First Nation and Remote Community Clean Energy Program.
- The China Creek independent power project was developed by the Hupacasath First Nation on Vancouver Island.

Achieve Electricity Self-Sufficiency by 2016

Achieving electricity self-sufficiency is fundamental to our future energy security and will allow our province to achieve a reliable, clean and affordable supply of electricity. It also represents a lasting legacy for future generations of British Columbians. That's why government has committed that British Columbia will be electricity self-sufficient within the decade ahead.

Through **The BC Energy Plan**, government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need. However, electricity generation and transmission infrastructure require long lead times. This means that over the next two decades, BC Hydro must acquire an additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports.

Small Power Standing Offer

Achieving electricity self-sufficiency in British Columbia will require a range of new power sources to be brought on line. To help make this happen, this policy will direct BC Hydro to establish a Standing Offer Program with no quota to encourage small and clean electricity producers. Under the Standing Offer Program, BC Hydro will purchase directly from suppliers at a set price. Eligible projects must be less than 10 megawatts in size and be clean electricity or high efficiency electricity cogeneration. The price offered in the standing offer contract would be based on the prices paid in the most recent BC Hydro energy call. This will provide small electricity suppliers with more certainty, bring small power projects into the system more quickly, and help achieve government's goal of maintaining a secure electricity supply. As well, BC Hydro will offer the same price to those in BC Hydro's Net Metering Program who have a surplus of generation at the end of the year.

Ensuring a Reliable Transmission Network

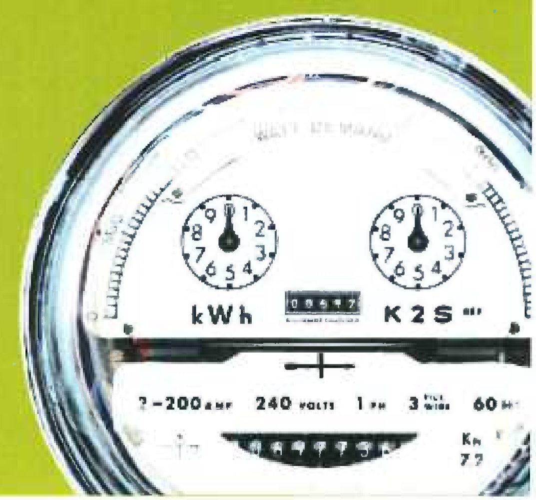
An important part of meeting the goal of self-sufficiency is ensuring a reliable transmission infrastructure is in place as additional power is brought on line. Transmission is a critical part of the solution as often new clean sources of electricity are located away from where the demand is. In addition, transmission investment is required to support economic growth in the province and must be planned and started in anticipation of future electricity needs given the long lead times required for transmission development. New and upgraded transmission infrastructure will be required to avoid congestion and to efficiently move the electricity across the entire power grid. Because our transmission system is part of a much larger, interconnected grid, we need to work with other jurisdictions to maximize the benefit of interconnection, remain consistent with evolving North American reliability standards, and ensure British Columbia's infrastructure remains capable of meeting customer needs.

BC HYDRO'S NET METERING PROGRAM: PEOPLE PRODUCING POWER

BC Hydro's Net Metering Program was established as a result of Energy Plan 2002. It is designed for customers with small generating facilities, who may sometimes generate more electricity than they require for their own use. A net metering customer's electricity meter will run backwards when they produce more electricity than they consume and run forward when they produce less than they consume.

The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced.

Net metering allows customers to lower their environmental impact and take responsibility for their own power production. It helps to move the province towards electricity self-sufficiency and expands clean electricity generation, making B.C.'s electricity supply more environmentally sustainable.



In order for British Columbia to ensure the development of a secure and reliable supply of electricity, **The BC Energy Plan** provides policy direction to the BC Transmission Corporation to ensure that our transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand. This will include ensuring there is adequate transmission capacity, ongoing investments in technology and infrastructure and remaining consistent with evolving North American reliability standards.

BC Transmission Corporation Innovation and Technology

As the manager of a complex and high-value transmission grid, BC Transmission Corporation is introducing technology innovations that provide improvements to the performance of the system and allow for a greater utilization of existing assets, ensuring B.C. continues to benefit from one of the most advanced energy networks in the world. BC Transmission Corporation's innovation program focuses on increasing the power transfer capability of existing assets, extending the life of assets and improving system reliability and security. Initiatives include:

- System Control Centre Modernization Project: This project is consolidating system operations into a new control center and backup site and upgrading operating technologies with a modern management system that includes enhancements to existing applications to ensure the electric grid is operating reliably and efficiently. The backup site will take over complete operation of the electric grid if the main site is unavailable.
- Real-Time Phasors: British Columbia is among the first North American jurisdictions to incorporate phasor measurement into control centre operations. Phasors are highly accurate voltage, current and phase angle "snapshots" of the real-time state of the transmission system that enable system operators to monitor system conditions and identify any impending problems.
- Real-Time Rating: This is a temperature monitoring system which enables the operation of two 500 kilovolt submarine cable circuits at maximum capacity without overloading. The resulting increase in capacity is estimated to be up to 10 per cent, saving millions of dollars.
- Electronic Temperature Monitor Upgrades for Station Transformers: In this program, existing mechanical temperature monitors will be replaced with newer, more accurate electronic monitors on station transformers that allow transformers to operate to maximum capacity without overheating. In addition to improving performance, BC Transmission Corporation will realize reduced maintenance costs as the monitors are "self-checking."
- Life Extension of Transmission Towers: BC Transmission Corporation maintains over 22,000 steel lattice towers and is applying a special composite corrosion protection coating to some existing steel towers to extend their life by about 25 years.

Public Ownership

Public Ownership of BC Hydro and the BC Transmission Corporation

BC Hydro and the BC Transmission Corporation are publicly-owned crown corporations and will remain that way now and into the future. BC Hydro is responsible for generating, purchasing and distributing electricity. The BC Transmission Corporation operates, maintains, and plans BC Hydro's transmission assets and is responsible for providing fair, open access to the power grid for all customers. Both crowns are subject to the review and approvals of the independent regulator, the BC Utilities Commission.

BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians. These heritage assets require maintenance and upgrades over time to ensure they continue to operate reliably and efficiently. Potential improvements to these assets, such as capacity additions at the Mica and Revelstoke generating stations, can make important contributions for the benefit of British Columbians.

Confirming the Heritage Contract in Perpetuity

Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With **The BC Energy Plan**, government confirms the heritage contract in perpetuity to ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come.

British Columbia's Leadership in Clean Energy

The BC Energy Plan will continue to ensure British Columbia has an environmentally and socially responsible electricity supply with a focus on conservation and energy efficiency.

British Columbia is already a world leader in the use of clean and renewable electricity, due in part to the foresight of previous generations who built our province's hydroelectric dams. These dams - now British Columbians' 'heritage assets' - today help us to enjoy 90 per cent clean electricity, one of the highest levels in North America.

All New Electricity Generation Projects Will Have Zero Net Greenhouse Gas Emissions

The B.C. government is a leader in North America when it comes to environmental standards. While British Columbia is a province rich in energy resources such as hydro electricity, natural gas and coal, the use of these resources needs to be balanced through effective use, preserving our environmental standards, while upholding our quality of life for generations to come. The government has made a commitment that all new electricity generation projects developed in British Columbia and connected to the grid will have zero net greenhouse gas emissions. In addition, any new electricity generated from coal must meet the more stringent standard of zero greenhouse gas emissions.

POLICY ACTIONS

PUBLIC OWNERSHIP

- **Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.**
- **Establish the existing heritage contract in perpetuity.**
- **Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.**

POLICY ACTIONS

REDUCING GREENHOUSE GAS EMISSIONS FROM ELECTRICITY

- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**
- **Require zero greenhouse gas emissions from any coal thermal electricity facilities.**
- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.**
- **No nuclear power.**

Zero Net Greenhouse Gas Emissions from Existing Thermal Generation Power Plants by 2016

Setting a requirement for zero net emissions over this time period encourages power producers to invest in new or upgraded technology. For existing plants the government will set policy around reaching zero net emissions through carbon offsets from other activities in British Columbia. It clearly signals the government's intention to continue to have one of the lowest greenhouse gas emission electricity sectors in the world.

Ensure Clean or Renewable Electricity Generation Continues to Account For at Least 90 per cent of Total Generation

Currently in B.C., 90 per cent of electricity is from clean or renewable resources. **The BC Energy Plan** commits to maintaining this high standard which places us among the top jurisdictions in the world. Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from organic municipal waste.

Zero Greenhouse Gas Emissions from Coal

The government is committed to ensuring that British Columbia's electricity sector remains one of the cleanest in the world and will allow coal as a resource for electricity generation when it can reach zero greenhouse gas emissions. Clean-coal technology with carbon sequestration is expected to become commercially available in the next decade. Therefore, the province will require zero greenhouse gas emissions from any coal thermal electricity facilities which can be met through capture and sequestration technology. British Columbia is the first Canadian jurisdiction to commit to using only clean coal technology for any electricity generated from coal.

Burrard Thermal Generating Station

A decision regarding the Burrard Thermal Natural Gas Generating Station is another action that is related to environmentally responsible electricity generation in British Columbia.

Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run. However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations.

By 2014, BC Hydro plans to have firm electricity to replace what would have been produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014. However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise.

No Nuclear Power

As first outlined in Energy Plan 2002, government will not allow production of nuclear power in British Columbia.

Benefits to British Columbians

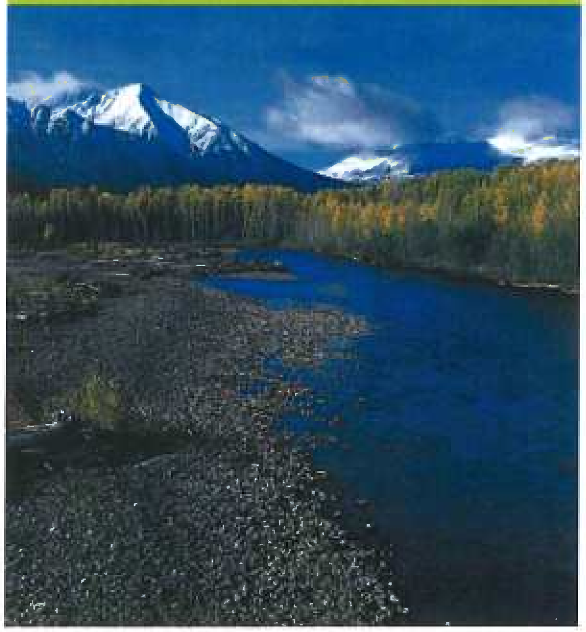
Clean or renewable electricity comes from sources that replenish over a reasonable time or have minimal environmental impacts. Today, demand for economically viable, clean, renewable and alternative energy is growing along with the world's population and economies. Consumers are looking for power that is not only affordable but creates minimal environmental impacts. Fortunately, British Columbia has abundant hydroelectric resources, and plenty of other potential energy sources.

Maintain our Electricity Competitive Advantage

British Columbians require a secure, reliable supply of competitively priced electricity now and in the future. Competitively priced power is also an incentive for investors to locate in British Columbia. It provides an advantage over other jurisdictions and helps sustain economic growth. We are fortunate that historic investments in hydroelectric assets provide electricity that is readily available, reliable, clean and inexpensive. By ensuring public ownership of BC Hydro, the heritage assets and the BC Transmission Corporation and confirming the heritage contract in perpetuity, we will ensure that ratepayers continue to receive the benefits of this low cost generation. Due to load growth and aging infrastructure, new investments will be required. Investments in maintenance and in some cases expansions can be a cost effective way to meet growth and reduce future rate increases.

CARBON OFFSETS AND HOW THEY REDUCE EMISSIONS

A carbon offset is an action taken directly, outside of normal operations, which results in reduced greenhouse gas emissions or removal of greenhouse gases from the atmosphere. Here's how it works: if a project adds greenhouse gases to the atmosphere, it can effectively subtract them by purchasing carbon offsets which are reductions from another activity. Government regulations to reduce greenhouse gases, including offsets, demonstrate leadership on climate change and support a move to clean and renewable energy.



ELECTRICITY

Government will establish a $25 million ***Innovative Clean Energy Fund.***

POLICY ACTIONS

BENEFITS TO BRITISH COLUMBIANS

- **Review BC Utilities Commissions' role in considering social and environmental costs and benefits.**
- **Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.**
- **Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.**
- **Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.**
- **Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.**

British Columbia must look for new, innovative ways to stay competitive. New technologies must be identified and nurtured, from both new and existing industries. By diversifying and strengthening our energy sector through the development of new and alternative energy sources, we can help ensure the province's economy remains vibrant for years to come.

Ensure Electricity is Secured at Competitive Prices

One practical way to keep rates down is to ensure utilities have effective processes for securing competitively priced power. As part of **The BC Energy Plan**, government will work with BC Hydro and parties involved to continue to improve the Call for Tender process for acquiring new generation. Fair treatment of both buyers and sellers of electricity will facilitate a robust and competitive procurement process. Government and BC Hydro will also look for ways to further recognize the value of intermittent resources, such as run-of- river and wind, in the acquisition process – which means that BC Hydro will examine ways to value separate projects together to increase the amount of firm energy calculated from the resources.

Rates Kept Low Through Powerex Trading of Electricity

Profits from electricity trade also contribute to keeping our electricity rates competitive. BC Hydro, through its subsidiary, Powerex, buys and sells electricity when it is advantageous to British Columbia's ratepayers. Government will continue to support capitalizing on electricity trading opportunities and will continue to allocate trade revenue to BC Hydro ratepayers to keep electricity rates low for all British Columbians.

BC Utilities Commissions' Role in Social and Environmental Costs and Benefits

The BC Energy Plan clarifies that social, economic and environmental costs are important for ensuring a suitable electricity supply in British Columbia. Government will review the BC Utilities Commissions' role in considering social, environmental and economic costs and benefits, and will determine how best to ensure these are appropriately considered within the regulatory framework.

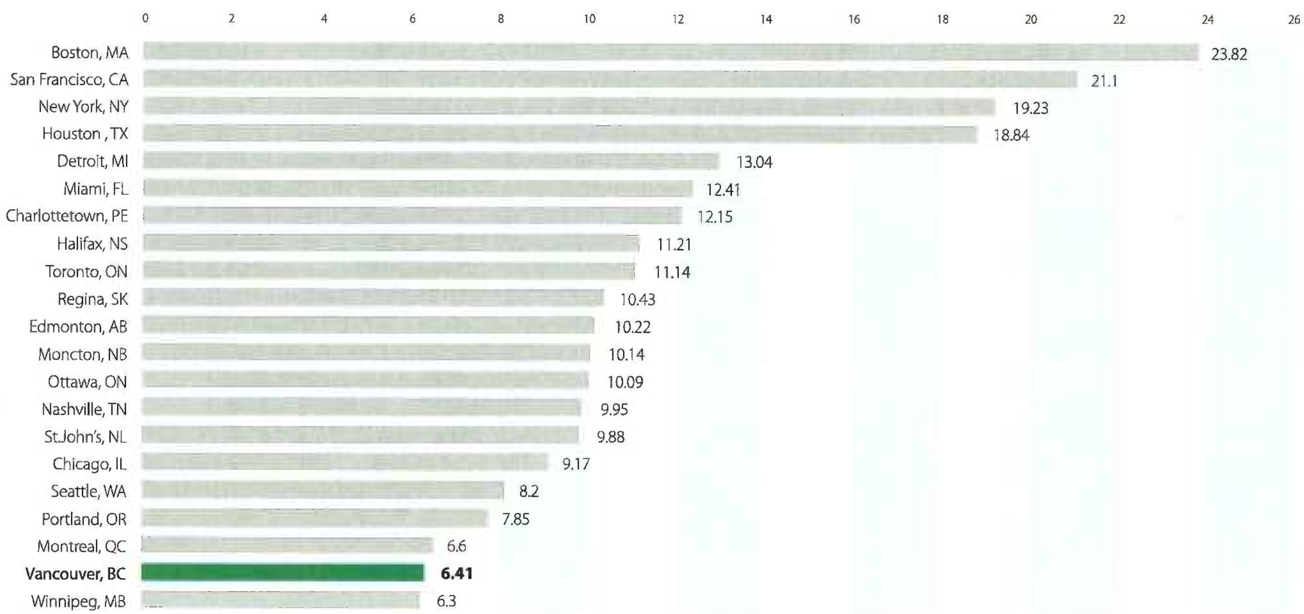
Bring Clean Power to Communities

British Columbia's electricity industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services. British Columbia's electricity industry already fosters economic development by implementing cost effective and reliable energy solutions in communities around the province. However, British Columbia covers almost one million square kilometres and electrification does not extend to all parts of our vast province.

Government and BC Hydro have established First Nation and remote community energy programs to implement alternative energy, energy efficiency, conservation and skills training solutions in a number of communities. The program focuses on expanding electrification services to as many as 50 remote and First Nations communities in British Columbia, enabling them to share in the benefits of a stable and secure supply of electricity. Government will put the policy framework in place and BC Hydro will implement the program over the next 10 years. The **Innovative Clean Energy Fund** can also support technological advancements to address the issue of providing a clean and secure supply of electricity to remote communities.

2006 Average Residential Electricity Price

Price (Canadian cents per kilowatt hour)



Source: Hydro Quebec comparison of Electricity Prices in Major North American Cities, April 2006

BRINGING CLEAN POWER TO ATLIN

Electricity in the remote community of Atlin in northwestern British Columbia is currently supplied by diesel generators. The First Nations and Remote Community Clean Energy Program is bringing clean power to Atlin.

The Taku Land Corporation, solely owned by the Taku River Tlingit First Nation will construct a two megawatt run-of-river hydroelectric project on Pine Creek, generating local economic benefits and providing clean power for Atlin. The Taku Land Corporation has entered into a 25 year Electricity Purchase Agreement with BC Hydro to supply electricity from the project to Atlin's grid. Over the course of the agreement, this will reduce greenhouse gas emissions by up to 150,000 tonnes as the town's diesel generators stand by.

The province is contributing $1.4 million to this $10 million project. This is the first payment from a $3.9 million federal contribution to British Columbia's First Nations and Remote Community Clean Energy Program. Criteria for federal funding included demonstrating greenhouse gas emissions reductions, cost-effectiveness, and partnerships with communities and industry.

Government will work with other agencies to maximize opportunities to develop, deploy and export British Columbia clean and alternative energy technologies.

POLICY ACTIONS

INVESTING IN INNOVATION

- **Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.**
- **Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.**
- **Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.**

Innovative Clean Energy Fund

British Columbia's increasing energy requirements and our ambitious greenhouse gas emission reduction and clean energy targets require greater investment and innovation in the area of alternative energy by both the public and private sector.

To lead this effort, the government will establish an **Innovative Clean Energy Fund** of $25 million to help promising clean power technology projects succeed. The fund will be established through a small charge on energy utilities. The Minister of Energy, Mines and Petroleum Resources will consult with the energy utilities on the implementation of this charge.

Proponents of projects that will be supported through the fund will be encouraged to seek additional contributions from other sources. Government's new **Innovative Clean Energy Fund** will help make British Columbia a world leader in alternative energy and power technology. It will solve some of B.C.'s pressing energy challenges, protect our environment, help grow the economy, position the province as the place international customers turn to for key energy and environmental solutions, and assist B.C. based companies to showcase their products to world wide markets.

Following the advice of the Premier's Technology Council and the Alternative Energy and Power Technology Task Force, the fund will focus strictly on projects that:

- Address specific British Columbia energy and environmental problems that have been identified by government.
- Showcase B.C. technologies that have a strong potential for international market demand in other jurisdictions because they solve problems that exist both in B.C. and other jurisdictions.
- Support pre-commercial energy technology that is new, or commercial technologies not currently used in British Columbia.
- Demonstrate commercial success for new energy technologies.

Some problems that the fund could focus on include:

- Developing reliable power solutions for remote communities-particularly helping First Nations communities reduce their reliance on diesel generation for electricity.
- Advance conservation technologies to commercial application.
- Finding ways to convert vehicles to cleaner alternative fuels.
- Increasing the efficiency of power transmission through future grid technologies.
- Expanding the opportunities to generate power using alternative fuels (e.g.mountain pine beetle wood).

The British Columbia Bioenergy Strategy: Growing Our Natural Energy Advantage

Currently, British Columbia is leading Canada in the use of biomass for energy. The province has 50 per cent of Canada's biomass electricity generating capacity. In 2005, British Columbia's forest industry self-generated the equivalent of $150 million in electricity and roughly $1.5 billion in the form of heat energy. The use of biomass has displaced some natural gas consumption in the pulp and paper sector. The British Columbia wood pellet industry also enjoys a one-sixth share of the growing European Union market for bioenergy feedstock. The province will shortly release a bioenergy strategy that will build upon British Columbia's natural bioenergy resource advantages, industry capabilities and academic strength to establish British Columbia as a world leader in bioenergy development.

British Columbia's plan is to lead the bioeconomy in Western Canada with a strong and sustainable bioenergy sector. This vision is built on two guiding principles:

- Competitive, diversified forest and agriculture sectors.
- Strengthening regions and communities.

The provincial Bioenergy Strategy is aimed at:

- Enhancing British Columbia's ability to become electricity self-sufficient.
- Fostering the development of a sustainable bioenergy sector.
- Creating new jobs.
- Supporting improvements in air quality.
- Promoting opportunities to create power from mountain pine beetle-impacted timber.
- Positioning British Columbia for world leadership in the development and commercial adoption of wood energy technology.
- Advancing innovative solutions to agricultural and other waste management challenges.
- Encouraging diversification in the forestry and agriculture industries.
- Producing liquid biofuels to meet Renewable Fuel Standards and displace conventional fossil fuels.

Generating Electricity from Mountain Pine Beetle Wood: Turning Wood Waste into Energy

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant impact on forestry-based communities and industries, and heightens forest fire risk. There is a great opportunity to convert the affected timber to bioenergy, such as wood pellets and wood-fired electricity generation and cogeneration.

Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.

MOUNTAIN PINE BEETLE INFESTATION: TURNING WOOD WASTE INTO ENERGY

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant economic impact on B.C.'s forestry industry and the many communities it helps to support and sustain. The forest fire risk to these communities has also risen as a result of their proximity to large stands of "beetle-killed" wood.

B.C. has developed a bioenergy strategy to promote new sources of sustainable and renewable energy in order to take advantage of the vast amounts of pine beetle-infested timber and other biomass resources. In the future, bioenergy will help meet our electricity needs, supplement conventional natural gas and petroleum supplies, maximize job and economic opportunities, and protect our health and environment.

The production of wood pellets is already a mature industry in British Columbia. Industry has produced over 500,000 tonnes of pellets and exported about 90 per cent of this product overseas in 2005, primarily to the European thermal power industry. Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for further electricity generation from wood residue and mountain pine beetle-infested timber.

GOVERNMENT TO USE HYBRID VEHICLES ONLY

The provincial government is continuing the effort to reduce greenhouse gas emissions and overall energy consumption.

As part of this effort, government has more than tripled the size of its hybrid fleet since 2005 to become one of the leaders in public sector use of hybrid cars.

Hybrids emit much less pollution than conventional gas and diesel powered vehicles and thus help to reduce greenhouse gases in our environment. They can also be more cost-effective as fuel savings offset the higher initial cost.

As of 2007, all new cars purchased or leased by the B.C. government are to be hybrid vehicles. The province also has new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.

Addressing Greenhouse Gas Emissions from Transportation

The BC Energy Plan: A Vision for Clean Energy Leadership takes a first step to incorporate transportation issues into provincial energy policy. Transportation is a major contributor to climate change and air quality problems. It presents other issues such as traffic congestion that slows the movement of goods and people. The fuel we use to travel around the province accounts for about 40 per cent of British Columbia's greenhouse gas emissions. Every time we drive or take a vehicle that runs on fossil fuels, we add to the problem, whether it's a train, boat, plane or automobile. Cars and trucks are the biggest source of greenhouse gas emissions and contribute to reduced air quality in urban areas.

The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California's tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards.

British Columbians want a range of energy options for use at home, on the road and in day-to-day life. Most people use gasoline or diesel to keep their vehicles moving, but there are other options that improve our air quality and reduce greenhouse gas emissions.

Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution. Fuel cell vehicles are propelled by electric motors powered by fuel cells, devices that produce electricity from hydrogen without combustion.

Cars that run on blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants. Electricity can provide an alternative to gasoline vehicles when used in hybrids and electric cars.

By working with businesses, educational institutions, non-profit organizations and governments, new and emerging transportation technologies can be deployed more rapidly at home and around the world. British Columbia will focus on research and development, demonstration projects, and marketing strategies to promote British Columbia's technologies to the world.

Implementing a Five Per Cent Renewable Fuel Standard for Diesel and Gasoline

The BC Energy Plan demonstrates British Columbia's commitment to environmental sustainability and economic growth by taking a lead role in promoting innovation in the transportation sector to reduce greenhouse gas emissions, improve air quality and help improve British Columbians' health and quality of life in the future. The plan will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry. It will further support the federal action of increasing the ethanol content of gasoline to five per cent by 2010. The plan will also see the adoption of quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions. These renewable fuel standards are a major component and first step towards government's goal of reducing the carbon intensity of all passenger vehicles by 10 per cent by 2020.

Government will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.

A Commitment to Extend British Columbia's Ground-breaking Hydrogen Highway

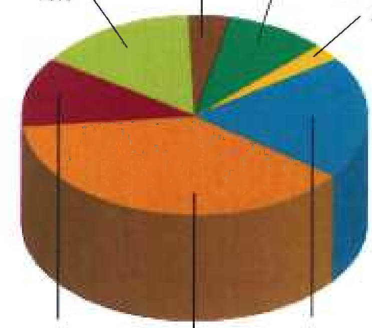
British Columbia is a world leader in transportation applications of the Hydrogen Highway, including the design, construction and safe operation of advanced hydrogen vehicle fuelling station technology. The Hydrogen Highway is a large scale, coordinated demonstration and deployment program for hydrogen and fuel cell technologies.

Vancouver's Powertech Labs established the world's first fast-fill, high pressure hydrogen fuelling station. The station anchors the Hydrogen Highway, which runs from Victoria through Surrey to Vancouver, North Vancouver, Squamish, and Whistler. Additional hydrogen fuelling stations are now in operation in Victoria and at the University of British Columbia.

The goal is to demonstrate and deploy various technologies and to one day see hydrogen filling stations around the province, serving drivers of consumer and commercial cars, trucks, and buses.

The unifying vision of the province's hydrogen and fuel cell strategy is to promote fuel cells and hydrogen technologies as a means of moving towards a sustainable energy future, increasing energy efficiency and reducing air pollutants and greenhouse gases. The Hydrogen Highway is targeted for full implementation by 2010. Canadian hydrogen and fuel cell companies have invested over $1 billion over the last five years, most of that in B.C. A federal-provincial partnership will be investing $89 million for fuelling stations and the world's first fleet of 20 fuel cell buses.

British Columbia will continue to be a leader in the new hydrogen economy by taking actions such as a fuel cell bus fleet deployment, developing a regulatory framework for micro-hydrogen applications, collaborating with neighbouring jurisdictions on hydrogen, and, in the long term, establishing a regulatory framework for hydrogen production, vehicles and fuelling stations.



B.C. Greenhouse Gas Emissions by Sector

(Based on 2004 data)
Source: Ministry of Environment

Cars and trucks are the biggest source of greenhouse gas emissions and reduce the quality of air in urban areas.

POLICY ACTIONS

ADDRESSING GREENHOUSE GAS EMISSIONS FROM TRANSPORTATION AND INCREASING INNOVATION

- **Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.**
- **Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.**
- **Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.**
- **Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.**

Vehicles that run on electricity, hydrogen and blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants.

LOCALMOTION FUND: REDUCING AIR POLLUTION IN YOUR COMMUNITY

The province has committed $40 million over four years to help build cycling and pedestrian pathways, improve safety and accessibility, and support children's activity programs in playgrounds.

This fund will help local government shift to hybrid vehicle fleets and help retrofit diesel vehicles which will help reduce air pollution and ensure vibrant and environmentally sustainable communities. This investment will also include expansion of rapid transit and support fuel cell vehicles.

Promote Energy Efficiency and Alternative Energy

It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province.

Environmental Leadership in Action

The BC Energy Plan: A Vision for Clean Energy Leadership complements other related cross-government initiatives that include supporting transportation demand management, reducing traffic congestion and better integrating land use and transportation planning. These plans include actions across a broad range of activities. Some key initiatives and recent announcements include:

- Extending the tax break on hybrid vehicle purchases beyond the current March 2008 deadline.
- Government to purchase hybrid vehicles exclusively.
- Reducing diesel emissions through new financial incentives to help municipalities shift to hybrid vehicle fleets and retrofit diesel vehicles with cleaner technologies.
- Green Ports:
  - Working with ports and the shipping sector to reduce emissions from their activities and marine vessels.
  - The Port of Vancouver has established idle reduction zones and has reduced truck emissions with its container reservation system which has reduced average wait times from two hours to approximately 20 minutes.
  - The port is also evaluating port-side electrification which would see vessels using shore-side electrical power while berthed rather than diesel power.
- Improving upon the monitoring and reporting of air quality information.
- Highway Infrastructure and Rapid Transit Infrastructure funding including the Gateway Program, the Border Infrastructure Program, high occupancy vehicle lanes, construction of the Rapid Transit Canada Line linking Richmond, the Vancouver International Airport and Vancouver, and the Rapid Transit Evergreen Line linking Burnaby to Coquitlam.
- Expanding the AirCare on the Road Program to the Lower Fraser Valley and other communities.
- Implementing the LocalMotion Program for capital projects to improve physical fitness and safety, reduce air pollution and meet the diverse needs of British Columbians.

A Choice of Electricity Options

The range of supply options, both large and small, for British Columbia include:

Bioenergy: Bioenergy is derived from organic biomass sources such as wood residue, agricultural waste, municipal solid waste and other biomass and may be considered a carbon-neutral form of energy, because the carbon dioxide released by the biomass when converted to energy is equivalent to the amount absorbed during its lifetime.

A number of bioenergy facilities operate in British Columbia today. Many of these are "cogeneration" plants that create both electricity and heat for on-site use and in some cases, sell surplus electricity to BC Hydro.

Reliability[1]: FIRM
Estimated Cost[5]: $75 – $91

Coal Thermal Power: The BC Energy Plan establishes a zero emission standard for greenhouse gas emissions from coal-fired plants. This will require proponents of new coal facilities to employ clean coal technology with carbon capture and sequestration to ensure there are no greenhouse gas emissions.

Reliability[1]: FIRM
Estimated Cost[5,6]: $67– $82

Geothermal: Geothermal power is electricity generated from the earth. Geothermal power production involves tapping into pockets of superheated water and steam deep underground, bringing them to the surface and using the heat to produce steam to drive a turbine and produce electricity. British Columbia has potential high temperature (the water is heated to more than 200 degrees Celsius) geothermal resources in the coastal mountains and lower temperature resources in the interior, in northeast British Columbia and in a belt down the Rocky Mountains. Geothermal energy's two main advantages are its consistent supply, and the fact that it is a clean, renewable source of energy.

Reliability[1]: FIRM
Estimated Cost[2]: $44 - $60

Hydrogen and Fuel Cell Technology:
British Columbia companies are recognized globally for being leaders in hydrogen and fuel cell technology for mobile, stationary and micro applications. For example, BC Transit's fuel cell buses are planned for deployment in Whistler in 2009.

Reliability[1]: FIRM
Estimated Cost[2]: n/a

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[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant. The BC Energy Plan requires coal power to meet zero GHG emissions
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero GHG emissions for coal thermal power

GOVERNMENT'S COMMITMENT TO THE ENVIRONMENT – THE ENVIRONMENTAL ASSESSMENT PROCESS

The environmental assessment process in British Columbia is an integrated review process for major projects that looks at potential environmental, community and First Nation, health and safety, and socioeconomic impacts. Through the environmental assessment process, the potential effects of a project are identified and evaluated early, resulting in improved project design and helping to avoid costly mistakes for proponents, governments, local communities and the environment.

An assessment is begun when a proposed project that meets certain criteria under the ***Environmental Assessment Act*** makes an application for an environmental assessment certificate. Each assessment will usually include an opportunity for all interested parties to identify issues and provide input; technical studies of the relevant environmental, social, economic, heritage and/or health effects of the proposed project; identification of ways to prevent or minimize undesirable effects and enhance desirable effects; and consideration of the input of all interested parties in compiling the assessment findings and making decisions about project acceptability. The review is concluded when a decision is made to issue or not issue an environmental assessment certificate. Industrial, mining, energy, water management, waste disposal, food processing, transportation and tourist destination resort projects are generally subject to an environmental assessment.

ELECTRICITY CHOICES

WHAT IS THE DIFFERENCE BETWEEN FIRM AND INTERMITTENT ELECTRICITY?

Firm electricity refers to electricity that is available at all times even in adverse conditions. The main sources of reliable electricity in British Columbia include large hydroelectric dams, and natural gas. This differs from intermittent electricity, which is limited or is not available at all times. An example of intermittent electricity would be wind which only produces power when the wind is blowing.

Large Hydroelectric Dams: The chief advantage of a hydro system is that it provides a reliable supply with both dependable capacity and energy, and a renewable and clean source of energy. Hydropower produces essentially no carbon dioxide.

Site C is one of many resource options that can help meet BC Hydro's customers' electricity needs. No preferred option has been selected at this time; however; it is recognized that the Province will need to examine opportunities for some large projects to meet growing demand.

As part of **The BC Energy Plan**, BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known. The purpose of this step is to engage the various parties up front to obtain input for the proposed engagement process. The decision-making process on Site C includes public consultation, environmental impact assessments, obtaining a Certificate of Public Convenience and Necessity, obtaining an Environmental Assessment Certificate and necessary environmental approvals, and approval by Cabinet.

Reliability[1]: FIRM
Estimated Cost[2]: $43 - $62

Natural Gas: Natural gas is converted into electricity through the use of gas fired turbines in medium to large generating stations; particularly high efficiencies can be achieved through combining gas turbines with steam turbines in the combined cycle and through reciprocating engines and mini and macro turbines. Combined cycle power generation using natural gas is the cleanest source of power available using fossil fuels. Natural gas provides a reliable supply with both dependable capacity and firm energy.

Reliability[1]: FIRM
Estimated Cost[2 6]: $48 - $100

Small Hydro: This includes run-of-river and micro Hydro. These generate electricity without altering seasonal flow characteristics. Water is diverted from a natural watercourse through an intake channel and pipeline to a powerhouse where a turbine and generator convert the kinetic energy in the moving water to electrical energy.

Twenty-nine electricity purchase agreements were awarded to small waterpower producers by BC Hydro in 2006. These projects will generate approximately 2,851 gigawatt hours of electricity annually (equivalent to electricity consumed by 285,000 homes in British Columbia). There are also 32 existing small hydro projects in British Columbia that generate 3,500 gigawatt hours (equivalent to electricity consumed by 350,000 homes in British Columbia).

Reliability[1]: INTERMITTENT
Estimated Cost[3]: $60 – $95

Solar: With financial support from the Ministry of Energy, Mines and Petroleum Resources, the "Solar for Schools" program has brought clean solar photovoltaic electricity to schools in Vernon, Fort Nelson, and Greater Victoria.

The BC Sustainable Energy Association is leading a project which targets installing solar water heaters on 100,000 rooftops across British Columbia.

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $700 - $1700

Tidal Energy: A small demonstration project has been installed at Race Rocks located west-southwest of Victoria. The Lester B. Pearson College of the Pacific, the provincial and federal government, and industry have partnered to install and test a tidal energy demonstration turbine at Race Rocks. The project will generate about 77,000 kilowatt hours on an annual basis (equivalent to electricity consumed by approximately eight homes).

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $100 - $360

Wind: British Columbia has abundant, widely distributed wind energy resources in three areas: the Peace region in the Northeast; Northern Vancouver Island; and the North Coast. Wind is a clean and renewable source that does not produce air or water pollution, greenhouse gases, solid or toxic wastes.

Three wind generation projects have been offered power purchase contracts in BC Hydro's 2006 Open Call for Power. These three projects will have a combined annual output of 979 gigawatt hours of electricity (equivalent to electricity consumed by 97,900 homes).

Reliability[1]: INTERMITTENT
Estimated Cost[5]: $71 – $74

[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant.
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero net GHG emissions for natural gas

RACE ROCKS TIDAL ENERGY PROJECT

Announced in early 2005, this demonstration project between the provincial and federal governments, industry, and Pearson College is producing zero emission tidal power at the Race Rocks Marine Reserve on southern Vancouver Island. Using a current-driven turbine submerged below the ocean surface, the project is producing about 77,000 kilowatt hours of electricity per year, enough to meet the needs of approximately eight households. The knowledge gained about tidal energy will help our province remain at the forefront of clean energy generation technology.

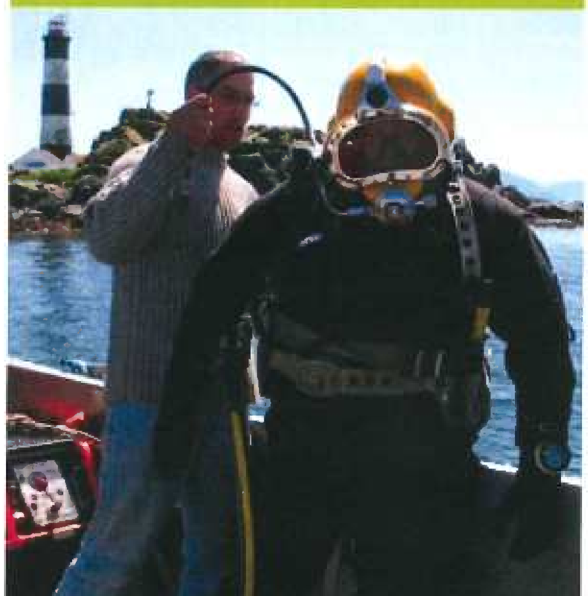


Table 1: Summary of Resource Options

Description	Estimated Cost[1] $ /megawatt hour	Reliable[2]	Greenhouse gas emissions[3] tonnes per gigawatt hour
Energy conservation/ efficiency	32 – 76	Yes	0
Large hydroelectric	43 – 62	Yes	0
Natural gas	48 – 100[8]	Yes	0 – 350[4,8]
Coal	67 – 82[9,10]	Yes	0 – 855[5,9]
Biomass	75 – 91[10]	Yes	0 – 500[6]
Geothermal	44 – 60	Yes	0 – 10
Wind	71 – 74[10]	Depends on the availability and speed of wind	0
Run-of-river small hydro	60 – 95[10]	Depends on the flow of water, which varies throughout the year	0
Ocean (wave and tidal)	100 – 360[7]	Future supply option which has great potential for British Columbia	0
Solar	700 – 1700[7]	Depends on location, cloud cover, season, and time of day	0

1 Source: BC Hydro's 2006 Integrated Electricity Plan Volume 1 of 2, page 5-6
2 Reliability refers to energy that can be depended on to be available whenever required
3 Source: BC Hydro's 2006 Integrated Electricity Plan, Volume 2 of 2, Appendix F page 5-14 and Table 10-2
4 Based on a 250 MW combined cycle gas turbine plant
5 Based on a 500 MW supercritical pulverized coal combustion unit
6 GHG are 0 for wood residue and landfill gas. GHG is 500 tonnes per gigawatt hour for municipal solid waste
7 Source: BC Hydro's 2004 Integrated Electricity Plan, page 69
8 The BC Energy Plan requires natural gas plants to offset to zero net greenhouse gas emissions. These costs do not reflect the costs of zero net GHG emissions
9 The BC Energy Plan requires zero greenhouse gas emissions from any coal thermal electricity facilities
The costs do not include the costs of requiring zero emissions from coal thermal power
10 Source: BC Hydro's F2006 Open Call for Power Report

The majority of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation by all British Columbians and new electricity from independent power producers.

British Columbia's Strength in Electricity Diversity

British Columbia is truly fortunate to have a wide variety of future supply options available to meet our growing demand for energy. A cost effective way to meet that demand is to conserve energy and be more energy efficient. However, British Columbia will still need to bring new power on line to meet demand growth in the years ahead. In order to ensure we have this critical resource available to British Columbians when they need it, government will be looking to secure a range of made-in-B.C. power to serve British Columbians in the years ahead.

Government's goal is to encourage a diverse mix of resources that represent a variety of technologies. Some resource technologies, such as large and small hydro, thermal power, wind and geothermal provide well-established, commercially available sources of electricity. Other emerging technologies that are not yet widely used include large ocean wave and tidal power, solar, hydrogen and advanced coal technologies.

2004 Total Electricity Production by Source (% of total)

	Other Renewables	Hydro Electric	Nuclear	Waste and Biomass	Natural Gas	Diesel Oil	Coal	TOTAL
British Columbia	**0.0**	**92.8**	**0.0**	**1.0**	**6.0**	**0.2**	**0.0**	**100**
Alberta	2.3	4.4	0.0	0.0	12.0	2.6	78.7	100
Australia	0.3	6.9	0.0	0.6	12.3	0.70	79.2	100
California	10.7	17.0	14.5	0.0	37.7	0.0	20.1	100
Denmark	16.3	0.1	0.0	8.8	24.7	4.0	46.1	100
Finland	0.4	17.6	26.5	12.4	14.9	0.7	27.5	100
France	0.2	11.3	78.3	1.0	3.2	1.0	5.0	100
Germany	4.2	4.5	27.1	2.6	10.0	1.6	50.0	100
Japan	0.4	9.5	26.1	1.9	22.6	12.3	27.2	100
Norway	0.3	98.8	0.0	0.5	0.3	0.0	0.1	100
Ontario	1.8	24.8	49.7	0.0	5.2	0.5	18.0	100
Oregon	2.3	64.4	0.0	0.0	26.3	0.1	6.9	100
Quebec	0.7	94.5	3.2	0.0	0.1	1.5	0.0	100
United Kingdom	0.5	1.9	20.2	2.1	40.3	1.2	33.8	100
Washington	2.3	70.0	8.8	0.0	8.6	0.1	10.2	100

SHARING SOLUTIONS ON ELECTRICITY

The BC Energy Plan has a goal that most of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation and energy efficiency by all British Columbians, coupled with generation by independent power producers. However, these new projects take time to plan and implement. In addition, many of these sources provide limited amounts of firm supply. The province will also need to consider options for new, large scale sources to meet forecasted demand growth in the next 10 to 20 years. Large scale options could include Site C, large biomass facilities, clean coal or natural gas plants. As with all large scale undertakings, these kinds of projects will require years of lead time to allow for careful planning, analysis, consultation and construction.

Perhaps the biggest challenge facing British Columbians is simply to begin choosing our electricity future together. Demand for electricity is projected to grow by up to 45 per cent over the next 20 years. To meet this projected growth we will need to conserve more, and obtain more electricity from small power producers and large projects. Given the critical importance of public participation and stakeholder involvement in addressing the challenges and choices of meeting our future electricity needs, government and BC Hydro will seek and share solutions.

Rapid expansion of our energy sector means a growing number of permanent, well-paying employment opportunities are available.

Taking Action to Meet the Demand for Workers

The energy sector has been a major contributor to British Columbia's record economic performance since 2001. **The BC Energy Plan** focuses on four under-represented groups that offer excellent employment potential: Aboriginal people, immigrants, women and youth.

At the same time, the energy sector must overcome a variety of skills training and labour challenges to ensure future growth.

These challenges include:

- An aging workforce that upon retirement will leave a gap in experience and expertise.
- Competition for talent from other jurisdictions.
- Skills shortages among present and future workers.
- Labour market information gaps due to a lack of in-depth study.
- The need to coordinate immigration efforts with the federal government.
- The need for greater involvement of under-represented energy sector workers such as Aboriginal people, immigrants, women, and youth.
- A highly mobile workforce that moves with the opportunities.
- The need to improve productivity and enhance competitiveness.

Innovative, practical and timely skills training, and labour management is required to ensure the energy sector continues to thrive. As part of **The BC Energy Plan**, government will work collaboratively with industry, communities, Aboriginal people, education facilities, the federal government and others to define the projected demand for workers and take active measures to meet those demands.

Attract Highly Skilled Workers

Demographics show that those born at the height of the baby boom are retired or nearing retirement, leaving behind a growing gap in skills and expertise. Since this phenomenon is taking place in most western nations, attracting and retaining skilled staff is highly competitive.

To ensure continued energy sector growth, we need to attract workers from outside the province, particularly for the electricity, oil and gas, and heavy construction industries where the shortage is most keenly felt. At this time, a significant increase in annual net migration of workers from other provinces and from outside Canada is needed to complement the existing workforce.

Government and its partners are developing targeted plans to attract the necessary workers. These plans will include marketing and promoting energy sector jobs as a career choice.

Develop a Robust Talent Pool of Workers

It is vital to provide the initial training to build a job-ready talent pool in British Columbia, as well as the ongoing training employees need to adapt to changing energy sector technologies, products and requirements. We can ensure a thriving pool of talent in British Columbia by retraining skilled employees who are without work due to downturns in other industries. Displaced workers from other sectors and jurisdictions may require some retraining and new employees may need considerable skills development.

Another way to help ensure there are enough skilled energy sector workers in the years ahead is to educate and inform young people today. By letting high school students know about the opportunities, they can consider their options and make the appropriate training and career choices. Government will work to enhance information relating to energy sector activities in British Columbia's school curriculum in the years ahead.

Retain Skilled Workers

Around the world, energy facility construction and operations are booming, creating fierce, global competition for skilled workers. While British Columbia has much to offer, it is critical that our jurisdiction presents a superior opportunity to these highly skilled and mobile workers. That is why we need to ensure our workplaces are safe, fair and healthy and our communities continue to offer an unparalleled lifestyle with high quality health care and education, affordable housing, and readily available recreation opportunities in outstanding natural settings.

Inform British Columbians

To be effective in filling energy sector jobs with skilled workers, British Columbians need to be informed and educated about the outstanding opportunities available. As part of **The BC Energy Plan**, a comprehensive public awareness and education campaign based on sound labour market analysis will reach out to potential energy sector workers. This process will recognize and address both the potential challenges such as shift work and remote locations as well as the opportunities, such as obtaining highly marketable skills and earning excellent compensation.

Be Among the Most Competitive Oil and Gas Jurisdictions in North America

Since 2001, British Columbia's oil and gas sector has grown to become a major force in our provincial economy, employing tens of thousands of British Columbians and helping to fuel the province's strong economic performance. In fact, investment in the oil and gas sector was $4.6 billion in 2005. The oil and gas industry contributes approximately $1.95 billion annually or seven per cent of the province's annual revenues.

The BC Energy Plan is designed to take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas sector in British Columbia. With a healthy, competitive oil and gas sector comes the opportunity to create jobs and build vibrant communities with increased infrastructure and services, such as schools and hospitals. Of particular importance is an expanding British Columbia-based service sector.

There is a lively debate about the peak of the world's oil and gas production and the impacts on economies, businesses and consumers. A number of countries, such as the UK, Norway and the USA, are experiencing declining fossil fuel production from conventional sources. Energy prices, especially oil prices have increased and are more volatile than in the past. As a result, the way energy is produced and consumed will change, particularly in developed countries.

The plan is aimed at enhancing the development of conventional resources and stimulating activity in relatively undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources such as as tight gas, shale gas, and coalbed gas. The plan will further efforts to work with the federal government, communities and First Nations to advance offshore opportunities.

The challenge for British Columbia in the future will be to continue to find the right balance of economic, environmental and social priorities to allow the oil and gas sector to succeed, while protecting our environment and improving our quality of life.

The New Relationship and Oil and Gas

Working together with local communities and First Nations, the provincial government will continue to share in the many benefits and opportunities created through the development of British Columbia's oil and gas resources.

Government is working to ensure that oil and gas resource management includes First Nations' interests, knowledge and values. Government has recently concluded consultation agreements for oil and gas resource development with First Nations in Northeast British Columbia. These agreements increase clarity in the process and will go a long way to enhancing our engagement with these First Nations.

Government will continue to pursue opportunities to share information and look for opportunities to facilitate First Nations' employment and participation in the oil and gas industry to ensure that Aboriginal people benefit from the continued growth and development of British Columbia's resources.

POLICY ACTIONS

ENVIRONMENTALLY RESPONSIBLE OIL AND GAS DEVELOPMENT

- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**
- **Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.**
- **Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.**
- **Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.**

The BC Energy Plan adopts a triple bottom line approach to competitiveness, with an attractive investment climate, environmentally sustainable development of B.C.'s abundant resources, and by benefiting communities and First Nations.

While striving to be among the most competitive oil and gas jurisdictions in North America, the province will focus on maintaining and enhancing its strong competitive environment for the oil and gas industry. This encompasses the following components:

- A competitive investment climate.
- An abundant resource endowment.
- Environmental responsibility.
- Social responsibility.

Leading in Environmentally and Socially Responsible Oil and Gas Development

The BC Energy Plan emphasizes conservation, energy efficiency, and the environmental and socially responsible management of the province's energy resources. It outlines government's efforts to meet this objective by working collaboratively with involved and interested parties, including affected communities, landowners, environmental groups, First Nations, the regulator (the Oil and Gas Commission), industry groups and others. Policy actions will support ways to address air emissions, impacts on land and wildlife habitat, and water quality.

The oil and gas sector in British Columbia accounts for approximately 18 per cent of greenhouse gas air emissions in the province. The main sources of air emissions from the oil and gas sector are flaring, fugitive gases, gas processing and compressor stations. While these air emissions have long been part of the oil and gas sector, they have also been a source of major concern for oil and gas communities.

Eliminate Flaring from Oil and Gas Producing Wells and Production Facilities By 2016

Through **The BC Energy Plan**, government has committed to eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011. In addition, government will adopt policies to reduce natural gas flaring and venting at test sites and pipelines, and encourage compressor station efficiency to cut back emissions. Government will also explore opportunities and new technologies for safe, underground disposal of carbon dioxide or sequestration from oil and gas facilities. Sequestration is considered a cost effective mitigation strategy in reducing carbon dioxide emissions.

Enhance Carbon Dioxide Sequestration in British Columbia

British Columbia is a member of the Plains CO2 Reduction (PCOR) Partnership composed of nearly 50 private and public sector groups from nine states and three Canadian provinces that is assessing the technical and economic feasibility of capturing and storing carbon dioxide emissions from stationary sources in western sedimentary basins.

B.C. is also a member of the West Coast Regional Carbon Sequestration Partnership, made up of west coast state and provincial government ministries and agencies. This partnership has been formed to pursue carbon sequestration opportunities and technologies.

To facilitate and foster innovation in sequestration, government will develop market oriented requirements with a graduated schedule. In consultation with stakeholders, a timetable will be developed along with increasing requirements for sequestration.

BRITISH COLUMBIA COMPANIES RECOGNIZED AS WORLD ENERGY TECHNOLOGY INNOVATORS

The leadership of British Columbian companies can be seen in all areas of the energy sector through innovative, industry leading technologies.

Production of a new generation of chemical injection pump for use in the oil and gas industry is beginning. The pumps, developed and built in British Columbia, are the first solar powered precision injection pumps available to the industry. They will reduce emissions by replacing traditional gas powered injection systems for pipelines.

Other solar technologies developed in British Columbia provide modular power supplies in remote locations all over the globe for marine signals, aviation lights and road signs.

Roads in B.C. and around the world are hosting demonstrations of fuel cell vehicles built with British Columbia technology. Thanks to the first high pressure hydrogen fuelling station in the world, compatible fuel cell vehicles in B.C. can carry more fuel and travel farther than ever before.

The **Innovative Clean Energy Fund** will help to build B.C.'s technology cluster and keep us at the forefront of energy technology development.

Government will work to improve oil and gas tenure policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval.

POLICY ACTIONS

OFFSHORE OIL AND GAS DEVELOPMENT

- **Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.**
- **Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.**
- **Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.**
- **Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.**

Environmental Stewardship Program

In 2004, the Ministry of Energy, Mines and Petroleum Resources initiated the Oil and Gas Environmental Stewardship Program having two components: the Environmental Policy Program and the Environmental Resource Information Project. The Environmental Policy Program identifies and mitigates environmental issues in the petroleum sector focusing on policy development in areas such as environmental waste management, habitat enhancement, planning initiatives, wildlife studies for oil and gas priority areas and government best management practices. Some key program achievements include the completion of guidelines for regulatory dispersion modeling, research leading to the development of soil quality guidelines for soluble barium, a key to northern grasses and their restorative properties for remediated well sites, and moose and caribou inventories in Northeast British Columbia.

The Environmental Resource Information Project is dedicated to increasing opportunities for oil and gas development, through the collection of necessary environmental baseline information. These projects are delivered in partnership with other agencies, industry, communities and First Nations.

The BC Energy Plan enhances the important Oil and Gas Environmental Stewardship Program. This will improve existing efforts to manage waste and preserve habitat, and will establish baseline data as well as development and risk mitigation plans for environmentally sensitive areas. Barriers need to be identified and steps taken for remediation, progressive reclamation, and waste management.

Best Coalbed Gas Practices in North America

Government will continue to encourage coalbed gas development with the intent of demonstrating that British Columbia is a leading socially and environmentally responsible coalbed gas developing jurisdiction. Coalbed gas, also known as coalbed methane, is natural gas found in coal seams. It is one of the cleanest burning of all fossil fuels. Proponents wanting to develop coalbed gas must adopt the following best practices:

- Fully engage local communities and First Nations in all stages of development.
- Use the most advanced technology and practices that are commercially viable to minimize land and aesthetic disturbances.
- Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
- Meet any other conditions the Oil and Gas Commission may apply.
- Demonstrate the company's previous experience with coalbed gas development, and information must be made publicly available as to how the company plans to meet and be accountable for these best practices.

Ensuring Offshore Oil and Gas Resources are Developed in a Scientifically Sound and Environmentally Responsible Way

The BC Energy Plan includes actions related to the province's offshore oil and gas resources. Since 1972, Canada and British Columbia have each had a moratorium in place on offshore oil and gas exploration and development. With advanced technology and

British Columbia's oil and gas industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services.

positive experiences in other jurisdictions, a compelling case exists for assessing British Columbia's offshore resource potential.

Government will work with coastal communities, First Nations, the federal government, environmental organizations, and others to ascertain the benefits and address the concerns associated with offshore oil and gas development.

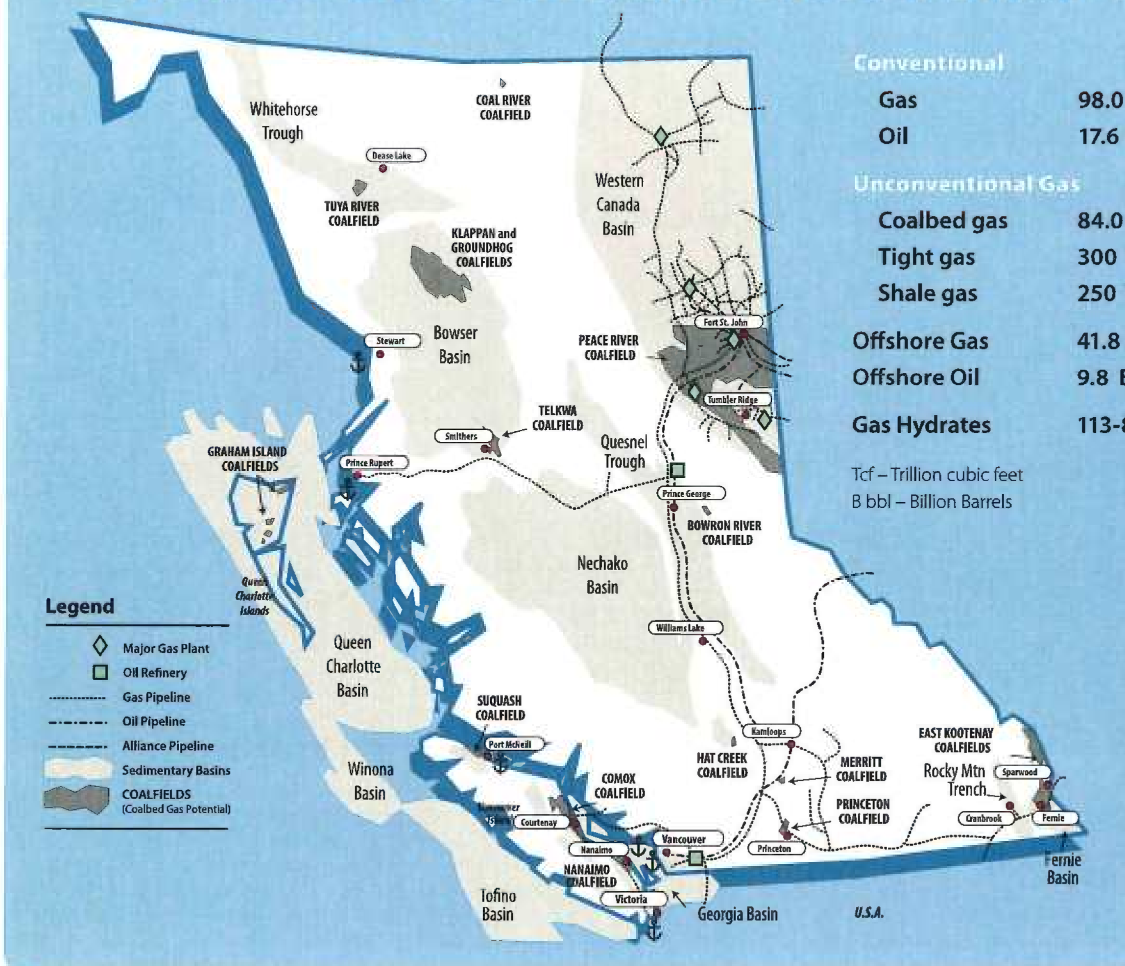
Maintaining B.C.'s Competitive Advantage as an Oil and Gas Jurisdiction

British Columbia's oil and gas industry is thriving thanks to high resource potential, industry and service sector expertise, and a competitive investment climate that includes a streamlined regulatory environment. To attract additional investment in British Columbia's oil and gas industry, we need to compete aggressively with other jurisdictions that may offer lower taxes or other investment incentives.

Another key way to be more competitive is by spurring activity in underdeveloped areas while heightening activity in the northeast, where our natural gas industry thrives. The province will work with industry to develop new policies and technologies for enhanced resource recovery making, it more cost-effective to develop British Columbia's resources.

By increasing our competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

BC OIL AND GAS UNDISCOVERED RESOURCE ESTIMATES



Conventional	
Gas	98.0 Tcf
Oil	17.6 B bbl
Unconventional Gas	
Coalbed gas	84.0 Tcf
Tight gas	300 Tcf
Shale gas	250 Tcf
Offshore Gas	41.8 Tcf
Offshore Oil	9.8 B bbl
Gas Hydrates	113-847 Tcf

Tcf – Trillion cubic feet
B bbl – Billion Barrels

British Columbia's Enormous Natural Gas Potential

The oil and gas sector will continue to play an important role in British Columbia's future energy security. Our province has enormous natural gas resource potential and opportunities for significant growth. **The BC Energy Plan** facilitates the development of B.C.'s resources.

British Columbia has numerous sedimentary basins, which contain petroleum and natural gas resources. In north-eastern British Columbia, the Western Canada Sedimentary Basin is the focus of our thriving natural gas industry. The potential resources in the central and northern interior of the province, the Nechako and Bowser Basins and Whitehorse Trough, have gone untapped.

The delayed evaluation and potential development of these areas is largely due to geological and physical obstructions that make it difficult to explore in the area. Volcanic rocks that overlay the sedimentary package combined with complex basin structures, have hindered development.

The BC Energy Plan is aimed at enhancing the development of conventional resources and stimulating activity in undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources and take a more stringent approach on coalbed gas to meet higher environmental standards.

Attracting Investment and Developing our Oil and Gas Resources

The BC Energy Plan promotes competitiveness by setting out a number of important regulatory and fiscal measures including: monitoring British Columbia's competitive ranking, considering a Net Profit Royalty Program, promoting a B.C. service sector, harmonizing and streamlining regulations, and developing a Petroleum Registry to examine royalty and tenure incentives, and undertaking geoscience programs.

Establishment of a Petroleum Registry

The establishment of a petroleum registry that functions as a central database will improve the quality and management of key volumetric, royalty and infrastructure information associated with British Columbia's oil and gas industry and promote competition while providing transparency around oil and gas activity.

NEEMAC: SUCCESS THROUGH COMMUNICATION

As energy, mining and petroleum resource development increases in northeast B.C., so too does the need for input from local governments, First Nations, community groups, landowners and other key stakeholders. In 2006, the Northeast Energy and Mines Advisory Committee (NEEMAC) was created to provide an inclusive forum for representative organizations to build relationships with each other, industry and government to provide input on Ministry policy, and recommend innovative solutions to stakeholder concerns.

Since its creation, NEEMAC has identified and explored priority concerns, and is beginning to find balanced solutions related to environmental, surface disturbance, access and landowner rights issues. The Ministry is committed to implementing recommendations that represent the broad interests of community, industry and government and expects that the committee will continue to provide advice on energy, mining and petroleum development issues in support of **The BC Energy Plan**.

An opportunity to increase competitiveness exists in British Columbia's Interior Basins – namely the Nechako, Bowser and Whitehorse Basins – where considerable resource potential is known to exist.

Increasing Access

In addition to regulatory and fiscal mechanisms, the plan addresses the need for improving access to resources. Pipelines and road infrastructure are critical factors in development and competitiveness. **The BC Energy Plan** calls for new investment in public roads and other infrastructure. It will see government establish a clear, structured infrastructure royalty program, combining road and pipeline initiatives and increasing development in under-explored areas that have little or no existing infrastructure.

Developing Conventional and Unconventional Oil and Gas Resources

To support investment in exploration, **The BC Energy Plan** calls for partnerships in research and development to establish reliable regional data, as well as royalty and tenure incentives. The goal is to attract investment, create well-paying jobs, boost the regional economy and produce economic benefits for all British Columbians. We can be more competitive by spurring activity in underdeveloped areas while heightening activity in the northeast where our natural gas industry thrives. The plan advocates working with industry to develop new policies and technology to enhance resource recovery, including oil in British Columbia.

Improve Regulations and Research

The province remains committed to continuous improvement in the regulatory regime and environmental management of conventional and unconventional oil and gas resources. The opportunities for enhancing exploration and production of tight gas, shale gas, and coalbed gas will also be assessed and supported by geoscience research and programs. **The BC Energy Plan** calls for collaboration with other government ministries, agencies, industry, communities and First Nations to develop the oil and gas resources in British Columbia.

Focus on Innovation and Technology Development

The BC Energy Plan also calls for supporting the development of new oil and gas technologies. This plan will lead British Columbia to become an internationally recognized centre for technological advancements and commercialization, particularly in environmental management, flaring, carbon sequestration and hydrogeology. The service sector has noted it can play an important role in developing and commercializing new technologies; however, the issue for companies is accessing the necessary funds.

THE HUB OF B.C.'S OIL AND GAS SECTOR

Oil and gas is benefiting all British Columbians - not just those living in major centres. Nowhere is this more apparent than in booming Fort St. John, which has rapidly become the oil and gas hub of the province. Since 2001, more than 1,400 people have moved to the community, an increase of 6.3 per cent and two per cent faster growth than the provincial average. Construction permits are way up - from $48.7 million in 2004, to $50.6 million in 2005, to over $123 million in 2006. In the past five years, over 1,000 new companies have been incorporated in Fort St. John, as young families, experienced professionals, skilled trades-people and many others move here from across the country.

POLICY ACTIONS

BE AMONG THE MOST COMPETITIVE OIL AND GAS JURISDICTIONS IN NORTH AMERICA

- **Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.**
- **Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.**
- **Encourage the development of conventional and unconventional resources.**
- **Support the growth of British Columbia's oil and gas service sector.**
- **Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.**
- **Encourage the development of new technologies.**
- **Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.**

Technology Transfer Incentive Program

A new Oil and Gas Technology Transfer Incentive Program will be considered to encourage the research, development and use of innovative technologies to increase recoveries from existing reserves and encourage responsible development of new oil and gas reserves. The program could recover program costs over time through increased royalties generated by expanded development and production of British Columbia's petroleum resources.

Scientific Research and Experimental Development

The BC Energy Plan supports the British Columbia Scientific Research and Experimental Development Program, which provides financial support for research and development leading to new or improved products and processes. Through credits or refunds, the expanded program could cover project costs directly related to commercially applicable research, and development or demonstration of new or improved technologies conducted in British Columbia that facilitate expanded oil and gas production.

Research and Development

The BC Energy Plan calls for using new or existing research and development programs for the oil and gas sector. Government will develop a program targeting areas in which British Columbia has an advantage such as well completion technology and hydrogeology.

A program to encourage oil and gas innovation and research in British Columbia's post-secondary institutions will be explored. These opportunities will be explored in partnership with the Petroleum Technology Alliance Canada and as part of the April 2006 Memorandum of Understanding between British Columbia and Alberta on Energy Research, Technology Development and Innovation.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator, a site which provides innovators with space to build prototypes and carry out testing as well as providing business infrastructure and assistance accessing additional support will be established, allowing entrepreneurs to develop and test new innovations and commercialize new, innovative technologies and processes.

Nechako Initiative

The BC Energy Plan calls for government to partner with industry, the federal government, and Geoscience BC to undertake comprehensive research in the Nechako Basin and establish new data of the resource potential. It will include active engagement of communities and the development and implementation of a comprehensive pre-tenure engagement initiative for First Nations in the region. Specific tenures and royalties will be explored to encourage investment, as well as a comprehensive Environmental Information Program to identify baseline information needs in the area through consultations with government, industry, communities and First Nations.

By increasing our oil and gas industry's competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

Value-Added Opportunities

To improve competitiveness, **The BC Energy Plan** calls for a review of value-added opportunities in British Columbia. This will include a thorough assessment of the potential for processing facilities and petroleum refineries as well as petrochemical industry opportunities. The Ministry of Energy, Mines and Petroleum Resources will conduct an analysis to identify and address barriers and explore incentives required to encourage investment in gas processing in British Columbia. A working group of industry and government will develop business cases and report to the Minister by January 2008 with recommendations on the viability of a new petroleum refinery and petrochemical industry and measures, if any, to encourage investment.

Oil and Gas Service Sector

British Columbia's oil and gas service sector can also help establish our province as one of the most competitive jurisdictions in North America. The service sector has grown over the past four years and with increased activity, additional summer drilling, and the security of supply, opportunities for local companies will continue. Government can help maximize the benefits derived from the service sector by:

- Promoting British Columbia's service sector to the oil and gas industry through participation at trade shows and providing information to the business community.
- Identifying areas where British Columbian companies can play a larger role, expand into other provinces, and through procurement strategies.

The government also supports the Oil and Gas Centre of Excellence at the Fort St. John Northern Lights College campus, which will provide oil and gas, related vocational, trades, career and technical programs.

Improving Oil and Gas Tenures

Government will work to improve oil and gas tenure issuance policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval by the end of 2007. This will provide clear parameters for industry regarding areas where special or enhanced management practices are required. These measures will strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into the oil and gas development process.

Create Opportunities for Communities and First Nations

Benefits for British Columbians from the Oil and Gas Sector

The oil and gas sector offers enormous benefits to all British Columbians through enhanced energy security, tens of thousands of good, well-paying jobs and tax revenues used to help fund our hospitals and schools. However, the day-to-day impact of the sector has largely been felt on communities and First Nations in British Columbia's northeast. Community organizations, First Nations, and landowners have communicated a desire for greater input into the pace and scope of oil and gas development in British Columbia.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator will be established, allowing entrepreneurs to develop and test new innovations.

Through **The BC Energy Plan**, government intends to develop stronger relationships with those affected by oil and gas development, including communities and First Nations. The aim is to work cooperatively to maximize benefits and minimize impacts. The plan supports improved working relationships among industry, local communities and landowners by increased and improved communication to clarify and simplify processes, enhancing dispute resolution methods, and offering more support and information.

The government will also continue to improve communications with local governments and agencies. Specifically, **The BC Energy Plan** calls for efforts to provide information about increased local oil and gas activities to local governments, education and health service providers to improve their ability to make timely decisions on infrastructure, such as schools, housing, and health and recreational facilities. By providing local communities and service providers with regular reports of trends and industry activities, they can more effectively plan for growth in required services and infrastructure.

POLICY ACTIONS

WORKING WITH COMMUNITIES AND FIRST NATIONS

- **Provide information about local oil and gas activities to local governments, First Nations, education and health service providers to inform and support the development of necessary social infrastructure.**
- **Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.**
- **Support First Nations in providing cross-cultural training to agencies and industry.**
- **Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.**
- **Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.**

Building Better Relationships with Landowners

The BC Energy Plan: A Vision for Clean Energy Leadership also supports improved working relationships between industry, local communities and landowners and First Nations. Landowners will be notified in a more timely way of sales of oil and gas rights on private land. Plain language information materials, including standardized lease agreements will be made available to help landowners deal with subsurface tenures and activity. There will be a review of the dispute resolution process between landowners and industry by the end of 2007. The existing setback requirements, the allowed distance of a well site from a residence, school or other public place, will also be examined. These measures seek to strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into oil and gas development.

Working in Partnership with First Nations and Communities

Government will work with First Nations communities to identify opportunities to benefit from oil and gas development. By developing a greater ability to participate in and benefit from oil and gas development, First Nations can play a much more active role in the industry. **The BC Energy Plan** also supports increasing First Nations role in the development of cross-cultural training initiatives for agencies and industry.

Conclusion

The BC Energy Plan: A Vision for Clean Energy Leadership sets the standard for proactively addressing the opportunities and challenges that lie ahead in meeting the energy needs for all the citizens of the province, now and in the future. Appendix A provides a detailed listing of the policy actions of the plan.

The BC Energy Plan will attract new investments, help develop and commercialize new technology, build partnerships with First Nations, and ensures a strong environmental focus.

British Columbia has a proud history of innovation that has resulted in 90 per cent of our power generation coming from clean sources. This plan builds on that foundation and ensures B.C. will be at the forefront of environmental and economic leadership for years to come.

APPENDIX A The BC Energy Plan: Summary of Policy Actions

ENERGY CONSERVATION AND EFFICIENCY

1. Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
2. Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
3. Encourage utilities to pursue cost effective and competitive demand side management opportunities.
4. Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
5. Implement Energy Efficiency Standards for Buildings by 2010.
6. Undertake a pilot project for energy performance labeling of homes and buildings in coordination with local and federal governments, First Nations, and industry associations.
7. New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
8. Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.
9. Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.

ELECTRICITY

10. Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
11. Establish a standing offer for clean electricity projects up to 10 megawatts.
12. The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.
13. Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.
14. Ensure that the province remains consistent with North American transmission reliability standards.
15. Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.
16. Establish the existing heritage contract in perpetuity.
17. Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.
18. All new electricity generation projects will have zero net greenhouse gas emissions.
19. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
20. Require zero greenhouse gas emissions from any coal thermal electricity facilities.
21. Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
22. Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
23. No nuclear power.
24. Review BC Utilities Commissions' role in considering social and environmental costs and benefits.
25. Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.
26. Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.
27. Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
28. Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.

ALTERNATIVE ENERGY

29. Establish the **Innovative Clean Energy Fund** to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
30. Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
31. Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
32. Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
33. Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
34. Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
35. Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

OIL AND GAS

36. Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.
37. Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.
38. Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
39. Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.
40. Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
41. Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.
42. Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.
43. Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.
44. Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.
45. Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.
46. Encourage the development of conventional and unconventional resources.
47. Support the growth of British Columbia's oil and gas service sector.
48. Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.
49. Encourage the development of new technologies.
50. Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.
51. Provide information about local oil and gas activities to local governments, education and health service providers to inform and support the development of necessary social infrastructure.
52. Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.
53. Support First Nations in providing cross-cultural training to agencies and industry.
54. Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.
55. Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.

Energy in Action

POWERSMART
BC Hydro offers a variety of incentives to adopt energy saving technologies. Incentives such as rebates on efficient lighting or windows encourages British Columbians to improve the energy efficiency of their homes and businesses.

PROVINCIAL SALES TAX EXEMPTIONS
Tax breaks are offered for a wide variety of energy efficient items, making it easier to conserve energy. Tax concessions are in place for alternative fuel and hybrid vehicles as well as some alternative fuels. Bicycles and some bicycle parts are exempt from provincial sales tax, as are a variety of materials, such as Energy Star qualified windows, that can make homes more energy efficient.

NET METERING
The Net Metering program offered by BC Hydro for customers with small generating facilities, allows customers to lower their environmental impact and take responsibility for their own power production. The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced. Net Metering helps to move the province towards electricity self sufficiency and expands clean electricity generation.

POWERING THE ECONOMY
The Oil and Gas sector invested $4.6 billion in B.C. in 2005 and contributed more to the provincial treasury than any other resource in 2005/06. In 2006 1,416 oil and gas wells were drilled in the province and between 2002 and 2005, summer drilling increased 242 per cent.

FRIDGE BUY-BACK PROGRAM
This program offers customers $30 in cash and no-cost pickup and disposal of an old, inefficient second fridge. If all second operating fridges in B.C. were recycled, we would save enough energy to power all the homes in the city of Chilliwack for an entire year.

LIGHTING REBATES
This program offers instant rebate coupons for the retail purchase of Energy Star light fixtures and Energy Star® CFLs (Compact Fluorescent Lights).

WINDOWS REBATE
The Windows Rebate Program offers rebates for the installation of Energy Star® windows in new, renovated or upgraded single-family homes, duplexes, townhouses or apartments.

PRODUCT INCENTIVE PROGRAM
The Product Incentive Program provides financial incentives to organizations which replace inefficient products with energy efficient technologies or add on products to existing systems to make them more efficient.

HIGH-PERFORMANCE BUILDING PROGRAM FOR LARGE COMMERCIAL BUILDINGS
Financial incentives, resources, and technical assistance are available to help qualified projects identify energy saving strategies early in the design process; evaluate alternative design options and make a business case for the high-performance design; and, offset the incremental costs, if any, of the energy-efficient measures in the high-performance design.

HIGH-PERFORMANCE BUILDING PROGRAM FOR SMALL TO MEDIUM COMMERCIAL BUILDINGS
Incentives and tools are offered to help owners and their design teams create and install more effective and energy-efficient lighting in new commercial development projects.

NEW HOME PROGRAM
Builders and developers are encouraged to build energy efficient homes by offering financial incentives and Power Smart branding for homes that achieve energy efficient ratings.

ANALYZE MY HOME
BC Hydro offers an online tool that provides a free, personalized breakdown of a customer's home energy use and recommendations on where improvements can be made to lower consumption.

CONSERVATION RESEARCH INITIATIVE
A 12-month study in six communities that examines how adjusting the price of electricity at different times of day influences energy use by residential customers, and how individual British Columbians can make a difference in conserving power in their homes and help meet the growing demand for electricity in B.C.

THE GREEN BUILDINGS PROGRAM
Provides tools and resources to support school districts, universities, colleges, and health authorities to improve the energy efficiency of their buildings across the province.

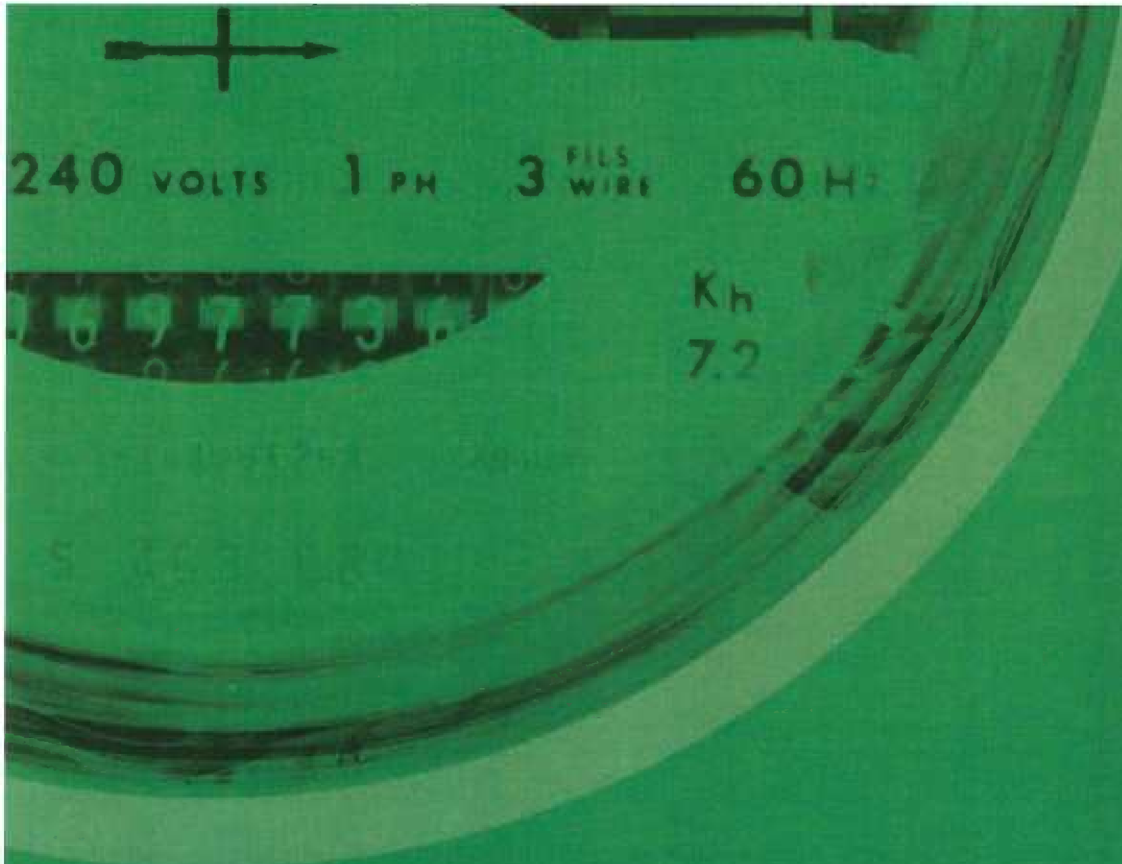
ATTRACTING WORKERS
The Ministry of Energy, Mines and Petroleum Resources hosts job fairs across B.C. to attract workers to the highly lucrative oil and gas sector. Job fairs were held in 14 communities in 2005 and 16 communities in 2006 attracting thousands of people and resulting in hundreds of job offers. Centre of Excellence Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

CENTRE OF EXCELLENCE
Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

100,000 SOLAR ROOFS FOR B.C.
The Ministers of Environment, and Energy, Mines and Petroleum Resources are sponsoring the development of a plan that will see the aggressive adoption of solar technology in B.C. The goal of the project is to see the installation of solar roofs and walls for hot water heating and photovoltaic electricity generation on 100,000 buildings around B.C.

PARTNERING FOR SUCCESS
Since 2003, the Province of B.C. has partnered in the construction of $158 million in new oil and gas road and pipeline infrastructure. The Sierra Yoyo Desan Road public private partnership improved the road allowing year round drilling activity in the Greater Sierra natural gas play. The project was recognized with the Gold Award for Innovation and Excellence from the Canadian Council for Public Private Partnerships in 2004.

ENERGY EFFICIENT BUILDINGS: A PLAN FOR BC
This strategy will lower energy costs for new and existing buildings by $127 million in 2010 and $474 million in 2020, and reduce greenhouse gas emissions by 2.3 million tonnes in 2020. The Province is implementing ten policy and market measures in partnership with the building industry, energy consumer groups, utilities, non-governmental organizations, and the federal government.



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British Columbia
The Best Place on Earth

Ministry of
Energy, Mines and
Petroleum Resources

Appendix T

BILL 15 UTILITIES COMMISSION AMENDMENT ACT (2008)

2008 Legislative Session: 4th Session, 38th Parliament
THIRD READING

Certified correct as passed Third Reading on the 8th day of April, 2008
Ian D. Izard, Q.C., Law Clerk

HONOURABLE RICHARD NEUFELD
MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

BILL 15 — 2008
UTILITIES COMMISSION AMENDMENT ACT, 2008

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follows:

1 Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by adding the following definitions:

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand;

"government's energy objectives" means the following objectives of the government:

(a) to encourage public utilities to reduce greenhouse gas emissions;

(b) to encourage public utilities to take demand-side measures;

(c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;

(e) to encourage public utilities to use innovative energy technologies

(i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or

(ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;

(f) to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation;

"transmission corporation" has the same meaning as in the *Transmission Corporation Act*; ***.***

2 Section 2 (4) is amended by striking out "1 to 3 and 5 to 13***" and substituting "***1 to 13***".***

3 Section 3 is repealed and the following substituted:

Commission subject to direction

3 (1) Subject to subsection (3), the Lieutenant Governor in Council, by regulation, may issue a direction to the commission with respect to the exercise of the powers and the performance of the duties of the commission, including, without limitation, a direction requiring the commission to exercise a power or perform a duty, or to refrain from doing either, as specified in the regulation.

(2) The commission must comply with a direction issued under subsection (1), despite

(a) any other provision of

(i) this Act, except subsection (3) of this section, or

(ii) the regulations, or

(b) any previous decision of the commission.

(3) The Lieutenant Governor in Council may not under subsection (1) specifically and expressly

(a) declare an order or decision of the commission to be of no force or effect, or

(b) require the commission to rescind an order or a decision.

4 Section 5 is amended

(a) by adding the following subsection:

(0.1) In this section, **"minister"** means the minister responsible for the administration of the *Hydro and Power Authority Act*. ***,***

(b) in subsection (3) by adding "British Columbia or***" after "***enactment of***", and***

(c) by adding the following subsections:

(4) The commission, in accordance with subsection (5), must conduct an inquiry to make determinations with respect to British Columbia's infrastructure and capacity needs for electricity transmission for the period ending 20 years after the day the inquiry begins or, if the terms of reference given under subsection (6) specify a different period, for that period.

(5) An inquiry under subsection (4) must begin

(a) by March 31, 2009, and

(b) at least once every 6 years after the conclusion of the previous inquiry,

unless otherwise ordered by the Lieutenant Governor in Council.

(6) For an inquiry under subsection (4), the minister may specify, by order, terms of reference requiring and empowering the commission to inquire into the matter referred to in that subsection, including terms of reference regarding the manner in which and the time by which the commission must issue its determinations under subsection (4).

(7) The minister may declare, by regulation, that the commission may not, during the period specified in the regulation, reconsider, vary or rescind a determination made under subsection (4).

(8) Despite section 75, if a regulation is made for the purposes of subsection (7) of this section with respect to a determination, the commission is bound by that determination in any hearing or proceeding held during the period specified in the regulation.

(9) The commission may order a public utility to submit an application under section 46, by the time specified in the order, in relation to a determination made under subsection (4).

5 Section 22 is repealed and the following substituted

Exemptions

22 (1) In this section:

"eligible person" means a person, or a class of persons, that

(a) generates, produces, transmits, distributes or sells electricity,

(b) for the purpose of heating or cooling any building, structure or equipment or for any industrial purpose, heats, cools or refrigerates water, air or any heating medium or coolant, using for that purpose equipment powered by a fuel, a geothermal resource or solar energy, or

(c) enters into an energy supply contract, within the meaning of section 68, for the provision of electricity;

"minister" means the minister responsible for the administration of the *Hydro and Power Authority Act*.

(2) The minister, by regulation, may

(a) exempt from any or all of section 71 and the provisions of this Part

(i) an eligible person, or

(ii) an eligible person in respect of any equipment, facility, plant, project, activity, contract, service or system of the eligible person, and

(b) in respect of an exemption made under paragraph (a), impose any terms and conditions the minister considers to be in the public interest.

(3) The minister, before making a regulation under subsection (2), may refer the matter to the commission for a review.

6 Section 43 (1) is repealed and the following substituted:

(1) A public utility must, for the purposes of this Act,

(a) answer specifically all questions of the commission, and

(b) provide to the commission

(i) the information the commission requires, and

(ii) a report, submitted annually and in the manner the commission requires, regarding the demand-side measures taken by the public utility during the period addressed by the report, and the effectiveness of those measures.

(1.1) The authority, in addition to providing the information and reports referred to in subsection (1), must provide to the commission, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of whether the authority's electricity rates are competitive with those other rates.

7 The following sections are added:

Long-term resource and conservation planning

44.1 (1) In this section, **"demand increase"** means the greater of

(a) the difference between

(i) the sum of the estimate referred to in subsection (4) (b) and a prescribed amount, if any, and

(ii) the demand the authority would serve during the period referred to in subsection (4) (b) if the demand in each year of that period remains equal to the demand referred to in subsection (4) (a), and

(b) zero.

(2) Subject to subsection (4), a public utility must file with the commission, in the form and at the times the commission requires, a long-term resource plan including all of the following:

(a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

(e) information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);

(f) an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures;

(g) any other information required by the commission.

(3) The commission may exempt a public utility from the requirement to include in a long-term resource plan filed under subsection (2) any of the information referred to in paragraphs (a) to (f) of that subsection if the commission is satisfied that the information is not applicable with respect to the nature of the service provided by the public utility.

(4) A long-term resource plan filed under subsection (2) by the authority before the end of the 2020 calendar year must include, in addition to everything referred to in subsection (2) (a) to (g), all of the following:

(a) a statement of the demand for electricity the authority served in the year beginning on April 1, 2007, and ending on March 31, 2008;

(b) an estimate of the total demand for electricity the authority would expect to serve in the period beginning on April 1, 2008, and ending on March 31, 2021, if no new demand-side measures are taken during that period;

(c) a statement of the demand-side measures the authority would need to take so that, in combination with demand-side measures taken by the government of British Columbia or of Canada or a local authority, the demand increase would be reduced by 50% by 2020.

(5) The commission may establish a process to review long-term resource plans filed under subsection (2).

(6) After reviewing a long-term resource plan filed under subsection (2), the commission must

(a) accept the plan, if the commission determines that carrying out the plan would be in the public interest, or

(b) reject the plan.

(7) The commission may accept or reject, under subsection (6), a part of a public utility's plan, and, if the commission rejects a part of a plan,

(a) the public utility may resubmit the part within a time specified by the commission, and

(b) the commission may accept or reject, under subsection (6), the part resubmitted under paragraph (a) of this subsection.

(8) In determining under subsection (6) whether to accept a long-term resource plan, the commission must consider

(a) the government's energy objectives,

(b) whether the plan is consistent with the requirements under sections 64.01 and 64.02, if applicable,

(c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(9) In accepting under subsection (6) a long-term resource plan, or part of a plan, the commission may do one or both of the following:

(a) order that a proposed utility plant or system, or extension of either, referred to in the accepted plan or the part is exempt from the operation of section 45 (1);

(b) order that, despite section 75, a matter the commission considers to be adequately addressed in the accepted plan or the part is to be considered as conclusively determined for the purposes of any hearing or proceeding to be conducted by the commission under this Act, other than a hearing or proceeding for the purposes of section 99.

Expenditure schedule

44.2 (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:

(a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

(b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;

(c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

(2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless

(a) the expenditure is the subject of a schedule filed and accepted under this section, or

(b) the amendment or rescission is for the purpose of setting an interim rate.

(3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5) and (6), must

(a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or

(b) reject the schedule.

(4) The commission may accept or reject, under subsection (3), a part of a schedule.

(5) In considering whether to accept an expenditure schedule, the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) whether the schedule is consistent with the requirements under section 64.01 or 64.02, if applicable,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

(6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

8 Section 45 (6.1) and (6.2) is repealed.

9 Section 46 is amended

(a) in subsection (3) by striking out "The commission***" and substituting "***Subject to subsections (3.1) and (3.2), the commission***", and***

(b) by adding the following subsections:

(3.1) In deciding whether to issue a certificate under subsection (3), the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

(c) whether the application for the certificate is consistent with the requirements imposed on the public utility under sections 64.01 and 64.02, if applicable.

(3.2) Section (3.1) does not apply if the commission considers that the matters addressed in the application for the certificate were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

10 Section 58 is amended by adding the following subsections:

(2.1) The commission must set rates for the authority in accordance with

(a) the prescribed requirements, if any, and

(b) the prescribed factors and guidelines, if any.

(2.2) A requirement prescribed for the purposes of subsection (2.1) (a) applies despite

(a) any other provision of

(i) this Act, including, for greater certainty, section 58.1, or

(ii) the regulations, except a regulation under section 3, or

(b) any previous decision of the commission.

(2.3) Subsections (2.1) (a) and (2.2) are repealed on March 31, 2010.

(2.4) Despite subsection (2.3), a requirement prescribed for the purposes of subsection (2.1) (a) that is in effect immediately before March 31, 2010, continues to apply after that date as though subsection (2.2) were still in force, unless the prescribed requirement is amended or repealed after that date.

11 The following section is added:

Rate rebalancing

58.1 (1) In this section, **"revenue-cost ratio"** means the amount determined by dividing the authority's revenues from a class of customers during a period of time by the authority's costs to serve that class of customers during the same period of time.

(2) This section applies despite

(a) any other provision of

(i) this Act, or

(ii) the regulations, except a regulation under section 3 or 125.1 (4) (f), or

(b) any previous decision of the commission.

(3) The following decision and orders of the commission are of no force or effect to the extent that they require the authority to do anything for the purpose of changing revenue-cost ratios:

(a) 2007 RDA Phase 1 Decision, issued October 26, 2007;

(b) order G-111-07, issued September 7, 2007;

(c) order G-130-07, issued October 26, 2007;

(d) order G-10-08, issued January 21, 2008,

and the rates of the authority that applied immediately before this section comes into force continue to apply and are deemed to be just, reasonable and not unduly discriminatory.

(4) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission may not set rates for the authority for the purpose of changing the revenue-cost ratio for a class of customers.

(5) Subsection (4) is repealed on March 31, 2010.

(6) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission, after March 31, 2010, may not set rates for the authority such that the revenue-cost ratio, expressed as a percentage, for any class of customers increases by

more than 2 percentage points per year compared to the revenue-cost ratio for that class immediately before the increase.

12 Section 61 (2) is amended by adding "rescinded or***" after "***must not be***".***

13 The following Part is added:

PART 3.1 — ENERGY SECURITY AND THE ENVIRONMENT

Electricity self-sufficiency

64.01 (1) The authority must

(a) by the 2016 calendar year, achieve electricity self-sufficiency according to the prescribed criteria, and

(b) maintain, according to the prescribed criteria, electricity self-sufficiency in each calendar year after achieving it.

(2) A public utility, in planning for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider the government's goal that British Columbia be electricity self-sufficient by the 2016 calendar year and maintain self-sufficiency after that year.

Clean and renewable resources

64.02 (1) To facilitate the achievement of the government's goal that at least 90% of the electricity generated in British Columbia be generated from clean or renewable resources, a person to whom this section applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) This section applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

Standing offer

64.03 (1) In this section, **"eligible facility"** means a generation facility that

(a) either

(i) has only one generator with a nameplate capacity of 10 megawatts or less or has more than one generator and the total nameplate capacity of all of them is 10 megawatts or less, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities.

(2) The authority must establish and maintain a standing offer

(a) during the times prescribed by and in accordance with the regulations, if any, and

(b) on the terms and conditions, if any, approved by the commission under subsection (3),

to enter into an energy supply contract for the purchase of electricity from eligible facilities.

(3) Subject to regulations made for the purposes of subsection (2) (a), the commission, by order and on application by the authority, may approve terms and conditions for the purposes of subsection (2) (b) if the commission considers that the terms and conditions are in the public interest.

(4) The commission may not issue an order under section 71 (3) with respect to a contract entered into in accordance with the regulations made for the purposes of subsection (2) (a), and exclusively on the terms and conditions referred to in subsection (2) (b), of this section.

Smart meters

64.04 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) If a public utility, other than the authority, makes an application under the Act in relation to advanced meters, the commission, in considering that application, must consider the government's goal of having advanced meters and associated infrastructure in use with respect to customers other than those of the authority.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters.

14 Section 71 (2) is repealed and the following substituted:

(2) The commission may make an order under subsection (3) if the commission, after a hearing, determines that an energy supply contract to which subsection (1) applies is not in the public interest.

(2.1) In determining under subsection (2) whether an energy supply contract is in the public interest, the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) whether the energy supply contract is consistent with requirements imposed under section 64.01 or 64.02, if applicable,

(d) the interests of persons in British Columbia who receive or may receive service from the public utility,

(e) the quantity of the energy to be supplied under the contract,

(f) the availability of supplies of the energy referred to in paragraph (e),

(g) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (e), and

(h) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (e).

(2.2) Subsection (2.1) (a) to (c) does not apply if the commission considers that the matters addressed in the energy supply contract filed under subsection (1) were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

(2.3) A public utility may submit to the commission a proposed energy supply contract setting out the terms and conditions of the contract and a process the public utility intends to use to acquire power from other persons in accordance with those terms and conditions.

(2.4) If satisfied that it is in the public interest to do so, the commission, by order, may approve a proposed contract submitted under subsection (2.3) and a process referred to in that subsection.

(2.5) In considering the public interest under subsection (2.4), the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1,

(c) whether the application for the proposed contract is consistent with the requirements imposed on the public utility under sections 64.01 and 64.02, if applicable, and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(2.6) If the commission issues an order under subsection (2.4), the commission may not issue an order under subsection (3) with respect to a contract

(a) entered into exclusively on the terms and conditions, and

(b) as a result of the process

referred to in subsection (2.3).

15 Section 88 (4) is amended by striking out "a matter that is subject***" and substituting "***a person, or a person in respect of a matter, who has been exempted under***".***

16 Section 108 (b) is amended by adding "responsible for the administration of the *Hydro and Power Authority Act****" after "***minister***".***

17 The following sections are added:

Minister's regulations

125.1 (1) In this section, **"minister"** means the minister responsible for the administration of the *Hydro and Power Authority Act*.

(2) The minister may make regulations respecting the government's energy objectives, as defined in section 1, including, without limitation, regulations as follows:

(a) defining a word or phrase used in the definition;

(b) prescribing actions and goals for the purposes of paragraph (f) of the definition;

(c) establishing factors or guidelines the commission must use in considering the government's energy objectives, including guidelines regarding the relative priority of the objectives referred to in paragraphs (a) to (f) of the definition.

(3) A regulation under subsection (2) may be made with respect to the government's energy objectives generally or with respect to their application in any particular case.

(4) The minister may make regulations as follows:

(a) making declarations for the purposes of section 5 (7);

(b) respecting exemptions under section 22;

(c) respecting reports to be provided to the commission by the authority under section 43 (1.1), including, without limitation, respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(d) prescribing, for the purposes of paragraph (a) (i) of the definition of "demand increase" in section 44.1 (1), an amount representing an increase in resource requirements of the authority not related to an estimated increased demand referred to in section 44.1 (4) (b);

(e) for the purposes of section 44.1 and 44.2,

(i) prescribing rules for determining whether a demand-side measure, or a class of demand-side measures, is adequate, cost-effective or both,

(ii) declaring a demand-side measure, or a class of demand-side measures, to be cost effective and necessary for adequacy,

(iii) prescribing rules or factors a public utility must use in making the estimate referred to in section 44.1 (2) (a), and

(iv) prescribing rules or factors the authority must use in making the estimate referred to in section 44.1 (4) (b);

(f) prescribing requirements for the purposes of section 58 (2.1) (a);

(g) prescribing factors and guidelines for the purposes of section 58 (2.1) (b), including, without limitation, factors and guidelines to encourage

(i) energy conservation or efficiency,

(ii) the use of energy during periods of lower demand,

(iii) the development and use of energy from clean or renewable resources, or

(iv) the reduction of the energy demand a public utility must serve;

(h) defining a term or phrase used in section 58.1 and not defined in this Act;

(i) identifying facts that must be used in interpreting the definition in section 58.1;

(j) defining a term or phrase used in Part 3.1 and not defined in that Part;

(k) prescribing criteria respecting self-sufficiency for the purposes of section 64.01 (1) (a) and (b);

(l) prescribing targets for the purposes of section 64.02 (1) (a), guidelines for the purposes of section 64.02 (1) (b) and public utilities and classes of public utilities for the purposes of section 64.02 (2) (b);

(m) for the purposes of section 64.03, respecting eligible facilities, including prescribing generation facilities and classes of generation facilities, and respecting the standing offer to be established and maintained under that section;

(n) for the purposes of section 64.04, respecting smart meters and their installation, including, without limitation,

(i) the types of smart meters to be installed, including the features or functions each meter must have or be able to perform, and

(ii) the classes of users for whom smart meters must be installed, and requiring the authority to install different types of smart meters for different classes of users;

(o) prescribing standard-making bodies for the purposes of section 125.2 (1) and matters for the purposes of section 125.2 (3) (d);

(p) prescribing owners, operators, direct users, generators and distributors, or classes of any of them, for the purposes of section 125.2 (8).

(5) In making a regulation under this section, the minister may

(a) make regulations of specific or general application, and

(b) make different regulations for different persons, places, things, measures, transactions or activities.

Adoption of reliability standards, rules or codes

125.2 (1) In this section:

"reliability standard" means a reliability standard, rule or code established by a standard-making body for the purpose of being a mandatory reliability standard for planning and operating the North American bulk power system, and includes any substantial change to any of those standards, rules or codes;

"standard-making body" means

(a) the North American Electric Reliability Corporation,

(b) the Western Electricity Coordinating Council, and

(c) a prescribed standard-making body.

(2) For greater certainty, the commission has exclusive jurisdiction to determine whether a reliability standard is in the public interest and should be adopted in British Columbia.

(3) The transmission corporation must review each reliability standard and provide to the commission, in accordance with the regulations, a report assessing

(a) any adverse impact of the reliability standard on the reliability of electricity transmission in British Columbia if the reliability standard were adopted under subsection (6),

(b) the suitability of the reliability standard for British Columbia,

(c) the potential cost of the reliability standard if it were adopted under subsection (6), and

(d) any other matter prescribed by regulation or identified by order of the commission for the purposes of this section.

(4) The commission may make an order for the purposes of subsection (3) (d).

(5) If the commission receives a report under subsection (3), the commission must

(a) make the report available to the public in a reasonable manner, which may include by electronic means, and for a reasonable period of time, and

(b) consider any comments the commission receives in reply to the publication referred to in paragraph (a).

(6) After complying with subsection (5), the commission, subject to subsection (7), must adopt the reliability standards addressed in the report if the commission considers that the reliability standards are required to maintain or achieve consistency in British Columbia with other jurisdictions that have adopted the reliability standards.

(7) The commission is not required to adopt a reliability standard under subsection (6) if the commission determines, after a hearing, that the reliability standard is not in the public interest.

(8) A reliability standard adopted under subsection (6) applies to every

(a) prescribed owner, operator and direct user of the bulk power system, and

(b) prescribed generator and distributor of electricity.

(9) Subsection (8) applies to a person prescribed for the purposes of that subsection despite any exemption issued to the person under section 22 or 88 (3).

(10) The commission may make orders providing for the administration of adopted reliability standards**.**

(11) The commission, on its own motion or on complaint, may

(a) rescind an adoption made under subsection (6), or

(b) adopt a reliability standard previously rejected under subsection (7)

if the commission determines, after a hearing, that the rescission or adoption is in the public interest.

(12) The commission, without the approval of the minister responsible for the administration of the *Hydro and Power Authority Act*, may not set a standard or rule under section 26 of this Act with respect to a matter addressed by a reliability standard assessed in a report submitted to the commission under subsection (3) of this section.

Consequential Amendments and Transition

Insurance Corporation Act

18 Section 44 of the Insurance Corporation Act, R.S.B.C. 1996, c. 228, is amended by striking out "other than sections 22, 23 (1) (a) to (d) and (2), 25 to 38, 40, 41, 45 to 57, 59 (2) and (3), 60 (1) (b) (ii) and (2) to (4), 97, 98, 106 (1) (k), 107 to 109 and 114 and Parts 4 and 5 of that Act,***" and substituting "***other than sections 3, 5 (4) to (9), 22, 23 (1) (a) to (d) and (2), 25 to 38, 40, 41, 43 (1) (b) (ii), 44.1, 44.2, 45 to 57, 59 (2) and (3), 60 (1) (b) (ii) and (2) to (4), Part 3.1, 97, 98, 106 (1) (k), 107 to 109 and 114, Parts 4 and 5 and sections 125.1 and 125.2 of that Act,***".***

Water Utility Act

19 Section 4 (b) of the Water Utility Act, R.S.B.C. 1996, c. 485, is amended by striking out "other than sections 28, 29 and 45 (2), (3), (5) and (6),***" and substituting "***other than sections 28, 29, 44.1, 44.2, 45 (2), (3), (5) and (6), 58 (2.1) and (2.2) and 58.1, Part 3.1 and sections 125.1 and 125.2,***".***

Transition

20 (1) For greater certainty, a regulation made under section 3 of the

Utilities Commission Act, as that section read immediately before the date section 3 of this Act comes into force, if that regulation was in effect immediately before that date, remains in effect and is deemed to be a regulation under section 3 of the *Utilities Commission Act* as that section reads immediately after section 3 of this Act comes into force.

(2) An exemption under section 22 of the *Utilities Commission Act*, as that section read immediately before the date section 5 of this Act comes into force, if that exemption was in effect immediately before that date, remains in effect and is deemed to be an exemption under section 22 of the *Utilities Commission Act* as that section reads immediately after section 5 of this Act comes into force.

Commencement

21 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Section 11	March 31, 2008

Appendix U

MINISTRY OF ENERGY AND MINES
APRIL 28, 2010 NEWS RELEASE

NEWS RELEASE

For Immediate Release
2010PREM0090-000483
April 28, 2010

Office of the Premier
Ministry of Energy, Mines and Petroleum Resources
BC Hydro

NEW ACT POWERS B.C. FORWARD WITH CLEAN ENERGY AND JOBS

VICTORIA, B.C. – British Columbia's new Clean Energy Act sets the foundation for a new future of electricity self-sufficiency, job creation and reduced greenhouse gas emissions, powered by unprecedented investments in clean, renewable energy across the province. Bill 17 builds upon British Columbia's unique heritage advantages and wealth of clean, renewable energy resources.

The act advances 16 specific energy objectives by expediting clean energy investments, protecting B.C. ratepayers, ensuring competitive rates, encouraging conservation, strengthening environmental protection and aggressively promoting regional job creation and First Nations' involvement in clean electricity development opportunities.

"The new Clean Energy Act opens the way to an exciting new age of economic growth and job creation by unleashing British Columbia's full potential in clean energy, power smart technologies, environmental stewardship and climate action," said Premier Gordon Campbell. "It will maximize the value of our public heritage assets for the benefit of British Columbians by forever securing competitive rates and generating new streams of revenue for crucial public services.

"Our goal is to build on our unique competitive advantages with record investments in our historic 'two rivers' public power system and with new clean and renewable electricity investments and partnerships," Campbell continued. "We want British Columbia to become a leading North American supplier of clean, reliable, low-carbon electricity and technologies that reduce greenhouse gas emissions while strengthening our economy in every region."

"British Columbia has a proud history of producing clean, reliable electricity at rates that are among the lowest in North America," said Blair Lekstrom, Minister of Energy, Mines and Petroleum Resources. "The Clean Energy Act builds on the work of the Green Energy Advisory Task Force with a new statutory framework to encourage new investments and jobs, strengthen BC Hydro and secure British Columbia's power needs at low rates for generations to come."

The new Clean Energy Act sets the foundation for three areas of priority:

1. Ensuring Electricity Self-Sufficiency at Low Rates

The act will strengthen B.C.'s legislated goal of electricity self-sufficiency by 2016 with a new regulatory framework for long-term electricity planning, bold commitments to clean and renewable electricity generation, streamlined approval processes, and new measures to promote electricity efficiency and conservation. It also strengthens protection for B.C. ratepayers with new measures to promote competitive rates and to ensure that all of the benefits from the province's heritage assets continue to flow to British Columbians. These objectives will be accomplished through long-term planning; public investments and conservation; and new investments in clean, renewable power and energy security. The British Columbia Utilities Commission will continue to ensure appropriate rates are set in advancing government's energy objectives and long-term resource plans.

2. Harnessing B.C.'s Clean Power Potential to Create Jobs in every Region

The act will provide BC Hydro and renewable power producers the tools necessary to establish British Columbia as a clean energy powerhouse that enables economic growth and job creation in every region. It will enable BC Hydro to maximize the value of its energy resources for ratepayers and taxpayers. It will provide a new model to secure long-term export power sales to other jurisdictions seeking clean power by partnering with renewable power producers without risk or cost to B.C. ratepayers.

The act also creates a First Nations Clean Energy Business Fund to provide the opportunity for First Nations to create investment and jobs in renewable power production.

3. Strengthening Environmental Stewardship and Reducing Greenhouse Gases

The act enshrines in law measures the Province will take to reduce greenhouse gas emissions, help customers save money through conservation and protect the environment.

The Environmental Assessment Act process will be strengthened to specifically provide for assessments of potential cumulative environmental effects. In addition, the development or proposal of energy projects in parks, protected areas and conservancies will be prohibited by law.

The Clean Energy Act builds on the work of the Green Energy Advisory Task Force, appointed in November 2009 to provide insights and recommendations on a comprehensive strategy to put B.C. at the forefront of clean energy development. A summary of the Task Force report can be found at http://www.gov.bc.ca/empr/index.htm

For more information on the Clean Energy Act including a complete set of backgrounders and factsheets go to www.gov.bc.ca/cleanenergyact .

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BACKGROUNDER

NEW ACT SETS THE FOUNDATION FOR THREE AREAS OF PRIORITY

The new Clean Energy Act establishes a long-term vision for British Columbia to become a clean-energy powerhouse. It sets out 16 specific energy objectives that will guide government, BC Hydro and the British Columbia Utilities Commission in advancing British Columbia's energy vision which focuses on three areas

1. Ensuring Electricity Self-Sufficiency at Low Rates

The act strengthens the goal of electricity self-sufficiency with a new regulatory framework for long-term electricity planning, commitments to clean and renewable electricity generation, streamlined approval processes, and new measures to promote electricity efficiency and conservation. It also strengthens protection for B.C. ratepayers. These objectives will be accomplished through three main components:

I. **Long-Term Planning:** A new process and mechanisms for planning and delivering a long-term clean energy vision will be established. These include:

- Replacing the current multitude of planning processes with a long-term Integrated Resource Plan (IRP) that allows for public input and long-term stability for the industry.
- Strengthening BC Hydro and the BC Transmission Corporation through consolidation into one utility to provide a single point of planning and authority to deliver the government's clean energy vision.
- By law, the low-rate benefits that come from B.C.'s existing and future heritage assets will flow exclusively to British Columbians and will not be used to subsidize foreign power sales.
- New opportunities will be provided for rural and remote residents to connect to the transmission system to access clean and renewable electricity at potentially lower rates from B.C.'s heritage assets.

II. **Public Investments and Conservation**: B.C.'s clean-energy vision includes the largest public investment in heritage assets and clean power in B.C. history, including new use of heritage assets for investment and direct and indirect job creation. Conservation and minimizing electricity waste will continue to be cornerstones to achieving long-term electricity self-sufficiency and low rates now and into the future. This includes:

- A new commitment to meet 66 per cent of BC Hydro's future incremental power demand from conservation and efficiency improvements by 2020, an increase from the current target of 50 per cent.
- A renewed commitment to smart meters and smart grids that will allow ratepayers to better manage their electricity use and save on power bills by taking advantage of new electricity pricing programs aimed at encouraging conservation and smart use of electricity during off-peak periods.
- New requirements to develop programs that will offer B.C. ratepayers in prescribed classes new options to contract with BC Hydro for long-term electricity purchases at set prices for limited volumes of power over defined periods of time. This will provide rate certainty and stability for customers and the potential for more competitive rates, while also providing BC Hydro more certainty for electricity planning purposes.

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- Facilitating net metering, which allows residential and commercial customers to sell excess power back to BC Hydro, or store power for personal use during an outage or higher-rate periods. Customers who produce their own power, such as solar, will be able to sell their excess power back into the grid.
- Key expansions of B.C.'s publicly-owned electricity system, including new transmission projects such as the Northwest Transmission Line, and new public power projects, including two additional turbines at Mica Dam, an additional turbine at Revelstoke Dam, and the Site C Clean Energy Project (subject to completing a comprehensive environmental assessment and meeting the Crown's constitutional obligations to First Nations).

III. **New Investments in Clean, Renewable Power and Energy Security:** The act will expedite BC Hydro's electricity purchase agreements with clean and renewable electricity producers to secure sufficient supplies of additional clean, renewable electricity that will ensure electricity self-sufficiency by 2016 and beyond. The direction it provides to the B.C. Utilities Commission will provide stimulus for early investment and job creation in clean electricity production, as follows:

- Under the "Standing Offer" program, all eligible generation facilities will be legally entitled to sell from 50 kilowatts up to 10 megawatts of clean power to BC Hydro at prices reflecting recent calls for power and under simplified terms and conditions.
- BC Hydro will be required to advance its acquisition of an additional 3,000 gigawatt hours (GWh) of electricity by 2020 instead of by 2026, beyond the amount specified in its base electricity supply obligations for self-sufficiency by 2016. The utility will also have new ability to use its available electricity and capacity to produce the highest return and best value for ratepayers and taxpayers.
- The Phase 2 Bioenergy Call for up to 1,000 GWh of electricity from wood waste will move forward, along with new energy projects approved under the 2008 Clean Power Call to acquire up to 5,000 GWh of electricity, and projects to increase power generation and efficiency at B.C.'s pulp mills. These specific clean-power procurement processes will not be put at risk or delayed. They will be exempt from unnecessary, costly and time-consuming reviews under the Utilities Commission Act. Yet they will still be subject to B.C. Utilities Commission oversight with respect to rate-setting requirements and to all existing environmental requirements and standards, as well as to the Crown's constitutional obligations to First Nations.

2. Harnessing B.C.'s Clean-Power Potential to Create Jobs in Every Region

The act will provide BC Hydro and renewable power producers the tools necessary to establish British Columbia as a clean-energy powerhouse that enables economic growth and job creation in every region. Key measures include:

- A new role for BC Hydro to actively market B.C. clean power and spearhead long-term competitively priced export contracts to neighbours in Canada and the U.S. that create new opportunities for investments and jobs across B.C. BC Hydro will become the aggregator of energy purchase agreements and work in partnership with B.C.'s renewable power producers and government. Consistent with government's commitment to one project – one process, export contracts will be exempt from B.C. Utilities Commission review, yet will remain subject to provincial environmental, First Nations and community consultation requirements.

- The British Columbia Utilities Commission will ensure appropriate rates are set in advancing government's energy objectives and long-term resource plans.
- A new structure for BC Hydro - consolidating with the BCTC - that will strengthen its public ownership and allow it to fully capitalize on its unique ability to manage generation and transmission facilities.
- Maximizing BC Hydro's firming and shaping capabilities to leverage new opportunities for growth in clean power technologies such as wind, solar, and run of river across B.C.
- Attracting new low-carbon investments and jobs in B.C. by permitting BC Hydro to enter into long-term sales contracts for green technology investments that require stable, predictable electricity prices.
- A new planning role for the B.C. Government that sets the broad framework for B.C.'s domestic electricity needs and advances its energy objectives and priorities without regulatory redundancy.
- Establishing a Feed-In Tariff program to foster the development of emerging technologies in renewable power production.
- Opening new regional economic opportunities by advancing the Northwest Transmission Line and establishing a new distribution extension policy to help connect rural and remote communities to BC Hydro's clean electricity grid.
- Creating a First Nations Clean Energy Business Fund to enable First Nations investments and partnerships in renewable power production.
- The largest investment in B.C.'s clean energy assets, including public investment in Site C, and the Mica Dam and Revelstoke Dam upgrades which are expected to create over 36,000 direct and indirect jobs.

- Ensuring the following projects will not be subject to unnecessary lengthy and costly processes before the B.C. Utilities Commission, but will still be subject to environmental assessments and ensuring the Crown's obligations to First Nations are met:
  - The Northwest Transmission Line
  - Mica units 5 and 6
  - Revelstoke unit 6
  - Site C Clean Energy Project
  - The Bioenergy Phase 2 Call for Power
  - BC Hydro's integrated power offer
  - The Clean Power Call
  - The Standing Offer Program
  - The Feed-in-Tariff Program
  - BC Hydro's Smart Metering and Grid Program.

3. <u>Strengthening Environmental Stewardship and Reducing Greenhouse Gases</u>

The act enshrines in law measures the Province will take to reduce greenhouse gas emissions, help customers save money through conservation and protect the environment. These include:

- Building on the commitment for net zero emissions from electricity generation, the act increases the legislated clean or renewable electricity generation target from 90 per cent to at least 93 per cent of total generation – one of the highest standards in the world.
- The Environmental Assessment Act process will now be strengthened to specifically provide for assessments of potential cumulative environmental effects.

- The act will prohibit the development, or proposal, of energy projects in parks, protected areas and conservancies.
- Rejecting consideration of nuclear power in implementing B.C.'s clean energy strategy.
- Restricting BC Hydro's operation of Burrard Thermal to only emergency situations and supporting transmission reliability.
- Legislation enshrining B.C.'s historic Two Rivers Policy by prohibiting, with the exception of Site C, future development of large scale hydroelectric storage projects on all river systems in British Columbia, including the nine sites previously considered by BC Hydro.
- Providing consumers with tools to manage their electricity use and reduce costs by replacing old mechanical meters with Smart Meters accompanied by in-home displays that show energy consumption in real time.
- Establishing programs to encourage the use of high-efficiency equipment using clean electricity or natural gas for heating and hot water, and to accelerate the deployment of natural gas and electric vehicles and fuelling infrastructure.
- New opportunities for rural and remote residents who are now dependent on diesel power to connect to the transmission system to access clean and renewable electricity from B.C.'s heritage assets.

For more information on the Clean Energy Act including a complete set of backgrounders and factsheets go to www.gov.bc.ca/cleanenergyact .

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Appendix V

CLEAN ENERGY ACT

IMPORTANT INFORMATION

This Act is Current to January 18, 2012

CLEAN ENERGY ACT

[SBC 2010] CHAPTER 22

Contents

Definitions

1 (1) In this Act:

"acquire", used in relation to the authority, means to enter into an energy supply contract;

"authority" has the same meaning as in section 1 of the *Hydro and Power Authority Act*;

"British Columbia's energy objectives" means the objectives set out in section 2;

"Burrard Thermal" means the gas-fired generation asset owned by the authority and located in Port Moody, British Columbia;

"clean or renewable resource" means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource;

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand,

but does not include

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increasegreenhouse gas emissions in British Columbia, or

(e) any rate, measure, action or program prescribed;

"electricity self-sufficiency" means electricity self-sufficiency as described in section 6 (2);

"expenditure for export" means the amount of an expenditure for the construction or extension of a plant or system or for an acquisition of electricity that is in addition to the amount the authority would have had to spend

(a) to achieve electricity self-sufficiency, and

(b) to undertake anything referred to in section 7 (1), except to the extent the expenditure is accounted for in paragraph (a);

"feed-in tariff program" means a program, that may be established under section 16, under which the authority offers to enter into energy supply contracts with persons generating electricity from clean or renewable resources using prescribed technologies in prescribed regions of British Columbia;

"greenhouse gas" has the same meaning as in section 1 of the *Greenhouse Gas Reduction Targets Act*;

"heritage assets" means

(a) any equipment or facilities for the transmission or distribution of electricity in respect of which, on the date on which this Act receives First Reading in the Legislative Assembly, a certificate of public convenience and necessity has been granted, or has been deemed to have been granted, to the authority or the transmission corporation under the *Utilities Commission Act*,

(b) generation and storage assets identified in Schedule 1 of this Act, and

(c) equipment and facilities that are for the transmission or distribution of electricity and that are identified in Schedule 1 of this Act;

"integrated resource plan" means an integrated resource plan required to be submitted under section 3;

"transmission corporation" means British Columbia Transmission Corporation.

(2) Words and expressions used but not defined in this Act or the regulations, unless the context otherwise requires, have the same meanings as in the *Utilities Commission Act*.

Part 1 — British Columbia's Energy Objectives

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

Integrated resource plans

3 (1) The authority must submit to the minister, in accordance with subsection (6), an integrated resource plan that is consistent with good utility practice and that includes all of the following:

(a) a description of the authority's forecasts, over a defined period, of its energy and capacity requirements to achieve electricity self-sufficiency;

(b) a description of what the authority plans to do to achieve electricity self-sufficiency and to respond to British Columbia's other energy objectives, including plans respecting

(i) the implementation of demand-side measures,

(ii) the construction or extension of facilities,

(iii) the acquisition of electricity from other persons, and

(iv) the use of rates, including rates to encourage

(A) energy conservation or efficiency,

(B) the use of energy during periods of lower demand,

(C) the reduction of the energy demand the authority must serve, or

(D) the development and use of electricity from clean or renewable resources;

(c) a description of the consultations carried out by the authority respecting the development of the integrated resource plan;

(d) a description of

(i) the expected export demand during a defined period,

(ii) the potential for British Columbia to meet that demand,

(iii) the actions the authority has taken to seek suitable opportunities for the export of electricity from clean or renewable resources, and

(iv) the extent to which the authority has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports;

(e) if the authority plans to make an expenditure for export, a specification of the amount of the expenditure and a rationale for making it.

(2) In the first integrated resource plan the authority submits to the minister, and in any

other integrated resource plan the minister by order specifies, the authority must include a description of the authority's infrastructure and capacity needs for electricity transmission for the period ending 30 years after the date the integrated resource plan is submitted.

(3) The description referred to in subsection (2) must include an assessment of the potential for developing, during the period referred to in subsection (2), grouped by geographic area, electricity generation from clean or renewable resources in British Columbia.

(4) The authority must carry out any consultations required by a regulation under section 35 (g) and submit a report to the minister, within the time prescribed, respecting those consultations.

(5) The authority must plan to rely on no energy and no capacity from Burrard Thermal, except in the case of emergency or as authorized by regulation.

(6) An integrated resource plan must be submitted

(a) within 30 months from the date this Part comes into force, and

(b) once every 5 years after the submission under paragraph (a), unless a submission date is prescribed for the purposes of this subsection, in which case an integrated resource plan must be submitted by the prescribed submission date.

(7) The authority may submit an amendment to an integrated resource plan approved under section 4, and section 4 applies to the submission.

(8) If the Lieutenant Governor in Council approves an amendment submitted under subsection (7), the approved amendment is to be considered a part of the approved integrated resource plan.

Approval and procurement

4 (1) After the minister receives an integrated resource plan, the Lieutenant Governor in Council, for the purposes of sections 44.2 (5.1), 46 (3.3) and 71 (2.21) and (2.51) of the *Utilities Commission Act*, may, by order,

(a) approve or reject the plan, and

(b) if the Lieutenant Governor in Council is satisfied that it is in the interests of British Columbians to pursue opportunities for export, require the authority, its subsidiaries or both to do the following:

(i) begin a process or processes by the time specified in the order to acquire the specified amount per year of energy and capacity from clean or renewable resources;

(ii) acquire the energy and capacity referred to in subparagraph (i) within the time specified in the order;

(iii) secure the necessary transmission capacity;

(iv) submit, for the purposes of subsection (2), a report to the minister respecting the expenditures for export resulting from compliance with subparagraphs (i) to (iii).

(2) In an order under subsection (1) (b) of this section, the Lieutenant Governor in Council

may exempt the authority from sections 45 to 47 of the *Utilities Commission Act* with respect to anything to be done under subsection (1) (b) (iii) of this section.

(3) The authority and its subsidiaries and persons and their successors and assigns who enter into an energy supply contract as a result of a process referred to in subsection (1) (b) (i) of this section are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(4) The Lieutenant Governor in Council, for the purposes of subsection (5) (a), may approve a report submitted under subsection (1) (b) (iv).

(5) In setting rates for the authority, the commission must ensure that the rates do not allow the authority to recover

(a) its expenditures for export as set out in a report approved by the Lieutenant Governor in Council under subsection (4), and

(b) any other expenditures for export.

Status report

5 (1) The authority must submit to the minister, by the time the minister requires, a status report respecting the authority's most recently approved integrated resource plan.

(2) The minister must make public a status report submitted under subsection (1) in the same manner and at the same time that the minister makes public a service plan under the *Budget Transparency and Accountability Act*.

Electricity self-sufficiency

6 (1) In this section:

"electricity supply obligations" means

(a) electricity supply obligations for which rates are filed with the commission under section 61 of the *Utilities Commission Act*, and

(b) any other electricity supply obligations that exist at the time this section comes into force,

determined by using the authority's prescribed forecasts of its energy requirements and peak load, taking into account demand-side measures, that are in an integrated resource plan approved under section 4;

"heritage energy capability" means the maximum amount of annual energy that the heritage assets that are hydroelectric facilities can produce under prescribed water conditions.

(2) The authority must achieve electricity self-sufficiency by holding,

(a) by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations, and

(b) by the year 2020 and each year after that, the rights to 3 000 gigawatt hours of energy, in addition to the amount of electricity referred to in paragraph (a), and the capacity required to integrate that energy solely from electricity generating facilities within the Province,

(c) assuming no more in each year than the heritage energy capability, and

(d) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

(3) The authority must remain capable of meeting its electricity supply obligations from the electricity referred to in subsection (2) (a) and (b), except to the extent the authority may be permitted, by regulation, to enter into contracts in the prescribed circumstances and on the prescribed terms and conditions.

(4) A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider British Columbia's energy objective to achieve electricity self-sufficiency.

Exempt projects, programs, contracts and expenditures

7 (1) The authority is exempt from sections 45 to 47 and 71 of the *Utilities Commission Act* to the extent applicable, and from any other sections of that Act that the minister may specify by regulation, with respect to the following projects, programs, contracts and expenditures of the authority, as they may be further described by regulation:

(a) the Northwest Transmission Line, a 287 kilovolt transmission line between the Skeena substation and Bob Quinn Lake, and related facilities and contracts;

(b) Mica Units 5 and 6, a project to install two additional turbines and related works and equipment at Mica;

(c) Revelstoke Unit 6, a project to install an additional turbine and related works and equipment at Revelstoke;

(d) Site C, a project to build a third dam on the Peace River in northeast British Columbia to provide approximately

(i) 4 600 gigawatt hours of energy each year, and

(ii) 900 megawatts of capacity;

(e) a bio-energy phase 2 call to acquire up to 1 000 gigawatt hours per year of electricity;

(f) one or more agreements with pulp and paper customers eligible for funding under Canada's Green Transformation Program under which agreement or agreements the authority acquires, in aggregate, up to 1 200 gigawatt hours per year of electricity;

(g) the clean power call request for proposals, issued on June 11, 2008, to acquire up to 5 000 gigawatt hours per year of electricity from clean or renewable resources;

(h) the standing offer program described in section 15;

(i) the feed-in tariff program described in section 16;

(j) the actions taken to comply with section 17 (2) and (3);

(k) the program described in section 17 (4).

(2) The persons and their successors and assigns who enter into an energy supply contract with the authority related to anything referred to in subsection (1) are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent the authority from doing anything referred to in subsection (1).

Rates

8 (1) In setting rates under the *Utilities Commission Act* for the authority, the commission must ensure that the rates allow the authority to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to

(a) the achievement of electricity self-sufficiency, and

(b) a project, program, contract or expenditure referred to in section 7 (1), except

(i) to the extent the expenditure is accounted for in paragraph (a), and

(ii) for costs, prescribed for the purposes of this section, respecting the feed-in tariff program.

(2) Subject to subsection (1) of this section, the commission must set under the *Utilities Commission Act* a rate proposed by the authority with respect to the project referred to in section 7 (1) (a) of this Act.

(3) The commission must not, except on application by the authority, cancel, suspend or amend a rate set in accordance with subsection (2).

(4) The authority must provide to the minister, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of the extent to which the authority's electricity rates continue to be competitive with those other rates.

Domestic long-term sales contracts

9 The authority must establish, in accordance with the regulations, a program to develop potential offers respecting domestic long-term sales contracts for availability to prescribed classes of customers on prescribed terms, including terms respecting price, for prescribed volumes of energy over prescribed periods.

Part 2 — Prohibitions

Two-rivers system development

10 In this Part:

"approval" includes a certificate, licence, permit or other authorization;

"prohibited projects" means

(a) a project of the authority, referred to in Schedule 2 of this Act, for electricity generation on a stream, and

(b) a project for electricity generation on a stream with a storage capability in excess of a prescribed storage capability,

but does not include the two-rivers projects;

"stream" has the same meaning as in section 1 of the *Water Act*;

"two-rivers projects" means

(a) the authority's facilities, on the Peace River and the Columbia River System, existing on the date this section comes into force and upgrades or extensions to those facilities, and

(b) the project commonly known as Site C.

Project prohibitions

11 (1) Despite any other enactment, a minister, or an employee or agent of the government or of a municipality or regional district, must not issue an approval under an applicable enactment for a person to

(a) undertake a prohibited project, or

(b) construct all or part of the facilities of a prohibited project.

(2) Despite any other enactment, an approval under another enactment is without effect if it is issued contrary to subsection (1).

Prohibited acquisitions

12 (1) In this section:

"facility" means a facility for the generation of electricity and any transmission or distribution equipment to deliver that electricity to the point of interconnection with the authority's integrated service area;

"protected area" means

(a) a park, recreation area, or conservancy, as defined in section (1) of the *Park Act*,

(b) an area established under the *Environment and Land Use Act* as a park or protected area, or

(c) an area established or continued as an ecological reserve under the *Ecological Reserve Act* or by the *Protected Areas of British Columbia Act*.

(2) The authority must not make an offer to acquire electricity from a person whose proposed facility is to be located, in whole or in part, in a protected area, unless the location is permitted under the enactments referred to in the definition of "protected area" in subsection (1).

(3) A person referred to in subsection (2) must not offer to sell electricity to the authority.

Burrard Thermal

13 The authority must not operate Burrard Thermal, except

(a) in the case of emergency,

(b) to provide transmission support services, or

(c) as authorized by regulation.

Part 3 — Preserving Heritage Assets

Sale of heritage assets prohibited

14 (1) The authority must not sell or otherwise dispose of the heritage assets.

(2) Nothing in subsection (1) prevents the authority from disposing of heritage assets if the assets disposed of are no longer used or useful for their intended purpose, or they are to be replaced with one or more assets that will perform similar functions.

Part 4 — Standing Offer and Feed-in Tariff Programs

Standing offer program

15 (1) In this section:

"eligible facility" means a generation facility that

(a) either

(i) has only one generator and the generator's nameplate capacity is less than or equal to the maximum nameplate capacity or has more than one generator and the total nameplate capacity of all of them is a capacity less than or equal to the maximum nameplate capacity, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities;

"maximum nameplate capacity" means 10 megawatts or, if another capacity is prescribed for the purposes of this section, the prescribed capacity.

(2) The authority must establish and, except in the prescribed circumstances, maintain a standing offer program to acquire electricity from eligible facilities.

(3) The authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions on which offers under the standing offer program under

subsection (2) are to be made.

Feed-in tariff program

16 (1) To facilitate the achievement of one or more of British Columbia's energy objectives, the Lieutenant Governor in Council, by regulation, may require the authority to establish a feed-in tariff program.

(2) If the authority is required to establish a feed-in tariff program, the authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions under which offers may be made under the feed-in tariff program.

(3) The authority may not enter into an energy supply contract as a result of an offer made under the feed-in tariff program if the energy supply contract, by itself or in aggregate with other energy supply contracts entered into under the feed-in tariff program, would result in an expenditure that exceeds the prescribed amount in the prescribed period.

(4) Without limiting section 34 (2) (c),

(a) requirements prescribed by the Lieutenant Governor in Council, and

(b) criteria, terms and conditions established by the authority

made for the purpose of subsection (2) may be made with respect to different regions, prices and technologies.

Part 5 — Energy Efficiency Measures and Greenhouse Gas Reductions

Smart meters

17 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart grid" means the prescribed equipment;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters and related equipment in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) The authority must establish a program to install and put into operation a smart grid in accordance with and to the extent required by the regulations.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors,

subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters, or of its smart grid.

(6) If a public utility, other than the authority, makes an application under the *Utilities Commission Act* in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority.

Improvement financing

17.1 (1) In this section:

"borrower" means an eligible person who receives financing under a financing agreement and includes a person to whom obligations are transferred as described in subsection (4) (a) or (6);

"eligible person" means a person who

(a) receives or will receive service in British Columbia from a prescribed public utility,

(b) has obtained an energy report from a qualified energy advisor, and

(c) meets the prescribed requirements, if any;

"energy report" means a report that

(a) is made and signed by a qualified energy advisor,

(b) evaluates the energy efficiency of a building, or a part of a building, owned or occupied by an eligible person,

(c) includes recommendations by the qualified energy advisor for improving the energy efficiency of the building, or the part of the building, referred to in paragraph (b), and

(d) meets the other prescribed requirements, if any;

"financing agreement" means an agreement entered into as a result of an offer made under the program;

"landlord" means a landlord as defined in

(a) the *Residential Tenancy Act*, and

(b) the *Commercial Tenancy Act*;

"program" means a program established under subsection (2);

"qualified energy advisor" means an energy advisor who meets the prescribed qualifications;

"qualified person" means a person who meets the prescribed qualifications;

"tenant" means a tenant as defined in

(a) the *Residential Tenancy Act*, and

(b) the *Commercial Tenancy Act*.

(2) A prescribed public utility must establish and maintain a program to offer financing to eligible persons for improving the energy efficiency of a building, or a part of a building, owned or occupied by a borrower.

(3) Subject to subsection (4), a prescribed public utility may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions on which offers under the program are to be made.

(4) A financing agreement must include the following terms:

(a) a borrower may transfer the borrower's obligations under a financing agreement to another person who has applied for service from the prescribed public utility at the building, or the part of the building, that is the subject of the financing agreement;

(b) a borrower's obligations under the borrower's financing agreement are not discharged until

(i) the full amount payable under the financing agreement has been paid,

(ii) the borrower has provided to the prescribed public utility a notice, in a form prescribed by the minister, of a transfer referred to in paragraph (a) or subsection (6), or

(iii) the obligations have been transferred under subsection (6) (a) or (b);

(c) a borrower who is a tenant must,

(i) before entering into the financing agreement, obtain written consent from the tenant's landlord to enter into the financing agreement, and

(ii) before obtaining the consent referred to in subparagraph (i), notify the landlord of the operation of subsection (6);

(d) an improvement financed under the financing agreement must be

(i) an improvement that is

(A) recommended in the energy report respecting the building, or the part of the building, owned or occupied by the borrower, and

(B) in a class of prescribed improvements, and

(ii) carried out by a qualified person.

(5) Subject to subsections (4) (b) and (6), if a borrower transfers a financing agreement to a person referred to in subsection (4) (a), the borrower's obligations under the financing agreement are transferred to the person on the date that the person begins to receive service from the prescribed public utility.

(6) If a landlord either transfers obligations under a financing agreement to a tenant under subsection (4) (a) or grants to a borrower the written consent referred to in subsection (4) (c), certain of the borrower's obligations under the financing agreement are transferred as follows:

(a) obligations that become due on or after the date that the borrower's tenancy with the landlord ends are transferred from the borrower to the landlord on that date;

(b) subject to subsection (7), obligations that become due on or after the date that a person begins a subsequent tenancy with the landlord respecting the rental unit previously occupied by the borrower are transferred from the landlord to the person on that date.

(7) A landlord referred to in subsection (6) must provide notice, as prescribed, to prospective tenants of the rental unit referred to in that subsection advising those prospective tenants of the operation of subsection (6) (b).

(8) A prescribed public utility may not enter into a financing agreement if doing so would result in the prescribed public utility having an aggregate outstanding balance of all of its financing agreements that exceeds the prescribed amount in the prescribed period.

(9) In setting rates under the *Utilities Commission Act* for a prescribed public utility that has entered into a financing agreement, the commission must incorporate the financing agreement into those rates.

(10) A prescribed public utility has the same remedies in the event of a borrower's failure to pay an amount under a financing agreement that has been incorporated into its rates as it has for a borrower's failure to pay any other rates the borrower is obligated to pay as a customer of the public utility.

(11) Without limiting section 36 (1) (c),

(a) a requirement prescribed by the minister, and

(b) criteria, terms and conditions established by a prescribed public utility

made for the purposes of subsection (3) of this section may be made with respect to different regions and improvements and, in the case of a requirement prescribed by the minister, with respect to different prescribed public utilities.

Greenhouse gas reduction

18 (1) In this section, **"prescribed undertaking"** means a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia.

(2) In setting rates under the *Utilities Commission Act* for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking.

(4) A public utility referred to in subsection (2) must submit to the minister, on the minister's request, a report respecting the prescribed undertaking.

(5) A report to be submitted under subsection (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies.

Clean or renewable resources

19 (1) To facilitate the achievement of British Columbia's energy objective set out in section 2 (c), a person to whom this subsection applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) Subsection (1) applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

Part 6 — First Nations Clean Energy Business Fund

First Nations Clean Energy Business Fund

20 (1) In this section:

"first nation" means

(a) a band, as defined in the *Indian Act* (Canada), and

(b) an aboriginal governing body, however organized and established by aboriginal people;

"power project" means an electricity generation or transmission project

(a) that is in a class of projects prescribed for the purposes of this section, other than a project of any organization in the government reporting entity, as defined in the *Budget Transparency and Accountability Act*,

(b) for which a licence, if applicable, under the *Water Act* for a power purpose, as defined section 1 of that Act, is issued after the date this section comes into force, and

(c) for which a prescribed authorization, if applicable, under an enactment respecting land is granted after this section comes into force;

"special account" means the special account, as defined in section 1 of the *Financial Administration Act*, established under subsection (2) of this section.

(2) A special account, to be known as the First Nations Clean Energy Business Fund special account, is established.

(3) The initial balance of the special account is an amount, not to exceed $5 million, prescribed by Treasury Board.

(4) The balance of the special account is increased by

(a) any other amount received by the government for payment into the account, and

(b) a prescribed percentage of the prescribed land and water revenues the government derives from power projects.

(5) Despite section 21 (3) of the *Financial Administration Act*, the minister, in accordance with a spending plan approved by Treasury Board, may pay an amount of money out of the special account for any of the following purposes:

(a) to share the revenues referred to in subsection (4) (b), up to a prescribed percentage of the revenue, under an agreement or agreements with one or more first nations;

(b) to facilitate the participation of first nations and aboriginal people in the clean energy sector;

(c) to pay the costs of administering the special account.

Part 7 — Transmission Corporation

Division 1 — Transfer of Property, Shares and Obligations

Definitions

21 In this Division:

"excluded contract" means a contract that was entered into, assumed by or assigned to the transmission corporation and that is governed by the law of a jurisdiction other than British Columbia;

"excluded permit" means a permit, approval, registration, authorization, licence, exemption, order or certificate issued, granted or provided to the transmission corporation under the law of a jurisdiction other than British Columbia;

"included contract" includes any contract entered into, assumed by or assigned to the transmission corporation, but does not include an excluded contract;

"included permit" includes a permit, approval, registration, authorization, licence, exemption, order or certificate, including a certificate of public convenience and necessity under the *Utilities Commission Act*, but does not include an excluded permit;

"right", in relation to a right held by the authority or the transmission corporation, includes a right under a trust, a cause of action and a claim.

Transfer of property

22 (1) Subject to subsection (2) and despite any enactment or law to the contrary, on the coming into force of this Part, all of the transmission corporation's rights, property, assets, included contracts and included permits are transferred to and vested in the authority.

(2) Subsection (1) does not apply to excluded contracts and excluded permits.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, the

shares of the transmission corporation are transferred to and vested in the authority.

(4) The shares transferred to and vested in the authority under subsection (3) must not be sold or otherwise disposed of, but may be surrendered for cancellation.

(5) Despite any enactment or law to the contrary,

(a) the transfer and vesting effected by subsections (1) and (3) take effect without

(i) the execution or issue of any record, or

(ii) any registration or filing of this Act or any other record in or with any registry or other office,

(b) the transfer and vesting effected by subsections (1) and (3) take effect despite

(i) any prohibition on all or any part of the transfer and vesting, and

(ii) the absence of any consent or approval that is or may be required for all or any part of the transfer and vesting,

(c) if any right, property, asset, included contract or included permit referred to in subsection (1) is registered or otherwise recorded in the name of the transmission corporation, the registration or record may remain but is deemed, for all purposes of this and all other enactments and law, to reflect that the right, property, asset, included contract or included permit is owned by and vested in or held by the authority, and

(d) in any record in or by which the authority deals with a right, property, asset, included contract or included permit referred to in subsection (1), it is sufficient to cite this Act as effecting and confirming the transfer from the transmission corporation to the authority of the included contract or included permit or of the title to the right, property or asset and the vesting of that title in the authority.

(6) For the purposes of this section, assets that become assets of the authority under this section include records and parts of records, and, without limiting this, all of the records and parts of records of the transmission corporation are transferred to and become the records of the authority on the coming into force of this Part.

(7) Without limiting subsection (5) (c) of this section, or section 383.1 of the *Land Title Act*, if a right, property or asset referred to in subsection (1) of this section is registered or recorded in the name of the transmission corporation,

(a) the authority may, in its own name,

(i) effect a transfer, charge, encumbrance or other dealing with the right, property or asset, and

(ii) execute any record required to give effect to that transfer, charge, encumbrance or other dealing, and

(b) an official

(i) who has authority over a registry or office, including, without limitation, the personal property registry and a land title office, in which title to or interests in the right, property or asset is registered or recorded, and

(ii) to whom a record referred to in paragraph (a) (ii) executed by or on behalf of the authority is submitted in support of the transfer, charge, encumbrance or other dealing

must give the record the same effect as if it had been duly executed by the transmission corporation.

Transfer of obligations and liabilities

23 On the coming into force of this Part, all obligations and liabilities of the transmission corporation, except for obligations and liabilities under an excluded contract or excluded permit,

(a) are transferred to and assumed by the authority,

(b) become the authority's obligations and liabilities,

(c) cease to be obligations and liabilities of the transmission corporation, and

(d) may be enforced against the authority as if the authority had incurred them.

Records of transferred assets and liabilities

24 (1) Subject to subsection (2), a reference to the transmission corporation in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be a reference to the authority.

(2) If, under this Part, a part of a right, property, asset, obligation or liability is transferred to the authority, any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be amended to reflect the authority's interests in that right, property, asset, obligation or liability.

Transfer is not a default

25 Despite any provision to the contrary in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate, the transfer to the authority of a right, property, asset, included contract, included permit, share, obligation or liability under sections 22 and 23 does not constitute a breach or contravention of, or an event of default under, or confer a right to terminate the document, and, without limiting this, does not entitle any person who has an interest in the right, property, asset, included contract, included permit, share, obligation or liability to claim any damages, compensation or other remedy.

Legal proceedings

26 (1) Any legal proceeding being prosecuted or pending by or against the transmission corporation on the date this Part comes into force may be prosecuted, or its prosecution may be continued, by or against the authority, and may not be prosecuted or continued against the transmission corporation.

(2) A conviction against the transmission corporation may be enforced against the authority,

and may not be enforced against the transmission corporation.

(3) A ruling, order or judgment in favour of or against the transmission corporation may be enforced by or against the authority, and may not be enforced by or against the transmission corporation.

(4) A cause of action or claim against the transmission corporation existing on the date this Part comes into force must be prosecuted against the authority.

(5) Subject to subsections (1) to (4), a cause of action, claim or liability to prosecution existing on the date this Part comes into force is unaffected by anything done under this Part.

Division 2 — Employees

Definitions

27 In this Division:

"adjustment plan" means an adjustment plan under section 54 of the *Labour Relations Code*;

"collective agreement" has the same meaning as in section 1 (1) of the *Labour Relations Code*.

Transfer of employees

28 (1) It is deemed that the persons who were, immediately before the coming into force of this Part, employees of the transmission corporation are, on the coming into force of this Part, transferred to and become employees of the authority.

(2) A question or difference between the authority and

(a) a transferred employee who is a member of a unit of employees for which a trade union has been certified under the *Labour Relations Code*, or

(b) a trade union representing transferred employees,

respecting the application of the *Labour Relations Code*, or the interpretation or application of this Division, may be referred to the Labour Relations Board in accordance with the procedure set out in the *Labour Relations Code* and its regulations.

(3) The Labour Relations Board may decide a question or difference referred to in subsection (2) in any of the ways, and by applying any of the remedies, available under the *Labour Relations Code*.

(4) On the date this Part comes into force, in respect of employees who are members of units of employees for which a trade union has been certified under the *Labour Relations Code*, the authority is the successor employer of those employees for the purposes of section 35 of the *Labour Relations Code*, without prejudice to the authority's right to apply for consolidation or merger of the bargaining units.

(5) If the authority or any trade union representing transferred employees makes an application to the Labour Relations Board to consolidate or merge the bargaining units representing transferred employees into a single bargaining unit for each trade union, the

Labour Relations Board must consider that application having regard to the principles of business efficiency and without reference to the labour relations history at the authority or the transmission corporation relating to the presence of more than one bargaining unit for each trade union.

Continuous employment

29 (1) The transfer of a transferred employee does not constitute a termination of the transferred employee's employment for the purposes of

(a) an applicable collective agreement,

(b) any employment contract involving the transferred employee, and

(c) the *Employment Standards Act*.

(2) A transferred employee who is not subject to a collective agreement is deemed to have been employed by the authority without interruption in service.

(3) The service, with the transmission corporation, of a transferred employee who is not subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any employment contract.

(4) For the purposes of seniority, a transferred employee who is subject to a collective agreement is deemed to have been employed by the authority without interruption in service, unless the authority and the trade union representing the transferred employee have agreed to other seniority terms in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting seniority in the adjustment plan apply.

(5) The service, with the transmission corporation, of a transferred employee who is subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any collective agreement,

unless the authority and the trade union representing the transferred employee have agreed to other probationary periods, benefits and entitlements in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting probationary periods, benefits and entitlements in the adjustment plan apply.

(6) A transferred employee is deemed not to have been constructively dismissed solely by virtue of the transfer under section 28.

(7) Nothing in this Part

(a) prevents the employment of a transferred employee from being lawfully terminated after the transfer under section 28,

(b) prevents any term or condition of the employment of a transferred employee from being lawfully changed after the transfer under section 28, or

(c) removes any right or remedy of a person who is terminated after the transfer under section 28 or in respect of whom a term or condition of employment has been changed after the transfer under section 28.

Pensions

30 (1) For the purposes of the *Pension Benefits Standards Act*, the transfer of a transferred employee does not constitute a termination of membership in the transmission corporation's registered pension plan, or any other pension arrangement sponsored by the transmission corporation.

(2) Despite section 36 (1) of the *Hydro and Power Authority Act*, the authority does not require the approval of the Lieutenant Governor in Council to amend the authority's registered pension plan to implement the provisions of this Part, including the authority's assumption of all liability for the pension benefits payable under the transmission corporation's registered pension plan.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, all of the rights, property and assets that comprise

(a) the balance of fund account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the balance of fund account of the pension fund of the authority's registered pension plan, and

(b) the index reserve account and past service index reserve account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the index reserve account of the pension fund of the authority's registered pension plan,

and the resulting pension fund must be held by the trustee of the pension fund of the authority's registered pension plan.

(4) Section 22 (5) applies to the transfer and vesting effected by subsection (3) of this section.

Division 3 — General

Repealed

31 [Repealed 2010-22-31(3).]

Utilities Commission Act

32 (1) No approval, authorization, permit, certificate, exemption, permission, registration or order is required under the *Utilities Commission Act* with respect to

(a) the transmission corporation's ceasing to provide the service referred to in subsection (2) (a), or

(b) any transfer under this Part.

(2) The authority is deemed to have all the approvals, authorizations, permits, certificates, exemptions, permissions, registrations or orders that, under the *Utilities Commission Act*, are or may be required to continue

(a) to provide the service the transmission corporation provided immediately before the coming into force of this Part, and

(b) to charge, collect and enforce the rates the transmission corporation charged, collected and enforced immediately before the coming into force of this Part.

(3) [Repealed 2010-22-32(4).]

(4) Subsection (3) is repealed on July 1, 2011.

Designated agreements

33 On the coming into force of this Part, the agreements designated under section 3 of the *Transmission Corporation Act* have no force or effect.

Part 8 — Regulations

Division 1 — Regulations by Lieutenant Governor in Council

General

34 (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the *Interpretation Act*.

(2) In making a regulation under this Act, the Lieutenant Governor in Council may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

Regulations

35 Without limiting section 34 (1), the Lieutenant Governor in Council may make regulations as follows:

(a) respecting forecasts for the purposes of the definition of "electricity supply obligations" in section 6 (1);

(b) adding a heritage asset to Schedule 1 of this Act;

(c) prescribing water conditions for the purposes of the definition of "heritage energy capability" in section 6 (1);

(d) modifying or adding to British Columbia's energy objectives, except for the objective specified in section 2 (g);

(e) for the purposes of sections 44.1, 44.2, 46 and 71 of the *Utilities Commission Act*, respecting the application of British Columbia's energy objectives to public utilities other than the authority;

(f) establishing factors or guidelines the commission must follow in respect of British Columbia's energy objectives, including guidelines regarding the relative priority of the objectives set out in section 2;

(g) respecting consultations the authority must carry out in relation to

(i) the development of an integrated resource plan and of an amendment to an integrated resource plan,

(ii) an integrated resource plan submitted under section 3 (6), and

(iii) an amendment to an integrated resource plan submitted under section 3 (7);

(h) prescribing submission dates for the purposes of section 3 (6);

(i) respecting the authority's obligation under section 6 (3), including, without limitation, regulations permitting the authority to enter into contracts respecting the electricity referred to in section 6 (2) (a) and (b) and prescribing the terms and conditions on which, and the volume of electricity about which, the contracts may be entered into;

(j) respecting the program referred to in section 9, including prescribing classes of customers and terms;

(k) prescribing storage capability for the purposes of the definition of "prohibited projects" in section 10, including, without limitation, prescribing storage capability in terms of time, impoundment, mechanism or area;

(l) respecting the standing offer program to be established under section 15, including, without limitation, regulations that

(i) prescribe requirements, technologies, generation facilities and classes of generation facilities for the purposes of the definition of "eligible facility" in section 15 (1),

(ii) prescribe a capacity for the purposes of the definition of "maximum nameplate capacity" in section 15 (1),

(iii) prescribe circumstances for the purposes of section 15 (2), and

(iv) prescribe requirements for the purposes of section 15 (3);

(m) respecting the feed-in tariff program that may be established under section 16, including, without limitation, regulations that

(i) prescribe regions and technologies for the purposes of the definition of "feed-in tariff program" in section 1 (1),

(ii) require the authority to establish the feed-in tariff program,

(iii) prescribe requirements for the purposes of section 16 (2),

(iv) prescribe amounts and periods for the purposes of section 16 (3), and

(v) prescribe costs for the purposes of section 8 (1) (b);

(n) for the purposes of the definition of "prescribed undertaking" in section 18, prescribing classes of projects, programs, contracts or expenditures that encourage

(i) the use of

(A) electricity, or

(B) energy directly from a clean or renewable resource

instead of the use of other energy sources that produce higher greenhouse gas emissions, or

(ii) the use of natural gas, hydrogen or electricity in vehicles, and the construction and operation of infrastructure for natural gas or hydrogen fueling or electricity charging.

Division 2 — Regulations by Minister

General

36 (1) In making a regulation under this Act, the minister may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

(2) The minister may make a regulation defining, for the purposes of this Act, a word or expression used but not defined in this Act.

Regulations

37 The minister may make regulations as follows:

(a) prescribing resources for the purposes of the definition of "clean or renewable resource" in section 1 (1);

(b) prescribing exclusions for the purposes of the definition of "demand-side measure" in section 1 (1);

(c) authorizing the authority for the purposes of sections 3 (5), 6 and 13;

(d) describing the projects, programs, contracts and expenditures referred to in section 7 (1), including, without limitation, by specifying the property, interests, rights, activities, contracts and rates that comprise the projects, programs, contracts and expenditures;

(e) specifying sections of the *Utilities Commission Act* for the purposes of section 7 (1);

(f) respecting reports to be provided to the minister by the authority under section 8 (4), including, without limitation, regulations respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(g) for the purposes of section 17, respecting smart meters and smart-grids and their installation, including, without limitation,

(i) prescribing the types of smart meters to be installed, including the features or functions each meter must have or be able to perform,

(ii) prescribing types of smart grids to be installed, including, without limitation, equipment to detect unauthorized use or consumption of electricity, equipment to facilitate distributed generation and associated telecommunication and back-up systems, and

(iii) prescribing the classes of users for whom smart meters must be installed, and, without limiting section 36 (1) (c), requiring the authority to install different types of smart meters for different classes of users;

(g.1) for the purposes of section 17.1, including, without limitation,

(i) prescribing requirements for the purposes of the definitions of "eligible person" and "energy report" in section 17.1 (1),

(ii) prescribing qualifications for the purposes of the definitions of “qualified energy advisor” and “qualified person” in section 17.1 (1),

(iii) prescribing public utilities and classes of public utilities to which section 17.1 (2) applies,

(iv) prescribing requirements for the purposes of section 17.1 (3),

(v) prescribing forms for the purposes of section 17.1 (4) (b) (ii),

(vi) prescribing classes of improvements for which financing agreements may be made,

(vii) respecting the notice referred to in section 17.1 (7), and

(viii) prescribing amounts and periods for the purposes of section 17.1 (8);

(h) prescribing targets, guidelines, public utilities and classes of public utilities for the purposes of section 19;

(i) issuing a direction for the purposes of section 31.

Division 3 — Regulations by Treasury Board

Regulations

38 Treasury Board may make regulations as follows:

(a) prescribing classes of projects and authorizations for the purposes of the definition of "power project" in section 20 (1), including, without limitation, prescribing classes of projects by reference to whether, or the extent to which, a project is a project of any organization of the government reporting entity, within the meaning of that definition;

(b) prescribing amounts and percentages for the purposes of section 20 (3), (4) (b) and (5) (a).

Part 9 — Transition

Transition

39 (1) The Lieutenant Governor in Council may make regulations considered appropriate for the purpose of more effectively bringing this Act into operation, and to remedy any transitional difficulties encountered in doing so, and for that purpose, may make regulations disapplying or varying any provision of this Act.

(2) Subject to subsection (3), this section is repealed on the date that is 2 years after the coming into force of this section and, on this section's repeal, any regulations made under it are also repealed.

(3) The Lieutenant Governor in Council, by regulation, may substitute for the date referred to in subsection (2) a date that is no later than 3 years after the coming into force of this section.

Part 10 — Consequential Amendments

Consequential and Related Amendments

[Note: See Table of Legislative Changes for the status of sections 40 to 76.]

Section(s)	Affected Act
40-43	*BC Hydro Public Power Legacy and Heritage Contract Act*
44	*Environmental Assessment Act*
45	*Financial Information Act*
46-51	*Forest Act*
52	*Freedom of Information and Protection of Privacy Act*
53-56	*Hydro and Power Authority Act*
57	*Transmission Corporation Act*
58-73	*Utilities Commission Act*
74-76	*Wildfire Act*

Commencement

77 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Section 21 to 33	July 5, 2010
3	Section 42	July 5, 2010
4	Section 45	By regulation of the Lieutenant Governor in Council
5	Section 52	By regulation of the Lieutenant Governor in Council
6	Section 55 (d)	July 5, 2010

7	Section 57	July 5, 2010
8	Section 59	July 5, 2010
9	Section 73	July 5, 2010

Schedule 1

Heritage Assets

Those generation and storage assets commonly known as the following:

Aberfeldie

Alouette

Ash River

Bridge River

Buntzen/Coquitlam

Burrard Thermal

Cheakamus

Clowhom

Duncan

Elko

Falls River

Fort Nelson

G. M. Shrum

Hugh Keenleyside Dam (Arrow Reservoir)

John Hart

Jordan

Kootenay Canal

La Joie

Ladore

Mica, including units 1 to 6

Peace Canyon

Prince Rupert

Puntledge

Revelstoke, including units 1 to 6

Ruskin

Site C

Seton

Seven Mile

Shuswap

Spillimacheen

Stave Falls

Strathcona

Waneta

Wahleach

Walter Hardman

Whatshan

Schedule 2

Prohibited Projects

The projects of the authority, as set out in appendix F-8 of the authority's long-term acquisition plan, exhibit B-1-1, filed with the commission on June 12, 2008, are prohibited projects for the purposes of section 10, in particular, the following projects identified in appendix F-8:

(a) Murphy Creek;

(b) Border;

(c) High Site E;

(d) Low Site E;

(e) Elaho;

(f) McGregor Lower Canyon;

(g) Homathko River;

(h) Liard River;

(i) Iskut River;

(j) Cutoff Mountain;

(k) McGregor River Diversion.

Appendix W

FORECAST RESULTS OF 2010-2011 NGV INCENTIVES

Appendix W
Forecast Results of 2010 – 2011 NGV Incentives
List of Schedules

Appendix W: Forecast Results of 2010 - 2011 NGV Incentives
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (2012 -2021)
City of Surrey, Kelowna School District, Waste Management, Vedder Transport
$000's, unless otherwise stated

		Reference	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1	Annual NG Volume (TJ)		176	176	176	176	176	176	176	176	176	176
2												
3	Discount Rate	2014 FEI After-Tax WACC	6.81%									
4	Discount Period (years)		1	2	3	4	5	6	7	8	9	10
5												
6	FEI Total Delivery Margin Projections $Millions	Note 1	575	577	588	600	612	624	637	649	662	676
7												
8	Net COS Benefit (Cost) to Existing Natural Gas Customers											
9	Annual Incremental Margin from additional NGT volume		529	540	540	540	555	571	583	594	606	618
10	Annual Incentive Funding COS				(974)	(934)	(893)	(853)	(813)	(773)	(732)	(692)
11	Net Annual COS Benefit (Cost) '000$	Line 9 + Line 10	529	540	(434)	(394)	(338)	(282)	(230)	(178)	(126)	(74)
12												
13	Approximate Annual FEI Delivery (Reduction) Increase, %	-Line 11 / (Line 6 x 1000), Note 2			0.07%	0.07%	0.06%	0.05%	0.04%	0.03%	0.02%	0.01%
14												
15	Present Value of Annual Net COS Benefit (Cost)	Line 11/(1+Line 3)^(Line 4)	496	474	(356)	(302)	(243)	(190)	(145)	(105)	(70)	(38)
16												
17	NPV of Net COS Benefit (Cost) '000$	Sum Line 15 2012 to year	496	969	613	311	67	(122)	(267)	(373)	(442)	(480)
18												
19	NPV of Net COS Benefit (Cost) 2012 to 2030 (19 Years)			1,229								

20 Note:
21 1: 2012, 2013 based on 2012-2013 RRA G-44-12 Compliance Filing May 1, 2012; 2014+ increase at 2%/year reflecting high level long range planning assumptions,
22 does not include any impact of the 2010 - 2011 NGV Incentives
23 2: Cumulative FEI Delivery (Reduction) increase, FEI delivery margin does not include any impact of the 2010 - 2011 NGV Incentives

Appendix W: Forecast Results of 2010 - 2011 NGV Incentives
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (continued 2022 - 2030)
City of Surrey, Kelowna School District, Waste Management, Vedder Transport
$000's, unless otherwise stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Annual NG Volume (TJ)		176	176	176	176	176	176	176	176	176
2											
3	Discount Rate	2014 FEI After-Tax WACC									
4	Discount Period (years)		11	12	13	14	15	16	17	18	19
5											
6	FEI Total Delivery Margin Projections $Millions	Note 1	689	703	717	731	746	761	776	792	808
7											
8	Net COS Benefit (Cost) to Existing Natural Gas Customers										
9	Annual Incremental Margin from additional NGT volume		631	643	656	669	683	696	710	725	739
10	Annual Incentive Funding COS		(652)	(611)	0	0	0	0	0	0	0
11	Net Annual COS Benefit (Cost) '000$	Line 9 + Line 10	(21)	32	656	669	683	696	710	725	739
12											
13	Approximate Annual FEI Delivery (Reduction) Increase, %	-Line 11 / (Line 6 x 1000), Note 2	0.00%	(0.00)%	(0.09)%	(0.09)%	(0.09)%	(0.09)%	(0.09)%	(0.09)%	(0.09)%
14											
15	Present Value of Annual Net COS Benefit (Cost)	Line 11/(1+Line 3)^(Line 4)	(10)	14	279	266	254	243	232	221	211
16											
17	NPV of Net COS Benefit (Cost) '000$	Sum Line 15 2012 to year	(490)	(476)	(197)	69	323	565	797	1,018	1,229

20 Note:
21 1: 2012, 2013 based on 2012-2013 RRA G-44-12 Compliance Filing May 1, 2012; 2014+ increase at 2%/year reflecting high level long range planning assumptions,
22 does not include any impact of the 2010 - 2011 NGV Incentives
23 2: Cumulative FEI Delivery (Reduction) increase, FEI delivery margin does not include any impact of the 2010 - 2011 NGV Incentives

Appendix X

BFI CANADA INC. DECISION COMMISSION ORDER C-6-12

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER C-6-12

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
for a Certificate of Public Convenience and Necessity
for Constructing and Operating a Compressed Natural Gas Refueling Station at BFI Canada Inc.

BEFORE: A.A. Rhodes, Panel Chair/Commissioner April 30, 2012
D.M. Morton, Commissioner

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On July 19, 2011 by Order G-128-11, the British Columbia Utilities Commission (Commission), among other thing, approved a revised contract between Waste Management of Canada Corporation (Waste Management) and FortisBC Energy Inc. (FEI, Fortis) for the provision of compression and dispensing services for Compressed Natural Gas (CNG) to Waste Management by FEI and accepted the expenditures required for FEI to construct the compression and dispensing facility. The Commission denied approval of the General Terms and Conditions for the provision of CNG Service and Liquefied Natural Gas (LNG) Service as applied for by FEI and indicated that it would approve revised General Terms and Conditions which better reflected full cost recovery from potential CNG and LNG Service customers (Waste Management Decision);

B. By Order G-95-11 dated May 24, 2011, the Commission established an Inquiry into FEI's offering of products and services in Alternative Energy Solutions (AES) and other New Initiatives (AES Inquiry), including the issue of the appropriateness of FEI's entry into the competitive domain of CNG and LNG fuelling;

C. By Order G-1-12 dated January 4, 2012, and Order G-9-12 dated January 31, 2012, the AES Inquiry Commission Panel established a zero dollar threshold for Certificate of Public Convenience and Necessity (CPCN) applications relating to AES and other New Initiatives projects on an interim basis, pending completion of the AES Inquiry;

D. On April 12, 2012, the Commission issued its Decision regarding the FortisBC Energy Utilities Revenue Requirements Application for the 2012 and 2013 test years (2012-2013 RRA) which approved, among other things, forecast expenditures of $569,396 and $601,119 for 2012 and 2013, respectively, for overhead, marketing, business development and customer education related to natural gas vehicle (NGV) services;

E. Revised General Terms and Condition Section 12B (GT&C 12B) were filed by FEI and were approved by Commission Order G-14-12 dated February 7, 2012;

F. On February 29, 2012, FEI applied to the Commission, pursuant to sections 45 and 46 of the *Utilities Commission Act* (the Act), for a CPCN for construction and operation of a CNG refuelling station at the premises of BFI Canada Inc. (BFI) located in Coquitlam, British Columbia (BFI Project) (the BFI Application);

G. FEI also seeks approval, pursuant to sections 59-60 of the Act, of the rate design and rates established in the Fueling Station License and Use Agreement with BFI for CNG Service (BFI Agreement) as just and reasonable;

H. By Order G-23-12 dated March 2, 2012, the Commission established a written hearing process for its review of the Application;

I. The Commission has reviewed the BFI Application and concludes that the CPCN should be granted;

J. The Commission has concerns regarding cross subsidization of the CNG and LNG Service by FEI's existing ratepayers and is also concerned that a significant number of costs are not included in the rate design and rates for the BFI Project.

NOW THEREFORE, the Commission determines as follows:

1. A CPCN for the construction of a CNG refuelling station at the premises of BFI is granted to FEI, pursuant to sections 45 and 46 of the *Utilities Commission Act*.

2. The Commission declines to approve the rates to be charged to BFI as proposed in the BFI Application.

3. FEI is directed to establish two new service classes, one for CNG Service and one for LNG Service.

4. The Commission re-affirms the following Commission directives in the Waste Management Decision and confirms their applicability to the BFI Application:

    a. Estimate the overhead and marketing expenses which relate to the CNG/LNG Service program and the expected sales volume and allocate those costs in a reasonable manner among CNG/LNG Service customers going forward;

    b. Keep the costs and revenues associated with the Waste Management Agreement and any other offerings separate and distinct and monitor such offerings during a two-year test period and provide a report by March 31, 2013, which includes the topics listed in Appendix 2 of the Waste Management Decision.

5. The Commission further directs:

   a. All overhead and marketing expenses, including, without limitation, business development, customer education and all costs relating to the CNG/LNG Service program are to be determined using approved fully allocated cost of service methodology and included in the cost of service.

   b. Fortis is to recalculate the Operations and Maintenance charge in the BFI rate to reflect the cost of the CNG/LNG Service program using the figures of $569,396 for 2012 and $601,119 for 2013, to be allocated among CNG/LNG Service customers in a reasonable manner.

   c. In order to set a fair and equitable rate which is not unjust or unreasonable within the meaning of section 59 of the *Utilities Commission Act*, and that therefore reflects the full cost of service of this offering, for more particularity, FEI is to include the following amounts in the rate applicable to BFI:

      - Actual construction costs for the BFI Fuelling Station;
      - Cost of the BFI Application in the amount of $75,000;
      - Branding Costs for the installation of signs and to affix decals;
      - BFI's proportionate share of the overhead and marketing costs, including, without limitation, business development, customer education and all costs relating to the CNG/LNG Service program;
      - Any other costs which may not have been factored into the cost charged to BFI including, for example, increased insurance premiums, as Fortis is required to obtain a number of specific insurance coverages, and to include BFI as an additional insured on it Comprehensive General Liability Policy.

   d. FEI is to establish a rate base deferral account to capture the revenues associated with volumes in excess of BFI's "take or pay" commitment which may be credited back to BFI in the event that BFI is required to pay the un-depreciated capital cost of the fuelling station (i.e. amounts collected in excess of the "take or pay" commitment representing one half of the applicable capital rate).

   e. FEI is to include all other amounts paid by BFI for volumes in excess of the "take or pay" commitment in the existing rate base deferral account approved in the Waste Management Decision to capture incremental CNG and LNG Service recoveries received from actual volumes purchased in excess of minimum take or pay commitments, for refund to all non by-pass customers.

6. In recognition of the fact that the costs and revenues associated with the BFI Project were not included in the 2012-2013 RRA, the Commission directs that:

   a. FEI establish a rate base deferral account for all revenues from the BFI Project excluding revenues in excess of the "take or pay" commitment;

   b. FEI establish a rate base deferral account for all costs for the BFI Project.

…/4

7. If FEI chooses to have its shareholders bear any of the costs which the Commission has found properly attributable to BFI, these amounts are to be identified and reported on a line by line basis and are to be specifically disclosed in and excluded from any future revenue requirement applications.

8 FEI is directed, within 30 days of the date of this Order, to provide the Commission with an updated rate filing, including the details of any amounts to be borne by the shareholder.

DATED at the City of Vancouver, in the Province of British Columbia, this 30th day of April 2012.

BY ORDER

Original signed by:

A.A. Rhodes
Commissioner/Panel Chair

Attachment

IN THE MATTER OF

FORTISBC ENERGY INC.
CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY APPLICATION FOR CONSTRUCTING AND OPERATING A COMPRESSED NATURAL GAS REFUELLING STATION AT BFI CANADA

REASONS FOR DECISION

April 30, 2012

BEFORE:

A.A. Rhodes, Commissioner/Panel Chair
D.M. Morton, Commissioner

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1.0 APPLICATION

On February 29, 2012, FortisBC Energy Inc. (Fortis or FEI) applied to the British Columbia Utilities Commission (BCUC or Commission) seeking:

- A Certificate of Public Convenience and Necessity (CPCN) for the construction and operation of a Compressed Natural Gas (CNG) fuelling station on the premises of BFI Canada Inc. (BFI) pursuant to sections 45 and 46 of the Utilities Commission Act (UCA or Act) and Commission Order G-9-12; and
- Approval of the rate design and rates agreed to as between BFI and Fortis in the Fuelling Station License and Use Agreement made January 31, 2012, pursuant to sections 59 to 61 of the UCA.

  (the BFI Application or BFI Project)

BFI is a waste hauler with operations and facilities in, among other places, Coquitlam, British Columbia. The Coquitlam operation site is designated to serve the City of Surrey. BFI was awarded the contract for curbside waste collection services for the City of Surrey in December of 2011, pursuant to its response to Surrey's Request for Proposals for Municipal Waste Collection Services (RFP). The RFP required the use of natural gas trucks for the waste collection services. BFI's bid for the Surrey work was an annual price of $9,505,923, which was approximately $2 million lower than the next lowest bid. (Exhibit A2-7, p. 10; Exhibit B-1, p. 7)

BFI and Fortis subsequently entered into a contract dated January 31, 2012 (the Fuelling Station Agreement) pursuant to which Fortis is to supply, install and maintain a natural gas compression and dispensing facility on BFI's Coquitlam site. The CNG fuelling facility is to accommodate a return-to-base fleet of 52 waste haul vehicles, which BFI plans to acquire initially, with a potential increase to 86 vehicles in the future. (Exhibit B-1, p. 7)

The fuelling facility will be located on BFI property, but will be owned by FEI. Its primary purpose is to compress natural gas that is purchased by BFI, as an FEI natural gas monopoly distribution customer. BFI will pay FEI for delivery of the "uncompressed" natural gas. BFI will also pay FEI a fuelling charge, under the terms of the Fuel[l]ing Station Agreement, to compress the natural gas and deliver it into BFI's vehicles.

The fuelling facility has an estimated capital cost of $1.9 million. Although this is below the CPCN threshold amount of $5 million that is generally applicable to FEI, the Commission recently established a zero-dollar threshold for projects involving Alternative Energy and other New Initiatives. (Commission Order G-9-12)

FEI proposes to charge BFI a fuelling charge of $4.66/GJ, on a "take-or-pay" basis, with a minimum contract demand of 60,000 Gigajoules (GJ) per year. Over the seven-year term of the contract, this represents a recovery of $1,957,200 (in nominal dollars).

2.0 BACKGROUND

2.1 Regulatory Framework

2.1.1 Definition of a Public Utility

Section 1 of the UCA defines a public utility, in part, as follows: **"public utility"** means a person... who owns or operates in British Columbia, equipment or facilities for

> (a) the production, generation, storage, transmission, sale, delivery or provision of ..., natural gas ...to or for the public or a corporation for compensation...
>
> but does not include …
>
> (e) a person not otherwise a public utility who is engaged in the petroleum industry or in the wellhead production of oil, natural gas or other natural petroleum substances...

Section 1 of the UCA defines "petroleum industry" as including... "(e) the retail distribution of liquefied or compressed natural gas."

The exemption from regulation cited in part (e) of the definition of public utility (above) is of particular applicability to this Application is Only because the Applicant is a public utility, are its activities to provide CNG as a vehicle fuel regulated. An entity that is not "otherwise a public utility" would not be subject to regulation for the provision of the identical service.

2.1.2 Certificate of Public Convenience and Necessity

Subsection 45(1) of the UCA states:

> "Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation."

Subsection 46(3) sets out the Commission's powers with respect to granting a CPCN, and states, in part, that the Commission:

> "...may attach to the exercise of the right or privilege granted by the certificate, terms, including conditions about the duration of the right or privilege under this Act as, in its judgment, the public convenience or necessity may require."

Section 45(8) states that the Commission:

> "… must not give its approval unless it determines that the privilege, concession or franchise proposed is necessary for the public convenience and properly conserves the public interest."

Subsection 46(3.1) requires the Commission, in deciding whether to issue a CPCN to a public utility (other than British Columbia Hydro and Power Authority), to consider British Columbia's energy objectives, which are set out in section 2 of the *Clean Energy Act*, SBC 2010, c. 22 (CEA) as well as the most recent long-term resource plan filed by the utility under section 44.1 of the Act*.*

By Order G-50-10, the Commission provided guidelines to assist public utilities and other parties wishing to construct or operate utility facilities in preparing CPCN applications to facilitate the Commission's review of such applications (CPCN Guidelines).

2.1.3 Setting of Rates

The Commission must address the setting of rates under sections 59 and 60 of the UCA*,* which require that rates are not unjust, unreasonable, unduly discriminatory or unduly preferential.

In this Application, the Panel is further guided by the General Terms and Conditions, as approved by Commission Order G-14-12 for the provision of CNG and Liquefied Natural Gas (LNG) Service (GT&C 12B).

2.2 Waste Management Application – General Terms and Conditions Application

On December 1, 2010, Fortis applied to the Commission for approval of expenditures in the amount of approximately $775,000 for a similar project, being the construction and operation of a CNG fuelling station on the premises of another waste hauler, Waste Management of Canada Corporation (Waste Management). Fortis also sought Commission approval of its contract with Waste Management and approval of General Terms and Conditions for the provision of compression and dispensing services for CNG and the provision of transportation, delivery, storage and dispensing services for LNG for inclusion in future agreements with customers for these services. Approval for the expenditures was sought pursuant to section 44.2 of the UCA. (Waste Management Application)

On July 19, 2011, by Order G-128-11, the Commission, among other things, approved a revised contract between Fortis and Waste Management on a final basis and accepted the expenditures required for Fortis to construct the compression and dispensing facility. The Commission declined to approve the General Terms and Conditions proposed, but indicated that it would approve revised General Terms and Conditions which better reflected full cost recovery from potential CNG/LNG Service customers. It also approved three deferral accounts:

- A non-rate base deferral account attracting an Allowance for Funds Used During Construction (AFUDC) to capture the cost of the Application for General Terms and Conditions for the provision of compression and dispensing service for CNG and for the provision of transportation, delivery, storage and dispensing services for LNG, including the cost of the Application relating to the contract with Waste Management. This deferral account was to be amortized through delivery rates charged to all non-bypass customers over a three-year period commencing on January 1, 2012. *Future individual application costs must be recovered from those customers.* [Emphasis added]
- A non-rate base deferral account attracting AFUDC to capture the Operating and Maintenance costs and the cost of service associated with capital additions to the delivery system as well as CNG and LNG Service recoveries received prior to January 1, 2012 for contracts approved by the Commission, and to recover or refund the balance to all non-bypass customers by amortizing the balance through delivery rates over a three-year period commencing on January 1, 2012.

- An ongoing rate base deferral account to capture incremental CNG and LNG recoveries from actual volumes purchased in excess of minimum contract "take or pay" commitments to be refunded to all non-bypass customers by amortizing the balance through delivery rates over a one-year period, commencing the following year, to be effective as of January 1, 2012.

In its accompanying Reasons for Decision (Waste Management Decision), the Commission Panel questioned whether it was in the interests of Fortis' existing ratepayers to bear the costs or risks associated with the project's benefits, being a reduction of carbon emissions for the transportation sector, when those ratepayers represent only a portion of the province's population and, generally speaking, are not responsible for the emissions. The Panel concluded that Fortis' ratepayers should not bear those costs or risks and should be kept whole; insulated, to the greatest extent possible, from the costs and risks associated with Fortis' entry into the Natural Gas Vehicle (NGV) fuelling business. (Waste Management Decision, p. 17)

The Commission Panel also noted that Fortis was proposing to enter the CNG/LNG fuelling services business in its capacity as a regulated public utility when it was free to do so through a non-regulated subsidiary and thereby avoid Commission oversight. (Waste Management Decision, p. 18) The Commission Panel expressed the view that, to the extent that Fortis intended to provide CNG/LNG fuelling services in its capacity as a public utility, the public interest required that it "do so without utilizing any potential economic leverage which it may have as a result of its status as a monopoly distributor of natural gas". It found that the public interest would not be served by effectively providing Fortis with a competitive advantage over other potential industry participants if Fortis were able to subsidize the cost of what would otherwise be an unregulated service, with monies from existing ratepayers. It also found that Commission approval of a tariff for the provision of CNG/LNG fuelling services would not result in any corresponding obligation on the part of Fortis to serve other potential customers. (Waste Management Decision, pp. 19, 29)

The Panel in the Waste Management Application also required that Fortis include a provision in its General Terms and Conditions requiring the CNG/LNG Service customer to bear the risk of the stranding of fuel station assets and directed that the ratepayer be insulated from any risk relating to the long-term viability of the CNG/LNG transportation fuel market to the fullest extent possible. The Panel also rejected Fortis' argument that it needed flexibility to negotiate different terms with different customers in favour of a more structured, standard form approach to the draft General Terms and Conditions for which approval was sought. (Waste Management Decision, pp. 22-23)

The Panel found that it was not "just and reasonable" for Fortis' ratepayers to subsidize the cost of CNG/LNG fuelling facilities. The Panel found:

> "[a] CNG or LNG facility is not an extension of the distribution system.... If a CNG station...were provided by an unregulated entity, there would be no requirement, or need, for existing ratepayers to share the cost of providing the facilities, yet they would still benefit from increased throughput in [Fortis'] distribution system."

The Panel therefore "require[d] that, to the extent possible, none of the actual costs of the CNG/LNG service offerings be recovered from existing ratepayers." (Waste Management Decision, p. 24)

In accordance with this line of reasoning, the Panel required that, to be approved, any General Terms and Conditions would need to use actual, as opposed to forecast, construction costs, charge all O&M costs to the cost-of-service calculation without reduction for capitalized overhead and escalated in accordance with the British Columbia Consumer Price Index, include negative salvage value and also include an allocation of estimated overhead and marketing costs (among CNG/LNG customers only) in the cost-of-service calculation as reflected in the General Terms and Conditions. The Panel stated: "...to be approved, any General Terms and Conditions must include a cost of service calculation which reflects the actual full cost of service, including the cost of establishing, maintaining and promoting the program, as closely as possible." (Waste Management Decision, p. 28)

Also pursuant to this line of reasoning, the Panel directed that Fortis include a provision to ensure that the entire cost of the fuelling station be recovered from the customer over the term of the contract in any revised General Terms and Conditions. (Waste Management Decision, p. 29)

The Panel also directed Fortis to keep the costs and revenues associated with the Waste Management Agreement and any other offerings separate and distinct, to be monitored over a two-year test period, with a detailed report to be provided by March 31, 2013. (Waste Management Decision, pp. 30-31)

Revised General Terms and Conditions Section 12B (GT&C 12B) were filed on February 6, 2012, and approved by Commission Order G-14-12 dated February 7, 2012. GT&C 12B uses a Cost of Service model and specifies that "[t]he total costs to be used in determining the cost of service to be recovered from the Customer under the Service Agreement include, *without limitation*:

> (a) the actual capital investment in the fuel[l]ing station including any associated labour, material, and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or nonfinancial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;
>
> (b) depreciation and net negative salvage rates and expense related to the capital assets associated with the vehicle fuel[l]ing station;
>
> (c) all operating and maintenance expenses, with no adjustment for capitalized overhead, necessary to serve the Customer, escalated annually by British Columbia CPI inflation rates as published by BC Stats monthly; and
>
> (d) an allowance for overhead and marketing costs relating to developing NGV Fuel[l]ing Station Agreements to be recovered from the Customer." [Emphasis added]

In addition to the costs identified, GT&C 12B requires the cost of service recovery to include applicable property and income taxes and the appropriate return on rate base as approved by the Commission for FEI.

2.3 Alternative Energy Solutions Services Inquiry

By Order G-95-11 dated May 24, 2011, the Commission established an Inquiry into Fortis' offering of products and services in Alternative Energy and other New Initiatives (AES Inquiry). One of the issues in the AES Inquiry is the appropriateness of Fortis' entry into the competitive domain of CNG/LNG fuelling. That Inquiry is ongoing.

By Order G-1-12 dated January 4, 2012, and Order G-9-12 dated January 31, 2012, the AES Inquiry Commission Panel established a zero-dollar threshold for CPCN applications relating to AES and other New Initiatives projects on an interim basis, pending completion of the Inquiry.

Appendix A to Order G-118-11: Scope of the AES Inquiry, the AES Inquiry Panel emphasized it does not intend to frustrate ongoing business:

> "The Panel agrees that it is not appropriate for this Inquiry to be used as a vehicle to re-open past Decisions of the Commission. With respect to ongoing processes that may have some degree of overlap with the issues being considered by this proceeding, the Panel believes that such processes will be decided on the basis of the evidence put before them. While it may be beneficial to have the outcome of this proceeding known before similar issues are dealt with in other ongoing proceedings, it would be inefficient and potentially unfair for such proceedings to be delayed. The Panel sees the outcome of this proceeding as being applied in a forward looking manner and not impinging on past or current ongoing proceedings." (Order G-118-1, Appendix A, p. 5)

3.0 CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY CONSIDERATIONS

3.1 Project Need and Justification

FEI submits that the City of Surrey's mandate for using CNG powered waste collection vehicles gave impetus to BFI's CNG fuelling station, the BFI Project advances British Columbia's energy objectives and the Project cost is reasonable. (FEI Final Submission, p. 10)

In the Waste Management Application, FEI argued that it was unaware of other businesses with the requisite expertise and technical capability to develop the fuelling station market in British Columbia that had also committed to do so. FEI did acknowledge that other non-regulated options had been available in the market for a number of years, but argued that the NGV market had stagnated prior to its promotion of CNG/LNG Service as a regulated offering. FEI took the position that if it did not provide the [regulated] service to "kick-start" the market, the market would not develop as quickly. (Waste Management Application, FEI Final Argument, pp. 23-24)

FEI also argued that "mandating that assets be held in a Non-Regulated Business ("NRB") would be inappropriate and counterproductive." (Waste Management Application, FEI Final Argument, p. 23)

With respect to the need for FEI, as a regulated public utility, to provide the compression and dispensing service to BFI, "FEI acknowledges the CNG/LNG fuel[l]ing service can be provided by a non-public utility third party in British Columbia" and lists a number of reasons BFI decided to work with FEI after a competitive bidding process. These reasons include, among other things, that the service was "competitively priced." FEI argues that since BFI chose FEI, it is necessary for FEI to provide the fuelling service. (FEI Final Submission, pp. 6-7)

The British Columbia Sustainable Energy Association (BCSEA) supports FEI's CPCN application, but submits that its support is "… limited to FEI's proposed focus on providing CNG and LNG service to the heavy duty vehicle sector in B.C., as distinct from the passenger vehicle sector where the current and anticipated availability of hybrid-electric and plug-in electric vehicles creates a very different GHG-reduction analysis." However, it further

submits that "… the Commission should conclude that the BFI fuel[l]ing project is in the public interest and warrants a CPCN." (BCSEA Final Submission, pp. 1, 4)
The Commercial Energy Consumers Association of British Columbia (CEC) submits that the proposed BFI refuelling station can be clearly seen to be in the public interest. It further submits that it has demonstrable benefits for FEI customers and notably demonstrable benefits for BFI's customers. (CEC Final Submission, p. 2)

3.2 Analysis of Alternatives

FEI states that the BFI Project is at the request of a customer and will be built to serve this particular customer's need and that this is unlike the usual CPCN applications to build and operate energy infrastructure. It submits that since BFI had decided to use CNG trucks for its waste collection services before contacting FEI, no analysis of alternatives is necessary. (Exhibit B-1, p. 5)

3.3 Public Consultation

FEI submits that, since the refuelling station will be completely built and operated on BFI's premises, its installation and operation will have little potential effect on First Nations and the public. Thus, FEI has not included any discussion on public and First Nations consultation in the BFI Application. Nor has FEI identified and assessed potential effects of the BFI Project on First Nations and the general public in terms of the physical, social or biological environment. FEI further submits that this is consistent with what was done for Waste Management. (Exhibit B-1, p. 5)

3.4 Alignment with Energy Policy

FEI estimates, using the GHGenius Model v3.20, that the greenhouse gas (GHG) emissions reduction of this project is 419 tonnes per year. It further states that this is equivalent to taking 75 passenger cars off the road. (Exhibit B-1, pp. 8-9)

FEI further states that any potential GHG emission reduction offsets generated by the operation of these CNG trucks will flow to BFI, but that FEI understands that BFI is obligated to pass these benefits on to the City of Surrey. (Exhibit B-1. p. 9)

The CEC submits that FEI has established that the proposed CNG Service will be aligned with government energy objectives and that it will create a significant impact on reducing GHG emissions. (CEC Final Submission, p. 2)

3.5 Project Benefits

Fortis attributes a number of benefits to the BFI Project including reduced fuel cost for BFI due to the lower cost of natural gas as compared to diesel, which may translate into a lower waste collection charge to the City of Surrey, benefitting Surrey residents; reduced GHG emissions of approximately 419 tonnes per year (based on 52 vehicles) and royalties to the Province flowing from natural gas production from Crown leases. (Exhibit B-1, pp. 8-9)

FEI also claims a small delivery rate benefit to existing natural gas ratepayers in the approximate amount of $84,000 per year from increased natural gas sales, which corresponds to a savings of approximately seven cents per year per Lower Mainland residential customer, all else equal. (Exhibit B-1, pp. 10-11)

Fortis also submits that the BFI Project is consistent with the most recent Long-Term Resource Plan filed by the Fortis Energy Utilities, which contemplated natural gas vehicle initiatives as part of a low carbon strategy. (Exhibit B-1, p. 11)

3.6 Public Interest

A significant public interest issue is that of a regulated entity operating in a competitive market and the potential for cross-subsidization of its new offerings by its existing ratepayers. The Waste Management Panel noted that FEI's CNG/LNG activities are subject to regulation only because it is otherwise a monopoly, and the regulatory framework exists to protect the public from the abuse of monopoly power. The Panel found that if FEI is to provide CNG/LNG Services in its capacity as a public utility, it must do so without utilizing any potential economic leverage which it may have as a result of its status as a monopoly distributor of natural gas. (Waste Management Decision, p. 18)

In response to questions about FEI's long-term role in the NGV market, FEI has clearly stated its intention to remain in the CNG/LNG market in its capacity as a regulated public utility. While FEI acknowledges that in the Waste Management Application it submitted that it should build fuelling facilities to "kick-start" the market, it asserts that at no time did it suggest that such offerings would be withdrawn once other participants entered the competitive marketplace. (Exhibit B-3, BCUC IR 1.3.1)

FEI relies on the opinion of its expert, Dr. Ware, in the AES Inquiry to the effect that 'if a regulated entity such as FEI is able, *without cross-subsidization from gas ratepayers*, to bring a cost effective service offering to the natural gas fuel[l]ing market the participation by FEI "would exert a valuable disciplinary force on the costs of rival suppliers." (Exhibit - B-3, BCUC IR 1.3.3) [Emphasis added]

As a result of concerns about the effect of unbudgeted costs, cost overruns and other factors that could require ratepayer subsidization, the Waste Management Panel directed that none of the actual costs of the CNG/LNG Service offerings be recovered from existing ratepayers (Waste Management Decision, p. 24). The Panel also directed that ratepayers were to be insulated from the risk in assuming the long-term viability of the NGV market, to the fullest extent possible.

3.7 Commission Panel Determination

As discussed elsewhere in this Decision, the BFI Application fails to adequately address these concerns.

The Commission Panel accepts that BFI's use of CNG as a fuel in place of diesel will reduce GHG emissions in the province and that the BFI Project is not inconsistent with Fortis Energy Utilities' (FEU) most recent Long-Term Resource Plan. **The Panel is generally satisfied that the compression facilities for the BFI Project meet the CPCN Guidelines and grants the CPCN.** However, in doing so, it has a number of significant concerns.

First, the Panel notes that the concept of a CPCN – a Certificate of Public Convenience and Necessity – was developed historically as a means to regulate capital projects of private companies operating in a monopoly environment. A CPCN is generally applied for, and granted, for a project that lies within the franchise area of the applicant, where no other company is in a position to undertake the project. In such circumstances, it is incumbent on the applicant company to show that the project is necessary, and, once it has done so, some or all of the costs of the project may be recovered from a broad base of its ratepayers. It is important to note that in the case of the BFI fuelling station, there is no exclusive franchise area for CNG fuelling services and any company could build the compressor station. Further, if another company did so, it would not be subject to regulation (provided that it is "not otherwise a public utility") and a CPCN would not be necessary.

This issue was explored in some detail in the Waste Management Application and is also a key issue in the ongoing AES Inquiry. Accordingly, this Panel makes no determinations on whether FEI should or should not be participating in this activity in its capacity as a regulated public utility in this Proceeding. However, the Panel is mindful that there are competitive aspects to the Natural Gas for Transportation (NGT) marketplace and finds that the public interest requires the Panel to ensure that granting this CPCN does not impose unfair burdens on either FEI's ratepayers or other companies seeking to provide a similar service.

The Panel finds the presence of both regulated and unregulated competitors in a competitive market is problematic. It underscores the need for this Panel to ensure that there is no cross-subsidization from FEI's distribution customers and also that there is no assignment of CNG/LNG-related risk to those customers. In this regard, the Panel notes that the recent Commission decision dated March 9, 2012 in FortisBC Energy Inc.'s Application for a CPCN to provide Thermal Energy Service to Delta School District No. 37 (the Delta School District Decision) was informed by the regulatory principle that a competitive service provider that is also a natural monopoly requires active Commission oversight to reduce the potential for cross-subsidization between the competitive service and the natural monopoly service. The Panel is encouraged that FEI agrees with this principle, as is evidenced by its assertion that its role in the marketplace should be "without cross-subsidization from gas ratepayers." Later in this Decision, the Panel will address how this goal can be achieved.

The Panel does not agree with FEI's position as to the relationship of the CNG Service to the natural gas system. In the Waste Management Decision, the Panel found that "…a CNG or LNG refuelling facility is not an extension of the distribution system." (Waste Management Decision, p. 35) This Panel finds that circumstances have not changed in any way that would cause that finding to be different in this case. Since the CNG Service is not an extension of the existing service, it is irrelevant whether BFI is an existing customer or not. The CNG Service is a new class of service for FEI, with only a single existing customer – Waste Management – already taking that service. Further, the Panel notes that the CNG Service is downstream of the meter, so it is in no way the same service as FEI's monopoly distribution business. Of additional concern to the Panel is the fact that no material benefits accrue to Fortis' existing ratepayers from the BFI Project yet they are being asked to bear risk as well as to fund any costs which have not been included in the rate to be paid by BFI. This finding flows from the fact that the City of Surrey mandated the use of NGVs and BFI made the decision to purchase NGVs, hence requiring natural gas as a fuel. Thus, little to no incremental benefits flow to Fortis' ratepayers as a result of Fortis' construction, ownership and operation of a CNG fuelling facility. A third party could perform this task and the same throughput benefit claimed throughout the BFI Application (i.e., $84,000 per year or a $0.07 reduction in Lower Mainland residential customers' annual bills) would follow. There are no alternatives for BFI to obtain natural gas other than through the Fortis monopoly natural gas distribution system. The same is true of the claim for GHG reduction benefits and for royalty revenues to the Province, although in the case of royalty revenues, there is also no evidence that the incremental natural gas to be purchased by BFI would necessarily come from Crown leases in British Columbia or that the royalty revenue would be forgone if a fuelling station was not constructed for BFI.

The only arguable benefit which could flow to existing Fortis ratepayers would be sourced in the $0.20 per GJ contribution towards overhead included in the fuelling charge, discussed in the next section. Assuming 60,000 GJs per year, this would amount to $12,000 per annum or less than a $0.01 reduction in the annual bill for existing Lower Mainland residential ratepayers. (This also assumes that there is no increase to overhead costs as a result of the BFI Project.)

4.0 RATE DESIGN ISSUES

The proposed charge to BFI for FEI to recover the cost of the CNG facility is structured by way of an annual commitment from BFI to take delivery of, or pay a fuelling charge of $4.66 per GJ for, a minimum volume of 60,000 GJs of CNG (the "take or pay" commitment). The contract term is seven years (expiry date is September 30, 2019) and is renewable at the option of the customer (BFI) for a further term of three years. Over the course of the initial contract term, this equates to 1,153 GJs per vehicle per year, based on 52 vehicles.

The fuelling charge amounts are broken down as follows:

Component	Fuelling Charge $/GJ	Escalation Per Year
Capital	$3.63	2%
O&M	$0.83	CPI
Overhead	$0.20	CPI
Total Charge	**$4.66**	

(Source: Exhibit B-1, p. 17, Table 6)

Volumes in excess of 5,000 GJs in any month are charged at the O&M rate plus one half the capital rate (as set out above). (Exhibit B-1, pp. 7, 11; Exhibit B-1, Appendix A, section 7.1(c); Exhibit B-1, Appendix A, section 1; Exhibit B-3, BCUC IR 1.24.1)

Volumes in excess of 60,000 GJs per annum (the "take or pay" amount) are therefore proposed by FEI to be charged at approximately $2.845/GJ. (Exhibit B-3, BCUC IR 1.39.1 – numbers may vary slightly due to rounding)

The Fuelling Station Agreement provides that the "take or pay" volume and rates have been based on a 20-year term, notwithstanding the actual seven-year term of the contract (with a provision for a three-year extension). The Fuelling Station Agreement provides, among other things, that if it is terminated without cause before the 20th anniversary of its effective date, BFI will pay, at a minimum, the remaining unrecovered, un-depreciated capital cost of the fuelling station (Buy Out Provision). (Exhibit B-1, Appendix A, clause 11.1)

The Fuelling Station Agreement also provides, however, that "[t]he payments received [from BFI] with respect to the Capital Rate pursuant to section 7.1(c), [which determines the rate payable for volumes of CNG taken in excess of the annual 60,000 GJs "take or pay" amount], if any, will be applied to the...capital cost calculation...to reduce the un-depreciated capital cost of the Fuel[l]ing Station" (Exhibit B-1, Appendix A, Schedule B) Thus, to the extent that BFI takes CNG volumes in excess of its "take or pay" commitment, it will receive a credit of one half of the capital rate of $3.63 per GJ, or $1.815 per GJ towards any un-depreciated capital cost it would otherwise be required to pay when the Buy Out Provision is triggered.

Consequently, if the Buy Out Provision is not triggered, FEI's non-bypass customers will receive a possible benefit of $2.845/GJ for volumes in excess of 60,000 GJ (assuming that the O&M charge is not variable with volume). If the Buy Out Provision is triggered, non-bypass customers would receive only a possible benefit of $1.033/GJ for volumes in excess of 60,000 GJ, again assuming that O&M is not variable with volume. (Exhibit B-3, BCUC IR 1.39.1, BCUC IR 1.43.1)

Fortis takes the position that the service charge to BFI complies with GT&C 12B. Fortis also submits that where it has deviated from the requirements of the approved General Terms and Conditions, it has taken adequate steps to mitigate ratepayer risk. However, it also states that it "does not foresee conditions where [Natural Gas for Transportation] losses would be borne by the shareholder." (Exhibit B-3, BCOAPO IR 1.4.2)

The British Columbia Old Age Pensioners' Organization (BCOAPO) suggests that "[s]ince FEI's shareholders receive a significant return on investment, it is reasonable that they also assume some risk for the potential failure of the BFI Agreement and other NGT related opportunities FEI may wish to pursue in the future. Accordingly, BCOAPO requests that the Commission consider the need to include a risk factor for extraordinary events in the calculation of cost of service." The BCOAPO also submits that if the Commission determines that GT&C 12B does not appropriately insulate captive ratepayers from the costs and risks associated with FEI's provision of NGT services, GT&C 12B should be revisited and the BFI Agreement approved on an exception basis only. (BCOAPO Final Submission, pp. 4, 6)

With regard to potential cross-subsidization and the assumption of risk by FEI's distribution customers, Clean Energy Fuels submitted, in the AES inquiry, that any regulated gas distribution utility "…should be precluded from using ratepayer funding to build, own and operate CNG or LNG refueling stations that are primarily intended to compete directly with refueling stations owned by non-utility enterprises. Ratepayer funding should be limited to the construction of refueling stations located on utility property that are needed to refuel the utility's fleet natural gas vehicles (NGVs). Public access refueling services should only be provided from such facilities when the retail refueling price is sufficiently high to recover the fully allocated cost of service..." (Exhibit A2-8, p. 3)

The BCOAPO submits that the delivery revenue margin of $84,000 per year, which accrues to FEI's natural gas ratepayers, provides a benchmark for the maximum level of reasonable cost and risk that can be imposed on ratepayers. (BCOAPO Final Submission, p. 2)

BCSEA submits that: "…it appears that the BFI Service Agreement does conform with section 12B, however BCSEA is not in a position to verify that conclusion because it has not conducted a detailed analysis and does not have access (by choice) to FEI's confidentially filed evidence." (BCSEA Final Submission, p. 5)

CEC submits that the rate for the BFI refuelling service is fair, just and reasonable and that the Commission can approve the rate as in the public interest. (CEC Final Submission, p. 4)

4.1 Capital Costs

4.1.1 Construction Costs

The General Terms and Conditions require actual construction costs to be used in the rate calculation. However, Fortis has chosen to use forecast as opposed to actual construction costs in determining the capital component of the fuelling charge, although if the actual cost varies from the forecast cost by plus or minus two percent the parties have agreed to amend the charge. Based on the expected construction costs, the variance limit is $37,000, the impact of which Fortis argues is immaterial to delivery rates for natural gas customers.

The BCOAPO submits that this "…imposes an acceptable level of risk on ratepayers." (BCOAPO Final Submission, p. 2; Exhibit B-1, p. 15; Exhibit B-3, BCUC IR 1.33.5)

4.1.2 Capital Cost Recovery

The capital component of the fuelling charge is based on the (forecast) cost to construct the fuelling facility of $1,885,259. This component of the fuelling charge will recover depreciation expense for the plant in service, including negative salvage, over the seven-year contract term. It also recovers property taxes, income taxes and earned interest. (Exhibit B-1, pp. 17-18)

The rate of return is based on a mix of 40 percent equity at a rate of 9.5 percent, 58.37 percent long-term debt at a rate of 6.95 percent, and 1.63 percent short-term debt at a rate of 4.5 percent. (Exhibit B-1, Appendix D, Schedule 10) FEI states that the fuelling charge will not be adjusted to reflect changes in the approved return on equity, debt rates or capital structure during the term of the BFI Agreement. (Exhibit B-3, BCUC IR 54.1.1, p. 128)

As discussed above, BFI is obliged to pay the un-depreciated capital cost of the fuelling station asset at the end of the contract, or when the Buy Out Provision is triggered. (Exhibit B-1, p.16, Exhibit B-1, Appendix A, subsection 11.1) However, Fortis has agreed to credit BFI with the capital rate amounts it pays on any fuel purchases in excess of the 5,000 GJs monthly “take or pay” commitment, to reduce the un-depreciated capital cost it would otherwise owe. (Exhibit B-1, Appendix A, subsection 7.1(c), Schedule B)

4.1.3 Cost of this Application

Although specifically instructed to do so in the Waste Management Decision, Fortis did not include the costs of the BFI Application in the fuelling service charge. It estimates the cost of the BFI Application to be in the order of $75,000. Fortis takes the position that it did not include these costs because it did not expect the associated regulatory process to be as lengthy. (Exhibit B-3, BCUC IR 1.46.2, 1.147.2)

The BCOAPO submits that in future applications, the estimated cost of the regulatory process should be included in the cost-of-service calculation. (BCOAPO Final Submission, p. 3)

4.2 O&M Costs

Fortis has calculated the $0.83 per GJ charge for O&M from an estimated operating and maintenance cost of $50,000 per year, which it advises is based on its previous experience maintaining fuelling stations. No portion of the O&M charge is capitalized. (Exhibit B-1, p. 18) The O&M cost estimate includes:

- Regular maintenance labour
- Emergency call out labour
- Regular preventative maintenance parts
- General repair parts
- Major overhauls
- Recertification of relief valves – bi-annual
- Regulatory inspections and permits
- Communications lines (phone and internet)

- External contractors (control systems changes and electrical)
- Emergency calls for service
- Waste oil and dryer water disposal

(Exhibit B-3, BCUC IR 1.41.1.2)

BCOAPO states that it is satisfied that the Service Charge includes a reasonable estimate of FEI's normal operating and maintenance costs, but hopes that in the future, as FEI's experience with operating NGT fuelling stations grows, ordinary O&M costs can be more accurately tracked and forecast to ensure there is a match between actual operation costs and the forecasts used in the cost-of-service calculation. (BCOAPO Final Submission, p. 2)

4.2.1 Branding Costs

The Fuelling Station Agreement entitles Fortis to install signage within the fuelling station area (which is to be situated on the premises of BFI), and also allows Fortis to affix its corporate logo and other branding and marketing materials to the exterior of the fuelling station, and to attach decals to the exterior of the vehicles owned by BFI advertising the vehicles as being powered by natural gas by Fortis. (Exhibit B-1, Appendix A, clauses 5.5, 5.6)

Fortis estimates the cost of affixing signage to the fuelling station to be approximately $265 and the cost of affixing decals to 52 vehicles to be approximately $2,500 based on past experience. These costs are not proposed to be charged to the BFI Project but to the general communications budget for the account of existing ratepayers. (Exhibit B-3, BCUC IR 1.50.1)

The BCOAPO submits that ratepayers should not bear the cost of corporate branding for the BFI fuelling station and trucks because the benefits of goodwill, including the name recognition function of corporate branding, accrues primarily to FEI's shareholders, not to its ratepayers. (BCOAPO Final Submission, p. 4)

4.2.2 Unanticipated Events and Insurance Costs

The application is silent on costs arising from unanticipated technical or environmental issues. In its final submission, BCOAPO expresses concern that there does not appear to be any monetary allocation for bearing the risks associated with extraordinary events: "For example, does FEI carry insurance to cover costs arising out of unexpected technical or environmental failures? If so, what deductible applies, and how is FEI compensated for being at risk on the deductible or for premium increases consequent on making a claim?" (BCOAPO Final Submission, p. 3)

BCOAPO also raises the issue of a hypothetical BFI insolvency. It submits, all else being equal, the longer the contract term, the greater the risk of insolvency. FEI states that it has performed an internal credit assessment and deemed BFI to be approved for service with no security requirements. BCOAPO submits that since there is no way to determine the adequacy of FEI's internal credit assessment or to estimate the risk of a BFI credit default, it may be appropriate for the Commission to require security or, alternatively, to weigh the relative costs and benefits of such a requirement and provide guidance as to when security may be appropriate and the form it should take. (Exhibit B-3, BCUC IR 1.33.1.1; BCOAPO Final Submission, p. 3)

4.3 Overhead, Marketing, Business Development and Customer Education Costs

In the Waste Management Decision, the Commission required that to be approved, any General Terms and Conditions Section 12B would need to "include a cost of service calculation which reflects the actual full cost of service, including the cost of establishing, maintaining and promoting the program, as closely as possible." It directed "that any revised General Terms and Conditions contain a provision whereby FEI will estimate the overhead and marketing expenses which relate to the CNG/LNG program and the expected CNG/LNG sales volume and allocate those costs in a reasonable manner among CNG/LNG customers going forward." (Waste Management Decision, p. 28) As a result, the approved revised GT&C 12B require an allowance for overhead and marketing costs relating to developing NGV fuelling station agreements to be recovered from the Customer.

In the FEU's 2012-2013 Revenue Requirements Application (2012-2013 RRA), Appendix I, Fortis estimated costs for development of its NGT business to be $480,275 and $551,637 for 2010 and 2011, respectively. These amounts "represent the cost associated with contacting, signing up customers to FEI Rate Schedules and fuel[l]ing station agreements, customer education, as well as short and long term business development activities." (Exhibit B-1, p. 19) FEU forecast these costs to increase to $569,396 in 2012 and $601,119 in 2013 (Exhibit B-3, BCUC IR 1.51.99)

In this Application, FEI submits that a reasonable cost allocation for overhead and marketing recovered under Section 12B of FEI's GT&Cs should be limited to the incremental cost associated with adding a new CNG/LNG fuelling service customer. It states that NGT activities such as customer education and long-term business development are not directly related to the cost of adding incremental CNG/LNG Service customers such as BFI. To this end, it has included an amount of $0.20 per GJ to recover a portion of the overhead and marketing costs which relate to the CNG/LNG Service program. FEI estimates this based on the assumption that its Commercial and Industrial Manager (now known as its Natural Gas for Transportation Sales Manager), spends approximately 25 percent of his time signing up new CNG/LNG Service customers. This cost of this position is $131,762 per year, a quarter of which amounts to approximately $33,000. Fortis further estimates that it will sell 163,489 GJs of CNG/LNG Service in 2012. This number is derived from estimated sales to the following customers:

Customer	**Amount (GJ)**
Waste Management	30,000
Kelowna School District	5,000
BFI	15,000
Vedder	113,489
TOTAL	**163,489**

(Source: Exhibit B-1, p. 19)

Fortis then calculates the incremental cost for a new CNG/LNG Service customer by dividing the cost of one quarter of the manager's time by the total estimated GJ sales for 2012 of 163,489 GJs. Consequently, the only cost included in the CNG/LNG Service overhead component is a portion of one manager's time.

4.4 Termination for Cause

The BCOAPO submits that, if BFI terminates the BFI Agreement for cause, BFI can require FEI to remove the fuelling station without compensation and at FEI's cost. It further submits that while it is uncommon for parties to enter into contracts with the intention of breaching them, if a breach occurs, or even if one is alleged, FEI's residential ratepayers will likely suffer the consequences. (BCOAPO Final Submission, p. 3) There is no contingency provided for termination for cause.

4.5 Commission Panel Determination

The Commission Panel has a number of concerns with the proposed rate and with the potential for the assumption of risk by FEI's distribution ratepayers. Of paramount concern is the fact that no unique, material benefits accrue to Fortis' existing ratepayers from the BFI Project by virtue of FEI's expenditures for this CPCN, yet they are being asked to bear a number of risks in addition to funding any costs which have not been included in the rate to be paid by BFI. This result flows from the fact that the City of Surrey mandated the use of NGVs so that any successful proponent for the RFP was compelled to use natural gas, and they could have contracted with any company to compress that gas for their delivery trucks. In any other circumstance, the resultant amount of natural gas used would be exactly the same. The demand for natural gas is driven by the City of Surrey's garbage collection requirements, not by the choice of operator of the compression facility.

As the BFI fuelling station is located in FEI's distribution franchise area, there are no alternatives for BFI to obtain natural gas other than through the Fortis monopoly natural gas distribution system. Thus the Panel particularly disagrees with the BCOAPO's suggestion that the delivery margin is a "benchmark for the maximum level of reasonable cost and risk that can be imposed on ratepayers." Given that the ratepayers would receive the delivery margin benefit no matter what organization was awarded the CNG compression and fuelling contract, the Panel considers $0 to be a more appropriate benchmark for the maximum level of reasonable cost and risk that can be imposed on ratepayers.

As discussed, there are also a significant number of costs that have not been included in the Cost of Service calculation. The Panel declines to approve the recovery from FEI's existing ratepayers of this under-allocation of costs. **Accordingly, the Commission Panel declines to approve the rate proposed to be charged to BFI. FEI is directed to either revise the rate or, alternatively, to ensure that any amounts which relate to the BFI Project and are not borne by BFI are borne by the shareholder and not the ratepayer. Amounts to be borne by the shareholder are to be identified and reported on a line by line basis and are to be specifically disclosed in and excluded from any future revenue requirement applications.**

Also of concern to the Panel is the allocation of marketing, business development and customer education and other overhead expenses. There were approximately $1 million in expenses associated with NGT incurred in F2010 and F2011. FEI has provided a forecast of the amounts to be spent going forward, which exceed the amounts spent in 2010 and 2011, but argues that GT&C 12B requires only the incremental cost of the BFI addition to be charged to BFI. Fortis provides an amount of some $33,000 annually as that incremental cost. This represents the cost of 0.25 FTE. No other justification has been provided for that amount. (Exhibit B-1, p. 19)

FEI argues that it is taking the lead in the development of the NGT market in the province and also that NGT activities such as customer education and long-term business development are not directly related to the cost of adding incremental CNG/LNG Service customers such as BFI. Presumably for this reason, it has excluded most of the overhead costs from the Cost of Service calculation for BFI's rate. To the extent that FEI is indeed taking the lead, the Panel agrees that there may be an argument that some of the business development costs may not be directly attributable to FEI's fuelling station customers and could be borne by the distribution ratepayers. However, in this regard, the Panel points out that in the case of a competitor also promoting NGT, none of its business development activities will be subsidized by FEI's distribution ratepayers, even though those activities would, in all likelihood, similarly result in increased throughput and therefore lower prices for FEI's distribution customers. In this eventuality, the competitor would also have long-term business development costs which would include customer education and these costs would not be recoverable from FEI's distribution ratepayers. In any event, the Panel has seen no evidence that FEI is kick-starting a market on behalf of other companies who may provide compression services. On the contrary, it appears to the Panel that FEI's marketing and business development activities have primarily been focussed on the development of its own fuelling station business.

The issue of cross-subsidization was thoroughly examined by the Waste Management Panel. Further, GT&C 12B was specifically intended to address cross-subsidization issues. Cross-subsidization and its potential effect on competition is also an issue for the AES Inquiry. However, this Panel is not of the opinion that there is a need to wait until that Inquiry is completed in order to reach a decision on this matter. The AES Panel has clearly stated that the AES Inquiry is forward looking and is not intended to impinge on any current proceeding and that such proceedings should consider the evidence before them. Accordingly, this Panel will further direct FEI in how the issues of cross-subsidization and risk due to be addressed.

The Panel disagrees with both FEI's interpretation of GT&C 12B, and with its calculation; use of an "incremental portion" of its overhead and marketing costs. GT&C 12B states that an allowance for overhead and marketing costs relating to developing NGV fuelling station agreements is to be recovered from the customer. This means that overhead and marketing costs, including, without limitation, business development, customer education and all other costs relating to the CNG/LNG Service program, should be allocated proportionately, not incrementally, to NGT customers. When a business venture is initiated, there is no way of knowing what the actual business development and marketing costs will be, just as there is no way of knowing what the actual sales will be. However, it is incumbent upon a nascent business to arrive at an estimate of these amounts, in order to come up with an input cost for its pricing model. If actual costs are greater than estimated, the business is faced with choices such as: attempting to recover additional costs from customers that have already taken service; recovering such costs from future customers; or failing to recover such costs, which would impact investors. If actual costs are less than estimated, the business is at risk of having over-priced its offering and thus possibly being less successful than planned.

The Panel requires FEI to structure its cost recovery of overheads proportionately for two reasons. First, it ensures that there is no cross-subsidization from distribution customers. Second, importantly, in the NGT market FEI is potentially competing with other unregulated organizations. In this regard, the Panel notes Clean Energy Fuels' concerns. Generally speaking, none of FEI's potential competitors has access to a large group of customers in a regulated monopoly market that is available to assume risk, cost overruns and start-up costs of an NGT venture. To allow FEI access to its ratepayer base in this manner is neither just nor fair.

Previously in this Decision, we have discussed FEI's position that the NGT business is an extension of the natural gas distribution service. The Waste Management Panel disagreed with this characterization as discussed in the Waste Management Decision. This Panel concurs. The NGT business is "downstream of the meter" and it is not a natural monopoly, unlike the regulated distribution franchise. The Panel considers that those taking service under GT&C 12B are not in the same customer class as are any of FEI's existing distribution customers (at least in respect of the service taken under GT&C 12B – an NGT customer may also be a distribution customer). Further, the Panel considers that there are sufficient differences between the nature of CNG Service and LNG Service that it would be premature to conclude that these services should be contained within the same class.

Accordingly, the Panel directs that FEI establish two new service classes, one for CNG Service and one for LNG Service.

The employment of appropriate and approved cost allocation methodologies and policies would serve to alleviate the Panel's concerns relating to cross-subsidization of the new classes by existing ratepayers. In the Panel's further view, this is of particular importance here, where it has found that the benefits to Fortis' ratepayers from the Fuelling Service Agreement are negligible.

The Panel re-affirms the following Commission directives in the Waste Management Decision and confirms their applicability to this Decision:

1. **Estimate the overhead and marketing expenses which relate to the CNG/LNG Service program and the expected sales volume and allocate those costs in a reasonable manner among CNG/LNG Service customers going forward.**

2. **Keep the costs and revenues associated with the Waste Management Agreement and any other offerings separate and distinct, monitor such offerings during a two-year test period and provide a report by March 31, 2013, which includes the topics listed in Appendix 2 of the Waste Management Decision.**

The Panel further directs:

1. **All overhead and marketing expenses referred to above, including, without limitation, business development, customer education and all costs relating to the CNG/LNG Service program are to be determined using approved fully allocated cost of service methodology and included in the cost of service.**

2. **Fortis to recalculate the Operating and Maintenance charge in the BFI rate to reflect the cost of the CNG/LNG Service program using the figures of $569,396 for 2012 and $601,119 for 2013, to be allocated in a reasonable manner.**

3. **Therefore, in order to set a fair and equitable rate which is not unjust or unreasonable within the meaning of section 59 of the *Utilities Commission Act*, and that therefore reflects the full cost of service of this offering, for more particularity, Fortis is to include the following amounts in the rate applicable to BFI:**

   - **Actual construction costs for the BFI fuelling station;**
   - **Cost of the BFI Application in the amount of $75,000;**
   - **Branding costs for the installation of signs and to affix decals;**
   - **BFI's proportionate share of the overhead and marketing costs, including, without limitation, business development, customer education and all costs relating to the CNG/LNG Service program;**
   - **Any other costs which may not have been factored into the cost charged to BFI including, for example, increased insurance premiums, as Fortis is required to obtain a number of specific**

insurance coverages, and to include BFI as an additional party insured on its Comprehensive General Liability Policy.

4. **Fortis to establish a rate base deferral account to capture the revenues associated with volumes in excess of BFI's "take or pay" commitment which may be credited back to BFI in the event that BFI is required to pay the un-depreciated capital cost of the fuelling station (i.e., amounts collected in excess of the "take or pay" commitment representing one half of the applicable capital rate).**

5. **Fortis to include all other amounts paid by BFI for volumes in excess of the "take or pay" commitment in the existing rate base deferral account approved in the Waste Management Decision to capture incremental CNG and LNG Service recoveries received from actual volumes purchased in excess of minimum "take or pay" commitments, for refund to all non-bypass customers.**

As the Panel notes that the costs and revenues associated with the BFI Project were not included in FEU's recent Revenue Requirements Application, **the Panel further directs Fortis to**:

1. **Establish a rate base deferral account for all revenues (excluding revenues in excess of the "take or pay" commitment) from the BFI Project.**

2. **Establish a rate base deferral account for all costs of the BFI Project.**

If Fortis chooses to have its shareholder bear any of the amounts which the Panel has found properly attributable to BFI, these amounts are to be identified and reported on a line by line basis and are to be specifically disclosed in and excluded from any future revenue requirement applications.

Fortis is directed, within 30 days of the date of this order, to provide the Commission with an updated rate filing, including details of any amounts to be borne by shareholders.

Alternatively, the Commission Panel notes that the Fuelling Station Agreement specifically contemplates the assignment by Fortis to any of its affiliates. (Exhibit B-1, Appendix A, clause 18.4) In the Panel's view, and as discussed throughout these Reasons, the necessity for proper and fair cost allocation is heightened by Fortis' entry, in its capacity as a public utility, into what would otherwise be a competitive business environment. The Panel is of the view that the BFI Project is a prime candidate for the use by Fortis of a non-regulated subsidiary to provide the fuelling service. The use of a separate entity and employment of appropriate and approved transfer pricing policies would serve to alleviate the Panel's concerns relating to cost allocation and cross-subsidization. It would also reduce costs associated with the regulatory process which this Application has necessitated. However, while FEI has clearly stated its preference not to provide CNG/LNG Services through a separate affiliate, given the above noted concerns with inadequate cost-recovery and cross-subsidization, the Panel defers the ultimate resolution of the appropriate framework for FEI's participation in a competitive, unregulated activity to the AES Inquiry.

Appendix Y

EXCERPTS FROM THE 2008 EEC PROCEEDING

- working with manufacturers and distributors to ensure that energy efficient technologies are available in the marketplace
- working with appliance salespeople to educate them about the benefits to their customers of selecting a more energy efficient appliance

6.8. Conservation Potential Review ($500,000)

Funding is being requested with this Application to update the Terasen Utilities Conservation Potential Review in 2009. The updated Conservation Potential Review Study would be received in 2010, and would then form the basis of an application to the Commission for the next tranche of Energy Efficiency and Conservation funding for the period 2011 to 2014.

6.9. Innovative Technologies, NGV and Measurement Program Area ($3 million)

The Companies are in a unique position to foster and further the deployment of forward-looking low carbon technologies, including measurement technologies, and are therefore seeking funding with this Application, specific to this arena. The amount and activity for Innovative Technologies, NGV and Measurement will need to be refined – if an effective program in Innovative Technologies, NGV and Measurement can be developed over the funding timeframe, the Companies wish to have to the ability to fund such a program over the funding timeframe. The activity in this area would be in the nature of pilot programs, with limited time frames, geographic areas and number of installations. Some reasons that program activity would be considered not viable would be if the technologies prove to be prohibitively costly, or cannot be readily installed or serviced using local tradespeople, or are found to not provide adequate long term potential for widespread implementation.

This Section of the Application provides an overview of potential areas of opportunity for innovative technology investment that the Companies intend to pursue if the Application is approved. The information is divided into energy efficiency and fuel substitution activities, and by sector (Residential and Commercial).

It should be noted that the initiatives listed in this Section do not include all the innovative technologies that the Companies may pursue, but rather provide an overview of the types of initiatives the Terasen Utilities intend to pursue, all having the same underlying characteristics:

1) Each promotes the efficient use of natural gas through sustainable design
2) None are currently a mainstream technology
3) Each offers the potential for at least a 10% GHG benefit.

For all sectors, programs for fuel-substitution include plans that displace less efficient and dirtier fuels with natural gas or add cleaner renewable fuels to natural gas for further efficiency and GHG benefits.

Funding eligibility and incentive amounts are provided in Table 6.9.6 for budgetary purposes, but would require further analysis before implementation and would include both new construction and retrofit opportunities.

6.9.1. Innovative Technologies

This Section provides an overview of energy efficiency initiatives the Companies intend to pursue through the use of innovative technologies, if the Application is approved. The target market would include all residential and commercial applications.

Residential

Hydronic based heating systems - Hydronic heating systems use liquid (heated water or glycol usually) to distribute energy for space and domestic hot water heating through a supply and return closed-loop insulated piping system. The methods can include radiators, baseboards or fan coils, or a combination. The flexible nature of this system is that the heat input can be changed with changes in technology, knowledge or public policy, thus promoting a more sustainable energy design. Where an old low efficiency boiler might have been used an upgrade can be made to a high efficiency condensing boiler, and eventually a change could be made to supply heat to the water from biomass, ground or solar sources. By utilizing this type of system, an owner will be in a position to replace one type of heat source with another that is cleaner as technology advances. Given existing technologies, upgrading from a low-efficient boiler to a high efficient boiler could result in a 20-30% reduction in natural gas consumption. For the average family home this alone would be equivalent to 725 to 900 Kg of CO2e/yr.

The cost on average for hydronic underfloor system materials is estimated to be about $4,000, not including the boiler. The average cost of hydronic baseboard materials is estimated to be about $2,000, again not including the boiler.

In order to promote a sustainable energy design, the Companies would consider providing incentives up to 25% of cost of the hydronic underfloor piping materials (oxygen barrier tubing) to a maximum of $1,000 and hydronic baseboard materials up to 25% and a maximum of $500.

Integrated Energy Systems (or combo systems) - Integrated Energy or “combo” Systems are defined as a single appliance supplying both space and domestic hot water (DHW) heating. Combo heating systems can be cost effective and increase the operating efficiency of tank-style water heaters by reducing their normal standby energy losses. The hot water tank can be connected to a fan coil to provide forced air heating, and the fan coils can be upgraded to provide air conditioning as well. Combo systems can also be connected to in-floor tubing to provide in-floor radiant heat.

TGI is already encouraging efficient boilers in new construction with heat exchangers through the existing Efficient Boiler Program, although the smallest boiler is 300,000 Btu/hour, thus precluding residential boilers from this program. There is a possibility that more high efficient hot water tanks could be utilized in combo systems.

GHG savings would be accomplished through energy use improvements in domestic water heating. Standard gas hot water tanks are about 60% efficient and moving this part of the load to above 90% efficiency would certainly reduce GHGs.

A program to fund high efficiency (condensing) hot water tanks used for space and domestic hot water heating would help to drive demand for high efficiency gas hot water tanks. Right now these types of tanks cost about $3,000-$3,500 compared to $450-650 for a standard gas hot water tank. Installation costs would be comparable for both tanks. Instantaneous or tankless systems can be used for this Application as well. Given that the average single family dwelling consumes 25 GJs of gas for domestic hot water, moving from 60% to 90% efficiency would produce savings of about 8.3 GJs per household per year. This could equate to a reduction of about 400 kilograms/year of CO2e on the domestic hot water side. The Terasen Utilities would consider providing incentives up to 25% of total cost of condensing hot water tanks to a maximum of $1000. This would cover condensing instantaneous and condensing storage type of water heaters.

Solar thermal - A subset of hydronic heating systems, solar systems also use water or glycol heated by the sun, with the thermal energy transferred for domestic hot water or space heating. Solar space and water heating is usually supplemental to existing systems, reducing the requirement for the primary energy source used in the system.

Solar thermal space heating is cost prohibitive today and would likely add about $30,000 to the cost for average new home construction. Solar thermal domestic water heating costs about $8 000 for an average house and can be used as a supplement to the existing hot water tank to supply roughly half of the yearly water heating energy requirements.

Any solar energy usage results in GHG savings for that part of the load that it displaces. As a result, GHG production can be reduced by about 50%.

The average household uses approximately 25GJ/year for domestic water heating. If there was an annual reduction in gas usage of 12.5 GJ/year, that would reduce household greenhouse gas production by approximately 600 kilograms/year of CO2e.

The Companies would consider providing incentives of $500 towards solar pre-piping as long as a gas hot water tank is installed.

Commercial

As with the residential sector, energy efficiency programs for the commercial sector will include retrofit and new construction programs.

These include, but are not limited to:
MFDs and commercial office space;

Institutional (any government buildings, post-secondary campuses and schools);
Hospitals;
Hotel/motel buildings;
Malls.

Hydronic based heating systems – As with residential applications hydronic heating systems for commercial applications use water or glycol to distribute energy for space and domestic hot water heating through a supply and return closed-loop insulated piping system. In commercial applications or multi-unit residential buildings, the initial heat is usually supplied through a central boiler system. Along with supply through radiators, baseboards or fan coils, independent in-suite hydronic installations are available through compact boilers and dual mode hot water tanks. Again, the flexible nature of these systems is that the heat input can be changed with advances in technology, thus promoting the latest sustainable energy practices. Even further efficiencies can be gained in MFDs if suites are individually metered as there are studies that show 20 – 30% reductions in natural gas consumption and GHG emissions when consumption is measured and known.

The cost of a particular hydronic system is based largely on the size of commercial building. As with residential systems, the Companies are contemplating offering an incentive for a portion of the cost of either underfloor piping materials or hydronic baseboard materials in commercial buildings, including MFDs. Due to the high degree of variability in hydronic system installation costs in commercial buildings, further program development must be undertaken to develop an appropriate incentive level for this heating technology.

Solar thermal – For Commercial applications, solar heating can be a great fit with gas water and space heating. As with residential applications, solar heating is supplemental and allows reductions in gas use by as much as half. As a result GHG emissions can also be reduced up to 50%.

For commercial buildings the Companies would consider matching all or part of the ecoEnergy incentives which pay $10/GJ saved up to 25% of the project and up to $50,000 total. The GHG savings are easily calculated at .05 tonnes of CO2e/GJ conserved.

6.9.2. Fuel-Substitution Initiatives

Similar to the Innovative Technologies programs, the Terasen Utilities fuel-substitution initiatives will target new construction and retrofit markets in both TGI and TGVI. Fuel-substitution under this category refers to the displacement of natural gas using cleaner renewable technologies. GHG benefits will come from burning a cleaner fuel and or from blending such fuels with natural gas. Any overall energy efficiency gains combined with the volume of natural gas displaced results in fewer GHG emissions.

Due to the potential complexity of programs for this initiative, the discussion below merely summarizes areas of potential program activity. More detailed program development work must be completed by Terasen in conjunction with industry groups before such programs are rolled out. The Companies would only allocate funding to such initiatives if it appears that effective programs can be developed.

Residential

Hydrogen / Fuel Cell Power Generation - Hydrogen and hydrogen fuel cell projects currently appear to be some time away from being commercially viable. However, natural gas reformation is presently one of the most economic ways to produce hydrogen. The Companies are monitoring developments in this industry closely and are currently a member of Hydrogen Fuel Cells Canada. In some applications, burning hydrogen from natural gas reformation can be 30% more efficient than burning natural gas directly, and therefore, involvement in this field will likely continue to be important.

Stationary natural gas fuel cell projects for residential homes are currently underway in Japan where customers are seeing a 20-30% savings on their energy bill. This program is heavily subsidized by the government and would likely only be feasible on a small scale demonstration project.

The Companies would consider offering incentives on a trial basis for demonstration projects that support the hydrogen industry using natural gas as its primary fuel source.

Commercial

Biogas – the Terasen Utilities are in the process of conducting a feasibility study on the development of a biogas market in British Columbia and the role the Companies may play in the industry. TGI has been approached by a handful of parties interested in participating in a pilot project to inject pipeline quality biogas into its distribution system.

Preliminary economic analysis has determined that many biogas projects are unlikely to stand on their own from a financial perspective. As such, they would require subsidization or support through a relative premium paid for the commodity. TGI has been working with Metro Vancouver and their Lions Gate Treatment Plant to examine the possibility of injecting upgraded biogas produced from its operations into the Companies' distribution system.

Efforts have begun through dialogue with provincial government employees from Ministry of Energy Mines and Petroleum Resources, the Ministry of Agriculture, the Ministry of Environment, and the Premier's Technology Council to evaluate the environmental and community benefits of the development of a biogas industry in British Columbia.

While investigation into this field is preliminary, the Companies feel there may be a an opportunity to invest in several biogas projects over the next few years which would supplement the distribution systems with renewable fuels, thus displacing natural gas by the amount of biogas accepted into the distribution system.

6.9.3. NGV - Natural Gas Vehicle projects

Natural gas vehicle projects have a number of opportunities to reduce GHG emissions over conventional fuel choices and further increase energy efficiency and emission savings by utilizing liquefied natural gas in heavy-duty vehicle applications or utilizing renewables or hydrogen in combination with natural gas in specific transportation applications.

Vehicle Grants – In order to continue to promote the use of a growing variety of natural gas vehicle applications, customers that would not otherwise be eligible for grants under Rate 6 may be eligible through this fund instead. Grants for light duty vehicles are currently $1,500-$2,500 per vehicle, medium duty vehicles are $5,000 and heavy duty vehicles are $10,000. Special demonstration grants are available as well of up to $100,000 per year.

Hydrogen / Compressed Natural Gas blended projects ("HCNG") - Unlike conventional Compressed Natural Gas ("CNG") vehicles, new technology is emerging whereby hydrogen is blended at the pump with compressed natural gas: a 20% blend of hydrogen is added to the fuel. The mix is then dispensed into a tank on the vehicle and the 80/20 blend is burned in a standard natural gas engine. TransLink has a demonstration project underway with 4 buses utilizing this blend. HCNG is one of the most promising near-term opportunities for utilizing hydrogen in vehicles and moving towards a more hydrogen driven economy. As hydrogen burns cleaner than natural gas, further emission reductions are gained and 10-20 % GHG reductions over CNG can be achieved. Other HCNG initiatives may include fuel for trains, fleets and other vehicle applications.

The Companies see participation in this field as a viable opportunity to promote cleaner natural gas vehicles and projects would be reviewed on an individual basis.

Biogas vehicles - Biogas as explained above is the capture of methane from organic waste. This methane can be cleaned up and utilized in several different ways, one of them being as a vehicle fuel. The emission reductions from such initiatives can be significant.

6.9.4. Stationary Power Generation

There are several new stationary power generation projects underway whereby natural gas is used as the feedstock to provide heat and power to homes, ships and other commercial buildings. As mentioned above, the Terasen Utilities are keeping a close eye on this industry and foresee the potential for participation in this field. Funding would only be allocated to this initiative if further potential developed.

6.9.5. Measurement

Residential

The target market for real-time energy consumption would be multi-family complexes such as town-houses, row-houses and high-rise multi unit buildings.

Real-time energy consumption measurement - Real-time energy consumption metering can be an important tool in energy measurement and management. A reduction in energy use of 20-30% in multi-family developments can result from enhanced visibility and individual energy measurement with the installation of individual meters. The program objective will be to provide customers with the initial tools and data necessary to reduce energy use and increase efficiencies.

The Companies would consider providing an incentive for builders and developers of $100 per suite to install individual meters or thermal metering to cover the cost of added fittings, valves and promote the use of energy measurement.

6.9.6. Other

Other potential Innovative Technologies include natural gas powered generation for ships while in Port (to reduce or eliminate the need to idle on diesel), net zero buildings and district energy solutions using renewables.

Table 6.9.5 below shows the breakdown for expenditures in all program areas:

Table 6.9.5 - Proposed Expenditure Innovative Technologies, NGV and Measurement

Innovative Technologies, NGV and Measurement						
Utility	Sector	Nature of Proposed Expenditure	2008	2009	2010	Total
TGI	Residential	Incentives	$400,000	$400,000	$400,000	$1,200,000
TGI	Commercial	Incentives	$400,000	$400,000	$400,000	$1,200,000
TGVI	Residential	Incentives	$100,000	$100,000	$100,000	$300,000
TGVI	Commercial	Incentives	$100,000	$100,000	$100,000	$300,000
		Total	$1,000,000	$1,000,000	$1,000,000	$3,000,000

IN THE MATTER OF

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

AND

ENERGY EFFICIENCY AND CONSERVATION APPLICATION

DECISION

April 16, 2009

Before:

A.W.K. Anderson, Commissioner
A.A. Rhodes, Commissioner

2.4.3 Innovative Technologies, NGV and Measurement

Terasen states that it is in a unique position to foster and further the deployment of forward-looking low carbon technologies, including measurement technologies, and is therefore seeking funding with this Application, specific to this arena. (Exhibit B-1, p. 69)

Terasen states that "[t]he amount for Innovative Technologies, NGV and measurement will need to be refined – if an effective program in Innovative Technologies, NGV and Measurement can be developed over the funding timeframe, the Companies wish to have the ability to fund such a program over the funding timeframe." (Exhibit B-1, pp. 53, 69) Terasen states that the activity in this area would be in the nature of pilot programs, with limited time frames, geographic areas and numbers of installations. The Companies indicate that they would pursue technologies with the same underlying characteristics:

- Each promotes the efficient use of natural gas through sustainable design;
- None are currently a mainstream technology;
- Each offers the potential for at least a 10 percent GHG benefit.

Energy efficiency technologies the Companies would intend to pursue include:

- Residential
  - hydronic based heating systems;
  - Integrated energy systems providing both space heat and DHW;
  - Solar thermal assisted space or DHW systems;

- Commercial
  - hydronic based heating systems;
  - Solar thermal assisted space or DHW systems.

(Exhibit B-1, p. 73)

Terasen states that it would aim fuel-substitution initiatives at both new construction and retrofit markets in both the TGI and TGVI service areas, and notes that fuel-substitution in this category refers to the displacement of natural gas using cleaner renewable technologies. The Companies state that more detailed program development work must be completed by Terasen in conjunction with industry groups before programs are rolled out or funding is allocated. (Exhibit B-1, p. 74)

Commission Determination

The Commission Panel considers that Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies to reduce or replace natural gas consumption and related GHG emissions.

However, as noted above, Terasen acknowledges that further refinement of this program is required and indicates uncertainty as to whether an effective program can be developed over the funding timeframe. The Commission Panel finds that there is insufficient evidence with respect to the nature and scope of the proposed program, and accordingly rejects the Innovative Technologies, NGV and Measurement program expenditures at this time. Terasen may wish to bring forward projects in this program area for consideration as they become more fully developed.

Appendix Z

DRAFT ORDER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

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DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
for Approval of Rate Treatment of Expenditures
under the Greenhouse Gas Reductions (Clean Energy) Regulation and
Prudency Review of Incentives under the 2010 – 2011 Commercial NGV Demonstration Program

BEFORE:

(Date)

WHEREAS:

A. On May 14, 2012, the Lieutenant Governor In Council approved the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012 (the GGRR);

B. On August 21, 2012, FortisBC Energy Inc. (FEI) applied (the Application) to the British Columbia Utilities Commission (the Commission), pursuant to sections 59 to 61, and 90 of the Utilities Commission Act (the Act), for approval of deferral accounts and the accounting and rate treatment methodology for the three prescribed undertakings established by the GGRR;

C. In the Application, FEI also seeks an order from the Commission that past natural gas vehicle (NGV) incentive expenditures totaling $5.6 million (the 2010-2011 Incentives) as described in Section 7 of the Application were prudently incurred and can be recovered through rates from FEI's non-bypass natural gas customers;

D. In the Application, FEI has committed to treating the 2010-2011 Incentives as being part of the $62 million expenditure cap that is established in section 2(1)(c) of the GGRR;

E. The Commission has reviewed the Application and considered FEI's commitment as described in recital D and concludes that the Application should be approved.

NOW THEREFORE pursuant to sections 59-61 and 90 of the Act, the Commission orders as follows:

1. The 2010-2011 Incentives were prudently incurred and are recoverable through rates from FEI's non-bypass natural gas customers in the manner described in item 2 of this Order.

2. The 2010-2011 Incentives will be subject to the accounting and rate treatment that FEI has described in Section 5 of the Application for all expenditures incurred under the prescribed undertaking established by section 2(1) of the GGRR (Prescribed Undertaking 1), and as established by items 3a and 4 of this Order.

3. FEI is permitted to establish and maintain the following deferral accounts, which are subject to the Order set out in item 4 below :

    a. A non-rate base deferral account (the NGT Incentives Account) attracting AFUDC to capture: (a) all grants and costs, including a portion of application costs, related to Prescribed Undertaking 1 for the period until December 31, 2013; and (b) to capture the 2010-2011 Incentives in the amount of $5.6 million. This account is to be transferred to rate base, effective January 1, 2014, and will continue to capture the actual incentives granted under Prescribed Undertaking 1 and will be amortized over a 10 year period into the delivery rates of all non-bypass natural gas customers; and

    b. A non-rate base deferral account attracting AFUDC (the Fueling Station Variance Account) to capture the total revenue surplus or deficiency pertaining to fueling station facility costs that have not been forecast in rates, as well as the administration and application costs, for the prescribed undertakings established under sections 2(2) and 2(3) of the GGRR. This account is to be transferred to rate base effective January 1, 2014, with an amortization period of three years into the delivery rates of all non- bypass natural gas customers.

4. The deferral accounts and prescribed undertaking expenditures described in items 3a and 3b of this Order are subject to the rate recovery and accounting treatment of costs as described in Sections 5 and 7 of the Application.

5. FEI will maintain records on the CNG and LNG stations that will allow for each station to be tracked separately.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 20XX.

BY ORDER