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October 18, 2010

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Utilities (comprised of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.) 2010 Long Term Resource Plan

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 1

On July 15, 2010, Terasen Gas filed the Application as referenced above. In accordance with Commission Order No. G-146-10 setting out the Regulatory Timetable for the review of the Application, the Terasen Utilities respectfully submit the attached response to BCUC IR No. 1.

If there are any questions regarding the attached, please contact the undersigned or Ken Ross at (604) 576-7343 or ken.ross@terasengas.com for further information.

Yours very truly,

on behalf of the TERASEN UTILITIES

Original signed:

Diane Roy

Attachment

cc (e-mail only): Registered Parties

1.0 Reference: Regulatory Context for Long Term Resource Planning

Exhibit B-1, Chapter 1, p. 5

Utilities Commission Act (UCA) section 44.1

The cover letter says that the Terasen Utilities are seeking acceptance of this LTRP in accordance with section 44.1 of the *UCA.* Page 5 of the Application states that under the *UCA*, the Commission has the authority to regulate utilities in the province and to require utilities to, among other things, submit resource plans.

Section 44.1 (6) of the *UCA* states that "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."

1.1 In the opinion of the Terasen Utilities, if the Commission accepts the 2010 LTRP, does the acceptance: (a) commit the Terasen Utilities to adopt the positions as recommended in the LTRP? (b) allow the Utilities to change course without notifying the Commission and stakeholders until the next LTRP? And (c) commit the Commission to approve cost estimates in future applications such as CPCNs or RRAs because these applications rely on plans as recommended in the LTRP?

Response:

The Terasen Utilities 2010 Long-Term Resource Plan ("LTRP") provides a snapshot in time of the Terasen Utilities ongoing resource planning process. Since the 2010 LTRP reflects the Terasen Utilities resource planning process, the Terasen Utilities have already "adopted" the positions recommended in the 2010 LTRP. The Commission's review of the LTRP under section 44.1 of the *Utilities Commission Act* provides the Commission with the opportunity to consider the current state of the Terasen Utilities resource planning and opine on whether carrying out the LTRP is in the public interest. As resource planning is an ongoing process, however, the LTRP is by its nature subject to change. Although drastic or sudden changes to the LTRP are not expected, it is in the interest of customers of the Terasen Utilities to be able to respond to new events and information with changes to its resource plan overtime. It is only with this freedom to adjust that the Terasen Utilities can take the actions that may be necessary to meet the objects of the LTRP, such as to ensure safe, reliable and secure supply. The Terasen Utilities therefore believe it is appropriate that while the Commission may "accept" or "reject" a resource plan in whole or in part, the *Utilities Commission Act* does not state that the utility is obligated to undertake aspects of the resource plan that are accepted.

Accordingly, while the Terasen Utilities expect to carry out an accepted LTRP, the Commission's acceptance of the 2010 LTRP does not commit the Terasen Utilities to carry out the actions in the LTRP for any particular time and there is nothing in the *Utilities Commission Act* that prohibits the Terasen Utilities from changing course. While the *Utilities Commission Act* does not impose any notification requirements for changing course, the Terasen Utilities expect that any changes would be transparent in the ongoing regulatory process, including in CPCN and revenue requirement proceedings, and in future LTRP filings. The Terasen Utilities would also seek to anticipate and address concerns of the Commission that may arise from deviations from an accepted LTRP.

Similarly, unless the Commission were to exercise its jurisdiction under section 44.1(7) of the *Utilities Commission Act* to determine a matter conclusively, the acceptance of the LTRP does not commit the Commission to approve cost estimates in future applications which may rely on plans recommended in the LTRP, especially since new, relevant evidence is likely to be brought forward that the Commission had not considered previously. The acceptance of an LTRP, however, may be relevant and persuasive depending on the matter at issue and arbitrarily inconsistent decisions are not expected.

2.0 Reference: Fortis Inc. Business Units

Exhibit B-1, Chapter 1, p. 3

Terasen Energy Services

"The activities of a forth [sic] company, Terasen Energy Services ("TES"), also provide an important backdrop in planning for the future of Terasen Utilities. Although this LTRP does not set out a strategic action plan for TES, beginning in 2010 the types of activities undertaken by this forth [sic] company are now being undertaken by TGI in relation to new projects. These activities include the development, construction and operation of alternative energy systems and the setting of rates and cost recovery for those systems."

2.1 Please describe how the activities of TES provide an important backdrop in planning for the future of Terasen Utilities and provide further information of the service areas, customers, revenue and expenses associated with TES activities.

Response:

The 2010 LTRP is related to Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. The information provided regarding TES's activities is contextual information related to the alternative energy services that TGI is now pursuing.[1] The delivery of alternative energy services to customers is a regulated activity under the *Utilities Commission Act* and TGI proposed to undertake alternative energy services in its 2010-2011 Revenue Requirement Application. Section 5 of the Negotiated Settlement Agreement with respect to that application, approved by the Commission in Order No. G-141-09, outlines the conditions under which TGI may provide alternative energy services in the service area of all the Terasen Utilities. TGI is now pursuing alternative energy services as described in Section 3.1.1 of the LTRP. In the respectful submission of the Terasen Utilities, it is the services being pursued by TGI that are the subject of this proceeding, rather than TES's services.

[1] Exhibit B-1, Page 3 and Exhibit B-1, Table 1-1 bottom notes, Page 4.

2.2 Would Terasen Utilities proceed with the implementation of TES activities irrespective of whether or not the Commission accepts the 2010 LTRP? Please explain why or why not.

Response:

The Terasen Utilities have assumed that the reference to "TES activities" in this question is a reference to the implementation of alternative energy services by TGI.

Terasen Gas Inc. plans to provide alternative energy services to customers in accordance with the terms of the Negotiated Settlement Agreement (the "NSA") for Terasen Gas Inc. approved by Commission Order No. G-141-09, dated November 26, 2009. As stated in section 3.1.1 of the LTRP, the Terasen Utilities will be applying to the Commission for approval of an overall business and regulatory model for each service offering and will be seeking approval of specific projects within those offerings. While these activities and plans for future applications are relevant background to the resource plan, the Terasen Utilities are not seeking any approvals in the LTRP to proceed with offering alternative energy services. TGI notes that no advance approval is required for TGI to file applications with the Commission to implement alternative energy services as contemplated by the NSA. For this reason, if the Commission were to accept the LTRP in whole or in part, the Terasen Utilities would not take this acceptance to be an endorsement of the Terasen Utilities plans to file future applications or a prejudgment of those future applications.

Similarly, the rejection of the LTRP would not prohibit TGI from making a future application to implement alternative energy services. The Terasen Utilities therefore anticipate that they would proceed with implementing alternative energy services whether or not the Commission accepts the LTRP. If the Commission were to reject the LTRP, however, the Terasen Utilities would seek to address in future applications any issues raised or recommendations made by the Commission in its Decision.

Please also see the response to BCUC IR 1.2.1.

3.0 Reference: Western Climate Initiative (WCI)

Exhibit B-1, Chapter 2, p. 22

WCI Initiative to Implement the Cap-and-Trade System

On July 27, 2010, seven US states and four Canadian provinces presented the WCI Partners Strategies, among which is the WCI regional cap-and-trade program which would be implemented through state and provincial regulations. Each partner jurisdiction implementing a cap-and-trade program will issue “emission allowances” to meet its jurisdiction’s specific goals. The planned program start date is January 2012.

3.1 If emissions from the transport, industrial, commercial and residential are capped as a result of provincial regulations, would this cap put downward pressures on GHG emissions and therefore allow Terasen Utilities to reduce the financial incentives designated for the long-term EEC programs? If no, please explain why not. If yes, please comment on how the EEC program design would address this scenario.

Response:

At this time, the only regulation issued under the Greenhouse Gas Reduction (Cap and Trade) Act is the Reporting Regulation, which requires reporting from B.C. facilities emitting 10,000 tonnes GHG /year or more. While government may be planning regulations capping emissions from the transportation industry, and commercial and residential buildings, details of such regulation have not been released, and the Terasen Utilities are thus unable to speculate on potential impacts on EEC programs from provincial government activities in support of the Western Climate Initiative. In general, however, the Terasen Utilities provide EEC incentives where they are needed and if policies or regulations make EEC incentives unnecessary, they are not provided. As noted in the text referenced in this Information Request, “The policy context in the western North America jurisdictions is fragmented and that makes it difficult to predict how the various initiatives will unfold and how each jurisdiction will be affected by the evolving areas of energy and climate change policy.” It should be noted, however, that the “Design for the WCI Regional Program” appears committed to “Advancing policies that expand energy efficiency programs, reduce vehicle emissions, encourage energy innovation in high-emitting industries, and help individuals transition to new jobs in the clean-energy economy,” [2] all of which are outcomes of Terasen Utilities’ EEC activities.

[2] http://westernclimateinitiative.org/component/remository/func-startdown/278/

3.2 Has a scenario(s) for trading (e.g., selling credits earned from EEC activities) in allowances been assumed or analyzed as part of Terasen Utilities' 2010 LTRP? Is so, please describe the scenario(s) and how it would impact the cost-benefit analysis. If such a scenario has not been assumed, please explain why not.

Response:

A scenario for trading in allowances has not been analyzed as part of the Terasen Utilities' 2010 LTRP, as the Terasen Utilities are currently in the process of reviewing:

- whether GHG reductions achieved as a result of the Terasen Utilities' energy efficiency initiatives qualify as offsets,
- whether such reductions meet the "additionality" test required for qualification, and
- the applicable protocol and cost of validating and verifying these offsets.

The Terasen Utilities are also still resolving how those offsets could be apportioned if they were part of a compliance portfolio. The Terasen Utilities have been reviewing and reporting their operating emissions to Environment Canada and will continue to analyze the WCI framework rules as they emerge.

3.3 Would the functioning WCI cap-and-trade system change the potential GHG emissions estimates in the 2010 LTRP (Ref: Figures 2-12, 2-13)? If so, by how much? If not, please explain why not.

Response:

Figures 2-12 and 2-13 on pages 32 and 33 respectively of the 2010 LTRP are not forecasts of energy and GHG emissions, but rather historical data obtained from NRCan. They are specific to the use of transportation fuels within BC. The Terasen Utilities have not developed estimates of the impact of planned or proposed future activities of WCI members on energy demand or GHG emissions in the transportation sector. As stated on page 22 of the LTRP as per the IR reference, it is difficult to predict how the various initiatives will unfold, including the details of a cap-and-trade program (see also the response to BCUC IR 1.3.1).

The Terasen Utilities would, however, expect that initiatives such as a cap and trade system will cause some transportation sector participants to change their behaviours in order to minimize the economic impact of such policies and regulations. Businesses that have transportation needs that will be affected by a cap-and-trade system will be looking to both the energy industry and equipment manufacturers to provide solutions to help them manage their GHG emissions.

Our NGV initiatives, described in Sections 3, 4 and 5 of the LTRP will be an important part of such solutions and are already in demand from our customers[3]. A cap-and-trade system may in fact accelerate demand for these solutions.

In summary, a cap-and-trade program will not simply make energy use go away or new, emission-free and cost effective technologies suddenly appear. The Terasen Utilities 2010 Long Term Resource Plan presents an Action Plan that aims to provide customer solutions to the challenge of GHG emissions and respond to both the opportunities and risks arising from emerging climate change policies and regulations.

[3] See Exhibit B-1, page 61 for a description of interest received in our NGV initiatives.

4.0 Reference: Carbon Pricing

Exhibit B-1, Chapter 2, p. 29

Assumptions used for Avoided Costs

The Application states that overall carbon taxes or cap-and-trade systems will lead to higher costs for fossil fuel consumption.

4.1 What is the assumption for avoided costs of energy consumption used in the evaluation of EEC programs?

Response:

The avoided cost of gas on a per unit basis is determined by the following method:

The avoided cost of gas on a per unit basis includes two components - an estimate of the commodity cost and an estimate of the midstream cost. The commodity cost is based on the 10 year AECO price forecast according to GLJ Petroleum Consultants (an independent energy consultant) based on their latest available forecast (updated by GLJ each quarter). The midstream costs are estimated by calculating an approximation of the pipeline transportation charges required by the Terasen Utilities to move the commodity supply to core markets as well as the storage costs associated with meeting winter load requirements. These midstream costs are then increased by an assumed inflation factor of 3% to account for the expected future cost increases of these resources. This resulting avoided cost represents the expected marginal cost of gas (including commodity, transportation and storage resources) to serve the Terasen Utilities' customers on a per unit basis. The latest avoided cost of gas is included in Attachment 4.1. Carbon tax is also accounted for in avoided costs for evaluating EEC programs, at known rates (i.e. those announced by government so far) and is also included in Attachment 4.1.

5.0 Reference: Federal Approaches to Climate Change in Canada and the U.S.

Exhibit B-1, Chapter 2, pp. 35, 36, 37

GHG Emissions and Energy Policy Reform

The Application states that NRCan has initiated public consultation and formed a roundtable to develop a roadmap for natural gas use in the transportation sector.

5.1 Please describe the extent that this initiative has been incorporated into the analysis of Terasen Utilities' NGV fuel switching program.

Response:

Given that the transportation sector is one of the biggest sources of GHG emissions in Canada, accounting for more than 25% of total emissions[4], the federal government along with other jurisdictions have focused their attention on ways to reduce emissions from this sector. The use of natural gas within this sector can help achieve the desired results in an economical way. Initiatives such as NRCan's roundtable[5] to develop a roadmap for natural gas use in the transportation sector support the Terasen Utilities' NGV service offerings (which will be filed as a separate application to the Commission by the end of 2010) by recognizing that natural gas can and should play a bigger role in providing energy for transportation. The Terasen Utilities are cognizant of the fact that governments at all levels acknowledge and promote the use of natural gas in transportation and therefore we have incorporated the need and the growing demand for natural gas in transportation as part of our analysis for NGV service offerings.

5.2 Please provide in your response a copy of NRCan consultation report(s) from the roundtable process to develop a roadmap for NGVs.

Response:

The final report on the roadmap is yet to be finalized and released. However, a synthesis of the roundtable discussion from the March 12, 2010 meeting is included in Attachment 5.2.

[4] Environment Canada. "Government of Canada to Reduce Greenhouse Gas Emissions from Vehicles". April 1, 2009. Retrieved from: http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=29FDD9F6-489A-4C5C-9115-193686D1C2B5

[5] Note that NRCan is at the initial consultation phase of the roundtable and therefore there has not yet been a formal report finalized and released.

6.0 Reference: Offset Emissions Regulation

Exhibit B-1, Chapter 2, p. 44

Pacific Carbon Trust

6.1 The Application states that the Pacific Carbon Trust acquires GHG offsets from projects that are located in B.C. and that meet provincial eligibility criteria. Please provide the PCT offset selling price and comment if the carbon offset price is the same input price to Terasen Utilities' own bioenergy strategy discussed in section 2.2.3.7.

Response:

The bioenergy strategy discussed in section 2.2.3.7 of the Application is the B.C. Bioenergy Strategy released by the Province (see Exhibit B-1, Appendix A-3).

The Pacific Carbon Trust indicates that they have initially set an offset selling price at $25 / Tonne[6]. The Terasen Utilities have not used the cost of offsets from the Pacific Carbon Trust in its own bioenergy strategy as the intent of TGI's proposed biomethane program is not to sell customers a marketable carbon offset, but rather a certain amount of renewable energy per GJ which, in turn, reduces their carbon footprint.

The current regulation is unclear about carbon offset opportunities for Terasen Utilities' customers. As indicated in the Biomethane Response to Workshop Undertaking, dated July 8, 2010, TGI may look at creating offsets on the customers' behalf in the future as a result of the offset created by consuming Biomethane in place of natural gas. However, this would involve third party validation and verification and the establishment of accepted protocols for these projects which have not been defined at this time, and would be a more appropriate exercise if TGI were to develop a carbon offset program, rather than the proposed renewable energy-based program. By displacing natural gas with Biomethane in end-use applications, all else being equal, there is a net reduction in the amount of GHGs which is the green attribute that customers would be paying for under the proposed program.

Please also refer to the Attachment 6.1 which includes excerpts from the TGI Biomethane Application, Exhibit B-2-1, Response to Workshop Undertaking and Exhibit B-7, Response to BCSEA IR 1.20.2.

[6] http://www.pacificcarbontrust.com/BuyOffsetsfromPCT/tabid/64/Default.aspx

7.0 Reference: Reduction of GHG Emissions

Exhibit B-1, Chapter 2, p. 45

Carbon Tax Act

The Application states that potential for carbon tax increases and the level of tax beyond 2012 remain uncertain at the present time. It further quotes some reports that indicate carbon taxes may need to go up to $300 per tonne in order to have a meaningful impact on consumer behavior and therefore reduce GHG emissions.

In the April 16 Decision on TGI/TGVI EEC Application, the Commission approved Terasen's proposal for the carbon tax impact reduction as an appropriate factor to be included in computing the EEC cost-benefit analysis.

7.1 What is the carbon tax/tonne assumed in the EEC programs' cost-benefit analysis?

Response:

The carbon tax/tonne assumed in EEC cost-benefit analysis is that which has been announced by government:

- $20/tonne effective July 1, 2010;
- $25/tonne effective July 1, 2011; and
- $30/tonne effective July 1 2012 and thereafter.

In the absence of information about the amount of the carbon tax beyond 2012, Terasen Utilities have applied a carbon tax amount of $30/ton to the cost of gas beyond 2012.

Please also see our response to BCUC IR 1.4.1.

7.2 Please provide the cost estimates of 100 GJ of energy with and without the carbon tax for 2010, 2020 and 2030.

Response:

The table below shows the cost estimates for 100 GJ of energy with and without the carbon tax for 2010, 2020, and 2030. Please note that the cost of carbon included in the cost estimates for 2020 and 2030 is $30/tonne. Please see also the response to BCUC IRs 1.4.1 and 1.7.3.

	2010	2020	2030
With carbon tax	$885	$1,297	$1,564
Without carbon tax	$785	$1,148	$1,414
Differential	$100	$150	$150

7.3 If the estimates above are lower than $300 per tonne, are the Terasen Utilities still assuming that the carbon tax would have a meaning impact on consumer behavior? To the extent possible, please quantify.

Response:

As noted in the response to BCUC IR 1.7.1, for the purposes of EEC cost-benefit analysis, the Terasen Utilities utilize the carbon tax amounts that have been announced by government. As noted on page 45 of Exhibit B-1 of the LTRP, "Potential for carbon tax increases and the level of tax beyond 2012 remain uncertain at the present time." It is reasonable to assume that the costs of carbon such as the carbon tax would have an impact on customer behaviour over time, similar to how energy prices can influence consumer behaviour.

7.4 What is the carbon tax/tonne, if any, that the Terasen Utilities have assumed in the long term load forecasting?

Response:

There are many factors that impact the demand for natural gas, one of which is the carbon tax per tonne. Given the challenges associated with isolating the demand response to the carbon tax per tonne alone, and also the uncertainty regarding future carbon tax levels, Terasen Utilities assumes the long-term carbon tax remains constant throughout the forecast period at $30/Tonne.

8.0 Reference: Exhibit B-1, Chapter 3, page 52

Low and No Carbon Initiatives

8.1 Section 3.1 in the Application states: "As such we believe that the requests set forth in this section should be approved to facilitate that development."

8.1.1 Please enumerate the "requests' being referred to in the quoted statement and explain what is the nature of the "approvals" being sought?

Response:

Section 3 of the LTRP does not contain any requests and the Terasen Utilities are not seeking any approvals in section 3. Much of the material in Section 3.1.1 of the LTRP, including the quoted sentence, was copied from Terasen Gas Inc.'s 2010-2011 Revenue Requirement Application. The particular sentence quoted in the information request, however, is not applicable to the LTRP and should not have been reproduced.

As described in Section 3, the Negotiated Settlement Agreement (the "NSA") for Terasen Gas Inc. ("TGI") approved by Commission Order No. G-141-09, dated November 26, 2009, contemplates that TGI would, or would be at liberty to, file specific applications as part of their next steps for each of the low and no-carbon initiatives.[7] In these specific applications, the particular business opportunities will be described along with the regulatory models, and supporting business analysis, being proposed for the Commission's approval. It is in the context of these applications that the Commission and intervenors will be able to consider fully the unique regulatory and business issues applicable to each of the initiatives. Indeed, this is the approach that has been taken in TGI's Biomethane Application, filed on June 8, 2010, which is currently under consideration by the Commission. In its final submission dated September 20, 2010, the Commercial Energy Consumers Association of British Columbia ("CEC") acknowledged (at page 1) that TGI's Biomethane Application "is consistent with what was agreed to in the Negotiated Settlement Process for the TGI 2010/2011 RRA".

Each of the low and no-carbon initiatives described in section 3 of the LTRP are relevant in different ways to the Terasen Utilities demand forecast or gas supply sources, and represent services and activities being sought from us by our customers. However, in this Application, the Terasen Utilities are not seeking approvals for any low or no-carbon initiatives, nor are the Terasen Utilities requesting a determination that its plan to bring forward future applications is in the public interest. The only approval that the Terasen Utilities are seeking in the LTRP is that the Commission accept the LTRP in accordance with Section 44.1 of the *Utilities Commission Act*. The Commission's acceptance of the LTRP is not a prerequisite for, and would not

[7] See, e.g.: Section 3.1.1.3, page 57; Section 3.1.5, page 65; and Section 3.1.7, page 73.

constitute approval or prejudgment of, the applications that the Terasen Utilities plan to file. Please also see the responses to BCUC IR 1.1.1 and 1.2.2.

8.2 Section 3.1.1 describes the renewable, thermal energy systems and states that they are an important part of the Utilities' strategy to become an integrated provider of thermal energy services and that these activities and resource needs form an integral part of the LTRP. Can these activities be tied to the EEC funding scenarios or are they separate and independent?

Response:

The Terasen Utilities are unclear as to what is meant by "tied to the EEC funding scenarios". The EEC funding scenarios put forward in Exhibit B-1 are intended to be illustrative and to indicate that, with increased and stable EEC funding, increased energy savings can be anticipated. The level of detailed program planning such as that which was completed for the TGI/TGVI 2008 EEC Application, was not undertaken in creating the three scenarios. The response to BCUC IR 1.19.1 describes how each of the three scenarios was created.

Program plans for the current tranche of approved EEC funding, which takes the Terasen Utilities to the end of 2011 do contemplate EEC incentives for such systems as geoexchange for multi-family and commercial buildings. However, plans for the current tranche of funding should not be confused with the illustrative EEC scenarios put forward in the LTRP. The LTRP states the Terasen Utilities' intention to submit a future request for expanded and ongoing funding. The illustrative nature of the three EEC scenarios in Exhibit B-1 support the need for such a future submission (please also see the response to BCUC IR 1.38.1).

9.0 Reference: Integrated Energy Systems for Buildings and Communities

Exhibit B-1, Chapter 3, pp. 54-56

Market Reliability and Competition

The Application describes the geo-exchange systems, solar-thermal and district energy systems as part of Terasen Utilities' future service offerings. It states that a single renewable energy source such as geo-exchange will be combined with conventional natural gas service and that district energy systems can employ multiple energy sources and systems to balance the heating and cooling needs for a community with many end-use needs.

9.1 Please discuss whether regulatory changes with respect to reliability of services are required to accommodate Terasen Utilities' future offerings described above.

Response:

The Terasen Utilities do not anticipate any adverse reliability impacts due to providing the integrated energy system services described in the LTRP. Therefore, no regulatory changes with respect to reliability of services are expected to be required to accommodate the future offerings.

9.2 Are there competitors to TGI in the area of offering integrated energy services? If yes, please list them and describe the competitors' target market shares. If TGI perceives no competition, please describe in detail the barriers to entry to this low or no carbon suite of services.

Response:

Yes there are competitors to TGI in the area of integrated energy services. However, competition is a Federal mandate under the Constitution of Canada and not, in and of itself, within the jurisdiction of the BCUC. Neither is the Commission's jurisdiction defined by reference to whether a service is subject to competition. Notably, the word "competition" does not occur in the *Utilities Commission Act.* The Terasen Utilities also note that it would be incorrect to conclude that the energy service provided to third parties by an owner and operator of geothermal, solar thermal or district energy systems is not monopolistic in nature. With respect to district energy system serving a community, for example, TGI or another provider selected by the consumer would have an effective monopoly over the provision of heat to the customers in the community.

At present, the Terasen Utilities is aware of private companies that own and operate or have indicated intentions to own and operate integrated energy services including: Central Heat Distribution, Corix Utilities, Dalkia, Van Maren Group of Companies, and Terrasource. Given the infancy of this market, we may not be aware of all competitors so this list should not be considered exhaustive.

In addition, some BC municipalities have created their own district energy utilities including City of North Vancouver, City of Vancouver, Town of Revelstoke, and Resort Municipality of Whistler. Municipalities could therefore be seen as competitors however they are not regulated by the BCUC. Throughout the province several large customers such as industrial manufacturing facilities, universities and hospitals are also operating energy systems serving several buildings that could loosely be termed district energy systems (although these systems only serve one customer). This market is at an early stage of development and as noted above there are several entities currently participating, but no one competitor appears to have a significant market share. In addition, there is currently no centralized data collection available of alternative energy systems that would enable the calculation of market shares.

The limited number of participants in this market is reflective of the significant upfront capital investment required, the relatively low Return on Equity ("ROE") required for the product to be competitive in the market, the long term required to realize the ROE, and the requirements for high levels of reliability and safety. As such, utility companies such as the Terasen Utilities, operating in a regulated environment, are best suited to this business.

10.0 Reference: Transportation Fuel Service Offerings - NGV

Exhibit B-1, Chapter 3, p. 58; Appendix A-1

Clean Energy Act

"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."

10.1 Do the Utilities consider the NGV market to be open to the currently licensed gas marketers? Why or why not?

Response:

The Terasen Utilities consider the NGV market to be open to any business that wishes to participate, including licensed gas marketers. The fact that the market for a particular service is available for businesses to begin serving does not ensure that such a role will be filled. In the LTRP, the Terasen Utilities have described the hurdles involved with increasing the penetration of NGV services in BC and have outlined the benefits that Terasen Utilities can provide in expanding the NGV market and helping to reduce emissions.

There are a multitude of roles that a business could play in the NGV market from equipment manufacturing to owning and operating public or private NGV fuelling infrastructure. In the TGI service area today, for example, any business that wishes to own and operate its own natural gas vehicles could also invest in, own and operate, or contract out, the fuelling infrastructure associated with that use and apply to the Terasen Utilities for gas service[8] as an industrial customer. In this case, TGI would deliver natural gas to the industrial customer's meter and be indifferent as to the way that customer uses the gas.

A licensed gas marketer could participate in this example in two ways. First, the industrial customer (under a transportation Rate Schedules such as 23 or 25) could opt to purchase its natural gas commodity from a licensed gas marketer and have the Terasen Utilities deliver that gas to its meter. Second, in the Terasen Utilities' view, the gas marketer could partner with the customer to own and operate the fuelling infrastructure, as could any other business that wished to enter that market place.

[8] Note that this example is different from TGI customers who wish to re-sell natural gas as a transportation fuel, through public filling stations for example, in which case they must apply to TGI for Rate 6 service. Currently, Rate 6 customers must purchase the natural gas commodity from TGI.

While the NGV market is open for currently licensed marketers and others to participate in as described above, it should be noted that the NGV market is not being actively developed by such entities today. For example, no new fuelling stations or NGV fleets have been developed for approximately the past decade and existing operations are being closed. Terasen Utilities believe that the present market conditions are favourable for developing NGV markets; hence we wish to extend our services to begin development of this market. As the market develops, through the sourcing of new vehicles and fuelling stations there will be more opportunities to participate in this market for all participants including gas marketers.

10.2 By assuming the financial risks in the natural gas for transportation application as stated in the preamble to this question, TGI would be assuming an overall riskier profile. Would TGI then apply to the BCUC for a premium to its allowed ROE?

Response:

TGI acknowledges that there is capital risk associated with our plans to enter the NGV refuelling market; however, we believe the data shows that the expected benefits to all customers significantly outweigh those risks. TGI does not expect that this prudent investment will negatively impact our risk profile. Therefore, TGI has no intention to apply for a premium on our rate of return on the basis that NGV service offerings increase our financial risk.

To minimize the capital risk to the Company and ensure greater benefit for all customers, TGI has taken the risk mitigation steps described below.

All assets required for the operation of NGV refuelling stations will be tied to contracts for the use of those stations. These contracts will ensure that, at a minimum, the cost of service over the course of the contract of the added capital will be recovered through the rate applied to the minimum contracted compression volumes for that station.

To protect against the unlikely event of contract default or non-renewal, Terasen Gas intends to install its NGV assets in such a manner that they are relatively easy and inexpensive to redeploy or liquidate. This will largely be done by skid-mounting the assets or using other similar methods of protecting their portability.

10.3 Under ss. 18(3) and 35(n) of the Clean Energy Act, the BCUC must not exercise a power in a way that would directly or indirectly prevent a public utility, for example Terasen, from carrying out a prescribed undertaking. Please confirm whether it is the Utilities' position that NGV programs which have been proposed in the Application are prescribed undertakings. Please explain your answer.

Response:

The NGV programs proposed in the Application are not "prescribed undertakings" at the present time. In order for the NGV programs or specific elements of the NGV programs to become "prescribed undertakings," the Lieutenant Governor in Council must issue a regulation that authorizes the specific projects, programs, contracts or expenditures associated with those NGV programs. The Lieutenant Governor in Council has not as yet issued any regulations under Section 18 of the *Clean Energy Act* for NGV programs or any other activities that might become the subject of "prescribed undertakings"

The use of natural gas in vehicles is directly referenced in Section 35 (n) of the *Clean Energy Act* which states:

> *(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.*

Based on this direct reference to NGV in the *Clean Energy Act,* the Terasen Utilities believes it is reasonable to expect that regulations may be issued to establish NGV programs or activities as prescribed undertakings. At this time, the Terasen Utilities does not know what the nature or timing of these regulations will be. Whether or not an NGV-related prescribed undertaking is established, it is the Terasen Utilities intent to move forward with the NGV programs as they have long-term benefits for existing customers and they help to achieve the energy objectives and GHG emission reduction goals of the province.

10.3.1 Would the NGV programs be better made through unregulated as opposed to regulated business? Please discuss from both the perspectives of utility ratepayers and the Utilities' shareholders.

Response:

The Terasen Utilities believes that it is beneficial both for ratepayers (including ratepayers that take or will take NGV service) and the Terasen Utilities to offer a comprehensive NGV service as part of its regulated service offerings.

1. Customers using natural gas for NGV applications are already a part of the Terasen Utilities customer base. TGI currently provides NGV-related services under Rate Schedule 6 (Natural Gas Vehicle Service), Rate Schedule 6A (General Service Vehicle Refuelling Service) and Rate Schedule 26 (NGV Transportation Service). Rate Schedule 6A includes the provision of compression as a regulated service. The offering of a comprehensive NGV service, including more involvement in compression and refuelling service, is therefore a natural extension of the natural gas service we offer today. The service is merely providing natural gas in a way that the NGV customer can use it by providing the pressure necessary to get the natural gas into the vehicle. This is not a fundamentally different concept from the provision of a regulator to reduce pressure to customers who require natural gas at a lower pressure from our distribution or transmission operating pressures.

2. The Terasen Utilities believes that they are in the best position to enhance service in the transportation sector by offering a comprehensive NGV service, including a compression and refuelling service. The Terasen Utilities possess the skills and knowledge to operate and maintain the required compression and refuelling equipment, which is similar to the equipment required for the natural gas distribution system. Through the Terasen Utilities' experience with NGV and demonstration programs, the Terasen Utilities are in a position to assist customers in the selection of appropriate compression and dispensing systems. This will result in a compression and refuelling service that meets customer needs.

3. A comprehensive NGV service provided by the Terasen Utilities and regulated by the BCUC would provide NGV customers with comfort that rates will be transparent, fair and reasonable.

4. All customers of the Terasen Utilities will benefit from the addition of load from regulated compression and refuelling service. The Terasen Utilities anticipate that new NGV customers will bring a flat load profile (relatively high load factor) to the system. This will benefit all existing customers because an increased, flat load will better utilize the distribution system and distribute the delivery cost across a greater volume of natural gas resulting in lower delivery costs for all customers, all else equal.

5. The Terasen Utilities believe that its proposed NGV programs will play a key role in enabling the development of an NGV industry in B.C. The expansion of NGV service would provide substantial GHG and other emission reductions from the transportation sector that the Terasen Utilities would be targeting.

11.0 Reference: Transportation Fuel Service Offerings

Exhibit B-1, Chapter 3, p. 61

Pilot Incentive Program

The Application states that 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.

11.1 The municipalities which have submitted expressions of interest have fiscal resources in the form of property taxes from home owners. Moreover, mandatory national emissions standards for the transportation sector are in place or being put in place (Ref: p. 2-35). Please justify why Terasen's industrial, commercial, and residential customers should fund the incremental cost of the purchase of NGVs for municipalities.

Response:

Municipalities in the Terasen Utilities service territory are commercial customers of the Terasen Utilities because the Terasen Utilities provides natural gas services to municipal buildings and services such as municipal halls, operations yards, libraries, swimming pools, skating rinks and other facilities. As such, municipalities are contributing to the funding of EEC programs through their natural gas rates in the same way that other commercial customers are.

Beyond this, there are a number of reasons why it is appropriate for the Terasen Utilities' customer classes to fund incentives for commercial customers in the target market segments, including municipalities, to adopt NGVs in their medium and heavy duty fleet vehicles. The first is that adding NGV load into the Terasen Utilities overall natural gas demand provides a unique opportunity to add revenues that will mitigate the margin decreases from declining natural gas use in the residential, commercial and industrial classes. At the same time adding NGV load enables the Terasen Utilities to make headway towards achieving the Province's energy objectives and the legislated objectives to reduce greenhouse gas emissions. The incremental margin from NGV sales will become an enduring benefit to other customer classes by keeping delivery rates below what they would otherwise be.

Secondly, even if it is possible to raise the incremental funding for switching a municipal fleet to natural gas through property taxes, the same obstacles exist for the adoption of NGV in municipal fleets as in commercial fleets. Municipal fleet managers may be interested by the potential benefits of operating cost savings and GHG emission reductions associated with converting to NGV, but they tend to be conservative in the management of their fleets. They are constrained by operating budgets and hesitant to adopt different fuel sources and technology for their fleets. The potential fuel cost savings for natural gas relative to conventional diesel or gasoline are generally not enough to overcome the perceived risks that come with having to operate and maintain unfamiliar vehicles and refuelling equipment. The incentives are an important tool needed to convince the municipal fleet managers to proceed with switching their fleets from conventional fuels to natural gas.

Thirdly, NGV programs for municipal fleets will subject to the same threshold as other DSM programs of having to pass the TRC test. This means that overall benefits from the NGV programs will exceed the costs.

Since residential, commercial, and industrial customers stand to benefit from the addition of NGV load into the overall gas load, the Terasen Utilities believes it is appropriate that these customer groups support NGV programs by, among other things, funding the incremental cost of the purchase of NGVs for commercial customers in the target market segments, including municipalities.

11.2 How much is the incremental cost of an NGV over conventional vehicle in the pilot program? Please provide the total funding in 2010 and 2011 of the adoption of 16 and 32 heavy duty diesel trucks as well as the estimated carbon offsets.

Response:

As referenced in Chapter 3, p. 64 of the 2010 LTRP Application, TGI has divided the heavy duty truck segment into two categories – Vocational trucks and Heavy Duty trucks. Vocational trucks refer to vehicles such as commercial waste haulers and refuse trucks which generally operate short-haul distances. These vehicles are best suited for fuelling by compressed natural gas ("CNG"). Preliminary conversations with the City of Surrey, City of Port Coquitlam, and other parties indicate the incremental cost of a CNG truck over its diesel equivalent ranges from $26,700 to $55,000. This cost varies due to specific usage and model requirements from fleet operators. TGI has selected an average of $41,000 for the purposes of this forecast.

Heavy Duty trucks refer to commercial Class 8 tractors which generally operate long-haul distances on the highway. These vehicles are best suited for fuelling by liquefied natural gas ("LNG"). Preliminary conversations with the City of Vancouver and Westport Innovations indicate the incremental cost of a LNG truck over its diesel equivalent is approximately $78,000.

The table below shows each category's respective forecast quantities for 2010 and 2011 as well as their total incremental cost.

	Number of Vehicles		Total Incremental Cost	
	2010	**2011**	**2010**	**2011**
Vocational Trucks (@ $41,000 per)	7	22	$ 287,000	$ 902,000
Heavy Duty Trucks (@ $78,000 per)	9	10	$ 702,000	$ 780,000
Total Heavy Duty Trucks:	16	32	$ 989,000	$ 1,682,000

The total incremental costs of $989,000 and $1,682,000 in each year fit within the EEC budget allocations. At this point in time these are estimates. Actual expenditures will depend on customer uptake and are subject to completion of a business case that includes a Total Resource Cost test that is dependent on the amount of diesel fuel that is displaced. This aspect of the program is also beneficial to all customers because it will add load and delivery revenue under existing tariffs which will help to keep rates lower for all customers into the future, all else equal.

TGI has developed its carbon offset (or carbon dioxide equivalent, "CO_2e") estimates on a per kilometer basis using emission factors from Natural Resources Canada's GHGenius model.[9]

As referenced in Appendix B-8 of the Resource Plan Application, TGI has assumed an average distance of 40,000 kilometers per year for Vocational trucks, and an average distance of 300,000 kilometers per year for Heavy Duty trucks.

The table below shows each category's respective carbon offset estimates for 2010 and 2011 using 16 and 32 incremental vehicle additions.

	Tonnes of CO_2e	
	2010	**2011**
Vocational Trucks (@ 40,000 km per year)		
Tonnes of CO_2e from Diesel	401	1,261
Tonnes of CO_2e from CNG	322	1,012
Tonnes of CO_2e reduced	79	249
Heavy Duty Trucks (@ 300,000 km per year)		
Tonnes of CO_2e from Diesel	3,869	4,299
Tonnes of CO_2e from LNG	2,795	3,105
Tonnes of CO_2e reduced	1,074	1,194
Total Tonnes of CO_2e reduced:	1,154	1,443

[9] Based on emissions factors of 1,433 grams per kilometre for diesel, 1,149.7 g/km for CNG and 1,035.1 g/km for LNG, published in GHGenius 3.17.Software available from Natural Resources Canada at www.ghgenius.com

Therefore TGI expects 1,154 and 1,443 tonnes of CO_2e savings in each of the two years. These reductions are the equivalent of taking 221 and 276 passenger vehicles off the road in 2010 and 2011, respectively.[10]

11.3 Would TGI receive credits for the carbon offsets for the pilot program? If so, please describe how TGI proposes to treat the carbon credits. If no, please describe which party is entitled to the carbon offsets and why.

Response:

TGI is not currently pursuing qualifying, validating and verifying carbon offsets generated from the pilot program in order to sell carbon offsets. The contracts for the provision of the energy efficiency incentives for the NGV pilot do not currently speak to the ownership of any potential carbon offsets. 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, the Terasen Utilities may consider including language in future NGV energy efficiency incentives that the Terasen Utilities are entitled to any GHG emission reductions as a result of the incentive, similar to current EEC terms and conditions. Therefore, if multiple projects qualify, the Terasen Utilities 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 EEC initiatives has not been resolved at this time.

[10] Numbers derived using the US Environmental Protection Agency, Greenhouse Gas Equivalency Calculator.

12.0 Reference: Transportation Fuel Service Offerings

Exhibit B-1, Chapter 3, pp. 62, 65; Chapter 4, p. 105

Target Markets

The Application states that the total transportation sector fuel usage was 370 PJ in 2007 and 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 per cent of this total market by 2030.

12.1 What is the estimated size of the target markets in 2030? Please provide the energy use by category (PJ) in 2030, as well as the respective growth rates per year for the different categories for the period 2007 to 2030.

Response:

TGI estimates the target market size in the transportation sector of 290 PJ in 2007 will grow to 458 PJ by 2030.

To estimate the 20 year future market outlook for its target market, TGI has chosen Gross Domestic Product ("GDP") [11] as a proxy for demand growth.[12] Transportation market growth comes from new vehicle additions replacing retired vehicles, as well as general population and economic growth.

Since the trucking sector represents a large portion of TGI's target market, the Terasen Utilities believe its market characteristics are most representative of the target market. The British Columbia Trucking Association ("BCTA") states that "trucking's contribution to the GDP reflects the economy in general - more trucks on the road means that people are spending money on the goods that they need".[13]

According to BC Stats, the British Columbian provincial GDP has grown at an average of 3.0% per year since 2000.[14] A correlation test shows a reasonable positive correlation between BC's

[11] As defined by BC Stats, the central statistics agency of the British Columbia Government

[12] GDP is a general indicator of economic activity and productive activities of individuals, businesses, and governments http://www.bcstats.gov.bc.ca/data/bus_stat/bcea/bcea_faq.asp#Q2

[13] Vancouver Sun, Paul Landry, September 3, 2010, http://communities.canada.com/VANCOUVERSUN/blogs/communityofinterest/archive/2010/09/03/overcoming-the-challenges-of-geography-amp-distance.aspx

[14] BC Stats, BC GDP http://www.bcstats.gov.bc.ca/data/bus_stat/bcea/bcgdp.asp

GDP growth rate and total number of vehicles.[15] In its March 2010 budget update, the BC government forecasted a GDP growth rate of 2.3% in 2011 and an annual average growth rate of 2.8% from 2012-2014.[16] TGI has decided to apply a more conservative estimate of 2.0% per year for each category to produce the outlook demonstrated in the table below:

	Target Market - Projected Energy Use (PJ) at 2% growth per year, per category					
Category	**2007**	**2010**	**2015**	**2020**	**2025**	**2030**
Passenger Cars	66.1	70.1	77.4	85.5	94.4	104.2
Light Duty Trucks	78.4	83.2	91.9	101.5	112.0	123.7
Medium Duty Trucks	20.9	22.2	24.5	27.1	29.9	33.0
Heavy Duty Trucks	66.0	70.0	77.3	85.3	94.2	104.0
Buses	4.6	4.8	5.3	5.9	6.5	7.2
Marine	54.3	57.6	63.6	70.2	77.5	85.5
Total	**290.3**	**308.0**	**340.0**	**375.4**	**414.5**	**457.7**

Note: Total for buses does not include school buses. The energy shown here for buses in 2007 differs from that shown in Table 4-4 of Exhibit B-1 (page 107) of the LTRP, which incorrectly stated that school buses were not included. The total size of bus (urban, transit and school) market was 6.1 PJ in 2007, which matches Figure 4-4.

12.2 Page 65 of the Application contemplates extension of a more complete NGV service to the TGVI and TGW service territories at a later date pending future unbundling of gas delivery rates. Please provide: (i) a detailed assessment of the current NGV experience in the Resort Municipality of Whistler and include in your discussion B.C. Transit's purchase of hydrogen and diesel bus to serve Whistler leading up to the Winter Olympics 2010; (b) the basis for the Utilities' conclusion on page 105 of the Application that the future development of B.C.'s NGV market will be quite different than past experiences.

<u>Response:</u>

The Terasen Utilities are unaware of an existing experience base with respect to NGVs in the Resort Municipality of Whistler. The Terasen Utilities are not in a position to comment on the

[15] Historically, the combined total number of light, medium and heavy duty trucks and buses in the B.C transportation market has grown at an average rate of 2.8% per year since 2000. Source is NRCan 2007.

[16] http://www.bcbudget.gov.bc.ca/2010/bfp/2010_Budget_Fiscal_Plan.pdf

decisions made with respect to purchasing hydrogen fuel cell powered buses for use in Whistler beyond the responses made to BCUC IR 1.1.1 in the Terasen Gas (Whistler) Inc. 2010-2011 RRA (please see Attachment 12.2). Key elements of that response were:

- The fuel cell bus purchase was part of an effort to showcase fuel cell technology under development in BC; and
- The cost of the fuel cell buses was approximately 5 times the cost of comparable NG buses and was only possible with project funding of $90 million from the Federal and Provincial governments.

The basis for the conclusion regarding future development of B.C.'s NGV market is based on research. The present market share of natural gas buses in North America is 18.6%[17] (12,370 NG Buses) which greatly exceeds the share of fuel cell buses. The share of fuel cell buses is presently too small to be tracked and reported separately by the American Public Transit Authority. A 2009 report indicates that only 10 fuel cell buses were in operation in the US market.[18] A further 20 buses were introduced in BC in 2010 as highlighted in Attachment 12.2. The relative merits of the various alternatives for transit buses will also be discussed in the upcoming Transportation Fuelling Service Application that Terasen Gas expects to submit by the end of 2010.

The Terasen Utilities would also point out that the share of natural gas in the BC transit market in 2008 was 6% as measured by energy consumed.[19]

Additional success in the BC market will depend on various factors such as:

- Availability of reliable vehicles;
- Relative cost of natural gas versus traditional fuels;
- Availability of fuelling infrastructure;
- Government policy and regulation; and
- Environmental concerns influencing purchasing decisions.

Each of these factors will be discussed in the upcoming NGV Application; however, it is possible to summarize at a high level the conditions that are present in the current market environment that will lead to success.

First, the strategy being pursued is to focus on return-to-home commercial vehicles – primarily heavy duty trucks and buses. NGV options[20] from major manufacturers such as Mack,

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[17] American Public Transit Association, 2010 Fact Book, p. 18 http://www.apta.com/resources/statistics/Documents/FactBook/APTA_2010_Fact_Book.pdf

[18] http://www.nrel.gov/hydrogen/pdfs/46490.pdf

[19] Canadian Urban Transit Authority, Canadian Transit Fact Book, 2008 Operating Data, p G15

Freightliner, Autocar, Kenworth, Peterbilt and Crane Carrier are available for these applications. This is in contrast to the previous NGV strategy that was more focused on serving private vehicles employing vehicle conversion kits.[21]

Second, natural gas net pricing to the user presently provides a 40 - 50% advantage over diesel and gasoline (including full cost of service for the fuelling infrastructure). The previous decline in NGV markets corresponded with a point in time when the price advantage for natural gas was lower. As detailed in Figure 2-4 in Chapter 2 of the LTRP, the price gap between natural gas and light crude oil (used for gasoline and diesel) is expected to maintain its differential in the future.

Third, fleet vehicles will be supported with limited fuelling infrastructure that will be paid for by NGV customers. This is in contrast to the previous approach which relied upon a network of public fuelling stations that was financed by all Terasen Utilities' customers without the benefit of load commitments.

Fourth, government policy is strongly encouraging cleaner options such as natural gas. An example is the recently introduced Low Carbon Fuel Requirement Regulation that mandates a 10% reduction in the carbon intensity of transportation fuels in BC.[22] This policy driver did not exist 10 – 15 years ago.

Finally, TGI's customers are expressing a desire to move towards fuels that have lower carbon intensity and are willing to enter into take or pay contracts for service. For example, Waste Management has executed an agreement for Terasen Gas to provide natural gas fuelling services to service 20 new natural gas refuse trucks.

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[20] Refers to NGV engine technology which has been manufactured and installed in Original Equipment Manufacturers (OEM) vehicles. NGV engine technology designed by Cummins-Westport has proven performance with over 25,000 engine deliveries worldwide. For more details, please see: http://www.westport.com/products/md.php

[21] Conversion refers to gasoline powered vehicles which are 'converted' to run on natural gas as a dedicated fuel (or as a bi-fuel running on gasoline or natural gas) using an aftermarket NGV engine conversion kit.

[22] http://www.empr.gov.bc.ca/RET/RLCFRR/Pages/default.aspx

13.0 Reference: Biomethane Offering

Exhibit B-1, Chapter 3, p. 66; Appendix B-9

Market Research

The Application asserts that Terasen's customers have a strong desire to purchase renewable clean energy from the Utilities. The Biogas Market Study in Appendix B-9 describes the discrete choice survey for residential customers conducted online with respondents sampled from the population of the TNS' Canadian online adult panel.

13.1 It appears that the results came from a survey sample from a population of adults who volunteer to complete surveys online from time to time. Given that a discrete choice questionnaire is normally more complex to respond to, would the results not be biased because the questionnaire was self-selected by volunteers with a strong opinion about the survey issues?

Response:

The result is not biased. While it is true that online panels are comprised of individuals who agree to participate in surveys from time to time, it is not true that this results in a biased sample for the Biogas study. Respondents were randomly selected from within TNS' Online Panel, which "is comprised of more than 110,000 individuals who have been recruited to participate in on-line, Internet surveys."[23] Quotas were established to ensure adequate sampling of Terasen Gas customers. Individuals who take part in online studies are not provided with detailed information about the study before they click the link to participate.

However, virtually any survey, in any format, will have an element of self-selection, because respondents always have the option to participate. For example, if interviews are conducted by telephone, individuals can choose whether or not they want to respond just as they can in an online panel. Although some individuals may opt to participate in a study because they have an interest in the subject matter, others may participate because they can obtain an incentive, or simply because they have free time. Choosing to participate in a study, regardless of the study format, does not mean that a respondent has a strong opinion on the subject.

Additionally, the Discrete Choice Model ("DCM") questions would not have deterred individuals from participating in the survey at the outset, because respondents would not be aware that the survey contained DCM questions until they reached that portion of the survey. Furthermore, a DCM matrix is not necessarily complex to respond to; it is a set of choices, and respondents choose between option A and option B. It is also less complex to respond to DCM questions

[23] TNS Website: http://www.tns-cf.com/services/panel.html#interactive

online than on the telephone, because in an online survey respondents have time to consider their answers and can return to previous questions and review or edit answers upon reflection.

For further information on this subject, please refer to Attachment 13.1, which includes the following IR responses from the Biomethane application: BCUC IR's 1.11.1 - 1.11.5, 1.43.1.2 - 1.43.1.5 and 1.45.3.

13.1.1 Please give a comparison of the survey respondents' demographic profile with the Companies' customer demographic profile?

Response:

We believe that the sample in the TNS residential Biogas study is representative of Terasen Gas' residential customer base. This is supported by the similarity of demographics in the Terasen Gas customers interviewed in the Biogas survey and the sample in Terasen Gas' 2010 Spring Residential Customer Satisfaction study (which is randomly drawn from the Terasen Gas' customer database and therefore representative of the customer base). We observe that the household characteristics of the two samples are very similar. Table below shows a comparison of the demographic household variables that are captured in both surveys.

	Biogas Study	Residential Customer Satisfaction Study
AREA OF RESIDENCE		
Lower Mainland & Whistler	58%	59%
Interior	30%	25%
Vancouver Island + Sunshine Coast	11%	15%
Decline	1%	0%
PEOPLE IN HOUSEHOLD		
One Person	9%	16%
Two People	43%	40%
Three to Five People	43%	40%
More than Five People	4%	4%
ANNUAL HOUSEHOLD INCOME		
Less than $15,000	3%	3%
$15,000 to less than $35,000	17%	10%
$35,000 to less than $60,000	26%	N/A
$35,000 to less than $65,000	N/A	27%
$60,000 to less than $100,000	39%	N/A
$65,000 to less than $125,000	N/A	30%
$100,000 or more	14%	N/A
$125,000 or more	N/A	13%

Please also refer to the response to BCUC IR 1.13.1.

14.0 Reference: Energy Forecasting

Exhibit B-1, Chapter 4, pp. 74, 105; Appendix B-5; May 27 2010 Workshop Resource Planning Backgrounder Slide 10

Forecast Approach and New Methodologies

The Terasen Utilities are in the process of developing new forecasting methodologies to accommodate the shifting trends in energy delivery in B.C. and the process includes on-going discussions with other B.C. utilities.

14.1 Please provide a brief discussion and tabular data regarding the level of consensus to date among utilities in B.C. regarding the energy consumption base line, shift in trends and the pace of the shifts relating to energy use per capita in B.C. and the demand for renewable thermal energy.

Response:

The development of new forecasting methodologies and the development of a baseline thermal energy demand forecast for the province are two separate, though related, initiatives. The Terasen Utilities are collaborating with other utilities in B.C. on both of these initiatives.

BC Hydro and FortisBC have expressed interest in our new forecasting approach and acknowledged that the Terasen Utilities are not the only organization shifting toward an end-use approach. No consensus has been sought nor received from other utilities with regard to our new forecasting methodologies; however, the Terasen Utilities do intend to continue collaborating with other forecasting organizations both within and outside of BC as we continue this work. Through this process the Terasen Utilities intend to identify the tools, data, research and resources needed to fully develop and test the effectiveness of these methodologies. We also intend to provide updates on the progress of these activities within submissions to the Commission that involve forecasting information and at other appropriate times.

In regard to a baseline thermal energy demand forecast for the province, the only consensus reached to date is an informal agreement to explore the potential for developing such a forecast. The Terasen Utilities plan to collaborate with BC Hydro, FortisBC and MEMPR to discuss an approach and hopefully to carry out this exercise. Terasen Utilities will re-commence this work in 2010 as demands on our resources from this Application and other important initiatives allow.

14.2 In developing the new end-use approach, have the Terasen Utilities sought the advice and experience of consultants and other natural gas utilities outside B.C. in terms of modeling techniques and data requirements? Please describe the nature and results of this work to date.

Response:

In developing the new end-use approach so far, the Terasen Utilities sought advice and experience from a number of sources, including informal discussions with consultants and other utilities. The results of this work are contained in the description of the new methodologies included in Section 4 of Exhibit B-1. No formal forecasting activities have been outsourced at this time. As current and future research studies are completed (such as the Conservation Potential Review, and the End User and Influencer Energy Preference Study), Terasen Utilities intend to explore further refinements to and completion of the methodologies developed thus far. Formal input into these methodologies from outside sources including attending seminars, conferences, collaboration with other utilities and the potential need for outsourcing portions of this work will continue to be a consideration as this initiative advances.

14.2.1 Given the additional research and data collection and analyses tasks, please provide the planned staff resources (FTE and costs) for energy and demand forecasting at the Utilities for the next four years.

Response:

The Terasen Utilities have been able to initiate this additional research and analysis work within its existing budgets. We continue to examine our needs beyond 2011 and if we believe additional resources are necessary, we will bring forward an appropriate request in future Revenue Requirement Applications.

Customer end-use and preferences studies for which funding was approved in the 2010-11 RRA will help to fill some of the data gaps that currently exist. The 2010–11 budget for Forecasting as presented in TGI's 2010-11 RRA Negotiated Settlement Agreement,[24] is $1.63 million and $1.67 million for 2010 and 2011, respectively, which includes 10 FTE positions in the areas of forecasting, planning and research.

As indicated in the 2010 LTRP, the development and testing of new forecasting methodologies for natural gas use, growth in integrated energy systems and customers, growth in new natural gas vehicle programs and other planning requirements is a significant undertaking and may well

[24] BCUC Order No. G-141-09, Appendix A, page 51 of 110, Line No. 34.

require additional internal and/or external resources. Given the limited history and uncertainty in the future pace of adoption for the Terasen Utilities' new initiatives, we will also need to continue to assess and address the frequency with which research activities are needed and the scope of future forecasting activities. To the extent possible, we will address these issues in the upcoming Revenue Requirement Application in 2011.

15.0 Reference: Exhibit B-1, Appendices B-2 and B-3

Demand Forecast Tables

15.1 Please provide a copy of the data presented in Appendices B-2 and B-3 in the form of a fully functional electronic spreadsheet.

Response:

Refer to Attachment 15.1 for fully functional spreadsheets of the data presented in Appendix B-2 and B-3.

15.1.1 Are the data presented in Appendices B-2 and B-3 'before' or 'after' EEC savings? If "after", please indicate the annual EEC savings that have been applied by updating Appendix B-2.

Response:

The Terasen Utilities confirm that the data presented in Appendices B-2 and B-3 is 'after' EEC Savings. The reference case demand forecast is after EEC savings and takes into consideration forecasted EEC savings based on current approved funding levels.

Annual EEC Savings have been updated to the Appendix B-2 based on Scenario A. Scenario A assumes that the current approved funding levels expire by the end of 2011. EEC Savings have been applied to TGI Residential (aggregate of Coastal and Interior), TGI Commercial (aggregate of Coastal and Interior), TGVI Residential and TGVI Commercial.

Please see the fully functioning spreadsheet provided in Attachment 15.1.1 for the demand forecast tables before EEC savings at currently approved funding levels.

15.2 Please provide a summary version of Appendix B-2 segmented by Residential, Commercial, Industrial, Transport/IT rate classes in each of the Utilities' service areas for the period 2010 to 2030. Please provide a copy in the form of an electronic spreadsheet.

Response:

Please see Attachment 15.2 for a fully functional spreadsheet.

15.3 For the data presented in Figure 4-1 on page 76, please confirm the period associated with the data.

Response:

The Terasen Utilities confirm that Figure 4-1 illustrates actual data up to and including February 2010.

15.4 Please provide data in tabular format as well as in a fully functional electronic spreadsheet for the period 2000 to 2030 segmented by rate class and service area indicating the annual average number of customer additions, total number of customers, average use per customer, annual demand, and design day demand. Please provide an electronic spreadsheet version.

Response:

Please refer to Attachment 15.1 in the response to BCUC IR 1.15.1 for the fully functional spreadsheet, outlining the data requested for the forecasting period 2010 to 2030.

Please also refer to Attachment 15.4 for the fully functional spreadsheet, outlining the data requested for the historical period from 2002 to 2009.

Peak Day demand is an estimate for the maximum consumption that can occur under the most extreme weather conditions. Peak day demand is used to ensure enough capacity rather than to match the maximum historical consumption. Actual data against which to compare forecast data is not available.

15.4.1 What is the average variance between forecasted and actual results for each parameter in the historical period from 2000 to 2010?

Response:

The calculated forecast variances with regards to the annual demand and average use per customer indicate that the Terasen Utilities' forecast figures are reasonable and within the expected range, ranging from 2 to 3% of the 2009 actual figures. Customer addition forecasts show much higher variances mostly due to a large degree of fluctuations observed in actual customer additions in the historical period which makes it difficult to identify an underlying trend.

For the historical period from 2002 to 2009, the forecast and actual results are summarized in the response to BCUC IR 1.15.4. The actual results for 2010 are not available at this time and are therefore excluded from comparison. The average variance between annual residential demand forecast and actual results is approximately 2.4 PJ, representing roughly 3% of the actual demand in 2009. Similarly, the average variance between annual commercial demand forecast and the actual is 1.2 PJ, which is approximately 3% of the total commercial demand in 2009. The average variance between the industrial demand forecast and the actual is 1.2 PJ, approximately 2% of the overall industrial demand in 2009.

16.0 Reference: Exhibit B-1, Chapter 4, p. 76

Population Growth

"The most important trend to be considered when preparing the demand forecasts is the anticipated growth in population. Current projections from B.C. Stats estimate the province will add approximately 1.5 million new residents over the course of the next 20 years which will bring the current population of 4.5 million to 6.0 million by 2030."

16.1 For the period 2000 to 2009, please provide tabular and graphical data that compares the number of Terasen Utilities customers to the population in British Columbia. From this data please calculate the average growth of Utilities customers as a percent of population growth. Please reconcile this analysis with the estimate of 150,000 new customers by 2030.

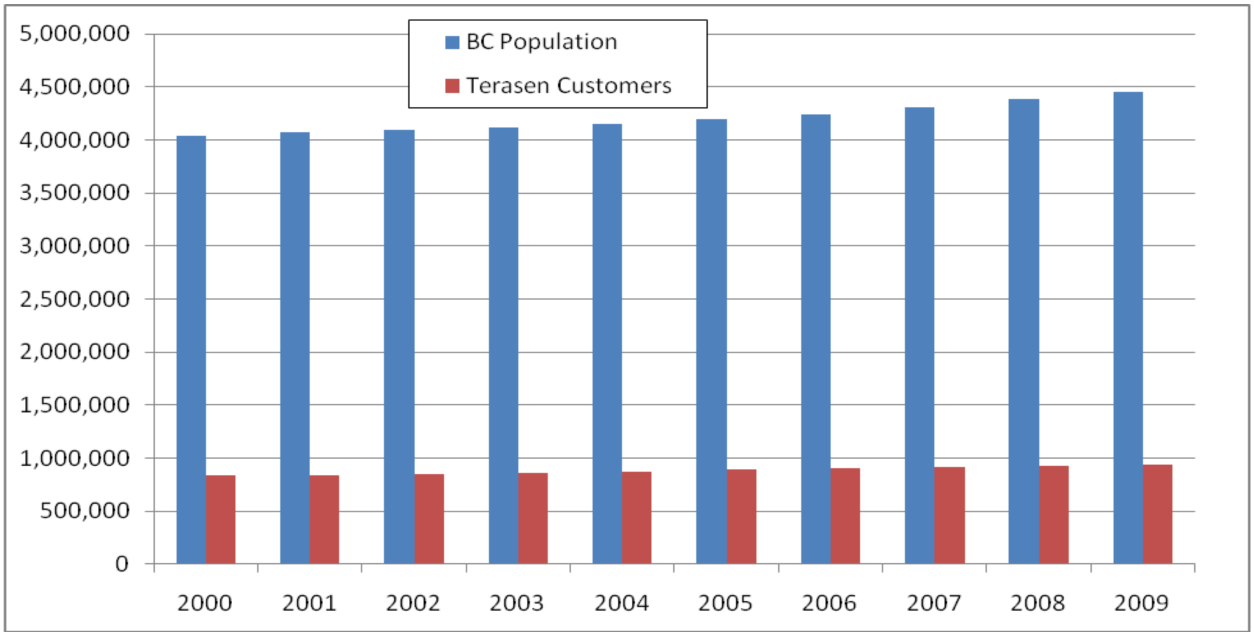
Response:

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2030
BC Population [1]	4,039,200	4,076,300	4,098,200	4,122,400	4,155,200	4,196,800	4,243,600	4,310,300	4,381,600	4,449,300	4,511,000	6,000,000
Terasen Utilities Customers [2]	834,657	841,091	850,712	859,173	875,150	890,354	904,777	918,631	931,446	939,577	948,999	1,105,994

[1] BC Stats "BC Population Projections 2009 to 2036" published June 2009

[2] Terasen Utilities Customer figures include TGI, TGVI, TGW

Average Population Growth from 2000 to 2030	**1.2%**
Average Terasen Customer Growth from 2000 to 2030	**0.9%**
Average Uptake from 2000 to 2030	**20.4%**



Based on the above historical data, Terasen Utilities' average customer uptake is approximately 20% of the BC Population. As shown in the table and chart above, based on the Terasen Utilities' customer forecast, customer uptake by 2030 is 18%.

The Terasen Utilities use the forecasts pertaining to the housing market (which incorporates population growth forecasts) as one of the factors in developing its demand forecast. Population growth is the biggest input into the forecasting of household formations and is, in this way, the most important trend in the development of customer forecasts. There are a number of challenges, however, in attempting to reconcile the provincial population growth to Terasen Utilities' forecast customer growth, including a lack of data pertaining to the forecast headship rates (average number of people per household) for single and multi-family dwellings, and also the fact that Terasen Utilities' service territories do not cover the entire province. We therefore cannot fully reconcile the variations in the ratio of customers to population.

17.0 Reference: Energy Forecasting

Exhibit B-1, Chapter 4, pp. 77-78 Tables 4-1, 4-2

Results from 2008 REUS

17.1 Please explain why survey results are presented in the form of unweighted data rather than weighted data which accounts for over representation or under representation of specific groups with the sample group. What level of reliable inference can one make with unweighted data provided in the 2008 REUS report?

Response:

As is common market research practice, only the base sample size presented in the tables is unweighted. The remainder of the survey results displayed in the 2008 Residential End Use Study tables (Tables 4-1 and 4-2 of Exhibit B-1 in the LTRP) are based on weighted data.

18.0 Reference: Energy Forecasting

Exhibit B-1, Appendix B-1, p.3-1 Exhibit 3.1

2008 REUS

18.1 Please confirm that the weather normalized use rates are not a calculation error or typo: (a) 98.4 in 2001 for TG; and (b) 85.6 in 2006 for TW.

Response:

The weather normalized use rates for TG in 2001 and TGW in 2006 are correct.

18.2 Please add a column to Exhibit 3.1 that shows the average commodity price for natural gas for that year.

It is not possible to isolate the commodity cost from delivery cost for all the divisions for the period 1999 to 2008. Midstream costs were blended with the commodity cost for the Lower Mainland and Inland prior to April 2004. To ensure consistency, the Lower Mainland and Inland price has been reported with the midstream cost included over the complete time period. TGVI and Whistler prices are a combination of delivery and commodity costs. The price reported for Fort Nelson is for commodity only. The footnotes at the bottom of the table below explain how the price has been reported for all divisions.

Year	LM		INT		TGVI		TGW		FN	
	Consumption (GJ)	Price ($)	Consumption (GJ)	Price ($)	Consumption (GJ)	Price ($)	Consumption (GJ)	Price ($)	Consumption (GJ)	Price
1999	121.9	$4.20	104.5	$3.15	71.9	$9.09	94.8	N/A	161.4	$2.24
2000	116.9	$5.96	99.5	$5.00	68.4	$9.23	91.8	$11.28	158	$3.06
2001	105.2	$5.86	88.1	$7.78	66.2	$9.52	87.9	$14.82	167.3	$5.07
2002	118.4	$6.46	89.5	$5.96	66.6	$9.63	89.4	$11.61	156.5	$4.23
2003	111.5	$5.80	89.2	$7.13	61.8	$12.55	90.6	$13.35	162.3	$5.48
2004	108.3	$8.22	86.1	$7.31	59	$12.35	85.7	$13.17	166.4	$5.95
2005	103.6	$8.61	82.4	$8.30	58.7	$13.22	93.4	$13.86	153.7	$6.76
2006	103.2	$8.24	82	$8.75	60.2	$13.23	85.6	$13.86	141.5	$7.41
2007	102.6	$6.21	80.8	$8.33	57	$13.72	95.7	$13.86	141.9	$6.87
2008	99.5	$7.31	76.5	$9.33	56.1	$14.19	95.2	$13.86	139.6	$8.39

LM and INT: Price includes both commodity cost and mid stream cost
INT is a weighted average of commodity and delivery costs for Columbia and Inland.
TGVI and TGW: costs are for commodity and delivery.
FN prices are for Gas Commodity only

19.0 Reference: Energy Forecasting

Exhibit B-1, Appendix B-1, p.3-15

2008 REUS

"Of note, estimates of long-run price elasticity for natural gas are influenced by the fact that changes to building codes and other regulations have effectively altered the efficiency choices available to consumers. These changes, in the strictest sense, are not due to changes in consumer behaviours or actions per se. But unless specifically isolated, these underlying structural changes will be implicitly embedded in the size of the long-run price elasticity estimates."

19.1 Please explain if, and how, historical and projected changes to building codes and other regulations affect the Terasen Utilities estimates of savings in the EEC portfolio. Please provide a tabular summary of the adjustments made to EEC estimated savings to account for changes in building codes and other regulations.

Response:

As the three EEC Funding Scenarios are intended to be high level and for illustrative purposes, changes in building codes have not been incorporated into savings estimates. Presumably though, EEC activity would support future changes in Minimum Equipment Performance Standards (MEPS) and building codes, and should be eligible for some attribution of savings from the introduction of future MEPS and building codes.

The savings presented in the three EEC Scenarios were derived as follows:

- Scenario A assumes that EEC funding ceases after the end of 2011, and that no additional energy savings are obtained beyond those EEC measures and programs that are implemented to the end of 2011.

- Scenario B assumes that EEC funding and the associated energy savings both continue at a constant level over the timeframe of the planning horizon.

- Scenario C assumes that EEC funding representing 5% of gross revenues, and energy savings based on current levels but increased proportionately to reflect the increase in funding over current levels , would run until 2022, and then both funding and energy savings would decrease by 5% to the end of the planning period.

19.2 In the April 16, 2009 Decision on EEC Application, the Commission denied Terasen's proposal to attribute savings from regulatory changes and standards for appliance, building or energy system over a span of five years from implementation date. In that decision, the Commission accepted BC Hydro's position that attribution of savings from codes and standards should be evaluated on a case-by-case basis and that the attribution rate should reflect the level of support for market transformation. Please describe how this Commission decision has affected or will affect Terasen's forecasting approach in terms of determination of energy consumption baseline in load forecasting.

Response:

The Commission's decision on a case-by-case attribution of energy savings from EEC programs and activity that support market transformation will not affect load forecasting as energy use reductions need to be incorporated into baselines for load forecasting regardless of the cause of those reductions. Rather, the Commission's decision on attribution and subsequent approval or disapproval of case-by-case EEC program attribution requests will affect the reported energy savings resulting from Terasen Utilities' EEC activity. Section 8.3 of the TGI and TGVI 2009 EEC Annual Report, which was filed with BCUC on March 31, 2010, outlines such an attribution proposal for market transformation activity related to domestic hot water.

20.0 Reference: Exhibit B-1, Chapter 4, pp. 78-80

Residential Use Trends and Furnace Efficiency Assumption

"Depending on the housing type and region, we estimate that a typical standard efficiency furnace consumes approximately 17 to 20 GJ87 more per year than higher efficiency furnaces."

20.1 Please provide the specific page references to the 2008 REUS report (Exhibit B-1, Appendix B-1) that support the conclusion that standard furnaces consume 17 to 20 GJ more energy per year than higher efficiency furnaces.

Response:

This estimate of GJ savings by switching from a standard efficiency natural gas furnace to a high efficiency furnace is a calculation based on the results of the Conditional Demand Analysis (CDA) portion of the 2008 REUS and does not appear in the REUS report.

The CDA assigns Unit Energy Consumption values (UEC's) for various natural gas end uses by housing type and region. The CDA estimates for primary heating represents an aggregate of consumption by all furnaces irrespective of efficiency levels. The allocation of consumption by furnace efficiency is based on the percentage of each type of furnace installed in the residences participating in the REUS and the overall efficiency level of each furnace type. The difference in consumption between a standard efficiency furnace and a high efficiency furnace in a single family dwelling was between 17 and 20 GJ depending on the region.

20.1.1 Given that the average residential customer consumes approximately 57.8 GJ per year (Exhibit B-1, Appendix B-1, 2008 REUS, p. 13-6) for home heating, would a 17 to 20 GJ per year difference in consumption indicate that high efficiency furnaces are between 28% to 33% more efficient than standard furnaces? If so, does this not exceed furnace manufacturer efficiency claims? (Exhibit B-1, Appendix B-1, 2008 REUS Report, p.5-13).

Response:

The estimate of GJ savings by switching from a standard efficiency natural gas furnace to a high efficiency furnace is in line with manufacturers claims.

The calculation is based on the results of the Conditional Demand Analysis ("CDA") portion of the 2008 REUS. The CDA assigns Unit Energy Consumption ("UEC") values for various natural gas end uses by housing type and region through mathematical modelling and billing analysis. The CDA model takes into account not only the efficiencies of the installed furnaces, but factors such as the efficiency of the building envelope, secondary heat, the square footage of the home and solar gain to calculate the consumption per appliance.

The allocation of consumption by furnace efficiency is based on the UEC for furnaces, the percentage of each type of furnace installed in the residences participating in the REUS and the overall efficiency level of each furnace type. The ratings assigned to each were of 67 per cent for standard efficiency and 93 per cent for a high efficiency furnace. These efficiency ratings are within established industry norms.

20.2 Figure 4-3 on p. 80 summarizes BC housing starts from 2000 to 2011F. Please discuss why Terasen Utilities rely on housing start data rather than housing completion data provided by CMHC.

Response:

The Terasen Utilities rely on housing start data as they provide a good proxy for growth in its customer base. The CMHC periodically provides forecasts of housing starts across the province of British Columbia. Relying on housing completions data in forecasting the demand for natural gas is not an option since housing completions are not forecast, and are only reported as actual results become available.

21.0 Reference: Exhibit B-1, Chapter 4, p. 82

Natural Gas Competitiveness

"The review of energy alternatives for space heating finds that natural gas remains at a similar level of competitiveness with respect to electricity as it has in recent years when factoring in the increases in carbon tax costs and the difference in upfront capital costs between electricity and natural gas heated homes."

21.1 Based on 2010 prices, please provide a comparison between the cost of residential heating ($/GJ) between natural gas and electricity sources of energy. Please assume a residential heating requirement of 60 GJ/year and include all associated costs and taxes.

The Terasen Utilities believes that natural gas currently remains at a similar level of competitiveness with respect to electricity sources of energy as it has in recent years. This analysis, however, does not factor in larger societal forces in terms of future public policy, potential increases in the carbon tax, changing public perceptions of burning fossil fuels, GHG emission reduction targets and changes to regulation that impact energy use. These future uncertainties will ultimately influence the future competitiveness of natural gas as much or more than a basic cost-benefit analysis

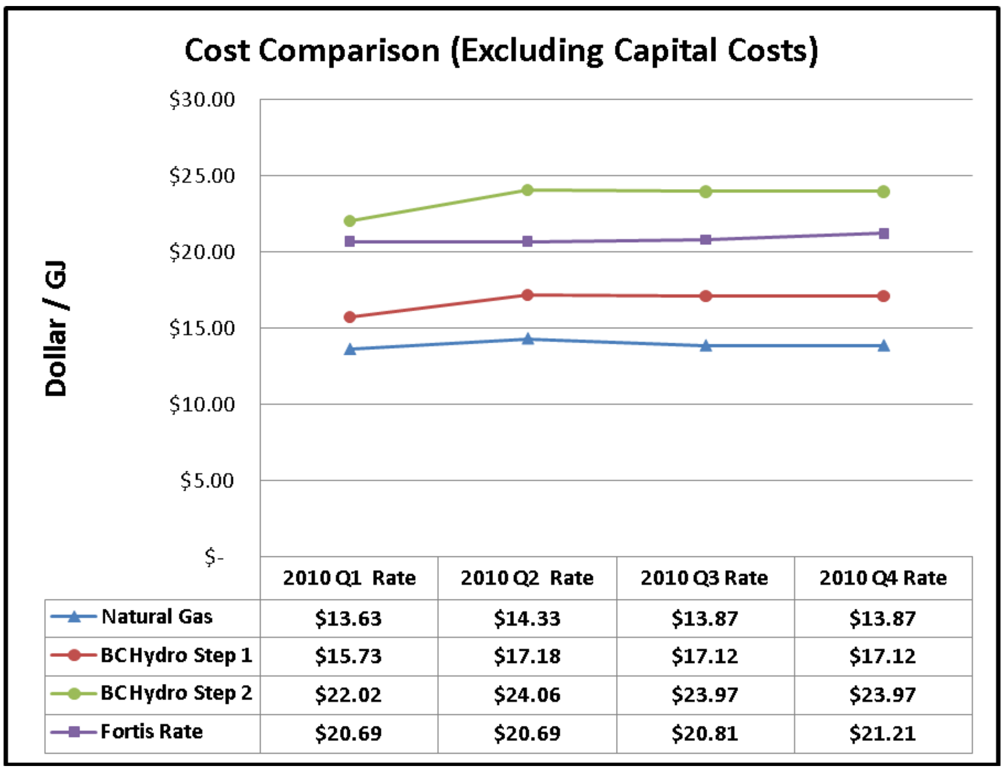
The table below provides a summary comparison between the cost of residential heating ($/GJ) for natural gas and electricity sources of energy based on 2010 prices. The 60GJ/year assumption was used to calculate total tax and capital cost impacts on the $/GJ figures. For a complete breakdown of rate components and calculations, please see attached fully functional spreadsheet.

		90% Efficiency		
Cost of residential heating ($/GJ)	**Natural Gas**	**BC Hydro (Tier 1)**	**BC Hydro (Tier 2)**	**FortisBC Bi-monthly residential rate**
Based on Q1 Rates	$ 13.63	$ 15.73	$ 22.02	$ 20.69
Based on Q2 Rates	$ 14.33	$ 17.18	$ 24.06	$ 20.69
Based on Q3 Rates	$ 13.87	$ 17.12	$ 23.97	$ 20.81
Based on Q4 Rates	$ 13.87	$ 17.12	$ 23.97	$ 21.21

The calculations in the above table were based on the following assumptions:

- The efficiency of gas equipment is assumed to be 90%, relative to 100% for electricity to determine equivalent electricity.
- The electric rates do not include the fixed monthly charges since it is assumed that a household already pays the base electric charges for non-heating use.
- The consumption of electricity for non-heating purposes will depend on various factors such as differences in size of premises, number of family members and their ages, quantity and brands of electrical appliances and usage patterns.
- All other associated costs and taxes are included, with Harmonized Sales Tax (HST) calculated at 5% to reflect the 7% residential energy credit.
- Electricity Equivalence rate determined based on GJ to kWh conversion:
    - 1 GJ = 277.8 kWh
    - 60 GJ = 16666.7 kWh
- FortisBC electric rate for Q3 is a weighted average of the Q2 residential rate and the new residential rate that became effective on September 1, 2010.
- The natural gas costs include midstream, commodity and delivery rates along with all other associated costs.

The figure below illustrates the comparative residential heating costs ($/GJ) based on an annual residential heating requirement of 60GJ/year.



	2010 Q1 Rate	2010 Q2 Rate	2010 Q3 Rate	2010 Q4 Rate
Natural Gas	$13.63	$14.33	$13.87	$13.87
BC Hydro Step 1	$15.73	$17.18	$17.12	$17.12
BC Hydro Step 2	$22.02	$24.06	$23.97	$23.97
Fortis Rate	$20.69	$20.69	$20.81	$21.21

As can be seen in the above figure, natural gas remains competitive against electricty on an operating cost basis. Nonetheless, this comparison does not consider the required recovery of the upfront capital costs, such as installing a natural gas furnace. Natural gas must maintain a significant annual operating cost advantage over electricity due to a significantly higher upfront capital cost requirement.

The capital and installation cost for a new natural gas high efficiency furnace and ducting system is approximately $7000[25] compared to an upfront capital cost of $2500[26] for the installation and purchase of electric baseboards. Assuming an interest rate of 6% and a measurable life of a high efficient furnace of 18 years, the capital cost of a high efficient furnace amortized over its measurable life is $646.00 per year. Comparatively, the yearly capital cost of electric baseboards amortized over the same period is significantly lower at $230.89.

When factoring in an average yearly maintenance cost of $100.00[27] for a furnace, a natural gas customer must recover $515.61 per year for 18 years to pay off the difference in capital costs. In other words, natural gas rates must be $8.59 per GJ cheaper than electricity rates for 18 years, assuming a residential heating requirement of 60 GJ per year, in order for natural gas to be competitive relative to electricity sources of energy. The impact of capital costs and furnace maintenance in dollars per GJ results in the addition of $12.44 per GJ over existing rates for a natural gas customer. For electricity energy users, the capital cost impact is equivalent to the addition of only $3.85 per GJ over existing rates.

The table below summarizes the yearly capital cost calculations[28].

[25] All the figures taken from Figure 2-11, Chapter 2, P.27 – 2010 LTRP.
[26] Ibid.
[27] Ibid.
[28] Calculations adjusted to 60 GJ based on Figure 2-11, Chapter 2, P.27 – 2010 LTRP.

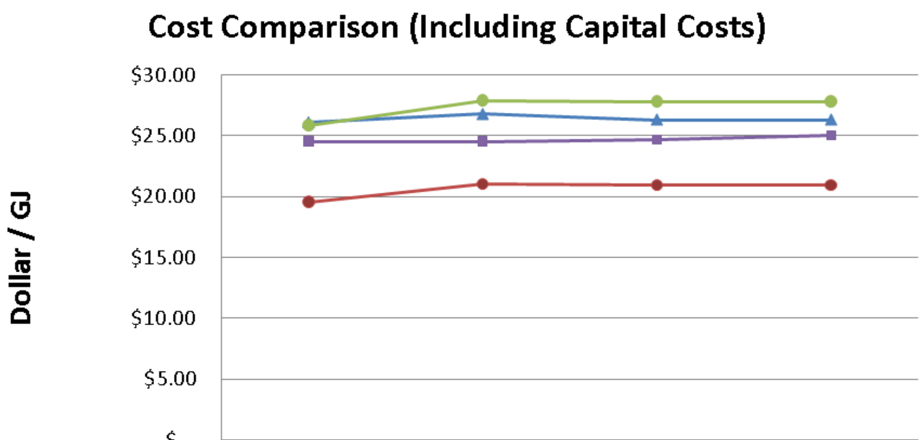
Interest Rate: 6%

Natural Gas	
Up Front Capital Cost for High Efficient Furnace and Ducting/Installation	$7000.00
Measurable Life of Furnace (Years)	18
Capital Cost Spread Over Measurable Life (per year)	$646.50
Add Annual Furnace Maintenance	$100.00
Total Yearly Capital Cost	**$746.50**
Additional $ per GJ for Capital Cost Recovery[29]	**$12.44**

Electric Energy Source	
Up Front Capital Cost for Electric Baseboards	$2500.00
Capital Cost Spread Over Measurable Life of a High Efficient Furnace and Ducting/Installation (per year)	$230.89
Total Yearly Capital Cost	**$230.89**
Additional $ per GJ for Capital Cost Recovery[30]	**$3.85**

After taking recovery of the upfront capital costs into account, natural gas remains competitive with electric sources of energy today. The figure below illustrates the dollar per GJ comparison between residential heating with natural gas and electricity sources of energy inclusive of the required capital costs.

[29] Based on 60 GJ/year consumption.
[30] Based on 60 GJ/year consumption.



	2010 Q1 Rate Plus Respective Capital Costs	2010 Q2 Rate Plus Respective Capital Costs	2010 Q3 Rate Plus Respective Capital Costs	2010 Q4 Rate Plus Respective Capital Costs
Natural Gas	$26.08	$26.77	$26.31	$26.31
BC Hydro Step 1	$19.57	$21.03	$20.97	$20.97
BC Hydro Step 2	$25.87	$27.91	$27.82	$27.82
Fortis Rate	$24.54	$24.54	$24.66	$25.06

As the figure above illustrates, natural gas today remains competitive with respect to electricity when factoring in the increases in carbon tax costs and the difference in upfront capital costs between electricity and natural gas heated homes.

Please refer to Attachment 21.1 for the fully functional spreadsheet.

21.1.1 Please repeat the above question for new constructions that includes a cost comparison for natural gas and electricity alternatives including the capital cost of appliances and installation. Please provide a copy of your calculations in the form of a fully functional electronic spreadsheet.

Response:

Please refer to the response to BCUC IR 1.21.1.

22.0 Reference: Exhibit B-1, Chapter 4, pp. 83-84

Commercial Use Rate

"Reasonable assumptions with respect to future average use per customer were developed for each sector by analyzing historical trends in consumption and considering expected efficiency improvements based on currently planned Commercial EEC programs."

22.1 Please provide details of the assumed average use per customer for each consuming sector that was adopted by Terasen Utilities in developing the LTRP forecast for 2012 to 2030.

Response:

The tables below illustrate the Year–end Use Per Customer for TGI Commercial Rate Schedule 2, Rate Schedule 3 and Rate Schedule 23 customers, in TJs.

Sector Rate 2	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25	Dec-26	Dec-27	Dec-28	Dec-29	Dec-30
Apartment/Condo	488	482	476	471	465	460	454	449	443	438	433	427	422	417	412	407	402	398	393
Wholesale/Retail	236	233	231	229	226	224	222	220	218	215	213	211	209	207	205	203	201	199	197
Restaurant	495	496	497	498	499	500	501	502	503	504	505	506	507	508	509	510	512	513	514
Commercial/Office Building	216	210	204	198	192	187	181	176	171	166	161	156	152	147	143	139	135	131	127
Education	594	578	562	547	532	518	504	490	477	464	452	439	428	416	405	394	383	373	363
others	278	273	269	265	261	257	253	250	246	242	239	235	231	228	225	221	218	215	211

Change in UPC:

Sector Rate 2	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25	Dec-26	Dec-27	Dec-28	Dec-29	Dec-30
Apartment/Condo		-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
Wholesale/Retail		-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
Restaurant		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial/Office Building		-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%
Education		-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%
others		-2%	-1%	-1%	-2%	-2%	-2%	-1%	-2%	-2%	-1%	-2%	-2%	-1%	-1%	-2%	-1%	-1%	-2%

Sector Rate 3	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25	Dec-26	Dec-27	Dec-28	Dec-29	Dec-30
Apartment/Condo	2,874	2,818	2,763	2,710	2,657	2,605	2,555	2,505	2,457	2,409	2,362	2,316	2,271	2,227	2,184	2,142	2,100	2,059	2,019
Wholesale/Retail	2,919	2,890	2,861	2,832	2,804	2,776	2,748	2,721	2,693	2,667	2,640	2,613	2,587	2,561	2,536	2,510	2,485	2,461	2,436
Restaurant	2,534	2,524	2,514	2,504	2,494	2,484	2,474	2,464	2,454	2,444	2,434	2,425	2,415	2,405	2,396	2,386	2,377	2,367	2,358
Commercial/Office Building	2,739	2,649	2,562	2,478	2,396	2,318	2,242	2,168	2,097	2,028	1,961	1,897	1,835	1,774	1,716	1,660	1,605	1,552	1,501
Health	3,385	3,273	3,165	3,061	2,960	2,862	2,768	2,677	2,588	2,503	2,420	2,340	2,263	2,188	2,116	2,046	1,979	1,914	1,850
Others	2,849	2,743	2,642	2,544	2,450	2,359	2,272	2,188	2,107	2,029	1,954	1,882	1,812	1,745	1,680	1,618	1,558	1,501	1,445

Change in UPC:

Sector Rate 3	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25	Dec-26	Dec-27	Dec-28	Dec-29	Dec-30
Apartment/Condo		-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%
Wholesale/Retail		-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
Restaurant		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial/Office Building		-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%
Health		-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%
Others		-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%

Sector Rate23	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25	Dec-26	Dec-27	Dec-28	Dec-29	Dec-30
Apartment/Condo	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943	3,943
Education	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701	4,701
Greenhouse	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875	9,875
Wholesale/Retail	5,335	5,282	5,229	5,177	5,125	5,074	5,023	4,973	4,923	4,874	4,825	4,777	4,729	4,682	4,635	4,588	4,543	4,497	4,452
Government Building	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339	4,339
others	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104	5,104

Change in UPC:

Sector Rate23	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25	Dec-26	Dec-27	Dec-28	Dec-29	Dec-30
Apartment/Condo		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Education		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Greenhouse		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Wholesale/Retail		-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
Government Building		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
others		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

TGI UPC	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25	Dec-26	Dec-27	Dec-28	Dec-29	Dec-30
Rate 2	320	319	318	318	317	316	316	315	314	314	313	312	312	311	310	310	309	309	308
Rate 3	3260	3260	3260	3261	3261	3261	3261	3262	3262	3262	3262	3262	3262	3262	3263	3263	3263	3263	3263
Rate 23	4955	4956	4957	4958	4959	4960	4961	4962	4963	4964	4965	4966	4967	4967	4968	4969	4970	4971	4971

The tables above show, that over the forecast period, the use rates for the top sectors are declining at a steady rate. These expected declines are attributed to the expected efficiency improvements based on currently planned Commercial EEC programs.

23.0 Reference: Exhibit B-1, Chapter 4, pp. 84-85

Commercial Use Rate

23.1 Terasen Utilities classify apartment and condominium customers as both commercial and industrial customer class. Please provide a brief description of the typical end user profile for each of Terasen's rate schedule.

Response:

The Terasen Utilities' customers are first segmented into three major classes- Residential, Commercial and Industrial customers. These customers are further segmented into specific customer classes based on volumetric measure or annual consumption.

Our industrial customers are made up of a variety of sectors depending on their industry standards and codes. Each customer within each sector consumes varied amounts of gas throughout the year. As a result, a customer that falls under an apartment /condo industry sector may be under either a commercial or industrial rate schedule depending on the customers' total consumption.

Please see Attachment 23.1 for a list and description of customer segments, service regions and rate classes.

23.2 Are commercial consumption weather normalized? Is the normalization methodology similar to that for residential use rate?

Response:

Commercial consumption is weather normalized, for the purpose of removing the weather effect for reviewing and forecasting energy use within the commercial sector.

Both Commercial and Residential use the same normalization methodology.

24.0 Reference: Energy Forecasting

Exhibit B-1, Chapter 4, p. 88

Robust Growth Scenario

The Application describes, under the robust growth scenario, that natural gas price advantage improves with respect to electricity due to larger than expected increases in electricity rates while natural gas costs remain stable.

24.1 Under the proposed new end-use forecasting methodology, is it true that the movements in natural gas prices would not be an input into the end-use models? If not, please describe how natural gas prices are used as inputs.

<u>Response:</u>

Under the proposed end-use methodology, the Terasen Utilities have not yet developed a formal mechanism to incorporate external factors such as the price of natural gas or other competing fuels. The models are still under development. The Terasen Utilities intend to determine the most appropriate treatment of the many external factors including the price of natural gas that impact the demand under the proposed end use methodology.

Under the current methodology, the Terasen Utilities have given the natural gas price a consideration when estimating the effects of natural gas commodity price levels on the demand for natural gas, and have done so through the use of regression analysis. Specifically, the Terasen Utilities have adopted a statistical model that determines the relationship between the annual demand for natural gas and natural gas commodity prices to estimate the effects of changes in natural gas commodity price on use rates. This is more commonly referred to as the price elasticity of demand for natural gas.

24.2 If the response to the above question is yes, does it mean that cross-elasticity will not be reflected in the forecasts?

Response:

The Terasen Utilities considered cross price elasticity while preparing the robust growth scenario, but have not developed formal models to incorporate the inputs and assess the effect on demand for natural gas. The Terasen Utilities are still in the process of developing their end-use model and considering natural gas prices as an input to the demand forecast to reflect cross-price elasticity.

25.0 Reference: Exhibit B-1, Chapter 4, p. 88

Upper and Lower Bound Scenarios for Demand Forecasting

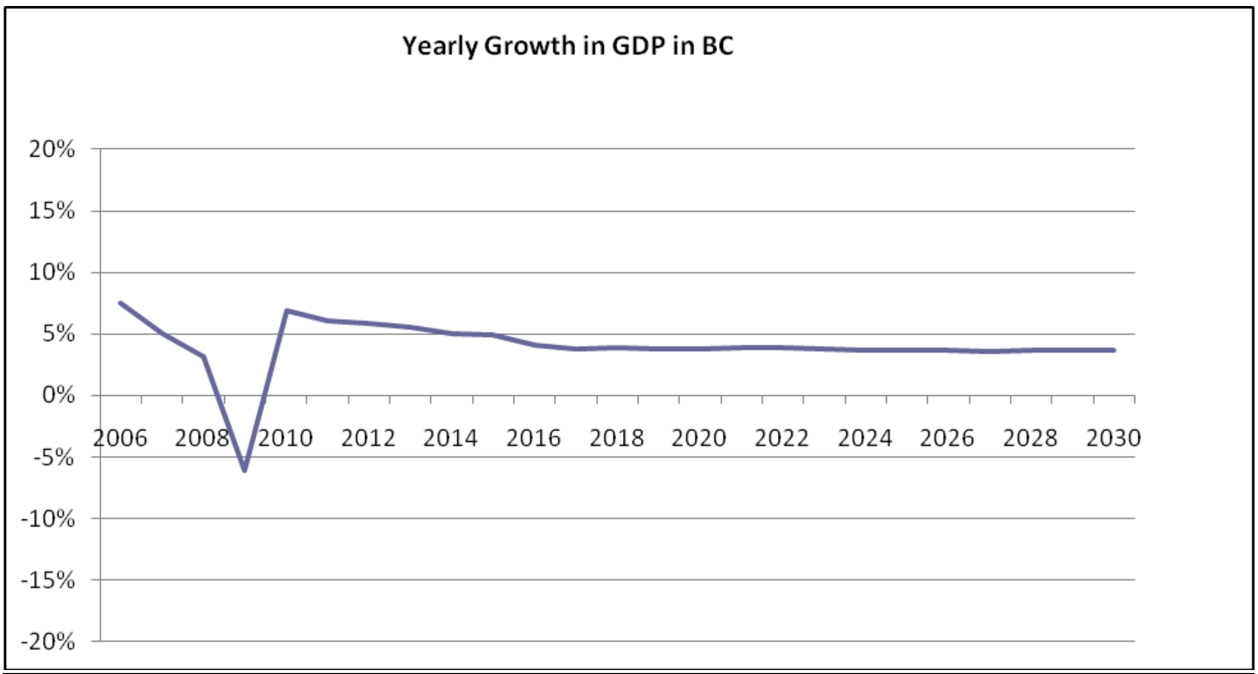
25.1 In tabular and graphical formats, please provide the base case GDP (nominal and real) statistics for British Columbia for the period 2005 to 2012 (historical and projections) and 2013 to 2030 (forecasts) for all three scenarios.

Response:

The following table illustrates the BC GDP growth rates based on the Long Term Forecast from the Conference Board of Canada over the period from 2006 to 2030.

GDP BC	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Growth Rate	8%	5%	3%	-6%	7%	6%	6%	6%	5%	5%	4%	4%

GDP BC	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Growth Rate	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%



As can be seen from the above graph, GDP is expected to grow at a rate of 6% over the next few years, then return to a more stable growth pattern with the expected long term growth rate of approximately 4%.

The Terasen Utilities reviews and monitors economic indicators such as GDP over time as these indicators help to understand the general direction in which the economy is heading. GDP growth, which provides a measure of the overall condition of the economy, is typically used to validate the forecast of industrial demand. As such, rather than being used explicitly, the impact of GDP was considered in a qualitative manner that validates or supports the forecast demand.

25.2 What probabilities have been assigned to robust, reference and low growth scenarios? Please provide a brief description of the impact of each scenario on forecasted demand and carbon emissions.

Response:

The Terasen Utilities have not assigned probabilities to the three demand scenarios due to the complexity of the factors impacting the demand for natural gas. The Terasen Utilities are of the view that the reference case represents a reasonable scenario that would be expected to occur based on historical analysis and an ongoing analysis of market trends. Rather than relying upon a single outcome, however, Terasen Utilities have developed an upper and lower range of demand scenarios that enable the Terasen Utilities to ensure that plans are in place to address the loads associated with those scenarios should they materialize. Although Terasen Utilities do not associate a probability to either the high or low case, the reference case is considered the most likely outcome. In the absence of better information at this point in time, there is equal probability of either upper or lower scenario occurring during the planning period.

As carbon emissions are directly related to consumption, and the demand for natural gas under the high and low scenarios is 16% greater and 11% lower, respectively, than that for the reference case, the Terasen Utilities estimate the resulting carbon emissions under the high and low scenarios to be 16% greater and 11% lower, respectively, than that for the reference case.

26.0 Reference: Exhibit B-1, Chapter 4, pp. 90, 92

Annual Demand Forecast

26.1 Can the data that make up Figure 4-9 be referenced to the tables in Appendix B-2? Please confirm whether the data in Figure 4-9 are 'before' or 'after' EEC savings. If 'after EEC savings', please provide details of assumed annual EEC savings.

Response:

The Terasen Utilities confirm that the data that makes up Figure 4-9 is derived from the Appendix B-2. Data in Figure 4-9 is 'after' EEC savings.

Please also refer to the response to BCUC IR 1.15.1.1, which provides the Annual EEC savings for TGI and TGVI.

26.1.1 Please extend Figures 4-9 and 4-10 to include actual demand (TJ) for the period 1992 to 2010. Please also provide disaggregated information by: (i) utility and (ii) customer rate group. Please provide tabular data and graphical representation in the form of a fully functional electronic spreadsheet.

Response:

Please see Attachment 26.1.1 for a fully functional spreadsheet which illustrates the historical actual results.

27.0 Reference: Design Day Demand

Exhibit B-1, Chapter 4, p. 93; Appendix B-4

Design Day

The design day temperature represents the coldest daily temperature that would be expected to occur once every twenty years.

27.1 Please explain why once every 20 years was selected instead of 10 years or 30 years. Is there an industry standard for natural gas utility when planning for design day demand? Do the Utilities use a 20-year design day temperature for all of their regulatory filings? If not, please explain why.

Response:

The "coldest day planned for", also referred to as the design day, represents the coldest day that is expected to occur once every 20 years, determined through an extreme value analysis. The return period of once every twenty years is used as it is consistent with past practice at TGI. This provides a reasonable timeframe from a planning perspective when the Terasen Utilities obligations to meet firm customer demand. The Terasen Utilities are not aware of an industry standard regarding the most appropriate return period. There is a range of design day criteria in use. Through attending conferences and having informal discussions with other utilities and consultants, the Terasen Utilities conclude the use of a one in twenty year return period to be a reasonable approach.

27.1.1 Have the Terasen Utilities interrupted customers due to peak day demand? If so, please provide a list of interruption to customers in the past 10 years by customer sector and by region; and describe if the interruption was due to adequate supply or infrastructure capability.

Response:

The Terasen Utilities have not interrupted any firm customers such as residential, commercial or small industrials (Rate Schedules 1 to 6) on their systems due to cold weather or peak day conditions. However, large industrial customers who have interruptible contracts or firm / interruptible contracts with the Terasen Utilities have experienced interruptions due to weather related events over the past 10 years. The service interruptions occurred in the Lower Mainland, Interior and on the TGVI system encompassing a wide range of business sectors. Contracts that are interruptible or include an interruptible component with large volume customers allow the Terasen Utilities to effectively manage the load resulting in no service interruptions to firm core customers such as the residential, commercial and small industrial customers during a cold snap or peak weather conditions. Some large interruptible customers have the ability to operate on alternative fuel sources should their gas services undergo any type of interruption during a given period.

In the Lower Mainland region, large industrial customers that had Rate Schedule 7, 22 and 27 contracts were interrupted for a total of 6.5 days (3 days in 2004, 1.5 days in 2006 and 2 days in 2008) while customers in the Interior region were interrupted for 1 day in 2006. The firm contract demand for industrial customers on the TGVI system has not been interrupted; however, there have been instances during peak winter conditions where requests for interruptible service in excess of firm contract demand has been restricted. Therefore, TGVI’s customers were not permitted to draft any linepack from that pipeline’s system due to additional demand while maximizing available pipeline capacity. Additionally, the Terasen Utilities has also restricted individual or small groups of customers in specific areas across the utilities as certain regions reach capacity restrictions.

Customer interruptions during peak weather conditions mainly result from capacity constraints on the various systems of the Terasen Utilities as a result of the high level of demand imposed by the firm core customers.

27.2 If ’10 year period’ had been used instead of ’20 year period’, what would the impact on the design day temperature and the figures in Table 3 in Appendix B-4?

Response:

Through applying the Extreme Value Analysis as described in the response to BCUC IR 1.3.2 from the 2008 TGI Resource Plan and also applying a ten-year return period, the resulting design day temperatures have been estimated. The following table illustrates the design day temperatures under both a 10-year and a 20-year return period.

Service Area	Design Temperature (Degrees Celsius) based on **20 year return period**	Design Temperature (Degrees Celsius) based on **10 year return period**
Lower Mainland	-12.8	-11.2
Inland	-26.1	-23.2
Columbia	-31.4	-30.0
Fort Nelson	-43.1	-41.6
TGVI	-10.7	-10.1
TGW	-23.3	-20.9

By applying both the ten and twenty-year return period design day temperatures to the design day models filed in the 2010 LTRP, the design day demand under both scenarios' was estimated. The following tables illustrate the design day demand estimated to occur when applying a 10-year return period and 20-year return period.

Design Day Demand based on a 10-year return period (TJ/Day)

Contract Year	09/10	10/11	11/12	12/13	13/14	14/15
Columbia	28	28	28	29	29	29
Coastal	870	877	884	891	898	906
Ft. Nelson	5	5	5	5	5	5
Inland	277	280	284	287	291	295
TGVI	108	112	116	120	123	127
TGW	7	7	7	7	7	7

Design Day Demand based on a 20-year return period (TJ/Day)

Contract Year	09/10	10/11	11/12	12/13	13/14	14/15
Columbia	28	29	29	30	30	30
Coastal	918	926	933	940	948	955
Ft. Nelson	5	6	6	6	6	6
Inland	297	301	305	309	313	317
TGVI	110	114	118	122	126	130
TGW	7	7	7	7	7	7

The expected changes on design demand due to moving from a 20-year to a 10-year period are an approximate 3% reduction in COL, 5% for LML, 10% for FTN, 7% for INL, and 2% for TGVI.

A return period of less than 20 years would result in a warmer design day temperature and subsequently a lower design day demand being estimated for the core customer segment. Given that the Terasen Utilities are the provider of last resort and are obligated to provide energy even under extreme weather conditions, the Terasen Utilities believes that a return period of 20-years is more appropriate for estimating design day temperatures than 10 years.

27.3 Terasen Utilities forecast a modest growth in design day demand for each of the utilities for the current planning period due to modest growth in customer additions. Please comment if the new customers (whose use of space heating is depicted in Figure 4 of Appendix B-5) are the main driver of design day demand growth.

Response:

The Terasen Utilities confirms that the main driver of design day demand growth will be new customers whose space heating demand is depicted in Figure 4 of Appendix B-5 of the LTRP. To a lesser extent additional customers will be added from the conversion activities of existing homes that previously did not have access to natural gas.

28.0 Reference: Energy Forecasting

Exhibit B-1, Appendix B-5

End-use Methodology versus Current Methodology

The Application mentions that "the Utilities are adopting an end-use natural gas demand forecasting methodology that complements and may in the future replace its current natural gas demand forecasting approach."

28.1 Please provide a summary, in tabular format, of the pros and cons of both the end-use and the current natural gas demand forecasting methodologies. Under what circumstances would Terasen Utilities replace the current methodology with the end-use methodology instead of having them complement one another?

Response:

The pros and cons of both the end use and existing natural gas demand forecasting methodologies are provided in the tables below.

End Use Methodology:

Pros	Cons
• Incorporates customer end-use data such as the type of appliance broken out by end uses (space heating, water heating etc), housing type and also region, which together add a level of rigour to the forecast. • Consideration of differences in behaviours and future energy decisions between new and existing customers allows for scenario analyses to be more readily developed. • Break out of new customers by housing types and end-uses enables more flexible segmentation and views of the data. • Greater flexibility is introduced, also lending itself to scenario analyses (as the inputs that are derived from studies and research can be modified and/or revised over time as customer behaviours evolve over time). • Provides a stronger basis for sensitivity analysis and scenario development when considering long term natural gas demand. • Further customer segmentation and appliance detail will help with future Rate Design analysis.	• Very little end use and housing type data makes it challenging for historical trending. • Limited regional data is available across the relatively smaller Terasen Utilities such as TGVI, FTN, and TGW. • Limited data regarding fuel choice considerations by end-use for the most recent customer additions presents challenges when forecasting. • Lack of awareness on consumer perceptions and influencers on the choice of fuel for future customer additions also present challenges when forecasting • Reliability on primary research data on a continuous basis to update the model can be questionable due to sampling.

Existing Methodology:

Pros	**Cons**
• Historical use rate and customer data are available by customer class and regions. • Models have been developed and validated both internally and by stakeholders. • There is a high degree of confidence in existing methodology and models to estimate future gas consumption. • Limited need for end use data and ongoing market research studies. • More appropriate for near term views such as the revenue requirement application.	• Since based largely on historical trends, less able to capture changes currently underway in energy markets, planning and policy. • No separation between existing and new customers. • No ability to incorporate end use behaviours. • It is challenging to forecast customer additions by housing type and end use. • No incorporation of end use data broken out by housing type and region. • It is challenging to develop scenarios that assume customer behaviours and preferences evolve over time. • Relies heavily on historical data to predict future use rates.

It is too early to state the circumstances under which the Terasen Utilities would replace the current methodology with the end-use methodology instead of having them complement one another. This is the first time that the Terasen Utilities have introduced the end use methodology and the Terasen Utilities need time to fully develop and implement it, verify the quality of the forecasting information it will provide and develop stakeholder confidence in its use.

29.0 Reference: Energy Forecasting

Exhibit B-1, Appendix B-5

Existing and New Customers

29.1 For clarity, could Terasen Utilities explain if new customers mean new accounts in new buildings? Are customers who have retrofitted or renovated their houses (e.g., new furnaces, upgraded windows, new insulation, etc.) considered existing customers?

Response:

New customer additions mean either new accounts in new buildings or new accounts in existing buildings that currently don't have natural gas. Customers who are currently on the gas system and retrofit or renovate their homes are considered existing customers.

30.0 Reference: Energy Forecasting

Exhibit B-1, Chapter 4, p. 103

Alternative Energy Forecasting Method

Terasen Utilities estimate that the current level of energy efficiency and conservation program funding that is available as part of the Innovative Technologies portfolio could support the implementation of 33 single family homes and townhomes per year.

30.1 Please provide the data and the underlying assumptions used in creating Figure 4-21.

Response:

Figure 4-21 in Exhibit B-1 is a comparison of the annual natural gas usage of homes with high efficiency natural gas space heating equipment versus the same homes with ground source heat pump space heating systems backed up by natural gas. The figure was developed for discussion purposes only, based on a potential EEC program under consideration within current funding levels and assuming that same level of funding is available through the year 2020.

The high efficiency natural gas space heating data assumes a 90% or higher efficiency furnace, single family home in the LML region with approximately 2300 Sqft. The data for natural gas demand in the ground source heat pump systems assumes a similar home and that the conventional natural gas back-up system is employed to supply 30% of that homes annual peak energy needs, or in other words, 30% of the energy consumed by a conventional system alone. The comparison assumes only natural gas usage and does not include electricity.

The annual total energy consumption comparison that appears in Figure 4-21, is based (as described in the paragraph before the figure) on installing each type of system in 33 homes per year over the analysis period. The 33 homes were established as follows. The Terasen Utilities allocated $100,000 from the Innovative Technologies portfolio from the 2010 approved EEC funding for ground source heat pump (GSHP) with gas back up technology for planning considerations. An incentive amount of $3,000 was estimated to be a reasonable amount to incent homeowners to install GSHP over conventional high efficiency gas equipment, based on internal research and informal conversations with industry associations. This resulted in approximately 33 homes per year becoming eligible for this program and that figure was used as an input to demonstrate the impact on carbon emissions and natural gas savings. The Terasen Utilities would like to point out that the innovative technologies portfolio is still under planning and information gathering stages and at this point in time no formal pilot program has been rolled out for GSHP technology for single family homes.

31.0 Reference: Exhibit B-1, Chapter 4, pp. 105-111

Natural Gas as a Transportation Fuel

31.1 Terasen Utilities has provided three NGV demand scenarios: Favorable, Plus Passenger, and Low Demand. In tabular format, please provide a quantitative comparison of the key assumptions for each scenario by including all appropriate factors including those referred to under Section 4.3.3: incentive levels, funding expectations, natural gas prices, availability of fuelling infrastructure, annual rate of market penetration, level of tax breaks, cost of converting vehicles to natural gas, etc. To the extent possible, please assign probabilities to each assumption.

Response:

The Terasen Utilities have provided three possible NGV demand scenarios in order to analyze and discuss the impact of different levels of potential future customer incentive funding on natural gas demand and GHG emission savings. The demand scenarios are based on market research with customers, equipment suppliers, government policy makers and other stakeholders with knowledge of NGV markets. The three scenarios presented in the LTRP are intended to provide a reasonable range of possible outcomes. The specific assumptions are provided in Section 4.3.3.of the LTRP but are summarized below for convenience.

The Low Growth scenario is one where incentives stimulate market growth, but growth does not extend beyond the funded projects. The Reference case is the scenario where the incentives lead to a degree of market transformation where growth levels continue beyond funded projects. The third scenario is one in which growth in the primary fleet markets are supplemented with a degree of market penetration in the passenger vehicle market.

The intent of providing these scenarios was to provide a range of possibilities that reflects the Terasen Utilities view of the range of outcome that may result from our NGV market development activities. The demand scenarios are, however, forecasts of possible developments in an emerging market and are therefore subject to inherent uncertainty. There are many factors influencing the market and these matters will be discussed as part of the upcoming Transportation Fuelling Service Application that TGI expects to submit by the end of 2010.

The Terasen Utilities also believe that it is not practical to assign probabilities to the myriad of possible combinations of factors that could influence rates of market adoption. Rather, TGI believes the more prudent approach is to recognize the level of uncertainty and to manage the risk through a market penetration strategy that focuses on a 'user pay' approach, through full cost of service rates over the contract term and 'take or pay' agreements with customers. A second line of risk management is to stage investments on a gradual project-by-project basis. These strategies will be explained in the more detailed application.

In addition to the risk mitigation measures outlined above, it should be noted that the load building benefits of adding NGV demand to the system are very significant to existing customers.

32.0 Reference: EEC

Exhibit B-1, Chapter 5, p. 115

Cost-Benefit Criteria

"We believe that the current cost-benefit criteria for some programs are outdated and limit the benefits that can be delivered for emission reductions and for certain customer groups such as low income earners."

32.1 Are all current cost-benefit criteria outdated? If only some, please list those that are outdated in the opinions of Terasen Utilities and give reasons for your conclusions that they are outdated.

Response:

The Terasen Utilities are finding that the current TRC test approach in measuring the success of EEC expenditures may not be appropriate in all cases as Government puts greater emphasis on Utility DSM programs to meet climate reduction goals. In order to be considered adequate, utilities DSM portfolios must incorporate demand side management measures for low income households and rental housing, and education programs for school and post-secondary students. The TRC test as outlined in the California Standard Practice Manual was originally developed in 1983. In the energy efficiency world, much has changed in the intervening 27 years.

Below, the Terasen Utilities have provided examples of programs and reasons where the current cost -benefit criterion may be outdated and have outlined next steps to evaluate alternate approaches.

In the case of low-income households, the entire cost of the measure must be covered by an EEC program in order to achieve any degree of program participation. In this case, the "incremental cost" considered in the TRC is in fact the entire cost of the measure. Costly items such as furnace and boiler replacements for low-income households fail the TRC as the energy savings over the lifetime of the equipment are not adequate to cover the entire cost of equipment replacement, even with the 30% "bump" in benefits allowed for in the DSM Regulation.

Another example of an EEC measure that has great merit is geoexchange systems for schools. Such a measure will supporting this sector of government buildings to achieve their legislated climate change targets, while at the same time providing an exceptional educational opportunity. Schools are government buildings, and as such must be GHG neutral by 2012. They are also ideal for geoexchange installations as they typically have playing fields into which the geoexchange loops can be placed. Schools, however, have relatively low energy usage as they have low domestic hot water demand, and are typically unoccupied at night and on weekends, so the energy savings available from geoexchange installations in schools are not adequate to cover the high cost of this technology, and thus fail the TRC test. A widespread program for geoexchange installations in schools would provide an outstanding opportunity to educate this generation of school age British Columbians about climate change and greenhouse gas reduction strategies.

Another example of a program with great GHG emissions reduction merit which is challenged by the TRC is a furnace early replacement program. In this instance, under conventional DSM cost-benefit analysis protocols, the incremental cost in the TRC would likely be considered the entire cost of a furnace installation, pro-rated for the remaining life of the furnace, and the energy savings considered would only be the difference in energy consumption between a high efficiency furnace and a standard efficiency furnace for the remaining life of that furnace, and thus a widespread furnace early retirement program fails the TRC. Education programs such as those required in the DSM Regulation in and of themselves generally fail the TRC as they do not generally provide hard, quantifiable energy savings to offset program costs.

While the Terasen Utilities proposed and had approved a portfolio-level TRC approach in its recent EEC Application, as legislated GHG emissions reduction targets approach and government leans more heavily on utility EEC programs to support these targets, we are finding that the TRC approach originally put forward and approved may not be appropriate in all cases. Attachment 32.1 is a paper called "Is It Time to Ditch the TRC", which lays out some of the reasons why it may be time to reconsider the use of the TRC as the appropriate test in all cases. It should be noted that the Terasen Utilities are not endorsing the use of the Participant test as the appropriate test as the paper suggests.

32.2 In Terasen Utilities' view, is the Commission determination relating to Societal Test still valid? (Ref: pp. 33-34 of the April 16, 2009 Decision on the TGI/TGVI EEC Application) If not, since when has it become invalid considering that the Terasen Utilities had not asked for a reconsideration of the Decision?

Response:

The Terasen Utilities are not putting the Societal Test forward as the appropriate tool for EEC cost-benefit analysis at this time. The Terasen Utilities agree that societal factors have significance but are rather subjective and difficult to measure, as stated in Commission Order No. 36-09 on the TGI-TGVI EEC Application, page 34:

> *The Commission Panel acknowledges the Societal test as one which addresses a broader spectrum of factors not included in the TRC test. While recognising that societal*

factors have significance, the Commission Panel views many of these factors as being rather subjective and difficult to measure. 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 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.

32.3 Ministerial Order 271, BC Regulation 326/2008 dated November 7, 2008 contained explicit cost-benefit criteria in determining cost effectiveness for low income groups. Is this considered part of the current cost-benefit criteria by the Terasen Utilities?

Response:

The 30% "bump" in benefits for low-income groups is incorporated into the Terasen Utilities' cost-effectiveness analysis of programs for this sector, and, as outlined in the response to BCUC IR 1.32.1, this deemed enhancement of benefits is not adequate for some programs for this sector.

33.0 Reference: EEC

Exhibit B-1, Chapter 5, p. 116 Table 5-1; p. 121

Rate Impact

As a result of Commission Order G-36-09 accepting certain expenditures pertaining to the energy efficiency programs and Orders G-140-09 and G-141-09 approving the RRA NSA for TGI and TGVI respectively, the total approved funding for EEC for 2010 and 2011 is $60.229 million for TGI and $12.086 for TGVI.

Terasen Utilities are contemplating to submit a request for on-going funding as part of the 2012 RRA for both TGI and TGVI and have developed three funding scenarios in this LTRP. Under Scenario C, EEC funding would equate to $80 million in 2012 and be fixed at five percent of the Utilities' gross revenue thereafter.

33.1 Assuming that the Scenario C version of EEC is accepted by the Commission for 2012 as part of accepting the 2010 LTRP, please provide a spreadsheet calculation of amortized EEC capital costs and EEC OMA costs. Please present the years from 2012 to 2021 based on the EEC programs from 2008 onward. Please also assume that the gross utility revenues remain constant until 2021.

Response:

The Terasen Utilities are not at this time requesting future funding for EEC activities within this LTRP. The request for future funding will be made in the Terasen Utilities' next Revenue Requirements Application or Applications. Terasen Utilities is anticipating to its next Revenue Requirements in the Spring or Summer of 2011. Further, the development and presentation of EEC Scenario C in the 2010 LTRP was for illustrative and discussion purposes only. It is not certain that EEC Scenario C will be the subject of future funding requests made through the Revenue Requirement Application(s) in 2011. Feedback obtained through the 2010 LTRP regulatory review process will help to inform that request.

As described in more detail in the response to BCUC IR 1.51.5, there is an error in Table 5-1, on page 116 of the LTRP, with respect to the approved funding amounts. This error has led to incorrect approved funding amounts being referenced in the preamble to this IR. The correct total approved funding for EEC for 2010 and 2011 is $55.463 million for TGI and $10.886 million for TGVI.

The intent of providing the different EEC funding scenario within the LTRP relates to the relationship between dollars available for EEC programs and activities and the energy savings from these programs and activities. In general, the more funds there are for EEC programs and activities the greater the energy savings. The EEC scenarios outlined in the LTRP illustrate this point. The Terasen Utilities must secure EEC funding beyond 2012 and the amount of funding that will be requested will be determined based on results of the CPR study that is currently underway.

In responding to BCUC IR 1.51.5, Terasen Utilities has prepared Attachment 51.5 that shows the rate base, cost of service, and rate impacts for each of Scenarios A, B, and C.

To respond specifically to the question 33.1, the amortized EEC capital costs for Scenario C are shown in Attachment 51.5, Tabs 3 (for TGI) and 6 (for TGVI), Pages 1 through 3. Since none of the EEC expenditures have been allocated to TGW for reasons given in the LTRP there is no impact on TGW or its customers.

There are no impacts on OMA costs for TGI or TGVI for any of the three Scenarios since all program and incentive expenditures are captured in the EEC Deferral Account.

<u>Assumptions used in Attachment 51.5</u>

The three scenarios show the impacts of a constant EEC expenditure of $4 million (Scenario A), $35 million (Scenario B) and $80 million (Scenario C) through 2031, except that in Scenario C, beginning in 2022 the EEC expenditure is decreased by $5 million per year. For all scenarios, 80% of the expenditures and any decreases are allocated to TGI and the balance to TGVI.

In calculating the cost of service impact and rates it was also assumed the future income tax rates from 2012 forward would remain constant at 25% and the financing of the Rate Base would be consistent with the 2011 approved ratios and rates. The amortization period for all expenditures starting in 2010 is 10 years; expenditures prior to 2010 were amortized over 3 years.

The impact on customer rates are shown on pages 3 through 6 of each Tab. With constant continuous expenditure at a specified dollar level, at about year 12 or 13 the incremental impact on rates becomes zero as there is very little change or no incremental change in the cost of service from the year before. In the case of Option C, when there is a declining level of expenditure the incremental impact on rates becomes negative, i.e., there is a continuous rate decline. This occurs because the older higher expenditures from the initial years are fully amortized and what is left is the continuing smaller EEC investments which lowers the rate base, earned return, associated income tax expense and amortization expense. The calculated incremental or decremental cost of service is allocated to each rate class proportional to each rate class' contribution to margin using 2011 as a proxy base and then dividing by the rate class annual volumes. For TGVI it is assumed in future years that all transport service customers would be impacted by the change in cost of service from EEC expenditures.

33.1.1 Please calculate the increases to rate base to the utilities for the next four years beginning 2011 as a result of the EEC programs;

Response:

Please see the response to BCUC IR 1.33.1 and 1.51.5 as well as Attachment 51.5, Tabs 3 (for TGI) and 6 (for TGVI), Pages 1-3.

33.1.2 Please describe the rate impact to customers by rate class based respectively on the capital structures and allowed rate of return on common equity for TGI, TGVI and TGW. Please make explicit your assumptions.

Response:

Please see the response to BCUC IR 1.33.1 and 1.51.5 as well as Attachment 51.5, Tabs 3 (for TGI) and 6 (for TGVI), Pages 4-6.

33.1.3 Would TGI contemplate to file a rate design study for review by stakeholders and the BCUC with a view to assess the potential effects to different ratepayer groups? If no, please explain why not.

Response:

At the present time, TGI is planning to file a Rate Design Application in 2012. As part of that Application, the allocation of EEC funding to the different ratepayer groups will be addressed.

34.0 Reference: Exhibit B-1, Chapter 5, p. 119

Innovative Technologies

"Innovative Technologies are defined as market ready technologies that have little or no market penetration in British Columbia … We are conducting market research to determine potential programs for these technologies, and their associated savings. It should be noted that the technologies in this portfolio and the resulting impact on load are subject to change depending on market conditions, including adoption rates and introduction of new technologies."

34.1 Please comment if, and how, the above products and services would change the risk profile of Terasen Utilities.

Response:

The Terasen Utilities assume that the reference to "the above products and services" in the question means the technologies of interest and not the EEC programs that will be developed under the Innovative Technologies funding. The Innovative Technologies funding itself will not have a material impact on the Terasen Utilities risk profile.

Many of the key trends in the energy industry in BC (that the Innovative Technologies funding is considering), such as increasing adoption of ground source heat pumps and migration to lower carbon energy sources, are increasing the risk profile of the Terasen Utilities overall . These issues were thoroughly canvassed in the TGI - TGVI 2009 Return on Equity and Cost of Capital hearing. The Terasen Utilities initiatives in the areas of NGV, biogas and alternative energy developments are strategies being adopted to respond to these increasing risks for the natural gas distribution business in BC. The NGV programs, for example, have the potential to mitigate the risks from declining gas use in other customer classes by increasing system throughput and generating incremental revenues based on the NGV delivery margin collected. The NGV programs will also advance the BC energy objectives by reducing GHG emissions in the transportation sector. The biogas and alternative energy programs also deliver on the BC energy objectives by providing low carbon or carbon-neutral energy solutions while at the same time helping to keep natural gas in the energy future in BC. Only time will tell how successful these initiatives will be and how much they are able to mitigate the growing risks facing natural gas. The Innovative Technologies funding will make an important contribution to finding the path forward in these endeavours.

34.2 Terasen Utilities has stated that they are "conducting market research to determine potential programs for these technologies, and their associated savings". When will the results be available? How do Terasen Utilities propose to proceed with the results, for example, design specific programs in the detailed long-term EEC Plan?

Response:

Initiatives for the Innovative Technologies portfolio are to be run as pilots that would subsequently provide data to enable the Company to establish the appropriate timelines, key milestones and completion dates for expanded program activity in the Innovative Technologies area. The Terasen Utilities will be in a better position to provide information as to the appropriate timelines, key milestones and completion dates for future programs after the Innovative Technologies pilot outlined on pages 114 – 116 in the EEC 2009 Annual Report that was filed with the BCUC on March 31, 2010.

There are pilot initiatives underway to gather data and associated program savings for Solar Thermal technologies. In the first pilot, Terasen Gas Inc. has initiated agreements with the City of Vancouver and SolarBC to pilot a residential program for new construction solar thermal hot water. Details are still being worked on as to the scope, measurement and marketing of this initiative. Energy savings, user acceptance, domestic hot water end use, incremental cost and system performance data will be available one full year from when monitoring systems are installed.

Through the Provincial Sector Energy Conservation Agreement ("PSECA"), the Terasen Utilities, NRCan and SolarBC are also initiating agreements to incent Solar thermal hot water projects for provincial sector buildings, including schools, universities, colleges, hospitals and crown corporations. Discussions are underway to determine the appropriate monitoring solutions to track the systems energy savings and end use domestic hot water amounts on selected projects. In order to gather sufficient data, monitoring will be facilitated throughout a 1 year period from when participants and measurement data is available.

The Terasen Utilities has also 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. Should these come to fruition, consumption data will be available every month and reviewed in one year to determine fuel switching benefits and program roll-out approaches.

Work has not yet commenced on market research on appropriate programs for Hydronic and Combination Heating Systems or GSHP.

34.3 Terasen Utilities defines Innovative Technologies as "market ready technologies that have little or no market penetration in British Columbia". Please also discuss how Terasen Utilities has assessed each of the determinants in reaching the conclusion that they are market ready technologies and that they are suitable for British Columbia. For example, please explain what market failures have occurred to date that could have hindered the emergence of Innovative Technologies in British Columbia and which necessitate financial incentives to be overcome the market failures.

Response:

The Terasen Utilities assess the number of manufacturers, active installers and actual number of systems installed within BC in order to determine if the technology is market ready. There have been several market failures that have affected each technology such as the lack of experienced installers and enforced best practices, limited system performance monitoring and inconsistent funding from provincial and federal governments. All these factors have affected the credibility and adoption of these technologies within British Columbia. The Terasen Utilities believes that offering incentives for market ready technologies will help overcome these shortcomings and add another layer of system enforcement, measurement and awareness. It is to be noted that technologies in the portfolio are subject to change depending on market conditions, introduction of new technologies and obtaining further data.

According to the Canadian Geoexchange database, there are 51 companies within British Columbia under the categories of geoexchange designers and drilling and 70 certified installers. Although the actual numbers of installations would be difficult to ascertain due to customer confidentiality, BC Ministry of Energy, Mines and Petroleum estimates that there are roughly 500 to 1000 installations within BC. Based on these numbers, the Terasen Utilities considers that geoexchange systems are market ready within BC. According to the Canadian Geoexchange Coalition there have been two major barriers. First is the lack of infrastructure ensuring high professional standards and capacity. Second is the limited availability of experienced installers and designers. These resulted in a number of poorly performing systems across the country that affected the credibility of the technology. The Terasen Utilities believes that incentives will encourage an increased demand within British Columbia and allow for other proactive measures to be taken to ensure that the design and the installation of the system encourage energy savings.

In the case of solar thermal technology, there are 29 certified solar installers according to the Solar BC Program and 24 manufacturers that service British Columbia, according to the Canadian Solar Industries Association. Once again, although the actual numbers of installations within BC would be difficult to quantify due to customer confidentiality, BC Ministry of Energy, Mines and Petroleum estimates that there are approximately 500 to 600 systems throughout BC. Based on these numbers, the Terasen Utilities considers that Solar Thermal Hot water systems are market ready within BC. According to the SolarBC Annual Report 2008/09, there have been 5 main market failures:

1. Lack of a standard approach to building code and regulatory requirements for solar hot water (SHW) which results in differing interpretations by building and plumbing officials of requirements for installation of SHW systems.
2. Unstable and changing incentives and requirements for SHW systems to qualify for incentives which create confusion with the public, energy advisors and installers.
3. Low public awareness of the practicality of SHW systems as well as the public's primary concern of immediate payback of SHW systems which results in a lower anticipated adoption rate.
4. Lack of certified installers in many BC communities makes SHW installations unavailable to residents or overly expensive due to travel costs for installers.
5. Lack of monitoring and evaluation regarding the systems performance and energy savings.

The Terasen Utilities believes that an incentive program for SHW will reduce the market barriers and encourage establishing a standard approach for regulatory requirements, reduce the confusion of changing program and incentive offerings, reduce the payback for SHW systems and facilitate the monitoring and evaluation of select SHW systems to gather data needed to validate energy saving assumptions.

In terms of NGV technology, as referenced in the 2010 LTRP, there are 10 manufacturers producing factory-built medium and heavy duty NGVs. There are approximately 600 natural gas light duty vehicles, medium duty delivery vans and urban buses in service throughout British Columbia. Based on the availability of factory-built medium and heavy duty NGVs, the Terasen Utilities feels that this is a market ready technology. One of the largest market failures is the declining NGV market since 1997. This was mainly due to the lack of OEM vehicle availability, unreliable conversion technology, lack of support from fuel vendors and a modest price differential between diesel fuel and natural gas. This affected the credibility and adoption of this technology within British Columbia as the reduction of access for fuel rendered NGV's impracticable. In recent years, due to increased uptake of this technology within the United States and a larger differential between diesel fuel and natural gas, the Terasen Utilities believes that there is an increased demand amongst return-to-home medium and heavy duty fleets for NGV's (see also the response to BCUC IR 1.12.2). The Terasen Utilities believes that offering incentives will renew faith and promote return-to-home medium and heavy duty fleets for NGV's as a cost effective and environmentally friendly alternative to using diesel.

34.4 To the best of Terasen Utilities' knowledge, have other comparable utilities successfully implemented similar DSM programs in solar thermal hot water, NGV, hydronic in combination heating systems, residential ground source heat pump systems, and commercial/industrial GSHP systems? Wherever possible, please provide references to the sources of information and data that Terasen Utilities has relied upon.

Response:

It is difficult to derive a complete list of all active DSM programs at other utilities that offer solar thermal hot water, NGV, hydronic systems and ground source heat pumps programs since offerings change based on timing, funding constraints and regulation updates. According to the DSMdat managed by E-Source, the following is a list of solar thermal hot water programs, ground source heat pump programs, natural gas vehicle programs and hydronic system programs. The Terasen Utilities cannot comment on their level of success as the criteria for each utility differs. However, for the Terasen Utilities, DSM program success is based on leveraging incentives to encourage market transformation for energy efficient methodologies and or technologies. The Terasen Utilities evaluates program success based upon energy savings, GHG emission reductions, number of participants, Regional adoption of technologies and customer feedback.

Technology	Program name	Program Location/Link
Solar Hot Water	Solar Water Heating Rebate	Gainesville Regional Utilities Florida
Solar Hot Water	Solar Water Heating System	Focus on Energy Wisconsin
Solar Hot Water	Solar Water Heating Program	City of Palo Alto California
Solar Hot Water	Solar Water Heating	National Grid Massachusetts
Solar Hot Water	Solar Water Heater Rebates	CPS Energy Texas
Solar Hot Water	Solar Water Heating	Energy Trust Oregon
Solar Hot Water	Solar Thermal Incentive Program - Commercial	Connecticut clean energy Fund
Solar Hot Water	Solar Domestic Water Heating	Conserve Nova Scotia
Geoexchange	Commercial Earth Power Program	Manitoba Hydro
Geoexchange	Geothermal Power Loan Program	SaskPower
Geoexchange	Commercial Ground Source Heat Pump Incentive	Focus on Energy Wisconsin
Geoexchange	Geothermal Hydro-Quebec Grant	Hydro Quebec
Geoexchange	Heat pump conservation rebates	Otter Tail Power Company Minnesota
NG Vehicles	Live Green, Think Blue CNG Rebate	Metropolitan Utilities District Nebraska
NG Vehicles	Conservation Program Commercial Natural Gas	Texas Gas Service
NG Vehicles	NGV and Fuelling Infrastructure Rebates	Texas Gas Service
NG Vehicles	Natural Gas Vehicle Rebate	Citizens Energy Group Indiana
NG Vehicles	NGV and Infrastructure Rebates and Technical Assistance	National Grid Massachusetts
NG Vehicles	Natural Gas Fuel Rate Reduction and Vehicle Incentives	Atmos Energy Texas
NG Vehicles	CNG Vehicle Incentive Program	City of Vacaville California
NG Vehicles	NGV Rebates and Natural Gas Fuel Rate Reduction	UGI Utilities Pennsylvania
NG Vehicles	Alternative Fuel Vehicle Rebate Program	City of Riverside California
Hydronic Systems	Commercial Hydronic Heating Program	Texas Gas Service Commercial
Hydronic Systems	Residential Hydronic Heating Program	Texas Gas Service Residential
Hydronic Systems	Multifamily New Construction Gas Incentives	Puget Sound Energy
Hydronic Systems	Heating System Rebates	Center Point Energy Arkansas
Hydronic Systems	Residential High Efficiency Rebate Program	Center Point Energy Arkansas

34.5 For each of the Innovative Technologies, how will Terasen Utilities determine the appropriate level of financial incentives necessary to make Innovative Technologies attractive to their customers? Please also discuss the timing and process that Terasen Utilities will use to test the optimum incentive level(s) and adoption rates for each of the proposed Innovative Technologies. Please provide specific metrics and milestones for each.

Response:

At this time, the Terasen Utilities does not have good data on the appropriate level of financial incentives necessary to make Innovative Technologies attractive to customers. There is therefore a need to conduct pilot programs to test the effect that differing levels of incentives have on adoption rates, such as the pilot programs currently underway for solar thermal and NGV. In the case of the NGV pilot program, which provides an incentive of up to 100% of the incremental capital cost for NGV, there have already been expressions of interest from prospective customers, which demonstrates that there is a strong correlation between the level of incentives and adoption for Innovative Technologies. The Terasen Utilities believes that the level of incentives may decline as the Innovative Technologies gain a greater share of the market, but determining exact values and timing cannot be estimated at this time.

34.5.1 For each Innovative Technology, please provide a forecast of the relationship between the level of incentives paid to customers and the corresponding adoption rate during the period 2012 to 2020. Please provide data in tabular and graphical format indicating the variation in adoption rates as a function of financial incentives for each innovative technology. Please also provide an electronic spreadsheet copy of the data.

Response:

As noted in the response to BCUC IR 1.34.5, the Terasen Utilities does not yet have good data on the level of incentives needed to spur the adoption of Innovative Technologies in British Columbia, resulting in the need to conduct pilot studies.

34.6 For the two most recent completed fiscal years, what portion of revenue (%) has Terasen Utilities devoted to R&D of innovative DSM technologies? Please provide details of R&D activities and results.

Response:

For the two most recent completed fiscal years, Terasen Utilities has not devoted any funding to R&D of innovative DSM technologies.

35.0 Reference: Exhibit B-1, Chapter 5, p. 119

Innovative Technologies NGV Incentives

"As a result of potential EEC incentives, the City of Vancouver, City of Surrey, City of Port Coquitlam and other third party partner have all expressed interest in converting some of their current high carbon diesel fleet into NGVs, and purchasing new NG trucks for garbage disposal."

35.1 Please confirm whether municipalities such as the City of Vancouver or City of Surrey currently receive financial DSM incentives from Terasen Utilities or any other utility operating. If "yes", please provide the amounts over the past five years.

<u>Response:</u>

The Terasen Utilities confirm that none of these municipalities have received any NGV incentives as of yet; however, the City of Vancouver has received financial DSM incentives from the Terasen Utilities in the past five years. One incentive for the amount of $25,515 was issued on 08/07/2007 and the second was issued on 12/11/2008 for the amount of $2,943. Both the incentives were issued from the efficient boiler program.

36.0 Reference: Exhibit B-1, Chapter 5, p. 119

Conservation Potential Review CPR) and the Three Funding Scenarios

36.1 The Application states that once the CPR results are received, Terasen Utilities would update the three funding scenarios. Please confirm that the CPR analysis will incorporate the Commission determinations, if any, with respect to regulated and non-regulated activities and the competitive nature of the conservation initiatives.

Response:

Terasen Utilities contacted the Commission staff to seek clarification of this question. The Commission staff responded with the following re- wording of the question:

36.0 Reference: Exhibit B-1, Chapter 5, pp. 119-120

Conservation Potential Review CPR) and the Three Funding Scenarios

"To determine what level of ongoing funding should be implemented; we examine the potential impact on natural gas demand and GHG emissions in three scenarios of future funding for EEC programs below. It should be noted that the scenarios have been developed using the best available data, but will be updated once the results of the CPR are received. "

36.1 The Application states that once the CPR results are received, Terasen Utilities would update the three funding scenarios. Please confirm that the updated CPR analysis will incorporate the Commission's determinations in the 2010 LTRP.

If the response to the above question is no, please describe how the updated CPR would be effective as a planning document.

The CPR study itself will not incorporate Commission determinations as it is intended to provide the Terasen Utilities with an "unfettered" view of the amount of cost-effective conservation available in its service territories. As with the original EEC Application that was submitted to the Commission in May 2008, the EEC funding request that the Terasen Utilities will be submitting in the 2012 RRA will be based upon the results of the CPR study, any Commission determinations, upcoming equipment and building regulations, government policy and areas of focus, and opportunities for partnership and leveraging other funding sources.

37.0 Reference: Exhibit B-1, Chapter 5, pp. 115, 120 - 121

Future EEC Funding Scenarios

"Since 1992, we have been operating EEC programs and initiatives which provide incentives and support customers in reducing their consumption of natural gas. Going forward, it is important for the Utilities to secure ongoing funding to provide consistent programs to the market and thereby maximize the benefits of EEC initiatives."

37.1 2010 marks the 20-year milestone of Terasen Utilities providing DSM programs. Please provide a summary of the three most successful and the three least successful programs in terms of Total Resource Cost (TRC) since Terasen Utilities inception of DSM programs in 1992. For each program noted, please provide an analysis of the critical factors and circumstances that contributed to their success or failure.

Response:

The best historical information regarding the TRC of the Terasen Utilities' DSM programs is found in the 2006 Annual Review. The programs reported in 2006 were relatively constant until the end of 2009, and there is insufficient information at this time to judge the success of the DSM programs that have been initiated pursuant to the Commission's approval of the EEC Application in April 2009. The table reporting the TRC for 2006 was presented on page 9 of section B-3 of the 2006 Annual Review, and is reproduced below.

Program Name	# of Participants	GJ saved per Participant	GJ saved per year	CO2e saved (tonnes) per year	TRC result	TRC Net Benefit
Energy Star Heating Upgrade	3300	13.8	45,540	2,308	1.82	$ 1,141,525
New Construction Heating Program	750	9.1	6,825	346	1.45	$ 162,158
Power Smart New Home Program	300	30	9,000	456	1.49	$ 604,529
Efficient Boiler Program	98	850	83,300	4,222	2.43	$ 4,101,737
Utilization Advisory	60 with 25% implementing	600	9,000	456	2.4	$ 366,204
Destination Conservation	18	113	2,034	103	2.21	$ 76,298
Totals			**155,699**	**7,892**	**1.97**	**$ 6,452,451**

It can be seen from the table above that most of the programs operating in 2006 had strong TRC results. Of the programs from 2006, the most successful would be the New Construction Heating Program, and the Energy Star Heating Upgrade Program, which were long-running market transformation programs that culminated in the introduction of provincial regulations requiring Energy Star Furnaces and Boilers for New Construction beginning on January 1 2008 and for retrofits beginning on December 31 2009, respectively. The Terasen Utilities would describe these programs as successful, as they had been in the marketplace for many years (in the case of the Energy Star Heating Upgrade program, since at least 1997), were consistent so that market actors had a sense of continuity and confidence in the program, and ultimately resulted in sufficient penetration of the program measure for government to enact regulation requiring the program measure as the minimum standard, which then enshrines program benefits in the marketplace. The Efficient Boiler Program for Commercial customers is another successful program. It was running as far back as 1997 and is still running today, though with some modifications, and had a 2009 TRC Result of 2.0 as reported on page 25 of the TGI and TGVI's 2009 EEC Annual Report. Again, this is a long-running program that has established some certainty in the marketplace, with the result that Natural Resources Canada has announced plans to regulate minimum efficiency standards for commercial boilers starting in March 2012.

Probably the least successful program of those presented in table above was the PowerSmart New Home Program, which was offered in conjunction with BC Hydro, and which did not achieve the levels of participation the Terasen Utilities had hoped for. As can be seen in the table above, it was hoped that the PowerSmart New Home Program would see 300 participants, but in fact there were only 80. Although the Terasen Utilities did not conduct any formal post-program analysis, anecdotal reports were that builders and developers were somewhat confused by the program offering as there were other designations in-market at the same time (Energuide 80, Built Green), and also because they found the application and documentation process overly onerous. Lessons learned from these 3 programs would be that programs for equipment and buildings should be long-running with an end goal of market transformation, and that programs should be simple with straightforward application processes.

37.2 If, as stated above that the benefits from energy efficiency and conservation programs are maximized through ongoing and consistent funding of EEC incentive programs (ref. p. 115), please explain why Terasen Utilities believe that Scenario A merits consideration as a possible alternative in the 2010 LTRP.

Response:

The three EEC Scenarios put forward are for illustrative purposes and to meet the requirement in section 44.1(2)(a) of the *Utilities Commission Act* to include "(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." Scenario A shows what happens to energy savings in the absence of any new long-term sustainable funding for EEC activities. The Terasen Utilities will be bringing forward their proposal for new EEC funding for 2012 and beyond in the Revenue Requirement Applications to be submitted in spring/summer 2011. See also the response to BCUC IR 1.38.1.

37.2.1 Are there situations in which consistent EEC programs, especially in changing markets, can lead to sub-optimal EEC benefits?

Response:

It is crucial for the success of market transformation initiatives that the various market actors have some certainty around the availability of stable long term EEC funding in order to support investment in more efficient technologies by those market actors. That said, there are indeed situations in which putting a program together and just leaving it in-market ad infinitum, without periodically reviewing program parameters and market conditions could result in sub-optimal results. For instance, if a relatively new efficient product is introduced into the marketplace, and an EEC program is put in place to encourage adoption of such products, but the EEC incentive amount is too low to encourage equipment adoption, and the incentive amount is not adjusted to increase equipment adoption, sub-optimal program results could be expected. The opposite is also true. If an incentive program has been in place for some time, and people are buying a particular piece of equipment as a matter of course, incentives are probably no longer needed for that particular piece of equipment.

37.3 Could variable EEC budget based on 5% of revenue result in an unstable budget that experiences year-over-year variations as a result of changing commodity prices of natural gas? Please discuss how Terasen Utilities would be able to make long-term plans and capital investments if their EEC budgets were coupled to the price of natural gas.

Response:

Potentially. As discussed in response to BCUC IR 1.38.1, Scenario C is put forward as a high-level illustration of the Terasen Utilities plan to pursue ongoing and expanded EEC funding. It does not, however, reflect the Terasen Utilities' preferred methodology of determining EEC funding. The Terasen Utilities will be developing a funding request for EEC activity beyond 2011 in the upcoming Revenue Requirement Applications that will be submitted to the BCUC in the spring/summer of 2011.

37.3.1 Using the EIA Henry Hub 2010 Spot Constant Reference case summarized in Figure 2-3, p. 17, please state the mean, median, maximum, and minimum prices of natural gas for in the period 2012 to 2030. Assuming Funding Scenario C, please calculate what Terasen Utilities EEC budget would be in 2012 for each of those natural gas prices.

Response:

The table below shows 2012 EEC funding based on Funding Scenario C, at each of the mean, median, maximum and minimum prices in Figure 2-3. The estimated revenues in 2012 are based on the most recent demand forecast filed in the 2010 LTRP, with 2011 approved delivery and midstream rates and margins remaining constant from 2011 onwards.

Cost of Gas Scenario	2012 EEC Funding-Scenario C *($ millions)*
Mean	**85**
Median	**85**
Maximum	**93**
Minimum	**81**

37.3.2 If funding options A and B were expressed as a percentage of revenue in 2012, what would be those percentages?

Response:

Funding scenarios A and B are based on the current approved amount of approximately $35 Million. Funding scenarios A and B in 2012 represent approx 2.3% as percent of revenues in that year. The revenues in 2012 are based on current demand forecast volumes as presented in 2010 LTRP with the 2011 approved delivery margin and cost of gas rates remaining constant through the planning term.

37.4 For Funding Scenario C, please explain why Terasen Utilities proposed an EEC costing formula based on gross revenue rather than margin (i.e., utility revenue less the purchased cost of gas).

Response:

It should be noted that the Scenarios presented are for illustrative purposes. The Terasen Utilities are not proposing any particular funding (vs. costing) formula for EEC in the LTRP. Rather, the Terasen Utilities are attempting to illustrate some possible energy savings and GHG emission reduction outcomes resulting from stable, long-term funding. The Terasen Utilities will be bringing forward a funding proposal in the 2012 Revenue Requirement Applications to be submitted in spring/summer 2011. Funding based on gross revenue is just one potential funding calculation method, and the Terasen Utilities recognize that calculating the funding from margin is a possibility as well.

37.4.1 EEC program costing that is based on utility revenue would result in higher EEC program costs as the price of natural gas increases. Please explain the rationale for permitting EEC budgets to fluctuate with the price of natural gas.

Response:

It should be noted that the Scenarios outlined do not represent EEC program costing but rather EEC program funding. EEC program costs do not necessarily increase as the price of natural gas increases; in fact, EEC program cost-effectiveness as measured by the TRC increases as the price of natural gas increases, as the avoided cost of gas which constitutes the benefit side of the TRC equation goes up.

One reason for permitting EEC funding to fluctuate with the price of natural gas might be that as gas prices increase, customers become more likely to be looking for ways to manage their energy bill, one of which could be implementing energy efficiency and conservation measures. It should be noted again, however, that the Terasen Utilities are not promoting the merits of EEC funding tied to gross revenues in this LTRP. Scenario C is intended to illustrate the potential savings associated with an increase in EEC funding. Selecting 5% of gross revenues as the level of EEC funding was somewhat arbitrary, but was illustrative of a long-term and expanded funding mechanism for EEC.

37.4.2 Is Terasen Utilities aware of any other Canadian utility that sets DSM program budgets on a percentage of gross revenue or margin? If "yes", please provide details of each.

Response:

No, the Terasen Utilities are not aware of any other Canadian utility that sets DSM program budgets on a percentage of gross revenue or margin. Scenario C was intended more to be illustrative of the kind of energy savings that could potentially be achieved with long-term funding equivalent to 5% of gross revenues. The Terasen Utilities are focussed on establishing long-term funding for EEC activity, to bring certainty to the marketplace.

37.4.3 Please provide tabular and graphical data of the variation of EEC program budgets (consolidated) for Terasen Utilities as a percentage of gross revenue and margin from the period 1992 to 2011. Please also extend the data to include proposed EEC budgets based on Funding Scenario A, B, and C for the period 2012 to 2030.

Response:

It is the Terasen Utilities' view that it is more relevant to present the information requested from 1998 forward, as EEC budget levels prior to Commission Order No. G-36-09 were set in the 1998-2000 Revenue Requirement Settlement and the Terasen Utilities do not have the necessary data from prior to 1998. The following table illustrates the variation of EEC program budgets as percentage of gross revenue and margin from 1998 to 2011. Please note that the revenues and the EEC program budgets are for TGI and TGVI only as the Terasen Utilities have not historically offered EEC programs for TGW. For the period 1998 to 2011, the EEC budgets presented are the amounts approved by the Commission in Order No. G-36-09, G-141-09 and G-140-09. The table for this time period of 1998 to 2011 would also represent Scenario A.

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
EEC Budget as percent of revenues	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.3%	0.3%	0.4%	2.1%	2.4%
EEC Budget as percent of margin	0.5%	0.2%	0.4%	0.5%	0.4%	0.4%	0.4%	0.4%	0.6%	0.8%	0.8%	1.0%	4.7%	5.2%

Estimating revenues for the next 20 years is challenging to forecast with any degree of accuracy; however the Terasen Utilities assumed the revenues to be directly proportional to the most recent demand forecast with current approved delivery margin and cost of gas rates remaining constant for the entire planning period. Based on this analysis, the EEC budgets as percent of revenues for scenarios B & C are estimated to be approx 2% and 5%, respectively, on an annual basis from 2012 until 2030.

As noted previously, the Terasen Utilities have presented the different EEC funding Scenarios for illustrative purposes and will be requesting approval of a formal funding mechanism and amount in the upcoming Revenue Requirement Application.

38.0 Reference: Exhibit B-1, Chapter 5, p.119; Appendix B-6

Impact on Energy Demand Emissions

"To determine what level of ongoing funding should be implemented; we examine the potential impact on natural gas demand and GHG emissions in three scenarios of future funding for EEC programs below."

38.1 Please provide a tabular summary of the sections and sub-sections of the Clean Energy Act (CEA) and Utilities Commission Act (UCA) that Terasen Utilities have relied upon in setting their EEC targets for 2020 and 2030. For each referenced section of the CEA and UCA, please describe how EEC Funding Scenarios A, B, and C adequately address the requirements of each Act.

Response:

The three funding scenarios are not EEC targets that the Terasen Utilities have set. Since a full analysis required to make a formal request for EEC funding to the commission is underway but not yet complete, the funding and resulting savings amounts contained in Section 5 of the LTRP have been presented to illustrate a range of EEC funding scenarios. In the following response, the Terasen Utilities will discuss how their plan for future EEC funding meets the requirements of the *Clean Energy Act* ("CEA") and *Utilities Commission Act* ("UCA") and then discuss the three funding scenarios.

TGI and TGVI have EEC funding approved and will deliver programs to customers through 2011. The Terasen Utilities' plan for EEC funding as contained in the LTRP is to complete the required analytical and planning work required for a full EEC funding request and apply for specific levels of expanded and ongoing EEC funding post 2011, which will include measures for low income housing, rental accommodations and student education. The Terasen Utilities plan to make this request for expanded and ongoing EEC funding in the upcoming revenue requirement application expected to be submitted to the Commission in the spring or summer of 2011[31]. As part of the Terasen Utilities' plan to complete the analytic and planning work for EEC funding, a Conservation Potential Review is underway that will identify the 'economic potential' for demand-side programming, which will then be further narrowed to determine the 'achievable potential' for DSM programming. The Terasen Utilities expect the results of this work will show that there is cost-effective demand-side programming available beyond the existing portfolio. The Terasen Utilities plan as presented in the LTRP is consistent with the British Columbia energy objectives in the CEA and shows that the Terasen Utilities intend to pursue adequate cost-effective demand-side measures as required by Section 44.1(8)(c) of the UCA.

As the analytics and planning required for a full EEC funding request is not yet complete, the three scenarios identified in the LTRP were presented for the purpose of discussing why

[31] Exhibit B-1, Section 5.7, page 129 and Section 8, item 1 page 185.

pursuing expanded and ongoing funding is an important part of the Terasen Utilities future plans.

1. Scenario A represents the current level of approved funding for the Terasen Utilities and assumes that EEC funding beyond 2011 will not be available to the Terasen Utilities customers. The spending amounts are known and estimated energy and GHG savings are based on previous analyses and review. Programs within the current funding limitations are in place and delivering results that are cost effective by meeting the Total Resource Cost effectiveness test. However, because the Terasen Utilities believe that cost-effective demand-side measures are available beyond 2011, the Terasen Utilities do not believe that Scenario A is consistent with the British Columbia energy objectives and would not reflect a plan to pursue adequate cost-effective demand side measures beyond 2011.

2. Scenario B represents the same annual level of funding as that of Scenario A, but assumes this level of funding is ongoing. The Terasen Utilities have not received approval for pursuing this scenario. The overall energy and GHG savings for Scenario B have been estimated with a reasonable level of confidence based on the analysis and planning for Terasen's current level of approved funding. The Terasen Utilities have assumed that current (and approved) program spending and the resulting estimated energy and GHG savings continue into the future over the planning horizon. While we believe that Scenario B could meet the objectives of the CEA and UCA, the Terasen Utilities believe that the results of the analytic and planning work will show that more cost-effective demand-side measures are possible.

3. The Terasen Utilities believe that of the three scenarios, Scenario C is the most consistent with the objectives of the CEA and UCA since it presents the implementation of an increase in cost effective DSM programs. As stated above, the Terasen Utilities believe that the results of the analytic and planning work will show that more cost-effective demand-side measures are possible. The criteria used to develop Scenario C and the resulting energy and GHG savings are presented as a high-level estimate that is meant to be illustrative of an expanded and ongoing EEC program. However, since the analytical and resulting planning work needed to confirm the amount of funding that can be achieved by a given level of ongoing funding is not yet completed, scenario C does not represent the Terasen Utilities future funding request and the Terasen Utilities are not seeking acceptance from the Commission that funding Scenario C is in the public interest.

Tables below discuss the consistency of the funding scenarios with the relevant sections and subsections of the CEA and UCA. Since the Terasen Utilities do not believe that Scenario A is consistent with the objectives of these Acts, it is omitted from the tables.

Funding Scenarios Consistency with Clean Energy Act

CEA Section / Subsection	**Description of Scenario B Consistency**	**Description of Scenario C Consistency**
Section 2 British Columbia Energy Objectives		
2 b)	Scenario B employs demand side and energy conservation measures consistent with this objective	Scenario C employs demand side and energy conservation measures consistent with this objective
2 d)	Funding in Scenario B is directed toward the implementation of innovative technologies.	Funding in Scenario C could support the implementation of innovative technologies to a greater degree than Scenario B.
2 g)	Energy savings and GHG reductions will result from Scenario B and will contribute to B.C. GHG reduction targets.	Energy savings and GHG reductions will result from Scenario C and will contribute to B.C. GHG reduction targets to a greater degree than Scenario B.
2 h)	Scenario B will result in fuel switching from higher carbon to lower carbon emitting fuels in the transportation and residential sectors where natural gas can be used in place of higher carbon fuels and where renewable thermal solutions can replace conventional gas and electric solutions.	Scenario C will result in greater fuel switching from higher carbon to lower carbon emitting fuels than Scenario B in the transportation and residential sectors where natural gas can be used in place of higher carbon fuels and where renewable thermal solutions can replace conventional gas and electric solutions.
2 i)	Scenario B will provide ongoing encouragement communities to conserve energy and reduce emissions.	Scenario C will provide ongoing encouragement to communities to conserve more energy and reduce emissions to a greater degree than in Scenario B.
2 j)	Scenario B could employ EEC funding to encourage the use of waste heat as part of innovative technology solutions funding.	Scenario C could expand EEC funding to assist with the development of biogas and biomass resources for use as renewable energy solutions to individual customers and district energy system customers.

CEA Section / Subsection	Description of Scenario B Consistency	Description of Scenario C Consistency
2 k)	The funding levels in scenario B will encourage the development and enhancements of businesses and jobs by extending the benefits and jobs created by current levels of approved funding into future years. The caption at the bottom of Exhibit B-1, page 115 shows one example.	Scenario C will support business and create jobs beyond that expected from Scenario B.
2 l)	Training for skills and energy efficiency improvements for rural industry and businesses will help foster the development of First Nations and Rural Communities.	Funding under Scenario C could be directed toward EEC programs that help develop First Nation and Rural Communities beyond the level that Scenario B can achieve.

Scenario's consistency with Utilities Commission Act

UCA Section / Subsection	Description of Scenario B compliance	Description of Scenario C compliance
44.1 (2)		
(b)	Scenario B employs cost effective demand side measure to reduce demand for natural gas. While customer additions are still expected, these measures would reduce use per customer.	Scenario C employs expanded cost effective demand side measures to reduce demand for natural gas further.
44.1 (8)		
(a)	Table 38.1 B above explains how Scenario B is consistent with the B.C. Energy Objectives of the CEA.	Table 38.1 B above explains how Scenario C is consistent with the B.C. Energy Objectives of the CEA.

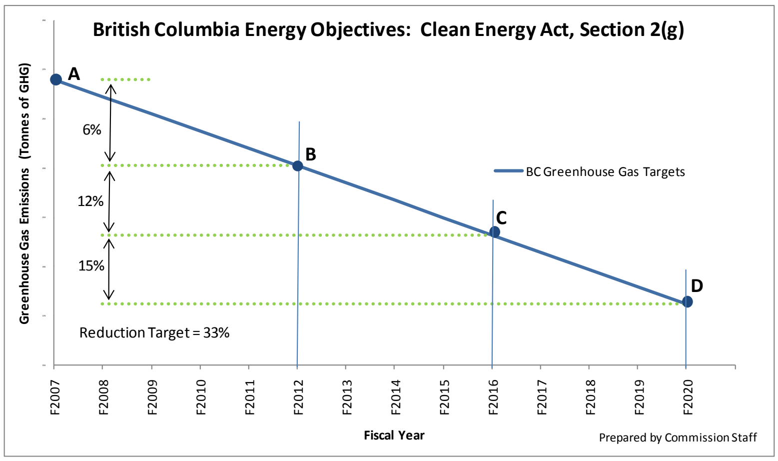
UCA Section / Subsection	Description of Scenario B compliance	Description of Scenario C compliance
(c)	While Scenario B could be adequate, the Terasen Utilities believe that the results of its analytic and planning work will show that more EEC funding can provide greater cost effective energy and GHG saving programming. Scenario B meets the requirements of Section 3 of the Demand-Side Measures Regulation[32] as the Terasen Utilities' existing EEC portfolio includes measures for low income housing, rental accommodations and student education.	Scenario C is presented as an estimate of energy and GHG savings that can be achieved with expanded and ongoing EEC funding. The Terasen Utilities believe this is most consistent with this section given its belief that the results of its analytic and planning work will show that more EEC funding can provide greater cost effective energy and GHG saving programming. Scenario B would also meet the requirements of Section 3 of the Demand-Side Measures Regulation[33] as it would include the current EEC measures for low income housing, rental accommodations and student education. Scenario C would allow for the possibility of expanding these measures.
(d)	Given that current levels of approved funding are in the interest of current and future customers, extending this level of funding into future years should also be in the interests of current and future customers.	Assuming the expanded and ongoing programs under Scenario C would be designed to be cost effective in increasing energy efficiency and conservation, and reducing GHG emissions, Scenario C would be in the interest of current and future customers

In conclusion, the Terasen Utilities' plan to seek expanded and ongoing funding as outlined in the LTRP complies with the UCA and CEA.

[32] Section 3 of the Demand-Side Measures Regulation specifies four requirements for the purposes of section 44.1(8)(c) of the *Utilities Commission Act.*

[33] Section 3 of the Demand-Side Measures Regulation specifies four requirements for the purposes of section 44.1(8)(c) of the *Utilities Commission Act.*

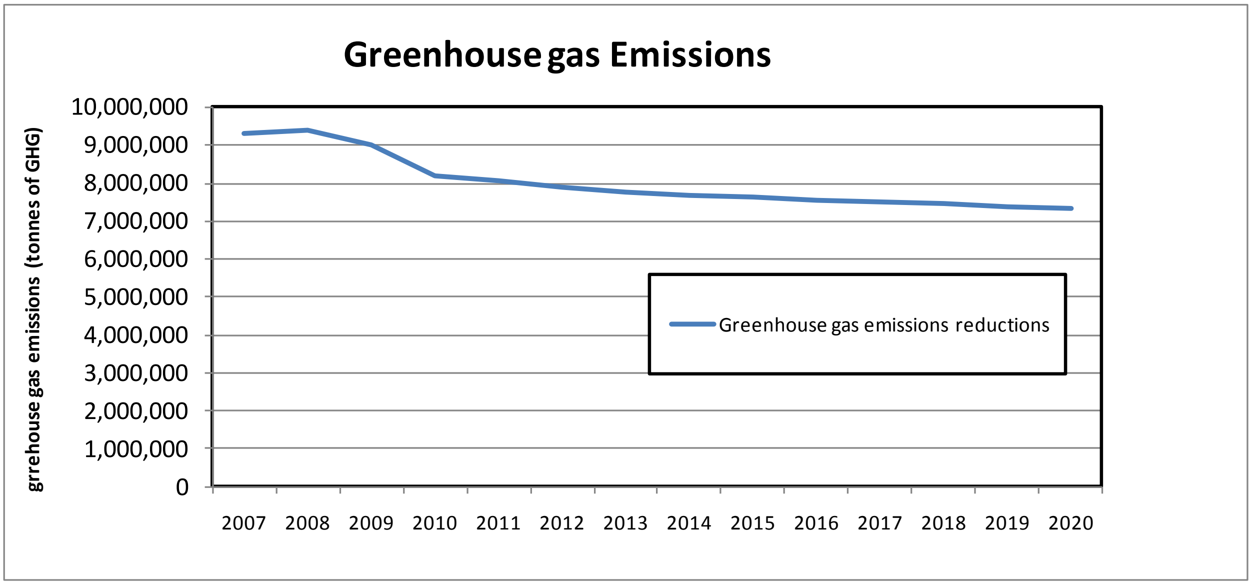
38.2 Section 2(g) of the Clean Energy Act requires reduced greenhouse emissions. The following graph depicts the greenhouse targets in Section 2(g). Please produce a similar graph that also shows Terasen Utilities GHG emission reduction in the 2010 LTRP.



Response:

Section 2(g) of the *Clean Energy Act* is one of the British Columbia energy objectives that must be considered by the Commission in determining whether to accept a long-term resource plan pursuant to section 44.1 of the *Utilities Commission Act*. It does not impose on the Terasen Utilities an obligation to meet certain GHG emissions reduction targets.

As discussed in the response BCUC IR 1.38.1, the scenarios are used for illustrative purposes and not to develop a portfolio that meets the Province's GHG emissions reduction targets. However, assuming that scenario C savings outcome is accurate, the chart below demonstrates that there could be potentially a 21% reduction in GHG emission reductions from the 2007 emission levels. The savings below only incorporate residential and commercial programs for both TGI and TGVI. The LTRP sets out a strategy for how the Terasen Utilities will help to meet these provincial targets and is therefore consistent with the British Columbia energy objectives in Section 2(g) of the CEA. The CEA does not specify sectors, utilities or initiatives from which specific amounts of the 33% reduction must come. Consistent with that, the LTRP does not set specific reduction targets for any or all of its customer groups. The data from which the chart below was created includes GHG emission reductions from new natural gas vehicle initiatives which, through fuel switching from gasoline or diesel to natural gas, result in an increase in GHG emissions from natural gas in BC, but an overall reduction in GHGs produced in the province. This overall reduction comes from the higher carbon to lower carbon fuel switching activity, which is supported by the British Columbia energy objective in Section 2(h) of the CEA "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia".



38.2.1 For each of the three funding scenarios, please provide a tabular summary of the actual and forecasted greenhouse emission from Utilities sale of natural gas for the period 2007 to 2020. Please segment by: (a) TGI, TGVI, and TGW; and (b) customer group.

Response:

The Terasen Utilities clarify that each scenario has the same composition of EEC programs and only those programs that are currently being implemented or being planned are included in each scenario.

Please see the tables below for the requested tabular summary. With respect to these tables, the Terasen Utilities note the following:

1. The actual GHG emissions in 2007, 2008, and 2009 are estimated from the actual throughput of natural gas for TGI and TGVI which includes the impact of EEC programs.
2. The forecast was based on the Terasen Utilities' current demand forecast presented in the 2010 LTRP after taking out the EEC savings from scenarios B and C.

3. The Terasen Utilities at this point have not included TGW as TGW has not historically offered EEC programs.

4. The emissions by industrial customer group is not presented as initiatives are currently being developed for this segment and it is not clear how future load will be affected by conservation efforts. Since the industrial customers are not weather dependent, the demand volumes and emissions is more a function of their economic cycles and hence has been excluded from the tables.

5. The tables below were created assuming 50.7 tonnes of CO_2/TJ.

TGI (tonnes CO2)	2007	2008	2009	2010	2011	2012	2013
TGI "A"	9,070,230	9,120,930	8,764,458	7,989,219	7,902,227	7,832,637	7,766,344
TGI "B"	9,070,230	9,120,930	8,764,637	7,965,335	7,866,441	7,763,596	7,662,782
TGI "C"	9,070,230	9,120,930	8,764,458	7,965,335	7,866,441	7,694,555	7,559,221

TGI (tonnes CO2)	2014	2015	2016	2017	2018	2019	2020
TGI "A"	7,708,987	7,718,185	7,733,081	7,744,760	7,765,672	7,780,601	7,794,075
TGI "B"	7,571,352	7,546,141	7,526,629	7,503,899	7,490,403	7,470,923	7,449,988
TGI "C"	7,433,717	7,374,098	7,320,176	7,263,039	7,215,133	7,161,245	7,105,901

TGVI (tonnes CO2)	2007	2008	2009	2010	2011	2012	2013
TGVI "A"	237,023	255,224	249,393	237,565	236,087	235,198	235,039
TGVI "B"	237,023	255,224	249,393	235,083	231,898	227,022	222,775
TGVI "C"	237,023	255,224	249,393	235,083	231,898	218,846	210,511

TGVI (tonnes CO2)	2014	2015	2016	2017	2018	2019	2020
TGVI "A"	235,668	237,286	239,879	241,952	244,432	246,728	248,796
TGVI "B"	219,316	217,404	216,021	214,118	212,621	210,941	209,032
TGVI "C"	202,965	197,522	192,163	186,283	180,810	175,154	169,268

Residential (TGI+TGVI) (tonnes CO2)	2007	2008	2009	2010	2011	2012	2013
Residential "A"	4,019,243	4,219,964	3,935,740	3,765,077	3,724,665	3,689,614	3,662,850
Residential "B"	4,019,243	4,219,964	3,935,740	3,749,534	3,702,169	3,645,837	3,597,186
Residential "C"	4,019,243	4,219,964	3,935,740	3,749,534	3,702,169	3,602,061	3,531,521

Residential (TGI+TGVI) (tonnes CO2)	2014	2015	2016	2017	2018	2019	2020
Residential "A"	3,643,456	3,632,200	3,629,043	3,628,634	3,635,023	3,640,452	3,644,836
Residential "B"	3,555,904	3,522,759	3,497,714	3,475,418	3,459,918	3,443,459	3,425,955
Residential "C"	3,468,351	3,413,318	3,366,385	3,322,201	3,284,813	3,246,466	3,207,074

Commercial (TGI+TGVI) (tonnes CO2)	2007	2008	2009	2010	2011	2012	2013
Commercial "A"	2,819,934	2,917,126	2,883,258	2,766,259	2,788,290	2,822,811	2,853,139
Commercial "B"	2,819,934	2,917,126	2,883,258	2,755,435	2,748,781	2,732,818	2,716,098
Commercial "C"	2,819,934	2,917,126	2,883,258	2,766,259	2,748,781	2,699,378	2,665,937

Commercial (TGI+TGVI) (tonnes CO2)	2014	2015	2016	2017	2018	2019	2020
Commercial "A"	2,885,686	2,920,725	2,954,410	2,980,925	3,008,955	3,031,868	3,053,654
Commercial "B"	2,699,825	2,683,775	2,667,278	2,650,781	2,634,284	2,617,787	2,601,290
Commercial "C"	2,633,391	2,601,290	2,568,296	2,535,302	2,502,309	2,469,315	2,436,321

38.2.2 Figure 5-1 on p. 122 provides a summary of cumulative natural gas savings from Utilities EEC scenarios. Based on current market prices ($/tonne) that carbon trades at, please provide an estimate of the nominal value ($ Cdn) of GHG savings that will be realized during the period F2012 to F2020 for Funding Scenarios A, B and C. Please present your annual estimate in tabular format with assumptions clearly stated.

Response:

The following table uses the known 2012 carbon tax of $30/tonne to estimate the nominal value of savings from the Scenarios provided, and given the uncertainty of potential future changes to the carbon tax assumes $30/tonne throughout the period. Note, the three scenarios were provided for discussion purposes only and as such, this table below does not represent a forecast of dollar savings from future programs, but rather an estimate based on the scenarios discussed. Please refer to the response to BCUC IR 1.46.1 for a discussion on how the scenarios where developed.

Funding Scenarios	**Cumulative GHG Savings F2012 to F2020 (TCO_2)***	**Cumulative GHG Savings Value F2012 to F2020 ($)****
Funding Scenario A	822,536	24,676,081
Funding Scenario B	9,119,928	273,597,832
Funding Scenario C	17,539,229	526,176,863

* Based on estimates from 2010 Terasen Gas Long Term Resource Plan (pg. 122,Figure 5-3)
** Based on current market price of $30/tonne from 2012 onwards

38.2.3 Please provide a description of the methodology used by Terasen Utilities to quantify the level of greenhouse gases emitted annually. To the extent possible, please provide references to industry standards and practices upon which this methodology is based.

Response:

The reference and the preamble to this question cite two different areas of the LTRP. As such, the Terasen Utilities have tried to provide a response that addresses the methodology for estimating both GHG emissions from a 100 unit condominium building as identified in Appendix B-6, and emission savings estimates from EEC activities as discussed on page 119 of Chapter 5 within the LTRP.

With regard to emissions comparisons provided in Appendix B-6, the Terasen Utilities first estimated energy consumption for a typical baseline energy level delivered today (electricity for space heating, Natural gas for water heating and make up air unit) against a geo-exchange system using natural gas as the back-up energy source based on the assumptions provided in Appendix B-6 . GHG emissions for electricity and natural gas energy usage under each scenario were then estimated by multiplying with the respective GHG emission factors. The Terasen Utilities relied on the BC Assessment Guides dated February 2009 and dated February 2008 for electricity and natural gas equipment respectively. For the EEC activities as discussed on page 119 of chapter 5, the Terasen Utilities have described methodologies for quantifying the level of GHGs emitted annually for conventional EEC programs and natural gas vehicles. For the traditional EEC programs, baseline energy consumption was developed for each program to estimate the savings based on the best information the Terasen Utilities have today. Under each scenario, an estimate of the total savings was developed based on programs and technologies available, measure life as well as participant uptake rate. The annual estimated savings was rolled up to the individual company to estimate the overall savings for the entire planning period. The overall savings was then multiplied by the natural gas emission factor[34] of 50.7 Tonnes CO_2 equivalent / TJ to estimate the total GHG reductions.

For natural gas vehicles, the Terasen Utilities developed its GHG emission estimates on a 'grams per kilometre' basis using emission factors from Natural Resources Canada's GHGenius model.[35] This model incorporates complete lifecycle emissions including materials, production, transportation, and vehicle operation. The 'grams per kilometre' approach is consistent with industry associations such as the Canadian Natural Gas Vehicle Alliance.[36] As referenced in Appendix B-8 of the LTRP, the Terasen Utilities have made assumptions on the average distance traveled per year for each vehicle category. In each demand forecast scenario, those estimates have been multiplied by GHGenius emission factors for each corresponding fuel type to estimate the total GHG savings.

[34] Based on estimates from GHG assessment guide. *www.townsfortomorrow.gov.bc.ca/.../ghg_assessment_guidebook_feb_2008.pdf*

[35] Based on emissions factors of 1,433 grams per kilometre for diesel, 1,149.7 g/km for CNG and 1,035.1 g/km for LNG, published in GHGenius 3.17.Software available from Natural Resources Canada at www.ghgenius.com

[36] http://www.cngva.org/en/home/environment--safety/lifecycle-emissions-benefits.aspx

38.3 Appendix B-6 summarizes energy usage assumptions and GHG emissions for a multi-family residential building. Please provide similar summaries for residential, commercial, and industrial rate groups.

Response:

The Terasen Utilities analyzed demand scenarios for lower density residential developments and multifamily buildings to describe the impact on gas savings and GHG reductions from the development of renewable thermal energy solutions. For commercial and industrial rate groups, the Terasen Utilities conceptually described the type of solutions under consideration but did not provide any specific examples. It is challenging and complex at this point in time to model the potential demand for commercial and industrial thermal energy uses. This is because there is a broad variation of commercial and industrial end uses for thermal energy from basic space and water heating needs to high temperature and pressure cleaning applications. Hence, the Terasen Utilities at this point are exploring the application of forecasting methodologies for commercial and industrial customers. It is only since 2007 with the introduction of BC Energy plan there has been a need to explore such initiatives and the Terasen Utilities are currently conducting market research and developing an approach to support the methodology. The following list provides a high level summary of the assumptions for annual space heating energy comparison for single family homes as illustrated in Figure 4-21 of the LTRP:

- The assumption for 33 new homes has been described in the response to BCUC IR 1.30.1.
- A single family home with approx 2339 Sqft in LML region.
- Space heating requirement is 46 GJ's based on current building codes and standards and results from hot 2000[37] model.
- 70% of peak day demand for space heating is met by ground source heat pump.
- GHG emissions for gas equip: 0.0510 tonnes per GJ.

[37] http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/eng/software_tools/hot2000.html

39.0 Reference: Exhibit B-1, Chapter 5, pp. 119 - 121

Rate Affordability and Diminishing Returns

"To determine what level of ongoing funding should be implemented; we examine the potential impact on natural gas demand and GHG emissions in three Scenarios of future funding for EEC programs below."

39.1 Terasen Utilities has provided a menu of three options for EEC programs consisting of Funding Scenario A, B, and C. Each Funding Scenario contemplates a different budget and different composition of DSM programs. Please provide tabular data that summarizes the 5, 10, 15, and 20 year costs and financial benefits associated with Funding Scenarios A, B, and C. Please also include a linear line graph that summarizes the tabular data.

Response:

The Scenarios are intended to be illustrative (please also see the response to BCUC IR 1.38.1). The funding scenarios do not contemplate a different composition of DSM programs. Rather, the savings associated with each Scenario are based upon savings associated with currently approved EEC expenditures and programs, proportional to the funding level in each Scenario. The Terasen Utilities believes that providing a tabular data or a graph as requested by the commission staff would not be meaningful at this point, as the estimated savings are directly proportional to the funding under each scenario, and the program planning for scenarios B and C has not been completed. .

The Conservation Potential Review that is currently underway will help form the types of future programs for future funding EEC requests.

39.1.1 For the above question, please also provide the net present value for 5, 10, 15, and 20 years. Please clearly indicate what discount rate has been applied.

Response:

As discussed in the response to BCUC IR 1.39.1 and BCUC IR 1.38.1, the Terasen Utilities have developed the scenarios for illustrative purposes and believe that the information as requested by the Commission staff would not be meaningful at this point in time.

39.2 For each of the Funding Scenarios A, B, and C, please provide Terasen Utilities 95% confidence intervals for 5, 10, 15, and 20 year EEC forecasts.

Response:

Funding Scenarios A, B, and C were developed for illustrative purposes, based on proportional increases in energy savings for currently approved EEC funding levels and activity, commensurate with changes in expenditure for each scenario. As such, the Terasen Utilities have not developed confidence intervals for the energy savings associated with each Scenario. Please see also the responses to BCUC IR 1.46.1 and 1.46.3.

39.3 Based on the Utilities previous five years of DSM experience, please quantify the impact that a 10% increase in DSM spending has had on gas consumption. For example, a 10% increase in DSM spending results in 0.5% to 0.75% decline in gas consumption with a 95% confidence level.

Response:

The Terasen Utilities cannot state unequivocally what impact a 10% increase in DSM spending has had on gas consumption. There are too many other factors that are relevant to such a calculation, such as economic conditions, changes to the housing mix and changes to the Terasen Utilities' customer demographics. The Terasen Utilities can report that in 2009, TGI expended $5.743 million on EEC activity, and that calculated NPV energy savings were 1,223,550 GJ, as per the 2009 EEC Annual Report filed to the Commission on March 31, 2010. This compares with expenditures of $2.484 million for TGI in 2008, and calculated savings of 612,651 GJ. Impacts on energy savings from incremental expenditures on DSM are dependent on what the incremental funding is being used for. For example, if incremental funding is used to incent more participants into current programs, one would expect an increase in energy savings proportional to the increase in the number o f participants in a program.

40.0 Reference: Exhibit B-1, Chapter 5, p. 121

Impact on Energy Savings Demand and Emissions - Future Funding Scenarios

"The measure life and participation rates will remain constant at the 2010 levels for all the planned programs."

40.1 Terasen Utilities has indicated that the life cycle and participation rates are assumed constant at 2010 levels for all planned programs. Please provide a tabular summary of program life cycles and participation rates for all planned Scenario B programs.

Response:

The program plan, with program details, lifecycles and participation rates for Scenario B has not been completed. Scenario B is based upon currently planned EEC expenditures and the associated energy savings; both of these are assumed to be constant over the planning timeline. As was done for the original EEC Application, more detailed program plans will be completed and submitted with the EEC Funding Request in the upcoming Revenue Requirement Applications for 2012.

40.2 For Funding Scenario B Terasen Utilities has assumed that the number of incremental vehicles will remain constant to those of Scenario A in 2011. Please confirm the assumed number of incremental vehicles per year.

Response:

The Terasen Utilities confirm that assumed number of incremental vehicles per year is 32.

41.0 Reference: Exhibit B-1, Chapter 5, p. 121

Acceleration of GHG Reduction

"The Utilities will only be claiming the consumption and GHG emissions reduction from the adoption of vehicles that were accelerated by EEC funding. In other words, the Utilities acknowledges that NGVs will gain market share in the future, but strongly believes that EEC funding is instrumental to transform the market and Terasen Utilities can therefore claim a portion of those savings."

41.1 In order to claim reductions in GHG emission that result from the acceleration of NGV, there needs to be a base case to quantify the rate at which the adoption of NGVs would have been without EEC funding. Please explain how Terasen Utilities will measure and validate the adoption rate of NGVs that would have occurred in the absence of proposed EEC programs.

Response:

The primary target fleets for NGV's are medium and heavy duty return to base fleets. There has been no NGV activity in these fleets since 2005, when TransLink ordered 50 natural gas buses. The NGV program that the Terasen Utilities have initiated, in which we provide an EEC incentive to cover up to 100% of the incremental cost, has been positively received by customers. Given that there has been no activity since 2005, and that activity now is being spurred by the availability of incentives, it can be concluded that at this time, absent incentives for NGVs, the baseline of NGV activity would be zero.

Over time the need for incentives is expected to decline as the adoption of NGVs increases because we expect that the incremental cost of NGVs will decline with volume production and the need for incentives should decline as the technology becomes more commonly used. Furthermore, when early adopters such as Waste Management are competing in their own markets (in this case waste collection services) with NGVs, it is likely to result in a competitive advantage that may lead their competition to also adopt an NGV fleet. For example, in the case of a request for proposal from a municipality that asks the service provider to outline the environmental impact of their proposed services, a business employing NGVs may be perceived as more favourable over one using a conventional diesel vehicles.

It is the Terasen Utilities' intent to adjust downward the percentage amount of EEC funding over time to ensure that the percent amount of funding of incremental costs is matched to a level that is consistent with the then current state of the market. At the outset the need is for 100% of the incremental cost to be covered by the incentive. Over time, the Terasen Utilities will adjust the level of incentive in line with market requirements. The intent is to continue to provide sufficient incentive to transform the market and to be able to utilize the available funding by eventually reducing the amount of the incentive funding so that more NGVs can be introduced to the market. The timing of the percentage reductions in funding will depend on the rate of market transformation and this is not possible to predict with any level of accuracy at this point in time.

41.2 How will Terasen Utilities adjust for free riders? For the period 2012 to 2020, please provide a tabular summary that quantifies annually the free rider adjustments as a percentage of forecasted GHG emission savings.

Response:

The Terasen Utilities do not anticipate that there will be free riders for EEC NGV grants for medium and heavy duty return to home fleets for the foreseeable future for the reasons outlined in the response to BCUC IR 1.41.1. Without the incentive, these fleets will not adopt the technology, and the incentives are being scaled to the level that is necessary in order to have participants adopt this technology.

42.0 Reference: Exhibit B-1, Chapter 5, pp. 120 - 122

Unit cost of EEC Energy Savings

42.1 On pages 120 to 122 of the Application, Terasen Utilities provided a description of Funding Scenarios A, B, and C together with estimates of EEC energy savings and costs. The table below summarizes estimated energy savings and costs. Do Terasen Utilities agree with the summary? If not, please provide an updated version together with a brief description explaining the differences.

Unit Cost of EEC Energy Savings by Funding Scenario for the Period 2009 to 2030*

Ref.		Funding Scenarios A	B	C	% Difference Between Scenario B and C
1	Forecasted Energy Savings (PJ)	12	148	243	64%
2	Forecasted EEC Program costs ($ million)	0	700	1600	129%
3	Unit cost of energy savings ($/GJ)	0	4.73	6.58	39%

*Prepared by Commission Staff

1 Forecasted energy savings from Exhibit B-1, Figure 5-1, p. 122

2 Forecasted EEC program costs (nominal) from Exhibit B-1, pp. 120 - 121. Funding Scenario B = $35 million per year x 20 years. Funding Scenario C = $80 million per year x 20 years)

3 Unit cost of energy saving = line 2/line 1

Response:

The Terasen Utilities do not agree with the summary. The Terasen Utilities indicated on page 121 of Exhibit B-1 that the funding for scenario C will begin to taper off by $5 Million annually from 2022 on to the end of the planning period, as would the proportional savings. It should be noted as well that the funding envelopes and energy savings presented in the different Scenarios are not forecasted so much as provided for illustrative purposes.

		Funding scenarios A	B	C	% Difference between scenarios B and C
1	Forecasted energy savings (PJ)	12	148	243	64%
2	Forecasted Program Costs ($Million)	0	700	1,375	96%
3	Unit cost of energy savings ($/GJ)	0	4.73	5.66	20%

42.1.1 Reference line 3 from the above table indicates that on a unitized basis ($/GJ), Funding Scenario C is approximately 39% more expensive than Funding Scenario B. Despite possible economies of scale, please explain why Funding Scenario C is considerably more expensive on a unitized basis.

Response:

Based on revised estimates as illustrated in the response to BCUC IR 1.42.1, Scenario C is 20% more expensive than Scenario B on a unitized basis. While economies of scale could certainly be anticipated in Scenario C, savings from the different Scenarios were modelled as being simply proportional to the amount of expenditure. No attempt was made by the Terasen Utilities to model the impact of scale. The savings of 243 PJ's in scenario C are net savings, incorporating not only energy efficiency activity, but also high-carbon fuel switching activity. This means that assumptions have been incorporated for additional load anticipated from heavy vocation trucks such as waste haulers, tractor trailers, and medium trucks to displace higher carbon content fuel such as diesel.

If the above calculation is done for unit cost of GHG savings, it can be seen that scenario C is as cost effective as scenario B in achieving higher GHG reductions as shown below:

	Funding scenarios			% Difference between scenarios
	A	B	C	B and C
Forecasted GHG savings(000 TCo2)	823	9,120	17,540	92%
Forecasted Program Costs($Million)	0	700	1,330	90%
Unit cost of energy savings($/GJ)	0	0.077	0.076	-1%

Going forward, it is the intent of the Terasen Utilities to pursue a continuous funding mechanism for EEC activity. The exact nature of ongoing funding mechanisms and funding level requirements will change once the results of the CPR become available, and will be submitted for approval in the 2012 Revenue Requirement Application.

42.1.2 Do the Utilities hold the view that funding EEC is economic in terms of unit cost of energy saved under all Funding Scenarios A, B, and C? Please explain your answer and provide supporting calculations and assumptions.

Response:

The EEC program plan and economic analysis required to support a funding request has not yet been completed; this will be done for the EEC funding request that will form part of the 2012 Revenue Requirement Applications. At a very high level, however, when comparing the unit cost of energy saved of $4.73/GJ for Scenario B and $5.47/GJ for Scenario C, as presented in the response to BCUC IR 1.42.1, with the current avoided cost of gas presented in the response to BCUC IR 1.4.1, it would appear that based on unit cost of energy saved, Scenarios B and C are economic.

42.1.3 For Funding Scenarios B and C, is there any commodity price of natural gas below which Utilities EEC programs are not economic? If "no", please explain. If "yes", please provide details.

Response:

Under current benefit-cost guidelines, using a portfolio level TRC, the point at which EEC activities becomes uneconomic is that where program costs outweigh the avoided cost of energy. It is challenging to state unequivocally at what commodity price that might be, as the program planning for Scenarios B and C has not been done. The Terasen Utilities are therefore unable to predict the mix of programs and activities, all with different cost-benefit profiles that might eventually make up Scenarios B and C.

Further, it is the view of the Terasen Utilities that simply using a portfolio level TRC may provide too narrow a view of the benefits of EEC activities, as explained in the response to BCUC IR 1.32.1. For example, the EEC activities provide economic spin-offs beyond just the avoided cost of energy, such as job creation, which are not captured in today's analysis of what is economic and what is not economic EEC activity. Scenario C funding may create significant employment for British Columbians, which would add to its economic viability. To encourage economic development and the creation and retention of jobs is one of British Columbia's energy objectives.

In addition, Scenario B and C funding levels would offer a mix of programs at differing cost-effectiveness levels, so there would be some low-cost, high return programs, and other programs for other customers that have higher costs associated with them. The importance of offering a fairly wide mix of programs, which by the nature of the programs have differing cost-effectiveness levels, nonetheless is needed to satisfy the EEC Program Principle of Universality, that is, offering programs to as wide a range of customers as possible.

43.0 Reference: Exhibit B-1, Chapter 5, p. 122

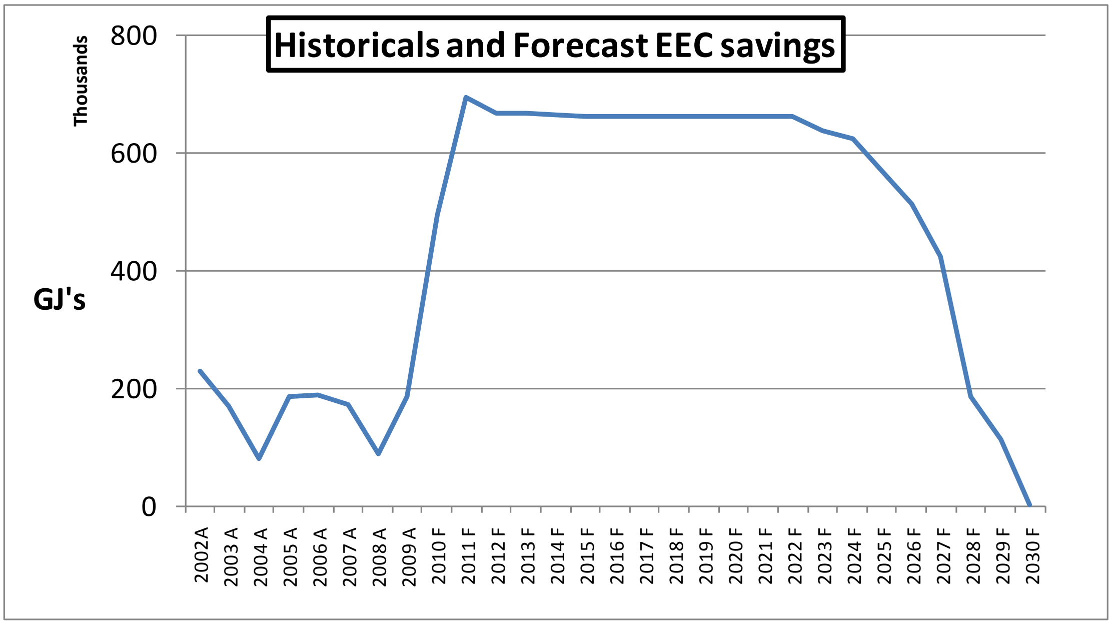
Impact on Energy Savings and GHG Reductions in Scenarios A, B, & C

"Each of the scenarios described above will have a significantly different impact on energy conserved. Figure 5-1 depicts the impact on energy savings from the above mentioned scenarios. As can be seen, Scenario C will conserve significantly more energy than Scenario A, 213.38 PJ (equivalent to 213,380,000 GJ) versus 11.75 PJ (11,750,00 GJ)."

43.1 Please provide a tabular and graphical summary of actual and forecasted EEC energy savings (PJ) for the period 2002 to the beginning of 2012. Please extend the data to 2030 based on Funding Scenario A.

Response:

As seen from the chart below based on the input assumptions for scenario A, there seems to be a direct relationship with the amount of EEC funding and anticipated savings assuming increased participation from the current level of participation in EEC programs. The actual savings from 2002 until 2009 fluctuates depending on program participation. Given the tenfold increase in the current levels of funding, there is a sharp increase in estimated savings during the initial years with increased participant uptake and then as funding expires by 2011, the savings remain constant for a while before declining. Scenarios described in the application are for illustrative purposes only and provide a range of savings proportional to the level of funding available.



Please note the chart above includes:

- The actuals for 2007, 2008, 2009 are taken from the Terasen Utilities Annual reports
- The forecast of energy savings is based on current approved EEC programs with current funding levels expiring by 2011.

43.1.1 Funding Scenario A forecasts that 12 PJ of incremental energy savings would be realized during the 20 year period contemplated by the Application. By comparing EEC energy savings in 2011 to forecast the 12 PJ incremental savings, please calculate the persistence of Utilities EEC portfolio. Please provide the underlying assumptions.

Response:

Please see the response to BCUC IR 1.46.4.

43.2 On page 129, Terasen concluded that the California Standard Practice may not be the appropriate analysis tool for Utility EEC programs of the future. Please describe how Terasen Utilities envisages changes to the evaluation, measurement and validation processes that it currently uses to report EEC costs and benefits. To the extent possible, please also provide an example of the format and content of any changes to EEC reporting standards currently employed by Terasen Utilities or currently researched by independent institutes (e.g., the Consortium of Energy Efficiency).

Response:

Please see also the response to BCUC IR 1.32.1. At this time, the Terasen Utilities have not envisaged specific changes to the evaluation, measurement and validation processes currently used to report EEC costs and benefits. The Terasen Utilities would anticipate that should such an undertaking occur, this work would be done on receipt of a Discussion Paper that the Terasen Utilities have commissioned as part of the CPR work, and that it would be done in consultation with stakeholders, and BCUC staff.

43.2.1 Please identify and prioritize the most crucial challenges that Terasen Utilities have faced in planning, implementing, and validating EEC programs over the past five years.

Response:

One major issue that the Terasen Utilities have encountered over the last five years is that there is a lack of capacity, knowledge and expertise in planning, implementing, and evaluating EEC activity in the BC marketplace. TGI and TGVI's approved funding and level of activity increased approximately ten-fold with the Commission's approval of the EEC Application in April 2009. The Tersaen Utilities have encountered a significant challenge in finding and training staff in order to implement the EEC program plan outlined in the EEC Application and the recent Revenue Requirements applications for TGI and TGVI. This could be alleviated somewhat through stable, long-term funding of utility EEC programs. The Terasen Utilities will present such a proposal for stable long-term funding for EEC activity in the next RRA, due to be submitted in the Spring/Summer of 2011.

As discussed at length during the EEC proceeding, as with every other utility in North America, another major challenge has been establishing a net-to-gross ratio that could be considered an accurate representation of the impacts of the Terasen Utilities' EEC activity. Free rider rates and spillover are challenging to quantify, are more art than science and it is the Terasen Utilities' view that the net-to-gross concept is outdated, especially when one considers that government's greenhouse gas reduction targets are absolute, not net. Attribution of energy savings from the introduction of regulation pursuant to a utility program in support of that regulation is another important area of activity that requires some work. And finally, as discussed in the response to BCUC IR 1.32.1, the Terasen Utilities feel that the current cost-benefit criteria that are applied to some EEC activities need to be revisited.

43.3 Please provide a tabular summary of evaluation, measurement and validation (EM&V) expenses associated with each of the Funding Scenarios between 2012 to 2030. Please indicate the cost of EM&V expenses in both dollars amounts and as a percentage of the total cost of each Funding Scenario.

Response:

This work has not yet been completed. As discussed, the three Scenarios are for illustrative purposes, and detailed program plans have not been prepared yet for the Scenarios. The mix of programs is unknown, and so therefore are the EM&V requirements.

43.3.1 To the extent possible, please provide a comparison of Utilities EM&V expenses to other similar utilities operating in Canada.

Response:

TGI's 2010 budget for program evaluation is $807,000 and the total approved expenditure is $25.845 million. Generally speaking, most other utilities with EEC programs of similar size are allocating 3 to 5% of total budget for evaluation; however, these utilities have generally had programs of significant magnitude for a number of years, so they actually have results to evaluate. The Terasen Utilities only received approval for the increase in EEC expenditure in April 2009, and the focus of the group to date has been on hiring and training program managers and developing the increased suite of programs and pushing them into the marketplace, as well as establishing systems and procedures and reporting out to stakeholders. The Terasen Utilities would anticipate that the evaluation budget will grow as programs start to generate results that need to be analyzed and confirmed.

43.4 For Funding Scenarios A, B, and C, please confirm what adjustments have been made to forecasted energy savings to adjust for free-ridership, persistence of savings, and attribution of benefits.

Response:

The three scenarios are based upon the Terasen Utilities' projections of energy savings associated with approved EEC activities. To the extent that the energy savings associated with approved EEC activity incorporate net-to-gross ratios and persistence, these adjustments are reflected in Scenarios A, B and C. However, program plans have not been prepared for the 3 funding scenarios and this analysis will not be done until the CPR is received and the results thereof begin to be refined. It is at that time that there will be more work done on the appropriate adjustments to gross energy savings from EEC activity.

43.5 For the period 2012 to 2030, please explain what measurement and validation processes are planned to quantify the following: (a) the difference between user per customer (UPC) that would have had occurred with and without EEC funding; (b) the degree to which UPC declines are more rapid in jurisdictions with DSM programs than without DSM programs; (c) the extent to which UPC declines are more rapid in jurisdictions with more aggressive and more costly DSM programs than in jurisdictions with less aggressive and less costly DSM programs; (d) the extent to which historical data indicates that declines in UPC are more rapid in years in which DSM expenditures have been relatively high, compared to those years in which expenditures have been lower.

Response:

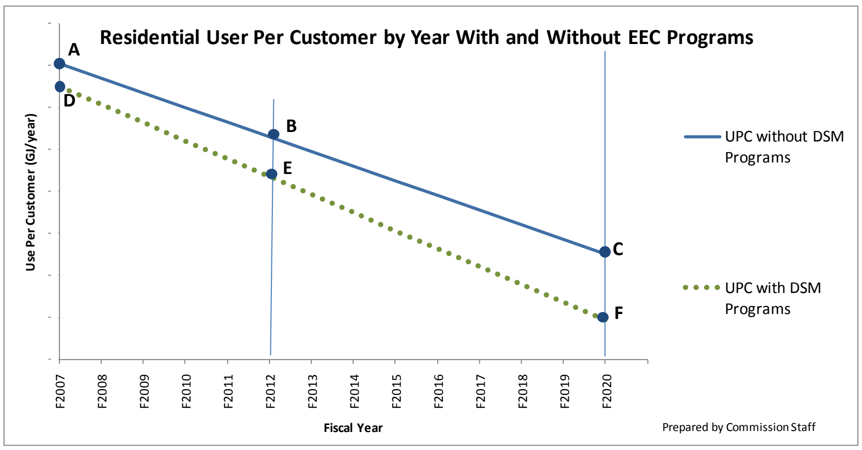
A stated in the response to BCUC IR 1.43.3, the Terasen Utilities have not conducted any formal analysis to estimate evaluation, measurement and verification (EM&V) expenses and processes. However, the Terasen Utilities plan to use meter data, site specific data collection and analysis using analytical tools, to establish control samples and to rely on internal customer information and participant tracking systems to quantify the differences between use per customer that would have occurred with and without EEC funding.

The Terasen Utilities believe that benchmarking the points in the Information Request to another utility with different demographics, building codes , equipment regulations , economic factors, influences of weather, saturation of efficient appliances and other behavioural efficiency and conservation influences is not useful. The difficulty of accounting for the effects of these confounding factors makes it practically impossible to measure these differences with any accuracy.

44.0 Reference: Exhibit B-1, Chapter 5, p. 122

Long-term resource and conservation planning

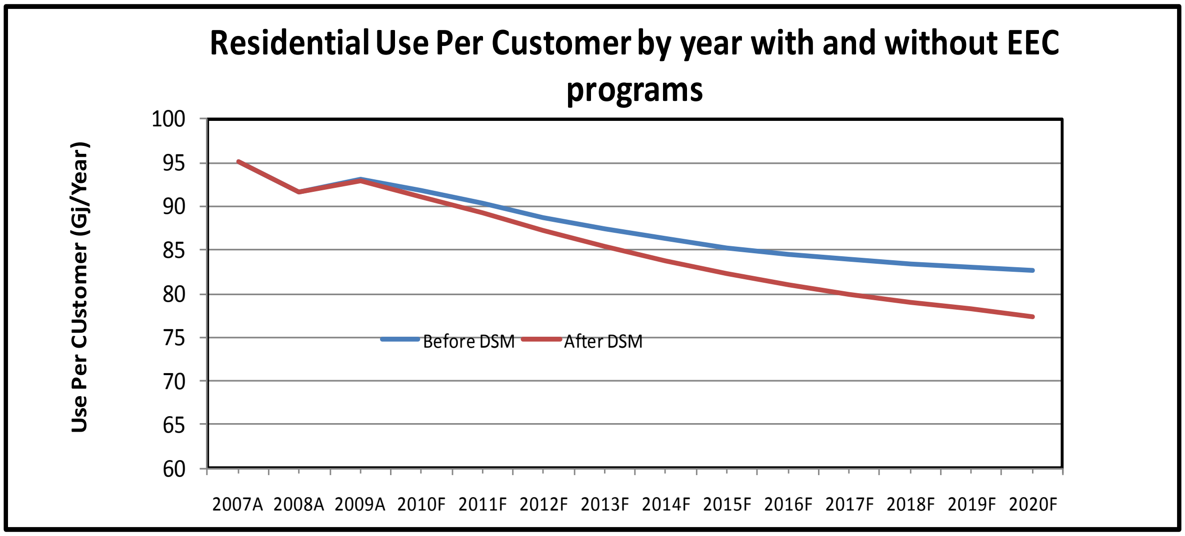
44.1 For residential customers, please provide tabular data that compares the use per customer (weather normalized) for the period 2007 to 2020 with and without DSM programs. Please assume Funding Scenario B. Please also provide a graphical summary in the following format:



<u>Response:</u>

The table and graph below illustrates the normalized use per account with and without DSM for funding scenario B. It can be seen below that continuous funding enables a consistent decline in use per customer.

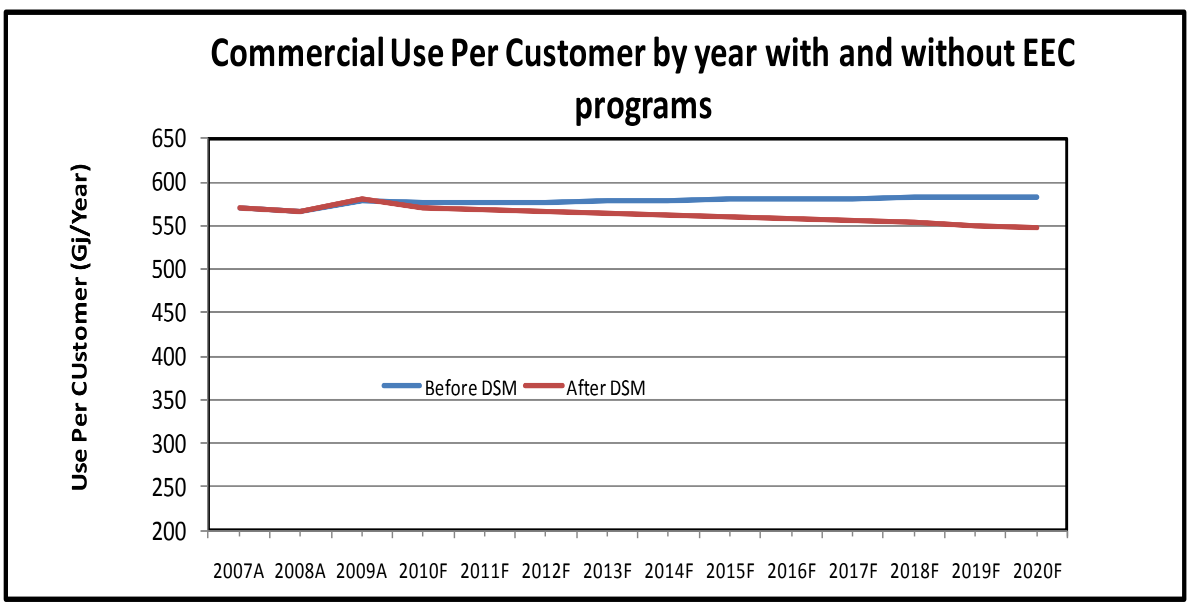
Residential	2007A	2008A	2009A	2010F	2011F	2012F	2013F	2014F	2015F	2016F	2017F	2018F	2019F	2020F
After DSM	95.0	91.6	92.9	91.2	89.3	87.3	85.4	83.8	82.3	81.0	80.0	79.1	78.2	77.3
Before DSM	95.2	91.7	93.0	91.9	90.3	88.8	87.4	86.3	85.3	84.5	83.9	83.5	83.0	82.6



44.1.1 Please respond to the above question for commercial customers.

Response:

The figure below illustrates use per customer for TGI commercial customers under Rate Schedules 2, 3 and 23 with and without DSM programs, assuming funding scenario B.



45.0 Reference: Exhibit B-1, Chapter 5, p. 122

Natural Gas Utility Comparison

45.1 For the period 2007 to 2013, please provide actual and forecasted DSM expenditures by year in the following format.

Terasen Utilities DSM Scenario C: Expenditures, by Year, as a Percentage of Revenue

	1	2	3 = 2 ÷ 1	4	5 = 2 ÷ 4
Fiscal Year	Gross Oper Rev (000s)	DSM Expenditures (000s)	DSM % of GOR (%)	GOR less Cost of Gas (000s)	% of Utility Revenue less Cost of Gas (%)
2007 (Actual)					
2008 (Actual)					
2009 (Actual)					
2010 (Projected)					
2011 (Projected)					
2012 (Scenario C Forecast)					
2013 (Scenario C Forecast)					

Response:

Please see the table below.

Please note:

- Revenues include TGI and TGVI
- Projected revenues are based on current demand forecast and 2011 approved delivery margin and cost of gas rates remaining constant though the planning period.

Fiscal Year	Gross Oper Rev** (000s)	DSM Expenditures*** (000s)	DSM % of GOR (%)	GOR less Cost of Gas (000s)	% of Utility Revenue less Cost of Gas (%)
2007 (Actual)	1,639,220	4,274	0.26%	561,133	0.76%
2008 (Actual)	1,617,826	4,274	0.26%	579,786	0.74%
2009 (Actual)	1,483,416	6,072	0.41%	628,281	0.97%
2010 (Projected)*	1,475,740	31,049	2.10%	666,492	4.66%
2011 (Projected)*	1,484,412	35,302	2.38%	692,338	5.10%
2012 (Scenario C Forecast)*	1,506,978	76,055	5.05%	692,338	10.99%
2013 (Scenario C Forecast)*	1,506,903	76,053	5.05%	692,338	10.98%

45.1.1 Please repeat the above question for Funding Scenarios A and B.

Response:

Please see the following two tables for Funding Scenario A and for Funding Scenario B.

Please note:

- Revenues include TGI and TGVI
- Projected revenues are based on current demand forecast and 2011 approved delivery margin and cost of gas rates remaining constant though the planning period.

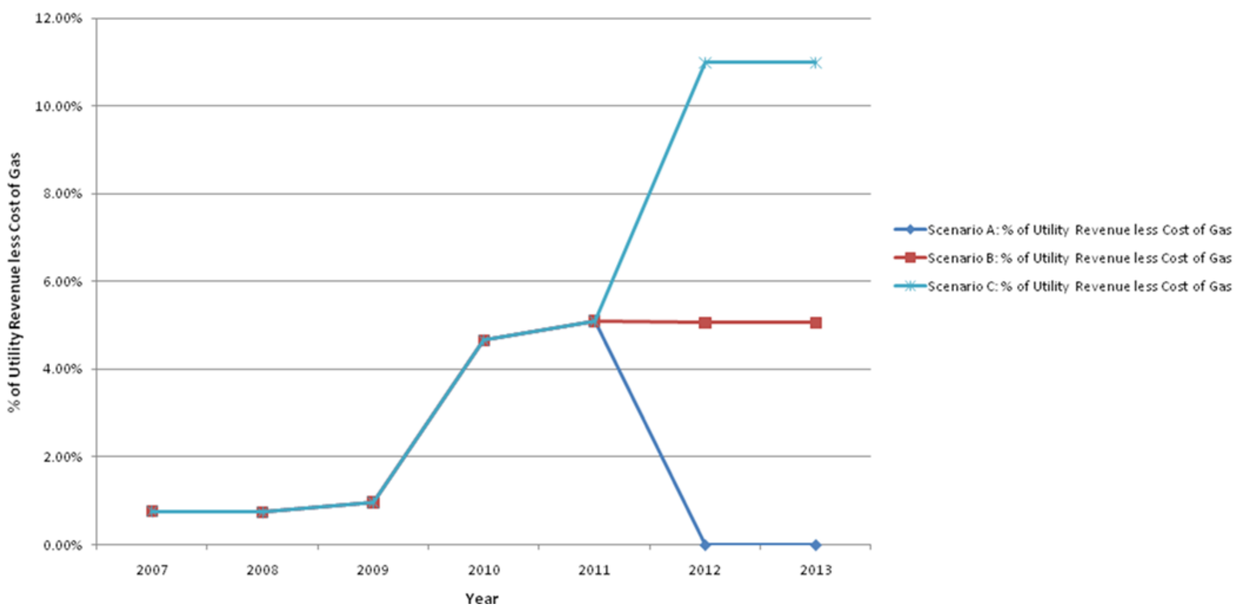
Fiscal Year	Gross Oper Rev** (000s)	DSM Expenditures*** (000s)	DSM % of GOR (%)	GOR less Cost of Gas (000s)	% of Utility Revenue less Cost of Gas (%)
2007 (Actual)	1,639,220	4,274	0.26%	561,133	0.76%
2008 (Actual)	1,617,826	4,274	0.26%	579,786	0.74%
2009 (Actual)	1,483,416	6,072	0.41%	628,281	0.97%
2010 (Projected)*	1,475,740	31,049	2.10%	666,492	4.66%
2011 (Projected)*	1,484,412	35,302	2.38%	692,338	5.10%
2012 (Scenario A Forecast)*	1,506,978	-	-	692,338	-
2013 (Scenario A Forecast)*	1,506,903	-	-	692,338	-

Fiscal Year	Gross Oper Rev** (000s)	DSM Expenditures*** (000s)	DSM % of GOR (%)	GOR less Cost of Gas (000s)	% of Utility Revenue less Cost of Gas (%)
2007 (Actual)	1,639,220	4,274	0.26%	561,133	0.76%
2008 (Actual)	1,617,826	4,274	0.26%	579,786	0.74%
2009 (Actual)	1,483,416	6,072	0.41%	628,281	0.97%
2010 (Projected)*	1,475,740	31,049	2.10%	666,492	4.66%
2011 (Projected)*	1,484,412	35,302	2.38%	692,338	5.10%
2012 (Scenario B Forecast)*	1,506,978	35,000	2.32%	692,338	5.06%
2013 (Scenario B Forecast)*	1,506,903	35,000	2.32%	692,338	5.06%

45.1.2 Please provide a time series graph for the period 2007 to 2013 that summarizes the percentage utility revenue less cost of gas (column 5 from the above table) for Funding Scenarios A, B, and C.

Response:

Please see the figure below.



45.2 The comparison of historical key performance metrics among natural gas utilities in Canada and the USA is helpful in assessing industry norms and trends. Please provide the following averages over the three-year fiscal reporting period 2007 to 2009:

Terasen Utilities DSM Scenario C: Expenditures, by Year, as a Percentage of Revenue

	1	2	3 = 2 ÷ 1	4	5 = 2 ÷ 4
Fiscal Year	Gross Oper Rev (000s)	DSM Expenditures (000s)	DSM % of GOR (%)	GOR less Cost of Gas (000s)	% of Utility Revenue less Cost of Gas (%)
2007 (Actual)					
2008 (Actual)					
2009 (Actual)					
2010 (Projected)					
2011 (Projected)					
2012 (Scenario C Forecast)					
2013 (Scenario C Forecast)					

Response:

Please see the information requested in the table below.

Utility	Jurisdiction	Gross Oper Rev (000s)	DSM Expenditures (000s)	Gross Oper Rev less Cost of Gas (000s)	Number of Utility Customers in Jurisdiction (000s)	DSM % of Gross Oper Rev (%)	DSM % of Utility Revenue less Cost of Gas (%)	DSM Budget Per Customer ($ per Customer)
ATCO GAS	Alberta	687,751	1,333	*see note [1]	1,021	0.2%	not applicable [1]	1.3
Enbridge Gas	Ontario	2,885,000	23,067	993,000	1,886	0.8%	2.3%	12.2
Gaz Metro	Quebec	1,625,333	13,930	464,000	176	0.9%	3.0%	79.1
Northwest Natural	Portland	1,027,920	*see note[2]	392,358	660	not applicable [2]	not applicable [2]	not applicable [2]
Puget Sound Energy	Seattle	3,302,140	49,776	2,562,533	1,807	1.5%	1.9%	27.6
Terasen	BC	1,630,895	4,873	589,733	896	0.3%	0.8%	5.4
Union Gas	Ontario	1,924,000	19,827	806,000	1,311	1.0%	2.5%	15.1

Notes:

[1]Atco does not purchase gas. It is solely distribution.

[2]Due to a 1999 energy restructuring law, the Oregon market is structured differently than many other U.S. states when it comes to implementing conservation programs. Utility customers pay a public benefits charge on their utility bills. The investor-owned utilities then give these funds to the Energy Trust of Oregon, a statewide non-profit organization. Energy Trust of Oregon implements DSM programs on behalf of the participating utilities, including Northwest Natural. As a result, it does not appear that Northwest Natural has DSM expenditures since it does not implement DSM programs.

45.2.1 Based on the results of the above table, please provide a DSM program budget based on forecasted 2011 margin in the following format:

DSM Budget for 2012 based on Utility Industry Average

Utility	2011 Margin[1] (000s)	DSM Budget for Funding Scenario A (000s)	DSM Budget for Funding Scenario B (000s)	DSM Budget for Funding Scenario C (000s)
Terasen Gas Inc.				
Tersen Gas Vancouver Island				
Terasen Gas Whistler				
Total				

1 Forecasted 2011 gross operating revenue less the cost of natural gas.

Response:

DSM program budgets for 2012 and beyond have not yet been developed, and therefore cannot be broken down into TGI/TGVI/TGW. The Terasen Utilities will request our recommended DSM budget in the next EEC funding request which will be in the Revenue Requirement Applications that will be filed in Spring/Summer 2011.

46.0 Reference: Exhibit B-1, Chapter 5, p. 122

Forecasted EEC energy saving

"Figure 5-1 depicts the impact on energy savings from the above mentioned scenarios. As can be seen, Scenario C will conserve significantly more energy than Scenario A, 213.38 PJs (equivalent to 13,380,000 GJs) versus 11.75 PJ (11,750,00 GJ)116."

46.1 Does Terasen Utilities have a predictive model to estimate EEC savings associated with each of the Funding Scenarios? If "yes", please provide an electronic copy in the form of a fully functional electronic spreadsheet. If "no", please discuss how Terasen Utilities forecasted EEC energy savings which have been summarized in Figure 5-1, p. 122. In both cases, please clearly state the input assumptions used to forecast energy savings.

Response:

The Terasen Utilities do not have a predictive model yet to estimate EEC savings. For the scenarios presented, we estimated savings based on the current EEC program portfolio with expanded savings proportional to the extended period and increased funding in each Scenario. The savings for the current conventional EEC programs have been estimated on a program by program basis by multiplying the number of expected participants with the estimated savings and the measure life, with an adjustment to create a net to gross ratio. The input assumptions on measure life, expected savings and number of participants have been discussed in detail in the 2009 EEC Annual Report[38]. The Terasen Utilities are still developing the Innovative Technologies portfolio, and have only incorporated the expected increase in demand from the replacement of high carbon diesel heavy-duty trucks with low carbon natural gas. The Terasen Utilities did not consider other planned programs within Innovative Technologies and Industrial EEC for any of the scenarios as we are still investigating the types of technologies and conducting analysis to determine feasibility. Going forward, as additional data becomes available through ongoing research and evaluation, measurement and verification activities, the Terasen Utilities will refine input assumptions for future program planning for the upcoming Revenue Requirement Application.

[38] http://www.terasengas.com/_AboutUs/RatesAndRegulatory/BCUCSubmissions/LowerMainlandSquamishInterior/EnergyEfficiencyConservationPrograms/default.htm

46.2 Please provide a summary of EEC savings and expenditures in the following format:

Cumulative Natural Gas Savings and Expenditures 2009 to 2030

Funding Scenarios	Cumulative Energy Savings* (PJ)	Cumulative EEC Program Expenditures ($ 000)	Average Cost of EEC Energy Savings ($/PJ)	GHG Savings (TCO_2)	Average Cost of GHG Savings ($/$TCO_2$)
	1	2	3 = 2 ÷ 1	4	5 = 2 ÷ 4
Funding Scenario A	12.00				
Funding Scenario B	148.00				
Funding Scenario C	243.00				

* Data from Exhibit B-1, Figure 5-1, p. 122

Response:

Please see the table below.

Cumulative Natural Gas Savings and Expenditures 2009 to 2030

Funding Scenarios	Cumulative Energy Savings (PJ)	Cumulative EEC Program Expenditures[1] ($ 000)	Average Cost of EEC Energy Savings ($ 000/PJ)	GHG Savings (TCO_2)	Average Cost of GHG Savings ($/$TCO_2$)
Funding Scenario A	12.00	72,423	6,035	822,536	88.05
Funding Scenario B	148.00	737,423	4,983	9,119,928	80.86
Funding Scenario C	243.00	1,359,086	5,593	17,539,229	77.49

46.3 The measurement of EEC saving involves the comparison of two values: actual observed gas consumption, and the consumption that would have been without the EEC programs. Please explain how Terasen Utilities achieves this comparison.

Response:

The Terasen Utilities achieve the comparison of actual observed gas consumption and the consumption without the EEC programs through conducting analyses during both the program planning and post implementation stages.

During program planning stages, where little historical data is typically available for analysis purposes, the Terasen Utilities lean towards adopting the estimated savings other utilities incorporate into their DSM program analyses. Through a combination of informal discussions with consultants and/or other industry experts and the Terasen Utilities' own analysis, the results obtained from other utilities are then validated for use.

During post program implementation evaluation, the Terasen Utilities rely on evaluation, measurement and verification (EM&V) methodologies, such as billing analysis, statistical estimates, and site specific market research, using control and program participant samples to determine the effects of EEC activities and measure implementation. The Terasen Utilities would like to point out that it takes considerable resources to conduct a post program evaluation and it makes sense to perform this analysis only for those programs that have been in the market place for some time in order to obtain meaningful results. For example, for the Heating System Upgrade program, the Terasen Utilities sampled the participants and a group of non-participants (a randomly selected control group) to analyze normalized consumption levels both prior and subsequent to participating in that program, which results in the savings for participants being estimated. Normalizing consumption data to remove the weather effect from the data and including a control group (that did not participate in the program) enables the Terasen Utilities to conclude that other external factors impact the participants in the same manner as they do the non-participants.

As stated in the response to BCUC IR 1.43.3, the Terasen Utilities have not conducted any formal analysis to estimate evaluation, measurement and verification (EM&V) expenses for the difference Scenarios at this time. When the Terasen Utilities bring forward, in the next Revenue Requirement Application, a specific EEC funding request, we will provide details on the EM&V processes that we plan to establish to quantify the impact before and after EEC programs.

46.3.1 How does Terasen Utilities isolate the effects of its EEC programs from the effects of weather, GDP, interest rates, changes in population, number of new housing starts, macro economic pressures, and other causal variables?

Response:

The scenarios described are for illustrative purposes with savings proportions based on current approved programs. For the current planned programs for the approved EEC funding, the Terasen Utilities incorporate normalized annual savings by normalizing the consumption data to remove the weather effects.

The other variables are isolated from the EEC savings during the program and process evaluation stages. One of the ways in which the Terasen Utilities isolate the effects is by establishing a control group of non-participants. The non-participants are expected to closely resemble the participant group in many demographic variables and are subjected to the same externalities, but do not implement the program measure and thereby serve as a comparison group when the results are evaluated. Through such mechanisms, the Terasen Utilities ensure that the externalities impacting the participants are the same as non-participants thereby concluding that the savings result from the program measure.

46.4 An important justification for EEC programs is their ability to influence customers total consumption patterns through the application of incentives and the degree to which those changes have persistence once the incentives have been removed. What explanatory data does Terasen Utilities have on the persistence of EEC programs over the past 10 years. Please provide a copy of the data in the form of a spreadsheet.

Response:

The Terasen Utilities do not have data on the persistence of their EEC programs over the past 10 years. However, the issue of persistence of program savings was explored in the recent TGI and TGVI Energy Efficiency and Conservation Application (filed with BCUC in May 2008) proceeding, wherein the program plan, energy savings (which are a function of persistence) and levels of expenditure for EEC activity were accepted and approved. BCUC IR 2.1.2 from the 2008 EEC proceeding, and TGI and TGVI's response to it, are excerpted below.

"1.2 Has Terasen considered both measure and claim persistence in calculating the savings attributed to the programs? If so, please explain in detail.

Response:
Measure persistence refers to the risk of a measure being discarded or replaced before the end of its expected life, and is a concern if the product is replaced with a less efficient unit. For the measures being considered in these programs (ie: furnaces, fireplaces, major appliances in residential buildings, building shell measures, and major water and heating equipment in commercial buildings), early replacement with less efficient equipment was not considered a significant risk, due to the high cost and inconvenience of doing so, and was not explicitly considered."

BCUC IR 3.1 series from the 2008 EEC proceeding, and the TGI and TGVI's response to it, are also excerpted below.

"1.0 Reference: Exhibit B-3, Terasen Response to BCUC IR No. 2. p. 1, question 1.2, Persistence

1.1 The above referenced second round Information Request asked if Terasen had considered both measure and claim persistence in calculating the savings attributed to its programs. Terasen's response addressed only *measure persistence. Claim persistence can be described as "having incented the customer to implement an energy efficiency measure, when would have the customer implemented the measure in the absence of the program?"*

Has Terasen considered claim persistence? Please discuss in detail and provide references or supporting documentation.

Response:

The approach Terasen has taken when designing most programs is to target customers who are intending to replace their equipment and then influence them to implement the more efficient option. With this approach, the next opportunity for the customer to implement the measure is when the efficient measure is replaced, presumably at the end of its life. Hence claim persistence is not an issue in the design of most of these programs.

For two of the Commercial sector retrofit programs, Building re-commissioning and Next Generation Building Automation Systems, claim persistence could be an issue in that customers may not be forced into a binary decision (install a standard efficiency product or a high efficiency product), and could choose to adopt the measures at some point in the future without the program. However, these measures do not have significant uptake at this time, and because of this, the program is required. Hence the likelihood of a "claim persistence" issue is thought to be small. As with all programs, when the market adopts the measure in a significant way without the program, the programs will be scaled back or modified. This is the essence of market transformation.

1.2 Measure persistence may be defined as the number of years a system will remain operating and delivering baseline savings. Terasen's response states that since early replacement with less efficient equipment was not considered a significant risk, measure persistence was not explicitly considered.

1.2.1 Does Terasen agree that measure persistence may be a concern where (say) a building or appliance is destroyed or becomes inoperative for some reason? If not, why not? Terasen Gas Inc ("Terasen Gas" or "TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") collectively the "Terasen Utilities" or the "Companies" Energy Efficiency and Conservation Programs Application (the "Application") Submission Date: October 6, 2008 Response to British Columbia Utilities Commission

("BCUC" or the "Commission") Information Request ("IR") No. 3 Page 2

Response:

The Companies do agree that measure persistence may be a concern where a building or appliance is destroyed, however the Companies' view is that because space and water heating equipment has a relatively high cost and is relatively inconvenient to replace when compared to say, a light bulb, it is less likely to be destroyed and thus measure persistence is less of a concern than it might be on the electricity side.

One of the principles behind the design of these DSM programs is to ensure that the customer who is making the decision to adopt the efficient measure is also making a significant financial contribution to purchase of the measure. (This is the rationale behind setting incentives at approximately 50% of the incremental cost). In this way, the customer has a financial incentive to ensure that he receives the economic benefit of the measure.

Further, in the case of a building, an owner is unlikely to make a significant investment in building efficiency if the building is expected to be demolished. In the case of movable measures, such as gas ranges and dryers, if the house is being demolished, the appliance is likely to be re-used in another location. As a point of interest, the number of residential demolition permits issued in the City of Vancouver in 2007 was 568; the 2006 Census data indicates that there are 253,212 occupied private dwellings in the City. Thus 0.22% of the occupied private dwellings in the City of Vancouver received demolition permits in 2007, which the Companies would consider to be immaterial as an input to cost-effectiveness analysis.

1.2.2 Please provide any empirical evidence Terasen has that measure persistence is not significant. Please canvas the opinion of Terasen's consultant Habart and Associates and in particular with reference to their experiences with BC Hydro.

Response:

Please see the response to BCUC IR 3.1.2.1 above. The Companies do not have any empirical evidence that measure persistence is not significant. Rather the Companies applied a common sense approach, and assumed that due to the relative high cost and inconvenience of replacing space and water heating equipment, the destruction of this *efficient equipment would likely only happen in the event of a demolition. Habart and Associates determined that this approach would be appropriate for the Terasen Utilities. Please note that Habart and Associates holds their experiences with BC Hydro as "client confidential"."*

Persistence is much less of an issue for natural gas EEC activity than for electric EEC activity because natural gas measures tend to be hard-wired and difficult to remove. It is far more difficult to remove a furnace after receiving an incentive than it is to remove a lightbulb. An EEC program plan, including assumptions of effective measure life, will be presented in the next Revenue Requirement Application.

As detailed in the 2008 EEC Application and TGI and TGVI's 2010 and 2011 RRA proceedings, one of the Terasen Utilities EEC Program principles is Market Transformation, a process by which utility incentives are used to support the introduction of ever-increasingly more stringent equipment and building performance regulations. Once an efficient technology or design has achieved adequate market maturity for regulation to be introduced requiring that technology or design, incentives can be removed from the market, and the change can be considered persistent as it is enshrined in regulation.

46.4.1 Please explain whether historical persistence levels are reliable indicators for the forecasts provided for Funding Scenarios A, B, and C. Please explain why or why not.

Response:

Please see the response to BCUC IR 1.46.4. The energy savings presented should not be considered "forecasts", but rather as energy savings outcomes proportional to expenditures, based on different EEC funding scenarios.

46.5 Please confirm the short-run and long-run own-price elasticity that has been assumed for residential, commercial and industrial customers in the development of EEC savings forecasts. Please summarize in tabular form.

Response:

As discussed in the response to BCUC IR 1.46.3, the Terasen Utilities' practice in estimating and evaluating EEC program savings is to conduct analyses during both the program planning and post implementation stages. Short-run and long-run own-price elasticity is not formally incorporated into the estimation and evaluation of EEC savings.

46.5.1 Please repeat the above question for the cross-price elasticity with electricity.

Response:

Please see the Terasen Utilities' response to BCUC IR 1.46.5.

46.5.1.1 Are these own-price elasticity values calculated from actual data or derived from published reports? If derived from reports, please provided a copy of the relied upon references.

Response:

Please see the response to BCUC IR 1.46.5.

46.5.2 Please explain the internal processes and management oversight that Terasen Utilities will employ to assess the efficiency of EEC implementation and validity of results for proposed Scenarios A, B, and C.

Response:

Scenarios A, B and C are presented for illustrative purposes. A request for EEC funding will be brought forward in the next Revenue Requirement Application, based upon a proposed program plan at that time. That request will include a discussion of process and management oversight, for which the Terasen Utilities will use the same internal control and management oversight processes that have been established for all the Terasen Utilities' EEC activity. These were discussed during the 2008 EEC Application proceeding, during the 2010 and 2011 Revenue Requirement Applications for TGI and TGVI, and most recently in Section 7 of the 2009 EEC Annual Report (please see Attachment 46.5.2).

47.0 Reference: Exhibit B-1, Chapter 5, p. 126

Home Heating Systems Regulation, Adoption Rate of High Efficiency Furnaces

"Without incentives in place to support the early retirement of stock, some customers may keep their furnaces for as long as 30 or 40 years …"

47.1 Please quantify the relationship between the level of financial incentives and the replacement rate of standard finances to high efficiency furnaces. To the extent possible, please provide tabular and graphical data that indicates the relationship between the level of incentive and replacement rate of furnaces.

Response:

This information has not been developed, as program design and consultation with stakeholders for a potential furnace early retirement program has not yet commenced. For a large-scale program, customer research needs to be conducted to establish what degree of incentive is needed in order to encourage a customer to replace his furnace, and to what degree end-of-life furnace replacements are being delayed.

47.1.1 As it relates to the above question, please confirm what the optimum incentive level is that would result in the highest benefit-cost ratio for Terasen Utilities home heating EEC program. Please clearly define all the key assumptions used in the analysis.

Response:

Please see the response to BCUC IR 1.47.1. Program design has not yet begun for a furnace early retirement program; therefore, the Terasen Utilities do not have adequate data to provide optimum incentive levels. The Terasen Utilities plan to consult with the EEC Stakeholder group on the appropriate inputs to the TRC test for such a program, such as assumptions for the appropriate incremental cost to use, and the appropriate allocation of savings from replacing a furnace early require the group's input.

47.1.2 Has Terasen Utilities taken into account the environmental and economic externalities associated with the pre-mature disposal of home heating systems? For example, heating systems are made up of many metal components, each with associated manufacturing GHGs. Likewise, there are GHGs associated with the installation and disposal of heating systems.

Response:

Product stewardship would be an important consideration for a large-scale furnace early retirement program, and would be one of the issues that needs to be dealt with during program design with inputs from stakeholders.

47.1.2.1 As it relates to the above question, if externalities have not been considered, please explain why. Alternatively, please quantify the impact of externalities on GHG savings.

Response:

Please see the response to BCUC IR 1.47.2.

48.0 Reference: Exhibit B-1, Chapter 5, p. 128

Risks Associated with Program Savings Estimates -- Risks Factors

"A challenge in developing EEC programs is estimating program uptake rates and energy savings. There are a number of factors that affect participation rates including emergence of new technologies, economic conditions, the political climate, changes in adoption rates for current technologies, energy price fluctuations, changes in consumer behaviour and consumption patterns, and initiatives by other utilities or government."

48.1 For the period 2007 to 2015, please provide a tabular summary that shows the annual incremental reduction in natural gas resulting from the EEC programs by TGI, TGVI and TGW. Please express the annual reduction as a percentage of the total annual gas consumed in each year.

Response:

The following table illustrates the tabular summary that shows the annual incremental reduction from EEC programs by TGI and TGVI from residential and commercial programs only. The Terasen Utilities at this point have not included TGW as we have traditionally not offered EEC programs in that region. The reduction is based on estimated scenario B savings which assume that the current approved level of funding remains throughout the planning period. The scenarios are for illustrative purposes and estimate savings proportional to funding levels based on the current portfolio of EEC programs.

	Actuals(GJ)			Estimated(GJ)					
Annual Incremental reduction (EEC scenario B savings)	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
TGI	166,310	88,766	125,267	471,093	705,830	1,361,760	2,042,640	2,714,688	3,393,361
TGVI	86,500	-	5,698	48,954	82,629	161,258	241,888	322,517	392,146

Annual reduction as percent of total annual gas consumed is illustrated in the table below. The annual volumes in TGVI only incorporate residential and commercial sectors.

	Actuals(GJ)			Estimated(GJ)					
Annual reduction as percent of total throughput	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
TGI	0.1%	0.0%	0.1%	0.3%	0.5%	0.9%	1.3%	1.8%	2.2%
TGVI	0.7%	0.0%	0.0%	0.4%	0.7%	1.4%	2.1%	2.7%	3.3%

48.1.1 Using the most current information available, please provide a table that compares how many years in advance DSM budgets are approved by utility regulators in the following natural gas markets: Con Edison, Enbridge Gas, Gaz Métro, SoCalGas, SaskEnergy, Terasen Utilities, Union Gas.

Response:

The information requested is presented in the table below. While some of the jurisdictions below have single or two-year approvals, it is the belief of the Terasen Utilities that multi-year EEC funding approval is preferable as this would give certainty to the marketplace that funds for EEC activity are available for a period of time.

Utility	Comments
ConEd	In NY State, the budgets were approved for three years (multi-year plan). Some of the budgets were approved in March 2009 (and some were approved in late 2009 or early 2010) for 2009, 2010 and 2011 programs. The residential gas rolled out first in July 2009 (same year as approval), others rolled out in early 2010. Others will roll out in 2011. (Source: E Source personal communication with utility)*
Enbridge Gas	Enbridge is on a multi-year plan, and have a base budget that is driven by an escalator. In this case, they have known their DSM budget for four years in advance. When they filed their multi-year plan in 2006, the stipulation was that the budget will be escalated by 5% year over year. (Source: E Source personal communication with utility)* Enbridge Gas Distribution Inc. ("Enbridge") filed an application with the Ontario Energy Board ("Board") dated May 28, 2010, seeking an order granting approval of its 2011 Natural Gas Demand Side Management ("DSM") plan. The Board assigned File No. EB-2010-0175 to this application. This application is in response to the request by the Board on January 7, 2010, directing Union Gas Limited and Enbridge to file a one-year DSM plan for 2011 based on the existing DSM framework established in the Generic DSM Proceeding (EB-2006-0021), including budget increases based on the established escalators. The Board approved this application on September 24, 2010. (Source: decision order EB-2010-0175)
SaskEnergy	Programs get their budgets approved in the same year or within 6 months. (Source: David Budeniuk, SaskEnergy Media Relations)
Union Gas	Union Gas had previously received approval for a 3-year plan to cover the period 2007 to 2009. For 2010, the Utility was asked to file a one-year plan as the OEB was uncertain as to the outcomes of the Green Energy Act. (Sources: E Source personal communication with utility* & EB-2008-0346 - Union Gas Limited - 2010 Demand Side Management Plan)
SoCalGas	**2009-2011 Energy Efficiency Savings Goals** and **2012-2020 Interim Energy Efficiency Savings Goals** were defined in Decision 08-07-047 dated July 31, 2008. The original filing was made April 13, 2006. The 2012-20 goals may be adjusted. **2006-2008 Energy Efficiency Programs and Budgets** were approved in Decision 05-09-043 on September 22, 2005. The original application filing was made June 1, 2005.
Gaz Métro	We were not able to gather information directly from Gaz Metro, but were able to find a regulatory filing that appears to show Gaz Metro received approval for its 2010 energy efficiency budget on December 7, 2009. The application was filed October 1, 2009. (See page 15 of D-2009-156.) Additional filings prior to 2009 suggest an annual budget approval cycle.

48.2 Please describe Terasen Utilities process for indentifying and quantifying the major risk areas in the implementation of the three EEC Funding Scenarios that have been proposed.

<u>Response:</u>

An EEC funding request with a program plan will be brought forward in the 2012 Revenue Requirement Application. Any specific risks associated with that funding request will be identified at that time; however, in general, the risks associated with any planned EEC activity are those identified in the excerpt above.

49.0 Reference: Exhibit B-1, Chapter 5, p. 128

Conservation Potential Review - Base Case Scenario

"Terasen Utilities also conduct a CPR every few years to examine the technologies available in the marketplace and determine the "conservation potential," including the amount of energy savings that can be achieved through EEC. The CPR analyzes the potential impacts of identified energy efficiency and fuel choice programs and initiatives to a base case scenario, and acts as the guiding document in designing future programs."

49.1 If the base case scenario is different from the reference case for consumption discussed in Section 4.2.6.1, p. 90, please provide tabular and graphical data to confirm what the base case scenario is for the period F2010 to F2030. Please also provide a list of key assumptions used to derive the base case scenario.

<u>Response:</u>

The Terasen Utilities confirm that the inputs going into the development of the base case scenario for the CPR is the same as that of the reference case used for the 2010 long term demand forecast in the 2010 LTRP. The Terasen Utilities have described the assumptions for the reference case in detail under section 4.2 of Exhibit B-1 of the LTRP.

50.0 Reference: Exhibit B-1, Chapter 5, p. 129

2010 CPR - EEC Program Evaluation Standards

"The paper should detail potential alternative EEC analysis approaches that look beyond the traditional economic focused California Standard Practice tests. These tests were developed to support "traditional" utility energy efficiency activity, and only consider the avoided costs of energy and the costs associated with energy efficiency activity, which is a very narrow view of energy efficiency activity in the larger context of support for long-term government policy goals. Based on these economically focused analysis tools as they are defined in the California Standard Practice Manual, the Terasen Utilities would not be able to engage in such programs as a furnace replacement initiative, funding the full cost of furnace upgrades for low-income households, or implementing geo-exchange systems for schools, all of which are laudable initiatives that support government's larger GHG emissions reduction goals."

50.1 As it pertains to the above quote, please define Terasen Utilities perspective of the critical factors that distinguishes a "traditional" activity from a non-traditional activity.

Response:

Please see also the response to BCUC IR 1.32.1.

The California Standard Practice tests were introduced in the early 1980's, when options for energy efficiency activity were simpler and utilities were engaged in much different activities than they are today. Today, for example, utilities are being asked by governments to support government policy through EEC activity on such things as low-income housing upgrades, and solar thermal projects. These newer activities are more complex with different energy forms and technologies being considered have broader goals than just energy reductions, and would be considered non-traditional activities.

50.2 Please provide specifics as to why EEC evaluations based on the California Standards Practice tests result in sub-optimal regulation of Terasen Utilities. Please discuss from the point of view of all stakeholders including ratepayers.

Response:

Please see also the responses to BCUC IR 1.32.1 and 1.50.1. The Terasen Utilities have not stated that EEC cost-benefit analysis based on the California Standards Practice tests "result in sub-optimal regulation." Rather the Terasen Utilities would like to explore broadening or altering the cost-benefit tests to allow Terasen Utilities to conduct EEC activity in accordance with the DSM regulation, as noted in the response to BCUC IR 1.32.1. It is the Terasen Utilities' intent to receive the discussion paper referenced in the preamble and then review the alternatives presented therein from the point of view of all stakeholders including ratepayers. This review will involve consultation with stakeholders, including ratepayer representatives.

51.0 Reference: Exhibit B-1, Chapter 5, p. 129

Mitigating Risks

"For this LTRP, Terasen Utilities analyzed 3 Scenarios, and concluded that in Scenario C, where EEC funding is approved up to 5 per cent of gross utility revenues, EEC activity could make a significant contribution of 16,000,000 tonnes of GHG reduction to government's GHG emissions reduction targets. Such a funding envelope would allow for a significant NGV uptake in the medium and heavy-duty "return to home" fleet market, a furnace retirement program and a water heater market transformation program."

51.1 Please provide a complete list of the premises that support Terasen Utilities' conclusion that Funding Scenario C is preferential to Funding Scenarios A and B. Please also provide a discussion of Terasen Utilities reasons for believing that the listed premises are more preferential to the selection of Scenario C than the other funding options.

Response:

Funding Scenarios A, B, and C were developed for illustrative purposes, based on proportional increases in energy savings for currently approved EEC funding levels and activity, commensurate with changes in expenditure for each scenario. The Scenarios are intended to show that with consistent, long term funding for EEC, significant energy savings are available. It is the intent of the Terasen Utilities to pursue a continuous long-term funding mechanism for expanded and ongoing EEC activity. The Terasen Utilities are not recommending one Scenario over another, or asking for any formal approval at this point in time and believe it is not meaningful at this time to make any conclusions that funding scenario C is preferential to other scenarios. As the results of the CPR become available, the Terasen Utilities will bring forward an application with a request for formal approval of the funding amount and with supporting documentation and arguments for the amount. The Terasen Utilities see this request being made in the upcoming 2012 Revenue Requirements Applications that will be filed with the BCUC in spring/summer 2011. Please also see the response to BCUC IR 1.38.1.

51.2 Please discuss the methodology that Terasen Utilities has applied in determining that Funding Scenario C is optimum. Please include a discussion of the rationale that has been applied in balancing the objectives set forth by the Clean Energy Act with the need to provide the least expensive energy with low risk that leads to a positive and measurable contribution to the environment and GHG concerns.

Response:

Please see the response to BCUC IR 1.51.1.

51.3 For Funding Scenarios A, B, and C, please provide separate tables containing key performance indicators in the following format. Please clearly state all input assumptions and hold them constant across Funding Scenarios A, B, and C.

EEC Funding Scenario C: Forecasted Key Performance Indicators for the Period 2012 to 2020[1]

	1	2	3	4	5 = 2 ÷ 4	6 = 2 ÷ 3
EEC Program	**Benefits[2] $_{TRC}$** ($ million)	**Costs[3] $_{TRC}$** ($ million)	**Volume of energy savings** (GWh)	**GHG emission savings** (TCO_2)	**Unit cost of carbon emission savings[4]** ($/ton)	**Unit cost of energy saved[4]** ($/ GJ)
EEC Program 1						
EEC Program 2						
EEC Program 3						
etc						
Total						

1 Forecasts based on incremental changes during the period 2012 to 2020.

2 The benefits component of the TRC test (California Standards Practice Test) which includes the avoided costs by the utility and the avoided costs by program participants. Please apply a discount rate equivalent to TGI's cost of capital.

3 The costs component of the TRC test (California Standards Practice Test) which is comprised of utility and net participant costs, and financial incentives paid to the utility over the stated five year period. Please apply a discount rate equivalent to TGI's cost of capital.

4 Based on weighted average over the period 2012 to 2020.

Response:

Please see the response to BCUC IR 1.51.1. TRC results cannot be provided for the Scenarios at this time as the Scenarios are intended to be illustrative only, and program plans and the resultant TRCs have not yet been developed.

51.3.1 For the above question, please provide a summary table that compares the key performance indicators (table columns 1 to 6) for Funding Scenarios A, B, and C.

Response:

Please see the response to BCUC IR 1.51.3.

51.4 The Utilities have proposed three Funding Scenarios that are vastly different in budget scale and program design (e.g., ~ $4 m for Scenario A to ~ $88 m for Scenario C). How do the Utilities reconcile their position in respect of putting forward three EEC Funding Scenarios which are fundamentally so different?

Response:

Please see the response to BCUC IR 1.51.1.

51.5 For each of the Funding Scenario, please provide an estimate of the 20-year impact on rates and ratebase of Scenarios A, B, and C. Please describe and quantify the input assumptions used in the calculation.

Response:

In Attachment 51.5, for each of the scenarios for TGI and TGVI the impact on rate base, customer rates and impact on cost of service is shown. For a description of the assumptions see the response to BCUC IR 1.33.1.

In Attachment 51.5, the results for TGI and TGVI are organized as follows:

Tab 1 – TGI Scenario A,
Tab 2 – TGI Scenario B,
Tab 3 – TGI Scenario C,
Tab 4 – TGVI Scenario A,
Tab 5 – TGVI Scenario B, and
Tab 6 – TGVI Scenario C.

In responding to this IR, TGI is correcting an error in Table 5-1 of the LTRP. The table incorrectly double counted the approved EEC funding for Affordable Housing. Per the Negotiated Settlement Agreements for TGI's and TGVI's 2010-2011 Revenue Requirements and Rates Applications, the Affordable Housing funding represents an allocation from the Residential and Commercial Programs, not an incremental funding envelope. The correct totals for TGI & TGVI EEC expenditures have been used in responding to BCUC IR 1.33.1, 1.33.1.1, 1.33.1.2 and 1.51.5. The corrected table is included below.

($000s)	TGI		TGVI	
	2010	2011	2010	2011
Residential and Commercial Programs	20,675	20,675	4,126	4,126
Affordable Housing	2,400	2,400	600	600
Industrial Interruptible	435	1,875	-	-
Innovative Technologies	2,334	4,669	478	956
Total	**25,844**	**29,619**	**5,204**	**5,682**

51.6 Scenario C represents in excess of a two-fold increase in Utilities DSM budget compared to previous years. Please discuss what improvements to the Utilities EEC measurement and validation processes are proposed as part of the 2010 LTRP in order to provide transparency to all stakeholders.

Response:

Please see also the response to BCUC IR 1.51.1. At this time, the Terasen Utilities is not requesting approval of any of the scenarios. Methods to provide transparency to EEC stakeholders were discussed and established during the original EEC Application proceeding in 2008. These included such things as establishing an EEC Stakeholder group, of which the Commission is part, holding two meetings of that group per year and the submission of an Annual EEC Report to the Commission that details results for the last year and outlines plans for the year upcoming. The first Annual EEC Report since the increased funding was approved, was filed with the Commission on March 31, 2010 for 2009 activities.

52.0 Reference: Exhibit B-1, Chapter 6, p.153

Gas Supply Sources

"The task of establishing fuelling infrastructure is not trivial and requires experience and expertise with respect to compressed gas facilities and/or cryogenic fuels. The provision of these services is consistent with the Terasen Utilities' role as a trusted supplier of energy products and services."

52.1 Does Terasen Utilities believe that the referenced services could be provided by firm(s) other than Terasen Utilities? If "no" please explain the rationale.

Response:

The Terasen Utilities believes that these services could be supplied by others; but the NGV market in British Columbia is not actively being developed by others at the present time. Please also see the response to BCUC IR 1.10.1. In Section 3.1.2 of Exhibit B-1 of the LTRP, the Terasen Utilities have described the market opportunity for new NGV initiatives and explained why the Terasen Utilities are in a position to provide such services and support the development of a NGV market in BC.

The following discussion outlines the current state of the NGV market in BC.

Within the Terasen Utilities' service territory, alternatives for providing NGV fuelling infrastructure are at present limited to two companies – Clean Energy Fuels Canada and IMW Industries, both of which operate only in the CNG market:

- Clean Energy Fuels Canada ("Clean Energy") took over operation of the former BC Gas CNG stations, but has been gradually withdrawing service and closing stations in BC as it concentrates on developing bigger markets in other jurisdictions. At present Clean Energy operates only eight remaining stations in the lower mainland and has offered these stations to the Terasen Utilities for purchase. Clean Energy is believed to have only two remaining employees in BC and has not invested in new stations in the Terasen Utilities service territory for approximately ten years.

- IMW Industries ("IMW") is another company that designs CNG station equipment such as compressors and dispensers for sale into global markets. IMW's present business model involves sale of the equipment to others who provide the fuelling service. Terasen Gas and IMW have been collaborating on the development of the BC market on this basis. Provision of a complete fuelling service[39] is critical to establishing the NGV market; IMW is fulfilling a role as an equipment supplier and Terasen Gas will be

[39] "Complete fuelling service" means providing the fuel to the customer's vehicle in a form that is usable by the customer without further processing.

providing the complete fuelling service to the customer. It should also be noted that IMW has recently been acquired by Clean Energy.

With respect to the LNG market, the Terasen Utilities are not aware of any local vendors who have the capability to provide LNG fuelling services at present. Clean Energy Fuels Canada, has sister company relationships with LNG expertise in the US market but no local capabilities in this regard.

As the NGV market develops and grows in BC, the Terasen Utilities believe that additional competition will enter the local market. At the present time, however, alternatives for customers are very limited.

53.0 Reference: Exhibit B-1, Appendix D-1, p. 11

Anticipated CPCNs – Huntington Station By-pass & Okanagan Reinforcement Project

"With the Huntington control Station located at a critical gas supply hub for the Pacific Northwest Region, it is exposed to single point failure, collateral damage from potential failure of neighbouring midstream facilities subject to security risks.

"Based on the 2010 core market demand forecast, the Interior Transmission System is anticipated to face system capacity shortfall by 2017."

53.1 Please identify the "neighbouring midstream facilities" being referred to and the nature of the security risks.

Response:

The neighbouring midstream facilities to the Huntingdon Control Station are Spectra Energy's Meter Station, and Williams Pipeline's Flow Control Station and Compressor Station. The Terasen Utilities are concerned with all security risks that could cause catastrophic failure of these facilities.

53.2 Has Terasen investigated a lower cost approach to achieve transmission system redundancy in the event of the contemplated potential catastrophic failure and/or other ways to minimize the consequences of the identified risk?

Response:

The Terasen Utilities has investigated a lower cost approach to achieve transmission system redundancy, but found the alternatives do not meet the Terasen Utilities' criteria to provide safe, reliable, environmentally acceptable delivery services to its customers. The feasible alternatives will be further investigated in detail in the preparation of the Certificate of Public Convenience and Necessity application for the Huntington Station By-pass Project.

53.3 Please provide a copy of the "2010 core market demand forecast".

Response:

As Exhibit B-1, Appendix D-1, p. 11 of the LTRP discusses system capacity, the 2010 core market demand forecast it refers to is in fact the 2010 Core Market Design Day Demand Forecast. The quoted passage is referring to design day demand, as opposed to annual demand. Design day demand is the main driver of system capacity planning projects such as the Huntingdon Station By-pass[40] & Okanagan Reinforcement Project[41]. The 2010 Core Market Design Day Demand forecast is illustrated in Appendix B-1 of the LTRP. Design day demand can be found in the last row of the table.

[40] A description of the Huntingdon Control Station Bypass is contained in Exhibit B-1, Appendix D-1, page 11.

[41] The Okanagan Reinforcement Project is discussed in Exhibit B-1, Section 6.1.1.4 pages 139 -142.

54.0 Reference: Exhibit B-1 Appendix D-2, p.6

Anticipated CPCN – Victoria Regional Office Land Purchase and Building

"The site is no longer suitable based on size and location."

"In comparing the cost model of a lease build to vs. purchase land/build, it (is) TGVI's preference is to purchase the land and build the site."

54.1 Please explain in greater detail why the existing site is no longer suitable.

Response:

On October 12, 2010, TGVI filed an application for a CPCN for the land acquisition for and construction of the regional operations centre. Section 3 of the CPCN application describes the justification for the project. In Section 3.3.1 of the CPCN application, TGVI explains why the existing site is no longer suitable as follows:

"The current leased space is not suitable both because it is too large and because the layout of the building is inefficient.

At the time that TGVI was purchased by Terasen Inc. in 2002, TGVI had approximately 215 employees. Through the efficiencies achieved with the amalgamation of the Terasen Utilities, TGVI had less than 100 employees at the end of 2009. Initiated by the decline in employees, a review of our existing and future space requirements was undertaken and confirmed that the current space is approximately 20% larger than what is necessary.

The layout of the current space is inefficient due to the age of the building. The Garbally building is almost 20 years old, and was planned and designed to suit the workforce as it functioned 20 years ago. There have been a number of developments over the last 10 years that have significantly changed the way businesses function, and as a result, the way work places are designed. These developments include technology improvements which allow great mobility and flexibility of personnel in the office and general acceptance of LEED adoption while promoting open office floor plan and team collaboration.

TGVI's function and the responsibility of the employees at the Garbally Facility have also changed over the years, resulting in the current facility not meeting the Company's requirements for the new work processes as described below:

- *The space on the main floor if fragmented due to the elevator core, stairs and other vertical penetrations which render the space difficult to utilize efficiently.*

- *The building features a reception area that is now redundant as the Company no longer provides on-site customer service.*
- *The building features offices located along the full perimeter of the space with the exception of the lunchroom. The closed single type function areas are wasteful and not conductive to employee collaboration.*
- *The building includes a large locker room area that is also duplicated in the warehouse and redundant as warehouse operation requirements have changes and space is being used inappropriately.*
- *The second floor layout does not maximize the space efficiently because the floor plate is broken up in the centre by the elevator core, stairs and other services that would be difficult and costly to relocate. This creates adjacency challenges as it separates functions that require shared common space with cannot be achieved due to lack of contiguous space.*
- *The interior function of the warehouse space has been expanded in an ad-hoc manner over time, with the addition of filed office facilities including a welding shop and storage mezzanine and the addition of washrooms and lockers to accommodate the field workers who are located too far form the washrooms and lockers in the main office building."*

Although information on the Victoria Regional Land Purchase and Building CPCN was filed in the 2010 LTRP, TGVI has now filed its CPCN Application with the Commission and the Terasen Utilities request that any further information requests on this topic be submitted in the Victoria Regional Land Purchase and Building CPCN proceeding.

54.2 Has TGVI investigated the cost and merits of modifying the existing facility to make it suitable? In no, please explain. if yes please provide the details of the analysis.

Response:

TGVI has investigated the cost and merits of modifying the existing facility to make it suitable. There were five alternatives explored in the selection of the final recommendation for the Victoria Regional Office. These included:

- Alternative 1: Extend the existing lease with no changes to current facilities;

- Alternative 2: Negotiate a new lease with the Landlord for a reduced facility footprint on the West side. Renovations to office, warehouse and yard would be required;
- Alternative 3: Negotiate a new lease with the Landlord for a reduced facility footprint on the East side. Renovations to office, warehouse and yard would be required;
- Alternative 4: Lease another existing suitable warehouse and office space facility; or
- Alternative 5: Purchase land and build warehouse and office space.

The details on the analysis of each of these alternatives are included in Section 4 of the Victoria Regional Office CPCN Application filed on October 12, 2010.

Although information on the Victoria Regional Land Purchase and Building CPCN was filed in the 2010 LTRP, TGVI has now filed its CPCN Application with the Commission and the Terasen Utilities request that any further information requests on this topic be submitted in the Victoria Regional Land Purchase and Building CPCN proceeding.

55.0 Reference: Stakeholder Consultation

Exhibit B-1, Chapter 7, p. 1

Workshops

55.0 Please attach the materials from the two rounds of workshops in your response to this IR.

Response:

Attachment 55.0 A provides the materials that were presented during the first round stakeholder workshop in February 2010, while attachment 55.1 B provides the materials presented during the second round workshops in May and June 2010. These materials can also be viewed on the Terasen Gas web site at:

http://www.terasengas.com/AboutUs/PlanningForFuture/IntegratedResourcePlanning/2010IRP.htm

During the February workshop, the Terasen Utilities also presented the Integrated Energy Solutions Video which can be viewed at:

http://www.terasen.com/EnergyServices/default.htm.

56.0 Reference: Exhibit B-1, Chapter 8, pp. 185-188

Action Plan - Regulatory Process

56.1 If funding for recommended EEC Scenario C or B is accepted in this filing, would Terasen Utilities be preparing a 20 year EEC plan for Commission approval? If "yes", please propose a filing date. If "no", please explain why.

Response:

As also discussed in the response to BCUC IR 1.38.1, the funding scenarios are not "recommended" scenarios but are illustrative of the range of possible directions for future EEC funding. The Commission's acceptance of the Terasen Utilities 2010 LTRP would not be an acceptance of any of the EEC Funding Scenarios presented in the 2010 LTRP.

The Terasen Utilities' plan is to pursue ongoing and expanded EEC funding as described in the 2010 LTRP. An application for ongoing and expanded funding for EEC activity beyond 2011 is planned to be filed in the late spring/early summer of 2011 as part of the Terasen Utilities next Revenue Requirements Applications. The Terasen Utilities would understand the Commission's acceptance of the 2010 LTRP to be an acceptance of the Terasen Utilities' plan to pursue ongoing and expanded EEC funding, but would not understand such acceptance to be a prejudgment or endorsement of the particular EEC program that the Terasen Utilities will be proposing in their next revenue requirement applications.

56.2 If the 2010 LTRP were accepted in its entirety, please provide a summary of the subsequent regulatory filings, and their approximate timing. If the financial commitment of capital would be necessary prior to the submission of subsequent regulatory filings, please quantify the amount and timing of those expenditures.

Response:

The Terasen Utilities understands this question to refer specifically to regulatory filings described in the Action Plan outlined in Section 8, pages 185 through 188 of the 2010 LTRP. As described in the response to BCUC IR 1.1.1, the submission of these filings is not contingent upon Commission acceptance, in all or in part, of the LTRP. A summary of anticipated regulatory filings described within the Action Plan is provided below:

- New EEC funding will be requested through the next Revenue Requirement Application to be submitted in spring or summer 2011. At this time, no additional EEC capital investment beyond that already approved in Order No. G-36-09, G-140-09 and G-141-09 is expected to be made prior to that filing (Action Plan item 1).

- An overall business and regulatory model for integrated energy system services is expected to be filled in 2011 along with CPCN approval requests for specific projects (Action Plan item 4). At this time, approximately $1.3 million in costs are expected for early design and development stage work on several projects. This work is part of the process required to take these projects from initial concept to a state where they are ready for submission to the Commission for approval. Projects that meet the requirements of both Terasen and the customer will be presented for review within the 2011 filing.

- A transportation fuelling service application is being prepared to support new NGV initiatives and is expected to be filed by the end of 2010. This application will include approval for two specific projects for which funding commitments are required in conjunction with the development of the application: approximately $700,000 for a project targeted for completion in December 2010 and $300,000 toward another project scheduled for completion in 2011. Customer agreements are contingent upon BCUC approval for these projects. The details of the projects will be presented for review within application (Action Plan item 4).

- A decision on the TGI Biomethane application for the acquisition and sale of carbon neutral biogas and specific projects, submitted earlier this year, is expected in Fall 2010 (Action Plan item 4).

- An application in support of enhancing the Terasen Utilities' Long Term System Sustainment Plan is expected – timing not yet determined (Action Plan item 5).

- Various CPCN applications are expected to support the Terasen Utilities' capital plan, an interim update on which is provided in Appendix D of the LTRP (Exhibit B-1), including timing and capital estimates. No capital spending commitments are anticipated at this time prior to approval (Action Plan item 6).

- A CPCN for the expansion of the gas transmission system in the Okanagan could be submitted as early as 2012 or 2013. Pre-approved capital spending commitments are not anticipated (Action Plan item 7).

- A potential CPCN to expand infrastructure and service for a full T-South Enhanced Service to promote southbound gas supply in and through the Province (Action Plan item 8). The Commission approved a maximum spending amount of $2 Million (Order No. G-70-10) for the preliminary feasibility study. Based on the results of current Stage 1 activities, the Terasen Utilities will assess the timing and support for proceeding with Stage 2 activities leading to a potential CPCN.

These represent the anticipated Commission filings that will result from the LTRP Action Plan.

56.2.1 Please repeat the above questions in consideration for Funding Scenario B.

Response:

Please see the response to BCUC IR 1.56.1.

57.0 Reference: Action Plan

Exhibit B-1, Chapter 8, pp. 185-188

Status Report

57.1 Please provide a report on the status of those activities (progress and expenditures) in the Action Plan of the 2008 LTRP as accepted by the Commission Order G-194-08 and the progress of those activities for the next four years in the Action Plan as contained in the 2010 LTRP Application.

Response:

The progress of the Action Plan Activities from the Terasen Gas 2008 Resource Plan has been provided in Table 1-2 on pages 7 to 9 of the 2010 LTRP. That table is reproduced below with an additional column to identify those activities from the 2008 Action Plan that are continuing as part of the 2010 4-year Action Plan.

	2008 Action Item	Status in 2010	Inclusion in 2010 Action Plan
1	Implement new energy efficiency and conservation (EEC) programs and continue research and planning for future EEC programming.	Final design and implementation of the approved demand side management[42] (DSM) programs for 2009 and 2010 are underway. Additional funding approved for industrial DSM program development and innovative technologies. Planning for updated Conservation Potential Review (CPR) is underway	2009 to 2011 EEC programs not part of 2010 Action Plan. Completion of new CPR is carried forward into 2010 Action Plan as a description although funding for CPR already approved. 2010 Action Plan item 1

42 http://en.wikipedia.org/wiki/Energy_demand_management

	2008 Action Item	Status in 2010	Inclusion in 2010 Action Plan
2	Participate in FortisBC and BC Hydro resource planning processes	Terasen Utilities provided input into both FortisBC and BC Hydro resource planning processes. Terasen Utilities' participation in the BC Hydro LTAP resulted in a decision to undertake to participate in an "Electric Load Avoidance" demand side study – the decision was later over turned by the Province. FortisBC's recommended future electricity generation resources include renewables backed up by natural gas fuelled generation during peak demand periods.	This is an ongoing activity and although not identified in the 2010 Action Plan, will be part of the Terasen Utilities activities on an ongoing basis.
3	Influence provincial and regional energy and climate-related policy development.	Terasen Utilities works with policy makers and energy planners to communicate the benefits and importance of using natural gas in the regional and provincial energy mix to reduce greenhouse gas emissions[43] and keep energy rates low. Examples include: • the Canadian Gas Association's "smart gas strategy" , (link to Vision of B.C. energy future PDF) • Input into the development of B.C.'s carbon credit system, advocating for renewable, end-use energy systems such as geoexchange[44] and solar thermal technology combined with natural gas[45]. • Provincial support for TGI's biogas and NGV initiative.	This is an ongoing activity and has been included in the 2010 Action Plan. 2010 Action Plan item 9

[43] http://en.wikipedia.org/wiki/Greenhouse_gas
[44] http://www.terasen.com/EnergyServices/GeoexchangeSystems/default.htm
[45] http://www.terasengas.com/_AboutNaturalGas/default.htm

	2008 Action Item	Status in 2010	Inclusion in 2010 Action Plan
4	Continue monitoring and evaluating system expansion needs in the Okanagan area.	Terasen Utilities continues to monitor FortisBC's Integrated Resource Plan[46] and their potential need for natural gas generation as a back-up to renewable electricity production during peak electric demand periods.	This activity continues and has been included in the 2010 LTRP Action Plan. 2010 Action Plan item 7
5	Plan for near-term distribution system requirements – Coquitlam Compressor Station and South Arm, Fraser River Crossing	Terasen Utlities received approval for a Certificate of Public Convenience and Necessity (CPCN) application, permitting the upgrade of the Fraser River South Arm Crossing[47] in March 2009. Work on the project is underway. Further investigation into the Coquitlam compressor units determined that replacement of only specific components within the units are required. A number of other projects outlined in the 2008 Terasen Utilities Resource Plan were undertaken.	The projects specifically mentioned here are completed and therefore are not part of the 2010 Action Plan. However, upcoming distribution system requirements are outlined in Appendix D and are referenced in the 2010 Action Plan. 2010 Action Plan item 6

46 http://www.fortisbc.com/about_fortisbc/planning/resource_planning.html
47 http://www.terasengas.com/_AboutUs/NewAndOngoingProjects/FraserRiver/default.htm

	2008 Action Item	**Status in 2010**	**Inclusion in 2010 Action Plan**
6	Investigate regional pipeline and storage infrastructure alternatives	This is an ongoing activity. The 2010 Northwest Gas Association (NWGA) Outlook Study identified that while regional gas supply infrastructure is being used very efficiently and currently meets the regions' capacity needs, growing demand for both residential use and electricity generation is causing increasing capacity constraints in the existing infrastructure. Terasen Utilities is monitoring opportunities to participate in or influence regional infrastructure projects that will best help to meet the needs of B.C. natural gas users. The 2010 LTRP describes emerging gas supply issues in the region upon which the Terasen Utilities must act to promote and protect the interests of their customers The Terasen Utilities will be monitoring the T-South Enhanced Service pilot with Westcoast in order to promote southbound gas supply in and through the province.	These are ongoing activities and have been included in the 2010 Action Plan as part of securing long-term gas supply while minimizing costs. 2010 Action Plan item 8 e), f) and g).
7	Pursue clean energy initiatives	Project initiatives underway include developing biogas[48] as an alternative supply, using natural gas for vehicles[49] as a transportation fuel for trucks, large fleets and other transportation industry needs, and development of alternative energy systems like geoexchange, solar thermal and district energy systems[50] in conjunction with natural gas for residential and commercial heating solutions.	These activities have been further advanced in the 2010 LTRP and are included again in the 2010 Action Plan. 2010 Action Plan items 4 and 10.

[48] http://www.terasengas.com/_AboutUs/NewAndOngoingProjects/BiogasProductionRFEOI/default.htm
[49] http://www.terasengas.com/_AboutNaturalGas/NaturalGasVehicles/default.htm
[50] http://www.terasen.com/EnergyServices/DistrictEnergySystems/default.htm

Attachment 4.1

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Carbon ($/tonne)	$20.00	$25.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Incremental Cost of Gas ($/GJ)	$7.85	$8.61	$9.04	$9.49	$10.00	$10.30	$10.53	$10.76	$11.00	$11.24	$11.48

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Carbon ($/tonne)	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Incremental Cost of Gas ($/GJ)	$11.72	$11.97	$12.22	$12.48	$12.75	$13.02	$13.30	$13.55	$13.84	$14.14

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Carbon ($/tonne)	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Incremental Cost of Gas ($/GJ)	$14.44	$14.75	$15.07	$15.39	$15.72	$16.06	$16.40	$16.75	$17.11	$17.48

Attachment 5.2

Roundtable on Natural Gas Use

in the Canadian Transportation Sector

Synthesis of Roundtable Discussion

March 12, 2010

Ottawa, Ontario

Introduction

The Roundtable on Natural Gas Use in the Heavy-Duty Transportation Sector is the fifth roundtable on energy policy to be held under the auspices of Natural Resources Canada since October of 2009. The first roundtable focused on Integrated Community Energy Solutions, while the second concentrated on Renewable Energy. The third Roundtable on Research and Development took place over two sessions: the first was on non-fossil fuel R&D, while the second concentrated on fossil fuel R&D. Separate reports have been prepared for each Roundtable meeting and are available on the NRCan website.

By bringing together senior decision-makers to discuss the steps that can be taken to move forward in each field, these roundtables are designed to help move Canada towards a low-carbon, clean-energy future. This transition will not only benefit the Canadian economy by conserving natural resources and creating green jobs, it will help Canada live up to its international climate change obligations. The Government of Canada is committed to reducing the country's greenhouse gas (GHG) emissions by 17 percent below 2005 levels by 2020, and by 60 to 70 percent by 2050.

The transportation sector is crucially important to achieving these commitments. It is one of the largest contributors to our national GHG profile and is experiencing the fastest growth in energy demand and GHG emissions.

The federal government is moving forward with several initiatives to reduce GHG emissions from the transportation sector, including GHG regulations for light-duty vehicles and the promotion of electrification and alternative fuels such as biofuels, ethanol and natural gas. Because of its intense fuel use, the heavy-duty vehicle sector (i.e., those vehicles that weigh more than 4.5 tonnes) is an obvious candidate for increasing the use of natural gas.

The use of natural gas in the heavy-duty transport sector has been promoted through a number of federal programs. The Market Development Incentive Payments program was created in 1989 in cooperation with the government of Alberta and funded natural gas infrastructure, light-duty natural gas vehicles, and research and development. The Commercial Transportation Energy Efficiency and Fuels Initiative was a joint NRCan/Transport Canada initiative launched in fiscal year 2003-04 aimed at reducing GHG emissions in commercial transportation fleets through the use of low-GHG emissions technologies and fuels. These programs have ended but the federal government currently provides an economic incentive to encourage the use of natural gas in the transportation sector by exempting the excise tax. Some provinces have also adopted policies to promote the use of natural gas in the transportation sector.

Despite these initiatives, natural gas makes up a tiny percentage of the fuel used in Canada's heavy-duty transportation sector. The purpose of this roundtable was to discuss a strategy for expanding the use of natural gas in this sector. In particular, the roundtable was intended to launch work and establish priorities on a joint industry/government initiative to develop a natural gas deployment roadmap. The present report summarizes the proceedings of the Roundtable.

Roundtable Goals and Format

Senior decision-makers from across Canada were invited by the Deputy Minister of Natural Resources, Cassie Doyle, to attend a half-day Roundtable on Natural Gas Use in the Heavy-Duty Transportation Sector. The meeting took place at the Deputy Minister's office in Ottawa on the morning of March 12, 2010.

In addition to the Deputy Minister and other officials from Natural Resources Canada, 21 senior-level stakeholders from industry and government - representing producers, distributors, technology companies, and potential end users of natural gas for transportation - in addition to representatives from environmental non-governmental organizations and academia, attended the meeting. A list of the participants can be found in the Appendix to this report.

The Roundtable was held under Chatham House rules, whereby participants are free to use the information they received during the meeting, but the identity and the affiliation of the speakers are kept in confidence. In keeping with these rules, this summary report provides an overview of presentations and discussions without any attribution. For the same reason, no media were allowed in the room during the discussions.

The purpose of the roundtable was to launch the development of a roadmap for increasing the use of natural gas in Canada's transportation sector. The roadmap work will address knowledge gaps, inform public and private decision-making, and define government, industry and stakeholder roles moving forward. It will investigate the transportation applications that would be optimal for the use of natural gas, assist in determining key actions required by governments, industry and stakeholders and outline key steps for implementation.

The session proceeded as follows:
- Opening remarks by Deputy Minister Cassie Doyle
- Short Presentations: Setting the Context: Canadian Natural Gas Supply and Demand (Éric Landry); Opportunities for Natural Gas Use in the Transportation Sector (Alicia Milner); Natural Gas Innovation in the Transportation Sector (Geoff Munro)
- Open discussion on scope, challenges and priorities for the Roadmap
- Open discussion on the Roadmap Work plan
- Next steps, and closing remarks by Deputy Minister Cassie Doyle.

What Participants Said

The following section captures the main discussion points organized into four main themes: the current and potential use of natural gas; the drivers for expanding the use of natural gas in the transportation sector; the barriers and challenges involved, and; the roadmap process, including priorities for the various working groups.

Current and potential use of natural gas in the transport sector

Natural gas vehicles

- There are about 10,000 compressed natural gas vehicles operating in Canada, mostly light-duty vehicles. This is down from a peak of 20,000 vehicles in the 1990s.
- Natural gas urban transit buses have declined to about 150 vehicles, due in part to the poor experience of some transit companies with older technology.
- There are about 45 natural gas school buses in use in Canada. This number has declined due to competition with diesel and the paucity of gasoline engine options available for conversion to natural gas.
- Canada is getting its first vocational and refuse trucks (two of each kind) in the coming weeks.
- There are no natural gas highway tractor-trailers in Canada.
- There are no liquid natural gas vehicles in use in Canada.

Natural gas infrastructure

- There are about 80 public refueling stations, found in five provinces (BC, Alberta, Saskatchewan, Ontario, Quebec). This is down from a peak of 200 stations in the 1990s.
- The majority of private stations are for off-road applications (forklift, ice resurfacer) with only a few private stations servicing transit and light-duty fleet operations.
- There is no liquid natural gas fueling infrastructure in Canada.
- In general, natural gas consumption in the transportation sector is very low compared to other sectors of the economy such as the industrial, residential, commercial and power generation sectors.

Potential for expansion

- In the bulk goods trucking sector, high-volume line-haul corridors in limited geographical areas hold the most potential for using natural gas. Examples include the Quebec City to Windsor and Edmonton to Calgary corridors.
- Natural gas powered refuse trucks represents a rapidly growing sector in the US and has good potential in Canada. Fleet operators in this sector have access to bio-methane from municipal landfill operations, which can further reduce the carbon footprint of natural gas fuelled trucks and increase their attractiveness as a low-carbon option.
- Return-to-base trucks (vocational trucks) present a large potential market in Canada as they operate in confined areas that can be readily outfitted with refueling and maintenance infrastructure.

- Transit vehicles were a popular market in the past and with the improved Canadian engine technology currently available, could offer an attractive alternative to diesel buses. Municipal access to bio-methane from landfill operations or sewage treatment plants could add to demand for natural gas vehicles in this sector. Many fleets have recently been renewed with diesel buses so the short-term potential in this sector is limited.

Drivers for Expanding Use of Natural Gas in the Transportation Sector

Abundant supply

- Canada is the third largest (after the US and Russia) natural gas producer in the world, producing 5.6 trillion cubic feet (Tcf) per year. This represents about 6 percent of world production or about 22 percent of North American production. Canada continues to export about 60 percent of its natural gas production, satisfying 15 percent of US demand.
- The North American supply portfolio is shifting from one dominated by conventional resources to one dominated by unconventional resources, particularly shale gas.
- While Canadian conventional natural gas production appears to be in permanent decline, shale gas development is expected to increase. Natural gas production in Canada declined in 2009, but by 2011, many analysts expect Canadian production to bottom out, and begin to rise again.
- Canada has enough proven reserves that can be recovered economically at current prices to meet demand for 11 years at current production rates.
- Combined Canada and US resources are thought to be enough for almost 100 years at current production rates.
- In the past, a perceived lack of long-term natural gas supply constrained thinking in terms of new prospects for natural gas use in Canada. The promise of a growing resource base is now driving industry efforts to stimulate demand for natural gas.

Cost advantage

- The global price for natural gas was traditionally set by long-term contracts linked to oil prices, based on energy equivalence.
- The global recession has shrunk demand for natural gas while the availability of shale gas is increasing supply. Thus, international prices for natural gas plunged in 2009.
- The price of natural gas has been decoupled from crude oil prices and is now selling at a substantial discount compared to oil. On an energy equivalent basis, natural gas is typically 20 to 40 percent less expensive than diesel fuel.
- Most analysts believe relatively low natural gas prices are here to stay.
- The cost advantage of natural gas compared to diesel is something that the industry would look to be sustained.

Lower emissions

- The transportation sector is the second largest (after industry) energy user in Canada, accounting for 29 percent of energy demand.

- The energy used in this sector is almost entirely (95 percent) from fossil fuels (mostly gasoline and diesel), making it the country's largest contributor of greenhouse gases. The on-road portion alone of the transportation sector accounts for 28 percent of Canada's emissions.
- Because of their intense energy use, heavy-duty vehicles contribute about one-third of GHG emissions from on-road sources, even though they comprise less than 4 percent of on-road vehicles.
- Carbon emissions from the transportation sector are growing faster than any other sector. Growth in emissions from heavy-duty diesel vehicles contributed almost half of the growth in emissions from on-road sources since 1990.
- Increasingly stringent diesel engine emissions standards have led to a reduction in criteria air contaminants (CACs), but natural gas engines still release fewer air pollutants than diesel vehicles for the same power output.
- The emission standards developed to address CACs have had no impact on carbon emissions. GHG emissions related to natural gas combustion are up to 25 percent lower compared to diesel. There is the potential to reduce GHG emissions by 85-90 percent lower emissions if the natural gas supply is supplemented with renewable sources.
- As a cleaner burning fuel, natural gas can reduce the carbon footprint of heavy-duty vehicle end-users and provide them with a marketing advantage over those using high-carbon containing fuels such as gasoline or diesel.

Mature vehicle and refuelling technologies

- Natural gas engines and the associated refueling infrastructure for heavy-duty vehicles are mature technologies in Canada.
- Heavy-duty natural gas engines are manufactured in Vancouver (Westport, Cummins Westport).
- The manufacturing of compressed natural gas refueling infrastructure takes place in Chilliwack (IMW Industries), Toronto (FTI Group), Winnipeg (Kraus Global), and Markham (Viridis Technologies).
- Components for compressed natural gas cylinders are manufactured in Calgary (Dynetek Industries), while heavy-duty vehicle fuel systems capacity is located in Kelowna (Enviromech Industries).
- Biogas upgrading equipment is manufactured in Blainville (Xebec Adsorption).
- An increasing number of original equipment manufacturers offer natural gas as a factory option on heavy-duty vehicles that are available in Canada.
- The growth of this sector in Canada has created industry advocates for a greater use of natural gas in heavy-duty transportation applications.

Barriers and Challenges

Fuel supply market conditions

- The price of natural gas (and oil) is expected to gradually rise to 2020 and beyond. However, price volatility makes it difficult to predict prices, therefore increasing risk.

- Although there is consensus among market analysts that natural gas will continue to sell at a discount compared to diesel, there is no guarantee.
- The challenge is to find ways to moderate price fluctuations and maintain the price differential with diesel.

Marketing existing technology

- The use of existing natural gas technologies across the transportation sector could play a significant role in helping Canada meet its short-term (2020) GHG emissions reduction target.
- Despite being a technology leader in the natural gas vehicle sector, Canada lags behind other jurisdictions when it comes to market adoption of heavy-duty natural gas vehicles. For example, natural gas engines manufactured in Canada by Westport are sold only outside of Canada.
- The greatest barrier to its adoption is the higher up-front capital cost associated with vehicles and refueling infrastructure, due mostly to the low market volume and limited competition. The challenge is to build market demand in order to realize economies of scale.
- First generation vehicle technology (especially buses) was problematic and this has raised barriers to acceptance of the new generation of natural gas technologies.
- Scarce refueling infrastructure is limiting market penetration of natural gas vehicles.
- Limited experience with natural gas vehicles raises maintenance issues for fleet operators.
- Codes and standards affecting natural gas vehicles and infrastructure vary from province to province (and in some cases, from city to city), which segments the market and adds to costs.
- Converting diesel vehicles to natural gas can be expensive and may raise original manufacturer's warranty issues.

Development of new technology

- Technological innovation is fundamental to transforming the market and meeting Canada's long-term (2050) GHG emission reduction goals.
- Research and development in natural gas vehicle technology has not kept pace with diesel vehicles.
- The air quality advantages of natural gas vehicles are diminishing as new rounds of CAC emission standards ratchet down emissions from diesel vehicles.
- There is also more drive-train competition from hybrids, plug-in hybrid electric vehicles, diesel, and gasoline direct injection.
- Innovation in natural gas vehicles must keep up with changing emissions standards if natural gas vehicles and their supporting infrastructure are to remain competitive with other options.
- Innovation is hampered by a lack of research and development investment (both public and private). A key challenge is to identify priority areas for strategic investment and adopt government policies that will promote investment in this sector.

The Roadmap and Working Group Priorities

The roadmap

- The Natural Gas in the Heavy-Duty Transportation Sector Roadmap will outline a deployment process for the increased use of natural gas in the heavy-duty vehicle transportation sector.
- The specific goals of the roadmap process need to be clearly articulated, whether that includes reduced GHG emissions, creating domestic demand for natural gas, the expansion of the market for Canadian technology or the development of new technology.
- The Roundtable process brings together the key players in the sector and it is important that this collaboration follows through to the development of the roadmap and, ultimately, to implementation.
- "Innovation" is the key word in this whole process, referring both to the need to find ways to bring existing technology to market and to develop new technologies that can be commercialized in Canada. The innovation system works best when industry, government and academia work together to find solutions. Partnerships and roles and responsibilities need to be established to push this agenda forward
- The roadmap should bring together existing data on the sector and fill information gaps as needed, but the focus should be on the action items needed to move forward on the ground.
- A market structure approach should be used such that the roadmap articulates roles and responsibilities across the system in order to contribute towards the achievement of a low-carbon reality.
- Actions needed to transform each market and improve acceptance of natural gas should be identified. In thinking through the needs of each market component, attention should be given to the short-, medium-, and long-term.
- The public policy recommendations made in the roadmap should draw from experience in other jurisdictions and form a coherent framework for moving forward.
- Six working groups were identified by Natural Resources Canada officials in consultation with stakeholders prior to the roundtable meeting. The discussion related to each of the proposed working groups is summarized below.

Working Group 1: Natural gas supply (fact base)

- An abundant fuel supply, price stability and the price differential between natural gas and competing fuels such as diesel are key to increasing the share of natural gas used in the heavy-duty transportation sector.
- This group should identify and synthesize existing data sources, including third--party consulting firms, demonstrating frequently updated and accurate supply and price forecasts. This is needed to reduce uncertainty for investors in the sector.
- This working group should explore models that fuel providers can use to reduce price volatility and maintain price differentials, such as hedging and long-term contracts.
- It is important to understand why and how natural gas and competing fuel prices move, including the fundamentals behind our expectation that prices will be less volatile and that the differential with other fuels will endure.

- The group should also look into demand forecasting and explore whether increasing domestic demand for natural gas in the heavy-duty transportation sector would put upward pressure on the price of natural gas.
- The mandate of this group should be expanded to cover data gathering for the whole natural gas life cycle (e.g., a life-cycle analysis of shale gas). If so, it could be renamed "natural gas facts" or "natural gas fundamentals".
- The group should also look at strategic issues such as quantifying the benefits of investment in promoting natural gas in the transportation sector compared to other options for reducing greenhouse gases (e.g., combined heat and power stations fueled by natural gas) and the emission benefits of natural gas compared to other emerging drive-trains (such as diesel-electric hybrids).
- Supply cost is another area that this group could investigate, including the threshold economics of different natural gas plays. There is also a need to understand how the components of cost vary by jurisdiction, starting with production, transmission, local delivery and dispensing the gas. This information can help inform business cases for investment in the sector in different parts of the country.

Working Group 2: Vehicle readiness and research and development

- In the short-term, the priority is to identify the full range of natural gas vehicle technologies available in Canada, suggest ways to stimulate demand for these technologies, and assess the readiness of manufacturers to expand supply. In the long-term, investment in research and development will be needed to make natural gas technology more competitive vis-à-vis other transportation technologies.
- This working group should provide information on the full range of natural gas technologies currently available. This should be complemented by information on prices, whether the technology is manufactured in Canada or not, the jobs involved, and the size of the various markets.
- There is a perception of increased risk associated with natural gas, and at current prices, the payback period on heavy-duty natural gas vehicles is in the four to six year range. This needs to be reduced to two years if demand for these vehicles is expected to increase. This working group should examine ways to reduce the price premium on natural gas vehicles and shorten payback times, including policy levers such as accelerated capital cost allowance and tax credits.
- Continuous innovation in natural gas vehicle technology is needed to keep up with changing emission and fuel efficiency standards and improvements in other drive-trains. This will require research and development investment in improving natural gas vehicle performance and exploring the feasibility of new options, such as hybrid natural gas vehicles. The working group should explore this potential and identify priority R&D needs for deeper study in this context. Attention should be given to each potential market and its R&D needs.
- The role of government in stimulating investment in vehicle R&D should also be covered by this working group. Governments can play a role in undertaking high-risk investments, de-risking private investment, and facilitating strategic partnerships.
- The Roadmap should begin by looking at the potential for natural gas in the broader transportation sector, including on-road (light, medium and heavy-duty) , rail, and marine applications before going on to focus on priority areas.

Working Group 3: Infrastructure readiness and research and development

- The priority of this working group will be to assess the current state and capacity of the natural gas fuelling infrastructure in Canada and explore opportunities for expansion.
- Innovation in this area is needed to reduce the cost and improve the reliability of new infrastructure if natural gas is to remain competitive with other options in the heavy-duty vehicle sector. The key is to identify priority R&D needs that will have the greatest impact in this area.
- As a way of proceeding, the working group could identify the different markets, assess the infrastructure needs for each of those markets and estimate the capital costs involved to fulfill those needs.
- The group should also explore various financing options and policy levers that could be used to facilitate investment in and the expansion of fuelling infrastructure in Canada.

Working Group 4: End-user needs

- This working group will assess the potential for natural gas to be introduced or expanded in various heavy-duty vehicle markets and suggest ways to reduce barriers to expansion.
- Canadian end users have access to excellent natural gas technologies, but they will adopt them only if these technologies can be integrated seamlessly into their operations. This working group should identify key barriers and propose solutions to such integration. For example, fuel providers could offer turn-key operations that provide a single window for fleet operators in terms of financing and fuel contracts.
- End users must be confident that the supply chain is there to support their choice of natural gas technology for the entire life cycle of the vehicle, both for OEM vehicles and after-market conversions.
- The group should also look into means to ensure that the rollout of fueling infrastructure is coordinated with vehicle fleet growth.
- The business case for various end users should be worked out to reduce the perception of risk in adopting natural gas technology. The group could proceed by segmenting users by different markets and carrying out a full-cost comparison of fuel sources and drive-train options open to that market.

Working Group 5: Codes and standards

- This working group will identify gaps in codes and standards related to the use of natural gas vehicles and infrastructure and suggest mitigation strategies.
- Safety regulations governing vehicles and fuelling infrastructure, building codes, zoning bylaws and other codes and standards can have a major impact on the technical feasibility of adopting natural gas in the transportation sector and on the perception of the risks involved. This working group should itemize the range of relevant codes and standards and identify inconsistencies among the standards within and between jurisdictions in Canada.

- The group should also explore the feasibility of harmonizing Canadian codes and standards with those used in other countries in order to reduce costs for Canadian manufacturers that sell internationally as they move into or expand their domestic markets.

Working Group 6: Information and awareness (Market Transformation – Policy Instruments)

- This working group should be called Market Transformation – Policy Instruments. It should cover not only information and awareness as a policy instrument, but also assess other policy levers. It would include looking at what has been done in other countries and mores specifically US alignment opportunities.
- Information dissemination and awareness building among potential customers can go a long way in the short-term to help expand markets for already available technology. The working group could advance this agenda by developing marketing plans, training programs, and information packages directed at the various end-user groups.
- It is important that technology providers be fully informed of the benefits of the natural gas option and in a position to discuss the customer's specifications and answer customer questions about the technology. The working group should develop a dealer-training curriculum to meet these needs.
- A communication strategy needs to be developed in order to address negative impressions among end users associated with earlier generations of natural gas vehicle technology. These potential customers need to be persuaded that the technology has improved considerably.
- The working group should also assess various public policy options related to information and awareness, such as government funding of high-profile demonstrations of natural gas vehicle deployment in the heavy-duty sector.
- Other working groups will also have elements of policy analysis in their work plans so coordination of this aspect of the Roadmap across working groups will be important.

Next Steps

This roundtable meeting was the first step in developing the roadmap on the use of natural gas in the heavy-duty transportation sector. At this stage, the working groups will convene, agree on a work plan, and begin work on their theme areas.

Each working group has two external stakeholder leads. NRCan leads will also be assigned to each group to support the work as needed. Together, the Leads will be responsible for selecting members for their respective groups and coordinating work related to their theme areas. A secretariat (NRCan) will also be available to facilitate the overall roadmap work. Any contract work to be carried out through the auspices of a working group will be cost-shared between government and industry, as deemed appropriate by the various working groups.

As a first task, NRCan will provide each working group with a list of work plan elements, as discussed at the Roundtable. Leads will then develop an initial work plan, including more detail on each work element, the form the deliverable will take and the timing of its completion. This will be submitted to NRCan for consolidation and distribution to all.

NRCan will create a password-protected website to post documents (such as work plans and draft deliverables for comment) related to the development of the roadmap for access by participants.

An interim meeting in June of 2010 will provide an opportunity for the groups to report on their progress, compare notes and adjust their work plans. A summary of that session will be produced and disseminated to the working groups.

A final report will be prepared based on the output of the various working groups. A contract will be put in place to hire a professional report writer to summarize the key findings, conclusions and recommendations, for government, industry and stakeholders. This final report will detail a deployment process for the increased use of natural gas across the transportation sector over the short-, medium- and long-term. The final report will also clearly articulate the roles and responsibilities of the various stakeholders and investments needed in terms of making the use of natural gas across the transportation sector a reality. The final bilingual report will be completed by the end of 2010.

Attendees

Name	Position	Organization
Robert Carrick	Western Region Vocational Manager, Natural Gas Freightliner Trucks	Daimler
Michael Cleland	President and Chief Executive Officer	Canadian Gas Association
Mark Corey	Acting Assistant Deputy Minister, Energy Sector and Assistant Deputy Minister, Earth Sciences Sector	Natural Resources Canada
David Demers	Chief Executive Officer	Westport Innovations Inc.
Cassie Doyle	Deputy Minister	Natural Resources Canada
Mike Ekelund	Assistant Deputy Minister, Strategic Initiatives	Alberta Department of Energy
John Foran	Director, Oil and Gas Policy and Regulatory Affairs Division	Natural Resources Canada
Anne Gleeson	Senior Project Manager Transportation Program	Pollution Probe
Julie Grignon	Directrice générale par intérim, Politiques, coordination et analyse économique du secteur Énergie	Ministère des Ressources naturelles et de la Faune du Québec
Kerry Guy	Manager, Natural Gas Advocacy	Canadian Association of Petroleum Producers
Éric Landry	Acting Director General, Petroleum Research Branch	Natural Resources Canada
Stephen Laskowski	Senior Vice President	Canadian Trucking Alliance
Les MacLaren	Assistant Deputy Minister, Electricity and Alternative Energy Division	British Columbia Ministry of Energy, Mines and Petroleum Resources
Eric Marsh	Executive Vice President, Natural Gas Economy	EnCana Corporation
Brad Miller	President	IMW Industries Ltd.
Alicia Milner	President	Canadian Natural Gas Vehicles Alliance
Geoff Munro	Chief Scientist and Assistant Deputy Minister of the Innovation and Energy Technology Section	Natural Resources Canada
Christopher Norris	Director, Technical Services	Canadian Urban Transit Association
Karen Oldfield	President and Chief Executive Officer	Halifax Port Authority
Michael Portmann	Vice President, Business Development	Dynetek Industries Ltd.
Marlo Raynolds	Executive Director	Pembina Institute
John Rilett	Vice President	Climate Change Central
Andrzej Sobiesiak	Auto 21 Researcher, and Professor and Head, Mechanical Automotive and Materials	Auto 21

	Engineering, University of Windsor	
Doug Stout	Vice President	Terasen Gas
John Van der Put	Vice President, Market Development, Canadian and Eastern U.S. Pipelines	TransCanada Pipelines
Paula Vieira	Director, Fuels Policy and Programs	Natural Resources Canada
Paul Wieringa	Executive Director, Alternative Energy Branch	British Columbia Ministry of Energy, Mines and Petroleum Resources

Attachment 6.1

Attachment 6.1

Tom A. Loski
Chief Regulatory Officer

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Regulatory Affairs Correspondence
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July 8, 2010

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("Terasen Gas" or "TGI")

Application for Approval of a Biomethane Service Offering and Supporting Business Model, for the Approval of the Salmon Arm Biomethane Project and for the Approval the Catalyst Biomethane Project (the "Application")

Response to Workshop Undertaking

On June 8, 2009, Terasen Gas filed the above noted Application. On June 24th, a Workshop was held to review the Application.

During the Workshop, there was discussion about the treatment of carbon offsets from the supply and consumption sides. The British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization *et al* ("BCOAPO") requested that Terasen Gas undertake to provide the details of the carbon offsets discussion into the record of the proceeding. What follows is a discussion about carbon offsets, recognizing that this is an emerging market and much remains uncertain about the rules and regulations at this time.

The creation of offsets and the potential value they create could help reduce the costs to customers who purchase Biomethane as proposed in Terasen Gas' Biomethane Application.

Outlined below is information describing how these offsets could potentially reduce costs to customers who purchase Biomethane.

a) What is an offset?

A carbon offset is a mechanism which enables the transfer of greenhouse gas emissions (GHGs) reductions credit from one entity to another. Carbon offsets are typically measured in metric tons of carbon dioxide-equivalent and one carbon offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other GHGs.

Once these offsets are created and validated they can be sold to parties as part of a financial transaction.

There are two markets for buyers of carbon offsets. The first is the "compliance market" where companies, government or other entities buy carbon offsets in order to comply with GHG caps or regulations on the total amount of carbon dioxide they are allowed to emit. The second marketplace is the "voluntary market" in which individuals, companies or governments buy offsets on a voluntary basis to reduce their carbon emissions.

On the supply side an offset is created by a project that reduces the total emissions of GHG in the short or long term. These offsets are typically created through renewable energy projects such as wind farms and biomass energy by displacing fossil fuels.

The offset industry and the business rules that apply to it is an evolving industry. The TGI Biomethane business model as presented in the application has the ability to adapt to the offset market as it evolves and this has the potential to help reduce customer costs to those who purchase Biomethane.

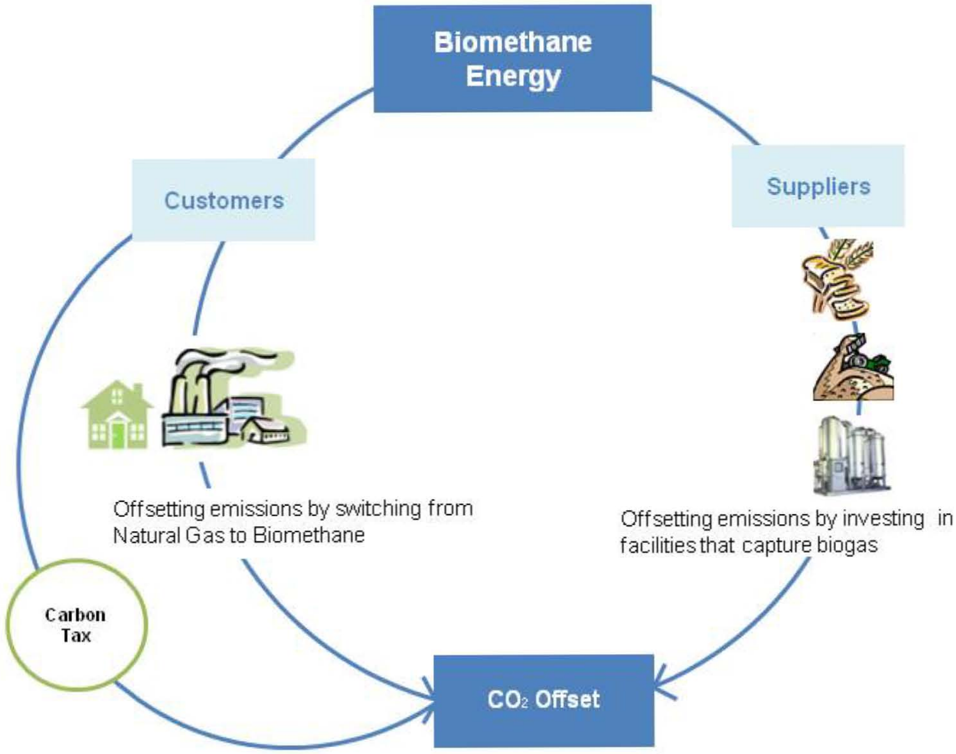
b) How are offsets created within the Terasen Gas Biomethane Application? Who has ownership of these offsets? How are the revenues from selling these offsets treated?

Within the Terasen Gas Biomethane Application there is the potential for two different sources to generate or create offsets:

1) Suppliers
2) Customers

These two sources of offsets are outlined in Figure 1 and are discussed further below.

Figure 1: Sources of Offsets Created from Biomethane by Suppliers and Customers



Suppliers:

During the process of capturing Biogas, there is the potential to create an offset. The offset in theory is created by capturing the Biogas that otherwise would have been released from the landfill, wastewater treatment plant or from the agricultural waste naturally decomposing. There is potential to have a greater quantity of offsets that associated with the biogas produced by the facility due to the fact that the release of raw methane has approximately 21 times the GHGs than that produced by burning the same quantity of natural gas.

Within the Application and specifically the two projects contained in the Application (Columbia Shuswap Regional District and Catalyst Power Inc.) the responsibility in creating offsets, having them validated, and qualifying them for sale resides with the Biogas producer. Each of the two supply contracts filed in this Application contain a clause that discusses the ownership of such an offset. Within these two contracts, the producer has ownership and therefore retains the value of this type of offset.

Over time, if the producer is able to qualify the project through third-party certification to show that an offset of this type has been created, the value of this offset would be incorporated into the producers revenue streams and therefore reduce the sale price TGI negotiates with the producers to pay for Biogas or Biomethane.

Given the uncertainty in this emerging field, TGI has chosen at this time to let the producer deal with the logistics and costs associated with establishing whether or not offsets from these projects can bring about a revenue stream to the project proponent. This was also the preference of the producers because it would be difficult to establish a long term price given the infancy of the market in BC.

Customers:

On the customer side, there is the potential for a further offset to be created by having customers consume the Biomethane in place of natural gas. Natural gas and the CO_2 produced from its combustion are considered to be GHGs because they add to the total amount of CO_2 in circulation in the atmosphere. This occurs once natural gas is removed from an underground source and is combusted. By displacing natural gas with Biomethane in end-use applications, all else being equal, there is a net reduction in the amount of GHGs in the atmosphere.

With regard to this type of offset, TGI is currently exploring an alternative in generating value to the customers that consume Biomethane by having them exempt from the carbon tax on the Biomethane they consume. On March 30, 2010 KPMG sent a letter to the Ministry of Finance on behalf of Terasen Gas Inc., (a copy of the letter is attached for reference) to ask for an exemption related to the carbon tax for the volume of Biomethane that customers consume. TGI is awaiting a tax ruling on this request from the B.C. provincial government. If this request is granted, in TGI's opinion, value has been created for the customer by not having to pay for the carbon tax.

Based on TGI's current understand of the rules to establish offsets through such organizations as the BC Carbon Trust, it is unclear if offsets can be created on the customer side even though the carbon tax may not apply to the consumption of Biomethane. TGI will continue to explore creating offsets of this type on behalf of Biomethane customers.

If the ruling regarding the carbon tax is not a positive one, TGI would request a change in the carbon tax regulation to allow the consumption of Biomethane to be exempted from the tax. Further, TGI may work to validate, qualify and sell the offset on the customer's behalf. This revenue stream would get reflected to the customer through the Biomethane Energy Recovery Charge by reducing their overall costs of Biomethane.

If you have any questions or require further information related to this Application, please do not hesitate to contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed by: Shawn Hill

For Tom A. Loski

Attachments

cc (email only): Registered Participants to the Biomethane Application

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~~Private and Confidential~~
Ms. Mary Kimpton
Director - Carbon and Resource Tax
Tax Policy and Legislation Branch
Ministry of Finance
Province of British Columbia

Our Ref MW/bc/60117340

Contact Mark Worrall
604-691-3106
mworrall@kpmg.ca

March 30, 2010

Dear Ms. Kimpton

Carbon Tax on Sale of Natural Gas

We are writing on behalf of our client, Terasen Gas Inc. (Terasen), to request a ruling regarding the application of Carbon Tax (CT) to the sale of natural gas by Terasen in the circumstances detailed herein.

Facts

1) Terasen is currently in the process of developing and/or acquiring various sources of natural gas derived from biogas.

2) Biogas is a blend of gases created from decomposing organic material. The largest components of raw biogas are methane (CH_4) and carbon dioxide (CO_2). Raw biogas also contains small or trace quantities of sulphurous gases (e.g. H_2S), oxygen (O_2), water and volatile organics.

3) The typical sources of biogas for Terasen will be from landfills, wastewater treatment plants, agricultural wastes, industrial process wastes (mainly from food processing), as well as organic waste streams from municipalities and commercial operations.

4) The main process by which biogas is produced from these organic waste materials is referred to as anaerobic digestion. In order to put the biogas to useful purpose a means of capturing the gas must be constructed. For the above sources this is done by carrying out the anaerobic digestion process within an enclosed tank or container, referred to as a digester.

5) The raw biogas captured by a digester is not of high enough quality to take directly into the Terasen natural gas pipeline system. It must be purified (or upgraded) to bring the biogas up to pipeline quality standards.

6) The resulting product stream after the biogas upgrading process (which will be referred to as "biomethane") has substantially the same composition as the conventional natural gas supplied by Terasen.

7) Terasen will obtain biomethane in one of two ways.

    a. Terasen will purchase raw biogas from biogas producers and undertake the upgrading process to produce biomethane using equipment owned and operated by Terasen.

    b. Alternatively, Terasen will purchasing pipeline quality biomethane from the third party supplier. In this case the third party supplier will undertake both the raw biogas generation/collection process and the upgrading process.

   In both cases Terasen will install the necessary equipment for measurement and gas quality monitoring together with the pipelines needed to connect to Terasen's existing pipeline network. Once injected into the natural gas pipeline system the biomethane will become commingled with the conventional natural gas stream.

8) The total costs of all of the biogas/biomethane contracts in operation will be pooled to develop an average cost of biomethane to be charged to customers purchasing the biomethane. The costs included in this pooled average cost will be the amounts paid to suppliers for the raw biogas or upgraded biomethane and the costs of owning and operating the Terasen-owned upgrading equipment and connecting facilities. At this point in time it is expected that the pooled average cost of biomethane will be considerably higher than the average cost of conventional natural gas.

9) Biogas upgrading and injection into the natural gas distribution system promotes the reduction of Greenhouse Gas (GHG) emissions by displacing energy demand that would otherwise be served by conventional natural gas. In some cases, where biogas capture has not been mandated, the capturing and upgrading of biogas will also avoid the fugitive emissions from un-combusted biogas and will therefore have a much larger GHG reduction benefit[1].

10) Terasen Gas is in the process of developing a biomethane product offering to be made available to its customers. It is currently expected that the product offering will priced based on a blend of 10% biomethane and 90% conventional natural gas[2].

[1] Methane is considered to have 21 times the impact as a greenhouse gas as carbon dioxide.
[2] Alternative blend proportions may be offered as experience is gained with the biomethane program.

11) Because of the commingling of biomethane with the conventional natural gas stream the physical molecules of natural gas delivered to a customer purchasing the biomethane product will not necessarily contain 10% physical molecules of biomethane.

12) The expected cumulative annual volume of biomethane supply that Terasen expects to acquire in the first five years of the program is between 0.5 and 1.0 petajoules (one million gigajoules) per year, or less than 1% of the current total natural gas annual throughput.

13) Since in the initial stages it is expected that there will be a limited amount of biomethane supply available the product offering will also be limited. Initially the product will be offered to the residential customer class. Enrollments for the biomethane product blend will be limited to the amount of supply available. The offering will be expanded to commercial and other customer classes in the future as the market matures.

14) The manner in which the volumes of biomethane and natural gas will be presented on customers' bills is still in the process of being finalized. Under Terasen's current billing system the customer's combined commodity consumption (i.e., 10% biomethane volume and 90% natural gas) will be presented on a single line on the bill. Terasen proposes to reflect the CT exemption for the 10% biomethane by charging CT on 90% of the customer's commodity consumption charges.

15) Terasen is in the process of developing a new customer billing system for implementation in 2012 and may have the ability with that new system to show the biomethane and conventional natural gas consumption on separate lines on the bill. If that proves to be the case then the CT would be charge only to the conventional natural gas line item.

16) Terasen will maintain a detailed accounting process to reconcile the costs and volumes for the biomethane supplies purchased and the commodity revenues received for biomethane volumes sold to customers. Terasen already maintains comprehensive accounting and reconciliation accounts for its natural gas commodity costs and the natural gas midstream costs (referred to as the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA), respectively). A similar comprehensive accounting process will be established for biomethane. Through this accounting mechanism Terasen would be able to control and confirm that the amount of CT exemption granted for the biomethane volumes is equal to the amount of biomethane purchased/produced by Terasen.

Rulings Requested

On behalf of Terasen we request confirmation of the following:

a) Terasen is not required to pay security under the Carbon Tax Act (CTA) in respect of its purchase of biogas and biomethane.

KPMG

Ms. Mary Kimpton
Tax Policy and Legislation Branch
Ministry of Finance
Carbon Tax on Sale of Natural Gas
March 30, 2010

b) Terasen is not required to collect CT on sales of natural gas to customers purchasing the biomethane product from Terasen based on the proportion of biomethane price paid by the customer (10% under the initial product offering).

c) Terasen's proposed methods of disclosing the exemption from CT to biomethane customers are appropriate.

Please contact the writer if you have any questions regarding this ruling request.

Regards,

Mark Worrall
Associate Partner, Indirect Tax

cc.
Mr. Paul Wieringa, Ministry of Energy, Mines and Petroleum Resources
Mr. Andrew McVie, Terasen Gas Inc.
Ms. Irene Dancause, Terasen Inc.
Ms. Charlene Dorward, Terasen Inc.

Terasen Gas

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August 17, 2010

BC Sustainable Energy Association
5-4217 Glanford Avenue
Victoria, BC
V8Z 4B9

Attention: Thomas Hackney, Director

Dear Mr. Hackney:

Re: Terasen Gas Inc. ("Terasen Gas" or the "Company")
Application for Approval of Biomethane Service Offering and Supporting Business Model, for the Approval of the Salmon Arm Biomethane Project and for the Approval of the Catalyst Biomethane Project (the "Application")

Response to the BC Sustainable Energy Association ("BCSEA") Information Request ("IR") No. 1, Question 20.2

On June 8, 2010, Terasen Gas filed the Application as referenced above. In accordance with Commission Order No. G-109-10 setting out the Regulatory Timetable for the review of the Application, Terasen Gas submitted its response to BCSEA IR No. 1 on August 6, 2010.

In order to take into account discussions with the Ministry of Finance and any recent developments, Terasen Gas committed to responding to IRs relating to the application of carbon tax by August 18, 2010. Accordingly, Terasen Gas respectfully submits the attached response to BCSEA IR 1.20.2.

If you have any questions or require further information related to this Application, please do not hesitate to contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachment

cc (e-mail only): Erica Hamilton, Commission Secretary
Registered Parties

20.0 Topic: GHG offsets

Reference: Exhibit B-2-1, Workshop Undertaking Response, GHG Offsets

"What follows is a discussion about carbon offsets, recognizing that this is an emerging market and much remains uncertain about the rules and regulations at this time."

"The creation of offsets and the potential value they create could help reduce the costs to customers who purchase Biomethane as proposed in Terasen Gas' Biomethane Application."

20.2 Please confirm that the program is not designed to, or intended to, provide participating customers with any marketable carbon offset.

Response:

Confirmed.

The intent of the program is not to sell customers a marketable carbon offset, rather a renewable energy product which in turn, reduces their carbon footprint.

The current regulation is unclear about carbon offset opportunities for customers. As indicated in the Response to Workshop Undertaking, dated July 8, 2010, TGI may look at creating offsets on the customers' behalf in the future as a result of the offset created by consuming Biomethane in place of natural gas. However, this would involve third party validation and verification and the establishment of accepted protocols for these projects which have not been defined at this time and would be more appropriate if TGI were to develop a carbon offset program, rather than the proposed renewable energy-based program. By displacing natural gas with Biomethane in end-use applications, all else being equal, there is a net reduction in the amount of GHGs in the atmosphere which is the green attribute that customers would be paying for under the proposed program.

Seeking to maximize value for our customers, the Company has applied to the British Columbia Ministry of Finance for confirmation that Biomethane as described in the Application will be exempt from Carbon Tax. On July 28th, 2010 Terasen Gas received a letter from the British Columbia Ministry of Finance, found in Attachment 20.2, confirming that combustion of both Biogas and Biomethane are activities exempt from the Carbon Tax. The Company had hoped to be able to provide a clear answer at this time as to whether or not the proposed Green Gas program will allow customers to be exempted from paying Carbon Tax on the portion of their purchased gas that is Biomethane. The Company is still in ongoing discussions with the British Columbia Ministry of Finance to clarify a point of ambiguity within the letter received on July 28th, 2010. In their letter, the Ministry of Finance stated that:

Terasen is proposing that carbon tax is invoiced and collected from customers based on a standard 90% natural gas/10% biomethane blend, when in fact the blend could vary. Under Section 13 of the CTA (Carbon Tax Act), Terasen is obligated to determine the amount of natural gas in the blend and invoice and collect carbon tax from purchasers accordingly. As biomethane is considered a non-taxable substance, no reference to the application/exemption of carbon tax on the biomethane in the blend is required on the invoice.

Terasen Gas believes that this statement is based on a misunderstanding of the concept of notional delivery, and will propose to the Ministry of Finance that we are in fact ensuring the integrity of the 90%/10% blend through our extensive monitoring of the Biomethane injected into the system and the Biomethane purchased by our customers to displace 10% of their natural gas consumption.

The Company is of the opinion that the likelihood of agreement between the parties is strong. The transportation and delivery of Natural Gas across North America is premised on all participant's acceptance of the concept of notional delivery through displacement, and the delivery of Biomethane to Green Gas customers through the existing gas distribution system will work no differently.

For taxation purposes, a comparable example is that of marketer gas moving through the existing distribution system. Marketers deliver their gas to supply hubs to displace gas the Company would otherwise have delivered to those supply hubs. Terasen Gas then notionally delivers this gas to customers of marketers. Since, the Company does not track molecules across our system, there is no way of knowing if the marketer gas is the same gas physically received by the customer, but the customer who purchased that gas from the marketer is billed for the gas they chose to purchase and consume at the agreed to price, and taxes are applied accordingly, even if the marketer gas was in actual fact delivered to a Terasen Gas commodity customer, or a customer of a different marketer. Based on this precedent, the Company believes that the existing gas tracking mechanisms will allow for the level of surety that the Ministry of Finance needs in order to allow Green Gas customers to be exempted from the Carbon Tax on the portion of their purchased gas that is Biomethane.

Terasen Gas believes that the measurement process proposed in the Application will provide sufficient documentation as to make the Biomethane portion of gas purchased through the Green Gas program exempt from Carbon Tax, and is seeking to clarify agreement on that point with the Ministry of Finance.

As soon as the Company has certainty on this issue, TGI will provide written documentation to the Commission and all registered interveners. Regardless of the outcome, Terasen Gas will work with the Ministry of Finance to ensure that we have done everything we can to protect the best interests of our customers.

BRITISH
COLUMBIA
The Best Place on Earth

July 28, 2010 228665

Mark Worrall, CA
Associate Partner, Indirect Tax
KPMG LLP
Chartered Accountants
PO Box 10426
777 Dunsmuir Street
Vancouver, BC V7Y 1K3

Dear Mr. Worrall,

Thank you for your letter dated March 30, 2010, regarding the application of carbon tax on the sale of natural gas by your client Terasen Gas Inc. (Terasen). I apologize for the delay in responding to your ruling request. The Ministry has now completed the review of the facts you have presented.

You have requested 3 rulings that confirm the following:

a) Terasen is not required to pay security under the Carbon Tax Act (CTA) in respect of its purchase of biogas and biomethane.
b) Terasen is not required to collect carbon tax on sales of natural gas to customers purchasing the biomethane product from Terasen based on the proportion of biomethane price paid by the customer.
c) Terasen's proposed method of disclosing the exemption from carbon tax to biomethane customers are appropriate.

In order to issue the rulings, the Ministry considered whether "biogas" and "biomethane" are substances which are intended to be:

- subject to security or tax
- not subject to security or tax (non-taxable substance), or
- exempt from security or tax

under the CTA.

.../2

Mailing Address:
2nd Floor - 1810 Blanshard Street
Victoria, BC V8T 4J1

Telephone: 250 356-0573
Facsimile: 250 356-7348

The ministry has determined that biogas and biomethane are not subject to security or tax under the CTA. Based on your explanation of how biogas and biomethane are derived, the Ministry does not consider that these substances are "natural gas" as it is currently defined under the CTA. And, as biogas and biomethane are not themselves substances that are included in Schedule 1 of the Act they not considered "fuel" for the purposes of the CTA. The security and tax scheme under the CTA is such that only substances that fall into the definition of "fuel" are subject to payment of security or tax.

> **"fuel"** means a substance set out in column 2 of the Table in Schedule 1 but does not include
> (a) methanol produced from biomass, and
> (b) methane produced by waste in a landfill.
>
> **"natural gas"** means natural gas, whether or not the natural gas
> (a) occurs naturally or results from processing, or
> (b) contains gas liquids,
> but does not include refinery gas.

As biomethane is considered a non-taxable substance, section 13(1) of the Act would apply to the application of carbon tax on the biomethane/natural gas blend.

Section 13 reads:

> **Calculation of tax for blends or mixtures**
> 13 (1) If a mixture or blend is composed of one or both of the following combinations:
> (a) one or more fuels, with or without one or more non-taxable substances or items;
> (b) one or more combustibles, with or without one or more non-taxable substances or items,
> the amount of tax payable for a fuel or combustible in the mixture or blend is to be determined by multiplying the rate of tax determined under the applicable provision of this Act by the amount of that fuel or combustible in the mixture or blend.
>
> (2) Subsection (1) does not apply to a prescribed fuel, combustible, substance or item or in prescribed circumstances.
> (3) Subject to subsection (4), if a mixture or blend includes a prescribed fuel, combustible, substance or item referred to in subsection (2), the amount of tax payable on the mixture or blend is the amount determined in accordance with the regulations.
> (4) If a substance or item is not taxable under this Act, the regulations may deem the substance or item to be taxable at a prescribed rate if the substance or item is included in a mixture or blend but comprises less than the prescribed percentage of the mixture or blend.

Fact #10, 11 and 14 in your correspondence appear to state that Terasen is proposing that carbon tax is invoiced and collected from customers based on a standard 90% natural gas/10% biomethane blend, when in fact the actual content of biomethane in the blend could vary. Under

.../3

section 13 of the CTA, Terasen is obligated to determine the amount of natural gas in the blend and invoice and collect carbon tax from purchasers accordingly. As biomethane is considered a non-taxable substance, no reference to the application/exemption of carbon tax on the biomethane in the blend is required on the invoice.

In your correspondence you reference a purification process that is undertaken to convert biogas into pipeline quality biomethane. If this process is similar to the processing of natural gas which includes the removal and combustion of acid gases (H_2S and CO_2); then the combustion of the acid gases is not subject to carbon tax. However, any "fuel" used to lift, or assist, in the combustion of acid gases is subject to carbon tax and should be included in the self-assessed amount on Terasen's tax return.

I trust this information adequately responds to your enquires. If you would like to discuss this response or require further clarification, please contact me directly at 250- 387-4174.

Yours truly,

M. Kimpton

Mary Kimpton
Director
Policy and Legislation Branch
Ministry of Finance

Attachment 12.2

1.0 Reference: Underlying Assumptions, Natural Gas Vehicles ("NGV")

Ex. B-1, Tab 3, Section 3.2 p. 15

"In prior years, Terasen Gas (Whistler) Inc. ("TGW") considered NGV to be a viable option in the Whistler region, and had received support for NGV buses from the RMOW Council. However, the Provincial Hydrogen Bus Project will be showcasing approximately 20 hydrogen buses in the Whistler region during the 2010 Winter Olympics and for several years afterwards. And given that, there will be no need for NGV buses in the region over the near term. Furthermore, as the projected NGV bus load was a determining factor for additional municipal and fleet vehicles in the region to be converted to NGV, it is unlikely that those conversions will take place either. Therefore, although TGW believes NGV is still a viable option in the future for this region, over the forecast period there is no projected growth for NGV loads."

1.1 What factors lead TGW to believe that NGV in Whistler are viable in the future given the market presence of hydrogen-powered vehicles?

Response:

BC Transit provides public transit service to municipalities outside the Metro Vancouver region. It is this body that decides how to service the transit needs of each municipality. As noted in response to IRs in the Whistler Natural Gas Project CPCN Application, the municipality of Whistler voiced a preference for NGV. However, subsequent to Commission Order No. G-53-06, in November 2006, and following the February 2007 Speech from the Throne, the Province announced an initial financial commitment to the Hydrogen Bus Project to "showcase B.C.'s commitment to reducing greenhouse gas emissions and the potential of hydrogen technology as an energy solution"[1]. As such the probability for attaching NGV load in Whistler was reduced.

The Provincial Hydrogen Bus Project (the "Hydrogen Bus Project") in Whistler is funded by both the provincial and federal governments. Total funding is approximately $90 million. The funding is to support the purchase of 20 hydrogen buses at a cost of approximately $2.5 million per bus (as compared to $0.5 million per NGV bus), refueling infrastructure and the cost of liquid hydrogen (approximately $180/100km for liquid hydrogen versus approximately $45/100km for compressed natural gas). TGW understands that funding will support the operation until 2014 at which time funding will be depleted. Unless additional funding is secured, or a different option arrived at, there will be no funds available to purchase liquid hydrogen to operate the buses after this date.

[1] Province of British Columbia News release, April 30, 2007

In response to BCUC IR 2.7.4 of the TGI RRA, the BCUC asked if TGI was in competition with the Hydrogen Highway. TGI's response is included below:

> *"Public perception is that the Hydrogen Highway will compete with both traditional fuels such as gasoline and diesel as well as alternative fuels such as electricity and natural gas. However, the Hydrogen Highway is not a realistic competitive threat and won't be for at least 10-20 years given that the technology is still in its infancy compared to any of the other energy forms.*
>
> *At present hydrogen is only used in "demonstration projects" because there are major challenges regarding availability, cost and technical performance. Progress on developing markets for hydrogen vehicles has been slow. In contrast, natural gas is a viable alternative for commercial applications today and is price competitive with commonly used fossil fuels like gasoline and diesel. TGI believes that compressed natural gas is a price competitive solution that will lower operating costs and greenhouse gas emissions and save vehicle operating costs."*

Hydrogen buses have an advantage over NGV buses with respect to tailpipe and lifecycle C02 emissions. However, due to the cost and limits with the technology, Hydrogen buses are not an economical long term solution. As such, this was not a decision of hydrogen buses over NGV, but rather a perceived opportunity to showcase technology and potential for clean transportation options.

In total Whistler requires 35 buses, of which 20 are hydrogen (until 2014), with the remaining buses powered by diesel. While the diesel buses have been purchased recently, they can be moved to serve other areas of the province. Since NGV buses are an economical long-term solution and produce fewer emissions than diesel, TGW believes that there is an opportunity for NGV buses to be viable in Whistler to replace the diesel buses and to replace the Hydrogen buses in 2014.

In addition, TGW has also been meeting with the Municipality regarding NGV for trash haulers and municipal fleet vehicles.

[redacted]

Attachment 13.1

11.0 Reference: Demand in British Columbia

Exhibit B-1, Section 5.2, Study Methodology, page 35

11.1 The study included three different types of residential household:

- 799 Terasen Gas customers who receive bills directly

- 200 customers who are not billed directly

- 50 customers that do not use gas

Total – 1049 interviews

11.2 Why were residential households sampled in the manner outlined above?

Response:

As a result of a typographical error in the Application, the above numbers for Residential households surveyed are incorrect. The table below shows the correct breakdown of Residential households included in the study. This information is also available in Appendix D-3, page 17 of the Application.

	Actual Interviews	Proportion of Total
	#	%
Residential Study		
Terasen Gas customers (receive gas bill directly from Terasen)	799	57%
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	14%
Non-customers (does not use gas at home)	352	25%
Residents who don't know their energy source	50	4%
Total Residential Interviews	1,401	100%

The sample for the Biogas Study used TNS's Online Panel and included a cross-section of BC households. A quota was established for Terasen Gas customers to ensure an adequate sampling size for analysis of specific Terasen Gas customer responses as discussed in BCUC IR 1.11.5.

To determine the demand for a Biogas Program, Terasen Gas needs to understand the perspectives of both its customers and non-customers, as well as identify demand among individuals who pay their bills indirectly (e.g., renters, stratas). Non-gas customers were included in the sample because the implementation of a Biogas Program could provide an incentive for respondents to convert to natural gas, and so that Terasen Gas would get a full picture of the BC residential energy market. Individuals who pay their bills indirectly were included as they may be interested in participating in a Biogas Program, and may in fact still influence decisions regarding their bills.

The sample was designed to identify differences in attitude, preferences, and responses among three distinct groups, reflecting the views of Terasen Gas customers and the residential energy market in BC.

11.3 Since the size of the premium for the biogas rate is so important, why did the study design include 24% of the study population made up of interviews with customers that do not pay their bills directly?

Response:

Please refer to the response to BCUC IR 1.11.2 for a detailed breakdown of Residential households included in the study. As identified in the response to BCUC IR 1.11.2, 14% of survey respondents pay their bills indirectly, not 24% as indicated above.

The sample was designed to represent a cross-section of BC households in order to determine if there were differences in terms of attitudes, preferences and responses among customers, gas users, and non-customers. The study was comprehensive, and was not designed to look only at customers who paid their bill directly. Furthermore, individuals who are not billed directly may in fact still be customers of TGI as they influence decisions regarding their energy choice through strata councils or landlords.

The Biogas study was designed to identify the market demand for biogas programs among BC households. By recruiting a variety of individuals for the study, including those who are not billed directly, the researcher was better able to segment responses and provide information regarding potential targeted marketing opportunities.

11.4 The total number of residential customers sampled appears to be 1049 interviews. What is the margin of error in a sample this size?

Response:

As Terasen Gas explained in the response to BCUC IR 1.11.2, the total number of residential household interviews was 1401, including 799 residential customers. The margin of error is +/-

2.6% at the 95% confidence level. This information is also stated in Section 5.2, page 36, of the Application.

11.5 If the sample size were reduced to interviews with customers that paid their bill directly (799 interviews), what would be the margin of error in this case?

Response:

For the 799 Terasen Gas customers who pay their bill directly, the margin of error is +/- 3.5% at the 95% confidence level versus the margin of error of +/- 2.6% at the 95% confidence level for the 1401 BC Household sample size as discussed in BCUC IR 1.11.2.

However, the Residential survey was designed to include a variety of respondents in order to identify demand for Biogas among BC households. Individuals who do not pay their bills directly, and individuals who are not current Terasen Gas customers, may be interested in participating in a Biogas program and may take steps to take advantage of such an offering either now, or in the future. Those who pay their bills indirectly may have input into the purchase decision (e.g. stratas or customers of Central Heat), and those who are not current customers may consider attaching to the natural gas system because of a Biomethane product offering, which helps to attract and retain customers to which all customers benefit.

The difference between the margin of error for Terasen Gas customers who pay their bills directly and the margin of error for the complete study is small, and TGI was able to drill down for specific results for TGI customers, with relative confidence as discussed in Section 5 of the Application for a TGI Biomethane initiative.

43.0 Reference: TNS Proposal for TGI Market Survey

Exhibit B-1, Appendix D – 1, page 21

[redacted]

43.1.2 Was TNS hired to conduct an independent, objective market research to determine if [redacted] for Green Gas?

Response:

This response also addresses BCUC IR's 1.43.1.3, 1.43.1.4, 1.43.1.5, and 1.43.1.6.

Yes, TNS was hired to conduct an independent, objective market research to determine the demand for Green Gas in BC. In TGI's 2010-2011 Revenue Requirement Application that was submitted June 15, 2009, TGI proposed the development of biogas supply as a pilot, and indicated that it would be pursuing the development of a Green Gas marketing plan in parallel with the supply development pilot. As explained in Part III: Section C – Tab 3: Page 253 of that RRA filing, the Company intended to further investigate numerous issues from the customer demand or sales perspective including the following:

- An assessment of market interest in a green gas offering;
- Determination of the nature of the initial offering:
  - A staged offering for particular rate classes or a broader offering;

- o Sell available green supply to interested customers on a first-come first-served basis until
- the supply is exhausted or develop natural gas / green gas blends to sell to a broader customer base;
- The development of terms and conditions of service of the offering; and
- Determination of rates for the offering, a rate adjustment methodology and frequency of rate changes.

TGI pursued a market research study to understand the potential market for biogas, its market drivers, and factors affecting price, and to determine the viability of a Biogas program. TNS was selected after a competitive Request for Proposal process September 28, 2009 and the first kick off meeting was held October 1, 2010 to review the objectives of the market research, addressing the customer demand issues that were identified in TGI's 2010-2011 Revenue Requirement Application that would assist with the development of a Green Gas offering. Specific research objectives for the Biogas study are as follows:

1. Determine market interest
2. Determine the potential target market and market size
3. Develop a clear and concise customer profile(s)
4. Determine market drivers
5. Determine price points and factors affecting price points
6. Understand customer perceptions on different product offerings – offsets / biomethane

Respondents were selected differently for the two studies. On the residential side, respondents were randomly selected from TNS' online panel. This includes both gas users and non-users. On the commercial survey, respondents were restricted to Terasen Gas customers and drawn randomly from TGI's database. On both studies, respondents who work for a utility, gas marketer, the media, a research or advertising firm, were screened out of the study.

Once responses were collected, TNS conducted statistical and segmentation analyses to identify the potential target market for Green Gas based on demographics and levels of interest identified in the survey. TNS also analyzed the survey results to determine potential market drivers and outline customer perceptions regarding the different product offerings explored in the survey.

TGI instructed TNS to determine, through objective market research, the level of demand among BC households and commercial customers for Green Gas, and to explore price points and the factors that affect them, addressing consumer demand issues identified in TGI's 2010-2011 Revenue Requirement Application.

43.1.3 Did TGI hire TNS before or after it decided to pursue a Green Gas strategy?

Response:

Please refer to the response to BCUC IR 1.43.1.2.

43.1.4 Was TNS's objective to find a market segment that was receptive to Green Gas?

Response:

Please refer to the response to BCUC IR 1.43.1.2.

43.1.5 Was TNS directed in any way to find a market segment receptive to Green Gas?

Response:

Please refer to the response to BCUC IR 1.43.1.2.

45.3 Does TGI believe that the sample of respondents is representative of TGI's customer base?

Response:

Yes. Respondents were randomly selected from within TNS' Online Panel, which "is comprised of more than 110,000 individuals who have been recruited to participate in on-line, Internet surveys." [5] Quotas were established to ensure adequate sampling of Terasen Gas customers.

We believe that the sample in the TNS residential study is representative of Terasen Gas' residential customer base. This is supported by the similarity of demographics in the Terasen Gas customers interviewed in the Biogas survey and the sample in Terasen Gas' 2010 Spring Residential Customer Satisfaction study (which is randomly drawn from the Terasen Gas' customer database and therefore representative of the customer base). We observe that the household characteristics of the two samples are very similar. The Table below shows a comparison of the demographic household variables that are captured in both surveys.

	Biogas Study	Residential Customer Satisfaction Study
AREA OF RESIDENCE		
Lower Mainland & Whistler	58%	59%
Interior	30%	25%
Vancouver Island + Sunshine Coast	11%	15%
Decline	1%	0%
PEOPLE IN HOUSEHOLD		
One Person	9%	16%
Two People	43%	40%
Three to Five People	43%	40%
More than Five People	4%	4%
ANNUAL HOUSEHOLD INCOME		
Less than $15,000	3%	3%
$15,000 to less than $35,000	17%	10%
$35,000 to less than $60,000	26%	N/A
$35,000 to less than $65,000	N/A	27%
$60,000 to less than $100,000	39%	N/A
$65,000 to less than $125,000	N/A	30%
$100,000 or more	14%	N/A
$125,000 or more	N/A	13%

[5] TNS Website: http://www.tns-cf.com/services/panel.html#interactive

Attachment 15.1

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Attachment 15.1.1

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Attachment 15.2

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Attachment 15.4

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Attachment 21.1

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Attachment 23.1

Segment	Region	Rate Classes	Annual Consumption	Description
Residential	TGI/FTN	Rate 1		This Rate Schedule is applicable to firm Gas supplied at one Premise for use in approved appliances for all residential applications in single-family residences, separately metered single family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments.
	TGVI	RGS		This Rate Schedule is applicable to firm Gas supplied at one Premise for use in approved appliances for all residential applications in single-family residences, separately metered single family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with Five or less apartments.
	TGW	SGS1/2Res		Use of Gas for residential purposes in a separately metered family dwelling unit consisting of living quarters for a single family.
Small Commercial	TGI	Rate 2	Up to 2,000 GJ/Yr	This Rate Schedule is applicable to Customers with a normalized annual consumption at onePremises of less than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations.
	FTN	Rate 2.1	less than 6,000 GJ	Small Commercial Service for commercial, institutional or small industrial operations. Natural gas supplied to commercial users at one point of delivery through one meter. Applicable to customers who have consumed less than 6,000 Gigajoules.
	TGVI	SCS1	0 - 199 GJ/Year	Small Commercial Service for commercial, institutional or small industrial operations. Natural gas supplied to commercial users at one point of delivery through one meter.
	TGVI	SCS2	200 - 599 GJ/Year	Small Commercial Service for commercial, institutional or small industrial operations. Natural gas supplied to commercial users at one point of delivery through one meter.
	TGW	SGS1/2Com	200 - 599 GJ/Year	Small Commercial Service for commercial, institutional or small industrial operations.
Large Commercial	TGI	Rate 3	Over 2,000 GJ/Yr	This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of greater than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations.
	FTN	Rate 2.2	equal to or greater than 6,000 GJ	Large Commercial Service for commercial, institutional or small industrial operations. Natural gas supplied to commercial users at one point of delivery through one meter. Applicable to customers who have consumed a quantity of gas equal to or greater than 6,000 Gigajoules.
	TGI	Rate 23	R3 Transport Large Commercial	Commercial Transportation.This Rate Schedule is applicable to Shippers with a normalized annual consumption at one Premises of greater than 2,000 Gigajoules of firmGas, for use in approved appliances in commercial, institutional or small industrial operations.
	TGVI/TGW	LCS1	600 - 1999 GJ/Year	Large Commercial Service for commercial, institutional or small industrial operations. Natural gas supplied to commercial users at one point of delivery through one meter.
	TGVI/TGW	LCS2	2000 - 5999 GJ/Year	Large Commercial Service for commercial, institutional or small industrial operations. Natural gas supplied to commercial users at one point of delivery through one meter.
	TGVI/TGW	LCS3	6000 plus GJ/Year	Large Commercial Service for commercial, institutional or small industrial operations. Natural gas supplied to commercial users at one point of delivery through one meter.
	TGVI	High Load Factor- HLF		The rate structure of Large Commercial Service Rate High Load Factor consists of a basic monthly charge, a demand charge per GJ per month, and an energy and energy charge apply to the amount of gas that a customer consumes, include both a delivery and commodity charge.
	TGVI	Inverse Load Factor -ILF		The rate structure of Large Commercial Service Rate Inverse Load Factor 150% consists of a basic monthly charge and an energy charge. The basic charge is a fixed monthly charge, while the energy charge applies to the amount of gas that a customer consumes, and includes both a delivery and commodity charge.

	TGVI	AGS	Apartment (minimum 6 units)	Natural gas supplied to Apartment General Service Rate of a basic monthly charge and an energy charge. The basic charge is a fixed monthly charge, while the energy charge applies to the amount of gas that a customer consumes, and includes both a delivery and commodity charge.
Seasonal Industrial	**TGI**	Rate 4	Standard rate is for Apr to Oct use only	This seasonal rate is intended for large commercial or institutional accounts that use gas only during the summer months -(e.g. municipal pools, water-slides and summer agricultural crops). The rate structure consists of a fixed Basic Monthly Charge that is applicable only to billing periods when gas is consumed. In addition, there are variable charges for each GJ of gas, which are based on the time of year that it is consumed.
General Firm Industrial	**TGI**	Rate 5	High Volume w/ Demand Charge -(Demand applies to calculated peak volume)	This General Firm Service Rate is for large volume commercial, institutional, multi-family and other accounts. This Rate Schedule applies to the sale of firm Gas, no portion of which may be resold, through one meter station to a Customer. For greater certainty, firm Gas service under this Rate Schedule means the Gas Terasen Gas is obligated to sell to a Customer on a firm basis subject to interruption or curtailment pursuant to sections 10 (Default for Bankruptcy), 13 (Force Majeure) and the General Terms and Conditions of Terasen Gas.
Natural Gas Vehical - Industrial	**TGI**	Rate 6	NGV Stations	This Natural Gas Vehicle Service rate is primarily for companies who retail natural gas to customers with natural gas vehicles or fleet customers who use natural gas for their own fleet. This Rate Schedule applies to the sale of firm Gas through one meter set for the purpose of compression and dispensing as fuel to operate vehicles.
General InterruptableService - Industrial	**TGI**	Rate 7	Interruptible Service	This Interruptible Service Rate is for large volume customers that have the ability to switch to an alternate energy source. This Rate Schedule applies to the provision of a bundled interruptible transportation service and the sale of firm Gas, no portion of which may be resold, through one meter station to a Customer.
Large Volume Transportation - Industrial	**TGI**	Rate 22	Large Volume Transportation	Large Volume Transportation. This Rate Schedule applies to the provision of firm and/or interruptible transportation service (subject to a minimum of 12,000 Gigajoules per Month) through the Terasen Gas System and through one meter station to one Shipper except as previously agreed upon.
Large Volume Transportation- Inland - Industrial	**TGI**	Rate 22A	12,000 GJ	Transportation Inland Service Area. Firm receipt service access from the EKE Interconnection Point (“Firm EKE Receipt Transport”) is available to Non-Bypass Shippers for Gas which is delivered to a Delivery Point in the Inland Service Area and for which the Shipper has a Transportation Agreement which is effective on the August 1st preceding the subject Contract Year (“Inland Non-Bypass Shippers”).
Large Volume Transportation- Columbia - Industrial	**TGI**	Rate22B		Transportation Columbia Service Area. This Rate Schedule applies to the provision of firm and interruptible transportation service through one meter station (except as otherwise specified in the Transportation Agreement) to the following existing large industrial Shippers.
R5 Transportation - Industrial	**TGI**	Rate 25	R5 Transportation -(High Volume)	General Firm Transportation. This Rate Schedule applies to the provision of firm transportation service through the Terasen Gas System and through one meter station to one Shipper.
R7 Transportation Interruptible - Industrial	**TGI**	Rate 27	R7 Transportation Interruptible	General Interruptible Transportation. This Rate Schedule applies to the provision of interruptible transportation service through the Terasen Gas System and through one meter station to one Shipper.

Notes:

TGI = Terasen Gas Inc.

TGVI = Terasen Gas (Vancouver Island) Inc.

TGW = Terasen Gas (Whistler) Inc.

FTN = Fort Nelson

RSK = Revelstoke

Attachment 26.1.1

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Attachment 32.1

Is it Time to Ditch the TRC?
Examining Concerns with Current Practice in Benefit-Cost Analysis

Chris Neme, Energy Futures Group
Marty Kushler, American Council for an Energy-Efficient Economy

ABSTRACT

For the past two decades, the Total Resource Cost Test (TRC) has been regulators' principal test for assessing energy efficiency program cost-effectiveness and approving utility funding. However, the TRC as commonly applied today has fundamental problems. In particular, it usually ignores non-energy benefits that are often critical to market acceptance of efficiency measures and increasingly emphasized in program delivery. For example, a residential weatherization investment must typically be justified by energy savings alone, even if improved comfort was more important to the home-owner.

This problem could theoretically be solved by including in the TRC the monetary value of non-energy benefits. However, determining which benefits drive consumer decisions and estimating the value of factors such as improved comfort, health and safety, worker productivity, etc. is so difficult, expensive and controversial that this solution is simply not practical.

Use of the TRC is also inconsistent with treatment of supply alternatives. For example, when a regulator approves a utility purchased-power contract with a customer with an on-site generator, there is no consideration given to what the customer costs or other benefits from that equipment might be. All that is considered germane is the purchase price to the utility for that resource. Why should regulators apply a more stringent standard to utility investment in energy efficiency resources?

While there are other venues (e.g., public policy modeling and planning) where including a TRC perspective is still helpful, we believe it is time to emphasize the program administrator cost test when making utility system resource decisions.

Introduction

Utility regulators and other policy-makers typically require that initiatives to promote energy efficiency and other demand-side investments are shown to be "cost-effective" before they are approved. In 1983, the California Public Utilities Commission and California Energy Commission jointly published what is now widely referenced as the California Standard Practice Manual. The manual identified and defined five cost-effectiveness tests: the Participant test, the Ratepayer Impact Measure (RIM) test, the Total Resource Cost (TRC) test, the Societal test, and the Program Administrator Cost Test (PACT).[1] Almost all jurisdictions use one or more of these tests. Many have historically referenced the California Standard Practice Manual in documenting how such tests are to be applied.

Over the more than 25 years since the California Standard Practice Manual was first published relatively little has changed with respect to how cost-effectiveness screening of

[1] In the most recent version (2001) of the California Standard Practice Manual, the Societal test is treated simply as a variant on the TRC and the Utility Cost Test (UTC) was renamed the Program Administrator Cost test.

efficiency programs and other demand-side management initiatives is conducted. Although the Manual has been updated twice – once in 1988 and again in 2001 – the changes did not materially affect the definitions of the different tests (CPUC/CEC 2001). More importantly, there has been relatively little change in the way different states and provinces have used the tests.

In contrast, efficiency programs have changed substantially with respect to the kinds of measures being promoted, the ways in which they are promoted and the breadth and depth of their impacts. In addition, the policy imperatives for more aggressive efficiency programs – including growing concerns about global climate change – have become even more compelling. The thesis of this paper is that such changes necessitate a re-examination of how cost-effectiveness screening of demand-side investments is conducted. In particular, we suggest that there is a need to reconsider the current reliance on the TRC for determining whether an energy efficiency measure or program is cost-effective. While our thesis applies to any government initiative, the focus of this paper is on efficiency programs funded by electric and gas rate-payers and approved by public utility commissions.

The Five Cost-Effectiveness Tests

The reason the California Standard Practice Manual describes five different cost-effectiveness tests is that cost-effectiveness can be viewed and assessed from at least that many different perspectives. All of the tests compare the net present value of a stream of benefits over the life of an investment with the net present value of a corresponding stream of costs.[2] What follows is a brief description of each of the five tests, as well as a summary table that compares the key benefits and costs that are included in each test. Note that there are a number of nuances about the tests, including such things as discount rates and how taxes (and tax credits) are treated, that we do not address as the principal focus of this paper is on higher level issues.

Participant Test

The Participant Test measures cost-effectiveness from the perspective of the efficiency program *participant*. It simply compares the bill savings (using retail rates) that the customer will realize over the life of an efficiency upgrade to the cost incurred by the customer to make the upgrade (i.e. net of any financial incentive the program provides).

[2] In many cases, there is no "stream of costs" because all costs are realized immediately at the time of purchase. However, in other cases, there are costs that occur over a number of years.

Ratepayer Impact Measure Test

The RIM Test measures whether billing rates will go up or down as a result of an efficiency program. Put another way, it measures whether *non-participants* in a program will be better or worse off as a result of the program. This is why it is sometimes also called the Non-Participant Test. It compares the value of avoided supply investments by the utility – including avoided energy costs, avoided transmission and distribution costs and avoided generation costs – to the sum of program costs and utility lost revenues from reduced sales.

Total Resource Cost Test

The TRC Test theoretically measures cost-effectiveness from the combined view point of program participants and non-participants. We say theoretically because in practice the TRC measures secondary fuel, water or other resource savings using avoided costs for such resources rather than retail prices for such resources as in the Participant Test (Fulmer & Biewald 1994). In short, the TRC compares the value of avoided energy and other resources from all sources with the full cost of the efficiency measures plus all non-measure program costs.

Societal Test

The Societal Test is a variant on the TRC.[3] It is intended to represent a broader *societal* view of cost-effectiveness. To that end, it is the same as the TRC except that it theoretically adds environmental and other non-energy benefits and costs to society into the calculation. We say theoretically because, as discussed more fully below, other non-energy benefits such as improved comfort, building durability, health and safety, worker productivity, public image and others are seldom addressed.

Program Administrator Cost Test

The Program Administrator Cost Test (previously known as the Utility Cost Test) measures cost-effectiveness from a *utility* perspective. It compares the value of the utility's avoided costs with the cost to the utility of acquiring the efficiency resources that produce those avoided costs. Thus, its primary differences from the TRC are that (1) it does not include any energy benefits for fuels the utility does not provide; (2) it does not include any other resource benefits such as water savings; and (3) it does not include any customer contributions to the cost of an efficiency investment.

[3] Indeed, the California Standard Practice Manual no longer lists it as a separate test.

Table 1. Summary of Key Benefits and Costs Included in Different Tests

	Partic. Test	RIM Test	TRC Test	Societal Test	PACT Test
Benefits[4]					
Primary Fuel(s) Avoided Supply Costs		✓	✓	✓	✓
Secondary Fuel(s) Avoided Supply Costs			✓	✓	
Primary Fuel(s) Bill Savings (retail prices)	✓				
Secondary Fuel(s) Bill Savings (retail prices)	✓				
Other Resource Savings (e.g. water)	✓		✓	✓	
Environmental Benefits				✓	
Other Non-Energy Benefits			rarely[5]	in theory only	
Costs[6]					
Program Administration[7]		✓	✓	✓	✓
Measure Costs					
Program Financial Incentives		✓	✓	✓	✓
Customer Contributions	✓		✓	✓	
Utility Lost Revenues		✓			

Which Tests are Predominant?

We have not conducted a comprehensive assessment of which jurisdictions are currently using which tests. However, based on both our own extensive experience with regulatory practice in a variety of jurisdictions and research on this question in recent years by the American Council for an Energy Efficient Economy (Amann 2006; also unpublished research) and the Regulatory Assistance Project (unpublished), several general conclusions can be drawn.

To begin with, many states and provinces require utilities or other program administrators to assess cost-effectiveness from multiple perspectives – often all five perspectives represented by the tests identified above. This is not because those jurisdictions require programs to pass all five tests in order to be approved. Rather, it is usually to provide useful insight into a range of issues programs might raise. For example, if a program fails the RIM test miserably, a regulatory agency may still approve the program but require that other actions are undertaken to

[4] We use the term "primary fuel(s)" to represent the fuels provided by the utility running the efficiency program; the term "secondary fuel(s)" refers to fuels not provided by the utility. For example, for an efficiency program run by an electric only utility, electricity savings are "primary fuel savings" and gas or fuel oil savings are "secondary fuel savings".

[5] Although not officially part of the California Standard Practice Manual definition, the original discussions underlying the TRC and the conceptual rationale for adding the participant's out-of-pocket costs to the utility's program costs are supportive of incorporating participant non-energy benefits into the calculation. At various times a number of states have attempted to measure and include these types of benefits, but the near-universal practice these days is to ignore them in the calculation of the TRC.

[6] Just as savings of secondary fuels and other resources are benefits captured by different tests, any increases in secondary fuel costs or other resource use would be captured as either increased costs or negative benefits. Such increases would be estimated using avoided costs or retail prices in the same way as the benefits from reductions in use of such resources would be estimated for the different tests.

[7] We use the term "administration" here to include all program costs other than financial incentives for efficiency measures. This includes program management, administration, marketing, training, evaluation, etc.

minimize concerns about inequities between participants and non-participants (e.g., ensuring that there is a broad enough range of programs offered so that all customers have the opportunity to participate in at least one over a reasonable period of time).

That said, most regulators rely primarily on one test to determine whether a program or portfolio of programs should be approved. In most jurisdictions with operating efficiency programs, that principal test is either the Total Resource Cost Test or Societal Test (NAPEE 2008). One or the other of those tests are the principal test used in most New England states, New York, New Jersey, Wisconsin, Missouri, California, Ontario, Quebec, British Columbia and elsewhere . A few jurisdictions, including Michigan and Connecticut, rely principally on the UCT. Although a few states (e.g. Florida) relied on the RIM test in the past, we are unaware of any states with significant energy efficiency programs that rely primarily on the RIM test today.

Concerns about the TRC and Societal Tests as Currently Applied

We have two fundamental concerns about the TRC and Societal Tests as they are currently applied:

1. Most non-energy benefits are not factored into the tests.
2. Supply investments are not subjected to the TRC, making the hurdle to pass screening greater for demand-side investments than for supply-side alternatives.

Failure to Address Non-Energy Benefits

Most efficiency measures have significant non-energy benefits. Sometimes this is just a natural by-product of the measure. For example, reducing the leakiness of a home improves comfort at the same time it saves energy. Similarly, day-lighting not only saves energy, it has been shown to improve worker productivity. On the other hand, the marriage of efficiency and other desirable attributes is sometimes an intentional result of manufacturers', designers' or builders' marketing or sales strategies. Often, such market players sell an "entry-level" product that is as basic and inexpensive as possible – usually meaning it is also inefficient; they also often bundle efficiency upgrades with other attractive features and market this bundle as a "premium" product. Consider refrigerators. It is impossible, to find two refrigerators that are identical other than in their efficiency ratings. More efficient refrigerators often have more shelves, better drawers, better aesthetics, etc. The bottom line is that efficiency is rarely the only attribute of a product that is of interest to either consumers or those who are selling to them.

If a market is valuing non-energy attributes that are by-products of or bundled with efficiency, a good efficiency program will factor those non-energy attributes into its design. Thus, many of today's most sophisticated energy efficiency programs intentionally emphasize the selling of non-energy benefits. For example, the fundamental design philosophy underlying the residential Home Performance with ENERGY STAR programs is that we should be selling consumers on all the things about which they may care, including comfort, building durability, and indoor air quality as well as efficiency. Evaluators of ENERGY STAR Homes (new construction) programs often assess whether builders are selling such homes on their non-energy benefits. An evaluation of Efficiency Vermont's 2004 program which showed that more than 60% of builders promoted increased comfort and lower maintenance costs as additional benefits of buying ENERGY STAR homes – a three-fold increase over 2001 – was seen as partial evidence of program success (Kema 2005). Similarly, most leading programs targeting commercial and industrial customers attempt to understand the business interests of those customers and find ways efficiency investments can help address those interests. Sometimes that is just by saving money on energy bills, but more often than not reducing waste streams, improving worker productivity or other factors are at least as important.

The TRC test as originally conceptualized was a robust test looking at "total" costs and benefits. Over time, however, it became apparent that measuring and quantifying "non-energy benefits" was very difficult and often controversial for regulators to accept as a legitimate factor to consider in utility regulation. As a result, the use of non-energy benefits atrophied, and today non-energy benefits are rarely incorporated into cost-effectiveness screening under the TRC or even under the Societal Cost Test. In contrast, the full retail cost of an efficiency investment (i.e. including both the participant's and the utility's contribution) is easy to quantify, and is virtually always used in TRC or SCT analyses. The end result is that cost-effectiveness screening becomes an inherently skewed comparison: all the costs are compared to just a portion – i.e. the energy portion – of the benefits.

There have been attempts to address this issue. For example, for the past decade in Massachusetts, the regulators have explicitly allowed the utilities to conduct studies of non-resource benefits and include the value of such benefits in their cost-effectiveness screening. However, with rare exceptions, the utilities have not factored such benefits into their analyses. In the past, regulators in Washington, D.C. have allowed a non-resource benefit adder to be applied to low income programs. However, such examples are very rare.

Inconsistency in Treatment of Demand and Supply Options

As noted above, supply investments are not subjected to TRC or Societal cost-effectiveness screening. For example, when a regulator approves a utility purchased power contract from a customer with an on-site generator, there is no consideration given to what the customer costs of installing or operating that equipment might be. All that is considered germane is the cost to the utility of purchasing that power resource from the customer. Similarly, in utility cost-recovery under a "renewable portfolio standard", regulators do not use the provider's investment costs for the renewable facility to screen out sources of supply. Instead they focus on the cost of the resource to the utility system. The same basic principle applies to independent power plant generators bidding into a power pool. No one cares what the cost of constructing the plant may have been. No one cares whether the plant operators need to generate revenue by selling gypsum from the plant's scrubber or waste heat in order to competitively price its power. No one cares whether any government subsidies (in any of their myriad forms) were essential to making the price of power competitive. All that matters is the final price for purchasing power from the plant. Simply put, applying a TRC screen to utility energy efficiency programs imposes a cost-effectiveness burden that is not applied to any other utility system resource.

Why TRC Failings Matter

The asymmetrical inclusion of participant costs while failing to include most participant non-energy benefits in cost-effectiveness screening fundamentally biases regulatory decisions against efficiency investments. The practical effect of such biases would not be great if the magnitude of the unquantified non-energy benefits were small. However, numerous studies suggest that they are actually quite large. For example, a U.S. Department of Energy evaluation of low income weatherization suggests that the value of non-energy benefits was slightly greater than the value of the energy benefits (Schweitzer & Tonn, 2002). A federally funded study of the cost-effectiveness of commercial building commissioning – a service promoted by numerous rate-payer funded efficiency programs – found non-energy benefits to be on the order of 50% of the value of energy savings in existing buildings and more than five times the value of energy savings in new construction (Mills et al. 2004). One study of 52 industrial energy efficiency improvements also found non-energy productivity benefits to be more than 120% of the value of the energy savings; another concluded that total savings from industrial energy efficiency projects are typically two to four times the value of the energy savings (Elliott, Laitner & Pye 1997) her study estimates that non-energy benefits across a wide range of efficiency programs range in value from 50% to more than 100% of the energy benefits (Skumatz 2006).

Because they can be so large, omitting such benefits from cost-effectiveness screening can significantly reduce the magnitude of savings that are realized from efficiency program portfolios by reducing the number of measures that can be promoted within programs or rejecting cost-effective programs altogether.

Consider a program designed to promote the purchase of efficient residential water heating equipment. If avoided supply costs were $0.14 per kWh,[8] $115 per peak kW, and $1.35 per therm – all approximately what is currently estimated in New England (Hornby et al. 2009) and higher than many other parts of the country – the net present value of the benefits of upgrading from a standard new electric water heater to a heat pump water heater would be roughly $3000, or about three times the incremental cost of a standard unit. Thus, a program administrator faced with such avoided costs could justify offering rebates for heat pump water heaters.[9] However, under the TRC or Societal Cost Test as they are typically used, the same program administrator would not be permitted to offer the very same rebate to a consumer who preferred instead to install a $6000 solar water heating system – even if the savings were slightly greater and the customer was willing to bear all of the added expense because it valued highly the ability to show off its commitment to the environment to its neighbors. While some of us may not support assigning a high value to such an attribute, the reality is that some people do. We use this somewhat extreme example to make the point that if we ignore the value that some people put on such attributes, we essentially begin using our personal values rather than market values to determine what is cost-effective. The result will be efficiency programs with at least somewhat lower levels of participation and savings.

Now consider Home Performance with ENERGY STAR programs. A good program in a northern climate should achieve on the order of 500 to 750 kWh and 300 therms of energy savings per home. This level of savings typically costs $7000 to $10,000 per home plus another $1000 to $2000 per home for marketing and administering the program. Using the same avoided supply costs described above, the net present value of the energy benefits would be on the order

[8] Roughly $0.03 of this is for environmental externalities.
[9] Assuming the program could be run for an administrative cost of less than $2000 per home.

of $5500 to $6500, depending on how much of the electric savings were cooling savings.[10] That is not enough to justify a program under the TRC test. This is not an extreme example. It addresses the largest energy end use of the residential sector in a large portion of the U.S. and all of Canada.

In the past, when efficiency programs were never funded anywhere close to levels necessary to achieve even all the efficiency that was cost-effective under the restrictive application of the TRC or SCT, such concerns may not have been as important. However, in the current era in which the policy imperatives for truly pursuing all cost-effective efficiency are more compelling than ever and several jurisdictions are actively pressing to determine how much efficiency savings can be achieved, restrictive applications of cost-effectiveness screening standards has become highly problematic. How can we talk about figuring out how to do deep energy retrofits if we cannot even justify the 25% to 30% heating savings values achieved by current Home Performance with ENERGY STAR programs?

Possible Solutions

Conceptually, we see three potential solutions to this problem:

1. Adjust the TRC so that only the "energy portion" of measure costs are included in the test;
2. Fix the TRC and Societal Tests by quantifying – even in approximate ways – and including in cost-effectiveness screening all non-energy benefits; or
3. Change the test being used – specifically, relying instead on PACT.

Each of these options has its proponents. Each also has both advantages and disadvantages. These are discussed briefly below.

Using Only the "Energy Portion" of Measure Costs in the TRC

If the problem with the TRC is that it compares total costs to only the energy benefits, then one option is to assess how much of the total cost is attributable to energy savings and use that energy portion of the total cost in the TRC cost-effectiveness calculation. This could theoretically be done by conducting studies on the factors that contributed to consumer decisions to make an efficiency investment and estimating the portion of the decisions that were attributable to interest in energy savings. Such an approach has recently been put forward for consideration in a docket of the Vermont Public Service Board.[11]

This approach would be a significant improvement over the current situation in that it would at least transform the TRC from a biased test to a comparison of apples (energy costs) to apples (energy benefits). This could enable some important and societally cost-effective efficiency programs that would otherwise fail the TRC as it is commonly applied to pass screening. Consider the Home Performance with ENERGY STAR program discussed above. If the average measure cost was $8500 per home, the average program administration cost was

[10] Assumes a real discount rate of 6%. The low end of the range assumes an average life of 10 years for the electric savings (mostly lighting) and 20 years for the gas savings. The high end of the range assumes significant cooling savings (with 15 year life) as well.

[11] http://psb.vermont.gov/docketsandprojects/eeu/screening

$1500 per home and the average energy benefits were $6000 per home, the program would fail the TRC with -$4000 in net benefits. However, if participant surveys suggested that, on average, only half of the participant cost should be attributed to an interest in energy savings (the remainder being associated with improved comfort and other benefits, the "adjusted measure cost" would be reduced to $4250. At that cost, the $6000 in energy benefits would exceed the $5750 ($4250 plus $1500 in administration costs) in "energy related costs", making the program cost-effective.

However, this approach also has some disadvantages. For one, it would also require potentially significant additional expenditure on evaluations. Such research would ideally need to be undertaken for numerous programs and markets. It may also need to be undertaken numerous times for the same market as programs evolve. Participants in the first year or two of a program may be fundamentally different than those in later years. The program could also change in ways that result in different customer perceptions of value. Moreover, market research into consumer decisions should ideally be undertaken retrospectively.[12] That is, one would ideally have a cadre of program participants to survey. This raises questions about how program administrators would assess *new* programs that have not yet been tested in the field, and more importantly, how regulators would view proposals from program administrators to pursue new programs that required significant non-energy benefits to pass screening. If the default would be for program administrators to not propose such programs and for regulators not to approve them, progress will have been very limited. In addition, the approach could still result in sub-optimal levels of efficiency investment because using customers' assessments of why they purchased a product to adjust cost rather than capturing the actual value of those benefits is likely, in at least some cases, to result in cost reductions that are worth much less than the full value of the non-energy benefits.[13] Finally, the process for getting such a different approach adopted by regulators could be difficult and lengthy.

Taken together, these disadvantages likely mean that efforts to address non-energy benefits through adjustments to the cost side of the equation are likely to be a sub-optimal but workable solution for only a limited set of markets or programs in only a few jurisdictions.

Quantifying All Non-Energy Benefits

The second option for fixing the TRC is to tackle the benefits side of the equation. Specifically, regulators could theoretically require that all non-energy benefits are estimated and factored into TRC screening.

Like the approach discussed above, this approach would also lead to a more balanced assessment of costs and benefits. From the perspective of pure economic theory, it is the best approach in that it ensures that both all societal benefits and all costs are factored into decision-making. Again, consider the Home Performance with ENERGY STAR program discussed above. We have already shown that an average per home measure cost of $8500, average per participant administration cost of $1500 and average per home energy benefits of $6000 would

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[12] In theory, one could conduct prospective market research about customers' willingness to pay. However, such assessments are likely to be less accurate than research on reasons why consumers *did* pay, in part because actual participants are likely to be different (demographically or otherwise) than those surveyed prospectively.

[13] Consider a case in which health and safety benefits were large enough to fully offset measure costs, but the consumer assigned only 20% of the reason they invested in the measures to such benefits. In that case, this approach would understate the value of the non-energy benefits by a factor of 5.

lead to a program failing the TRC with - $4000 in net benefits. However, if participant non-energy benefits such as improved comfort, health and safety, building durability and other factors were estimated to be worth the same as the energy benefits (i.e. another $6000), a corrected TRC test would appropriately show the program passing screening with $2000 in net benefits.

That said, this approach also has a number of disadvantages. First, if the aim was to comprehensively value all – or even just the most important – non-energy benefits, a potentially enormous additional investment in evaluation could be required. The fact that such benefits can vary from customer to customer, change as programs mature, and change as program designs themselves change only adds to the complexity and cost. Second, it is impossible to fully understand the full range of non-energy benefits that are valued by participants in large portfolios of efficiency programs. We are likely to only try to quantify those we already know – meaning we will understate the true value of such benefits. Third, just as with the adjustment to costs described above, valuation of non-energy benefits should ideally be performed retrospectively. It may be difficult to introduce new programs that rely on untested non-energy benefits. Fourth, because methods for quantifying non-energy benefits are imperfect, the results could be very controversial. Imagine, for example, attempts to quantify the health and safety benefits associated with replacing boilers with cracked heat exchangers. Finally, the regulatory process for considering this approach to fixing the TRC is likely to be extremely difficult, with regulators in many jurisdictions resisting the formal inclusion and monetization of factors they consider outside the realm of utility regulation.

The bottom-line is that while this approach is theoretically ideal, it is also likely to be so complex, controversial, and expensive that it is unworkable. It is almost certain that no jurisdiction will “go all the way” or even “most of the way” to fully address non-energy benefits in cost-effectiveness screening.

Switching to the Program Administrator Cost Test

The alternative to the two options for fixing the TRC is to replace it with a different test, specifically the PACT.[14]

This approach has a number of advantages. First, it is much simpler. There is no need to quantify non-energy benefits, which means much less complexity and controversy. Second, it is much less expensive. Not only do we not need to add potentially enormous new evaluation costs, we can even modestly reduce some existing expenditures because we no longer need to routinely estimate the full cost of efficiency measures since the PACT is concerned only with program spending.[15] Third, this approach would create some symmetry with how supply-side investments are assessed. Finally, while one should not underestimate the difficulties in persuading regulators to change the test that they use, for all of the reasons noted above we expect this approach could be adopted more easily, more comprehensively and more quickly than the other options discussed above.

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[14] The PACT could be supplemented with the Societal test when benefits external to the utility system need to be considered.

[15] There would still be some value to estimating full measure incremental costs. In particular, such estimates could be useful in informing program design, including incentive levels. However, such work would not need to be as routine or comprehensive as it is today.

Again, it is worth considering the Home Performance with ENERGY STAR program discussed above. It would fail the TRC as commonly applied today because the full $8500 customers paid on average for improvements to their home, plus the average program administration cost of $1500 per home, exceeds the average $6000 in energy benefits. Under the PACT, as long as the program provided a rebate of no more than $4500, it would pass cost-effectiveness screening.

The principle disadvantage of this approach is that it could theoretically result in the promotion of some efficiency measures that are not cost-effective from the perspective of society as a whole, even after accounting for non-energy benefits. However, the PACT ensures that all programs are cost-effective from an all rate-payers' perspective. By definition, any investment made by an efficiency program participant will be cost-effective from its perspective as well (otherwise they would not have made the investment).

In our view, switching to the PACT is the most workable solution for the purpose of selecting among utility resource options in the regulatory context.[16] Because so many measures have non-energy benefits, many of which are very large, we suspect that the potential for promoting some investments that are not societally cost-effective would be swamped by the significant increase in societal benefits that would accrue from pursuing investments that are societally cost-effective (when considering non-energy bnefits) but would have failed the TRC.

Conclusions

We believe it is clear that the TRC,[17] as currently applied, has significant flaws. Because of the asymmetrical application of the TRC test to energy efficiency resources, but not other utility resource options, efficiency resources are systematically disadvantaged. While historically this has had a rather limited practical impact (because energy efficiency programs have tended to pass both the TRC and PACT), that situation is beginning to change. As we move into an era of greatly expanded energy efficiency objectives, this additional burden for energy efficiency programs will likely result in substantially less energy savings being realized than if we were truly pursuing all cost-effective energy efficiency. If non-energy benefits are roughly equal to energy system benefits of typical efficiency investments, failing to account for such benefits is tantamount to reducing the cost-effectiveness of such programs by half. The "flip side" of that statement is that if participant costs are half the total cost of the installed energy efficiency measure, including those costs in the TRC greatly reduces the apparent cost-effectiveness of the energy efficiency program relative to other utility resource options. Maintaining the current TRC cost-effectiveness regime will mean that the savings realized will ultimately be substantially less than they would be if we were truly pursuing all cost-effective efficiencies. Given the currently very compelling policy imperatives for maximizing the amount of energy savings we can achieve, it is critical that this issue be addressed.

Given the options before us, switching from reliance on the TRC to the PACT appears the best way to address the problem both comprehensively enough and expeditiously. This is not to say that there is no role for a TRC type of analysis. There may well be important policy questions that would benefit from a more thorough assessment of the TRC perspective. There

[16] There are other purposes (e.g. macroeconomic modeling; overall public policy analysis and planning; etc.) for which a more comprehensive analysis of all energy and non-energy benefits and costs is very appropriate. We do not seek to minimize the importance of such analyses.

[17] And by extension, the Societal Test.

may also be value in furthering our understanding of the nature and value of non-energy benefits – to inform program design if nothing else. Such work could conceivably lead to more workable adjustments to the TRC in the future. However, we believe that the theoretically perfect solution is not attainable. Even if it was, we cannot afford to wait a decade for it to develop. This all suggests that a switch to primary reliance on the PACT for utility resource selection (supplemented as necessary by the Societal Test) is the best course of action today.

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Attachment 46.5.2

7. DATA GATHERING, REPORTING AND INTERNAL CONTROL PROCESSES

In its EEC Decision, the Commission directed the Companies to include a discussion in the Annual Report of the Companies internal data gathering, monitoring and reporting control practices. This section addresses that direction. As this section demonstrates, the Companies have business practices in place for EEC activities to ensure that these activities are in compliance with the general controls of the Company.

This section provides high level information on data gathering, and on the Companies' business practices related to program development and application processing. It also includes comments from the Companies' Internal Audit group on EEC initiative controls.

7.1 DSM System Project: Meeting the Growing Need for New Tracking and Reporting

The expansion of EEC programs resulting from the EEC Decision has created a need to develop a robust data capture and reporting system. With the anticipated increase in the number of programs and participants, the existing Excel-based DSM tracking and reporting methods would not be capable of handling the future business needs and requirements of the EEC Activities. The Companies determined that a new tracking system was needed to enable it to:

- Track EEC program participation, costs and energy savings for incentive-based programs;
- Track information about non-incentive programs and activities;
- Track actual and forecasts vs. budgets;
- Provide reports for internal and external stakeholders including program partners and the Commission;
- Allow for scenario modelling for program planning and design; and
- Support DSM benefit-cost analysis on a program by program basis as well as at the portfolio level (or EEC plan level).

To address the requirement for more robust program data gathering, tracking and reporting, the DSM System ("DSMS") project was launched in the fall of 2008. The Companies conducted research on the potential solutions available in the marketplace, as well as investigated having a system custom-built.

The Companies eventually selected a web-based program tracking and reporting system called TrakSmart, and entered into an Agreement with TrakSmart's provider Nexant, to obtain the TrakSmart system. Project implementation commenced early in 2010. Based on the project schedule, the DSMS will be implemented and will be operational by November 2010. The costs associated with implementing and maintaining DSMS will be added to the portfolio level expenditures in 2010. The costs to implement DSMS are $685,000 US and they are included in the Portfolio-level expenditures for 2010.

Once the DSMS is implemented, it will increase the ability of the Companies to capture and report on the following features:

- Program participants' information, costs and energy savings for EEC programs and activities;
- Forecasting / extrapolation based on estimates and actuals;
- Expenses and budget tracking associated with the EEC;
- Interface with SAP[20] application;
- Costs (program, incentive and administrations) associated with EEC projects; and
- Capture of information on a per participant basis i.e. equipment models, reasons for rejection etc.

Once the DSMS is in place and the transition period from the current system to new is completed, these features will help the EEC team to make data gathering, tracking and reporting more efficient and increase the overall efficiency of the workflow.

7.2 Robust Business Case Process Applied to All Programs

Before a new EEC program can be implemented, a program plan or business case must first be developed. The Companies are committed to putting each program through a high level of internal scrutiny before moving ahead with a program, and believe doing so ensures an increased chance of program effectiveness.

The business case developed includes information about program rationale and purpose as well as description of target audience, assumptions, costs-benefit tests and proposed evaluation methods is developed. Cost-benefit analysis is performed using the California Standard Tests ("CST") as outlined in California Standard Practice Manual. In partnership with Willis, the Companies have developed an in-house cost-benefit modelling tool based on CST that provides the following areas of analysis:

- Benefits incurred over measure life of the individual programs; including energy savings over the measure life of the program;
- Total costs incurred in implementing the program including administrative, incentive, marketing and evaluation; and
- The four CST tests (Rate Impact Measure ("RIM"), Utility, Participant and TRC).

The results from this modelling are used as inputs for the business cases, which are approved in accordance with the Companies' policy on financial authorization levels.

[20] System, Applications and Products ("SAP") is a financial tool used by the Companies. All EEC expenditures are captured within SAP.

7.3 Incentive Applications Vetted for Compliance with Program Requirements

Ensuring that all customer applications are compliant with program requirements is also part of the internal control process. The Companies' EEC activity has a number of mechanisms in place to ensure compliance of incentive applications with program requirements.

The verification process is specific to each program and is dependent on the type of program, its complexity, the financial value of the incentive and other parameters. The general principles applied are as follows:

1. Each application is reviewed for completeness and accuracy.

2. Applications must meet the criteria outlined in the terms and conditions of the program put forward through the approval process. Please refer to Appendix G for a copy of the Efficient Boiler Program's Terms and Conditions as an example.

3. Once approved, incentives are distributed to participants.

4. Copies of application and supporting documents are filed and stored for seven years in case of an audit.

7.4 Internal Audit Services

The EEC team engaged the Companies own Internal Audit Services ("IAS") group to review the controls associated with the EEC Initiative. Generally speaking, IAS found that there were no major weaknesses in the process and control environment, but that there were minor weaknesses requiring prompt management attention to ensure that the risks identified were mitigated. Management either has already taken action to address IAS' recommendations, or is going to do so as agreed upon on a timely basis.

The primary findings of weaknesses within the controls related to the Companies' EEC initiative are presented and commented upon below:

- Process and internal control documentation for various EEC programs was not readily available. This is true of some of the Companies' long-running initiatives such as the Efficient Boiler Program, however all new programs have process documentation in the Business Case for the Program, and on a go-forward basis, the EEC team will seek input from IAS on controls needed on a program-by-program basis
- Some of the EEC programs are administered by third-parties; however, their performance was not often monitored by the Companies. A periodic review of the effectiveness of third party administrators is recommended to ensure that quality of the program administration is acceptable, and this will be implemented by the EEC team on a go-forward basis
- There was one incident noted by IAS where an application approved did not follow one of the published terms and conditions of a program. The EEC team will ensure that program terms and conditions are followed.

The full report from the Companies' IAS group can be found at Appendix H.

7.5 Summary

The Companies are committed to strong internal controls in all aspects of the EEC Program. As demonstrated in this section, the Companies' business practices related to program development, application processing, and ongoing monitoring are all sound and subject to continuous improvement.

The Companies' EEC team is implementing a robust data gathering and program participation tracking system (the DSMS) in order to accommodate the increased level of EEC activity arising from the funding approval. Expenditures reported through the DSMS will be gathered from SAP, which tracks all of the Companies' financial activity.

All business case and financial approvals are performed in accordance with the Administrative Policy on the Companies' Authorization Levels. There are solid business practices in place related to EEC activity, such as a requirement for a detailed business case for all new programs and initiatives.

The Companies' Internal Audit group has reviewed the processes of the EEC team and while generally the controls related to EEC activity are adequate, there are some areas for improvement that the EEC team either already has addressed, or is in the process of addressing.

In 2010 and beyond the Company will continue to monitor its internal controls and to work with Internal Audit to do the same so that all aspects of the EEC Program are carried out with appropriate diligence and scrutiny.

Attachment 51.5

TERASEN GAS INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016
						1	2	3	4	5
1	EEC Expenditure	$ 654	3966	$ 25,845	$ 29,619	$ 3,200	$ 3,200	$ 3,200	$ 3,200	$ 3,200
2	Income Tax Offset	- 203	- 1,190	- 7,366	- 7,849	- 800	- 800	- 800	- 800	- 800
3	Net Additions	$ 451	$ 2,776	$ 18,479	$ 21,770	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400
4	Amortization 10 Years	$ 150	$ 925	$ 1,848	$ 2,177	$ 240	$ 240	$ 240	$ 240	$ 240
5										
6	EEC Deferral Account									
7	Opening Balance	$ 1,526	$ 1,205	$ 3,545	$ 21,670	$ 41,238	$ 39,258	$ 37,039	$ 34,579	$ 31,880
8	Net Additions	451	2,776	18,479	21,770	2,400	2,400	2,400	2,400	2,400
9	Amortization	- 772	- 436	- 355	- 2,202	- 4,379	- 4,619	- 4,859	- 5,099	- 5,339
10	Ending Balance	$ 1,205	$ 3,545	$ 21,670	$ 41,238	$ 39,258	$ 37,039	$ 34,579	$ 31,880	$ 28,940
11										
12	EEC Deferral Mid-Year	$ 1,366	$ 2,375	$ 12,608	$ 31,454	$ 40,248	$ 38,148	$ 35,809	$ 33,229	$ 30,410
13										
14	Change in Rate Base					$ 8,794	-$ 2,099	-$ 2,339	-$ 2,579	-$ 2,819
15										
16	EEC Deferral Impact on Non-Bypass Rates									
17	Change in Cost of Service					$ 3,619	$ 127	$ 105	$ 83	$ 61

TERASEN GAS INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1	EEC Expenditure	$ 3,200	$ 3,200	$ 3,200	$ 3,200	$ 3,200	$ 3,200	$ 3,200	$ 3,200
2	Income Tax Offset	- 800	- 800	- 800	- 800	- 800	- 800	- 800	- 800
3	Net Additions	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400
4	Amortization 10 Years	$ 240	$ 240	$ 240	$ 240	$ 240	$ 240	$ 240	$ 240
5									
6	EEC Deferral Account								
7	Opening Balance	$ 28,940	$ 25,761	$ 22,341	$ 18,682	$ 15,137	$ 13,200	$ 13,200	$ 13,200
8	Net Additions	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400
9	Amortization	- 5,579	- 5,819	- 6,059	- 5,945	- 4,337	- 2,400	- 2,400	- 2,400
10	Ending Balance	$ 25,761	$ 22,341	$ 18,682	$ 15,137	$ 13,200	$ 13,200	$ 13,200	$ 13,200
11									
12	EEC Deferral Mid-Year	$ 27,351	$ 24,051	$ 20,512	$ 16,909	$ 14,168	$ 13,200	$ 13,200	$ 13,200
13									
14	Change in Rate Base	-$ 3,059	-$ 3,299	-$ 3,539	-$ 3,602	-$ 2,741	-$ 968	$ -	$ -
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	$ 39	$ 17	-$ 5	-$ 484	-$ 2,396	-$ 2,672	$ -	$ -

TERASEN GAS INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Expenditure	$ 3,200	$ 3,200	$ 3,200	$ 3,200	$ 3,200	$ 3,200	$ 3,200	$ 3,200
2	Income Tax Offset	- 800	- 800	- 800	- 800	- 800	- 800	- 800	- 800
3	Net Additions	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400
4	Amortization 10 Years	$ 240	$ 240	$ 240	$ 240	$ 240	$ 240	$ 240	$ 240
5									
6	EEC Deferral Account								
7	Opening Balance	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200
8	Net Additions	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400
9	Amortization	- 2,400	- 2,400	- 2,400	- 2,400	- 2,400	- 2,400	- 2,400	- 2,400
10	Ending Balance	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200
11									
12	EEC Deferral Mid-Year	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200	$ 13,200
13									
14	Change in Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Attachment 51.1

TERASEN GAS INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1					2011					
2	Rate Impact Based on 2011 Margin & Volume			Margin at Revised Rates	Volume TJ					
3	Residential			$ 331,183	68,578.9	$ 0.032	$ 0.001	$ 0.001	$ 0.001	$ 0.001
4	Small Commercial			88,744	24,603.1	$ 0.024	$ 0.001	$ 0.001	$ 0.001	$ 0.000
5	Large Comercial - Sales			47,896	17,168.5	$ 0.019	$ 0.001	$ 0.001	$ 0.000	$ 0.000
6	Seasonal Service			265	184.6	$ 0.010	$ 0.000	$ 0.000	$ 0.000	$ 0.000
7	General Firm Service - Sales			7,380	3,184.3	$ 0.016	$ 0.001	$ 0.000	$ 0.000	$ 0.000
8	General Interruptible Service - Sales			47	22.7	$ 0.014	$ 0.000	$ 0.000	$ 0.000	$ 0.000
9	NGV			403	103.8	$ 0.026	$ 0.001	$ 0.001	$ 0.001	$ 0.000
10	Large Firm Transportation Service			5,224	8,103.2	$ 0.004	$ 0.000	$ 0.000	$ 0.000	$ 0.000
11	Large Interuptible T-Service			9,710	11,080.5	$ 0.006	$ 0.000	$ 0.000	$ 0.000	$ 0.000
12	Large Commercial T-Service			17,607	6,177.2	$ 0.019	$ 0.001	$ 0.001	$ 0.000	$ 0.000
13	General Firm T-Service			25,476	12,944.1	$ 0.013	$ 0.000	$ 0.000	$ 0.000	$ 0.000
14	General Interruptible T-Service			7,067	5,587.4	$ 0.008	$ 0.000	$ 0.000	$ 0.000	$ 0.000
15										
16	Total Non-Bypass Sales & T-Service			$ 541,002	157,738.3					

TERASEN GAS INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	$ 0.000	$ 0.000	-$ 0.000	-$ 0.004	-$ 0.021	-$ 0.024	$ -	$ -
4	Small Commercial	$ 0.000	$ 0.000	-$ 0.000	-$ 0.003	-$ 0.016	-$ 0.018	$ -	$ -
5	Large Comercial - Sales	$ 0.000	$ 0.000	-$ 0.000	-$ 0.002	-$ 0.012	-$ 0.014	$ -	$ -
6	Seasonal Service	$ 0.000	$ 0.000	-$ 0.000	-$ 0.001	-$ 0.006	-$ 0.007	$ -	$ -
7	General Firm Service - Sales	$ 0.000	$ 0.000	-$ 0.000	-$ 0.002	-$ 0.010	-$ 0.011	$ -	$ -
8	General Interruptible Service - Sales	$ 0.000	$ 0.000	-$ 0.000	-$ 0.002	-$ 0.009	-$ 0.010	$ -	$ -
9	NGV	$ 0.000	$ 0.000	-$ 0.000	-$ 0.003	-$ 0.017	-$ 0.019	$ -	$ -
10	Large Firm Transportation Service	$ 0.000	$ 0.000	-$ 0.000	-$ 0.001	-$ 0.003	-$ 0.003	$ -	$ -
11	Large Interuptible T-Service	$ 0.000	$ 0.000	-$ 0.000	-$ 0.001	-$ 0.004	-$ 0.004	$ -	$ -
12	Large Commercial T-Service	$ 0.000	$ 0.000	-$ 0.000	-$ 0.003	-$ 0.013	-$ 0.014	$ -	$ -
13	General Firm T-Service	$ 0.000	$ 0.000	-$ 0.000	-$ 0.002	-$ 0.009	-$ 0.010	$ -	$ -
14	General Interruptible T-Service	$ 0.000	$ 0.000	-$ 0.000	-$ 0.001	-$ 0.006	-$ 0.006	$ -	$ -
15									
16	Total Non-Bypass Sales & T-Service								

Attachment 51.1

TERASEN GAS INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Small Commercial	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Large Comercial - Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Seasonal Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	General Firm Service - Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	General Interruptible Service - Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	NGV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Large Firm Transportation Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Large Interuptible T-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Large Commercial T-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	General Firm T-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	General Interruptible T-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15									
16	Total Non-Bypass Sales & T-Service								

Attachment 51.1

TERASEN GAS INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016
						1	2	3	4	5
1	EEC Deferral Impact on Cost of Service									
2	Amortization Expense				$ 2,202	$ 4,379	$ 4,619	$ 4,859	$ 5,099	$ 5,339
3	Income Tax Expense				1,225	1,970	2,023	2,073	2,121	2,165
4	Earned Return				2,493	3,191	3,024	2,839	2,634	2,411
5	Total Impact on Cost of Service				$ 5,921	$ 9,540	$ 9,667	$ 9,771	$ 9,854	$ 9,915
6										
7	Change in Total Cost of Service					$ 3,619	$ 127	$ 105	$ 83	$ 61
8										
9	Income Tax Expense									
10	Earned Return				$ 2,493	$ 3,191	$ 3,024	$ 2,839	$ 2,634	$ 2,411
11	Less Utility Interest Expense				- 1,298	- 1,661	- 1,574	- 1,478	- 1,371	- 1,255
12	Add Amortization Expense				2,202	4,379	4,619	4,859	5,099	5,339
13	Taxable Income After Tax				$ 3,398	$ 5,909	$ 6,069	$ 6,220	$ 6,362	$ 6,495
14										
15	Taxable Income				$ 4,623	$ 7,879	$ 8,092	$ 8,294	$ 8,483	$ 8,660
16	Tax Rate	31%	30%	28.50%	26.50%	25%	25%	25%	25%	25%
17	Income Tax Expense				$ 1,225	$ 1,970	$ 2,023	$ 2,073	$ 2,121	$ 2,165
18										
19	Capital Structure & Embedded Cost									
20	% of Capital Structure									
21	Short Term Debt				1.63%					
22	Long Term Debt				58.37%					
23	Common Equity				40.00%					
24	Total				100.00%					
25										
26	Embedded Cost									
27	Short Term Debt				4.500%					
28	Long Term Debt				6.945%					
29	Common Equity				9.500%					
30										
31	Return on Rate Base				7.93%					
32	Cost of Debt (Before Tax)				4.13%					

TERASEN GAS INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017	2018	2019	2020	2021	2022	2023	2024
		6	7	8	9	10	11	12	13
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 5,579	$ 5,819	$ 6,059	$ 5,945	$ 4,337	$ 2,400	$ 2,400	$ 2,400
3	Income Tax Expense	2,206	2,244	2,280	2,196	1,625	967	967	967
4	Earned Return	2,168	1,907	1,626	1,340	1,123	1,046	1,046	1,046
5	Total Impact on Cost of Service	$ 9,954	$ 9,970	$ 9,965	$ 9,481	$ 7,085	$ 4,414	$ 4,414	$ 4,414
6									
7	Change in Total Cost of Service	$ 39	$ 17	-$ 5	-$ 484	-$ 2,396	-$ 2,672	$ -	$ -
8									
9	Income Tax Expense								
10	Earned Return	$ 2,168	$ 1,907	$ 1,626	$ 1,340	$ 1,123	$ 1,046	$ 1,046	$ 1,046
11	Less Utility Interest Expense	- 1,129	- 993	- 847	- 698	- 585	- 545	- 545	- 545
12	Add Amortization Expense	5,579	5,819	6,059	5,945	4,337	2,400	2,400	2,400
13	Taxable Income After Tax	$ 6,619	$ 6,733	$ 6,839	$ 6,587	$ 4,875	$ 2,902	$ 2,902	$ 2,902
14									
15	Taxable Income	$ 8,825	$ 8,978	$ 9,119	$ 8,783	$ 6,501	$ 3,869	$ 3,869	$ 3,869
16	Tax Rate	25%	25%	25%	25%	25%	25%	25%	25%
17	Income Tax Expense	$ 2,206	$ 2,244	$ 2,280	$ 2,196	$ 1,625	$ 967	$ 967	$ 967
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

Attachment 51.1

TERASEN GAS INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400
3	Income Tax Expense	967	967	967	967	967	967	967	967
4	Earned Return	1,046	1,046	1,046	1,046	1,046	1,046	1,046	1,046
5	Total Impact on Cost of Service	$ 4,414	$ 4,414	$ 4,414	$ 4,414	$ 4,414	$ 4,414	$ 4,414	$ 4,414
6									
7	Change in Total Cost of Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8									
9	Income Tax Expense								
10	Earned Return	$ 1,046	$ 1,046	$ 1,046	$ 1,046	$ 1,046	$ 1,046	$ 1,046	$ 1,046
11	Less Utility Interest Expense	- 545	- 545	- 545	- 545	- 545	- 545	- 545	- 545
12	Add Amortization Expense	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400
13	Taxable Income After Tax	$ 2,902	$ 2,902	$ 2,902	$ 2,902	$ 2,902	$ 2,902	$ 2,902	$ 2,902
14									
15	Taxable Income	$ 3,869	$ 3,869	$ 3,869	$ 3,869	$ 3,869	$ 3,869	$ 3,869	$ 3,869
16	Tax Rate	25%	25%	25%	25%	25%	25%	25%	25%
17	Income Tax Expense	$ 967	$ 967	$ 967	$ 967	$ 967	$ 967	$ 967	$ 967
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

TERASEN GAS INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016
						1	2	3	4	5
1	EEC Expenditure	$ 654	$ 3,966	$ 25,845	$ 29,619	$ 28,000	$ 28,000	$ 28,000	$ 28,000	$ 28,000
2	Income Tax Offset	- 203	- 1,190	- 7,366	- 7,849	- 7,000	- 7,000	- 7,000	- 7,000	- 7,000
3	Net Additions	$ 451	$ 2,776	$ 18,479	$ 21,770	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000
4	Amortization 10 Years	$ 45	$ 278	$ 1,848	$ 2,177	$ 2,100	$ 2,100	$ 2,100	$ 2,100	$ 2,100
5										
6	EEC Deferral Account									
7	Opening Balance	$ 1,526	$ 1,205	$ 3,545	$ 21,670	$ 41,238	$ 57,858	$ 72,379	$ 84,799	$ 95,120
8	Net Additions	451	2,776	18,479	21,770	21,000	21,000	21,000	21,000	21,000
9	Amortization	- 772	- 436	- 355	- 2,202	- 4,379	- 6,479	- 8,579	- 10,679	- 12,779
10	Ending Balance	$ 1,205	$ 3,545	$ 21,670	$ 41,238	$ 57,858	$ 72,379	$ 84,799	$ 95,120	$ 103,340
11										
12	EEC Deferral Mid-Year	$ 1,366	$ 2,375	$ 12,608	$ 31,454	$ 49,548	$ 65,118	$ 78,589	$ 89,959	$ 99,230
13										
14	Change in Rate Base					$ 18,094	$ 15,571	$ 13,471	$ 11,371	$ 9,271
15										
16	EEC Deferral Impact on Non-Bypass Rates									
17	Change in Cost of Service					$ 4,474	$ 4,232	$ 4,038	$ 3,845	$ 3,652

TERASEN GAS INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1	EEC Expenditure	$ 28,000	$ 28,000	$ 28,000	$ 28,000	$ 28,000	$ 28,000	$ 28,000	$ 28,000
2	Income Tax Offset	- 7,000	- 7,000	- 7,000	- 7,000	- 7,000	- 7,000	- 7,000	- 7,000
3	Net Additions	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000
4	Amortization 10 Years	$ 2,100	$ 2,100	$ 2,100	$ 2,100	$ 2,100	$ 2,100	$ 2,100	$ 2,100
5									
6	EEC Deferral Account								
7	Opening Balance	$ 103,340	$ 109,461	$ 113,481	$ 115,402	$ 115,577	$ 115,500	$ 115,500	$ 115,500
8	Net Additions	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000
9	Amortization	- 14,879	- 16,979	- 19,079	- 20,825	- 21,077	- 21,000	- 21,000	- 21,000
10	Ending Balance	$ 109,461	$ 113,481	$ 115,402	$ 115,577	$ 115,500	$ 115,500	$ 115,500	$ 115,500
11									
12	EEC Deferral Mid-Year	$ 106,401	$ 111,471	$ 114,442	$ 115,489	$ 115,538	$ 115,500	$ 115,500	$ 115,500
13									
14	Change in Rate Base	$ 7,171	$ 5,071	$ 2,971	$ 1,048	$ 49	-$ 38	$ -	$ -
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	$ 3,459	$ 3,266	$ 3,073	$ 2,424	$ 341	-$ 106	$ -	$ -

Attachment 51.1

TERASEN GAS INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Expenditure	$ 28,000	$ 28,000	$ 28,000	$ 28,000	$ 28,000	$ 28,000	$ 28,000	$ 28,000
2	Income Tax Offset	- 7,000	- 7,000	- 7,000	- 7,000	- 7,000	- 7,000	- 7,000	- 7,000
3	Net Additions	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000
4	Amortization 10 Years	$ 2,100	$ 2,100	$ 2,100	$ 2,100	$ 2,100	$ 2,100	$ 2,100	$ 2,100
5									
6	EEC Deferral Account								
7	Opening Balance	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500
8	Net Additions	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000
9	Amortization	- 21,000	- 21,000	- 21,000	- 21,000	- 21,000	- 21,000	- 21,000	- 21,000
10	Ending Balance	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500
11									
12	EEC Deferral Mid-Year	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500	$ 115,500
13									
14	Change in Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Attachment 51.1

TERASEN GAS INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1				2011						
2	Rate Impact Based on 2011 Margin & Volume			Margin at Revised Rates	Volume TJ					
3	Residential			$ 331,183	68,578.9	$ 0.040	$ 0.038	$ 0.036	$ 0.034	$ 0.033
4	Small Commercial			88,744	24,603.1	$ 0.030	$ 0.028	$ 0.027	$ 0.026	$ 0.024
5	Large Comercial - Sales			47,896	17,168.5	$ 0.023	$ 0.022	$ 0.021	$ 0.020	$ 0.019
6	Seasonal Service			265	184.6	$ 0.012	$ 0.011	$ 0.011	$ 0.010	$ 0.010
7	General Firm Service - Sales			7,380	3,184.3	$ 0.019	$ 0.018	$ 0.017	$ 0.016	$ 0.016
8	General Interruptible Service - Sales			47	22.7	$ 0.017	$ 0.016	$ 0.015	$ 0.015	$ 0.014
9	NGV			403	103.8	$ 0.032	$ 0.030	$ 0.029	$ 0.028	$ 0.026
10	Large Firm Transportation Service			5,224	8,103.2	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.004
11	Large Interuptible T-Service			9,710	11,080.5	$ 0.007	$ 0.007	$ 0.007	$ 0.006	$ 0.006
12	Large Commercial T-Service			17,607	6,177.2	$ 0.024	$ 0.022	$ 0.021	$ 0.020	$ 0.019
13	General Firm T-Service			25,476	12,944.1	$ 0.016	$ 0.015	$ 0.015	$ 0.014	$ 0.013
14	General Interruptible T-Service			7,067	5,587.4	$ 0.010	$ 0.010	$ 0.009	$ 0.009	$ 0.009
15										
16	Total Non-Bypass Sales & T-Service			$ 541,002	157,738.3					

Attachment 51.1

TERASEN GAS INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	$ 0.031	$ 0.029	$ 0.027	$ 0.022	$ 0.003	-$ 0.001	$ -	$ -
4	Small Commercial	$ 0.023	$ 0.022	$ 0.020	$ 0.016	$ 0.002	-$ 0.001	$ -	$ -
5	Large Comercial - Sales	$ 0.018	$ 0.017	$ 0.016	$ 0.012	$ 0.002	-$ 0.001	$ -	$ -
6	Seasonal Service	$ 0.009	$ 0.009	$ 0.008	$ 0.006	$ 0.001	-$ 0.000	$ -	$ -
7	General Firm Service - Sales	$ 0.015	$ 0.014	$ 0.013	$ 0.010	$ 0.001	-$ 0.000	$ -	$ -
8	General Interruptible Service - Sales	$ 0.013	$ 0.013	$ 0.012	$ 0.009	$ 0.001	-$ 0.000	$ -	$ -
9	NGV	$ 0.025	$ 0.023	$ 0.022	$ 0.017	$ 0.002	-$ 0.001	$ -	$ -
10	Large Firm Transportation Service	$ 0.004	$ 0.004	$ 0.004	$ 0.003	$ 0.000	-$ 0.000	$ -	$ -
11	Large Interuptible T-Service	$ 0.006	$ 0.005	$ 0.005	$ 0.004	$ 0.001	-$ 0.000	$ -	$ -
12	Large Commercial T-Service	$ 0.018	$ 0.017	$ 0.016	$ 0.013	$ 0.002	-$ 0.001	$ -	$ -
13	General Firm T-Service	$ 0.013	$ 0.012	$ 0.011	$ 0.009	$ 0.001	-$ 0.000	$ -	$ -
14	General Interruptible T-Service	$ 0.008	$ 0.008	$ 0.007	$ 0.006	$ 0.001	-$ 0.000	$ -	$ -
15									
16	Total Non-Bypass Sales & T-Service								

TERASEN GAS INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Small Commercial	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Large Comercial - Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Seasonal Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	General Firm Service - Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	General Interruptible Service - Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	NGV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Large Firm Transportation Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Large Interuptible T-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Large Commercial T-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	General Firm T-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	General Interruptible T-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15									
16	Total Non-Bypass Sales & T-Service								

Attachment 51.1

TERASEN GAS INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1	EEC Deferral Impact on Cost of Service									
2	Amortization Expense				$ 2,202	$ 4,379	$ 6,479	$ 8,579	$ 10,679	$ 12,779
3	Income Tax Expense				1,225	2,087	2,985	3,855	4,699	5,517
4	Earned Return				2,493	3,928	5,162	6,230	7,131	7,866
5	Total Impact on Cost of Service				$ 5,921	$ 10,395	$ 14,626	$ 18,665	$ 22,510	$ 26,162
6										
7	Change in Total Cost of Service					$ 4,474	$ 4,232	$ 4,038	$ 3,845	$ 3,652
8										
9	Income Tax Expense									
10	Earned Return				$ 2,493	$ 3,928	$ 5,162	$ 6,230	$ 7,131	$ 7,866
11	Less Utility Interest Expense				- 1,298	- 2,045	- 2,688	- 3,243	- 3,713	- 4,095
12	Add Amortization Expense				2,202	4,379	6,479	8,579	10,679	12,779
13	Taxable Income After Tax				$ 3,398	$ 6,262	$ 8,954	$ 11,566	$ 14,098	$ 16,550
14										
15	Taxable Income				$ 4,623	$ 8,350	$ 11,939	$ 15,421	$ 18,797	$ 22,067
16	Tax Rate	31.00%	30.00%	28.50%	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense				$ 1,225	$ 2,087	$ 2,985	$ 3,855	$ 4,699	$ 5,517
18										
19	Capital Structure & Embedded Cost									
20	% of Capital Structure									
21	Short Term Debt				1.63%					
22	Long Term Debt				58.37%					
23	Common Equity				40.00%					
24	Total				100.00%					
25										
26	Embedded Cost									
27	Short Term Debt				4.50%					
28	Long Term Debt				6.95%					
29	Common Equity				9.50%					
30										
31	Return on Rate Base				7.93%					
32	Cost of Debt (Before Tax)				4.13%					

Attachment 51.1

TERASEN GAS INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 14,879	$ 16,979	$ 19,079	$ 20,825	$ 21,077	$ 21,000	$ 21,000	$ 21,000
3	Income Tax Expense	6,308	7,072	7,809	8,405	8,489	8,463	8,463	8,463
4	Earned Return	8,435	8,836	9,072	9,155	9,159	9,156	9,156	9,156
5	Total Impact on Cost of Service	$ 29,622	$ 32,888	$ 35,961	$ 38,384	$ 38,725	$ 38,619	$ 38,619	$ 38,619
6									
7	Change in Total Cost of Service	$ 3,459	$ 3,266	$ 3,073	$ 2,424	$ 341	-$ 106	$ -	$ -
8									
9	Income Tax Expense								
10	Earned Return	$ 8,435	$ 8,836	$ 9,072	$ 9,155	$ 9,159	$ 9,156	$ 9,156	$ 9,156
11	Less Utility Interest Expense	- 4,391	- 4,601	- 4,723	- 4,766	- 4,768	- 4,767	- 4,767	- 4,767
12	Add Amortization Expense	14,879	16,979	19,079	20,825	21,077	21,000	21,000	21,000
13	Taxable Income After Tax	$ 18,923	$ 21,215	$ 23,428	$ 25,214	$ 25,467	$ 25,389	$ 25,389	$ 25,389
14									
15	Taxable Income	$ 25,230	$ 28,287	$ 31,238	$ 33,618	$ 33,957	$ 33,852	$ 33,852	$ 33,852
16	Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense	$ 6,308	$ 7,072	$ 7,809	$ 8,405	$ 8,489	$ 8,463	$ 8,463	$ 8,463
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

TERASEN GAS INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000
3	Income Tax Expense	8,463	8,463	8,463	8,463	8,463	8,463	8,463	8,463
4	Earned Return	9,156	9,156	9,156	9,156	9,156	9,156	9,156	9,156
5	Total Impact on Cost of Service	$ 38,619	$ 38,619	$ 38,619	$ 38,619	$ 38,619	$ 38,619	$ 38,619	$ 38,619
6									
7	Change in Total Cost of Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8									
9	Income Tax Expense								
10	Earned Return	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156
11	Less Utility Interest Expense	- 4,767	- 4,767	- 4,767	- 4,767	- 4,767	- 4,767	- 4,767	- 4,767
12	Add Amortization Expense	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000
13	Taxable Income After Tax	$ 25,389	$ 25,389	$ 25,389	$ 25,389	$ 25,389	$ 25,389	$ 25,389	$ 25,389
14									
15	Taxable Income	$ 33,852	$ 33,852	$ 33,852	$ 33,852	$ 33,852	$ 33,852	$ 33,852	$ 33,852
16	Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense	$ 8,463	$ 8,463	$ 8,463	$ 8,463	$ 8,463	$ 8,463	$ 8,463	$ 8,463
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

TERASEN GAS INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1	EEC Expenditure	$ 654	$ 3,966	$ 25,845	$ 29,619	$ 64,000	$ 64,000	$ 64,000	$ 64,000	$ 64,000
2	Income Tax Offset	- 203	- 1,190	- 7,366	- 7,849	- 16,000	- 16,000	- 16,000	- 16,000	- 16,000
3	Net Additions	$ 451	$ 2,776	$ 18,479	$ 21,770	$ 48,000	$ 48,000	$ 48,000	$ 48,000	$ 48,000
4	Amortization 10 Years	$ 45	$ 278	$ 1,848	$ 2,177	$ 4,800	$ 4,800	$ 4,800	$ 4,800	$ 4,800
5										
6	EEC Deferral Account									
7	Opening Balance	$ 1,526	$ 1,205	$ 3,545	$ 21,670	$ 41,238	$ 84,858	$ 123,679	$ 157,699	$ 186,920
8	Net Additions	451	2,776	18,479	21,770	48,000	48,000	48,000	48,000	48,000
9	Amortization	- 772	- 436	- 355	- 2,202	- 4,379	- 9,179	- 13,979	- 18,779	- 23,579
10	Ending Balance	$ 1,205	$ 3,545	$ 21,670	$ 41,238	$ 84,858	$ 123,679	$ 157,699	$ 186,920	$ 211,340
11										
12	EEC Deferral Mid-Year	$ 1,366	$ 2,375	$ 12,608	$ 31,454	$ 63,048	$ 104,268	$ 140,689	$ 172,309	$ 199,130
13										
14	Change in Rate Base					$ 31,594	$ 41,221	$ 36,421	$ 31,621	$ 26,821
15										
16	EEC Deferral Impact on Non-Bypass Rates									
17	Change in Cost of Service					$ 5,715	$ 10,190	$ 9,748	$ 9,307	$ 8,866

TERASEN GAS INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1	EEC Expenditure	$ 64,000	$ 64,000	$ 64,000	$ 64,000	$ 64,000	$ 60,000	$ 56,000	$ 52,000
2	Income Tax Offset	- 16,000	- 16,000	- 16,000	- 16,000	- 16,000	- 15,000	- 14,000	- 13,000
3	Net Additions	$ 48,000	$ 48,000	$ 48,000	$ 48,000	$ 48,000	$ 45,000	$ 42,000	$ 39,000
4	Amortization 10 Years	$ 4,800	$ 4,800	$ 4,800	$ 4,800	$ 4,800	$ 4,500	$ 4,200	$ 3,900
5									
6	EEC Deferral Account								
7	Opening Balance	$ 211,340	$ 230,961	$ 245,781	$ 255,802	$ 261,377	$ 264,000	$ 261,000	$ 255,300
8	Net Additions	48,000	48,000	48,000	48,000	48,000	45,000	42,000	39,000
9	Amortization	- 28,379	- 33,179	- 37,979	- 42,425	- 45,377	- 48,000	- 47,700	- 47,100
10	Ending Balance	$ 230,961	$ 245,781	$ 255,802	$ 261,377	$ 264,000	$ 261,000	$ 255,300	$ 247,200
11									
12	EEC Deferral Mid-Year	$ 221,151	$ 238,371	$ 250,792	$ 258,589	$ 262,688	$ 262,500	$ 258,150	$ 251,250
13									
14	Change in Rate Base	$ 22,021	$ 17,221	$ 12,421	$ 7,798	$ 4,099	-$ 188	-$ 4,350	-$ 6,900
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	$ 8,425	$ 7,983	$ 7,542	$ 6,644	$ 4,313	$ 3,480	-$ 800	-$ 1,434

TERASEN GAS INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Expenditure	$ 48,000	$ 44,000	$ 40,000	$ 36,000	$ 32,000	$ 28,000	$ 24,000	$ 20,000
2	Income Tax Offset	- 12,000	- 11,000	- 10,000	- 9,000	- 8,000	- 7,000	- 6,000	- 5,000
3	Net Additions	$ 36,000	$ 33,000	$ 30,000	$ 27,000	$ 24,000	$ 21,000	$ 18,000	$ 15,000
4	Amortization 10 Years	$ 3,600	$ 3,300	$ 3,000	$ 2,700	$ 2,400	$ 2,100	$ 1,800	$ 1,500
5									
6	EEC Deferral Account								
7	Opening Balance	$ 247,200	$ 237,000	$ 225,000	$ 211,500	$ 196,800	$ 181,200	$ 165,000	$ 148,500
8	Net Additions	36,000	33,000	30,000	27,000	24,000	21,000	18,000	15,000
9	Amortization	- 46,200	- 45,000	- 43,500	- 41,700	- 39,600	- 37,200	- 34,500	- 31,500
10	Ending Balance	$ 237,000	$ 225,000	$ 211,500	$ 196,800	$ 181,200	$ 165,000	$ 148,500	$ 132,000
11									
12	EEC Deferral Mid-Year	$ 242,100	$ 231,000	$ 218,250	$ 204,150	$ 189,000	$ 173,100	$ 156,750	$ 140,250
13									
14	Change in Rate Base	-$ 9,150	-$ 11,100	-$ 12,750	-$ 14,100	-$ 15,150	-$ 15,900	-$ 16,350	-$ 16,500
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	-$ 2,041	-$ 2,621	-$ 3,172	-$ 3,696	-$ 4,193	-$ 4,662	-$ 5,103	-$ 5,517

TERASEN GAS INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1				2011						
2	Rate Impact Based on 2011 Margin & Volume			Margin at Revised Rates	Volume TJ					
3	Residential			$ 331,183	68,578.9	$ 0.051	$ 0.091	$ 0.087	$ 0.083	$ 0.079
4	Small Commercial			88,744	24,603.1	$ 0.038	$ 0.068	$ 0.065	$ 0.062	$ 0.059
5	Large Comercial - Sales			47,896	17,168.5	$ 0.029	$ 0.053	$ 0.050	$ 0.048	$ 0.046
6	Seasonal Service			265	184.6	$ 0.015	$ 0.027	$ 0.026	$ 0.025	$ 0.024
7	General Firm Service - Sales			7,380	3,184.3	$ 0.024	$ 0.044	$ 0.042	$ 0.040	$ 0.038
8	General Interruptible Service - Sales			47	22.7	$ 0.022	$ 0.039	$ 0.037	$ 0.036	$ 0.034
9	NGV			403	103.8	$ 0.041	$ 0.073	$ 0.070	$ 0.067	$ 0.064
10	Large Firm Transportation Service			5,224	8,103.2	$ 0.007	$ 0.012	$ 0.012	$ 0.011	$ 0.011
11	Large Interuptible T-Service			9,710	11,080.5	$ 0.009	$ 0.017	$ 0.016	$ 0.015	$ 0.014
12	Large Commercial T-Service			17,607	6,177.2	$ 0.030	$ 0.054	$ 0.051	$ 0.049	$ 0.047
13	General Firm T-Service			25,476	12,944.1	$ 0.021	$ 0.037	$ 0.035	$ 0.034	$ 0.032
14	General Interruptible T-Service			7,067	5,587.4	$ 0.013	$ 0.024	$ 0.023	$ 0.022	$ 0.021
15										
16	Total Non-Bypass Sales & T-Service			$ 541,002	157,738.3					

Attachment 51.1

TERASEN GAS INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	$ 0.075	$ 0.071	$ 0.067	$ 0.059	$ 0.038	$ 0.031	-$ 0.007	-$ 0.013
4	Small Commercial	$ 0.056	$ 0.053	$ 0.050	$ 0.044	$ 0.029	$ 0.023	-$ 0.005	-$ 0.010
5	Large Comercial - Sales	$ 0.043	$ 0.041	$ 0.039	$ 0.034	$ 0.022	$ 0.018	-$ 0.004	-$ 0.007
6	Seasonal Service	$ 0.022	$ 0.021	$ 0.020	$ 0.018	$ 0.011	$ 0.009	-$ 0.002	-$ 0.004
7	General Firm Service - Sales	$ 0.036	$ 0.034	$ 0.032	$ 0.028	$ 0.018	$ 0.015	-$ 0.003	-$ 0.006
8	General Interruptible Service - Sales	$ 0.032	$ 0.031	$ 0.029	$ 0.025	$ 0.017	$ 0.013	-$ 0.003	-$ 0.005
9	NGV	$ 0.060	$ 0.057	$ 0.054	$ 0.048	$ 0.031	$ 0.025	-$ 0.006	-$ 0.010
10	Large Firm Transportation Service	$ 0.010	$ 0.010	$ 0.009	$ 0.008	$ 0.005	$ 0.004	-$ 0.001	-$ 0.002
11	Large Interuptible T-Service	$ 0.014	$ 0.013	$ 0.012	$ 0.011	$ 0.007	$ 0.006	-$ 0.001	-$ 0.002
12	Large Commercial T-Service	$ 0.044	$ 0.042	$ 0.040	$ 0.035	$ 0.023	$ 0.018	-$ 0.004	-$ 0.008
13	General Firm T-Service	$ 0.031	$ 0.029	$ 0.027	$ 0.024	$ 0.016	$ 0.013	-$ 0.003	-$ 0.005
14	General Interruptible T-Service	$ 0.020	$ 0.019	$ 0.018	$ 0.016	$ 0.010	$ 0.008	-$ 0.002	-$ 0.003
15									
16	Total Non-Bypass Sales & T-Service								

TERASEN GAS INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	-$ 0.018	-$ 0.023	-$ 0.028	-$ 0.033	-$ 0.037	-$ 0.042	-$ 0.046	-$ 0.049
4	Small Commercial	-$ 0.014	-$ 0.017	-$ 0.021	-$ 0.025	-$ 0.028	-$ 0.031	-$ 0.034	-$ 0.037
5	Large Comercial - Sales	-$ 0.011	-$ 0.014	-$ 0.016	-$ 0.019	-$ 0.022	-$ 0.024	-$ 0.026	-$ 0.028
6	Seasonal Service	-$ 0.005	-$ 0.007	-$ 0.008	-$ 0.010	-$ 0.011	-$ 0.012	-$ 0.014	-$ 0.015
7	General Firm Service - Sales	-$ 0.009	-$ 0.011	-$ 0.014	-$ 0.016	-$ 0.018	-$ 0.020	-$ 0.022	-$ 0.024
8	General Interruptible Service - Sales	-$ 0.008	-$ 0.010	-$ 0.012	-$ 0.014	-$ 0.016	-$ 0.018	-$ 0.020	-$ 0.021
9	NGV	-$ 0.015	-$ 0.019	-$ 0.023	-$ 0.027	-$ 0.030	-$ 0.033	-$ 0.037	-$ 0.040
10	Large Firm Transportation Service	-$ 0.002	-$ 0.003	-$ 0.004	-$ 0.004	-$ 0.005	-$ 0.006	-$ 0.006	-$ 0.007
11	Large Interuptible T-Service	-$ 0.003	-$ 0.004	-$ 0.005	-$ 0.006	-$ 0.007	-$ 0.008	-$ 0.008	-$ 0.009
12	Large Commercial T-Service	-$ 0.011	-$ 0.014	-$ 0.017	-$ 0.019	-$ 0.022	-$ 0.025	-$ 0.027	-$ 0.029
13	General Firm T-Service	-$ 0.007	-$ 0.010	-$ 0.012	-$ 0.013	-$ 0.015	-$ 0.017	-$ 0.019	-$ 0.020
14	General Interruptible T-Service	-$ 0.005	-$ 0.006	-$ 0.007	-$ 0.009	-$ 0.010	-$ 0.011	-$ 0.012	-$ 0.013
15									
16	Total Non-Bypass Sales & T-Service								

Attachment 51.1

TERASEN GAS INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1	EEC Deferral Impact on Cost of Service									
2	Amortization Expense				$ 2,202	$ 4,379	$ 9,179	$ 13,979	$ 18,779	$ 23,579
3	Income Tax Expense				1,225	2,258	4,381	6,442	8,442	10,382
4	Earned Return				2,493	4,998	8,266	11,153	13,659	15,785
5	Total Impact on Cost of Service				$ 5,921	$ 11,636	$ 21,826	$ 31,574	$ 40,881	$ 49,747
6										
7	Change in Total Cost of Service					$ 5,715	$ 10,190	$ 9,748	$ 9,307	$ 8,866
8										
9	Income Tax Expense									
10	Earned Return				$ 2,493	$ 4,998	$ 8,266	$ 11,153	$ 13,659	$ 15,785
11	Less Utility Interest Expense				- 1,298	- 2,602	- 4,303	- 5,806	- 7,111	- 8,218
12	Add Amortization Expense				2,202	4,379	9,179	13,979	18,779	23,579
13	Taxable Income After Tax				$ 3,398	$ 6,775	$ 13,142	$ 19,326	$ 25,327	$ 31,146
14										
15	Taxable Income				$ 4,623	$ 9,034	$ 17,522	$ 25,768	$ 33,770	$ 41,529
16	Tax Rate	31.00%	30.00%	28.50%	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense				$ 1,225	$ 2,258	$ 4,381	$ 6,442	$ 8,442	$ 10,382
18										
19	Capital Structure & Embedded Cost									
20	% of Capital Structure									
21	Short Term Debt				1.63%					
22	Long Term Debt				58.37%					
23	Common Equity				40.00%					
24	Total				100.00%					
25										
26	Embedded Cost									
27	Short Term Debt				4.50%					
28	Long Term Debt				6.95%					
29	Common Equity				9.50%					
30										
31	Return on Rate Base				7.93%					
32	Cost of Debt (Before Tax)				4.13%					

TERASEN GAS INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 28,379	$ 33,179	$ 37,979	$ 42,425	$ 45,377	$ 48,000	$ 47,700	$ 47,100
3	Income Tax Expense	12,261	14,079	15,837	17,417	18,453	19,325	19,170	18,883
4	Earned Return	17,531	18,896	19,881	20,499	20,824	20,809	20,464	19,917
5	Total Impact on Cost of Service	$ 58,171	$ 66,155	$ 73,697	$ 80,341	$ 84,654	$ 88,134	$ 87,334	$ 85,899
6									
7	Change in Total Cost of Service	$ 8,425	$ 7,983	$ 7,542	$ 6,644	$ 4,313	$ 3,480	-$ 800	-$ 1,434
8									
9	Income Tax Expense								
10	Earned Return	$ 17,531	$ 18,896	$ 19,881	$ 20,499	$ 20,824	$ 20,809	$ 20,464	$ 19,917
11	Less Utility Interest Expense	- 9,127	- 9,838	- 10,351	- 10,672	- 10,842	- 10,834	- 10,654	- 10,369
12	Add Amortization Expense	28,379	33,179	37,979	42,425	45,377	48,000	47,700	47,100
13	Taxable Income After Tax	$ 36,783	$ 42,238	$ 47,510	$ 52,251	$ 55,359	$ 57,975	$ 57,510	$ 56,648
14									
15	Taxable Income	$ 49,044	$ 56,317	$ 63,346	$ 69,668	$ 73,812	$ 77,300	$ 76,680	$ 75,530
16	Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense	$ 12,261	$ 14,079	$ 15,837	$ 17,417	$ 18,453	$ 19,325	$ 19,170	$ 18,883
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

Attachment 51.1

TERASEN GAS INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 46,200	$ 45,000	$ 43,500	$ 41,700	$ 39,600	$ 37,200	$ 34,500	$ 31,500
3	Income Tax Expense	18,467	17,926	17,265	16,486	15,594	14,593	13,486	12,277
4	Earned Return	19,192	18,312	17,301	16,183	14,982	13,722	12,426	11,118
5	Total Impact on Cost of Service	$ 83,858	$ 81,238	$ 78,065	$ 74,369	$ 70,176	$ 65,514	$ 60,411	$ 54,894
6									
7	Change in Total Cost of Service	-$ 2,041	-$ 2,621	-$ 3,172	-$ 3,696	-$ 4,193	-$ 4,662	-$ 5,103	-$ 5,517
8									
9	Income Tax Expense								
10	Earned Return	$ 19,192	$ 18,312	$ 17,301	$ 16,183	$ 14,982	$ 13,722	$ 12,426	$ 11,118
11	Less Utility Interest Expense	- 9,992	- 9,534	- 9,007	- 8,426	- 7,800	- 7,144	- 6,469	- 5,788
12	Add Amortization Expense	46,200	45,000	43,500	41,700	39,600	37,200	34,500	31,500
13	Taxable Income After Tax	$ 55,400	$ 53,778	$ 51,794	$ 49,458	$ 46,782	$ 43,778	$ 40,457	$ 36,830
14									
15	Taxable Income	$ 73,866	$ 71,704	$ 69,058	$ 65,944	$ 62,376	$ 58,370	$ 53,942	$ 49,106
16	Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense	$ 18,467	$ 17,926	$ 17,265	$ 16,486	$ 15,594	$ 14,593	$ 13,486	$ 12,277
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1	EEC Expenditure	$ -	133	$ 5,204	$ 5,683	$ 800	$ 800	$ 800	$ 800	$ 800
2	Income Tax Offset	-	-40	-1,483	-1,506	-200	-200	-200	-200	-200
3	Net Additions	$ -	$ 93	$ 3,721	$ 4,177	$ 600	$ 600	$ 600	$ 600	$ 600
4	Amortization 10 Years	$ -	$ 31	$ 372	$ 418	$ 60	$ 60	$ 60	$ 60	$ 60
5										
6	EEC Deferral Account									
7	Opening Balance	$ 195	$ -	$ 93	$ 3,805	$ 7,600	$ 7,401	$ 7,142	$ 6,823	$ 6,444
8	Net Additions	-	93	3,721	4,177	600	600	600	600	600
9	Amortization	-195	-	-9	-381	-799	-859	-919	-979	-1,039
10	Ending Balance	$ -	$ 93	$ 3,805	$ 7,600	$ 7,401	$ 7,142	$ 6,823	$ 6,444	$ 6,005
11										
12	EEC Deferral Mid-Year	$ 98	$ 47	$ 1,949	$ 5,702	$ 7,501	$ 7,272	$ 6,983	$ 6,633	$ 6,224
13										
14	Change in Rate Base					$ 1,798	-$ 229	-$ 289	-$ 349	-$ 409
15										
16	EEC Deferral Impact on Non-Bypass Rates									
17	Change in Cost of Service					$ 701	$ 60	$ 54	$ 49	$ 44

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1	EEC Expenditure	$ 800	$ 800	$ 800	$ 800	$ 800	$ 800	$ 800	$ 800
2	Income Tax Offset	- 200	- 200	- 200	- 200	- 200	- 200	- 200	- 200
3	Net Additions	$ 600	$ 600	$ 600	$ 600	$ 600	$ 600	$ 600	$ 600
4	Amortization 10 Years	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60
5									
6	EEC Deferral Account								
7	Opening Balance	$ 6,005	$ 5,506	$ 4,947	$ 4,327	$ 3,658	$ 3,300	$ 3,300	$ 3,300
8	Net Additions	600	600	600	600	600	600	600	600
9	Amortization	- 1,099	- 1,159	- 1,219	- 1,270	- 958	- 600	- 600	- 600
10	Ending Balance	$ 5,506	$ 4,947	$ 4,327	$ 3,658	$ 3,300	$ 3,300	$ 3,300	$ 3,300
11									
12	EEC Deferral Mid-Year	$ 5,755	$ 5,226	$ 4,637	$ 3,993	$ 3,479	$ 3,300	$ 3,300	$ 3,300
13									
14	Change in Rate Base	-$ 469	-$ 529	-$ 589	-$ 644	-$ 514	-$ 179	$ -	$ -
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	$ 38	$ 33	$ 27	$ 10	-$ 462	-$ 493	$ -	$ -

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Expenditure	$ 800	$ 800	$ 800	$ 800	$ 800	$ 800	$ 800	$ 800
2	Income Tax Offset	- 200	- 200	- 200	- 200	- 200	- 200	- 200	- 200
3	Net Additions	$ 600	$ 600	$ 600	$ 600	$ 600	$ 600	$ 600	$ 600
4	Amortization 10 Years	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60
5									
6	EEC Deferral Account								
7	Opening Balance	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300
8	Net Additions	600	600	600	600	600	600	600	600
9	Amortization	- 600	- 600	- 600	- 600	- 600	- 600	- 600	- 600
10	Ending Balance	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300
11									
12	EEC Deferral Mid-Year	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300	$ 3,300
13									
14	Change in Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1				2011						
2	Rate Impact Based on 2011 Margin & Volume			Margin at Revised Rates	Volume TJ					
3	Residential			$ 40,050	5,015.3	$ 0.059	$ 0.005	$ 0.005	$ 0.004	$ 0.004
4	Apartment General Service			4,602	1,116.6	$ 0.030	$ 0.003	$ 0.002	$ 0.002	$ 0.002
5	Small Commercial Service - 1			4,035	414.4	$ 0.071	$ 0.006	$ 0.006	$ 0.005	$ 0.004
6	Small Commercial Service - 2			4,358	485.2	$ 0.066	$ 0.006	$ 0.005	$ 0.005	$ 0.004
7	Large Commercial Service - 1			7,296	1,334.2	$ 0.040	$ 0.003	$ 0.003	$ 0.003	$ 0.002
8	Large Commercial Service - 2			5,758	1,396.8	$ 0.030	$ 0.003	$ 0.002	$ 0.002	$ 0.002
9	Large Commercial Service - 3			8,473	2,417.2	$ 0.026	$ 0.002	$ 0.002	$ 0.002	$ 0.002
10	Commercial High Load Factor			316	132.4	$ 0.017	$ 0.001	$ 0.001	$ 0.001	$ 0.001
11	Commercial Inverse Load Factor			201	120.5	$ 0.012	$ 0.001	$ 0.001	$ 0.001	$ 0.001
12	BC Hydro			14,894	17,945.0	$ 0.006	$ 0.001	$ 0.000	$ 0.000	$ 0.000
13	Joint Venture			2,776	2,920.0	$ 0.007	$ 0.001	$ 0.001	$ 0.000	$ 0.000
14	TGI - Squamish			443	422.3	$ 0.008	$ 0.001	$ 0.001	$ 0.001	$ 0.000
15	TGW			2,386	729.9					
16	Total Non-Bypass Sales & T-Service			$ 95,591	34,449.8					

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	$ 0.003	$ 0.003	$ 0.002	$ 0.001	-$ 0.039	-$ 0.041	$ -	$ -
4	Apartment General Service	$ 0.002	$ 0.001	$ 0.001	$ 0.000	-$ 0.020	-$ 0.021	$ -	$ -
5	Small Commercial Service - 1	$ 0.004	$ 0.003	$ 0.003	$ 0.001	-$ 0.047	-$ 0.050	$ -	$ -
6	Small Commercial Service - 2	$ 0.004	$ 0.003	$ 0.003	$ 0.001	-$ 0.043	-$ 0.046	$ -	$ -
7	Large Commercial Service - 1	$ 0.002	$ 0.002	$ 0.002	$ 0.001	-$ 0.026	-$ 0.028	$ -	$ -
8	Large Commercial Service - 2	$ 0.002	$ 0.001	$ 0.001	$ 0.000	-$ 0.020	-$ 0.021	$ -	$ -
9	Large Commercial Service - 3	$ 0.001	$ 0.001	$ 0.001	$ 0.000	-$ 0.017	-$ 0.018	$ -	$ -
10	Commercial High Load Factor	$ 0.001	$ 0.001	$ 0.001	$ 0.000	-$ 0.012	-$ 0.012	$ -	$ -
11	Commercial Inverse Load Factor	$ 0.001	$ 0.001	$ 0.000	$ 0.000	-$ 0.008	-$ 0.009	$ -	$ -
12	BC Hydro	$ 0.000	$ 0.000	$ 0.000	$ 0.000	-$ 0.004	-$ 0.004	$ -	$ -
13	Joint Venture	$ 0.000	$ 0.000	$ 0.000	$ 0.000	-$ 0.005	-$ 0.005	$ -	$ -
14	TGI - Squamish	$ 0.000	$ 0.000	$ 0.000	$ 0.000	-$ 0.005	-$ 0.005	$ -	$ -
15	TGW								
16	Total Non-Bypass Sales & T-Service								

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Apartment General Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Small Commercial Service - 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Small Commercial Service - 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Large Commercial Service - 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Large Commercial Service - 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Large Commercial Service - 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Commercial High Load Factor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Commercial Inverse Load Factor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	BC Hydro	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Joint Venture	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TGI - Squamish	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TGW								
16	Total Non-Bypass Sales & T-Service								

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016
						1	2	3	4	5
1	EEC Deferral Impact on Cost of Service									
2	Amortization Expense				$ 381	$ 799	$ 859	$ 919	$ 979	$ 1,039
3	Income Tax Expense				220	366	383	399	415	429
4	Earned Return				432	569	551	530	503	472
5	Total Impact on Cost of Service				$ 1,034	$ 1,734	$ 1,794	$ 1,848	$ 1,897	$ 1,940
6										
7	Change in Total Cost of Service					$ 701	$ 60	$ 54	$ 49	$ 44
8										
9	Income Tax Expense									
10	Earned Return				$ 432	$ 569	$ 551	$ 530	$ 503	$ 472
11	Less Utility Interest Expense				- 204	- 269	- 261	- 250	- 238	- 223
12	Add Amortization Expense				381	799	859	919	979	1,039
13	Taxable Income After Tax				$ 609	$ 1,099	$ 1,150	$ 1,198	$ 1,244	$ 1,288
14										
15	Taxable Income				$ 829	$ 1,465	$ 1,533	$ 1,598	$ 1,659	$ 1,717
16	Tax Rate	31.00%	30.00%	28.50%	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense				$ 220	$ 366	$ 383	$ 399	$ 415	$ 429
18										
19	Capital Structure & Embedded Cost									
20	% of Capital Structure									
21	Short Term Debt				6.40%					
22	Long Term Debt				53.60%					
23	Common Equity				40.00%					
24	Total				100.00%					
25										
26	Embedded Cost									
27	Short Term Debt				4.750%					
28	Long Term Debt				6.119%					
29	Common Equity				10.000%					
30										
31	Return on Rate Base				7.58%					
32	Cost of Debt (Before Tax)				3.58%					

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017	2018	2019	2020	2021	2022	2023	2024
		6	7	8	9	10	11	12	13
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 1,099	$ 1,159	$ 1,219	$ 1,270	$ 958	$ 600	$ 600	$ 600
3	Income Tax Expense	443	456	468	476	366	244	244	244
4	Earned Return	436	396	352	303	264	250	250	250
5	Total Impact on Cost of Service	$ 1,979	$ 2,011	$ 2,039	$ 2,049	$ 1,587	$ 1,094	$ 1,094	$ 1,094
6									
7	Change in Total Cost of Service	$ 38	$ 33	$ 27	$ 10	-$ 462	-$ 493	$ -	$ -
8									
9	Income Tax Expense								
10	Earned Return	$ 436	$ 396	$ 352	$ 303	$ 264	$ 250	$ 250	$ 250
11	Less Utility Interest Expense	- 206	- 187	- 166	- 143	- 125	- 118	- 118	- 118
12	Add Amortization Expense	1,099	1,159	1,219	1,270	958	600	600	600
13	Taxable Income After Tax	$ 1,329	$ 1,368	$ 1,405	$ 1,429	$ 1,097	$ 732	$ 732	$ 732
14									
15	Taxable Income	$ 1,772	$ 1,824	$ 1,873	$ 1,906	$ 1,462	$ 976	$ 976	$ 976
16	Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense	$ 443	$ 456	$ 468	$ 476	$ 366	$ 244	$ 244	$ 244
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION A - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 600	$ 600	$ 600	$ 600	$ 600	$ 600	$ 600	$ 600
3	Income Tax Expense	244	244	244	244	244	244	244	244
4	Earned Return	250	250	250	250	250	250	250	250
5	Total Impact on Cost of Service	$ 1,094	$ 1,094	$ 1,094	$ 1,094	$ 1,094	$ 1,094	$ 1,094	$ 1,094
6									
7	Change in Total Cost of Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8									
9	Income Tax Expense								
10	Earned Return	$ 250	$ 250	$ 250	$ 250	$ 250	$ 250	$ 250	$ 250
11	Less Utility Interest Expense	- 118	- 118	- 118	- 118	- 118	- 118	- 118	- 118
12	Add Amortization Expense	600	600	600	600	600	600	600	600
13	Taxable Income After Tax	$ 732	$ 732	$ 732	$ 732	$ 732	$ 732	$ 732	$ 732
14									
15	Taxable Income	$ 976	$ 976	$ 976	$ 976	$ 976	$ 976	$ 976	$ 976
16	Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense	$ 244	$ 244	$ 244	$ 244	$ 244	$ 244	$ 244	$ 244
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016
						1	2	3	4	5
1	EEC Expenditure	$ -	$ 133	$ 5,204	$ 5,683	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000
2	Income Tax Offset	-	- 40	- 1,483	- 1,506	- 1,750	- 1,750	- 1,750	- 1,750	- 1,750
3	Net Additions	$ -	$ 93	$ 3,721	$ 4,177	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250
4	Amortization 10 Years	$ -	$ 9	$ 372	$ 418	$ 525	$ 525	$ 525	$ 525	$ 525
5										
6	EEC Deferral Account									
7	Opening Balance	$ 195	$ -	$ 93	$ 3,805	$ 7,600	$ 12,051	$ 15,977	$ 19,378	$ 22,254
8	Net Additions	-	93	3,721	4,177	5,250	5,250	5,250	5,250	5,250
9	Amortization	- 195	-	- 9	- 381	- 799	- 1,324	- 1,849	- 2,374	- 2,899
10	Ending Balance	$ -	$ 93	$ 3,805	$ 7,600	$ 12,051	$ 15,977	$ 19,378	$ 22,254	$ 24,605
11										
12	EEC Deferral Mid-Year	$ 98	$ 47	$ 1,949	$ 5,702	$ 9,826	$ 14,014	$ 17,678	$ 20,816	$ 23,429
13										
14	Change in Rate Base					$ 4,123	$ 4,188	$ 3,663	$ 3,138	$ 2,613
15										
16	EEC Deferral Impact on Non-Bypass Rates									
17	Change in Cost of Service					$ 908	$ 1,073	$ 1,027	$ 980	$ 933

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1	EEC Expenditure	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000
2	Income Tax Offset	- 1,750	- 1,750	- 1,750	- 1,750	- 1,750	- 1,750	- 1,750	- 1,750
3	Net Additions	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250
4	Amortization 10 Years	$ 525	$ 525	$ 525	$ 525	$ 525	$ 525	$ 525	$ 525
5									
6	EEC Deferral Account								
7	Opening Balance	$ 24,605	$ 26,431	$ 27,732	$ 28,507	$ 28,768	$ 28,875	$ 28,875	$ 28,875
8	Net Additions	5,250	5,250	5,250	5,250	5,250	5,250	5,250	5,250
9	Amortization	- 3,424	- 3,949	- 4,474	- 4,990	- 5,143	- 5,250	- 5,250	- 5,250
10	Ending Balance	$ 26,431	$ 27,732	$ 28,507	$ 28,768	$ 28,875	$ 28,875	$ 28,875	$ 28,875
11									
12	EEC Deferral Mid-Year	$ 25,518	$ 27,081	$ 28,120	$ 28,638	$ 28,821	$ 28,875	$ 28,875	$ 28,875
13									
14	Change in Rate Base	$ 2,088	$ 1,563	$ 1,038	$ 518	$ 184	$ 54	$ -	$ -
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	$ 886	$ 839	$ 793	$ 734	$ 220	$ 148	$ -	$ -

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Expenditure	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000
2	Income Tax Offset	- 1,750	- 1,750	- 1,750	- 1,750	- 1,750	- 1,750	- 1,750	- 1,750
3	Net Additions	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250
4	Amortization 10 Years	$ 525	$ 525	$ 525	$ 525	$ 525	$ 525	$ 525	$ 525
5									
6	EEC Deferral Account								
7	Opening Balance	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875
8	Net Additions	5,250	5,250	5,250	5,250	5,250	5,250	5,250	5,250
9	Amortization	- 5,250	- 5,250	- 5,250	- 5,250	- 5,250	- 5,250	- 5,250	- 5,250
10	Ending Balance	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875
11									
12	EEC Deferral Mid-Year	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875	$ 28,875
13									
14	Change in Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1				2011						
2	Rate Impact Based on 2011 Margin & Volume			Margin at Revised Rates	Volume TJ					
3	Residential			$ 40,050	5,015.3	$ 0.076	$ 0.090	$ 0.086	$ 0.082	$ 0.078
4	Apartment General Service			4,602	1,116.6	$ 0.039	$ 0.046	$ 0.044	$ 0.042	$ 0.040
5	Small Commercial Service - 1			4,035	414.4	$ 0.093	$ 0.109	$ 0.105	$ 0.100	$ 0.095
6	Small Commercial Service - 2			4,358	485.2	$ 0.085	$ 0.101	$ 0.096	$ 0.092	$ 0.088
7	Large Commercial Service - 1			7,296	1,334.2	$ 0.052	$ 0.061	$ 0.059	$ 0.056	$ 0.053
8	Large Commercial Service - 2			5,758	1,396.8	$ 0.039	$ 0.046	$ 0.044	$ 0.042	$ 0.040
9	Large Commercial Service - 3			8,473	2,417.2	$ 0.033	$ 0.039	$ 0.038	$ 0.036	$ 0.034
10	Commercial High Load Factor			316	132.4	$ 0.023	$ 0.027	$ 0.026	$ 0.024	$ 0.023
11	Commercial Inverse Load Factor			201	120.5	$ 0.016	$ 0.019	$ 0.018	$ 0.017	$ 0.016
12	BC Hydro			14,894	17,945.0	$ 0.008	$ 0.009	$ 0.009	$ 0.009	$ 0.008
13	Joint Venture			2,776	2,920.0	$ 0.009	$ 0.011	$ 0.010	$ 0.010	$ 0.009
14	TGI - Squamish			443	422.3	$ 0.010	$ 0.012	$ 0.011	$ 0.011	$ 0.010
15	TGW			2,386	729.9					
16	Total Non-Bypass Sales & T-Service			$ 95,591	34,449.8					

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	$ 0.074	$ 0.070	$ 0.066	$ 0.061	$ 0.018	$ 0.012	$ -	$ -
4	Apartment General Service	$ 0.038	$ 0.036	$ 0.034	$ 0.032	$ 0.009	$ 0.006	$ -	$ -
5	Small Commercial Service - 1	$ 0.090	$ 0.086	$ 0.081	$ 0.075	$ 0.022	$ 0.015	$ -	$ -
6	Small Commercial Service - 2	$ 0.083	$ 0.079	$ 0.074	$ 0.069	$ 0.021	$ 0.014	$ -	$ -
7	Large Commercial Service - 1	$ 0.051	$ 0.048	$ 0.045	$ 0.042	$ 0.013	$ 0.008	$ -	$ -
8	Large Commercial Service - 2	$ 0.038	$ 0.036	$ 0.034	$ 0.032	$ 0.009	$ 0.006	$ -	$ -
9	Large Commercial Service - 3	$ 0.032	$ 0.031	$ 0.029	$ 0.027	$ 0.008	$ 0.005	$ -	$ -
10	Commercial High Load Factor	$ 0.022	$ 0.021	$ 0.020	$ 0.018	$ 0.005	$ 0.004	$ -	$ -
11	Commercial Inverse Load Factor	$ 0.015	$ 0.015	$ 0.014	$ 0.013	$ 0.004	$ 0.003	$ -	$ -
12	BC Hydro	$ 0.008	$ 0.007	$ 0.007	$ 0.006	$ 0.002	$ 0.001	$ -	$ -
13	Joint Venture	$ 0.009	$ 0.008	$ 0.008	$ 0.007	$ 0.002	$ 0.001	$ -	$ -
14	TGI - Squamish	$ 0.010	$ 0.009	$ 0.009	$ 0.008	$ 0.002	$ 0.002	$ -	$ -
15	TGW								
16	Total Non-Bypass Sales & T-Service								

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Apartment General Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Small Commercial Service - 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Small Commercial Service - 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Large Commercial Service - 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Large Commercial Service - 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Large Commercial Service - 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Commercial High Load Factor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Commercial Inverse Load Factor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	BC Hydro	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Joint Venture	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TGI - Squamish	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TGW								
16	Total Non-Bypass Sales & T-Service								

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1	EEC Deferral Impact on Cost of Service									
2	Amortization Expense				$ 381	$ 799	$ 1,324	$ 1,849	$ 2,374	$ 2,899
3	Income Tax Expense				220	397	628	852	1,069	1,279
4	Earned Return				432	745	1,063	1,341	1,579	1,777
5	Total Impact on Cost of Service				$ 1,034	$ 1,942	$ 3,015	$ 4,042	$ 5,022	$ 5,955
6										
7	Change in Total Cost of Service					$ 908	$ 1,073	$ 1,027	$ 980	$ 933
8										
9	Income Tax Expense									
10	Earned Return				$ 432	$ 745	$ 1,063	$ 1,341	$ 1,579	$ 1,777
11	Less Utility Interest Expense				- 204	- 352	- 502	- 634	- 746	- 840
12	Add Amortization Expense				381	799	1,324	1,849	2,374	2,899
13	Taxable Income After Tax				$ 609	$ 1,192	$ 1,885	$ 2,556	$ 3,207	$ 3,836
14										
15	Taxable Income				$ 829	$ 1,589	$ 2,513	$ 3,408	$ 4,276	$ 5,115
16	Tax Rate	31.00%	30.00%	28.50%	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense				$ 220	$ 397	$ 628	$ 852	$ 1,069	$ 1,279
18										
19	Capital Structure & Embedded Cost									
20	% of Capital Structure									
21	Short Term Debt				6.40%					
22	Long Term Debt				53.60%					
23	Common Equity				40.00%					
24	Total				100.00%					
25										
26	Embedded Cost									
27	Short Term Debt				4.75%					
28	Long Term Debt				6.12%					
29	Common Equity				10.00%					
30										
31	Return on Rate Base				7.58%					
32	Cost of Debt (Before Tax)				3.58%					

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line		2017	2018	2019	2020	2021	2022	2023	2024
No.	Particulars	6	7	8	9	10	11	12	13
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 3,424	$ 3,949	$ 4,474	$ 4,990	$ 5,143	$ 5,250	$ 5,250	$ 5,250
3	Income Tax Expense	1,482	1,677	1,866	2,045	2,099	2,135	2,135	2,135
4	Earned Return	1,935	2,054	2,133	2,172	2,186	2,190	2,190	2,190
5	Total Impact on Cost of Service	$ 6,841	$ 7,680	$ 8,473	$ 9,207	$ 9,427	$ 9,575	$ 9,575	$ 9,575
6									
7	Change in Total Cost of Service	$ 886	$ 839	$ 793	$ 734	$ 220	$ 148	$ -	$ -
8									
9	Income Tax Expense								
10	Earned Return	$ 1,935	$ 2,054	$ 2,133	$ 2,172	$ 2,186	$ 2,190	$ 2,190	$ 2,190
11	Less Utility Interest Expense	- 915	- 971	- 1,008	- 1,026	- 1,033	- 1,035	- 1,035	- 1,035
12	Add Amortization Expense	3,424	3,949	4,474	4,990	5,143	5,250	5,250	5,250
13	Taxable Income After Tax	$ 4,445	$ 5,032	$ 5,599	$ 6,135	$ 6,296	$ 6,405	$ 6,405	$ 6,405
14									
15	Taxable Income	$ 5,926	$ 6,710	$ 7,465	$ 8,180	$ 8,394	$ 8,540	$ 8,540	$ 8,540
16	Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense	$ 1,482	$ 1,677	$ 1,866	$ 2,045	$ 2,099	$ 2,135	$ 2,135	$ 2,135
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION B - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250
3	Income Tax Expense	2,135	2,135	2,135	2,135	2,135	2,135	2,135	2,135
4	Earned Return	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190
5	Total Impact on Cost of Service	$ 9,575	$ 9,575	$ 9,575	$ 9,575	$ 9,575	$ 9,575	$ 9,575	$ 9,575
6									
7	Change in Total Cost of Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8									
9	Income Tax Expense								
10	Earned Return	$ 2,190	$ 2,190	$ 2,190	$ 2,190	$ 2,190	$ 2,190	$ 2,190	$ 2,190
11	Less Utility Interest Expense	- 1,035	- 1,035	- 1,035	- 1,035	- 1,035	- 1,035	- 1,035	- 1,035
12	Add Amortization Expense	5,250	5,250	5,250	5,250	5,250	5,250	5,250	5,250
13	Taxable Income After Tax	$ 6,405	$ 6,405	$ 6,405	$ 6,405	$ 6,405	$ 6,405	$ 6,405	$ 6,405
14									
15	Taxable Income	$ 8,540	$ 8,540	$ 8,540	$ 8,540	$ 8,540	$ 8,540	$ 8,540	$ 8,540
16	Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense	$ 2,135	$ 2,135	$ 2,135	$ 2,135	$ 2,135	$ 2,135	$ 2,135	$ 2,135
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1	EEC Expenditure	$ -	$ 133	$ 5,204	$ 5,683	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000
2	Income Tax Offset	-	- 40	- 1,483	- 1,506	- 4,000	- 4,000	- 4,000	- 4,000	- 4,000
3	Net Additions	$ -	$ 93	$ 3,721	$ 4,177	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000
4	Amortization 10 Years	$ -	$ 9	$ 372	$ 418	$ 1,200	$ 1,200	$ 1,200	$ 1,200	$ 1,200
5										
6	EEC Deferral Account									
7	Opening Balance	$ 195	$ -	$ 93	$ 3,805	$ 7,600	$ 18,801	$ 28,802	$ 37,603	$ 45,204
8	Net Additions	-	93	3,721	4,177	12,000	12,000	12,000	12,000	12,000
9	Amortization	- 195	-	- 9	- 381	- 799	- 1,999	- 3,199	- 4,399	- 5,599
10	Ending Balance	$ -	$ 93	$ 3,805	$ 7,600	$ 18,801	$ 28,802	$ 37,603	$ 45,204	$ 51,605
11										
12	EEC Deferral Mid-Year	$ 98	$ 47	$ 1,949	$ 5,702	$ 13,201	$ 23,802	$ 33,203	$ 41,403	$ 48,404
13										
14	Change in Rate Base					$ 7,498	$ 10,601	$ 9,401	$ 8,201	$ 7,001
15										
16	EEC Deferral Impact on Non-Bypass Rates									
17	Change in Cost of Service					$ 1,209	$ 2,545	$ 2,438	$ 2,331	$ 2,224

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1	EEC Expenditure	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 15,000	$ 14,000	$ 13,000
2	Income Tax Offset	- 4,000	- 4,000	- 4,000	- 4,000	- 4,000	- 3,750	- 3,500	- 3,250
3	Net Additions	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 11,250	$ 10,500	$ 9,750
4	Amortization 10 Years	$ 1,200	$ 1,200	$ 1,200	$ 1,200	$ 1,200	$ 1,125	$ 1,050	$ 975
5									
6	EEC Deferral Account								
7	Opening Balance	$ 51,605	$ 56,806	$ 60,807	$ 63,607	$ 65,218	$ 66,000	$ 65,250	$ 63,825
8	Net Additions	12,000	12,000	12,000	12,000	12,000	11,250	10,500	9,750
9	Amortization	- 6,799	- 7,999	- 9,199	- 10,390	- 11,218	- 12,000	- 11,925	- 11,775
10	Ending Balance	$ 56,806	$ 60,807	$ 63,607	$ 65,218	$ 66,000	$ 65,250	$ 63,825	$ 61,800
11									
12	EEC Deferral Mid-Year	$ 54,205	$ 58,806	$ 62,207	$ 64,413	$ 65,609	$ 65,625	$ 64,538	$ 62,813
13									
14	Change in Rate Base	$ 5,801	$ 4,601	$ 3,401	$ 2,206	$ 1,196	$ 16	-$ 1,088	-$ 1,725
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	$ 2,117	$ 2,010	$ 1,903	$ 1,784	$ 1,211	$ 1,045	-$ 197	-$ 354

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Expenditure	$ 12,000	$ 11,000	$ 10,000	$ 9,000	$ 8,000	$ 7,000	$ 6,000	$ 5,000
2	Income Tax Offset	- 3,000	- 2,750	- 2,500	- 2,250	- 2,000	- 1,750	- 1,500	- 1,250
3	Net Additions	$ 9,000	$ 8,250	$ 7,500	$ 6,750	$ 6,000	$ 5,250	$ 4,500	$ 3,750
4	Amortization 10 Years	$ 900	$ 825	$ 750	$ 675	$ 600	$ 525	$ 450	$ 375
5									
6	EEC Deferral Account								
7	Opening Balance	$ 61,800	$ 59,250	$ 56,250	$ 52,875	$ 49,200	$ 45,300	$ 41,250	$ 37,125
8	Net Additions	9,000	8,250	7,500	6,750	6,000	5,250	4,500	3,750
9	Amortization	- 11,550	- 11,250	- 10,875	- 10,425	- 9,900	- 9,300	- 8,625	- 7,875
10	Ending Balance	$ 59,250	$ 56,250	$ 52,875	$ 49,200	$ 45,300	$ 41,250	$ 37,125	$ 33,000
11									
12	EEC Deferral Mid-Year	$ 60,525	$ 57,750	$ 54,563	$ 51,038	$ 47,250	$ 43,275	$ 39,188	$ 35,063
13									
14	Change in Rate Base	-$ 2,288	-$ 2,775	-$ 3,188	-$ 3,525	-$ 3,788	-$ 3,975	-$ 4,088	-$ 4,125
15									
16	EEC Deferral Impact on Non-Bypass Rates								
17	Change in Cost of Service	-$ 504	-$ 647	-$ 784	-$ 914	-$ 1,038	-$ 1,154	-$ 1,264	-$ 1,368

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1				2011 Margin at Revised Rates						
2	Rate Impact Based on 2011 Margin & Volume				Volume TJ					
3	Residential			$ 40,050	5,015.3	$ 0.101	$ 0.213	$ 0.204	$ 0.195	$ 0.186
4	Apartment General Service			4,602	1,116.6	$ 0.052	$ 0.110	$ 0.105	$ 0.101	$ 0.096
5	Small Commercial Service - 1			4,035	414.4	$ 0.123	$ 0.259	$ 0.248	$ 0.237	$ 0.227
6	Small Commercial Service - 2			4,358	485.2	$ 0.114	$ 0.239	$ 0.229	$ 0.219	$ 0.209
7	Large Commercial Service - 1			7,296	1,334.2	$ 0.069	$ 0.146	$ 0.139	$ 0.133	$ 0.127
8	Large Commercial Service - 2			5,758	1,396.8	$ 0.052	$ 0.110	$ 0.105	$ 0.101	$ 0.096
9	Large Commercial Service - 3			8,473	2,417.2	$ 0.044	$ 0.093	$ 0.089	$ 0.085	$ 0.082
10	Commercial High Load Factor			316	132.4	$ 0.030	$ 0.064	$ 0.061	$ 0.058	$ 0.055
11	Commercial Inverse Load Factor			201	120.5	$ 0.021	$ 0.044	$ 0.042	$ 0.041	$ 0.039
12	BC Hydro			14,894	17,945.0	$ 0.010	$ 0.022	$ 0.021	$ 0.020	$ 0.019
13	Joint Venture			2,776	2,920.0	$ 0.012	$ 0.025	$ 0.024	$ 0.023	$ 0.022
14	TGI - Squamish			443	422.3	$ 0.013	$ 0.028	$ 0.027	$ 0.026	$ 0.024
15	TGW			2,386	729.9					
16	Total Non-Bypass Sales & T-Service			$ 95,591	34,449.8					

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	$ 0.177	$ 0.168	$ 0.159	$ 0.149	$ 0.101	$ 0.087	-$ 0.016	-$ 0.030
4	Apartment General Service	$ 0.091	$ 0.087	$ 0.082	$ 0.077	$ 0.052	$ 0.045	-$ 0.008	-$ 0.015
5	Small Commercial Service - 1	$ 0.216	$ 0.205	$ 0.194	$ 0.182	$ 0.123	$ 0.106	-$ 0.020	-$ 0.036
6	Small Commercial Service - 2	$ 0.199	$ 0.189	$ 0.179	$ 0.168	$ 0.114	$ 0.098	-$ 0.019	-$ 0.033
7	Large Commercial Service - 1	$ 0.121	$ 0.115	$ 0.109	$ 0.102	$ 0.069	$ 0.060	-$ 0.011	-$ 0.020
8	Large Commercial Service - 2	$ 0.091	$ 0.087	$ 0.082	$ 0.077	$ 0.052	$ 0.045	-$ 0.008	-$ 0.015
9	Large Commercial Service - 3	$ 0.078	$ 0.074	$ 0.070	$ 0.065	$ 0.044	$ 0.038	-$ 0.007	-$ 0.013
10	Commercial High Load Factor	$ 0.053	$ 0.050	$ 0.047	$ 0.045	$ 0.030	$ 0.026	-$ 0.005	-$ 0.009
11	Commercial Inverse Load Factor	$ 0.037	$ 0.035	$ 0.033	$ 0.031	$ 0.021	$ 0.018	-$ 0.003	-$ 0.006
12	BC Hydro	$ 0.018	$ 0.017	$ 0.017	$ 0.015	$ 0.011	$ 0.009	-$ 0.002	-$ 0.003
13	Joint Venture	$ 0.021	$ 0.020	$ 0.019	$ 0.018	$ 0.012	$ 0.010	-$ 0.002	-$ 0.004
14	TGI - Squamish	$ 0.023	$ 0.022	$ 0.021	$ 0.020	$ 0.013	$ 0.011	-$ 0.002	-$ 0.004
15	TGW								
16	Total Non-Bypass Sales & T-Service								

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1									
2	Rate Impact Based on 2011 Margin & Volume								
3	Residential	-$ 0.042	-$ 0.054	-$ 0.066	-$ 0.076	-$ 0.087	-$ 0.096	-$ 0.106	-$ 0.114
4	Apartment General Service	-$ 0.022	-$ 0.028	-$ 0.034	-$ 0.039	-$ 0.045	-$ 0.050	-$ 0.055	-$ 0.059
5	Small Commercial Service - 1	-$ 0.051	-$ 0.066	-$ 0.080	-$ 0.093	-$ 0.106	-$ 0.118	-$ 0.129	-$ 0.139
6	Small Commercial Service - 2	-$ 0.047	-$ 0.061	-$ 0.074	-$ 0.086	-$ 0.098	-$ 0.108	-$ 0.119	-$ 0.129
7	Large Commercial Service - 1	-$ 0.029	-$ 0.037	-$ 0.045	-$ 0.052	-$ 0.059	-$ 0.066	-$ 0.072	-$ 0.078
8	Large Commercial Service - 2	-$ 0.022	-$ 0.028	-$ 0.034	-$ 0.039	-$ 0.045	-$ 0.050	-$ 0.055	-$ 0.059
9	Large Commercial Service - 3	-$ 0.018	-$ 0.024	-$ 0.029	-$ 0.034	-$ 0.038	-$ 0.042	-$ 0.046	-$ 0.050
10	Commercial High Load Factor	-$ 0.013	-$ 0.016	-$ 0.020	-$ 0.023	-$ 0.026	-$ 0.029	-$ 0.032	-$ 0.034
11	Commercial Inverse Load Factor	-$ 0.009	-$ 0.011	-$ 0.014	-$ 0.016	-$ 0.018	-$ 0.020	-$ 0.022	-$ 0.024
12	BC Hydro	-$ 0.004	-$ 0.006	-$ 0.007	-$ 0.008	-$ 0.009	-$ 0.010	-$ 0.011	-$ 0.012
13	Joint Venture	-$ 0.005	-$ 0.006	-$ 0.008	-$ 0.009	-$ 0.010	-$ 0.011	-$ 0.013	-$ 0.014
14	TGI - Squamish	-$ 0.006	-$ 0.007	-$ 0.009	-$ 0.010	-$ 0.011	-$ 0.013	-$ 0.014	-$ 0.015
15	TGW								
16	Total Non-Bypass Sales & T-Service								

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2008	2009	2010	2011	2012 1	2013 2	2014 3	2015 4	2016 5
1	EEC Deferral Impact on Cost of Service									
2	Amortization Expense				$ 381	$ 799	$ 1,999	$ 3,199	$ 4,399	$ 5,599
3	Income Tax Expense				220	442	984	1,509	2,018	2,512
4	Earned Return				432	1,001	1,805	2,518	3,140	3,671
5	Total Impact on Cost of Service				$ 1,034	$ 2,243	$ 4,788	$ 7,226	$ 9,557	$ 11,782
6										
7	Change in Total Cost of Service					$ 1,209	$ 2,545	$ 2,438	$ 2,331	$ 2,224
8										
9	Income Tax Expense									
10	Earned Return				$ 432	$ 1,001	$ 1,805	$ 2,518	$ 3,140	$ 3,671
11	Less Utility Interest Expense				- 204	- 473	- 853	- 1,190	- 1,484	- 1,735
12	Add Amortization Expense				381	799	1,999	3,199	4,399	5,599
13	Taxable Income After Tax				$ 609	$ 1,327	$ 2,951	$ 4,527	$ 6,055	$ 7,535
14										
15	Taxable Income				$ 829	$ 1,769	$ 3,935	$ 6,036	$ 8,074	$ 10,047
16	Tax Rate	31.00%	30.00%	28.50%	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense				$ 220	$ 442	$ 984	$ 1,509	$ 2,018	$ 2,512
18										
19	Capital Structure & Embedded Cost									
20	% of Capital Structure									
21	Short Term Debt				6.40%					
22	Long Term Debt				53.60%					
23	Common Equity				40.00%					
24	Total				100.00%					
25										
26	Embedded Cost									
27	Short Term Debt				4.75%					
28	Long Term Debt				6.12%					
29	Common Equity				10.00%					
30										
31	Return on Rate Base				7.58%					
32	Cost of Debt (Before Tax)				3.58%					

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2017 6	2018 7	2019 8	2020 9	2021 10	2022 11	2023 12	2024 13
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 6,799	$ 7,999	$ 9,199	$ 10,390	$ 11,218	$ 12,000	$ 11,925	$ 11,775
3	Income Tax Expense	2,989	3,450	3,896	4,322	4,614	4,875	4,836	4,763
4	Earned Return	4,111	4,460	4,718	4,885	4,976	4,977	4,894	4,764
5	Total Impact on Cost of Service	$ 13,899	$ 15,909	$ 17,813	$ 19,597	$ 20,807	$ 21,852	$ 21,655	$ 21,301
6									
7	Change in Total Cost of Service	$ 2,117	$ 2,010	$ 1,903	$ 1,784	$ 1,211	$ 1,045	-$ 197	-$ 354
8									
9	Income Tax Expense								
10	Earned Return	$ 4,111	$ 4,460	$ 4,718	$ 4,885	$ 4,976	$ 4,977	$ 4,894	$ 4,764
11	Less Utility Interest Expense	- 1,943	- 2,107	- 2,229	- 2,308	- 2,351	- 2,352	- 2,313	- 2,251
12	Add Amortization Expense	6,799	7,999	9,199	10,390	11,218	12,000	11,925	11,775
13	Taxable Income After Tax	$ 8,967	$ 10,351	$ 11,687	$ 12,966	$ 13,842	$ 14,625	$ 14,507	$ 14,288
14									
15	Taxable Income	$ 11,956	$ 13,802	$ 15,583	$ 17,288	$ 18,456	$ 19,500	$ 19,342	$ 19,050
16	Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense	$ 2,989	$ 3,450	$ 3,896	$ 4,322	$ 4,614	$ 4,875	$ 4,836	$ 4,763
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

Attachment 51.1

TERASEN GAS (VANCOUVER ISLAND) INC.
OPTION C - EEC EXPENDITURE ANALYSIS

Line No.	Particulars	2025 14	2026 15	2027 16	2028 17	2029 18	2030 19	2031 20	2032 21
1	EEC Deferral Impact on Cost of Service								
2	Amortization Expense	$ 11,550	$ 11,250	$ 10,875	$ 10,425	$ 9,900	$ 9,300	$ 8,625	$ 7,875
3	Income Tax Expense	4,657	4,520	4,353	4,156	3,930	3,677	3,398	3,093
4	Earned Return	4,590	4,380	4,138	3,871	3,583	3,282	2,972	2,659
5	Total Impact on Cost of Service	$ 20,797	$ 20,150	$ 19,365	$ 18,451	$ 17,413	$ 16,259	$ 14,994	$ 13,627
6									
7	Change in Total Cost of Service	-$ 504	-$ 647	-$ 784	-$ 914	-$ 1,038	-$ 1,154	-$ 1,264	-$ 1,368
8									
9	Income Tax Expense								
10	Earned Return	$ 4,590	$ 4,380	$ 4,138	$ 3,871	$ 3,583	$ 3,282	$ 2,972	$ 2,659
11	Less Utility Interest Expense	- 2,169	- 2,070	- 1,955	- 1,829	- 1,693	- 1,551	- 1,404	- 1,257
12	Add Amortization Expense	11,550	11,250	10,875	10,425	9,900	9,300	8,625	7,875
13	Taxable Income After Tax	$ 13,971	$ 13,560	$ 13,058	$ 12,467	$ 11,790	$ 11,031	$ 10,193	$ 9,278
14									
15	Taxable Income	$ 18,628	$ 18,080	$ 17,410	$ 16,622	$ 15,720	$ 14,708	$ 13,590	$ 12,370
16	Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
17	Income Tax Expense	$ 4,657	$ 4,520	$ 4,353	$ 4,156	$ 3,930	$ 3,677	$ 3,398	$ 3,093
18									
19	Capital Structure & Embedded Cost								
20	% of Capital Structure								
21	Short Term Debt								
22	Long Term Debt								
23	Common Equity								
24	Total								
25									
26	Embedded Cost								
27	Short Term Debt								
28	Long Term Debt								
29	Common Equity								
30									
31	Return on Rate Base								
32	Cost of Debt (Before Tax)								

Attachment 53.3

Coastal Region

YE Accounts by Rate Class

Core	2010	2011	2012	2013	2014	2015	2016	2017	2018
Rate 1	528,119	531,685	534,987	538,473	541,959	545,472	549,001	552,082	555,041
Rate 2	53,672	54,110	54,558	55,021	55,484	55,954	56,430	56,829	57,207
Rate 3	4,104	4,173	4,242	4,305	4,376	4,447	4,518	4,582	4,641
Rate 4	33	33	33	33	33	33	33	33	33
Rate 5	221	221	221	221	221	221	221	221	221
Rate 6	26	26	26	26	26	26	26	26	26
Total Coastal Region-Core	586,175	590,248	594,067	598,079	602,099	606,153	610,229	613,773	617,169
Transportation & IT Customers									
Rate 7	1	1	1	1	1	1	1	1	1
Rate 22	22	22	22	22	22	22	22	22	22
Rate 23	1,116	1,121	1,126	1,131	1,136	1,141	1,146	1,148	1,149
Rate 25	488	488	488	488	488	488	488	488	488
Rate 27	81	81	81	81	81	81	81	81	81
Total -Transportation & IT	1,708	1,713	1,718	1,723	1,728	1,733	1,738	1,740	1,741
Total Coastal Region	587,883	591,961	595,785	599,802	603,827	607,886	611,967	615,513	618,910

Percent change in YE Accounts

Core	2010	2011	2012	2013	2014	2015	2016	2017	2018
Rate 1		0.68%	0.62%	0.65%	0.65%	0.65%	0.65%	0.56%	0.54%
Rate 2		0.82%	0.83%	0.85%	0.84%	0.85%	0.85%	0.71%	0.67%
Rate 3		1.68%	1.65%	1.49%	1.65%	1.62%	1.60%	1.42%	1.29%
Rate 4		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 5		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 6		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transportation & IT Customers									
Rate 7		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 22		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 23		0.45%	0.45%	0.44%	0.44%	0.44%	0.44%	0.17%	0.09%
Rate 25		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 27		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Core	2010	2011	2012	2013	2014	2015	2016	2017	2018
Rate 1	98	97	95	94	93	92	91	90	90
Rate 2	335	334	334	333	332	332	331	330	330
Rate 3	3,276	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243
Rate 4	2,303	2,303	2,303	2,303	2,303	2,303	2,303	2,303	2,303
Rate 5	10,630	10,518	10,407	10,297	10,188	10,092	9,997	9,903	9,809
Rate 6	2,615	2,615	2,615	2,615	2,615	2,615	2,615	2,615	2,615
Transportation & IT Customers									
Rate 7	2,850	2,821	2,793	2,765	2,738	2,710	2,683	2,656	2,630
Rate 22	628,051	618,816	609,617	600,454	591,325	587,871	584,451	581,066	577,714
Rate 23	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865
Rate 25	17,904	17,672	17,440	17,210	16,981	16,866	16,752	16,640	16,528
Rate 27	59,348	58,737	58,128	57,523	56,920	56,651	56,385	56,122	55,861

Annual Demand by Rate Class(TJ)

Core	2010	2011	2012	2013	2014	2015	2016	2017	2018
Rate 1	51,935	51,403	50,929	50,560	50,280	50,093	49,999	49,960	50,006
Rate 2	17,980	18,073	18,222	18,322	18,421	18,577	18,678	18,754	18,878
Rate 3	13,445	13,533	13,757	13,961	14,191	14,422	14,652	14,859	15,051
Rate 4	76	76	76	76	76	76	76	76	76
Rate 5	2,349	2,325	2,300	2,276	2,252	2,230	2,209	2,188	2,168
Rate 6	68	68	68	68	68	68	68	68	68
Total Coastal Region-Core	85,854	85,477	85,352	85,263	85,288	85,466	85,683	85,905	86,246
Transportation & IT Customers									
Rate 7	3	3	3	3	3	3	3	3	3
Rate 22	13,817	13,614	13,412	13,210	13,009	12,933	12,858	12,783	12,710
Rate 23	5,429	5,454	5,478	5,502	5,527	5,551	5,575	5,585	5,590
Rate 25	8,737	8,624	8,511	8,399	8,287	8,231	8,175	8,120	8,066
Rate 27	4,807	4,758	4,708	4,659	4,611	4,589	4,567	4,546	4,525
Total Coastal Region-Transportation & IT	32,794	32,452	32,112	31,773	31,436	31,306	31,178	31,037	30,893
Total Coastal Region	**118,647**	**117,929**	**117,464**	**117,036**	**116,724**	**116,772**	**116,861**	**116,942**	**117,139**

Design Day Demand(TJ/Day)

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Core Customers	925.6	933.1	940.4	947.8	955.4	963.1	970.8	977.6	984.0

Coastal Region
YE Accounts by Rate Class

Core	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate 1	557,952	560,779	563,553	566,249	568,930	571,518	574,086	576,607	579,101
Rate 2	57,574	57,929	58,277	58,608	58,939	59,251	59,563	59,871	60,175
Rate 3	4,699	4,756	4,813	4,867	4,921	4,975	5,029	5,082	5,134
Rate 4	33	33	33	33	33	33	33	33	33
Rate 5	221	221	221	221	221	221	221	221	221
Rate 6	26	26	26	26	26	26	26	26	26
Total Coastal Region-Core	620,505	623,744	626,923	630,004	633,070	636,024	638,958	641,840	644,690
Transportation & IT Customers									
Rate 7	1	1	1	1	1	1	1	1	1
Rate 22	22	22	22	22	22	22	22	22	22
Rate 23	1,150	1,151	1,152	1,153	1,154	1,155	1,156	1,157	1,158
Rate 25	488	488	488	488	488	488	488	488	488
Rate 27	81	81	81	81	81	81	81	81	81
Total -Transportation & IT	1,742	1,743	1,744	1,745	1,746	1,747	1,748	1,749	1,750
Total Coastal Region	622,247	625,487	628,667	631,749	634,816	637,771	640,706	643,589	646,440

Percent change in YE Accounts

Core	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate 1	0.52%	0.51%	0.49%	0.48%	0.47%	0.45%	0.45%	0.44%	0.43%
Rate 2	0.64%	0.62%	0.60%	0.57%	0.56%	0.53%	0.53%	0.52%	0.51%
Rate 3	1.25%	1.21%	1.20%	1.12%	1.11%	1.10%	1.09%	1.05%	1.02%
Rate 4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transportation & IT Customers									
Rate 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 22	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 23	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%
Rate 25	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 27	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Core	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate 1	90	89	89	88	88	88	87	87	86
Rate 2	329	328	328	327	326	326	325	324	324
Rate 3	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243
Rate 4	2,303	2,303	2,303	2,303	2,303	2,303	2,303	2,303	2,303
Rate 5	9,717	9,625	9,535	9,445	9,356	9,268	9,181	9,095	9,010
Rate 6	2,615	2,615	2,615	2,615	2,615	2,615	2,615	2,615	2,615
Transportation & IT Customers									
Rate 7	2,603	2,577	2,552	2,526	2,501	2,476	2,451	2,426	2,402
Rate 22	574,396	571,110	567,858	564,638	561,451	558,295	555,171	552,078	549,016
Rate 23	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865
Rate 25	16,418	16,308	16,200	16,093	15,987	15,882	15,778	15,675	15,573
Rate 27	55,603	55,347	55,094	54,843	54,595	54,349	54,106	53,866	53,627

Annual Demand by Rate Class(TJ)

Core	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate 1	50,045	50,074	50,096	50,109	50,119	50,118	50,114	50,103	50,088
Rate 2	18,942	19,001	19,115	19,165	19,214	19,316	19,358	19,398	19,497
Rate 3	15,239	15,424	15,609	15,784	15,959	16,134	16,309	16,481	16,650
Rate 4	76	76	76	76	76	76	76	76	76
Rate 5	2,147	2,127	2,107	2,087	2,068	2,048	2,029	2,010	1,991
Rate 6	68	68	68	68	68	68	68	68	68
Total Coastal Region-Core	86,517	86,769	87,071	87,289	87,504	87,760	87,954	88,137	88,370
Transportation & IT Customers									
Rate 7	3	3	3	3	3	2	2	2	2
Rate 22	12,637	12,564	12,493	12,422	12,352	12,282	12,214	12,146	12,078
Rate 23	5,595	5,600	5,604	5,609	5,614	5,619	5,624	5,629	5,634
Rate 25	8,012	7,958	7,906	7,853	7,802	7,750	7,700	7,649	7,600
Rate 27	4,504	4,483	4,463	4,442	4,422	4,402	4,383	4,363	4,344
Total Coastal Region-Transportation & IT	30,750	30,608	30,468	30,330	30,192	30,057	29,922	29,789	29,658
Total Coastal Region	**117,266**	**117,378**	**117,539**	**117,619**	**117,696**	**117,817**	**117,876**	**117,926**	**118,028**

Design Day Demand(TJ/Day)

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Core Customers	990.3	996.4	1,002.5	1,008.3	1,014.1	1,019.7	1,025.4	1,030.9	1,036.3

Coastal Region

YE Accounts by Rate Class

Core	2028	2029	2030
Rate 1	581,568	584,022	586,447
Rate 2	60,476	60,774	61,070
Rate 3	5,188	5,243	5,296
Rate 4	33	33	33
Rate 5	221	221	221
Rate 6	26	26	26
Total Coastal Region-Core	647,512	650,319	653,093
Transportation & IT Customers			
Rate 7	1	1	1
Rate 22	22	22	22
Rate 23	1,159	1,160	1,161
Rate 25	488	488	488
Rate 27	81	81	81
Total -Transportation & IT	1,751	1,752	1,753
Total Coastal Region	649,263	652,071	654,846

Percent change in YE Accounts

Core	2028	2029	2030
Rate 1	0.43%	0.42%	0.42%
Rate 2	0.50%	0.49%	0.49%
Rate 3	1.05%	1.06%	1.01%
Rate 4	0.00%	0.00%	0.00%
Rate 5	0.00%	0.00%	0.00%
Rate 6	0.00%	0.00%	0.00%
Transportation & IT Customers			
Rate 7	0.00%	0.00%	0.00%
Rate 22	0.00%	0.00%	0.00%
Rate 23	0.09%	0.09%	0.09%
Rate 25	0.00%	0.00%	0.00%
Rate 27	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Core	2028	2029	2030
Rate 1	86	86	85
Rate 2	323	323	322
Rate 3	3,243	3,243	3,243
Rate 4	2,303	2,303	2,303
Rate 5	8,926	8,842	8,759
Rate 6	2,615	2,615	2,615
Transportation & IT Customers			
Rate 7	2,378	2,354	2,331
Rate 22	545,985	542,984	540,013
Rate 23	4,865	4,865	4,865
Rate 25	15,472	15,372	15,273
Rate 27	53,391	53,158	52,926

Annual Demand by Rate Class(TJ)

Core	2028	2029	2030
Rate 1	50,069	50,047	50,020
Rate 2	19,534	19,630	19,665
Rate 3	16,825	17,003	17,175
Rate 4	76	76	76
Rate 5	1,973	1,954	1,936
Rate 6	68	68	68
Total Coastal Region-Core	88,544	88,778	88,939
Transportation & IT Customers			
Rate 7	2	2	2
Rate 22	12,012	11,946	11,880
Rate 23	5,639	5,643	5,648
Rate 25	7,550	7,502	7,453
Rate 27	4,325	4,306	4,287
Total Coastal Region-Transportation & IT	29,528	29,399	29,271
Total Coastal Region	**118,072**	**118,177**	**118,211**

Design Day Demand(TJ/Day)

	2028	2029	2030
Core Customers	1,041.8	1,047.3	1,052.8

Interior Region
YE Accounts by Rate Class

Core	2010	2011	2012	2013	2014	2015	2016	2017
Rate 1	232,073	234,525	236,928	239,396	241,863	244,408	246,992	249,056
Rate 2	23,134	23,380	23,631	23,890	24,149	24,418	24,687	24,903
Rate 3	845	877	910	944	978	1,014	1,051	1,082
Rate 4	12	12	12	12	12	12	12	12
Rate 5	32	32	32	32	32	32	32	32
Rate 6	2	2	2	2	2	2	2	2
Total Coastal Region-Core	256098	258828	261515	264276	267036	269886	272776	275087
Transportation & IT Customers								
Rate 7	2	2	2	2	2	2	2	2
Rate 22	9	24	24	24	24	24	24	24
Rate 23	241	245	249	253	257	261	265	268
Rate 25	95	95	95	95	95	95	95	95
Rate 27	16	16	16	16	16	16	16	16
Total -Transportation & IT	363	382	386	390	394	398	402	405
Total Interior Region	**256461**	**259210**	**261901**	**264666**	**267430**	**270284**	**273178**	**275492**

Percent change in YE Accounts

Core	2010	2011	2012	2013	2014	2015	2016	2017
Rate 1		1.06%	1.02%	1.04%	1.03%	1.05%	1.06%	0.84%
Rate 2		1.06%	1.07%	1.10%	1.08%	1.11%	1.10%	0.87%
Rate 3		3.79%	3.76%	3.74%	3.60%	3.68%	3.65%	2.95%
Rate 4		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 5		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 6		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation & IT Customers								
Rate 7		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 22		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 23		1.66%	1.63%	1.61%	1.58%	1.56%	1.53%	1.13%
Rate 25								
Rate 27		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer by Rate Class(GJ)

Core	2010	2011	2012	2013	2014	2015	2016	2017
Rate 1	76	74	73	71	70	69	68	68
Rate 2	288	287	287	286	286	285	285	283
Rate 3	3,372	3,338	3,338	3,338	3,338	3,338	3,338	3,338
Rate 4	9,583	9,583	9,583	9,583	9,583	9,583	9,583	9,583
Rate 5	13,152	13,021	12,892	12,764	12,637	12,519	12,401	12,284
Rate 6	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Transportation & IT Customers								
Rate 7	1,897	1,878	1,859	1,841	1,822	1,804	1,786	1,768
Rate 22	1,585,924	563,301	531,882	500,464	469,048	468,929	468,812	468,696
Rate 23	5,362	5,363	5,364	5,365	5,366	5,367	5,368	5,368
Rate 25	35,516	35,278	35,042	34,807	34,572	34,447	34,322	34,199
Rate 27	42,324	41,651	40,980	40,311	39,643	39,468	39,295	39,124

Annual Demand by Rate Class(TJ)

Core	2010	2011	2012	2013	2014	2015	2016	2017
Rate 1	17,641	17,406	17,205	17,049	16,935	16,868	16,848	16,839
Rate 2	6,660	6,706	6,775	6,827	6,897	6,949	7,024	7,060
Rate 3	2,849	2,928	3,038	3,151	3,265	3,385	3,508	3,611
Rate 4	115	115	115	115	115	115	115	115
Rate 5	421	417	413	408	404	401	397	393
Rate 6	7	7	7	7	7	7	7	7
Total Coastal Region-Core	27,692	27,578	27,552	27,558	27,623	27,724	27,899	28,025
Transportation & IT Customers								
Rate 7	4	4	4	4	4	4	4	4
Rate 22	14,273	13,519	12,765	12,011	11,257	11,254	11,251	11,249
Rate 23	1,292	1,314	1,336	1,357	1,379	1,401	1,422	1,439
Rate 25	3,374	3,351	3,329	3,307	3,284	3,272	3,261	3,249
Rate 27	677	666	656	645	634	631	629	626
Total Interior Region-Transportation & IT	19,621	18,855	18,089	17,324	16,559	16,563	16,567	16,566
Total Interior Region	**47,313**	**46,433**	**45,642**	**44,881**	**44,181**	**44,287**	**44,466**	**44,591**

Design Day Demand(TJ/Day)

	2010	2011	2012	2013	2014	2015	2016	2017
Core Customers	335.0	339.4	343.7	348.2	352.7	357.4	362.1	366.0

Interior Region
YE Accounts by Rate Class

Core	2018	2019	2020	2021	2022	2023	2024	2025
Rate 1	251,010	252,862	254,639	256,333	257,973	259,630	261,239	262,792
Rate 2	25,108	25,300	25,484	25,654	25,817	25,980	26,136	26,289
Rate 3	1,113	1,142	1,169	1,196	1,224	1,253	1,282	1,312
Rate 4	12	12	12	12	12	12	12	12
Rate 5	32	32	32	32	32	32	32	32
Rate 6	2	2	2	2	2	2	2	2
Total Coastal Region-Core	277277	279350	281338	283229	285060	286909	288703	290439
Transportation & IT Customers								
Rate 7	2	2	2	2	2	2	2	2
Rate 22	24	24	24	24	24	24	24	24
Rate 23	271	274	277	280	283	286	289	292
Rate 25	95	95	95	95	95	95	95	95
Rate 27	16	16	16	16	16	16	16	16
Total -Transportation & IT	408	411	414	417	420	423	426	429
Total Interior Region	**277685**	**279761**	**281752**	**283646**	**285480**	**287332**	**289129**	**290868**

Percent change in YE Accounts

Core	2018	2019	2020	2021	2022	2023	2024	2025
Rate 1	0.78%	0.74%	0.70%	0.67%	0.64%	0.64%	0.62%	0.59%
Rate 2	0.82%	0.76%	0.73%	0.67%	0.64%	0.63%	0.60%	0.59%
Rate 3	2.87%	2.61%	2.36%	2.31%	2.34%	2.37%	2.31%	2.34%
Rate 4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation & IT Customers								
Rate 7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 23	1.12%	1.11%	1.09%	1.08%	1.07%	1.06%	1.05%	1.04%
Rate 25								
Rate 27	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer by Rate Class(GJ)

Core	2018	2019	2020	2021	2022	2023	2024	2025
Rate 1	67	67	66	66	66	65	65	64
Rate 2	283	282	281	281	280	280	279	279
Rate 3	3,338	3,338	3,338	3,337	3,337	3,337	3,337	3,337
Rate 4	9,583	9,583	9,583	9,583	9,583	9,583	9,583	9,583
Rate 5	12,169	12,055	11,942	11,830	11,719	11,609	11,501	11,393
Rate 6	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Transportation & IT Customers								
Rate 7	1,750	1,733	1,716	1,698	1,681	1,665	1,648	1,631
Rate 22	468,582	468,468	468,356	468,244	468,134	468,025	467,917	467,810
Rate 23	5,369	5,370	5,370	5,371	5,371	5,372	5,372	5,373
Rate 25	34,077	33,957	33,837	33,719	33,602	33,486	33,371	33,257
Rate 27	38,955	38,787	38,621	38,456	38,294	38,132	37,973	37,815

Annual Demand by Rate Class(TJ)

Core	2018	2019	2020	2021	2022	2023	2024	2025
Rate 1	16,870	16,893	16,909	16,919	16,923	16,927	16,927	16,922
Rate 2	7,117	7,146	7,172	7,219	7,238	7,281	7,300	7,339
Rate 3	3,715	3,812	3,902	3,992	4,085	4,181	4,278	4,378
Rate 4	115	115	115	115	115	115	115	115
Rate 5	389	386	382	379	375	372	368	365
Rate 6	7	7	7	7	7	7	7	7
Total Coastal Region-Core	28,214	28,358	28,487	28,630	28,743	28,883	28,995	29,126
Transportation & IT Customers								
Rate 7	4	3	3	3	3	3	3	3
Rate 22	11,246	11,243	11,241	11,238	11,235	11,233	11,230	11,227
Rate 23	1,455	1,471	1,488	1,504	1,520	1,536	1,553	1,569
Rate 25	3,237	3,226	3,215	3,203	3,192	3,181	3,170	3,159
Rate 27	623	621	618	615	613	610	608	605
Total Interior Region-Transportation & IT	16,565	16,564	16,564	16,564	16,564	16,564	16,564	16,564
Total Interior Region	**44,779**	**44,922**	**45,051**	**45,193**	**45,307**	**45,446**	**45,559**	**45,690**

Design Day Demand(TJ/Day)

	2018	2019	2020	2021	2022	2023	2024	2025
Core Customers	369.7	373.2	376.5	379.7	382.9	386.1	389.2	392.4

Interior Region
YE Accounts by Rate Class

Core	2026	2027	2028	2029	2030
Rate 1	264,320	265,838	267,249	268,690	270,132
Rate 2	26,441	26,590	26,719	26854	26989
Rate 3	1,340	1,368	1,396	1424	1452
Rate 4	12	12	12	12	12
Rate 5	32	32	32	32	32
Rate 6	2	2	2	2	2
Total Coastal Region-Core	292147	293842	295410	297014	298619
Transportation & IT Customers					
Rate 7	2	2	2	2	2
Rate 22	24	24	24	24	24
Rate 23	295	298	300	303	306
Rate 25	95	95	95	95	95
Rate 27	16	16	16	16	16
Total -Transportation & IT	432	435	437	440	443
Total Interior Region	**292579**	**294277**	**295847**	**297454**	**299062**

Percent change
in YE Accounts

Core	2026	2027	2028	2029	2030
Rate 1	0.58%	0.57%	0.53%	0.54%	0.54%
Rate 2	0.58%	0.56%	0.49%	0.51%	0.50%
Rate 3	2.13%	2.09%	2.05%	2.01%	1.97%
Rate 4	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 5	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 6	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation & IT Customers					
Rate 7	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 22	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 23	1.03%	1.02%	0.67%	1.00%	0.99%
Rate 25					
Rate 27	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer by
Rate Class(GJ)

Core	2026	2027	2028	2029	2030
Rate 1	64	64	63	63	62
Rate 2	278	278	277	277	276
Rate 3	3,337	3,337	3,336	3,336	3,335
Rate 4	9,583	9,583	9,583	9,583	9,583
Rate 5	11,287	11,181	11,077	10,974	10,872
Rate 6	3,500	3,500	3,500	3,500	3,500
Transportation & IT Customers					
Rate 7	1,615	1,599	1,583	1,567	1,551
Rate 22	467,704	467,599	467,495	467,393	467,291
Rate 23	5,374	5,374	5,374	5,375	5,375
Rate 25	33,145	33,033	32,923	32,814	32,706
Rate 27	37,659	37,504	37,350	37,199	37,049

Annual Demand by
Rate Class(TJ)

Core	2026	2027	2028	2029	2030
Rate 1	16,915	16,905	16,887	16,870	16,852
Rate 2	7,358	7,395	7,404	7,440	7,449
Rate 3	4,471	4,564	4,657	4,750	4,843
Rate 4	115	115	115	115	115
Rate 5	361	358	354	351	348
Rate 6	7	7	7	7	7
Total Coastal Region-Core	29,227	29,345	29,425	29,534	29,614
Transportation & IT Customers					
Rate 7	3	3	3	3	3
Rate 22	11,225	11,222	11,220	11,217	11,215
Rate 23	1,585	1,601	1,612	1,629	1,645
Rate 25	3,149	3,138	3,128	3,117	3,107
Rate 27	603	600	598	595	593
Total Interior Region-Transportation & IT	16,565	16,565	16,561	16,562	16,563
Total Interior Region	**45,791**	**45,910**	**45,986**	**46,095**	**46,177**

Design Day Demand(TJ/Day)

	2026	2027	2028	2029	2030
Core Customers	395.4	398.4	401.2	404.1	407.1

TGVI

TGVI Year end accounts by Rate Class

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
RGS	90,926	93,631	96,379	99,199	102,086	105,095	108,187	110,640
SCS1	5168	5275	5384	5496	5611	5731	5855	5950
SCS2	1420	1425	1430	1435	1440	1446	1452	1455
LCS1	1365	1370	1375	1380	1385	1390	1396	1399
LCS2	531	536	541	546	551	557	563	567
AGS	881	886	891	896	901	906	911	915
LCS3	125	128	131	134	137	140	143	146
HLF	6	6	6	6	6	6	6	6
ILF	8	8	8	8	8	8	8	8
Total	**100,430**	**103,265**	**106,145**	**109,100**	**112,125**	**115,279**	**118,521**	**121,086**

Percent change in Year end Accounts by Rate Class

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
RGS		2.97%	2.93%	2.93%	2.91%	2.95%	2.94%	2.27%
SCS1		2.07%	2.07%	2.08%	2.09%	2.14%	2.16%	1.62%
SCS2		0.35%	0.35%	0.35%	0.35%	0.42%	0.41%	0.21%
LCS1		0.37%	0.36%	0.36%	0.36%	0.36%	0.43%	0.21%
LCS2		0.94%	0.93%	0.92%	0.92%	1.09%	1.08%	0.71%
AGS		0.57%	0.56%	0.56%	0.56%	0.55%	0.55%	0.44%
LCS3		2.40%	2.34%	2.29%	2.24%	2.19%	2.14%	2.10%
HLF		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ILF		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
RGS	52	50	48	47	46	45	44	43
SCS1	116	116	116	116	116	116	116	116
SCS2	325	325	325	325	325	325	325	325
LCS1	980	980	980	980	980	980	980	980
LCS2	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481
AGS	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259
LCS3	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911
HLF	19,585	19,585	19,585	19,585	19,585	19,585	19,585	19,585
ILF	12,197	12,197	12,197	12,197	12,197	12,197	12,197	12,197

Annual Demand by Rate Class(TJ)

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
RGS	4,686	4,657	4,639	4,636	4,648	4,680	4,731	4,772
SCS1	602	614	627	640	653	667	682	693
SCS2	462	463	465	466	468	470	472	473
LCS1	1,337	1,342	1,347	1,352	1,357	1,362	1,368	1,371
LCS2	1,318	1,330	1,342	1,355	1,367	1,382	1,397	1,407
AGS	1,109	1,115	1,122	1,128	1,134	1,141	1,147	1,152
LCS3	1,864	1,909	1,953	1,998	2,043	2,087	2,132	2,177
HLF	118	118	118	118	118	118	118	118
ILF	98	98	98	98	98	98	98	98

Design Day Demand(TJ/Day)

	2010	2011	2012	2013	2014	2015	2016	2017
TGVI	114.2	118.1	122.0	125.8	129.7	133.8	137.9	140.9

TGVI

TGVI Year end accounts by Rate Class

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
RGS	112,820	114,956	117,025	118,942	120,876	122,857	124,704	126,541
SCS1	6032	6112	6187	6255	6324	6397	6461	6526
SCS2	1458	1461	1463	1464	1465	1467	1468	1469
LCS1	1402	1405	1407	1408	1409	1411	1412	1413
LCS2	570	573	575	577	579	581	583	584
AGS	918	921	923	925	927	929	931	933
LCS3	148	150	152	153	154	156	157	158
HLF	6	6	6	6	6	6	6	6
ILF	8	8	8	8	8	8	8	8
Total	**123,362**	**125,592**	**127,746**	**129,738**	**131,748**	**133,812**	**135,730**	**137,638**

Percent change in Year end Accounts by Rate Class

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
RGS	1.97%	1.89%	1.80%	1.64%	1.63%	1.64%	1.50%	1.47%
SCS1	1.38%	1.33%	1.23%	1.10%	1.10%	1.15%	1.00%	1.01%
SCS2	0.21%	0.21%	0.14%	0.07%	0.07%	0.14%	0.07%	0.07%
LCS1	0.21%	0.21%	0.14%	0.07%	0.07%	0.14%	0.07%	0.07%
LCS2	0.53%	0.53%	0.35%	0.35%	0.35%	0.35%	0.34%	0.17%
AGS	0.33%	0.33%	0.22%	0.22%	0.22%	0.22%	0.22%	0.21%
LCS3	1.37%	1.35%	1.33%	0.66%	0.65%	1.30%	0.64%	0.64%
HLF	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ILF	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
RGS	43	42	42	42	41	41	40	40
SCS1	116	116	116	116	116	116	116	116
SCS2	325	325	325	325	325	325	325	325
LCS1	980	980	980	980	980	980	980	980
LCS2	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481
AGS	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259
LCS3	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911
HLF	19,585	19,585	19,585	19,585	19,585	19,585	19,585	19,585
ILF	12,197	12,197	12,197	12,197	12,197	12,197	12,197	12,197

Annual Demand by Rate Class(TJ)

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
RGS	4,821	4,866	4,907	4,940	4,972	5,004	5,030	5,053
SCS1	702	712	720	728	736	745	752	760
SCS2	474	475	475	476	476	477	477	477
LCS1	1,374	1,377	1,378	1,379	1,380	1,382	1,383	1,384
LCS2	1,414	1,422	1,427	1,432	1,437	1,442	1,447	1,449
AGS	1,156	1,160	1,162	1,165	1,167	1,170	1,172	1,175
LCS3	2,207	2,237	2,266	2,281	2,296	2,326	2,341	2,356
HLF	118	118	118	118	118	118	118	118
ILF	98	98	98	98	98	98	98	98

Design Day Demand(TJ/Day)

	2018	2019	2020	2021	2022	2023	2024	2025
TGVI	143.8	146.7	149.3	151.5	153.7	155.7	157.9	159.9

TGVI

TGVI Year end accounts by Rate Class

Rate Class	2026	2027	2028	2029	2030
RGS	128,370	130,174	131,982	133,824	135,689
SCS1	6591	6655	6719	6784	6849
SCS2	1470	1471	1472	1473	1474
LCS1	1414	1415	1416	1417	1418
LCS2	585	586	587	588	589
AGS	935	937	939	941	943
LCS3	159	160	161	162	163
HLF	6	6	6	6	6
ILF	8	8	8	8	8
Total	**139,538**	**141,412**	**143,290**	**145,203**	**147,139**

Percent change in Year end Accounts by Rate Class

Rate Class	2026	2027	2028	2029	2030
RGS	1.45%	1.41%	1.39%	1.40%	1.39%
SCS1	1.00%	0.97%	0.96%	0.97%	0.96%
SCS2	0.07%	0.07%	0.07%	0.07%	0.07%
LCS1	0.07%	0.07%	0.07%	0.07%	0.07%
LCS2	0.17%	0.17%	0.17%	0.17%	0.17%
AGS	0.21%	0.21%	0.21%	0.21%	0.21%
LCS3	0.63%	0.63%	0.63%	0.62%	0.62%
HLF	0.00%	0.00%	0.00%	0.00%	0.00%
ILF	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer by Rate Class(GJ)

Rate Class	2026	2027	2028	2029	2030
RGS	40	39	39	38	38
SCS1	116	116	116	116	116
SCS2	325	325	325	325	325
LCS1	980	980	980	980	980
LCS2	2,481	2,481	2,481	2,481	2,481
AGS	1,259	1,259	1,259	1,259	1,259
LCS3	14,911	14,911	14,911	14,911	14,911
HLF	19,585	19,585	19,585	19,585	19,585
ILF	12,197	12,197	12,197	12,197	12,197

Annual Demand by Rate Class(TJ)

Rate Class	2026	2027	2028	2029	2030
RGS	5,075	5,094	5,112	5,130	5,147
SCS1	767	775	782	790	797
SCS2	478	478	478	479	479
LCS1	1,385	1,386	1,387	1,388	1,389
LCS2	1,452	1,454	1,457	1,459	1,461
AGS	1,177	1,180	1,182	1,185	1,187
LCS3	2,371	2,386	2,401	2,416	2,430
HLF	118	118	118	118	118
ILF	98	98	98	98	98

Design Day Demand(TJ/Day)

	2026	2027	2028	2029	2030
TGVI	161.9	163.8	165.7	167.6	169.6

TGW

TGW Year end accounts by Rate Class

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
SGS-1/2 RES	2,285	2,321	2,341	2,366	2,396	2,426	2,455	2,478
SGS-1/2 COM	173	175	178	181	184	187	190	192
LGS-1 COM	84	84	85	85	86	86	87	87
LGS-2 COM	51	52	52	53	53	53	53	54
LGS-3 COM	24	24	24	24	24	24	24	24

Percent change in Year end Accounts
By Rate Class

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
SGS-1/2 RES		1.6%	0.9%	1.1%	1.3%	1.3%	1.2%	0.9%
SGS-1/2 COM		1.2%	1.7%	1.7%	1.7%	1.6%	1.6%	1.1%
LGS-1 COM		0.0%	1.2%	0.0%	1.2%	0.0%	1.2%	0.0%
LGS-2 COM		2.0%	0.0%	1.9%	0.0%	0.0%	0.0%	1.9%
LGS-3 COM		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer
by Rate Class(GJ)

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
SGS-1/2 RES	82	82	82	82	82	82	82	82
SGS-1/2 COM	251	251	251	251	251	251	251	251
LGS-1 COM	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185
LGS-2 COM	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447
LGS-3 COM	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150

Annual Demand by Rate Class(TJ)

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017
SGS-1/2 RES	188	191	193	195	197	200	202	204
SGS-1/2 COM	43	44	45	45	46	47	48	48
LGS-1 COM	100	100	101	101	102	102	103	103
LGS-2 COM	125	127	127	130	130	130	130	132
LGS-3 COM	220	220	220	220	220	220	220	220

Design Day Demand(TJ/Day)

	2010	2011	2012	2013	2014	2015	2016	2017
TGW	7.1	7.2	7.2	7.3	7.3	7.4	7.4	7.5

TGW

TGW Year end accounts by Rate Class

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
SGS-1/2 RES	2,498	2,520	2,538	2,555	2,572	2,586	2,599	2,612
SGS-1/2 COM	194	196	198	200	202	203	204	205
LGS-1 COM	88	88	89	89	90	90	91	91
LGS-2 COM	54	54	54	55	55	55	55	56
LGS-3 COM	24	24	24	24	24	24	24	24

Percent change in Year end Accounts By Rate Class

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
SGS-1/2 RES	0.8%	0.9%	0.7%	0.7%	0.7%	0.5%	0.5%	0.5%
SGS-1/2 COM	1.0%	1.0%	1.0%	1.0%	1.0%	0.5%	0.5%	0.5%
LGS-1 COM	1.1%	0.0%	1.1%	0.0%	1.1%	0.0%	1.1%	0.0%
LGS-2 COM	0.0%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	1.8%
LGS-3 COM	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer by Rate Class(GJ)

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
SGS-1/2 RES	82	82	82	82	82	82	82	82
SGS-1/2 COM	251	251	251	251	251	251	251	251
LGS-1 COM	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185
LGS-2 COM	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447
LGS-3 COM	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150

Annual Demand by Rate Class(TJ)

Rate Class	2018	2019	2020	2021	2022	2023	2024	2025
SGS-1/2 RES	205	207	209	210	211	213	214	215
SGS-1/2 COM	49	49	50	50	51	51	51	51
LGS-1 COM	104	104	105	105	107	107	108	108
LGS-2 COM	132	132	132	135	135	135	135	137
LGS-3 COM	220	220	220	220	220	220	220	220

Design Day Demand(TJ/Day)

	2018	2019	2020	2021	2022	2023	2024	2025
TGW	7.5	7.6	7.6	7.6	7.7	7.7	7.7	7.8

TGW

TGW Year end accounts by Rate Class

Rate Class	2026	2027	2028	2029	2030
SGS-1/2 RES	2,624	2,638	2,650	2,662	2,673
SGS-1/2 COM	206	207	208	209	210
LGS-1 COM	92	92	93	93	94
LGS-2 COM	56	56	56	57	57
LGS-3 COM	24	24	24	24	24

Percent change in Year end Accounts
By Rate Class

Rate Class	2026	2027	2028	2029	2030
SGS-1/2 RES	0.5%	0.5%	0.5%	0.5%	0.4%
SGS-1/2 COM	0.5%	0.5%	0.5%	0.5%	0.5%
LGS-1 COM	1.1%	0.0%	1.1%	0.0%	1.1%
LGS-2 COM	0.0%	0.0%	0.0%	1.8%	0.0%
LGS-3 COM	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer
by Rate Class(GJ)

Rate Class	2026	2027	2028	2029	2030
SGS-1/2 RES	82	82	82	82	82
SGS-1/2 COM	251	251	251	251	251
LGS-1 COM	1,185	1,185	1,185	1,185	1,185
LGS-2 COM	2,447	2,447	2,447	2,447	2,447
LGS-3 COM	9,150	9,150	9,150	9,150	9,150

Annual Demand by Rate Class(TJ)

Rate Class	2026	2027	2028	2029	2030
SGS-1/2 RES	216	217	218	219	220
SGS-1/2 COM	52	52	52	52	53
LGS-1 COM	109	109	110	110	111
LGS-2 COM	137	137	137	139	139
LGS-3 COM	220	220	220	220	220

Design Day Demand(TJ/Day)

	2026	2027	2028	2029	2030
TGW	7.8	7.8	7.8	7.9	7.9

Attachment 55.0

Terasen Gas

2010 Integrated Resource Plan

February 2nd , 2010 Stakeholder Workshop

www.terasengas.com/irp

Terasen. A Fortis company.

Terasen

Welcome

…thank you for joining us today.

Agenda for Today

Welcome & Introductions	1:00pm
Regional Perspectives on Energy and Natural Gas Issues *Dan Kirschner, Executive Director , Northwest Gas Association*	
Terasen Gas - Our Company, Planning Environment and Vision *Doug Stout, VP Marketing and Business Development, Terasen Gas*	
Break	3:00pm
Stakeholder Perspectives – Facilitated Session *Chuck Brook, Founder and Principal, Brook & Associates*	
Terasen IRP Process, Feedback & Next Steps *Ken Ross, Integrated Resource Planning Manager, Terasen Gas*	
Dinner	4:30pm

Introductions

NW Gas Market Outlook: Opportunities and Challenges

Stakeholder Meeting

Terasen Integrated Resource Plan

February 2, 2010

Summary

- About the NWGA
- NW Energy Facts
- Policy Overview
- NW Gas Market Forecast
- Observations

NORTHWEST GAS ASSOCIATION

1914 Willamette Falls Dr., #255
West Linn, OR 97068
(503) 344-6637
www.nwga.org

NWGA Members:

Avista Corporation

Cascade Natural Gas Co.

Intermountain Gas Co.

NW Natural

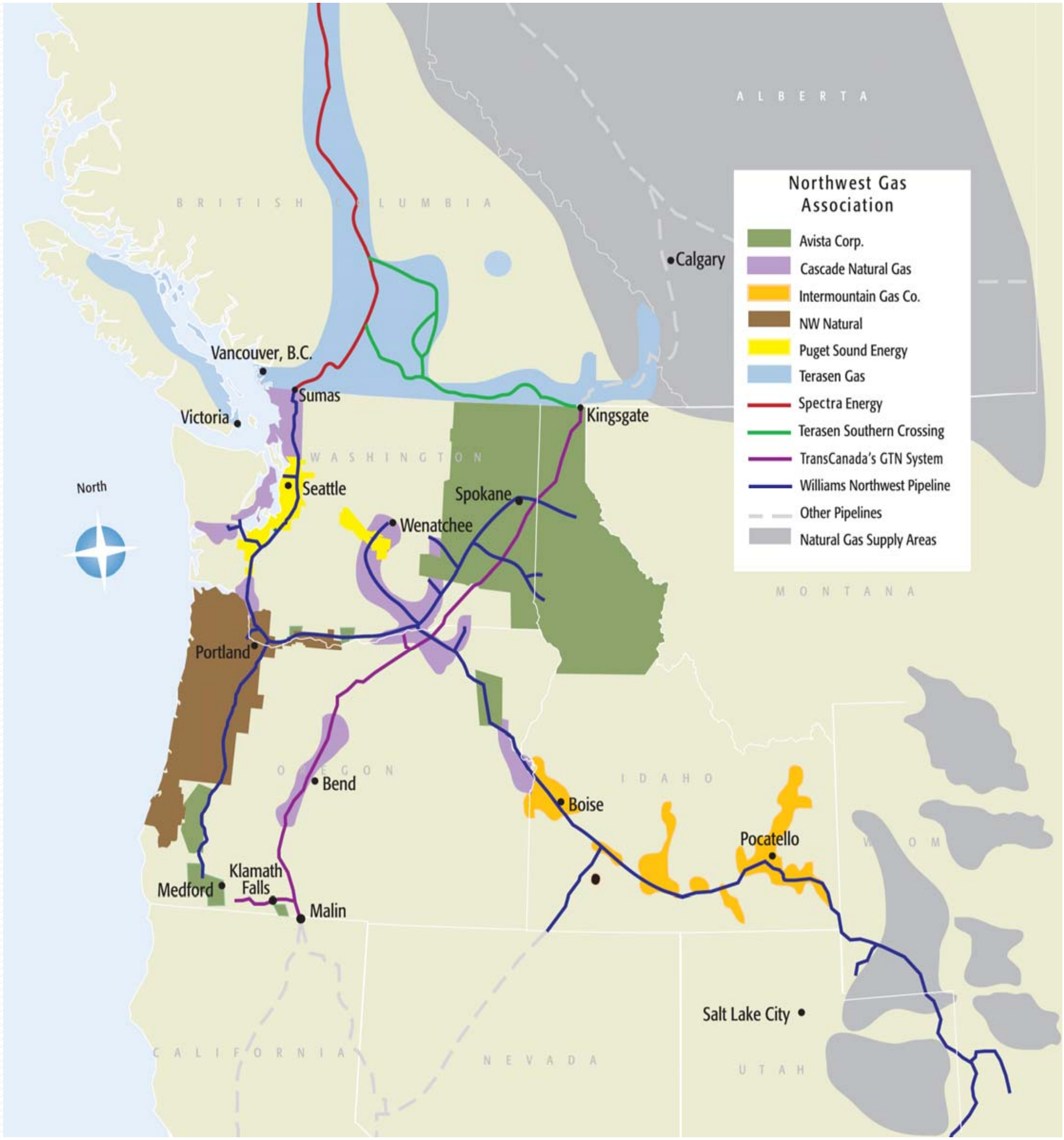
Puget Sound Energy

Spectra Energy Transmission

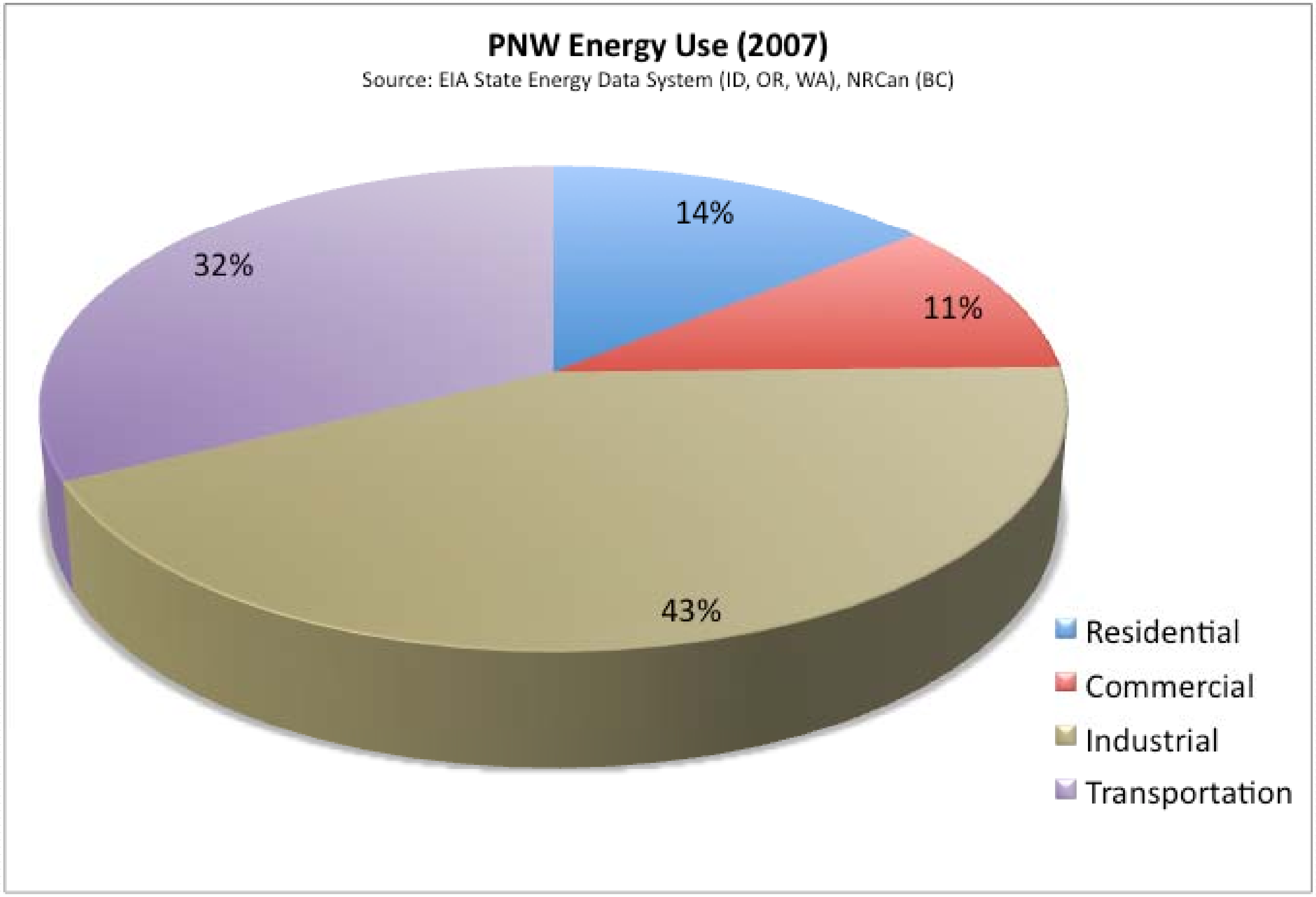
Terasen Gas

TransCanada's GTN System

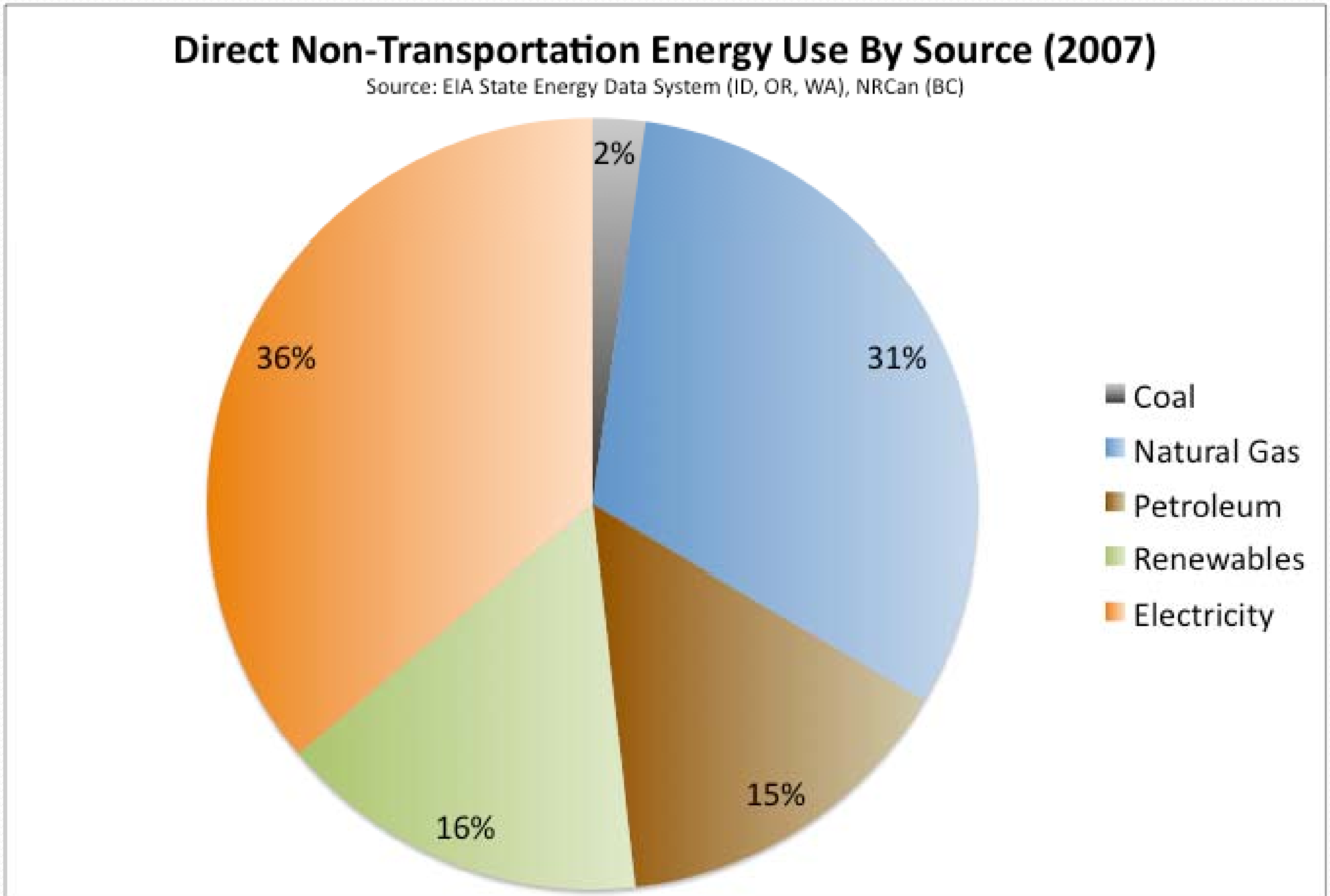
Williams NW Pipeline



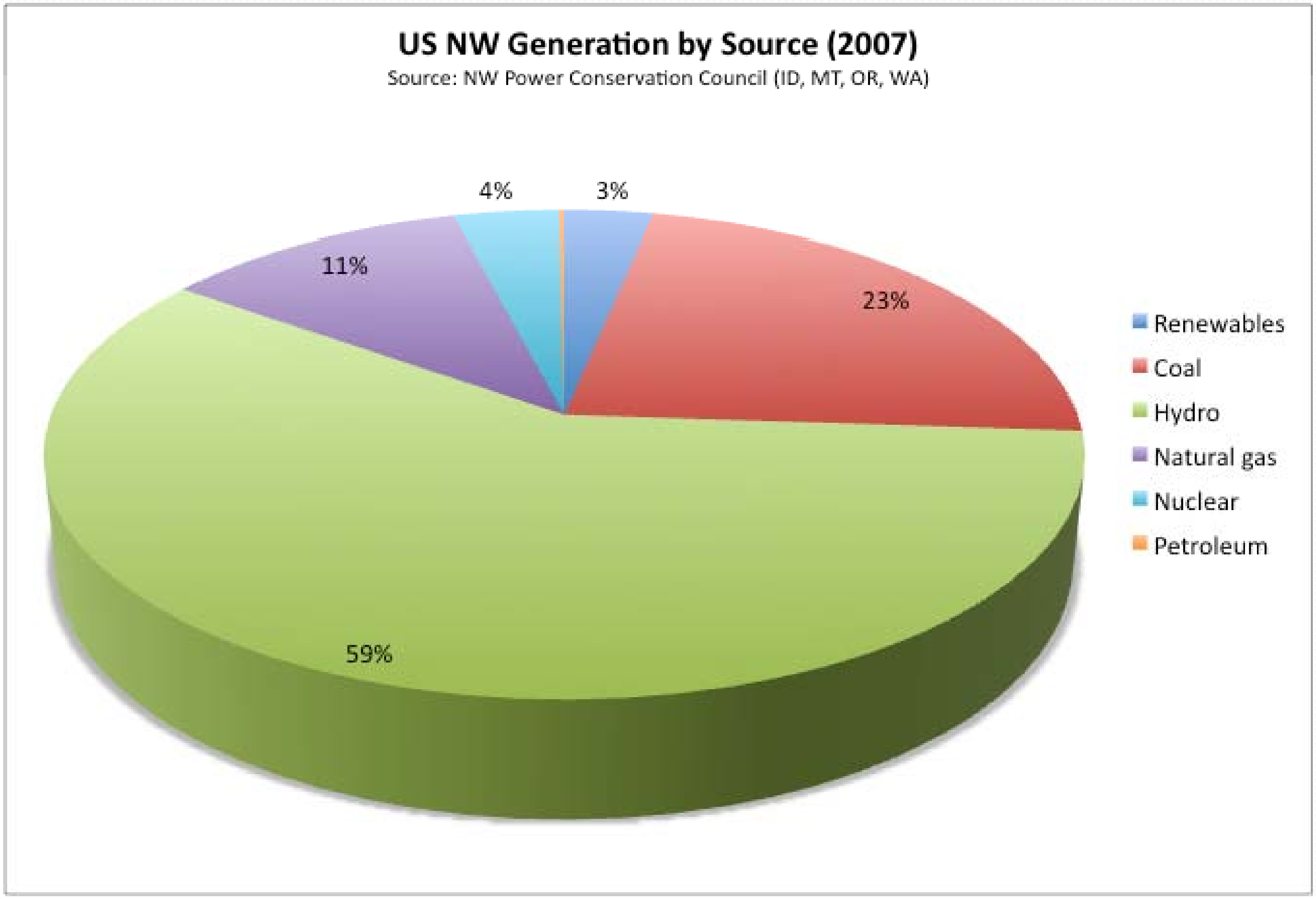
Northwest Energy Overview



Northwest Energy Overview

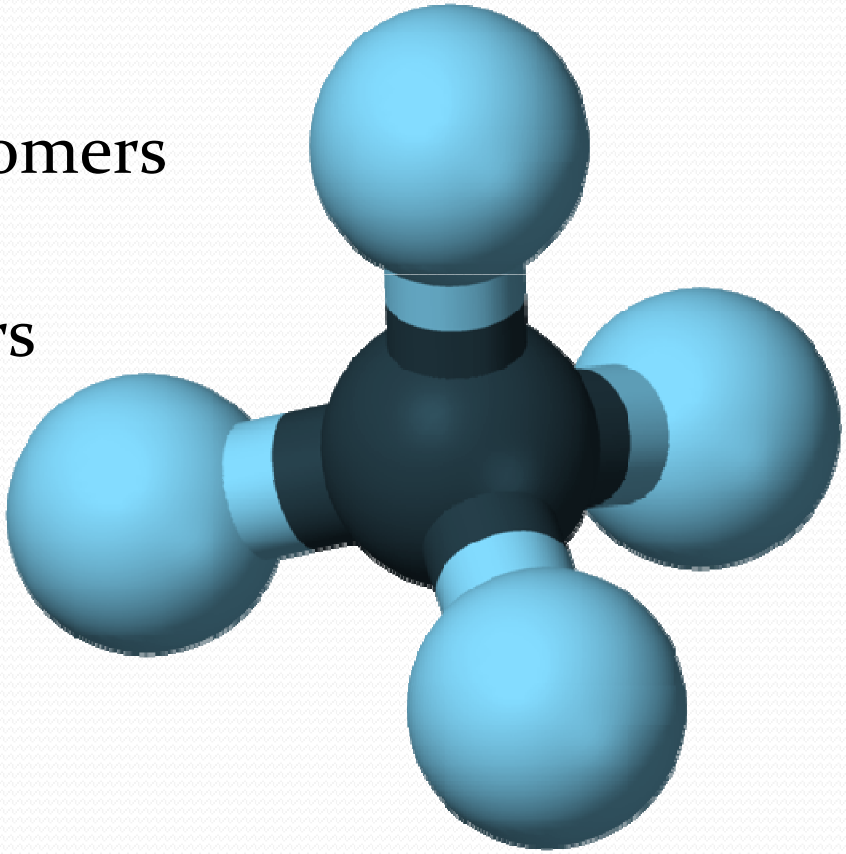


Northwest Energy Overview

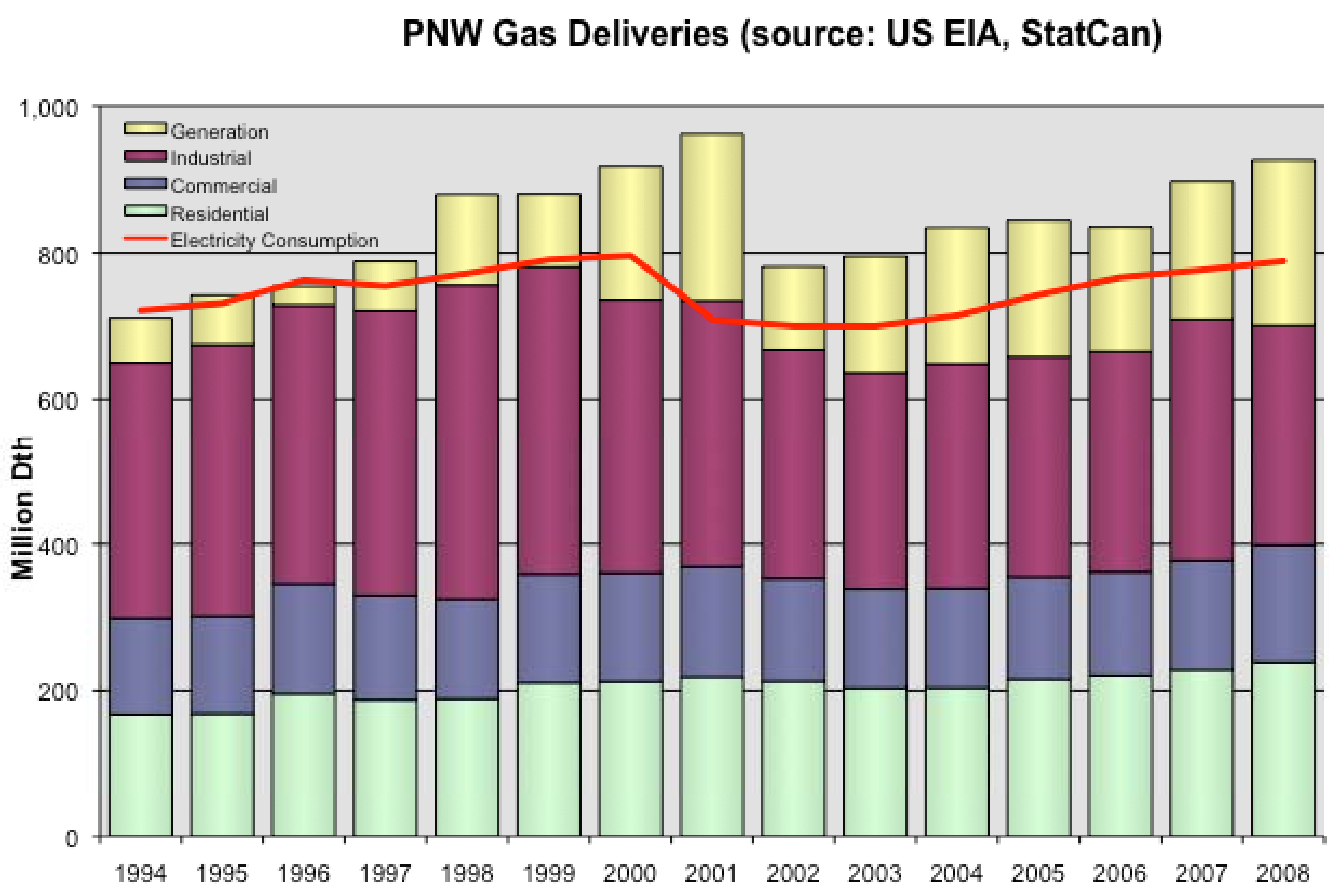


Northwest Energy Overview

- 2,874,335 residential gas customers
- 300,454 commercial gas customers
- 6,247 industrial gas customers



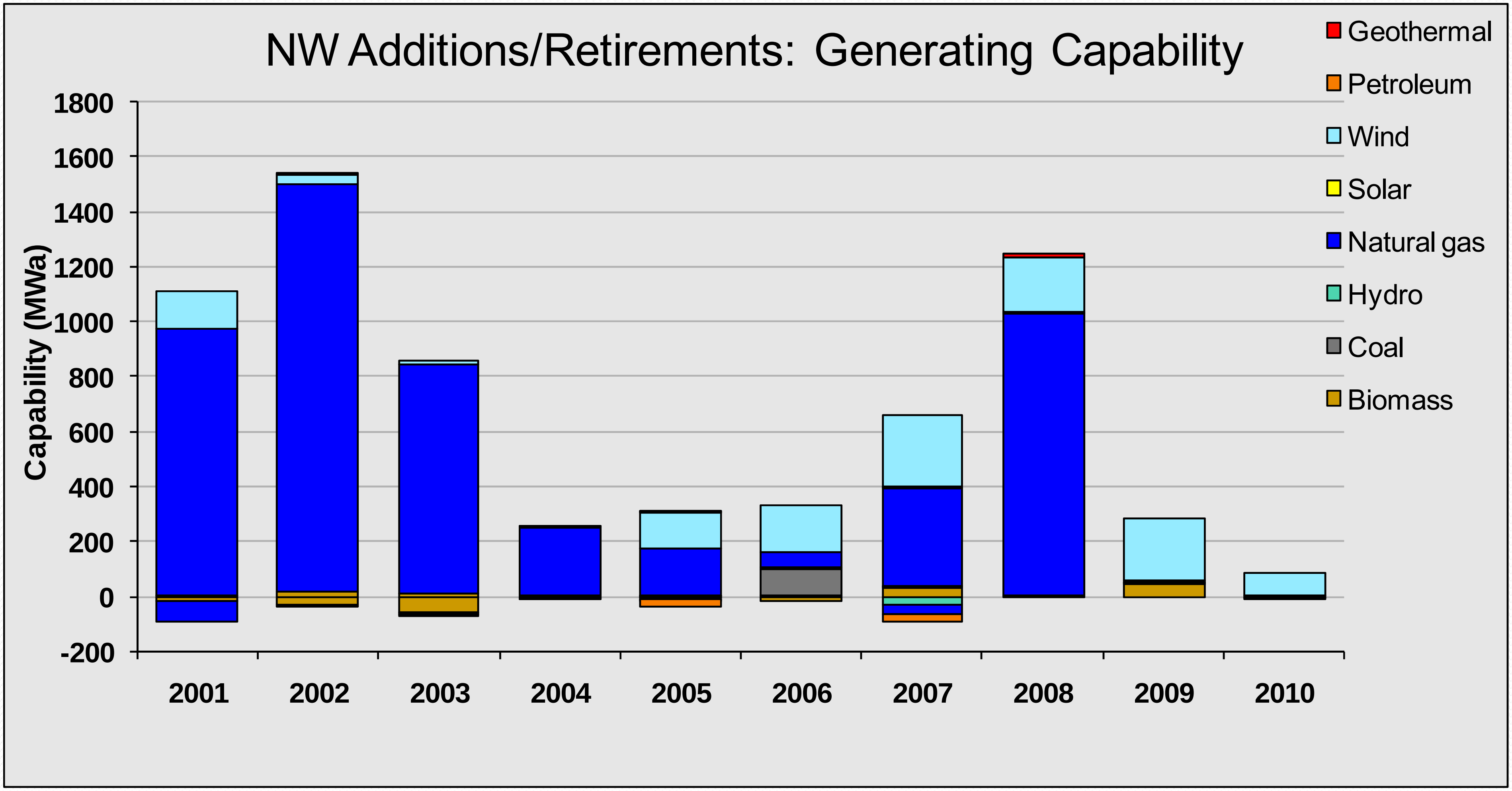
Recent Gas Demand



Policy Overview

- Climate Change: a political and policy reality
  - Kyoto, Kyoto II, Waxman-Markey, Kerry-Boxer, RGGI, WCI, State/Provincial Climate Change Inititatives
  - Carbon Tax, Cap-and-Trade, Renewable Energy Requirements, Emission Standards
- Regional Implications:
  - Acceleration of new technologies (e.g. alternative energy resources, CCS, etc.)
  - More gas-fired generation
  - Higher costs

…so we're building more of both.

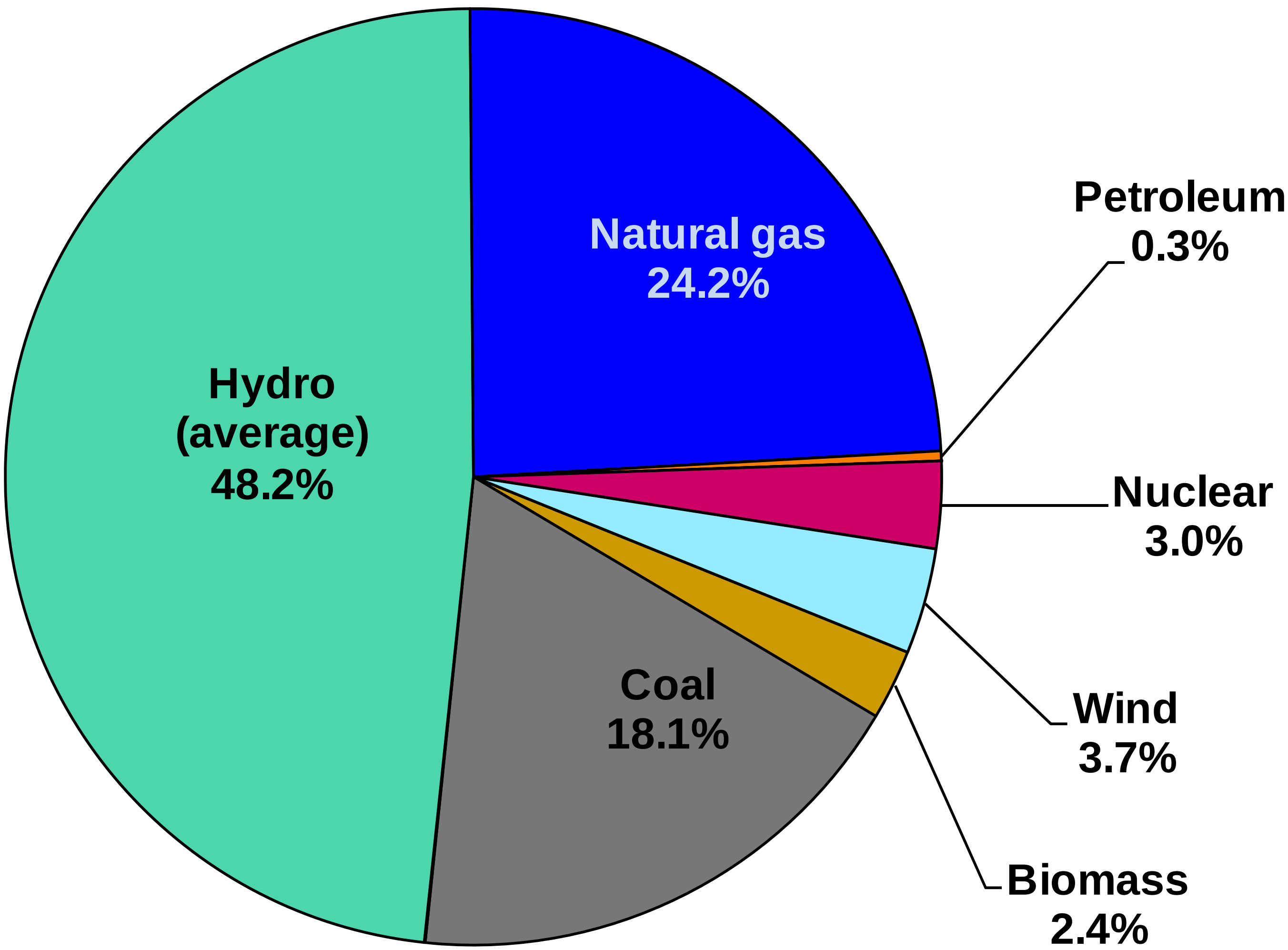


Northwest Power and Conservation Council

May, 2009

NW Electricity Mix

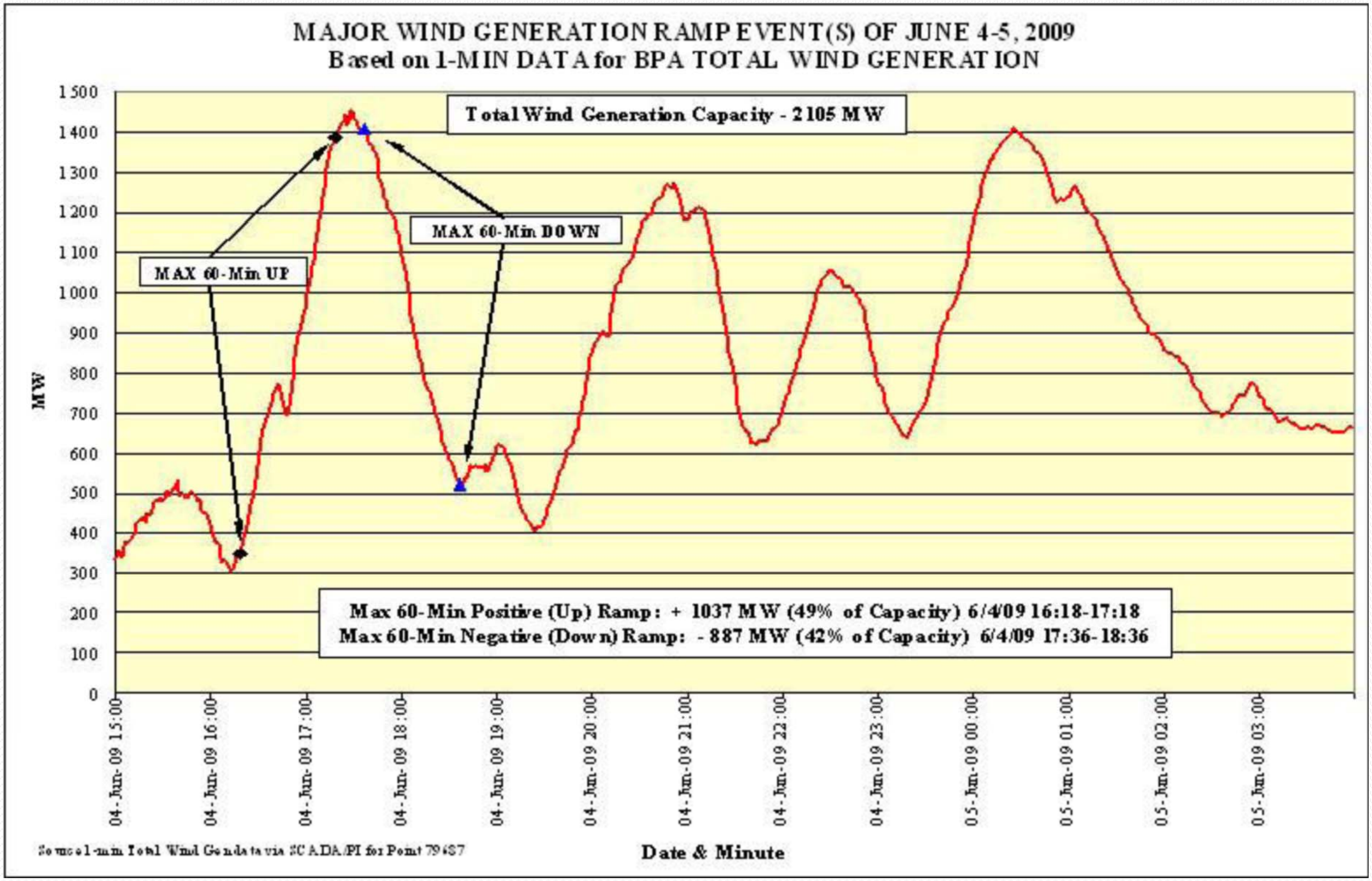
NW GENERATING CAPABILITY - 33,937 MWa

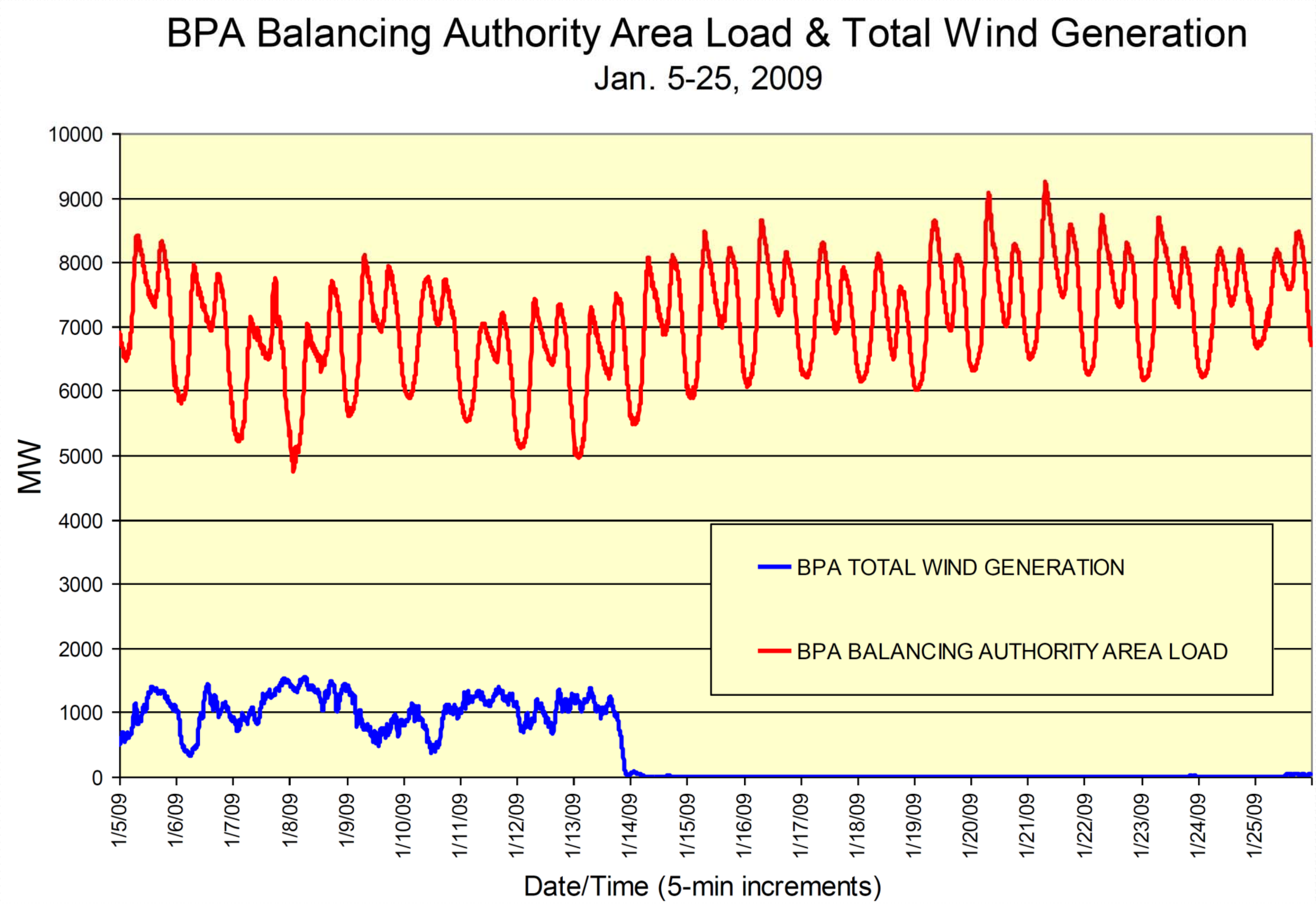


July, 2009

Northwest Power and Conservation Council

Gas supports renewable energy




BPA Balancing Authority Area Load & Total Wind Generation
Jan. 5-25, 2009
MW
Date/Time (5-min increments)
BPA TOTAL WIND GENERATION
BPA BALANCING AUTHORITY AREA LOAD
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
1/5/09
1/6/09
1/7/09
1/8/09
1/9/09
1/10/09
1/11/09
1/12/09
1/13/09
1/14/09
1/15/09
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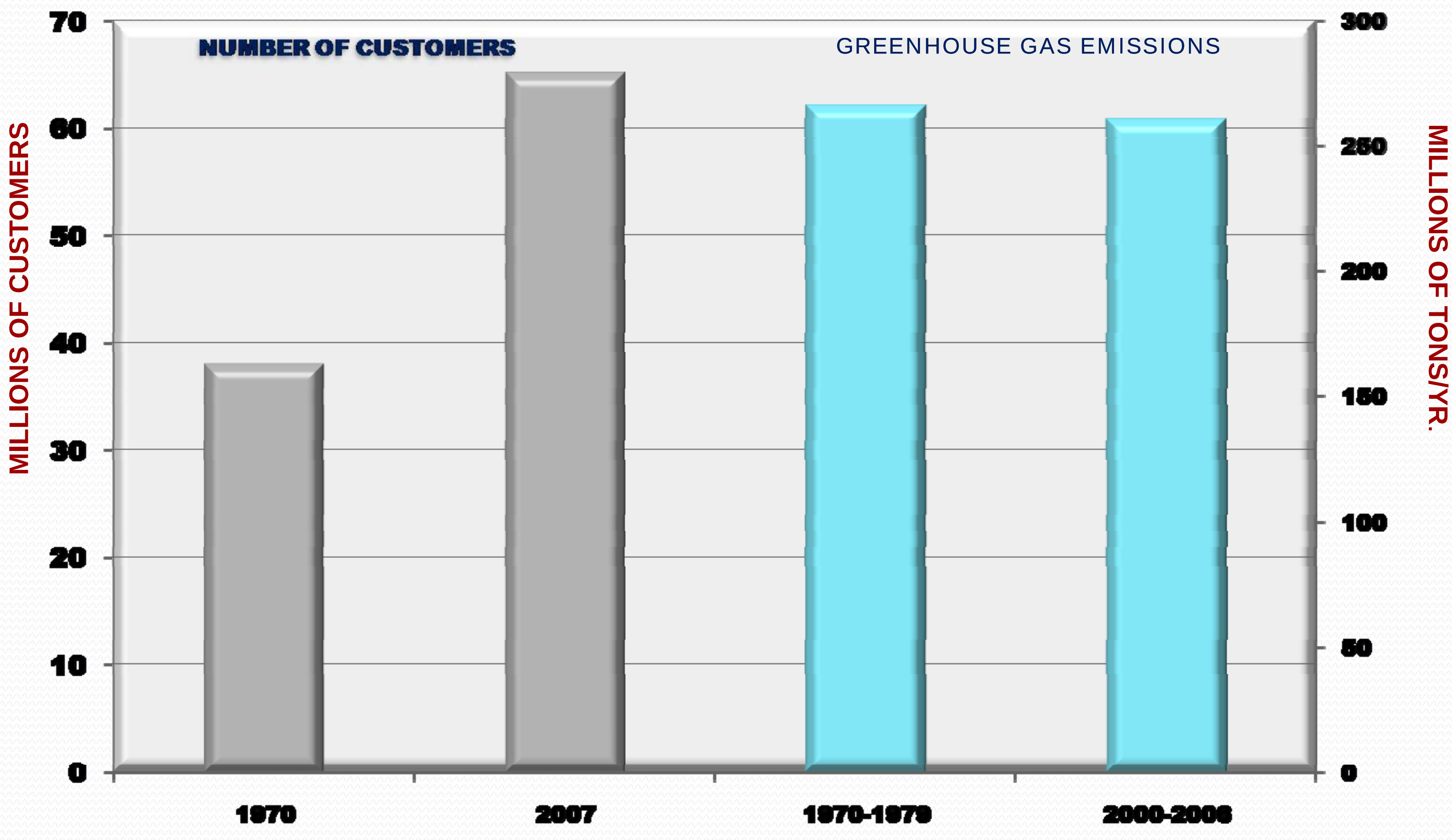
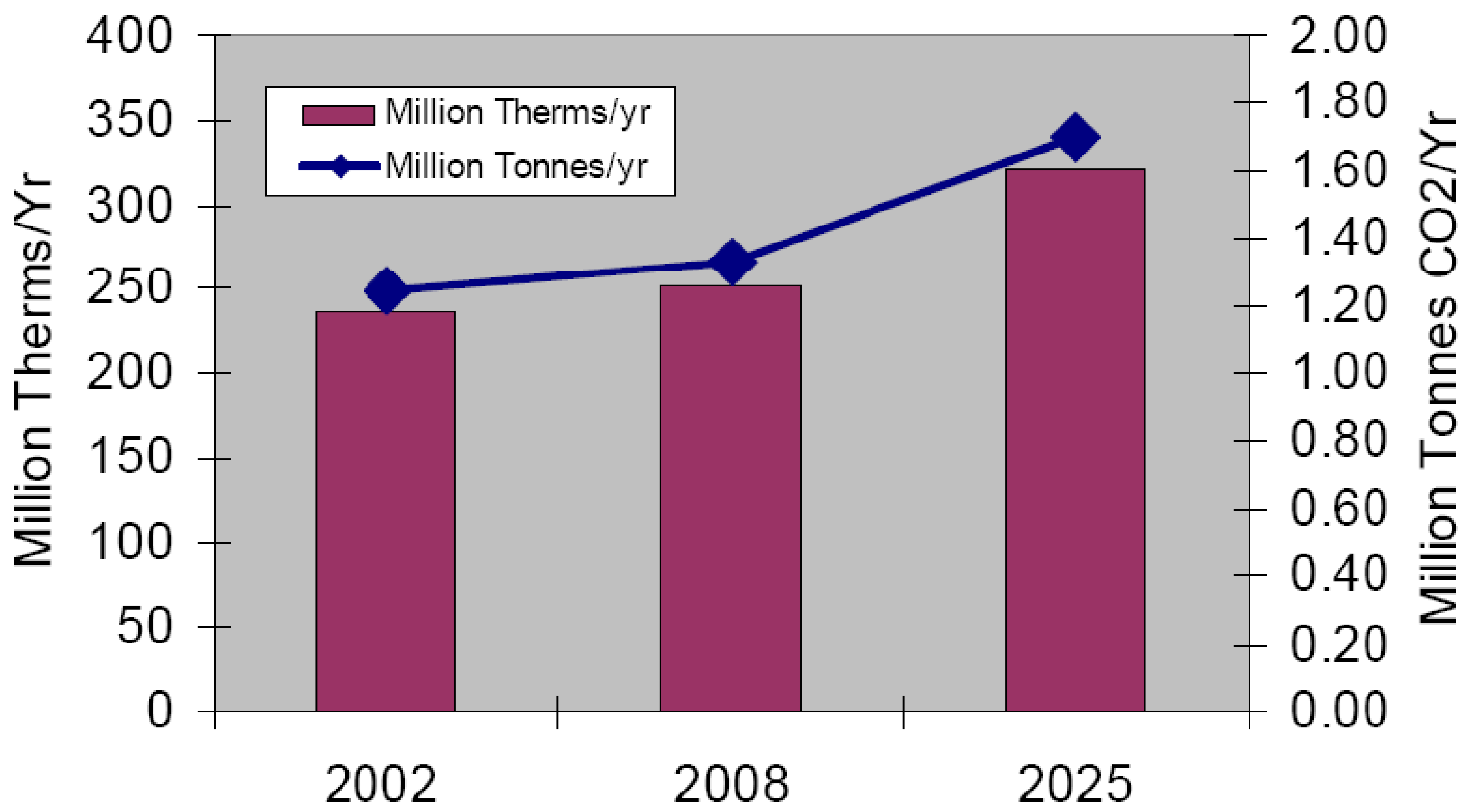
More NG Customers, Fewer GHG Emissions

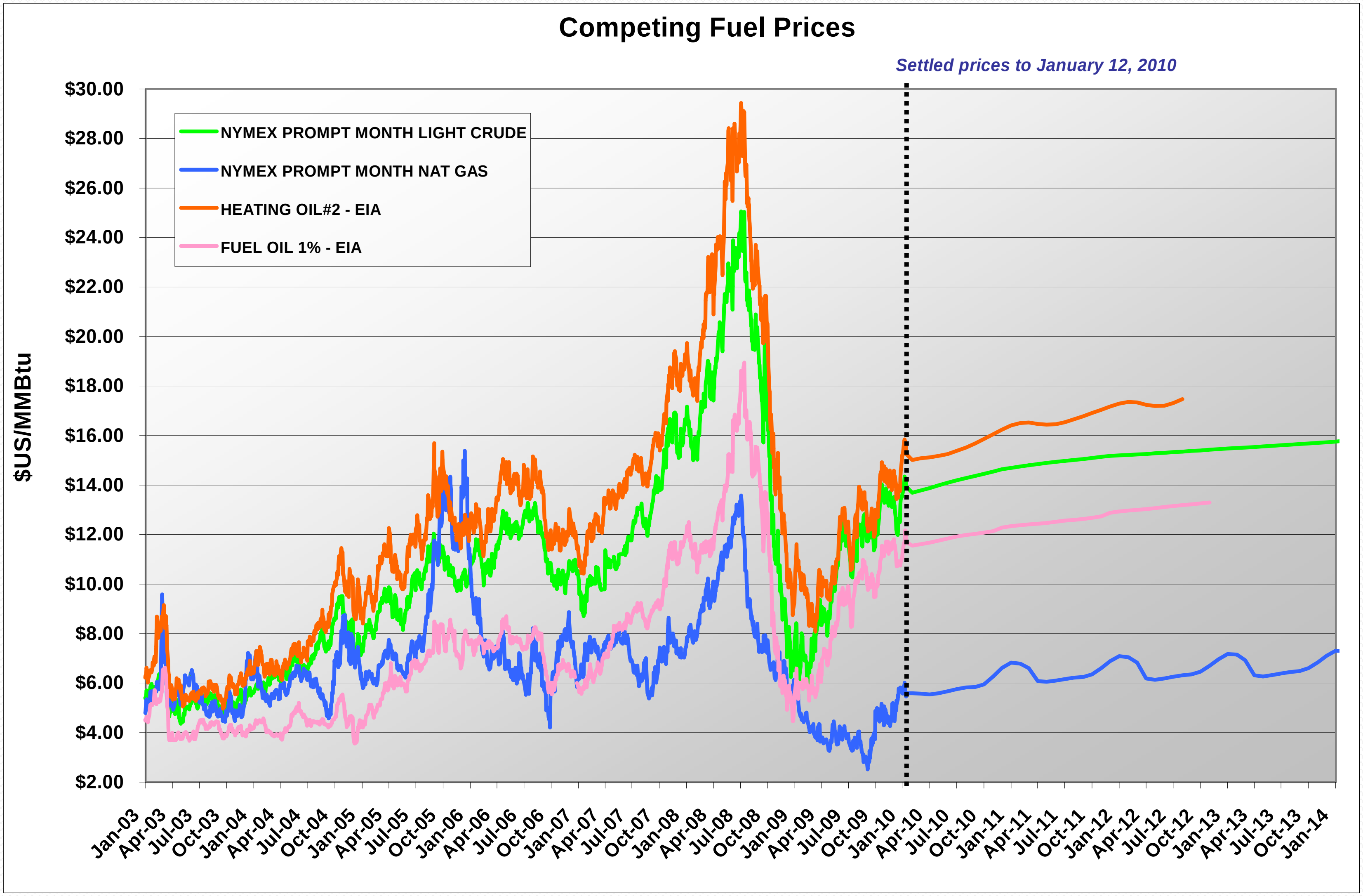


Source: *U.S. EPA, U.S. EIA* and the *American Gas Association*.

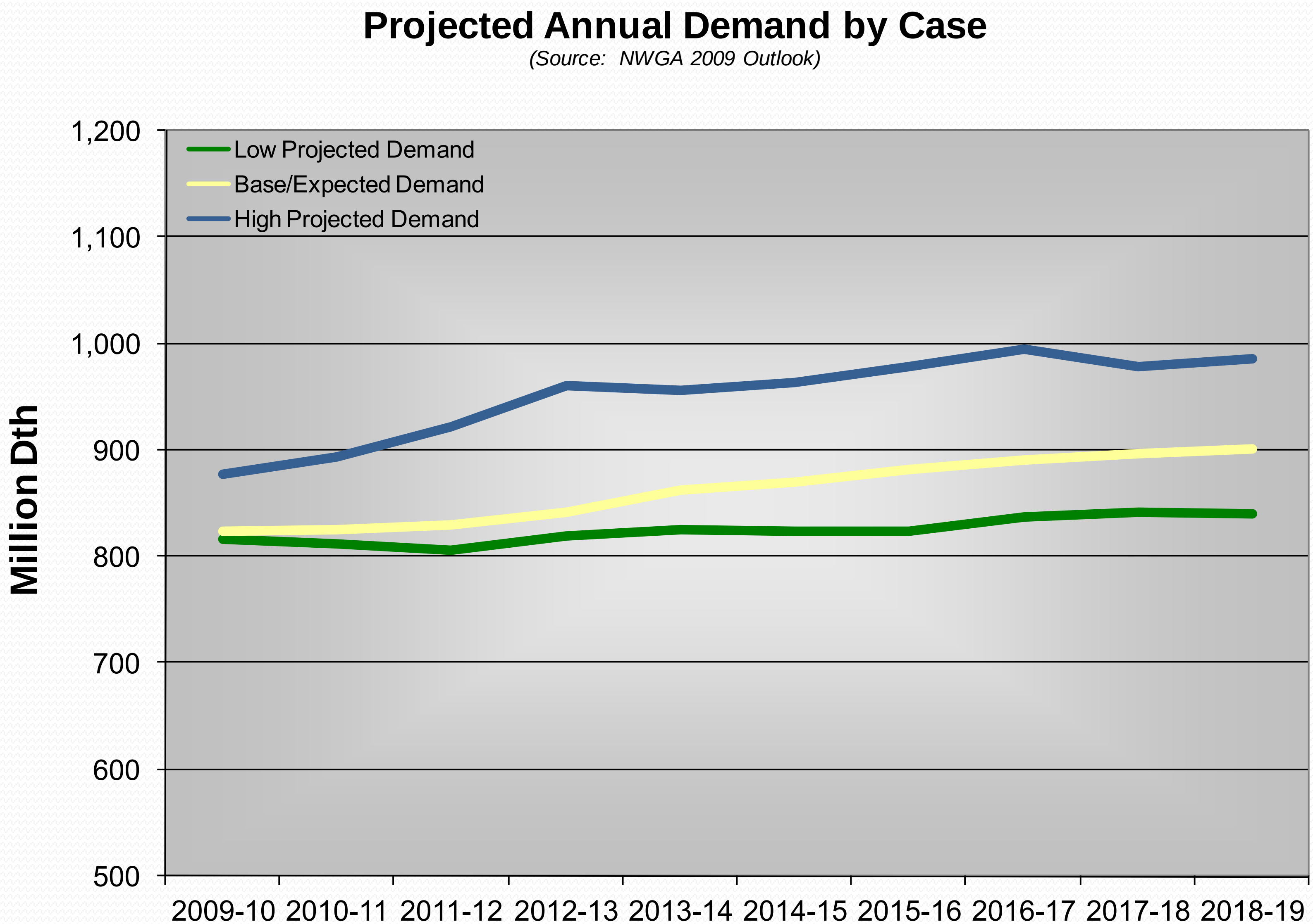
Potential PNW Energy and GHG Savings



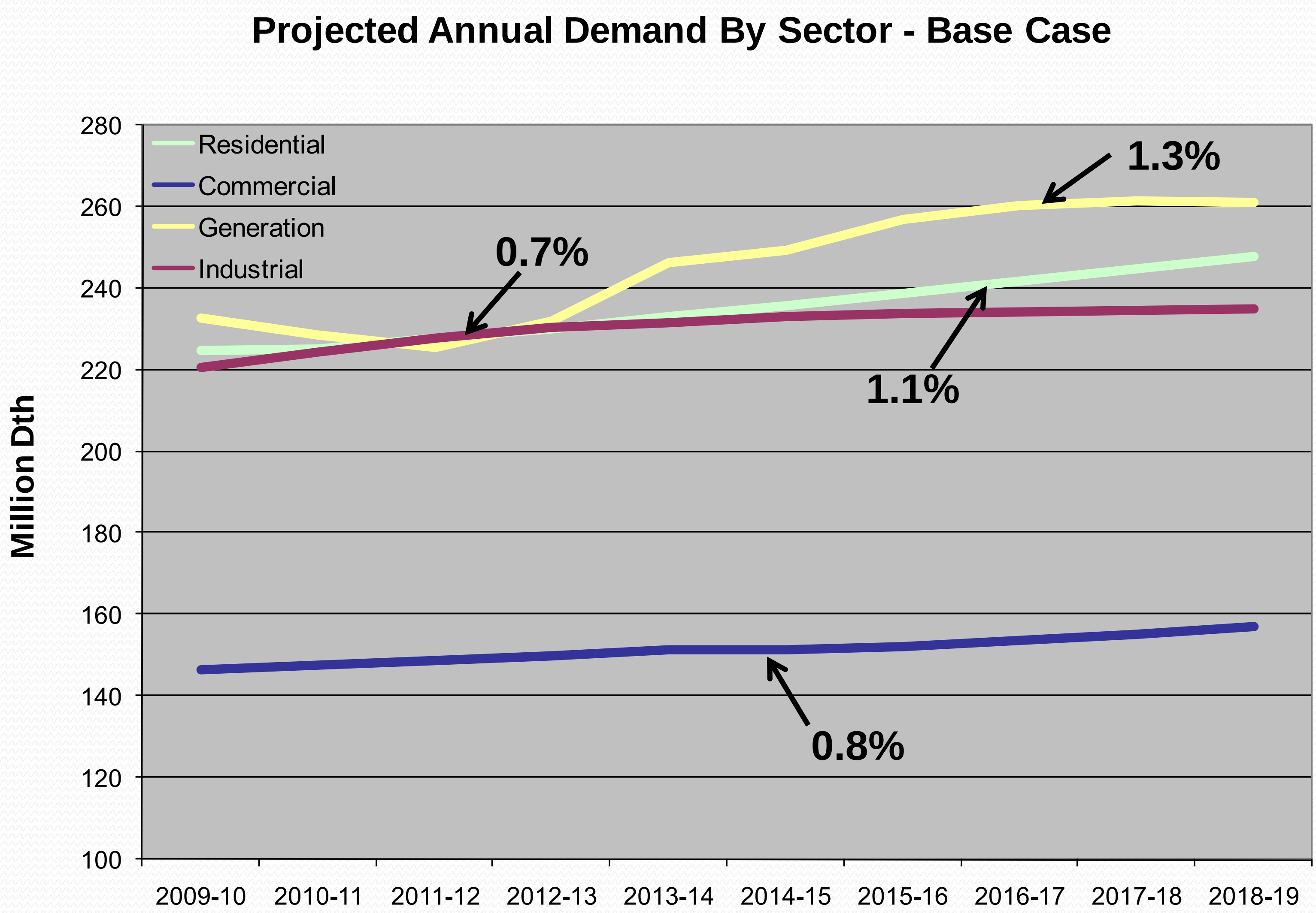
Natural Gas A Competitive Transportation Fuel



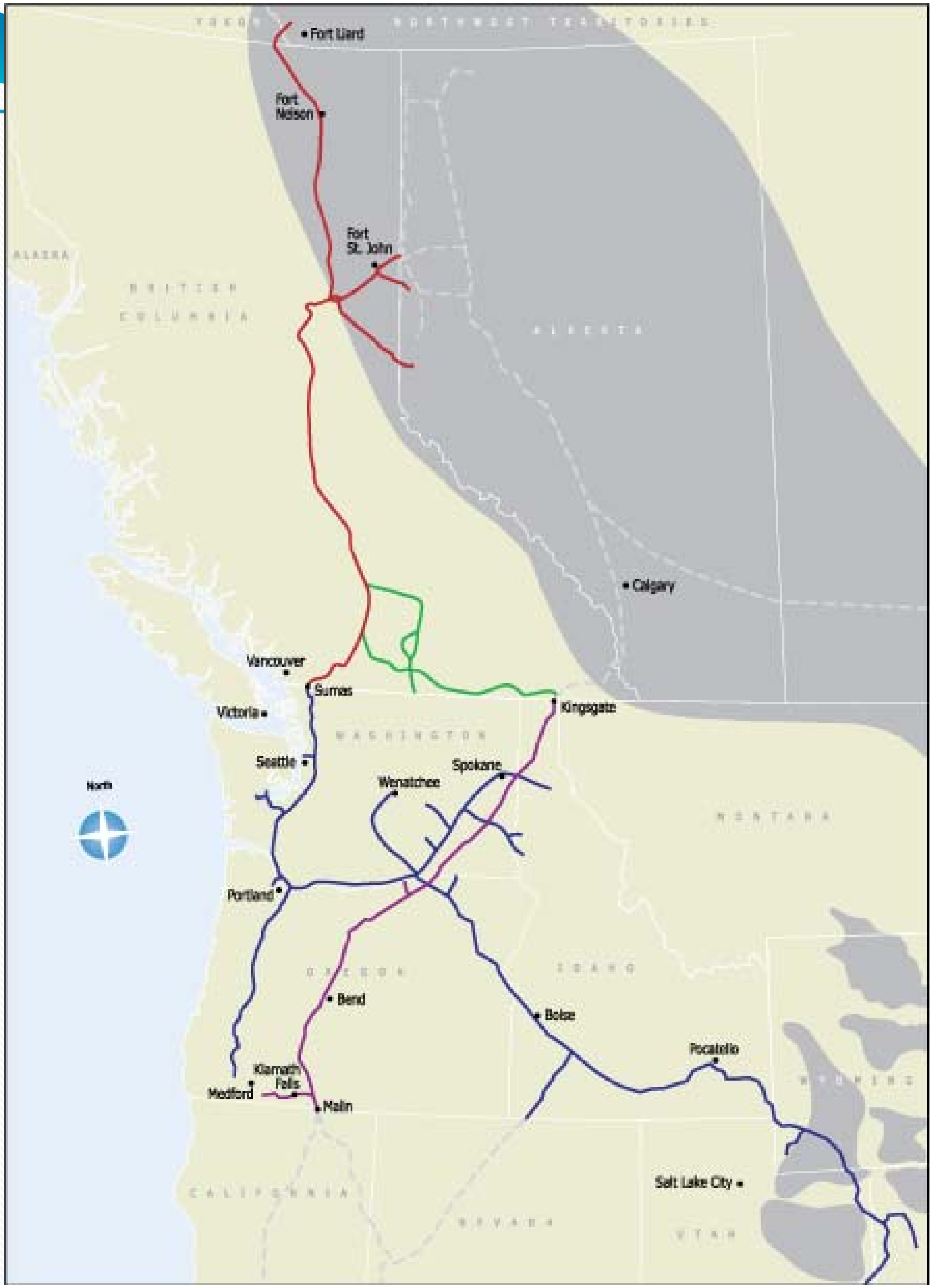
Demand Forecast by Case



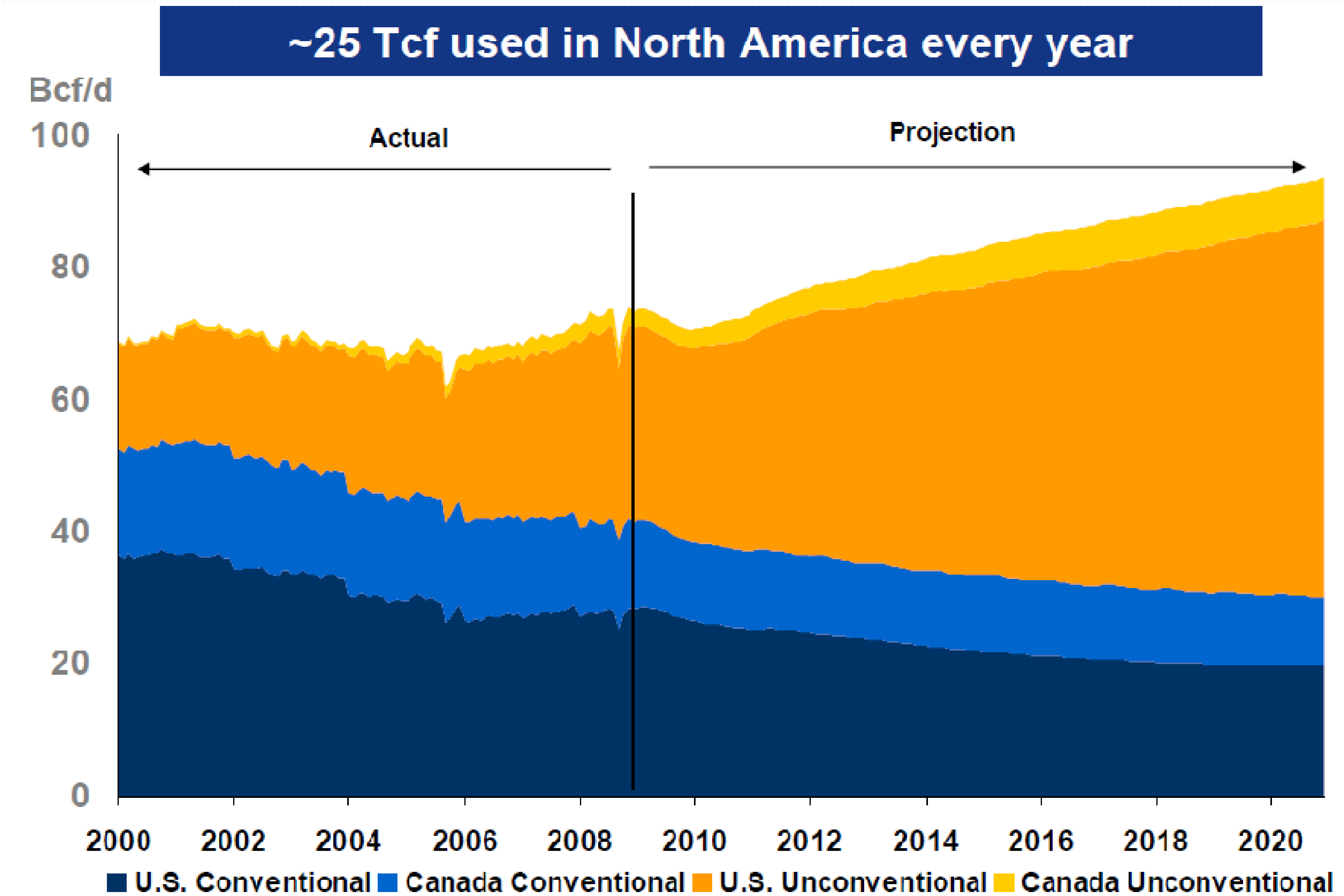
Base Case Forecast by Sector *(1%, 8.5%)*



PNW gas comes from WCSB and US Rockies.

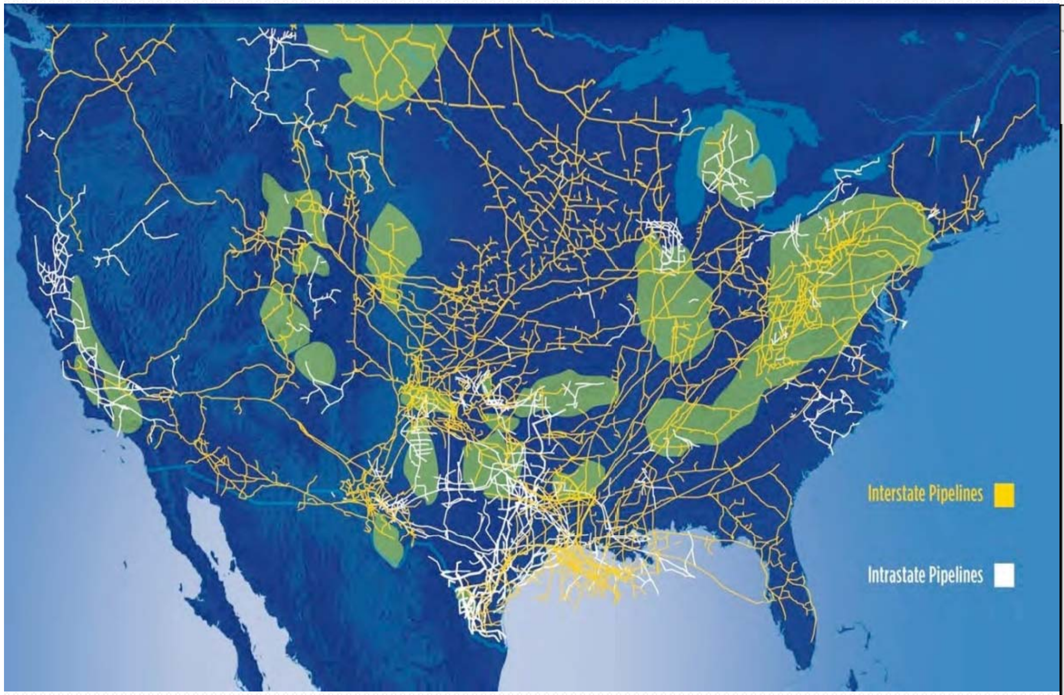


North American Supplies

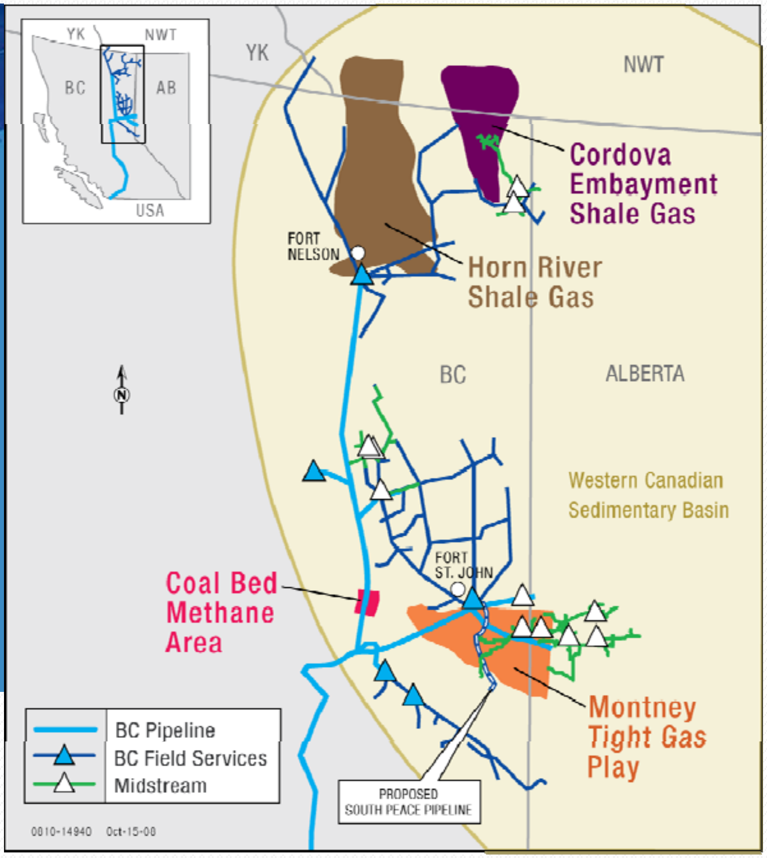


Shale Gas - *An Emerging Source of Significant Supply*

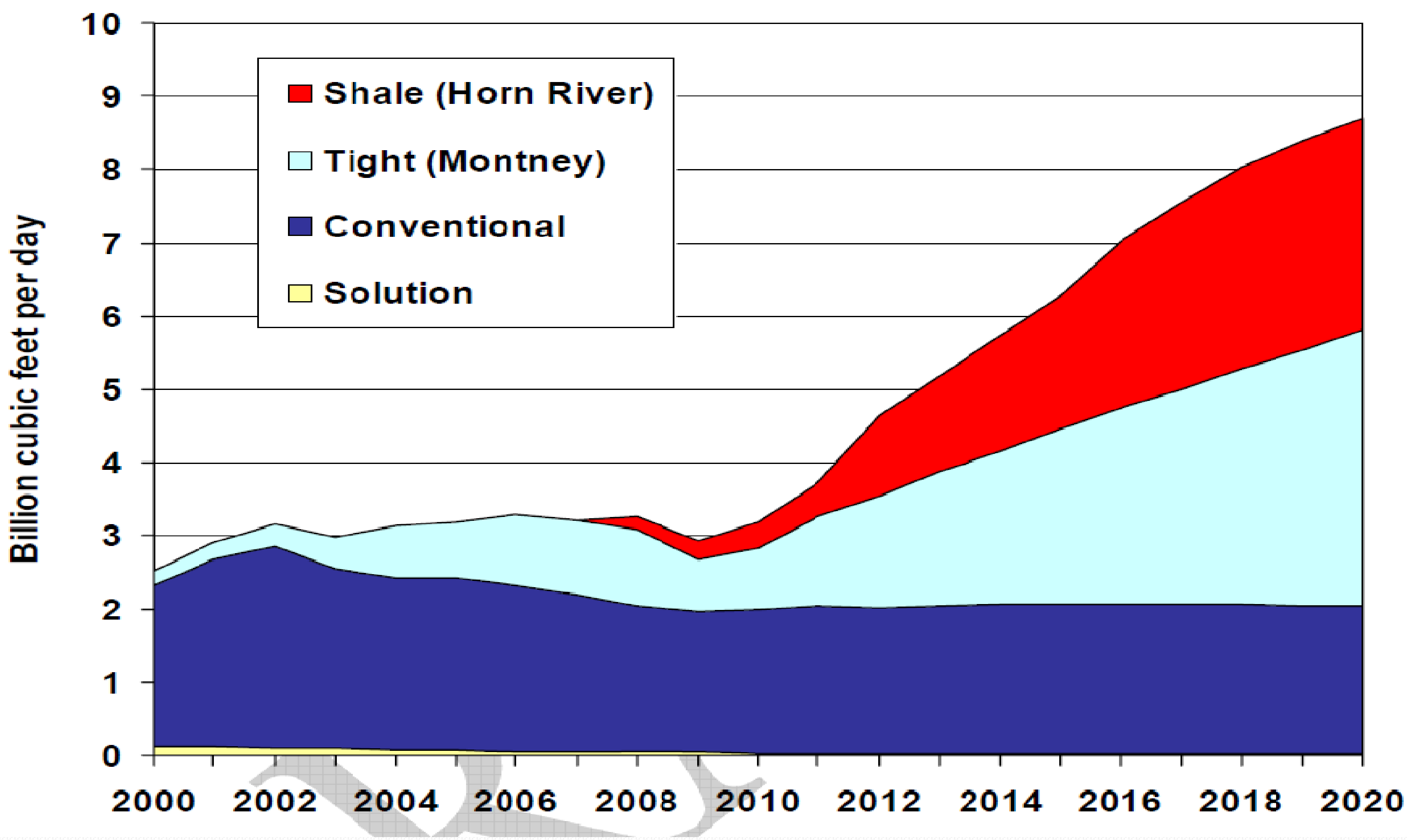
US Shale Gas Supply Areas



BC Shale/Tight Gas Supply Areas

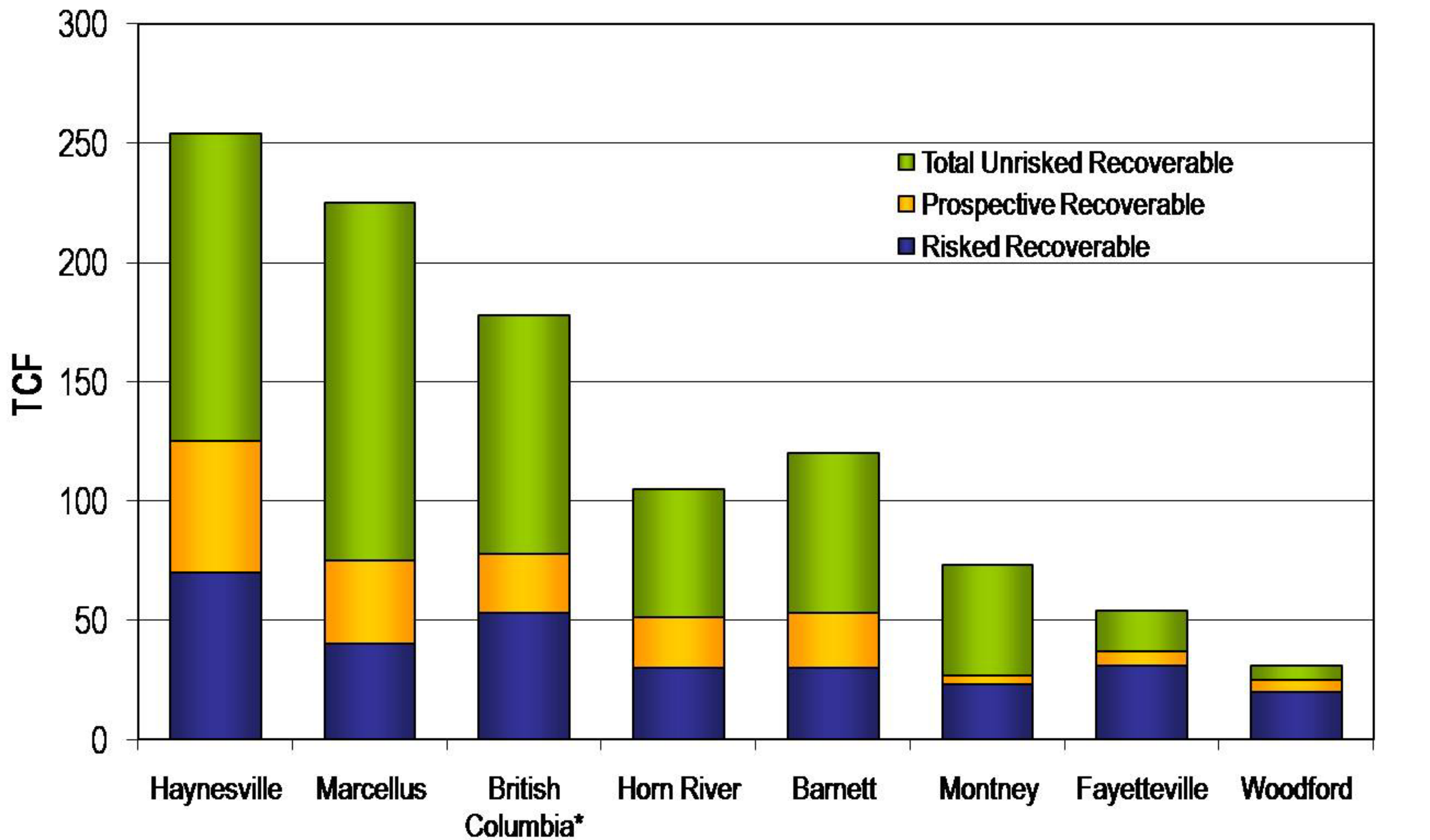


BC Gas Production Forecast (CAPP)



Source: Draft Final Report of the Oil and Gas Climate Action Working Group, Jan 2009

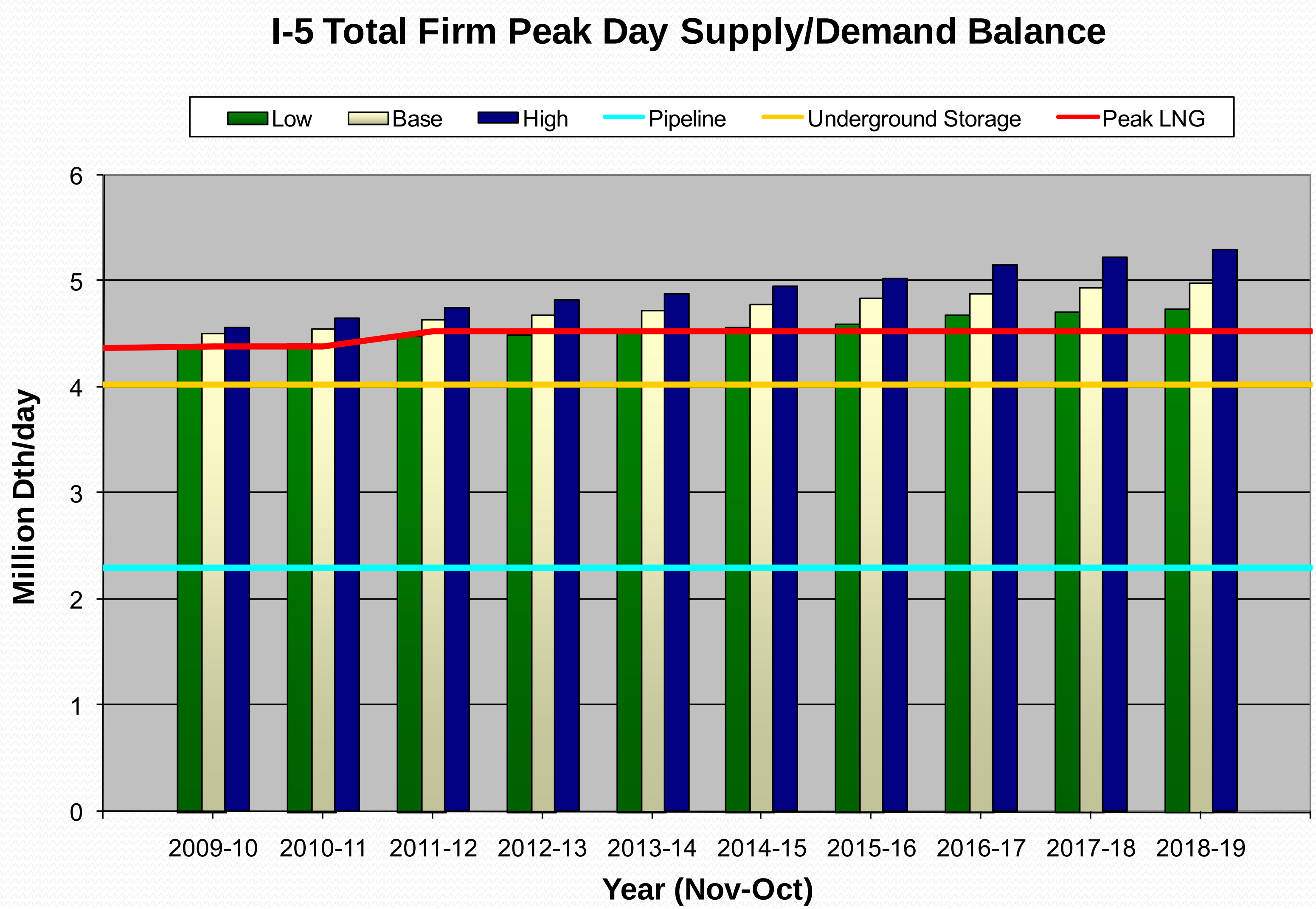
NA Shale Gas - Estimated Resource Potential



* Combined Horn River & Montney

Source: BMO Capital Markets

Extreme weather capacity stretched



Pipelines Proposed to Serve the Northwest

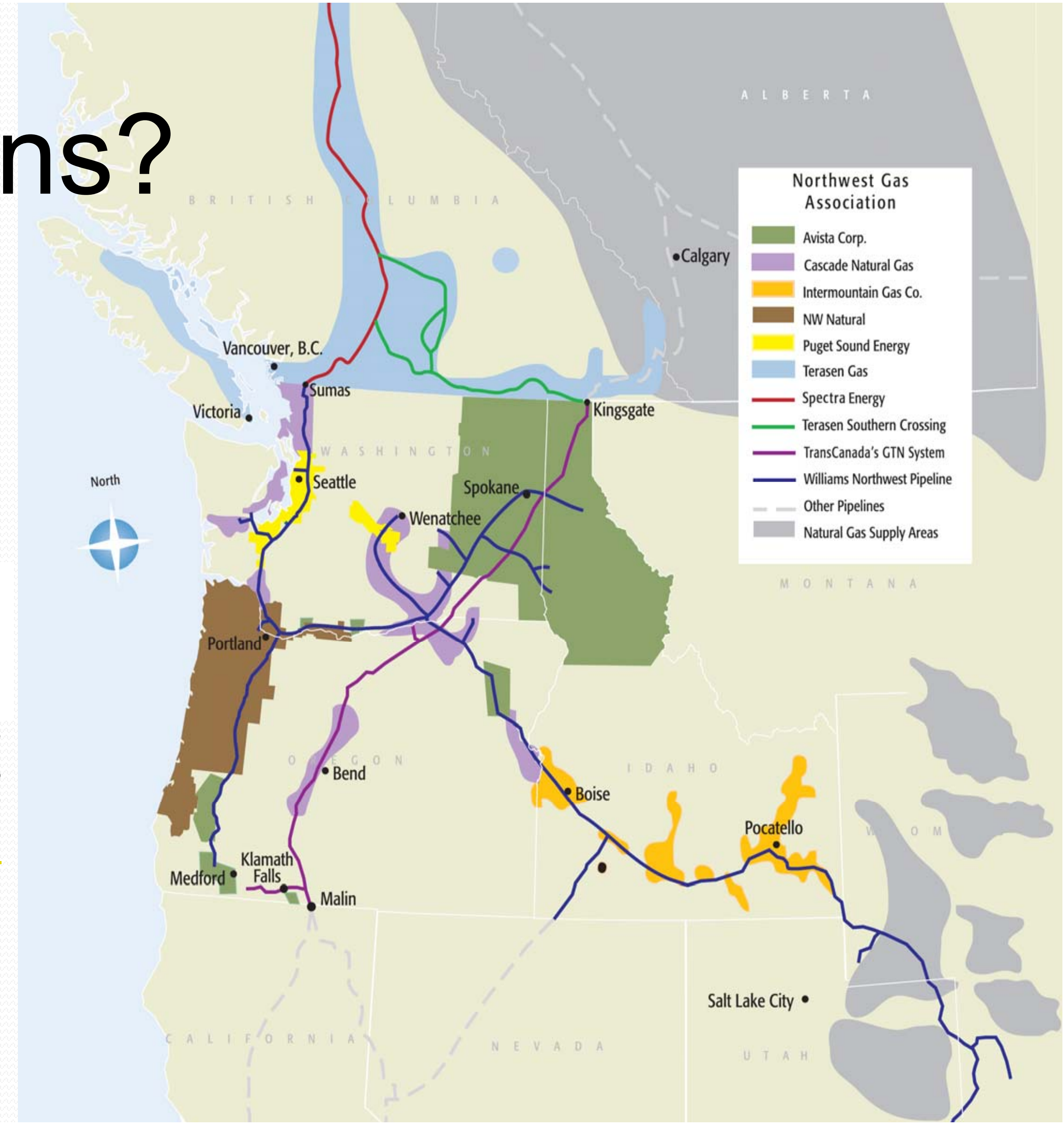
Pipelines

- Southern Crossing
- Palomar
- Blue Bridge
- Ruby

Observations

- ACES
  - Demand growing
    - Climate Change: NG will facilitate
      - generation
      - direct use
  - Supplies promising
      - improved technologies
      - infrastructure/access required
- Challenges
  - Adequate Infrastructure
  - Uncertain/Conflicting Public Policies
    - Demand, Supply, Infrastructure
  - Commodity Prices

Questions?



NWGA
NORTHWEST GAS ASSOCIATION
1914 Willamette Falls Dr., #255
West Linn, OR 97068
(503) 344-6637
www.nwga.org

Dan Kirschner
Executive Director
dkirschner@nwga.org

Integrated Resource Plan
Energy Solutions for British Columbia

February 2, 2010

Doug Stout

Vice President, Marketing & Business Development

Forward-Looking Statement

By their very nature, forward-looking statements are based on underlying assumptions and are subject to inherent risks and uncertainties surrounding future expectations generally. Such events include, but are not limited to, general economic, market and business conditions, regulatory developments, weather and competition. Terasen and Fortis cautions readers that should certain events or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary significantly from those expected. For additional information with respect to certain of these risks or factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. The Corporation disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Topics

terasen

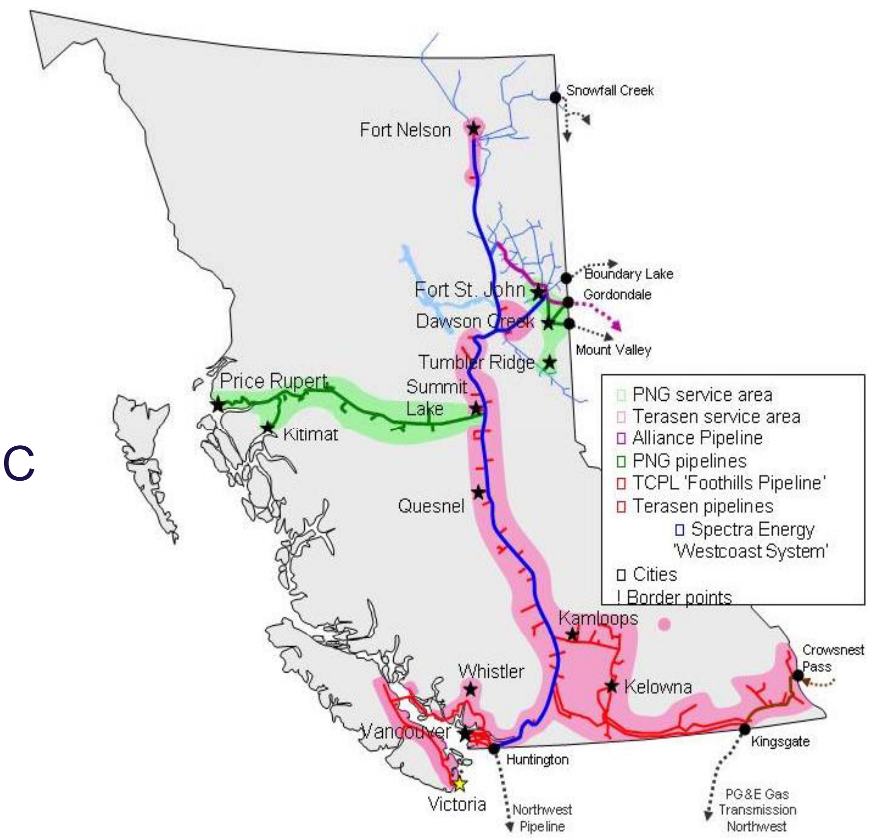
- Terasen - a Fortis Company
- External Factors Impacting:
  - Energy Use in BC
  - Energy Policy
  - GHGs
  - Use per Customer
  - New Supplies
- Terasen Solutions
- Vision for Future Energy Mix

Terasen - a Fortis Company

terasen

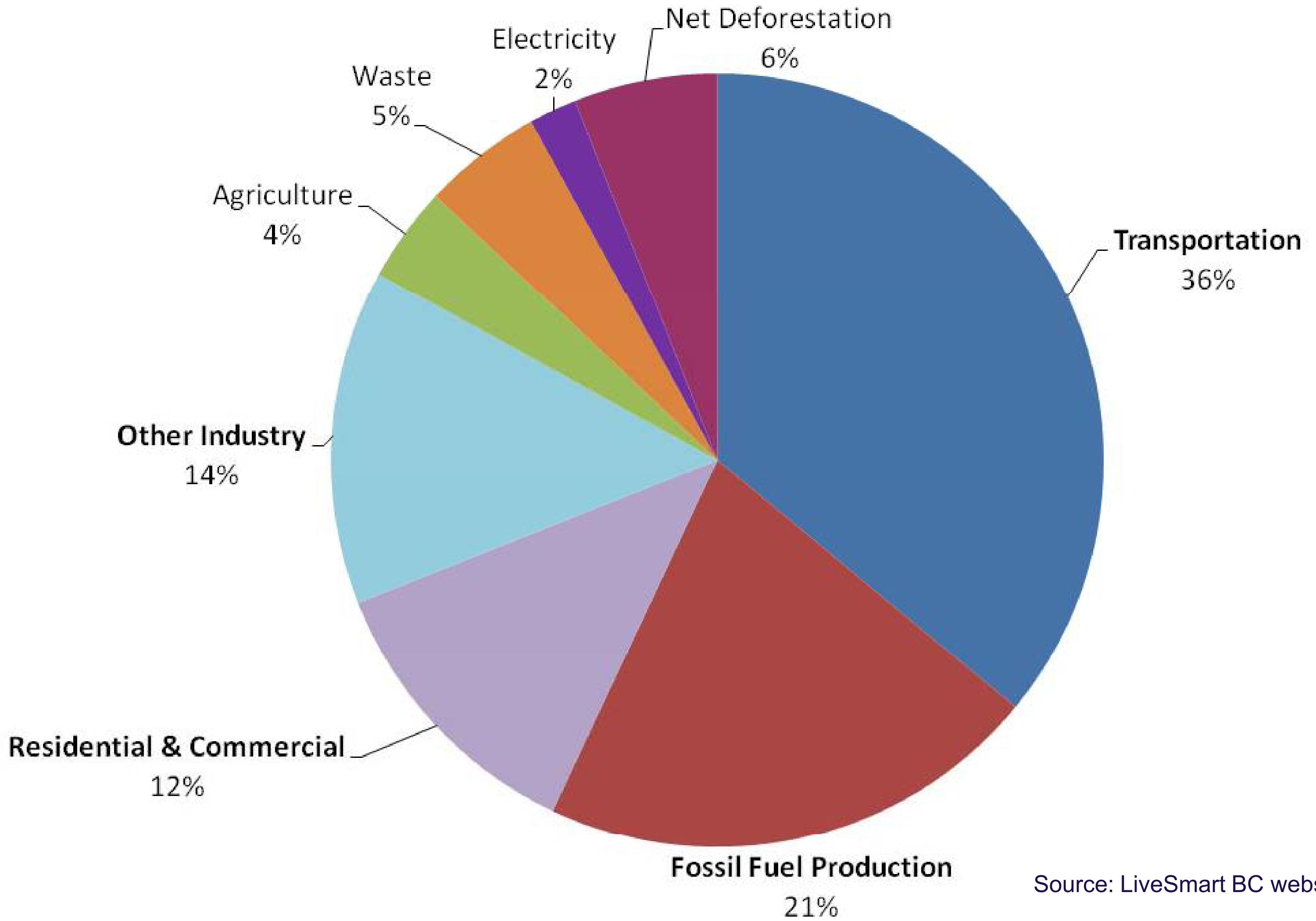
Deliver natural gas and provide alternative energy throughout BC

- Over 940,000 customers
- 125 communities
- 1400 employees
- 95% of the natural gas supplied in BC
- $4 billion investments in BC
- Regulated by BCUC



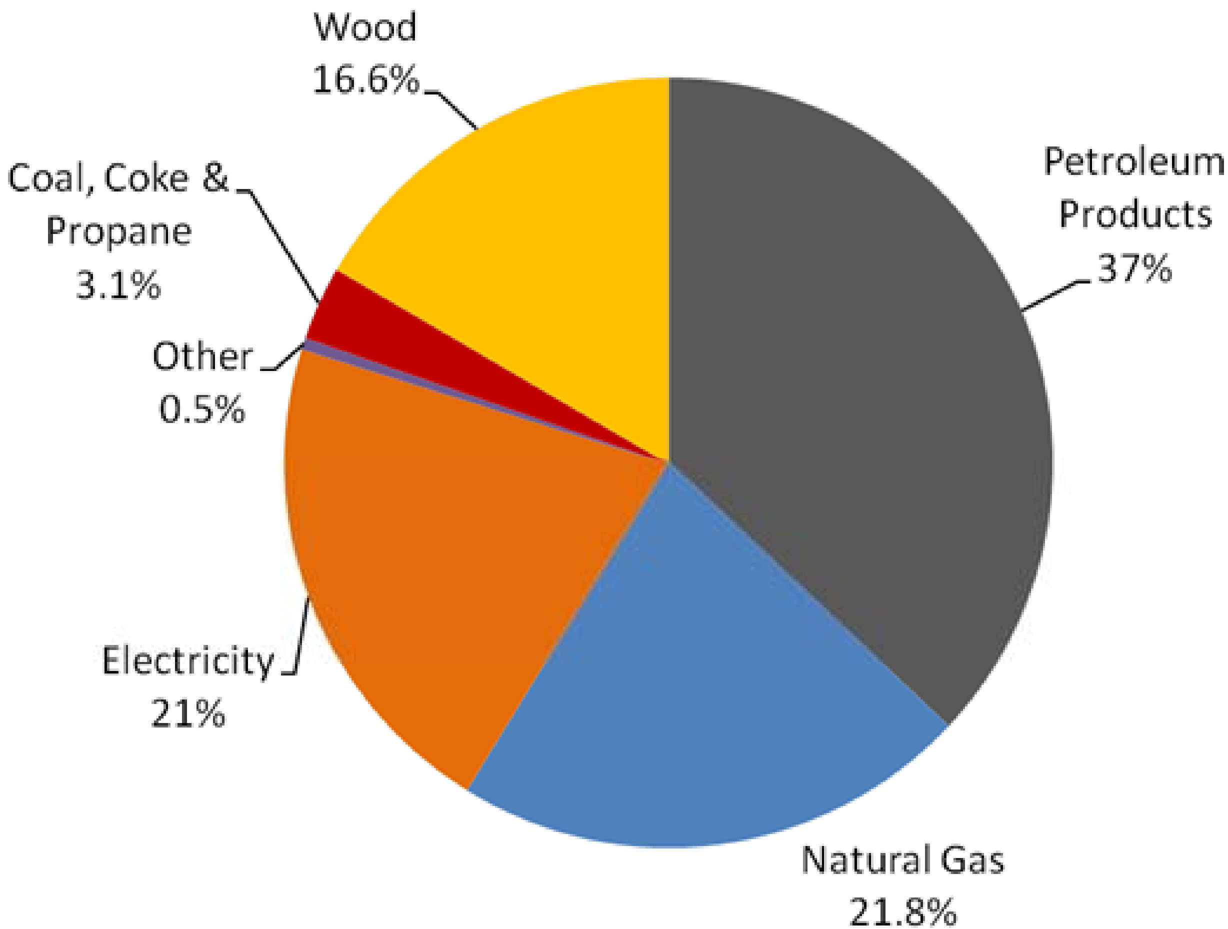
GHG Profile in BC: Opportunities to Reduce

terasen



Source: LiveSmart BC website (2006)

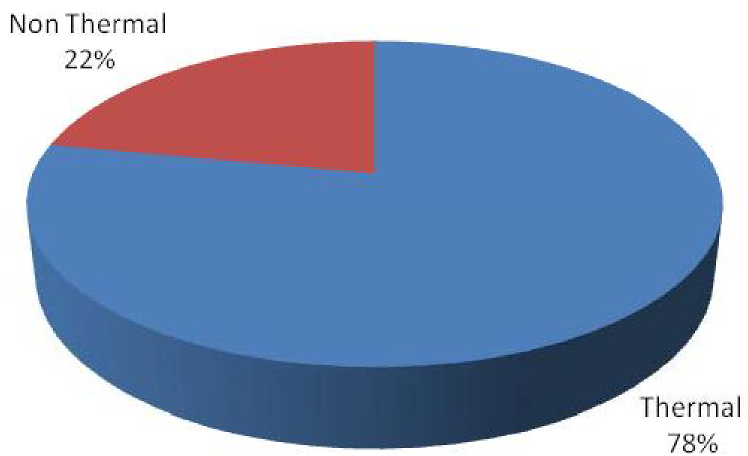
BC Energy End-Use



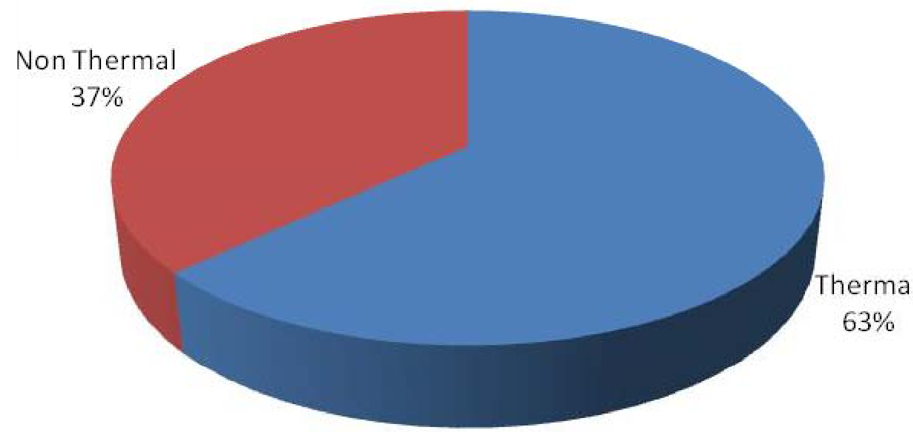
Source: NRCAN 2007 Stats

BC Energy End-Use Profiles

Residential



Commercial

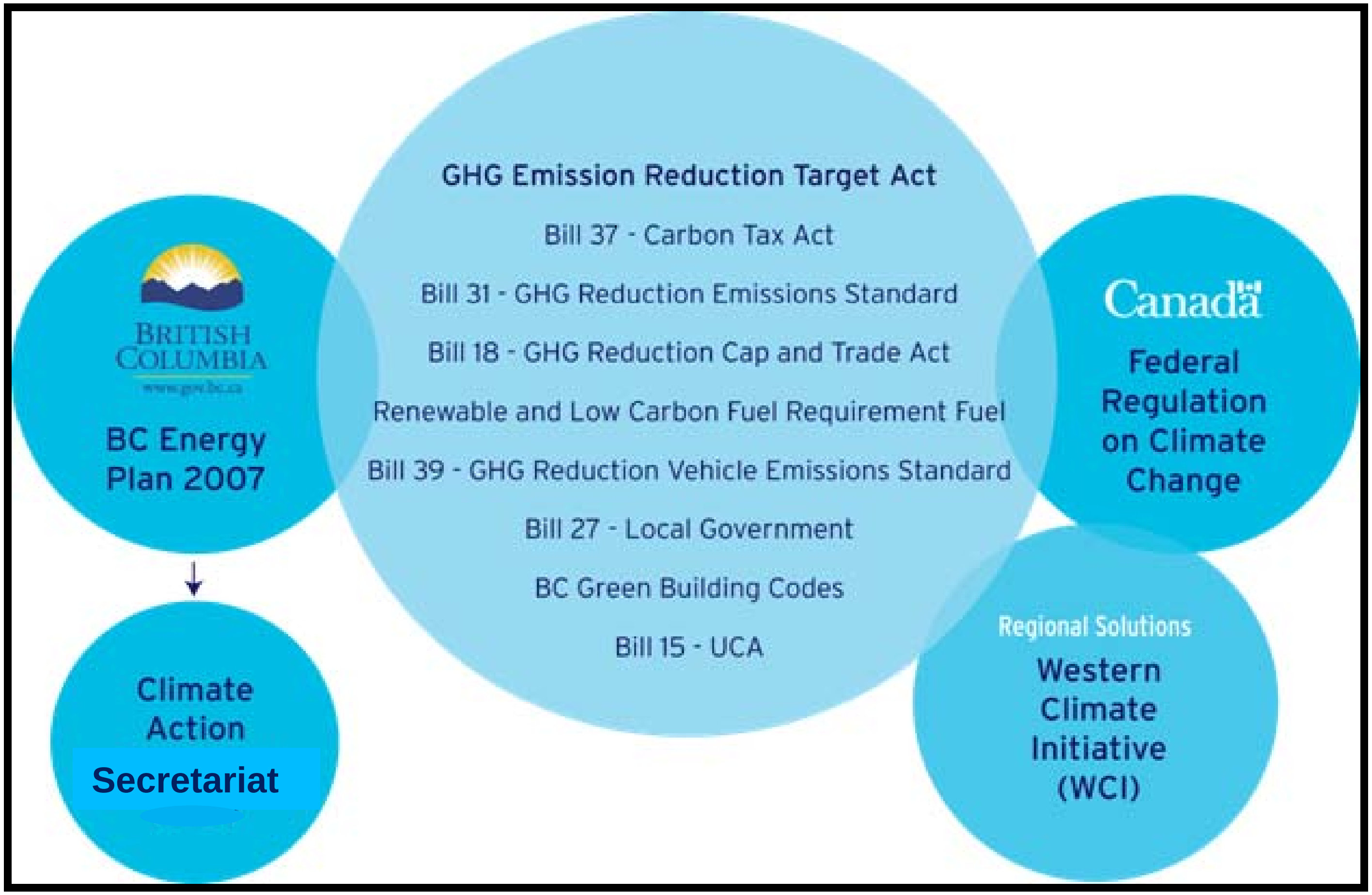


Thermal includes space heating, space cooling, water heating

Source: NRCAN 2007 Stats

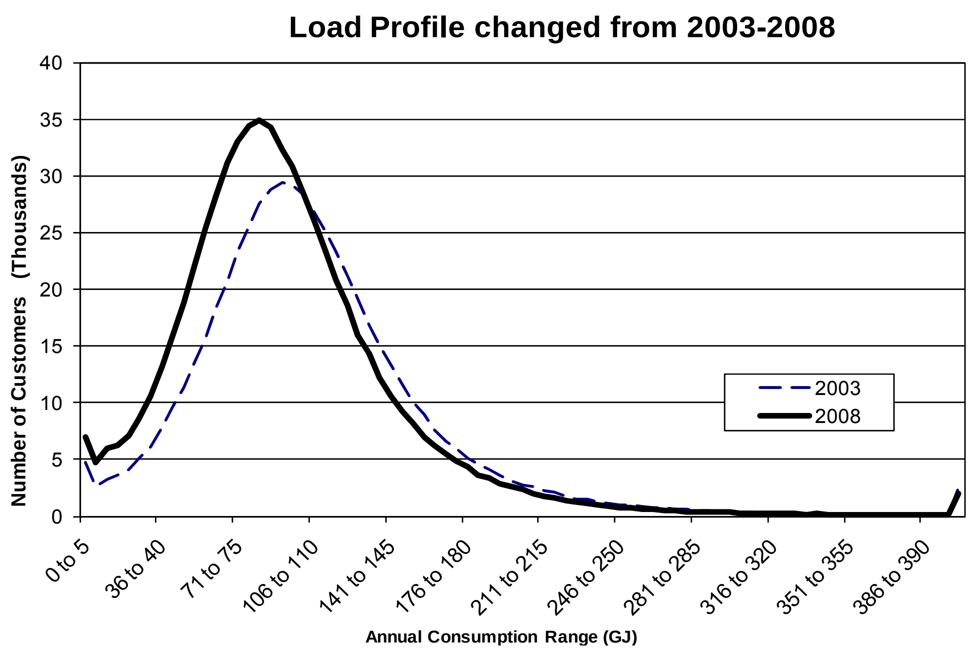
External Environment

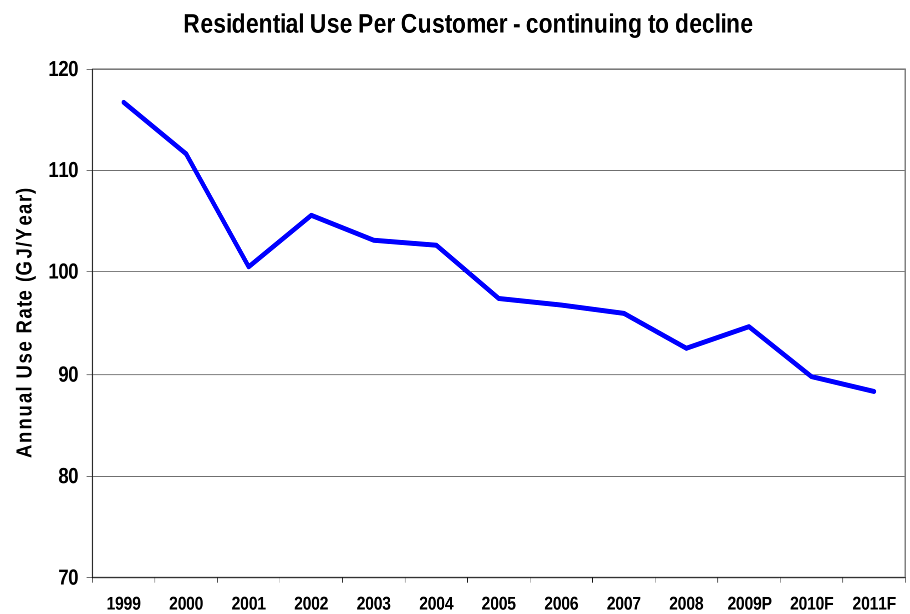
Changing Expectations & Regulation
All levels of Government



Residential Average Use Per Customer (TGI)

terasen

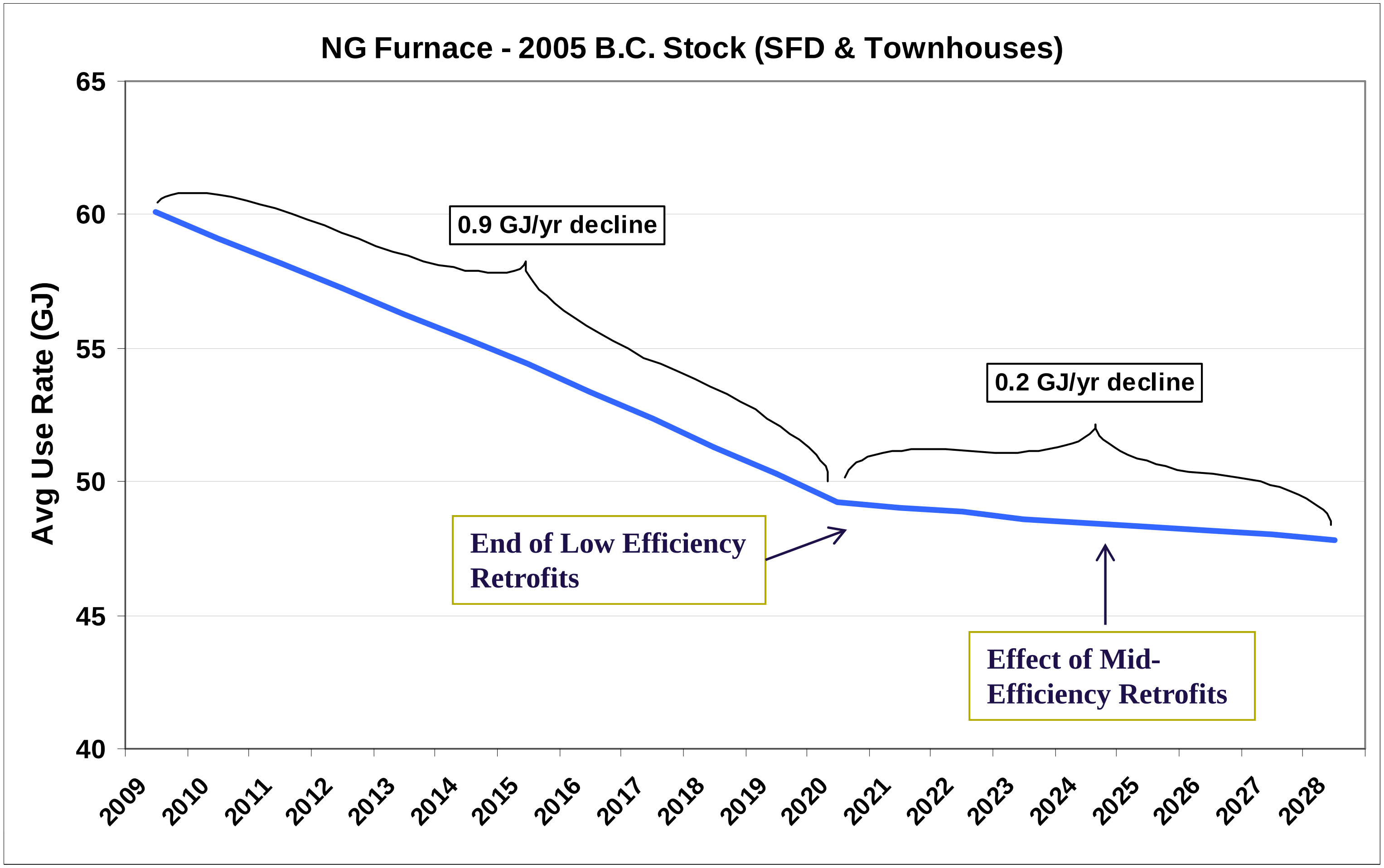




- Increased share of MFDs in the housing mix
- Retrofit of low & mid-efficient appliances
- Building Envelope
- Ongoing conservation efforts
- 21% decline since 1999 (2.5% annually)
- Reflects changing residential load profile
- Forecast is for a continuing decline in use rates

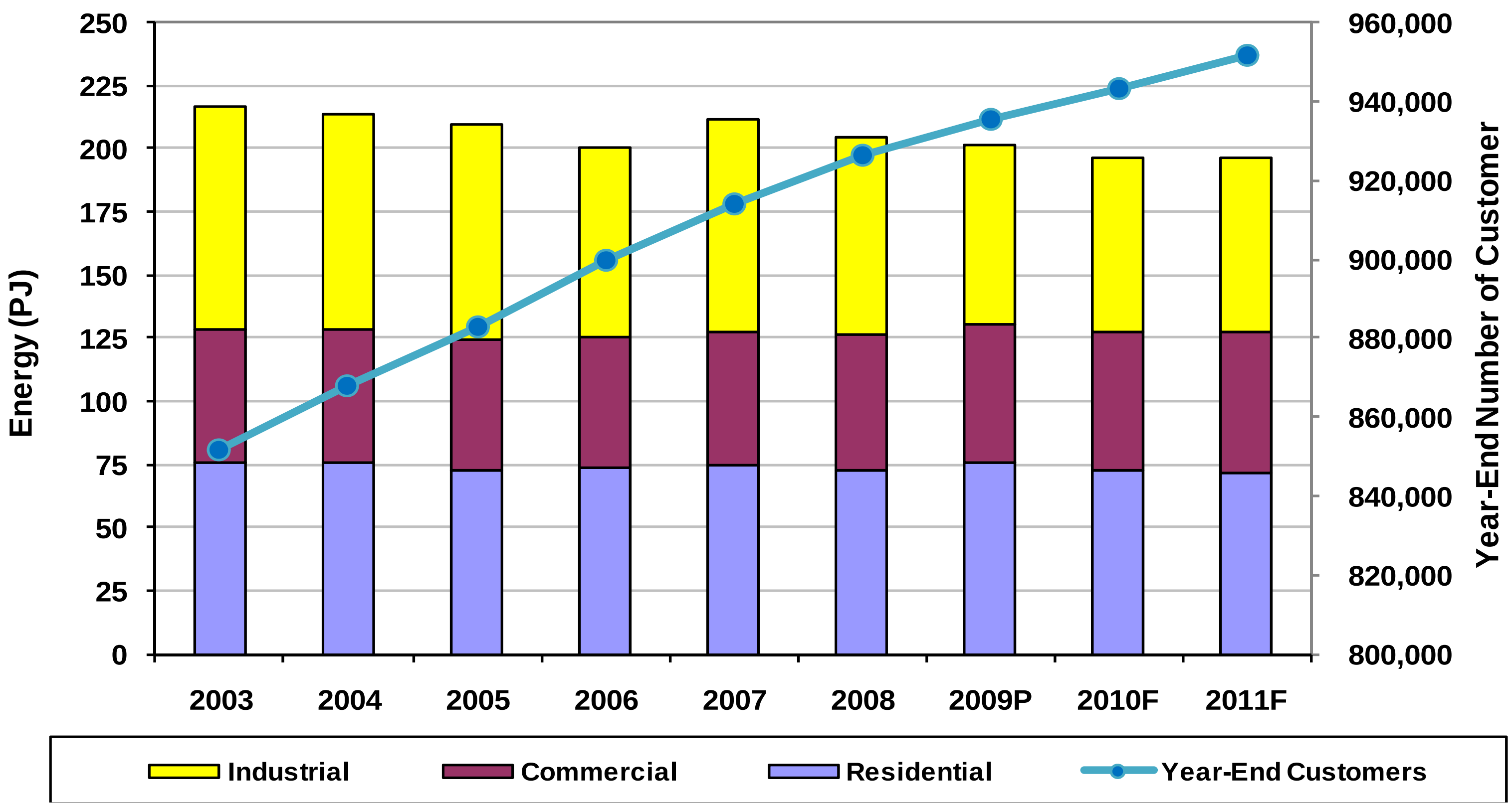
Impact of Furnace Retrofits on Use Per Account (TGI)

terasen



Improving Efficiency:
Demand Stable While Adding Customers

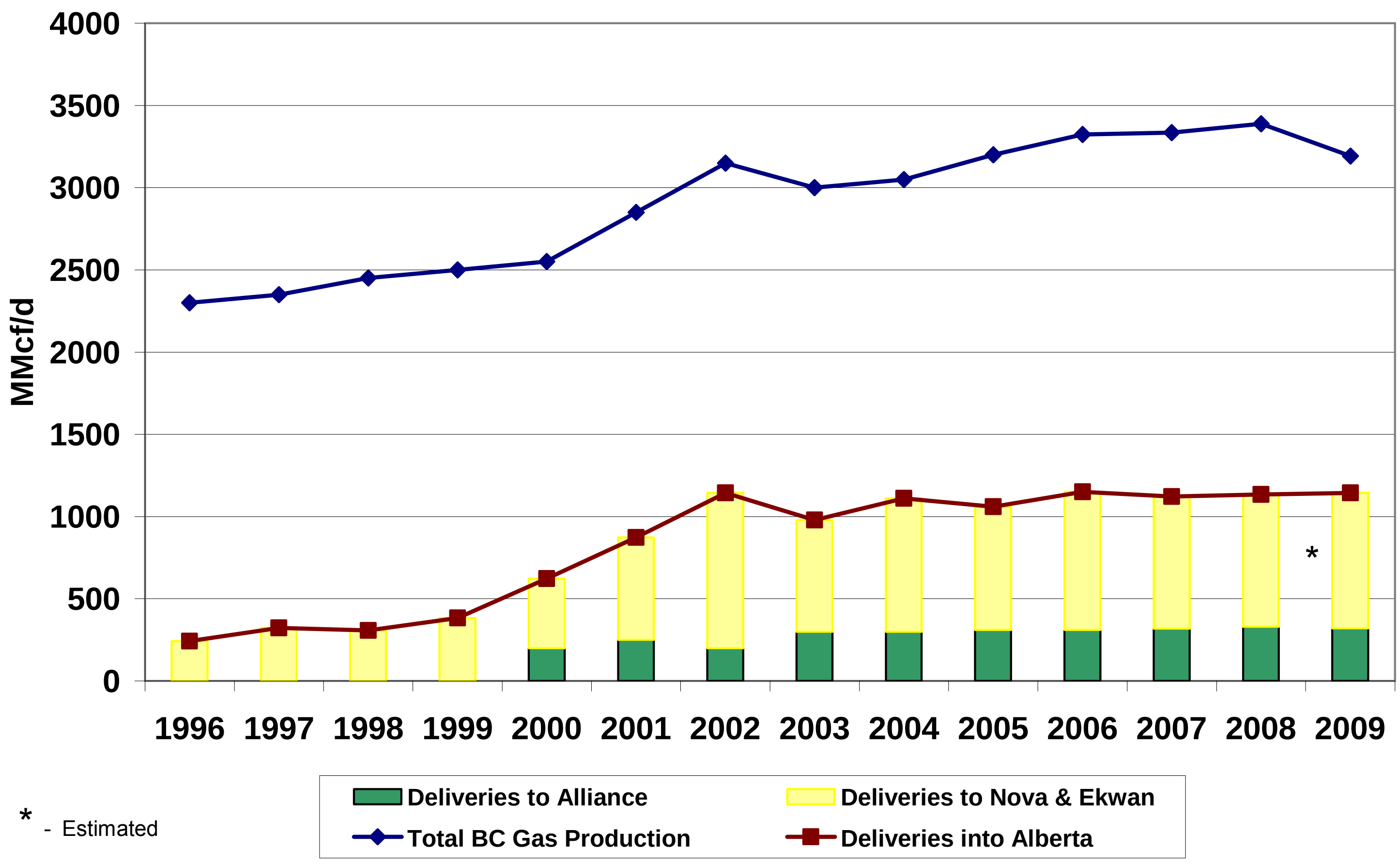
Terasen



100,000 customers added since 2003 with no change in demand

BC Gas Supply - Production & Flows

terasen

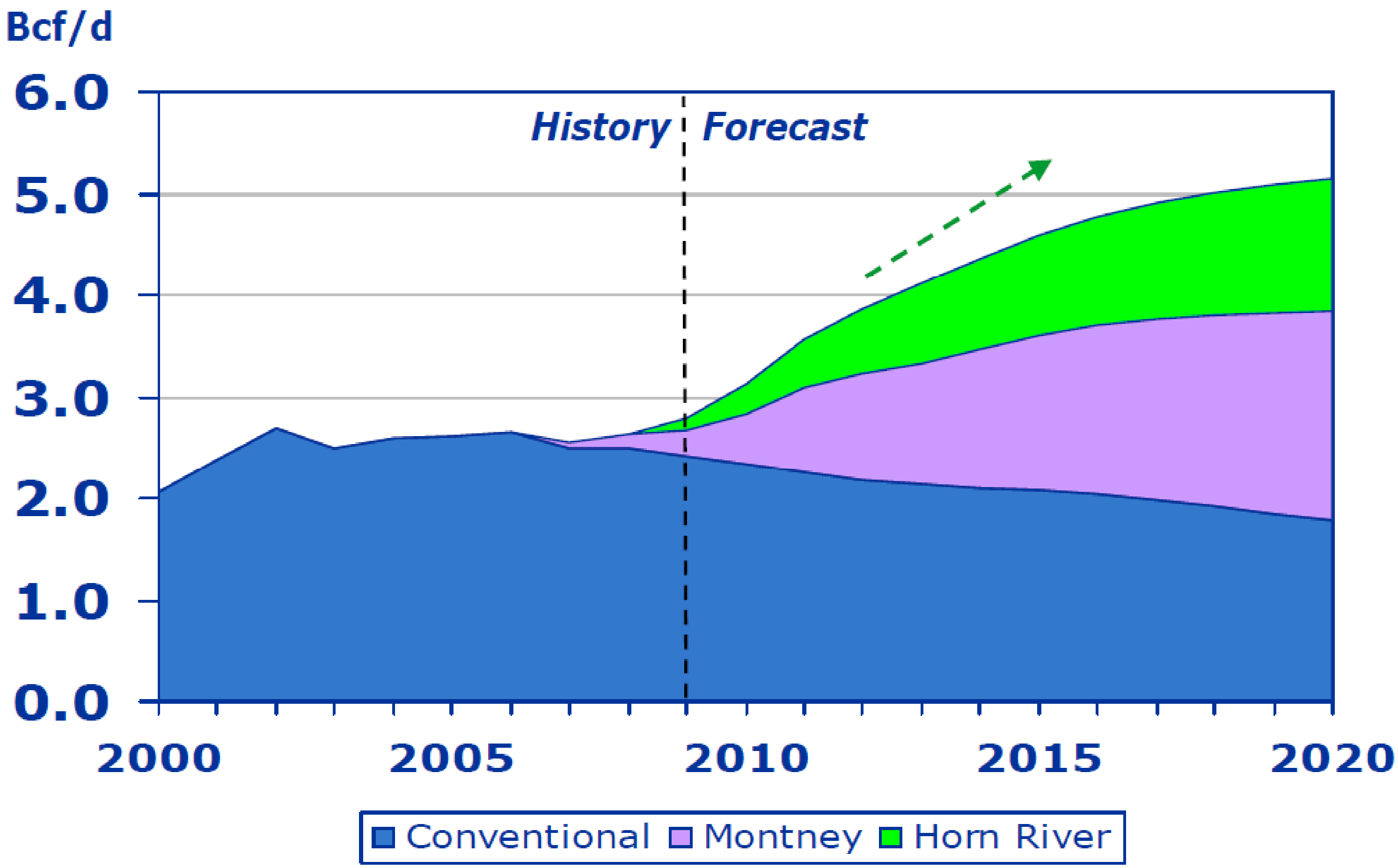


* - Estimated

Source: B.C. Ministry of Energy, Mines & Petroleum & Alliance Pipeline

BC Natural Gas Production Expected to Double in the Next 10 Years

terasen

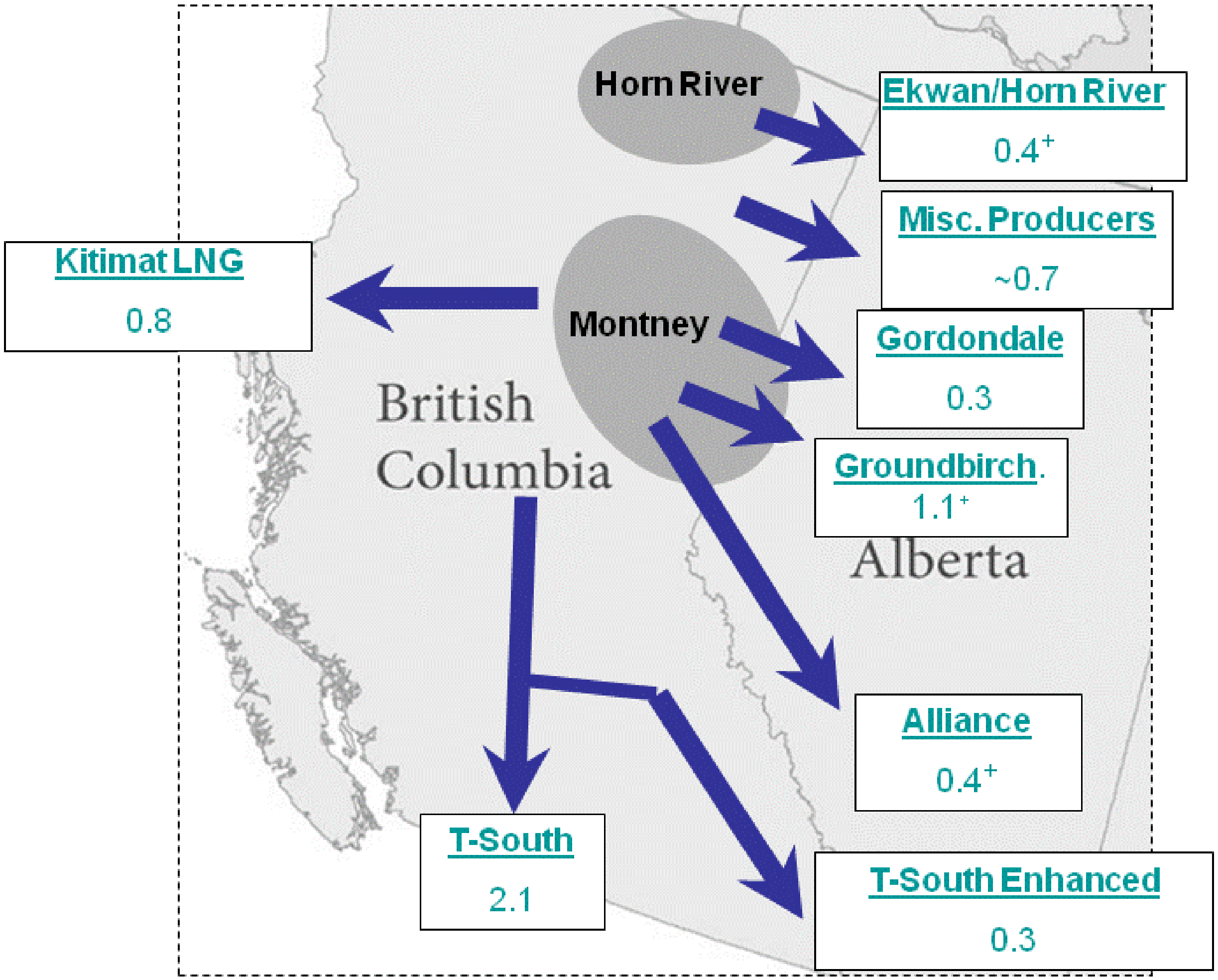


Source: TransCanada

Connecting BC Supply Basins

Terasen

Potential BC Take-Away Capacity 2015 (Bcf/d)

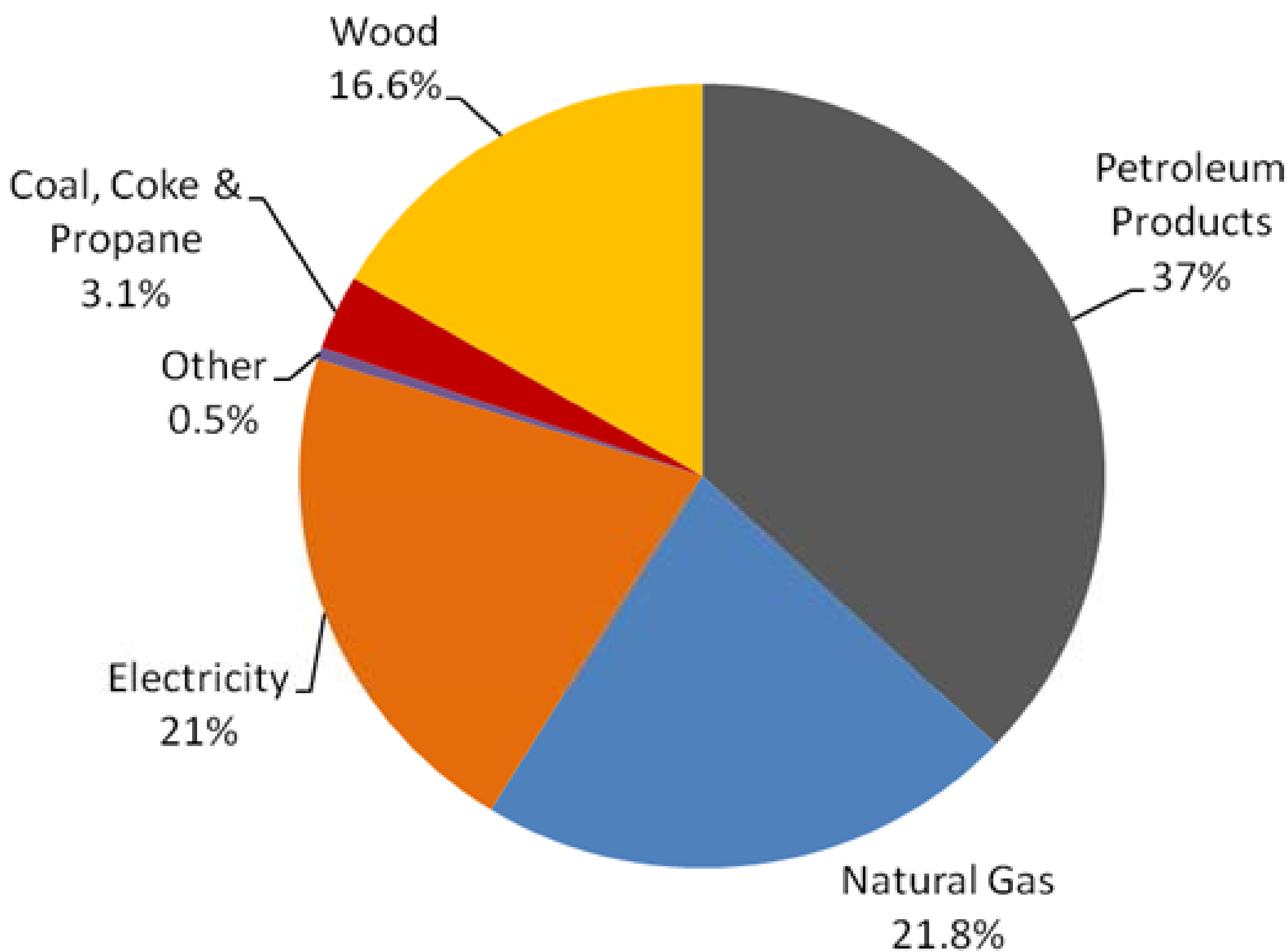


Abundance BC supply

Numerous projects proposed to export to Alberta and abroad

The Energy Challenge

terasen



Source: NRCAN 2007 Stats

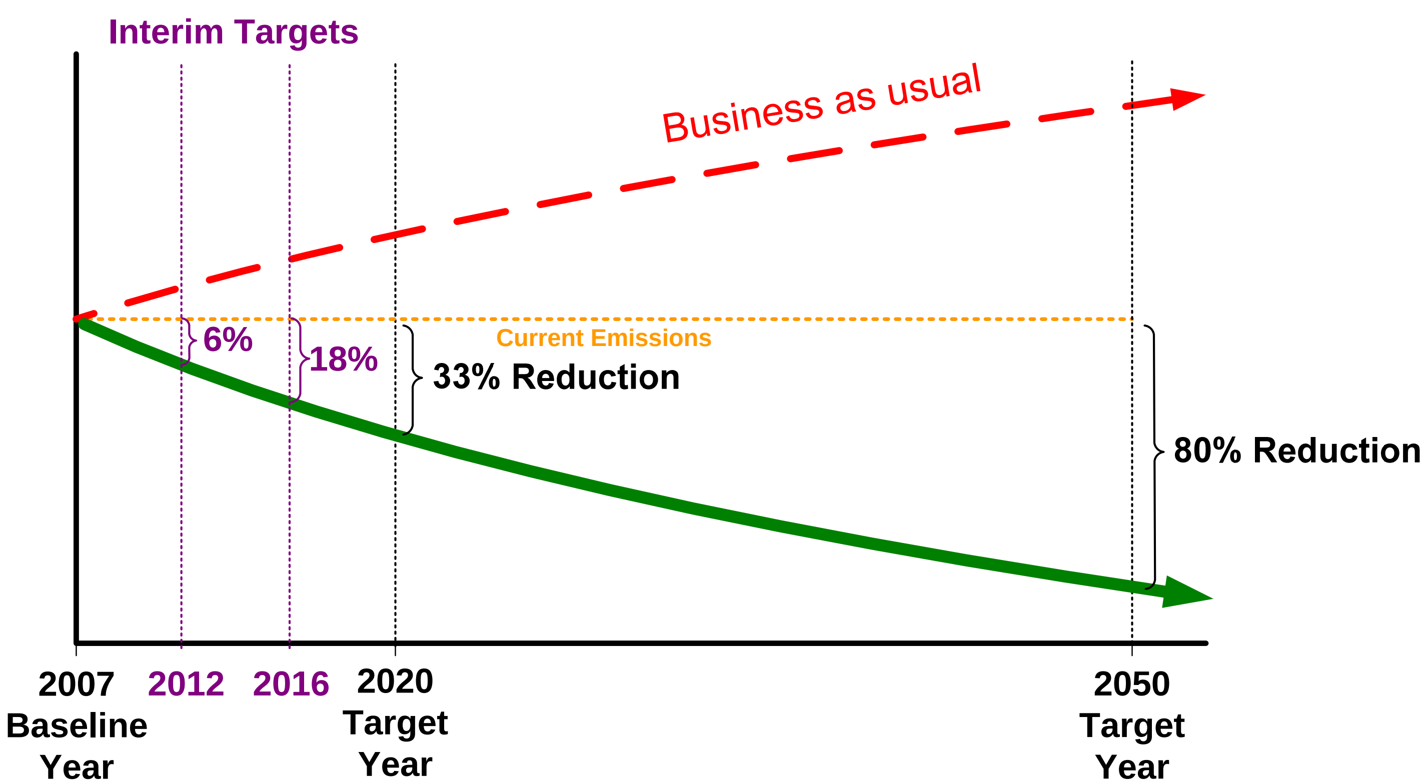
Summary: External Situation

- Growing population in BC will create demand for more energy
- Government Policy focused on GHG reductions
- Abundant sources of energy in BC
  - *Natural gas, renewable electricity, and renewable thermal energy, biogas*

Terasen:
Energy Solutions

BC Legislated Targets

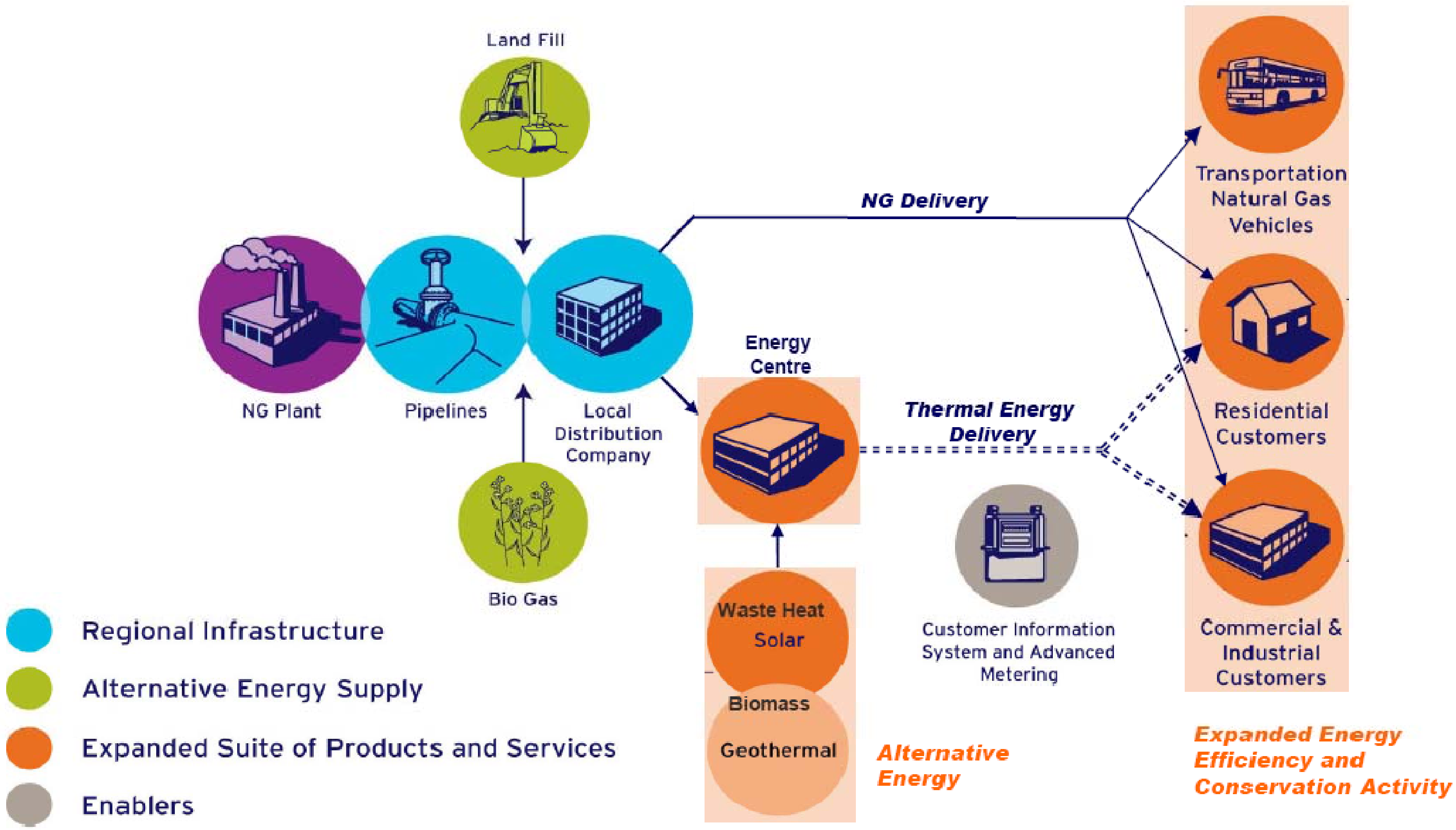
Reducing BC's GHG emissions by at least 33% below 2007 levels by 2020 and at least 80% below by 2050



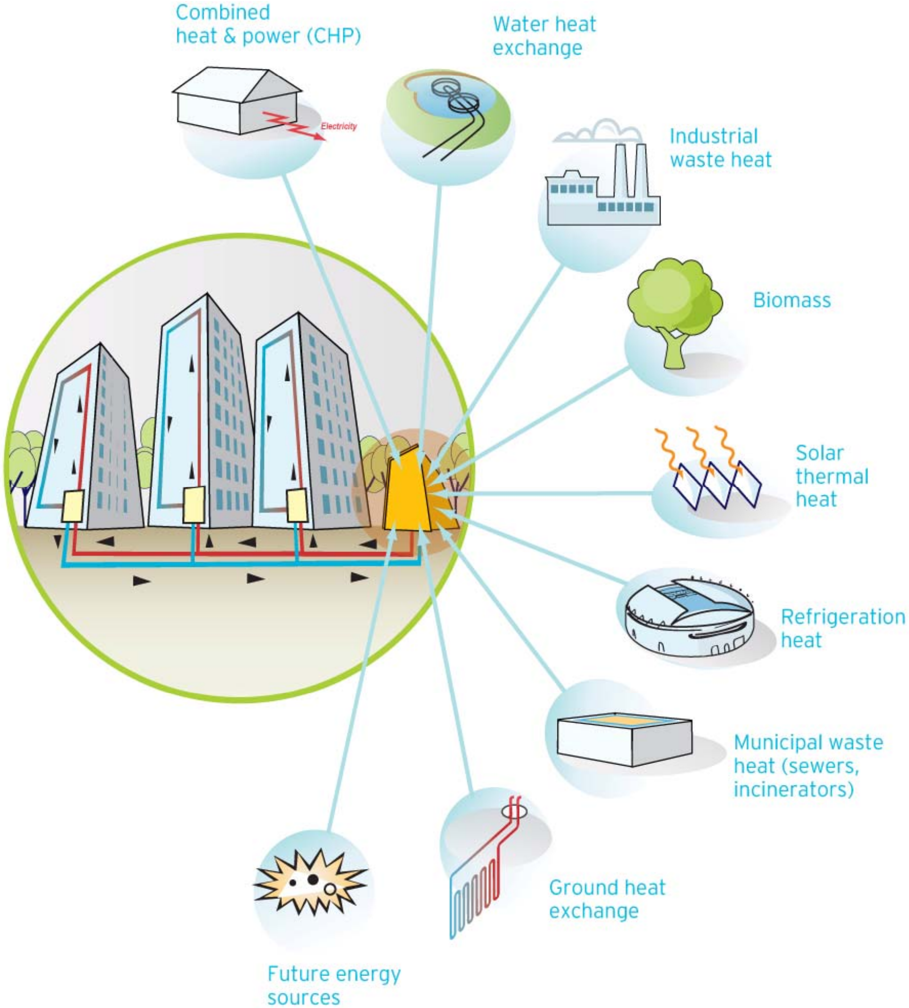
Terasen: Solution Assumptions

- One “climate system”
- Energy efficiency initiatives
- Energy form optimization

Integrated Piped Energy Utility



Harnessing Alternative Energy

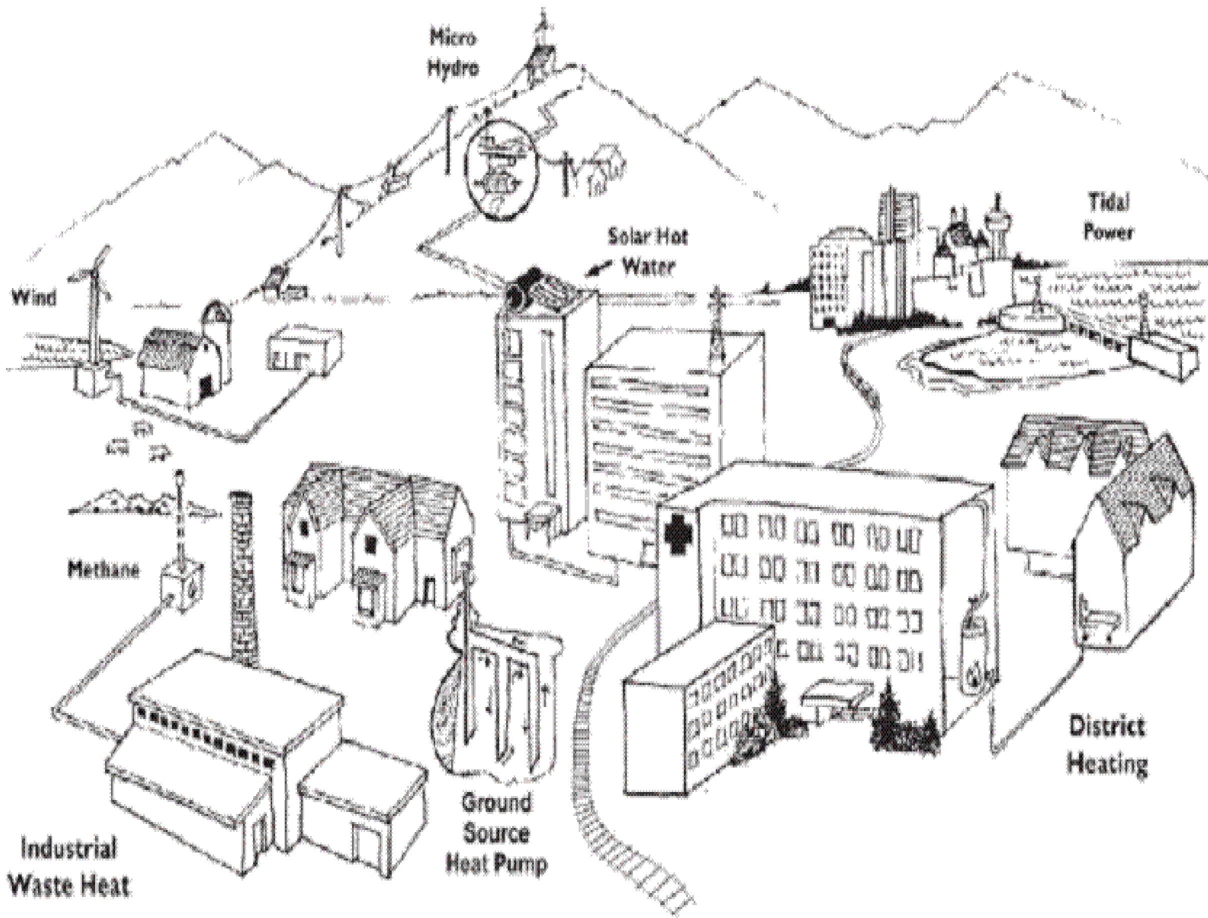


Thermal Energy Systems

- Multiple energy sources
- Energy Centre generates usable thermal energy
- Thermal energy delivered via piped water:
  - Hot for high-grade heat sources; no cooling
  - Ambient for combined heating & cooling
  - Chilled for high-grade cooling sources & no heating
- Scale – one building to complete communities

Integrated Community Energy Solutions

Terasen



Source: QUEST
www.questcanada.org

- **Cascading of energy use between customer types**
- **Smaller scale systems closer to & within buildings**
- **Integrated with elements of buildings & other infrastructure systems**
- **Multiple local energy sources**
- **Augmented by gas & electricity grids**
- **Over 50% reduction in grid energy use**

Transformation of Thermal Energy Delivery in BC

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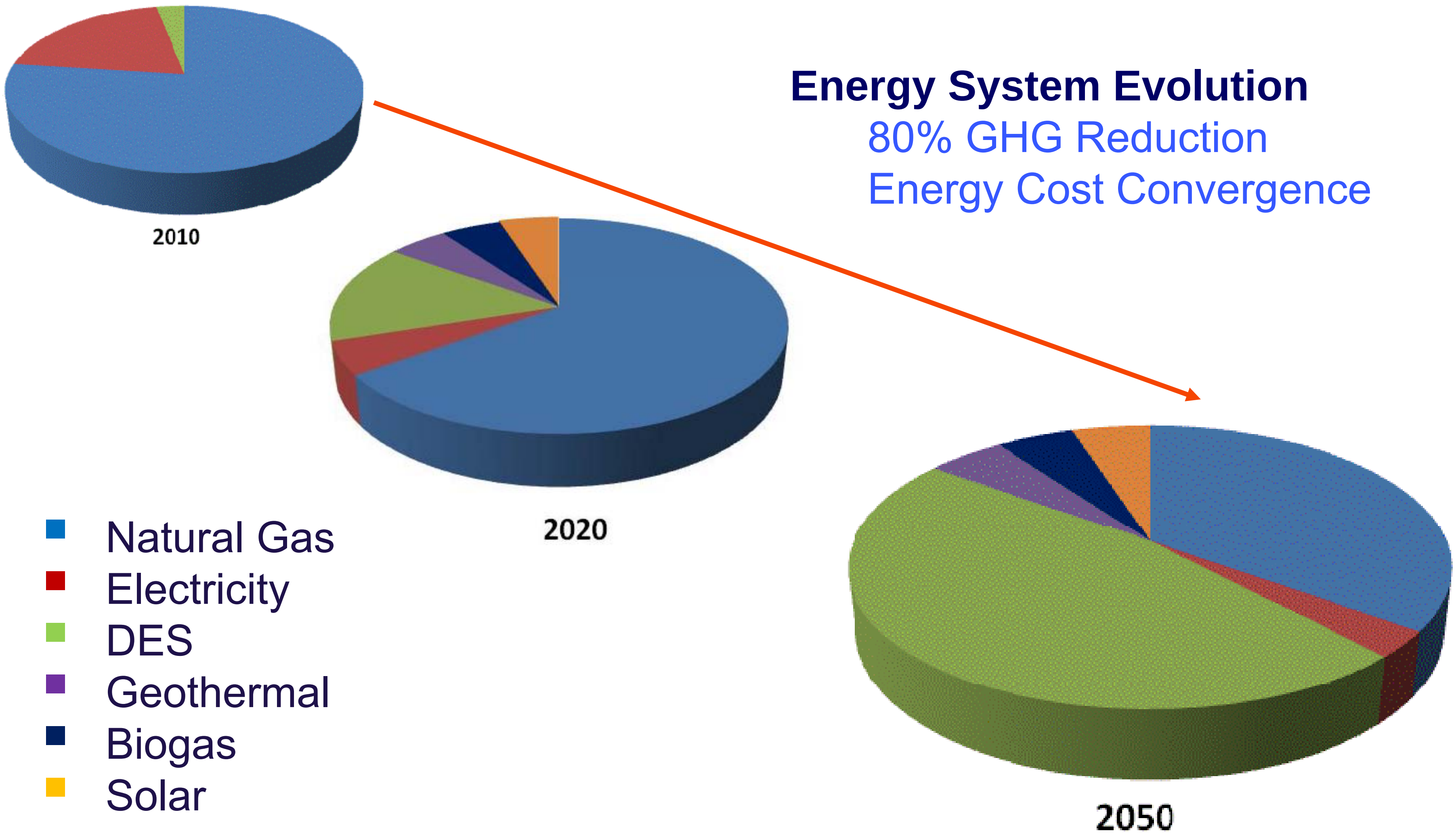

Energy System Evolution

80% GHG Reduction

Energy Cost Convergence

- Natural Gas
- Electricity
- DES
- Geothermal
- Biogas
- Solar

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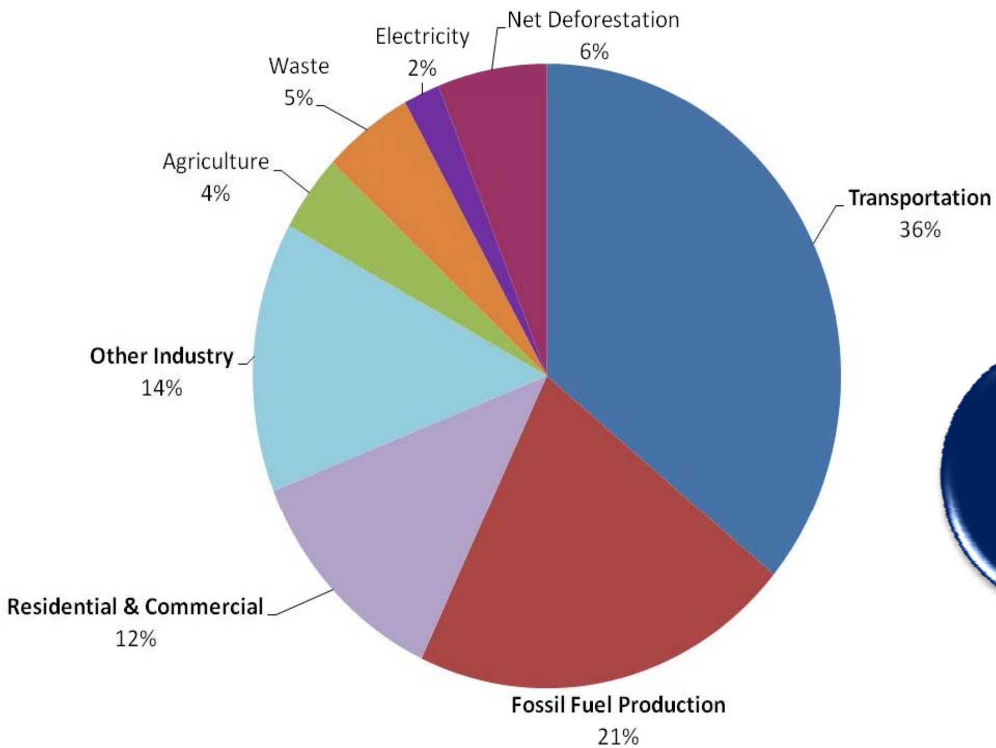
Customer Solutions

Video

BC GHG Emissions Solutions: A low-carbon energy generation



Source: LiveSmart BC website (2006)

Natural Gas Home Heating Innovation

Terasen

Micro Combined Heat & Power Systems

- Provides space & water heating
- Generates electricity
- Combined efficiency 85%

Climate Energy's Freewatt system

NGV for Transportation

Terasen

LCNG Station

Public Fuelling Station

Passenger Vehicles

Material Handling Equipment

Yard Trucks

Waste Haulers

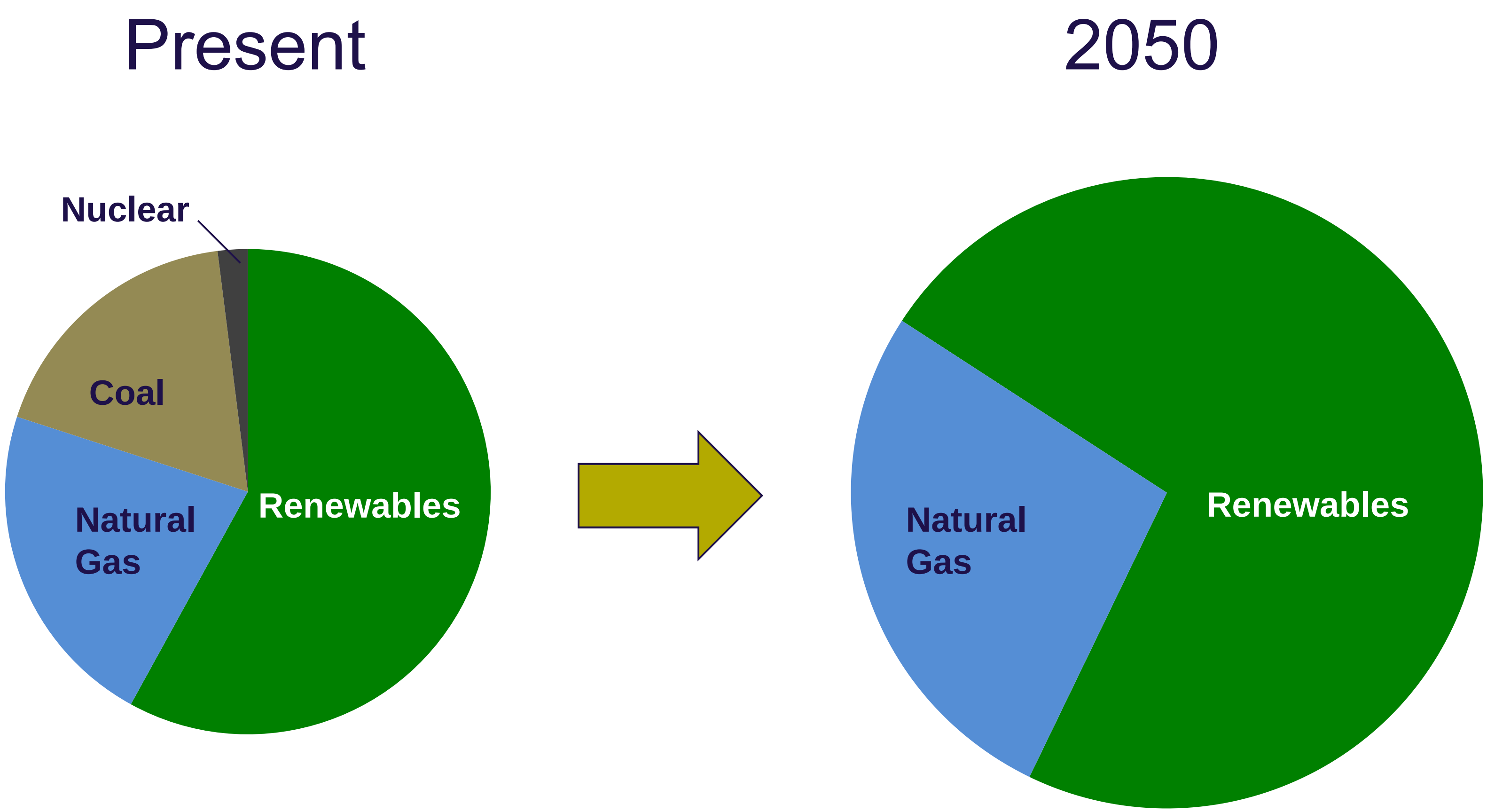
Transit Buses

Class 6/7/8 Trucks

Future?

Conclusion
Regional Energy Mix for Today and Tomorrow

Regional Energy Mix
Electricity



Regional Energy Mix
Heat, Cooling & Hot Water

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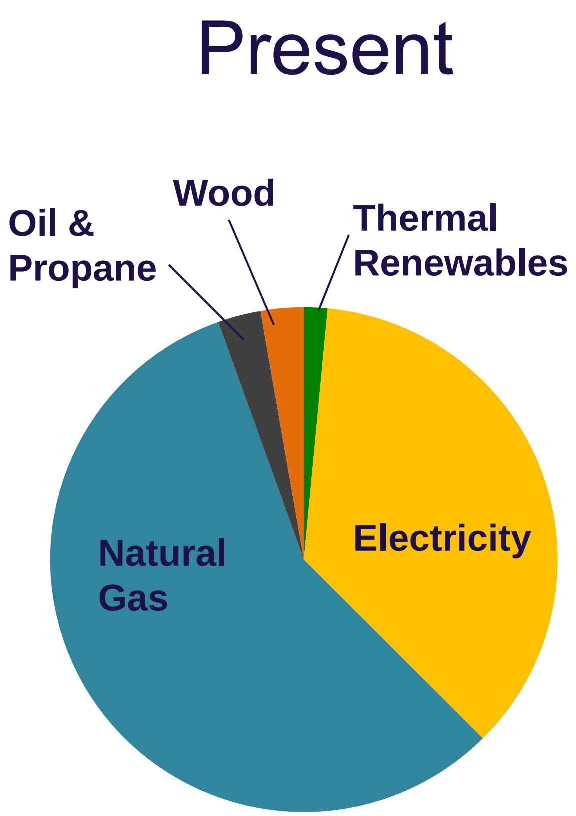
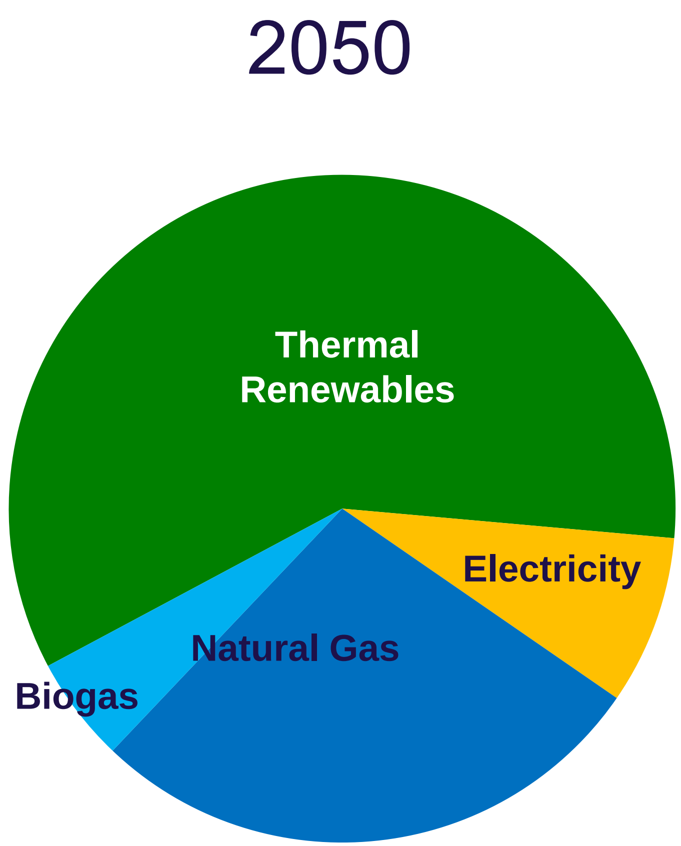
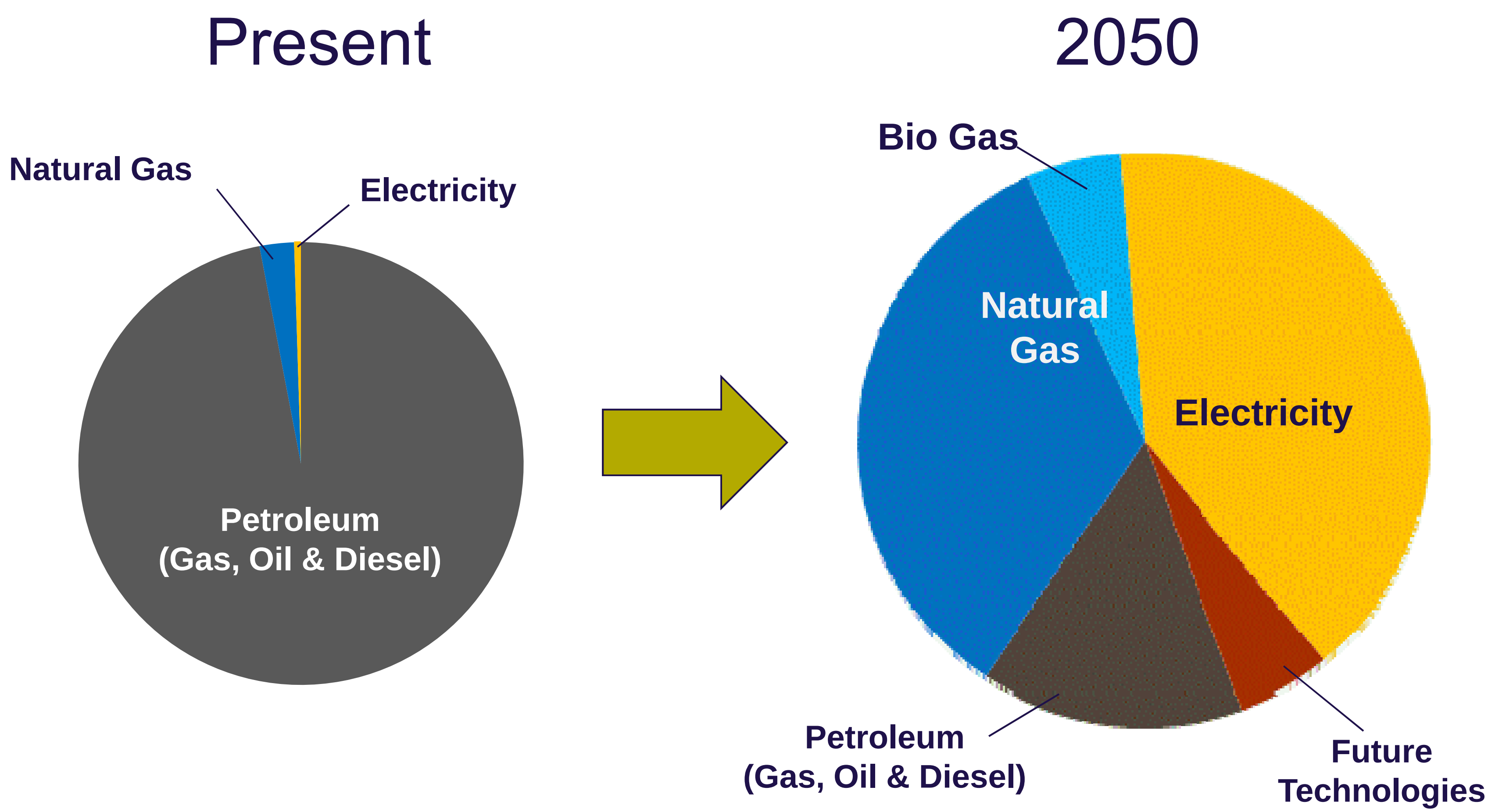


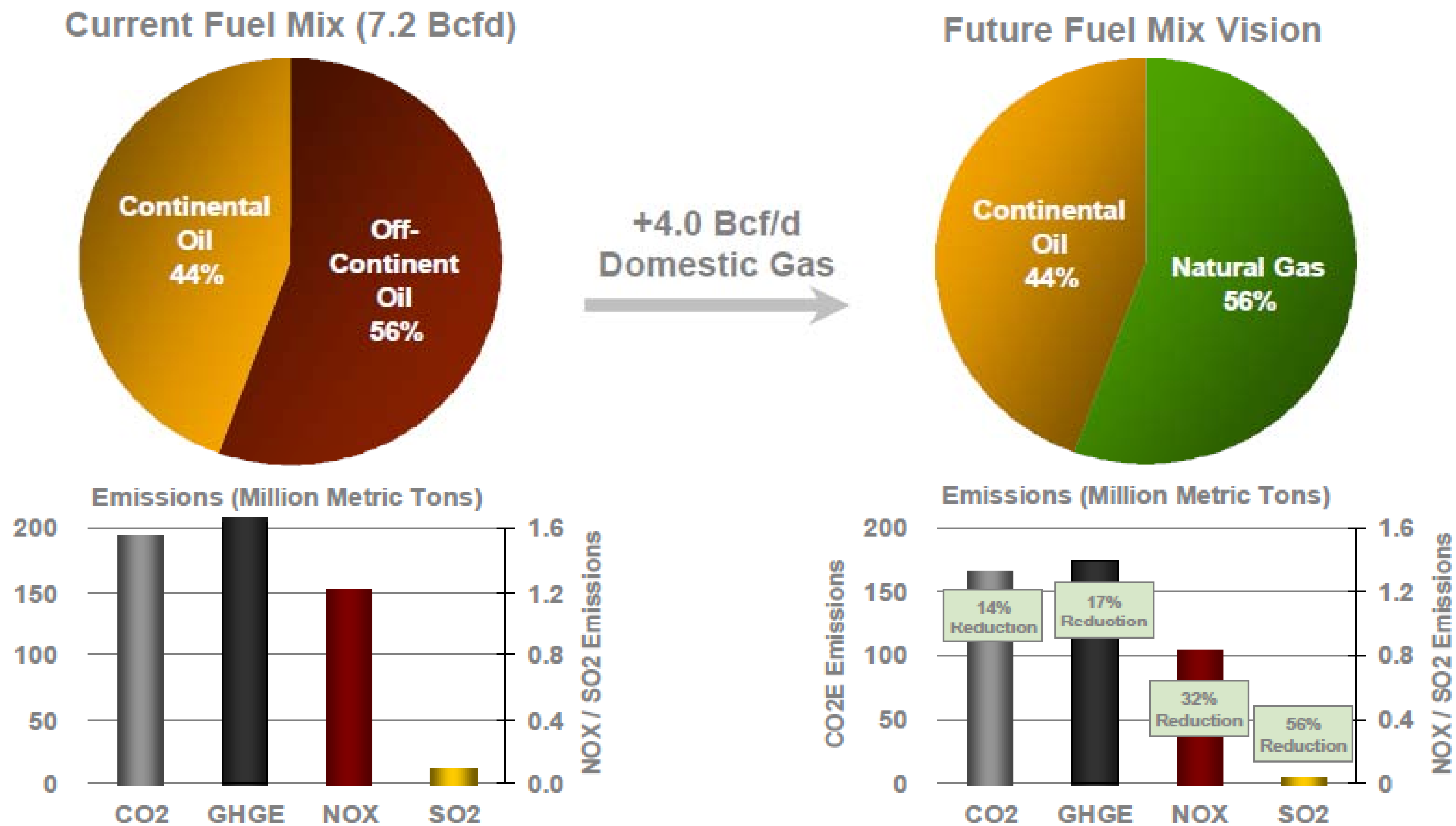


Regional Energy Mix
Transportation

terasen



Encana's Future Transportation Example



28MM tons of CO_2 = 5% of Canada Total CO_2 Emissions in 2008

Balancing & Considering Different Objectives

- Energy
  - Efficient end use of energy
  - Optimization of energy forms
- Economy
  - Creating value for BC
    - Competitive energy costs for consumers
    - Technology Development
    - Exporting Energy (natural gas and electricity)
- Environment
  - Movement to low carbon solutions

Let's Collaborate…

Terasen Gas

2010 Integrated Resource Plan

February 2nd , 2010 Stakeholder Workshop

Ken Ross
Resource Planning Manager

Contact: 604-576-7343
ken.ross@terasengas.com

www.terasengas.com

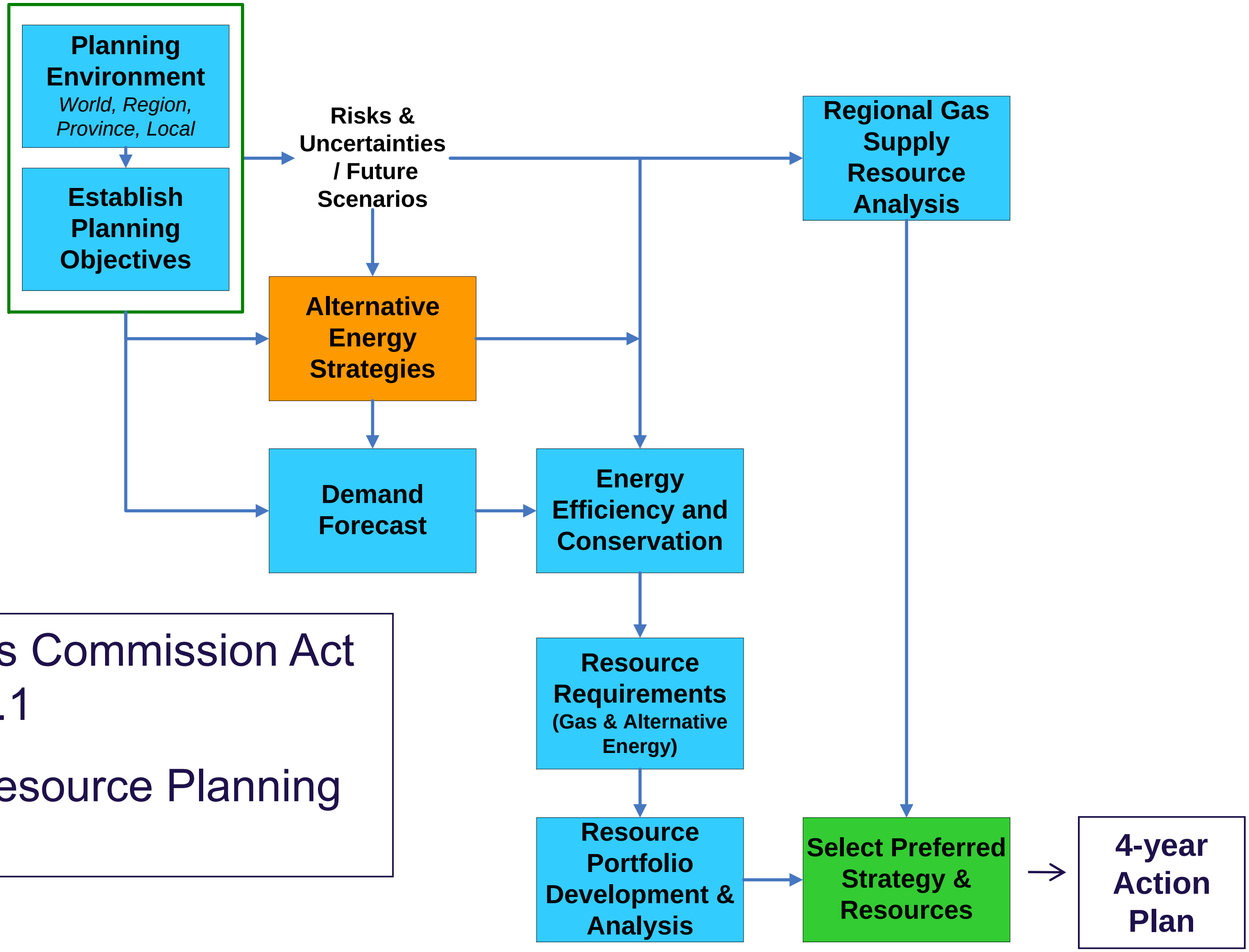
Terasen. A Fortis company.

Agenda

terasen

- Integrated Resource Planning Process
- IRP Objectives
- Update on 2008 Action Plan
- Timeline – 2010 IRP
- Feedback

IRP Process



The Utilities Commission Act Section 44.1

BCUC – Resource Planning Guidelines

IRP Objectives

Terasen

Ongoing:

- Safe, Reliable, Secure Energy Supply
- Cost Effective Service to Customers
- Energy Efficiency & Conservation
- Manage Social & Environmental Impacts

New?

- Integrate Alternative Energy Products
- Contribute Climate Change Solutions

Terasen


2008 Resource Plan
Terasen
Gas
Blue path
Green future
www.terasengas.com

Update on 2008 Action Plan

terasen

	Action Item	Current Status
1	Implementation of new EEC Programs	•Programs underway ✓ •Additional Approval ✓ •Conservation Potential Review ✓
2	Plan for near term Distribution Requirements	•Fraser River South Arm ✓ •Coquitlam Compressor ✓
3	System expansion needs in Okanagan	•Monitor FortisBC's IRP ✓
4	Investigate regional pipeline and storage alternatives	• 2010 NWGA outlook study ✓ •Capacity constraints in the near future

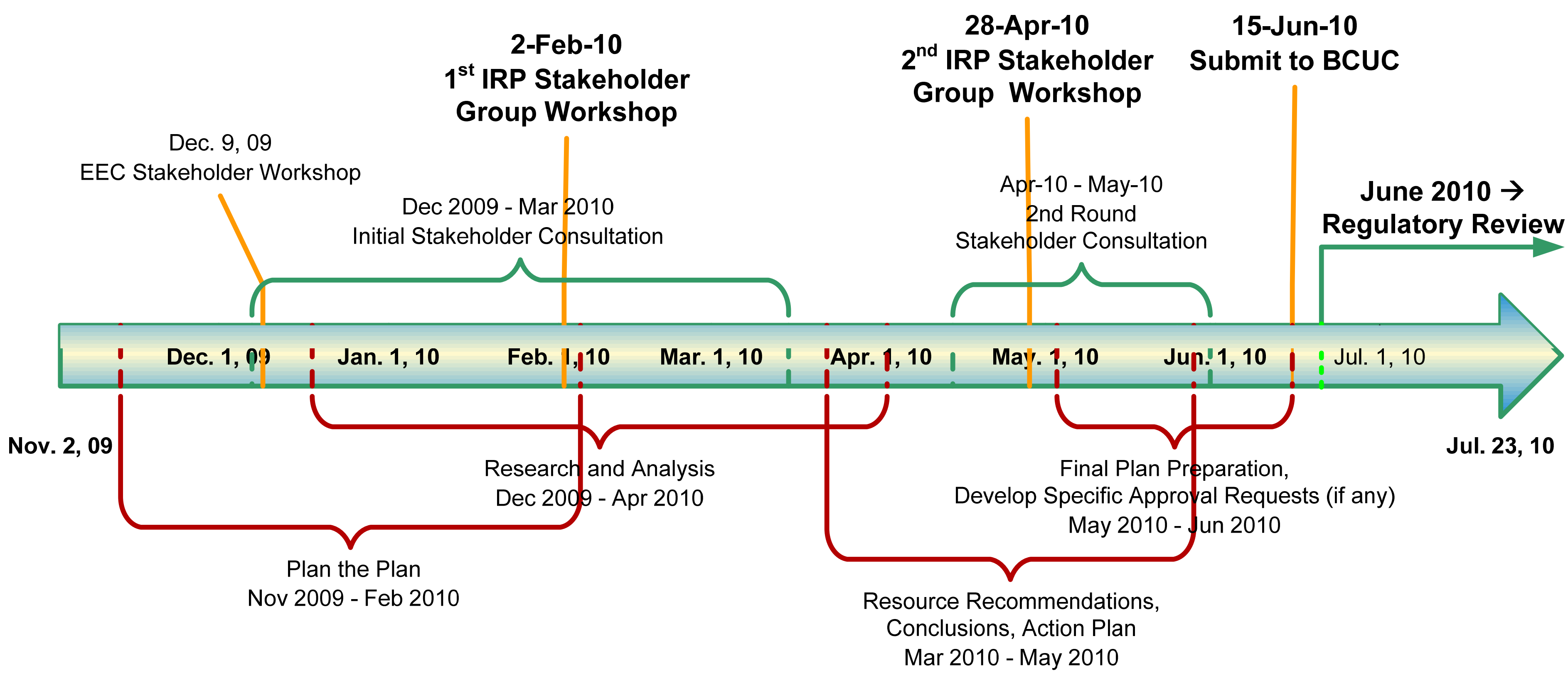
Update on 2008 Action Plan

Terasen

	Action Item	Current Status
5	Pursue Clean Energy Alternatives	• Bio Gas ✓ • Natural Gas Vehicles ✓ • District Energy Systems ✓ • Innovative Technologies ✓
6	Influence climate related policy	• Collaboration with policy makers and energy planners✓ • Advocating renewable sources✓
7	Participate in BC Hydro & Fortis BC IRP Process	• Provided Input into Fortis BC 's & Hydro's IRP process✓ • Monitor Fortis BC's future need for a peaking gas fired facility✓

2010 IRP Timeline

terasen



Feedback from this Workshop

Terasen

Please provide any written feedback you have electronically by February 19th, 2010 to:

IRP@terasengas.com

For more information about Terasen's IRP as this process proceeds, please visit:

www.terasengas.com/IRP

RESOURCE PLAN WORKSHOP – February 2nd, 2010
EVALUATION SURVEY & FEEDBACK FORM

Please take a few minutes to evaluate this workshop and identify areas in which improvements could be made.

1. The meeting room facilities met all of my needs.

Strongly disagree ⟶ **Strongly agree**

1 2 3 4 5

Comments:

2. The material presented was clear and easy to understand.

Strongly disagree ⟶ **Strongly agree**

1 2 3 4 5

Comments:

3. I found the workshop discussions valuable & informative.

Strongly disagree ⟶ **Strongly agree**

1 2 3 4 5

Comments:

4. I feel that I had sufficient opportunity to ask questions & provide input.

Strongly disagree ⟶ **Strongly agree**

1 2 3 4 5

Comments:

5. The facilitated portion of the workshop was helpful for sharing views and providing input.

Strongly disagree ⟶ **Strongly agree**

1 2 3 4 5

Comments:

RESOURCE PLAN WORKSHOP – February 2nd, 2010
EVALUATION SURVEY & FEEDBACK FORM

6. The length of the workshop was appropriate.

Strongly disagree ⟶ **Strongly agree**

1 2 3 4 5

Comments:

7. Terasen's vision / initiatives for the future provide important energy and climate change solutions for BC.

Strongly disagree ⟶ **Strongly agree**

1 2 3 4 5

Comments:

Additional Comments:

(Please provide any additional comments you would like regarding either the workshop itself or the topics discussed – include additional sheets as necessary)

Thank you for taking the time to discuss these important issues with us and provide your input.

If you are unable to complete this survey before leaving the workshop and would still like to submit comments, please forward them by May 9, 2008 to**:**

Terasen Gas
16705 Fraser Highway
Surrey, B.C. V4N 0E8

Attention: Ken Ross
Resource Planning Manager
604-576-7343
ken.ross@terasengas.com

Terasen Gas

2010 Long Term Resource Plan

May 27th, 2010 Stakeholder Workshop - Vancouver

www.terasengas.com/irp

Terasen. A Fortis company.

Welcome

…thank you for joining us today.

LTRP – Long Term Resource Plan

IRP – Integrated Resource Planning

RP – Resource Plan

Agenda for Today

terasen

9:10 am	Energy Solutions for British Columbia	**Doug Stout** V.P., Marketing & Business Development
	Resource Plan – Background / Update	**Ken Ross** Integrated Resource Planning Manager
	Conservation and Energy Efficiency	**Sarah Smith** Manager, Marketing & Energy Efficiency
	Terasen Integrated Energy Solutions	**Jason Wolfe** Manager, Community Energy Solutions
Lunch	Energy Demand Forecasting	**Arvind Ramakrishnan** Resource Planning Analyst
	Natural Gas Supply	**Rohit Pala** Midstream Operations Manager
	Natural Gas System Requirements	**Edmond Leung** Manager, Transmission Assets
3:00 pm	Feedback and Next Steps	**Ken Ross**

Introductions

Energy Solutions for British Columbia

Long Term Resource Planning Workshop

May 27, 2010

Doug Stout

Vice President, Marketing & Business Development

Forward-Looking Statement

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Fortis Inc. In BC

- Over one million gas and electric customers
- 135 communities across BC
- Combined assets of $6.4 billion
- Over 1,800 employees
- $1.03 billion investments since 2007
- Integrated energy portfolio now includes regulated and unregulated
  - hydroelectric
  - district energy systems
  - geo-exchange
  - solar thermal

Terasen Inc.

terasen

Deliver natural gas and provide alternative energy throughout BC

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- 1400 employees
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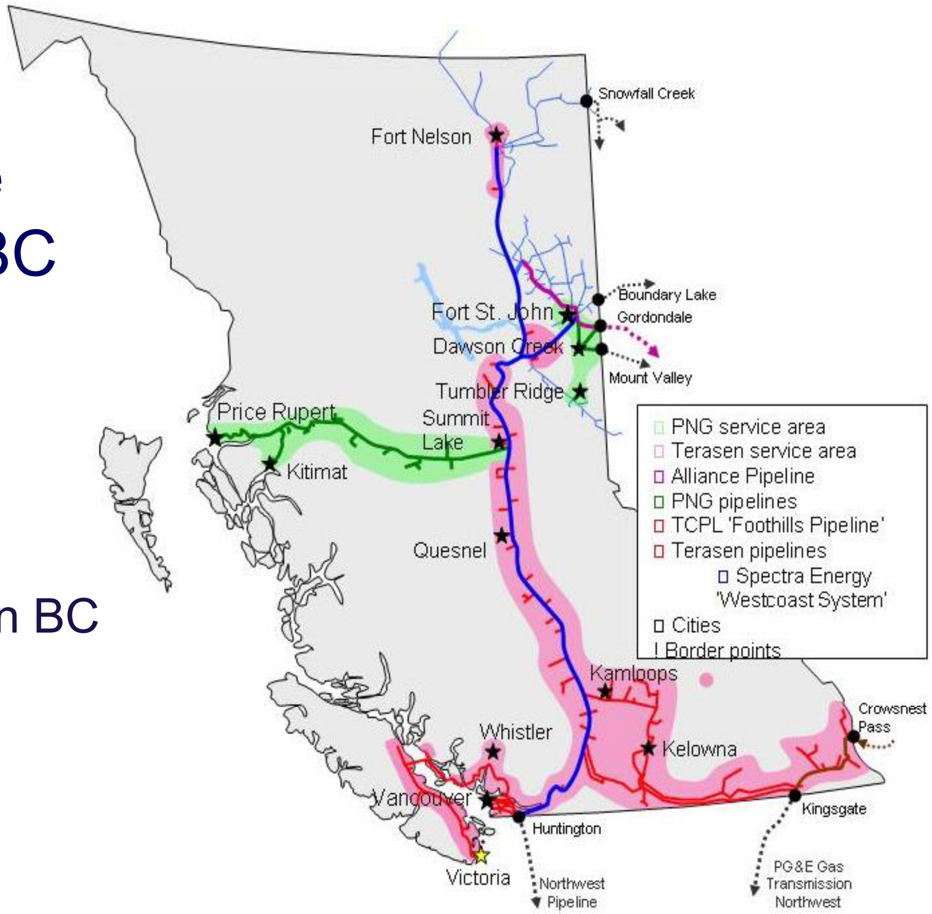

Balancing & Considering Different Objectives

terasen

Energy

- Efficient end use of energy
- Optimization of energy forms

Economy

- Creating Value for BC and our Customers

Environment

- Movement to lower carbon solutions

Transformation of Thermal Energy Delivery in BC

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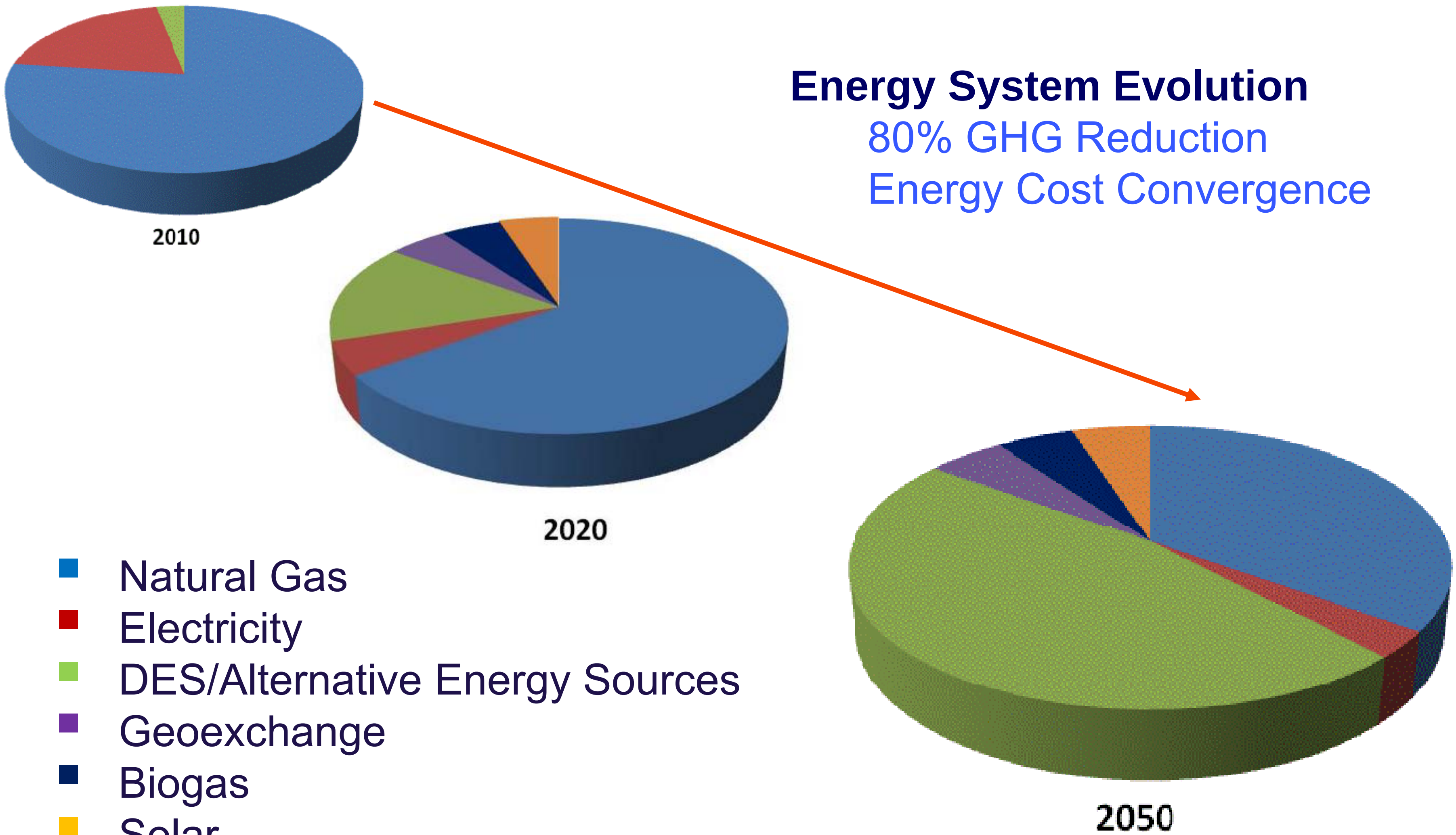


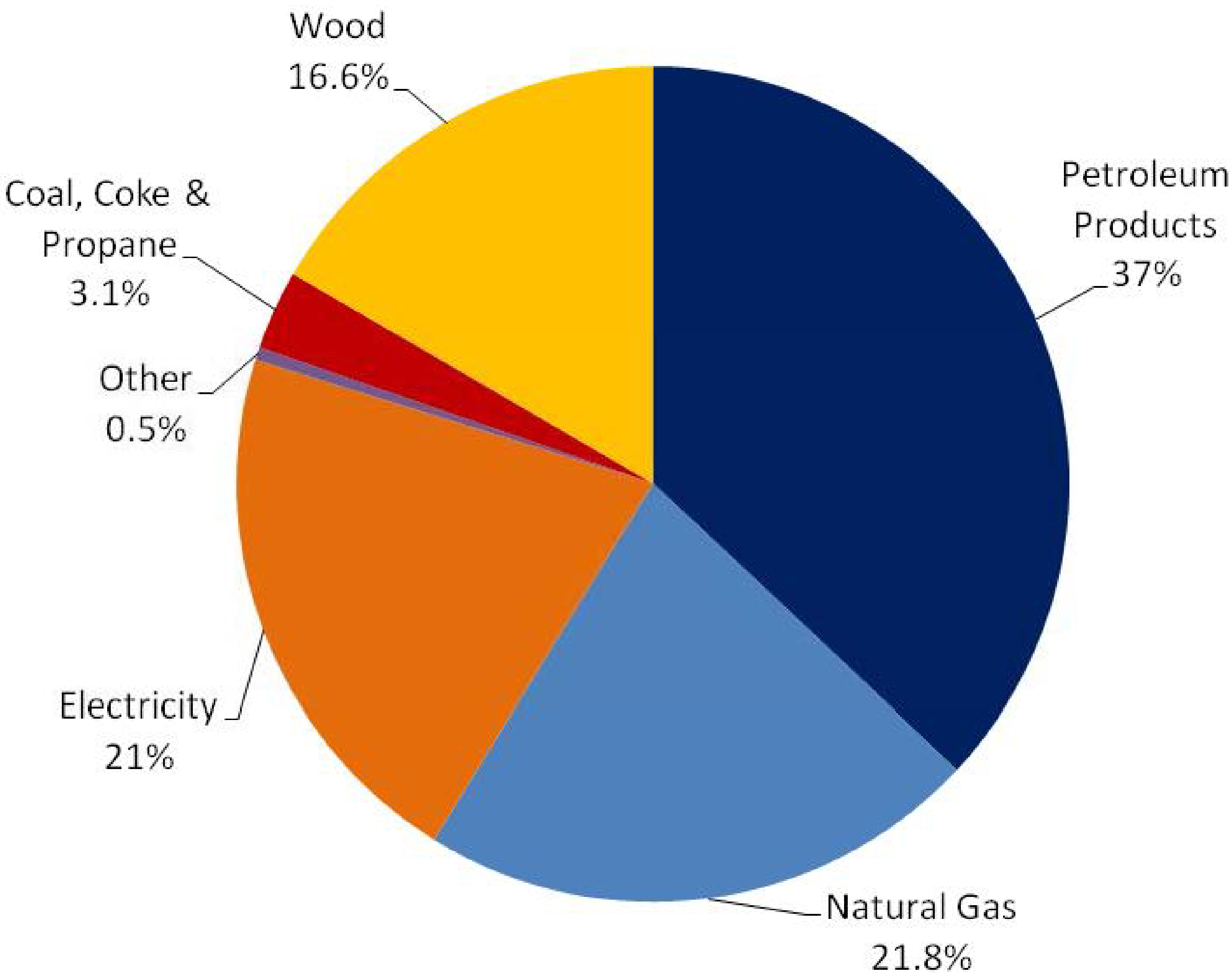
Energy System Evolution

80% GHG Reduction

Energy Cost Convergence

- Natural Gas
- Electricity
- DES/Alternative Energy Sources
- Geoexchange
- Biogas
- Solar

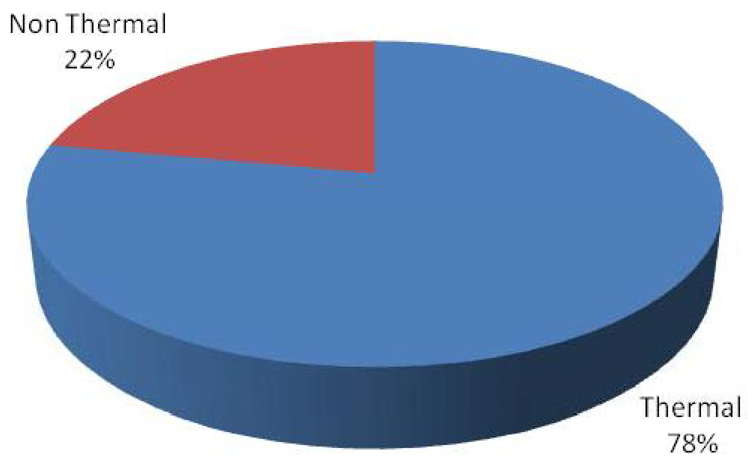
BC Energy End-Use



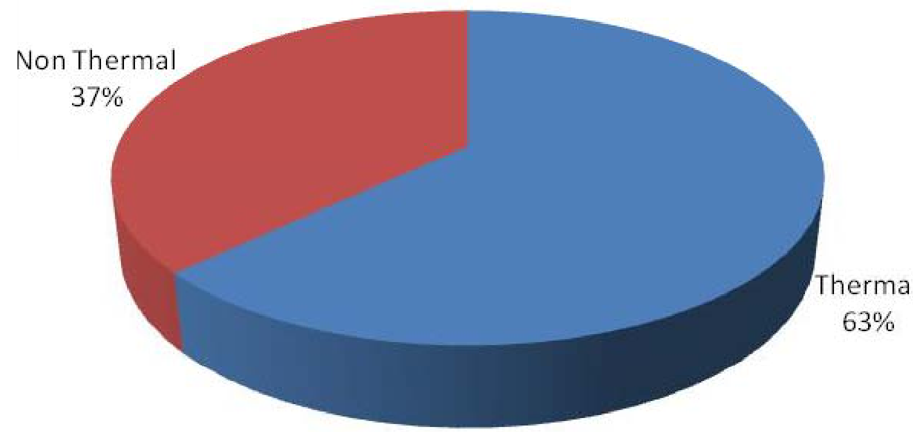
Source: NRCAN 2007 Stats

BC Energy End-Use Profiles

Residential



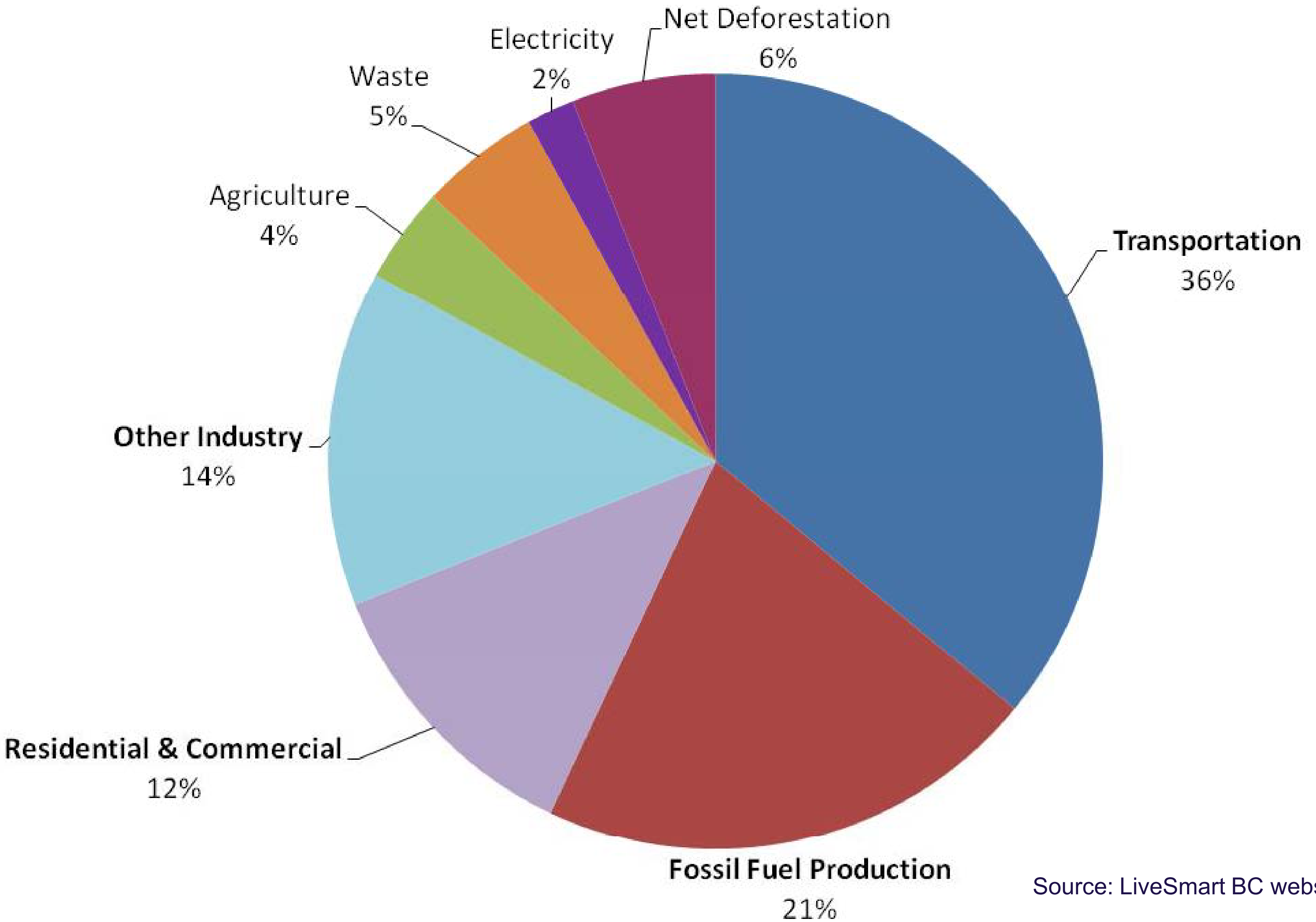
Commercial



Thermal includes space heating, space cooling, water heating

Source: NRCAN 2007 Stats

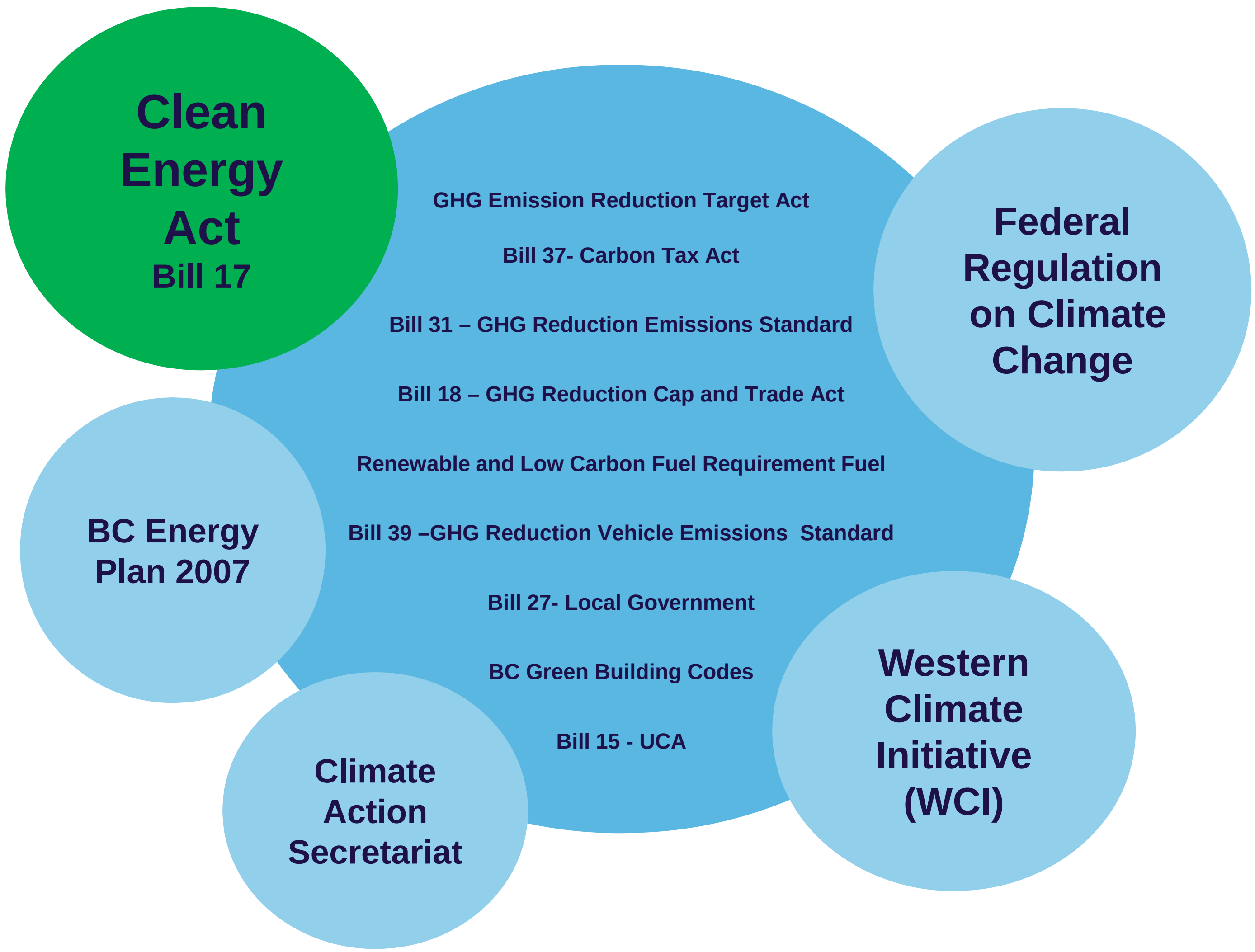
GHG Profile in BC
Opportunities to Reduce



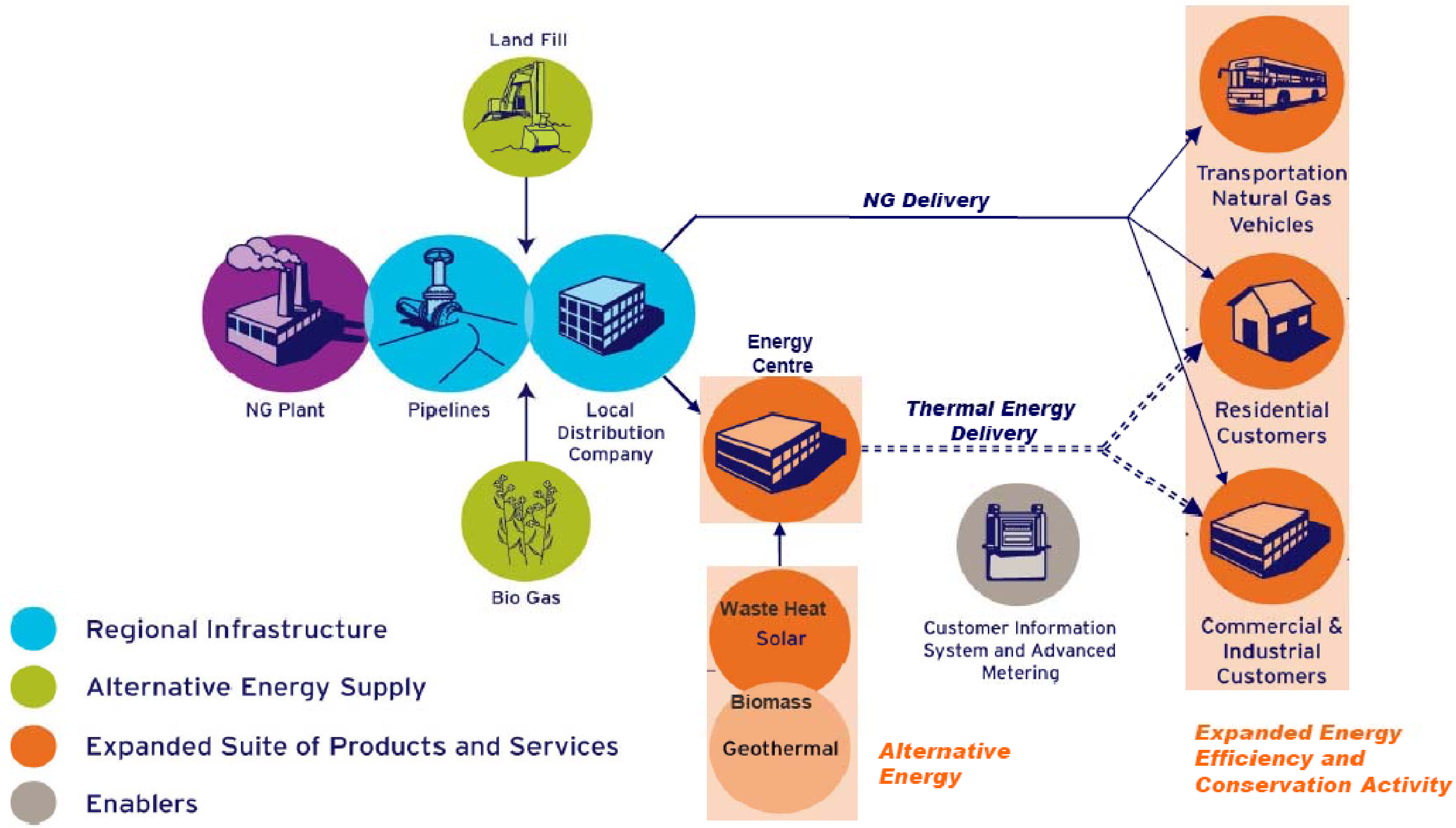
Source: LiveSmart BC website (2006)

Changing Expectations & Regulation
All levels of Government

terasen



Integrated Energy Utility

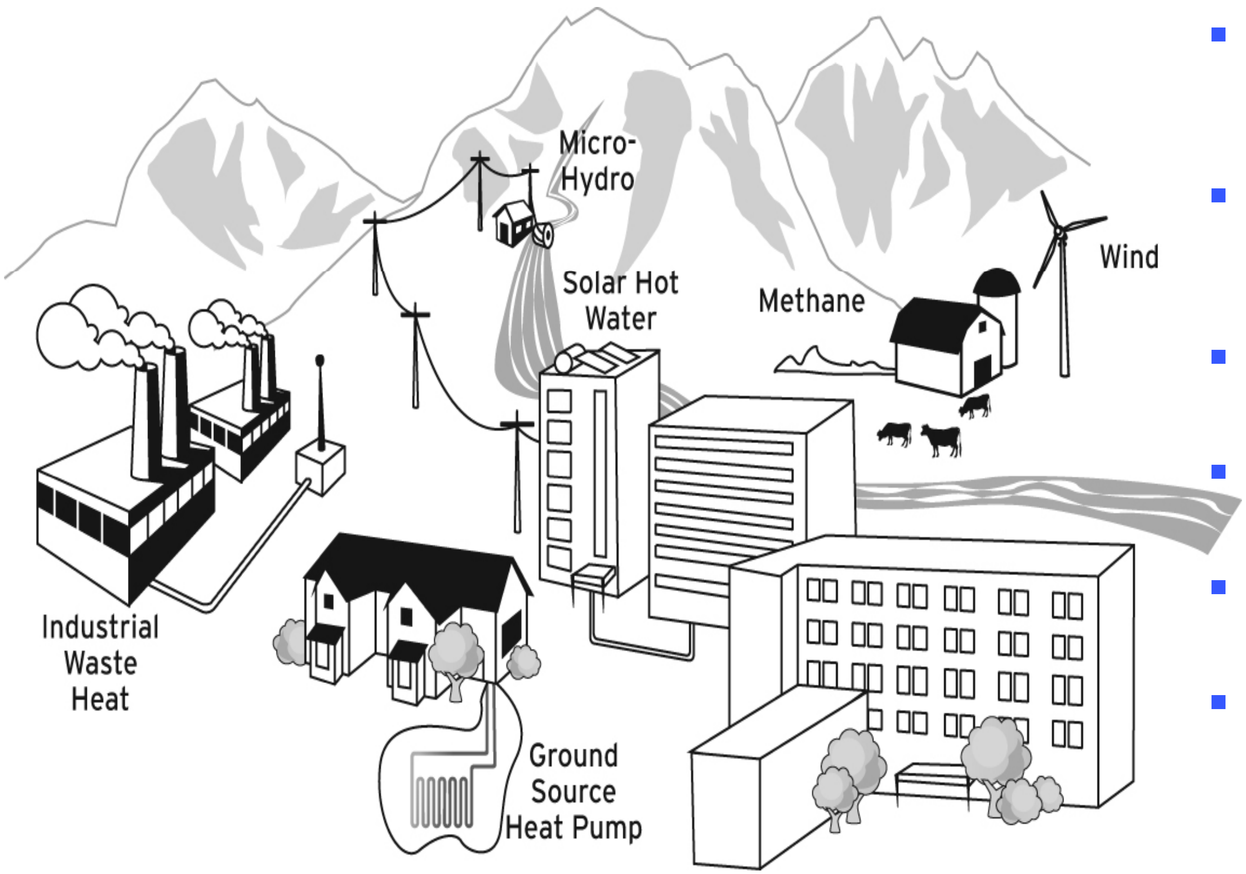


Integrated Energy Services

Terasen

	Terasen Gas Inc.	
Energy Service	**Natural Gas**	**Alternative Energy**
Service Offerings	**Natural Gas** **EEC** **Biogas** **NGV**	**Solar** **District Energy** **Geothermal**
	Regulated by British Columbia Utilities Commission (BCUC)	

Community Wide Solutions



- **Heating, Hot Water and Cooling to buildings**
- **Energy Efficiency and Conservation Programs**
- **Waste optimization**
- **Heat recovery**
- **Biogas**
- **Transportation**
  - **CNG and LNG**

Resource Planning Backgrounder

Long Term Resource Planning Workshop

May 27th, 2010

Ken Ross
Integrated Resource Planning Manager

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www.terasengas.com

Terasen. A Fortis company.

Key Messages

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Integrated Resource Planning is ongoing

– the Long Term Resource Plan presents a snapshot in time.

2008 Action Plan accomplished.

Stakeholder input is key to Resource Planning.

Filing the 2010 Long Term Resource Plan by the end of June.

IRP Process

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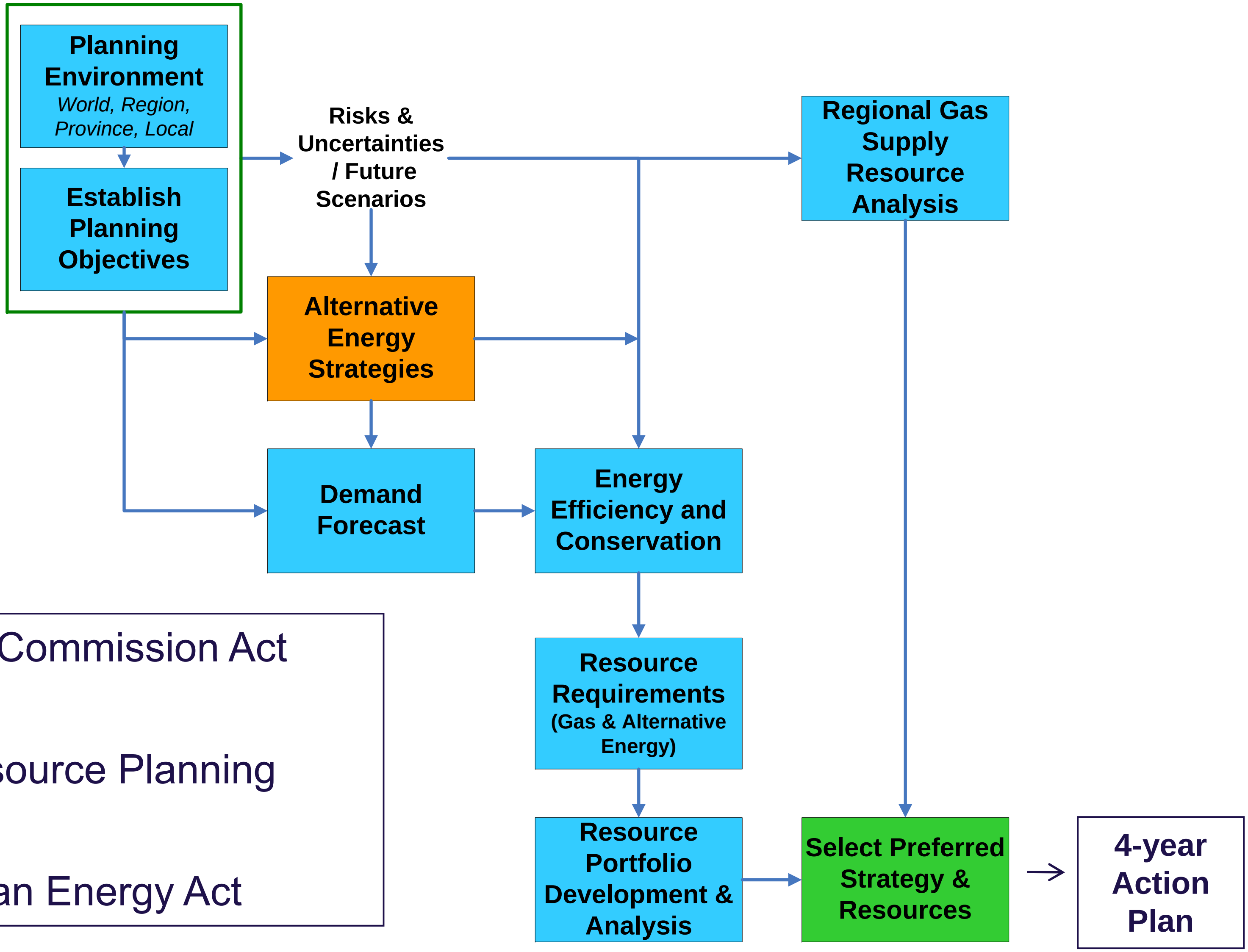

The Utilities Commission Act Section 44.1

BCUC – Resource Planning Guidelines

Bill 17 – Clean Energy Act

Resource Plan Objectives

Terasen

- Provide Innovative and Cost Effective Energy Solutions
- Ensure Safe, Reliable, Secure Energy Service
- Expand Energy Efficiency & Conservation Initiatives
- Act on Social & Environmental Priorities
- Contribute to Climate Change Solutions

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2008 Resource Plan
Terasen
Gas
Blue path
Green future
www.terasengas.com

2008 Action Plan - Accomplished

Terasen

	Action Item	Current Status
1	Implementation of new EEC Programs	•Programs underway ✓ •Additional Approval ✓ •Conservation Potential Review ✓
2	Plan for near term system requirements	•Fraser River South Arm ✓ •Coquitlam Compressor ✓
3	System expansion needs in Okanagan	•Monitor FortisBC's IRP ✓
4	Investigate regional pipeline and storage alternatives	• 2010 NWGA outlook study ✓ •Capacity constraints in the near future

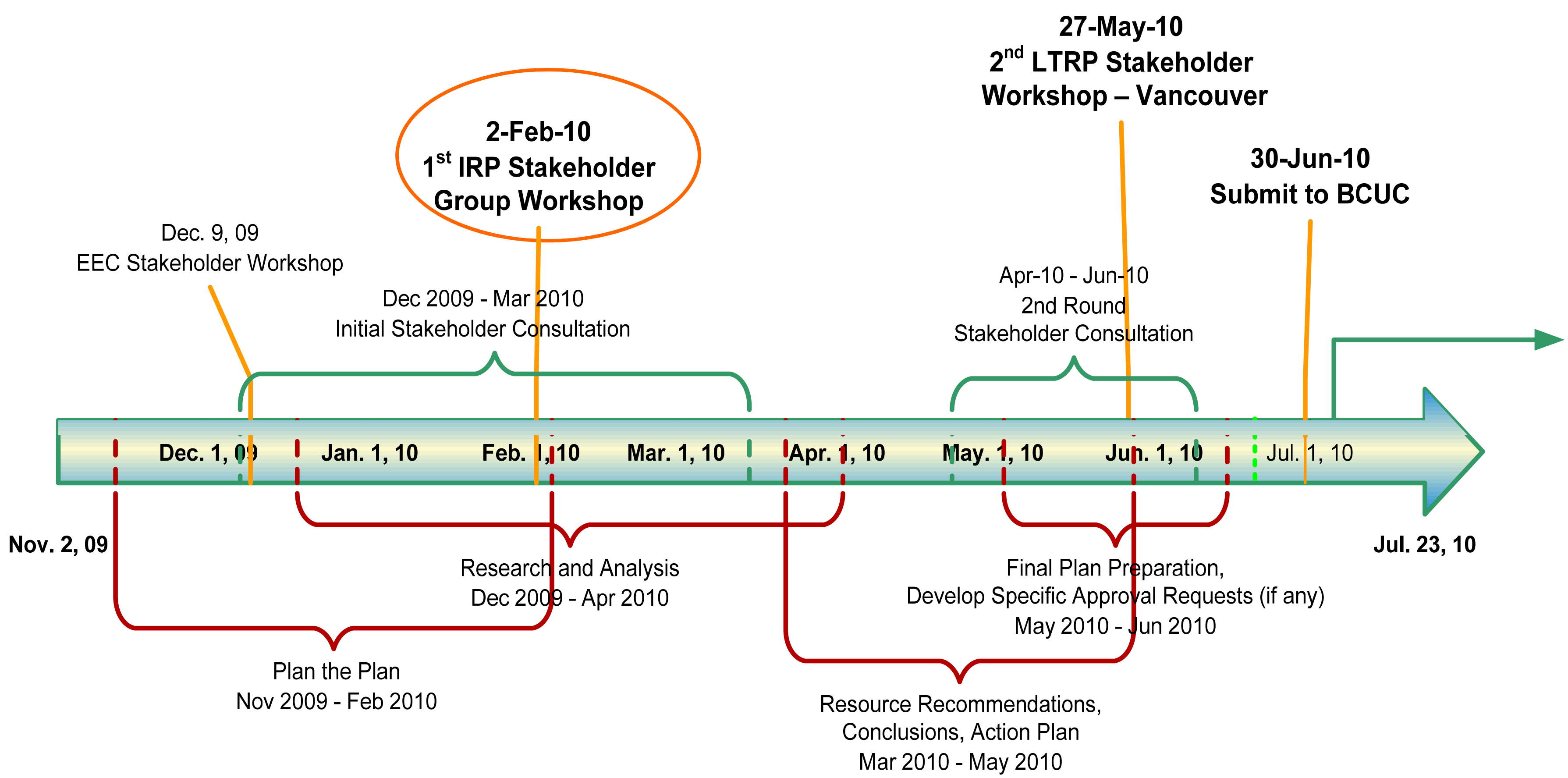
2008 Action Plan - Accomplished

Terasen

	Action Item	Current Status
5	Pursue Clean Energy Alternatives	• Bio Gas ✓ • Natural Gas Vehicles ✓ • District Energy Systems ✓ • Innovative Technologies ✓
6	Influence climate related policy	• Collaborate with policy makers and energy planners✓ • Advocate renewable thermal sources✓
7	Participate in BC Hydro & FortisBC IRP Process	• Provided Input into Fortis BC ‘s & Hydro’s IRP process✓ • Monitor Fortis BC’s future need for a peaking gas fired facility✓

2010 IRP Timeline

Terasen



February Feedback

Terasen

What we heard:

- Support integrated energy approach
  - traditional supply and energy efficiency with renewable thermal technologies, green supply and transportation solutions
  - As a utility, it makes sense for Terasen to develop integrated energy infrastructure as part of its customer service offerings
- Work more closely with other utilities and government
- Provide more opportunity for dialogue and learning
- Use pilot studies to test new ideas and technologies
- Ensure movement to lower carbon intensity is timely, cost effective and ongoing

Actions from Feedback

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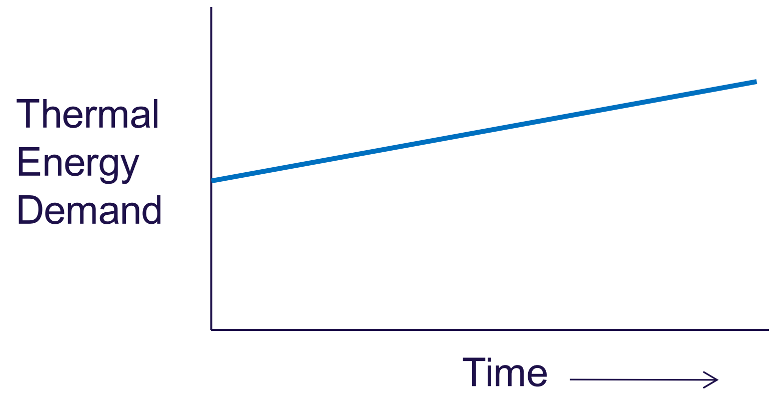
- Working with other utilities:
  - Ongoing discussions with FortisBC and BC Hydro to assess the total thermal energy demand in BC



  - Discussing transportation energy demand with utilities and MoT to assess transportation energy needs and solutions
  - Collaborating on Energy Efficiency and Conservation

Actions from Feedback

Terasen

- More dialogue and opportunities for learning and input.
  - Propose establishing a Resource Plan Advisory Group (RPAG) of external stakeholders
  - Ongoing RPAG workshops (at least 2 per year) to discuss resource issues and Terasen initiatives
  - Formal invitation to stakeholders late summer / early fall

2010 IRP Timeline

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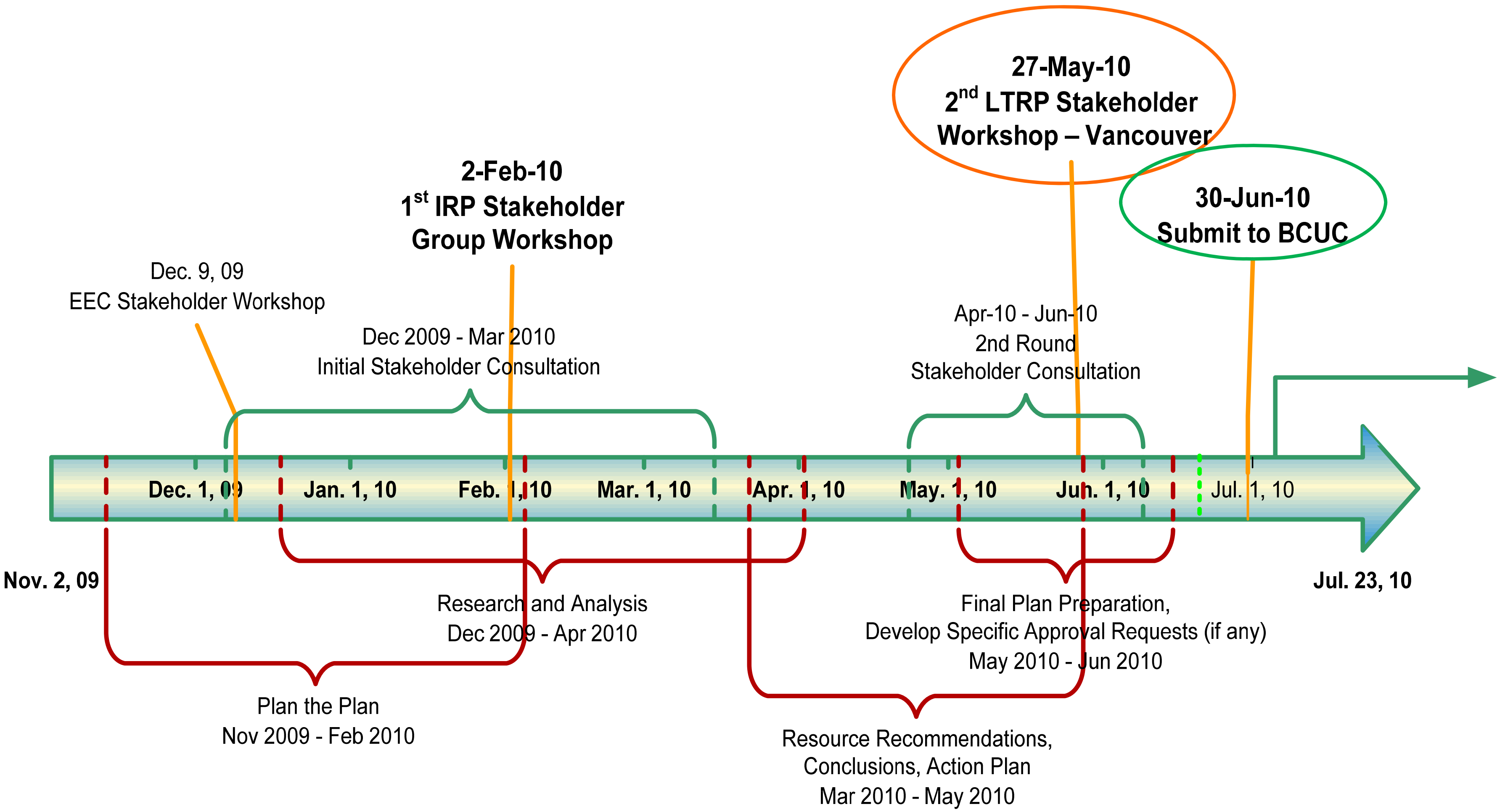

2010 Long Term Resource Plan

Questions / Discussion?

terasengas.com

Energy Efficiency and Conservation Project Update

Sarah Smith
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Terasen. A Fortis company.

Energy Efficiency and Conservation (EEC) Key Messages

Terasen

1. EEC benefits consumers, the utility, the government, and the environment

2. The success of Terasen's historical activities in DSM led to the approval of increased funding for EEC activities in 2009, 2010, and 2011

3. EEC programs are expected to reduce demand by 1,284,100 GJs in 2009 and 2,031,015 GJs in 2010

4. Consistent funding is necessary to give certainty to the marketplace, build on success, and continue to meet current and future energy needs

Why focus on EEC?

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Government
- 2007 Energy Policy
- 2010 Clean Energy Act

Customers
- Lower energy bills
- Infrastructure optimization

Shareholders
- Align interests with other stakeholders

Environment
- Infrastructure optimization
- GHG reduction

EEC benefits everyone

Historical Activities

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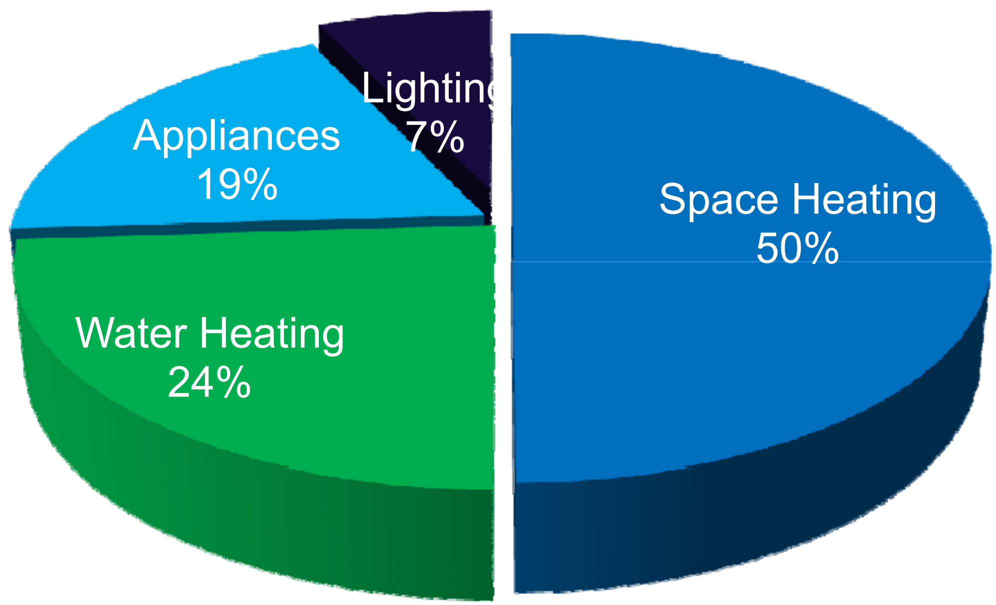
- Funding approval approximately $4 million to 2008
- Cost-effective activity
- Significant opportunity available
- 2008 EEC Application

Residential Energy Use Profile



Space and water heating make up 75% of a home's energy use

Conservation of natural gas presents a significant opportunity to reduce energy consumption

EEC Funding 2009 - 2011

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2009, 2010, 2011 Funding Breakdown ($ Millions)

	2009		2010	2011
	O & M	Deferral (Forecast)	Deferral	Deferral
EEC Programs	1,981	8,907	27,801	27,801
Interruptible Industrial	0	0	435	1,875
Innovative Technologies	0	0	2,812	5,625

Energy Savings from EEC Programs

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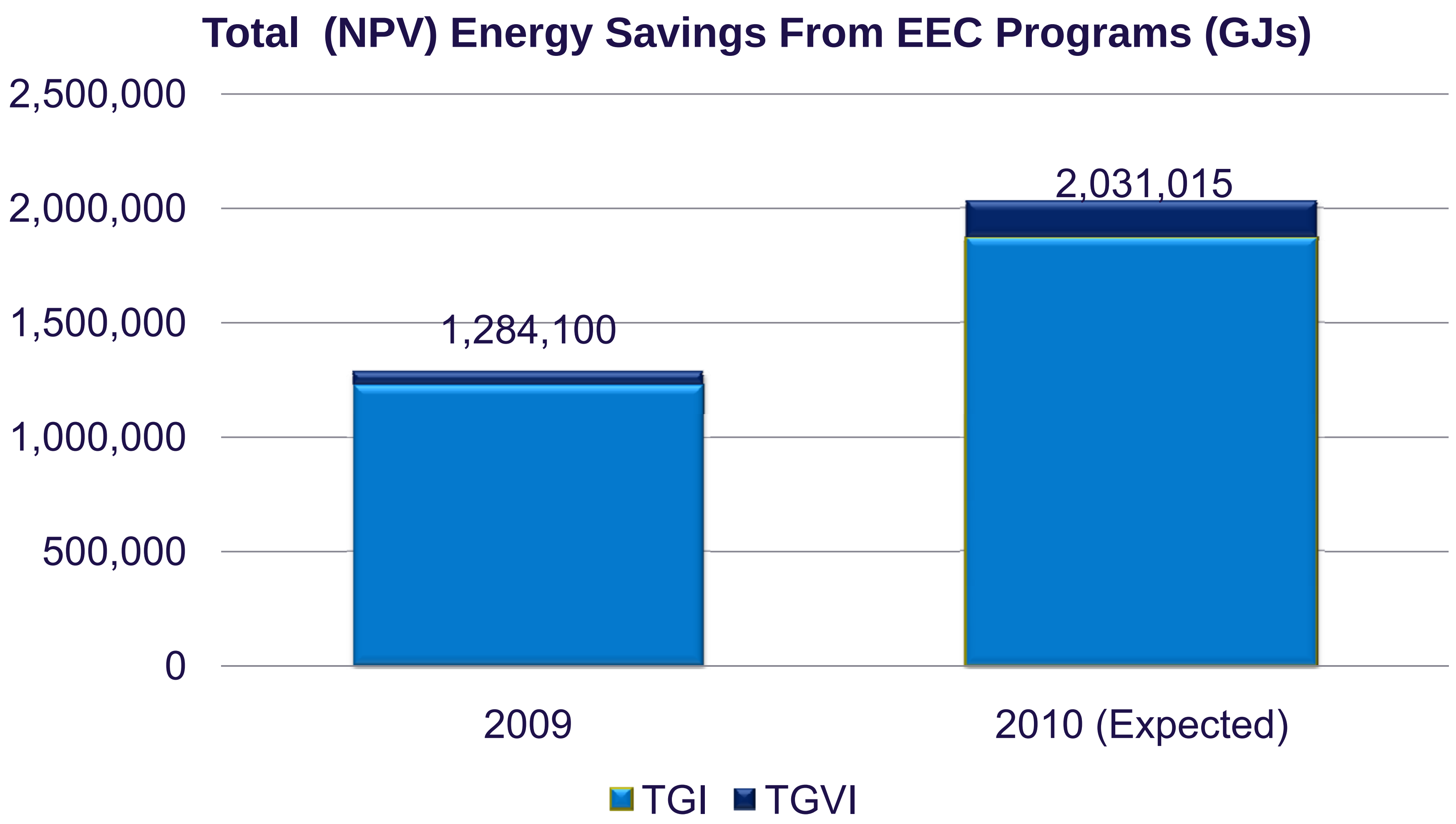

Total Energy Savings - 2010 Programs (GJ)

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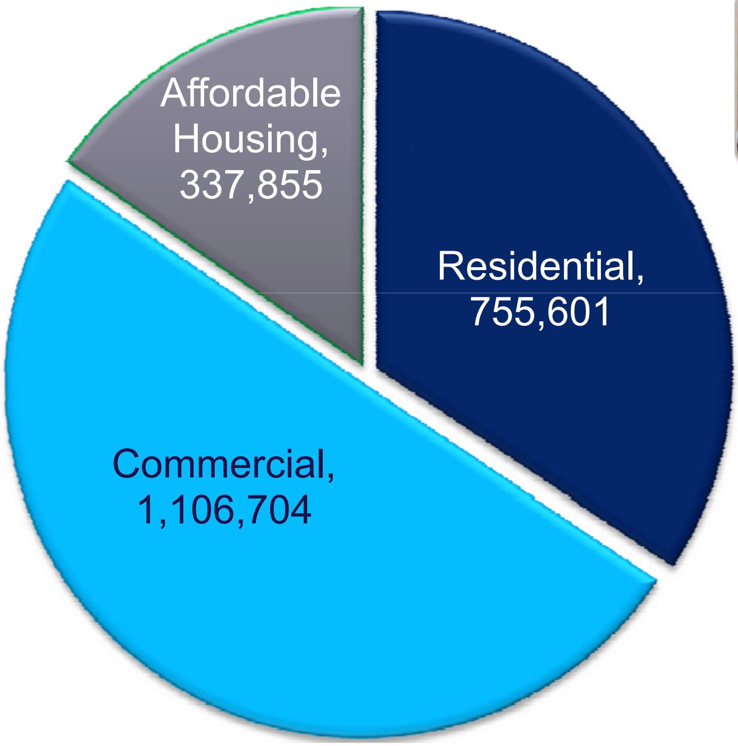

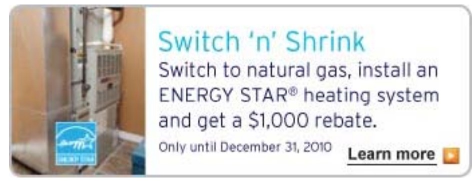

Fuel Switching (169,145)

Projected 2010 net natural gas conservation 2,031,015 GJs from "Conventional EEC" programs

New EEC Program Areas

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As part of Terasen's 2010-2011 Revenue Requirement Application, the Commission approved increased funding for two new program areas

Interruptible Industrial Customers

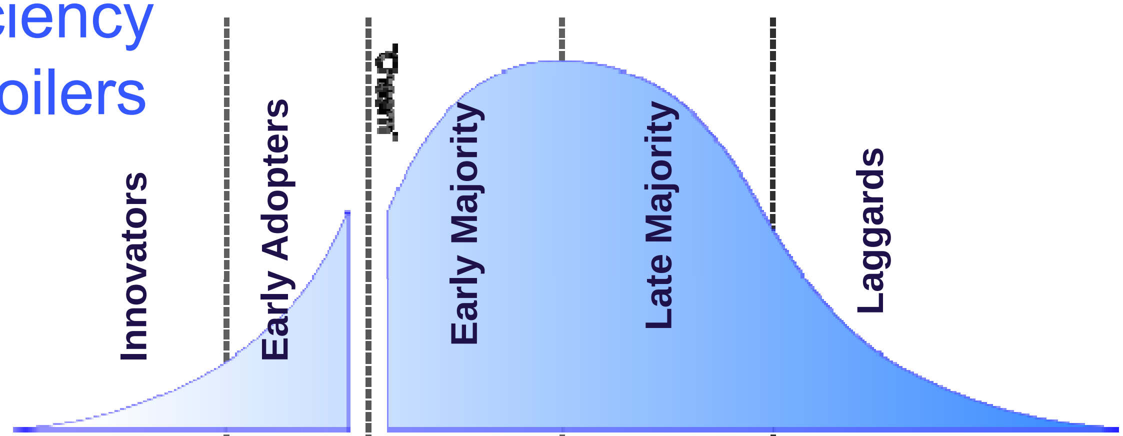
- Responsible for 29% of TG's load
- Potential for significant reduction in consumption

- Evaluating potential energy savings
- Includes: Solar Thermal Hot Water, Natural Gas Transportation (NGT), Hydronic and Combination Heating Systems, Residential GSHP Systems, Commercial/Industrial GSHP Systems

Goal of EEC: Market Transformation

Terasen

- The goal of EEC is to transform the market to a point where energy efficient equipment/systems/buildings are the new baseline for regulation
  - Can be achieved through organic behaviour change influenced by education, or through direct measures like changes in regulated standards
  - E.g. minimum efficiency for furnaces and boilers



Regulations, Codes and Standards

- EnerGuide 80 Building Code
- Minimum efficiency of 0.80 EF for residential water heaters
  - May lead to load loss because of higher incremental cost of installing natural gas versus electric heating systems

Work collaboratively with government in development and implementation of regulations & proactively engage in market research

Conservation Potential Review

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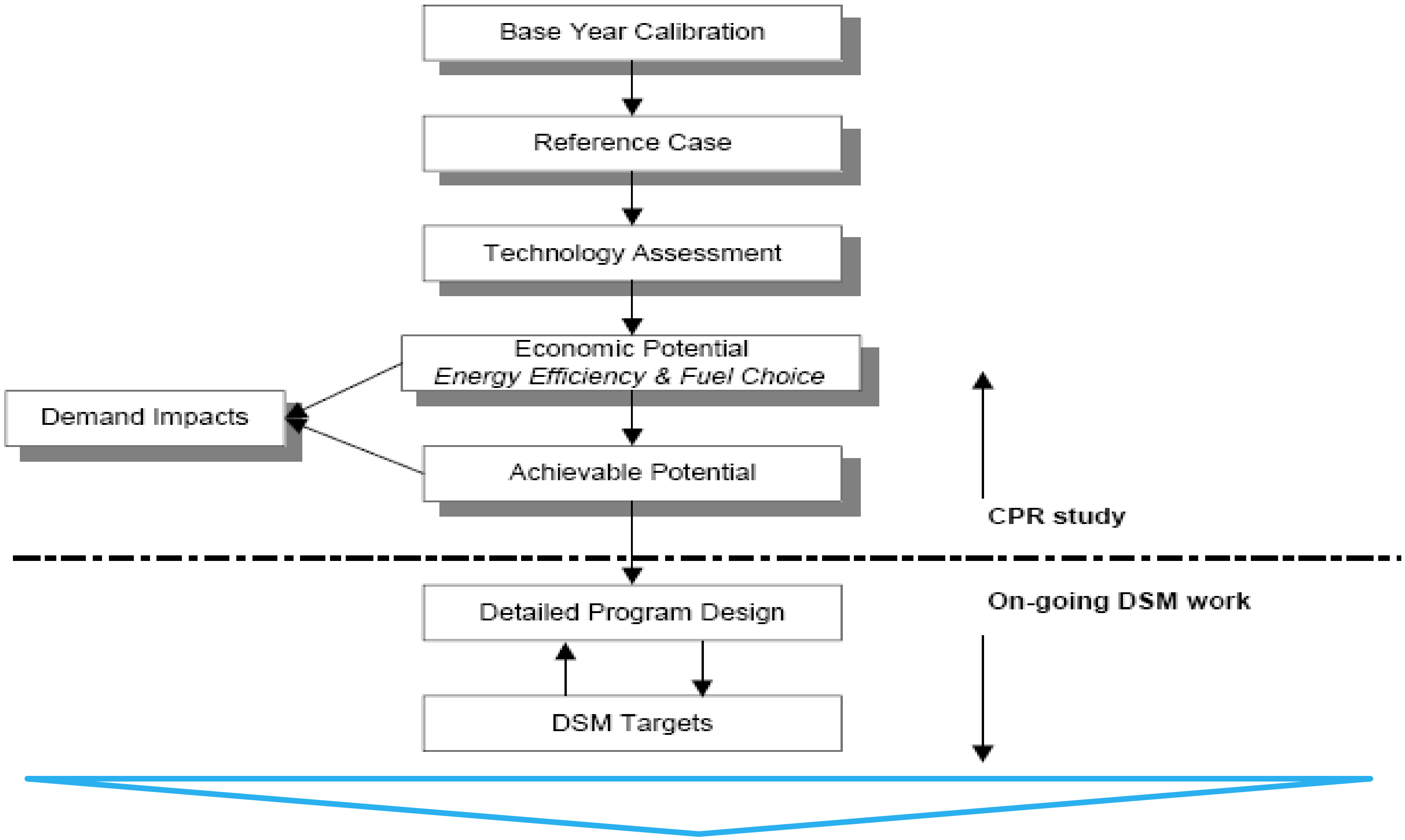

Results from CPR 2010 will support future EEC Activities

How EEC can impact long term demand

Terasen

Scenario A	Scenario B	Scenario C
• Funding ends after 2011 • Programs run in 2010 and 2011, then end	• Funding and savings continue at $35.3M for 2011 and beyond	• Secure, long-term funding of 5% of revenues • Approx $80M starting in 2012
~ 13,800,000 GJs conserved	~160,000,000 GJs conserved	~260,000,000 GJs conserved

Opportunity: Accelerated Retirement

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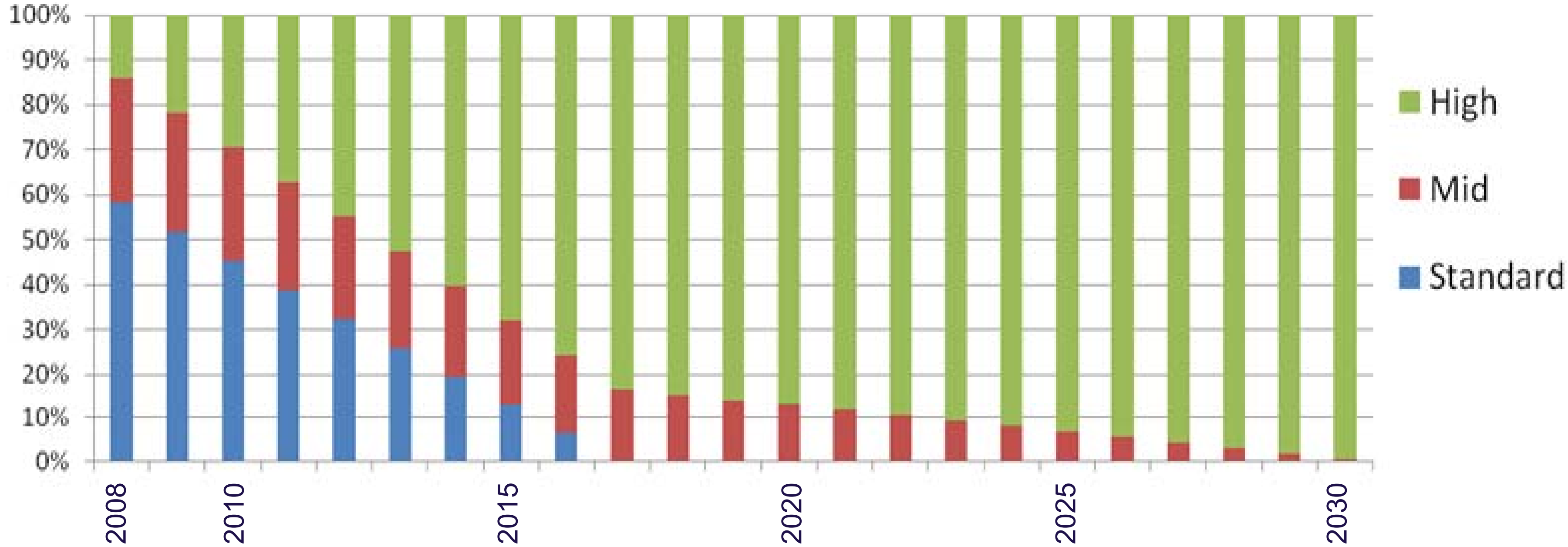
Forecast of Furnace Efficiency Mix in Single Family Dwellings



EEC Scenarios Moving Forward

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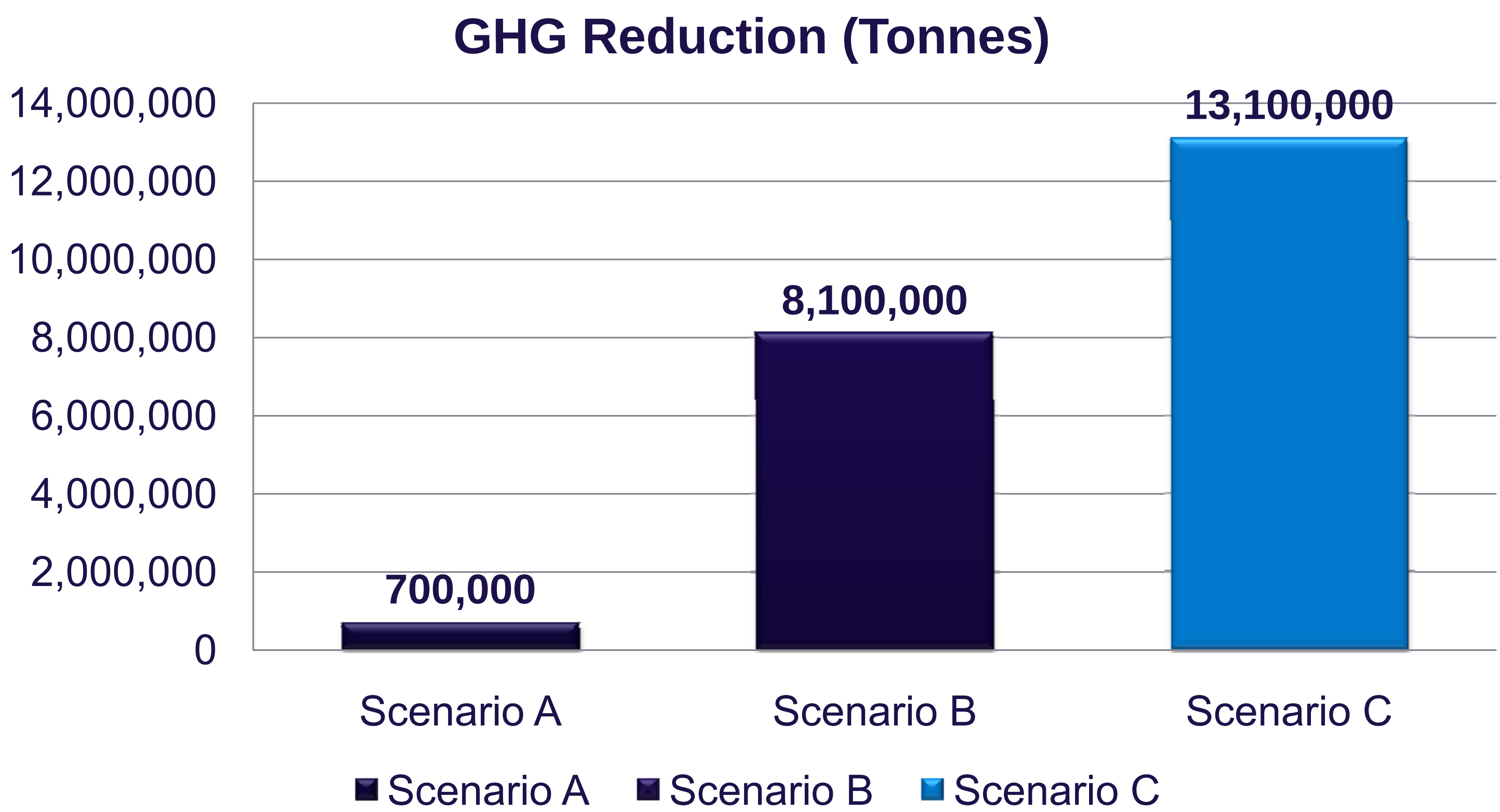

Terasen Gas

Thank You

Questions?

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Terasen Gas. A Fortis company.

Terasen

Terasen Integrated Energy Projects

2010 Long Term Resource Planning Workshop

May 27, 2010

Jason Wolfe
Manager, Community Energy Solutions
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Integrated Energy Services

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	Terasen Gas Inc	
Energy Service	**Natural Gas**	**Alternative Energy**
Service Offerings	Natural Gas EEC Biogas NGV	Solar District Energy Geothermal

Regulated by
British Columbia Utilities Commission
(BCUC)

Regulatory Process

Terasen

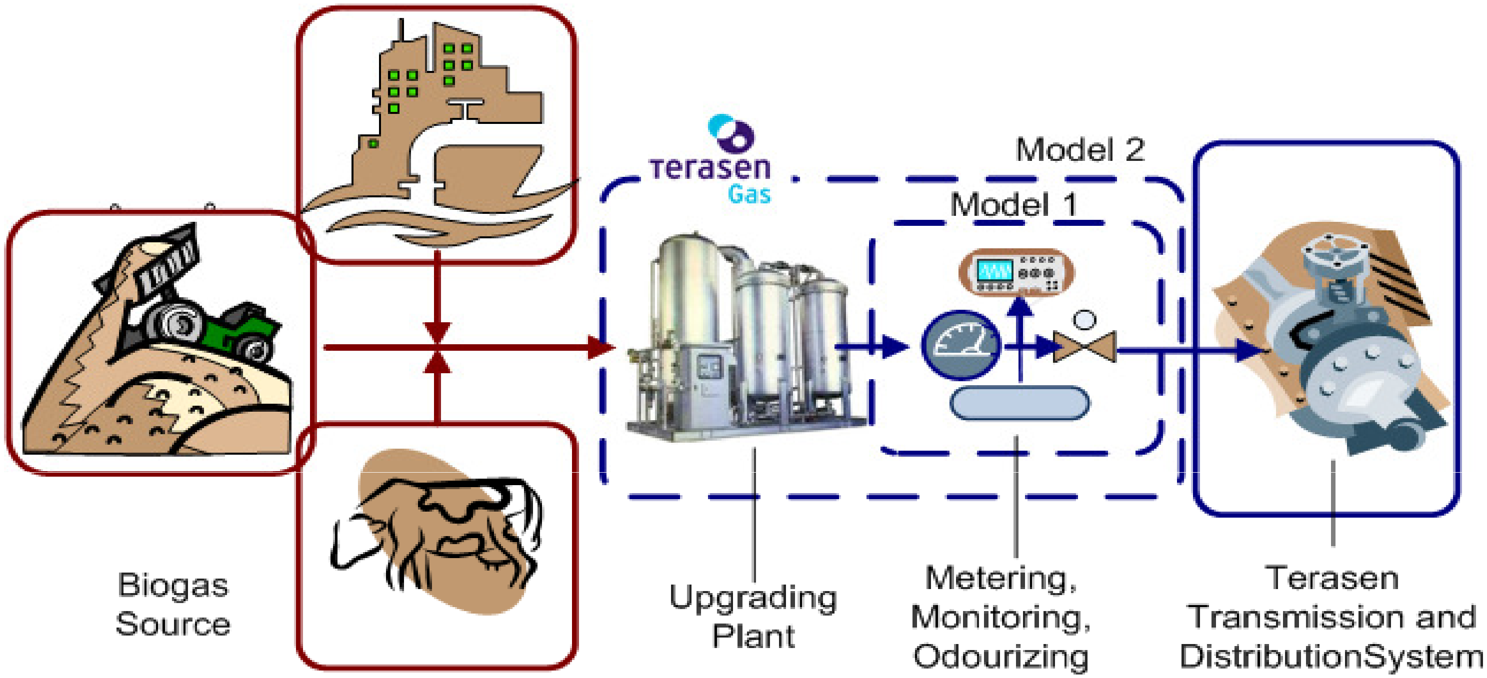
- 2008 Resource Plan
  - Identified Integrated Energy solutions as a business strategy
- 2010 TGI/TGVI Revenue Requirement
  - Sought Approval for:
    - Alternative Energy, NGV Compression, Biogas, Expanded EEC
  - Negotiated Settlement
    - Alternative Energy approved (deferral acct. tracking of costs)
    - EEC Approved
    - NGV and Biogas Terasen would bring forward projects in future

Biogas - Overview

- Research
  - Customers want Terasen involved in renewable energy, and are willing to pay the associated premiums
  - Customers prefer a biogas offering to alternatives such as an offset program

- Two Phase Biogas Offering to Customers
  - TGI Residential product, 10% biogas blend – opt-in
  - Roll out to all Rate Classes

Bio-gas Upgrading:
Supply Arrangements



Model 1

– Terasen buys upgraded biomethane and ensures it is safely injected into the distribution grid

Model 2

– Terasen buys raw biogas, upgrades it to biomethane, and ensures it is safely injected into the distribution grid

Biogas Projects

Terasen

CSRD
COLUMBIA SHUSWAP REGIONAL DISTRICT

CATALYST POWER INC.

Columbia Shuswap Regional District

Project – LFG to pipeline quality bio-methane –

- 100,000 GJ/year
- $0.6M – Investment
- $12/GJ
- Gas flow by summer 2010

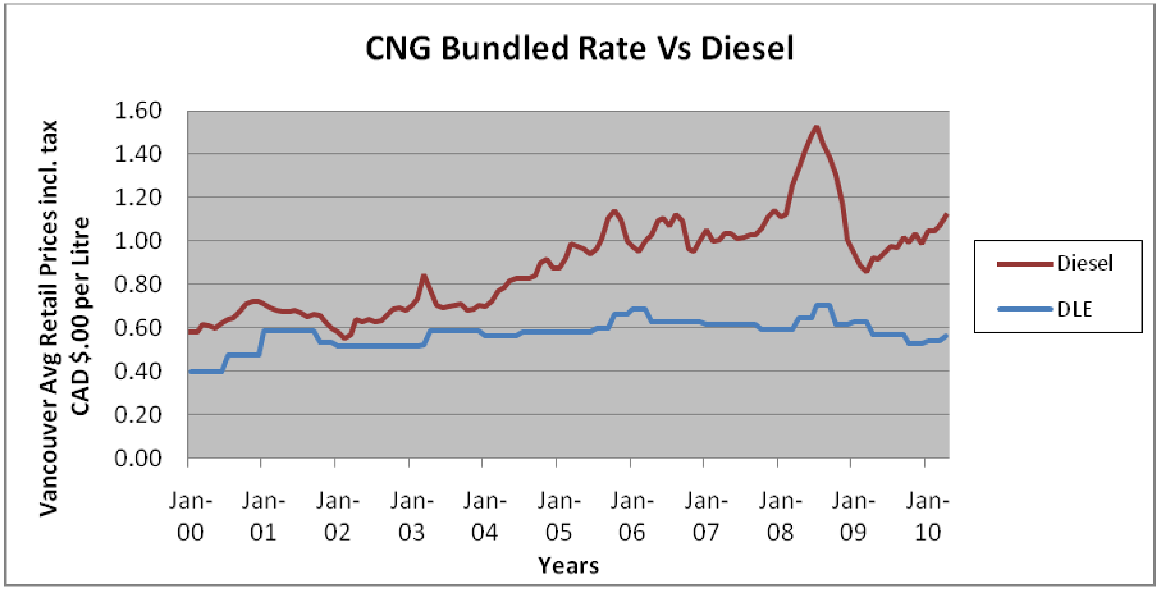
Catalyst Power

Digester to pipeline quality bio-methane

- 20,000 - 40,000 GJ/year
- $2.2M –Investment
- $10/GJ
- Gas flow by end of 2010

Natural Gas Vehicle Business Proposition

Terasen



Fuel	Base Carbon Intensity (gms CO2e/MJ)	Engine Efficiency Factor	Adjusted Carbon Efficiency (gms CO2e/MJ)
Reformulated 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

Carbon Intensity

28% < Diesel
38% < Gasoline

Natural Gas Vehicle Projects

Transit NGV - $2.5 million

Waste Transfer LNG - $1.2 million

Waste hauling- $1 million

Renewable Thermal Energy Delivery Projects

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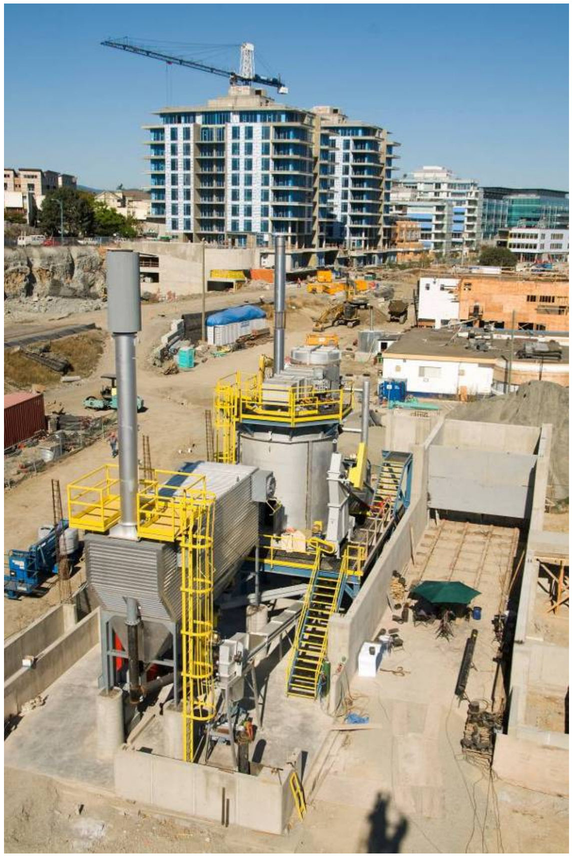
- Dockside Green
  - Brownfield re-development
  - Biomass Gasification Plant ,Natural gas back-up & peaking



- Fraser Mills, Coquitlam
  - 89 acre brownfield re-development
  - Ambient temperature DES
  - Geo-exchange, biomass

Energy System Proposals

Terasen

Prepared for:

Provincial Health Services Authority
Purchasing Department, Rm H203
4500 Oak Street
Vancouver, BC V6H 3N1

Provincial Health Services Authority
Province-wide solutions. Better health.

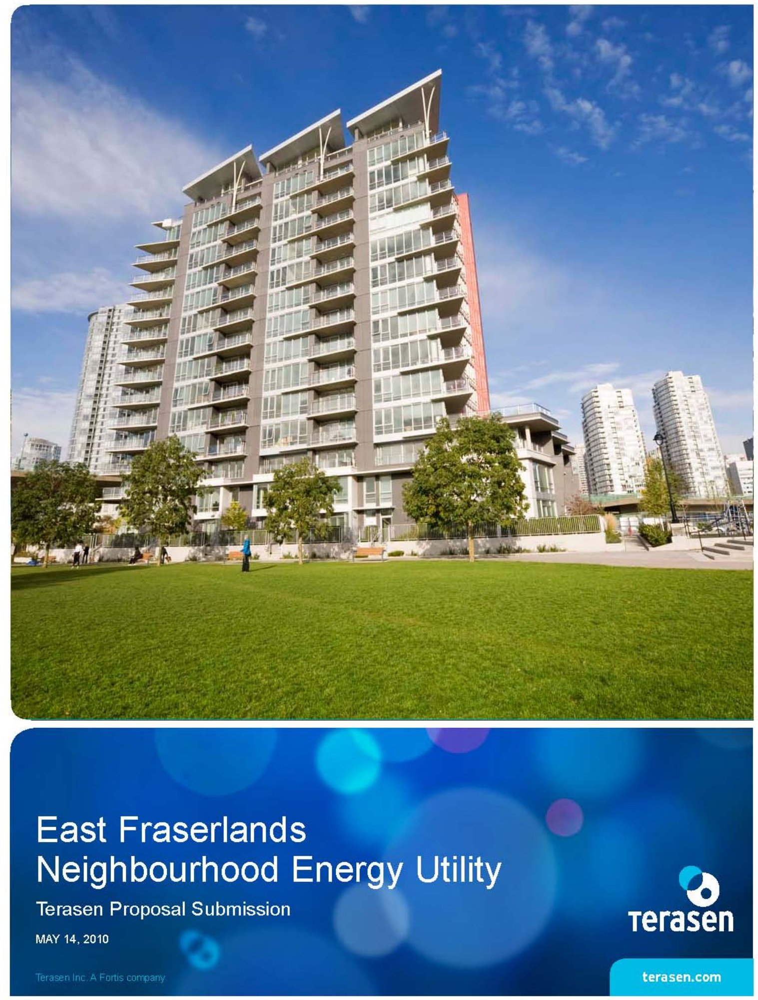
Women's
BC Women's Hospital & Health Centre

BC Children's Hospital

Prepared by:

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Terasen



Summary

- Committed to new integrated energy solutions as part of carbon reduction strategy
- Integrated energy system projects already in progress
- Alternative, integrated energy services an essential component in Terasen's Long Term Resource Planning

Demand Forecast

May 27, 2010 Resource Planning Workshop

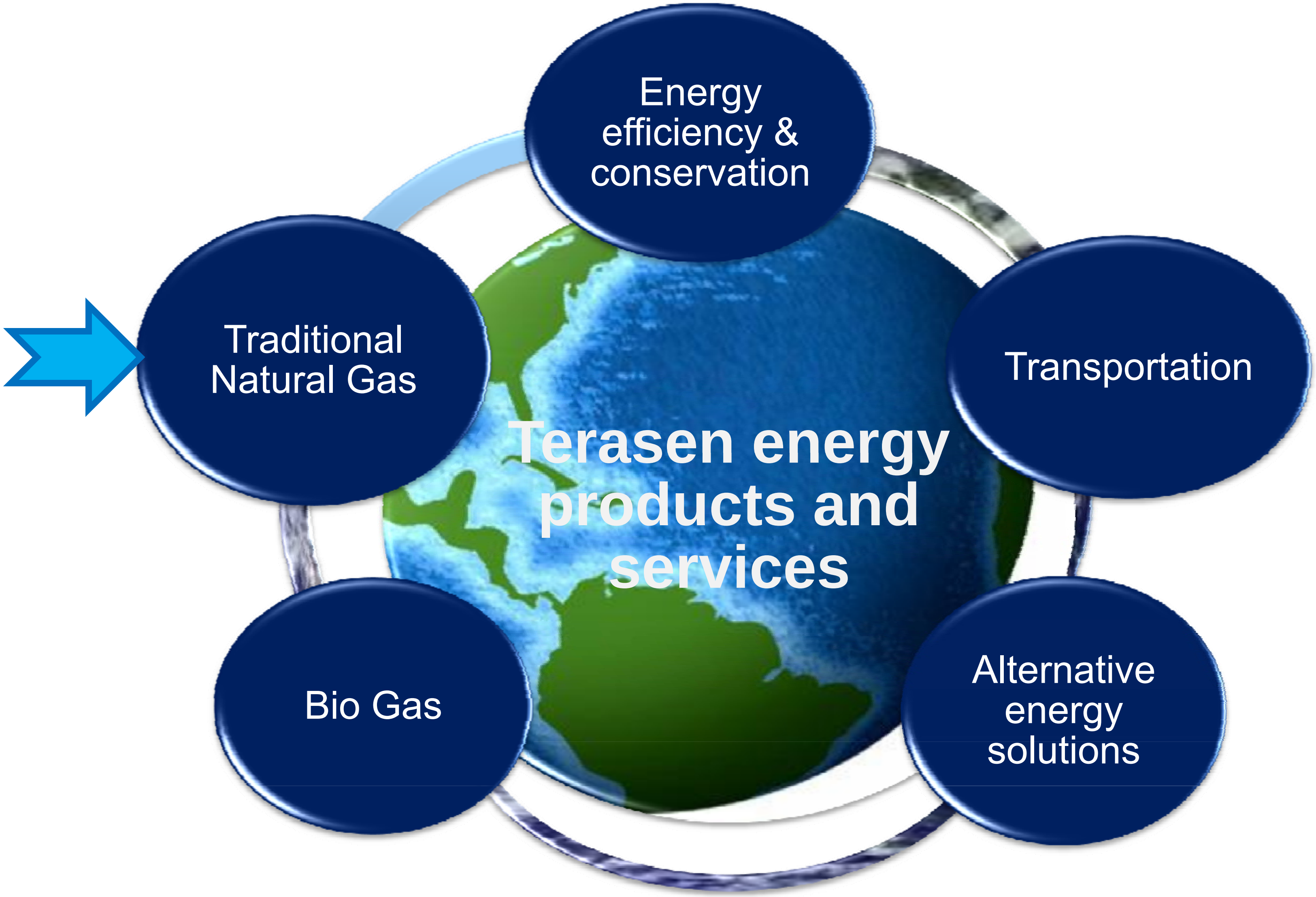
Arvind Ramakrishnan
Business Development Analyst

Demand Forecast Key Messages

terasen

- Demand forecasting forms a key input into the long range planning.
- Continue to forecast natural gas demand.
  - Demand expected to remain level
- Need to forecast demand for a broad range of energy solutions.
  - Developing new approaches

Future of Demand Forecasting



Natural Gas Demand Drivers

Lower Demand | **Reference** | **Greater Demand**

Population growth/Economy

High carbon fuel switching

Efficient appliances

Transportation

Housing Type

Competitiveness

Alternative Energy

Policies/Perception/Building codes and standards

Annual Gas Demand - Current Methodology

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Total demand

Residential and Commercial Demand + Industrial demand

Total number of customers × average use rate

Surveys, contracts, sector analysis and economic reports

Traditional approach

Reference Case(TGI)
Annual Demand

Residential Average Use Per Customer

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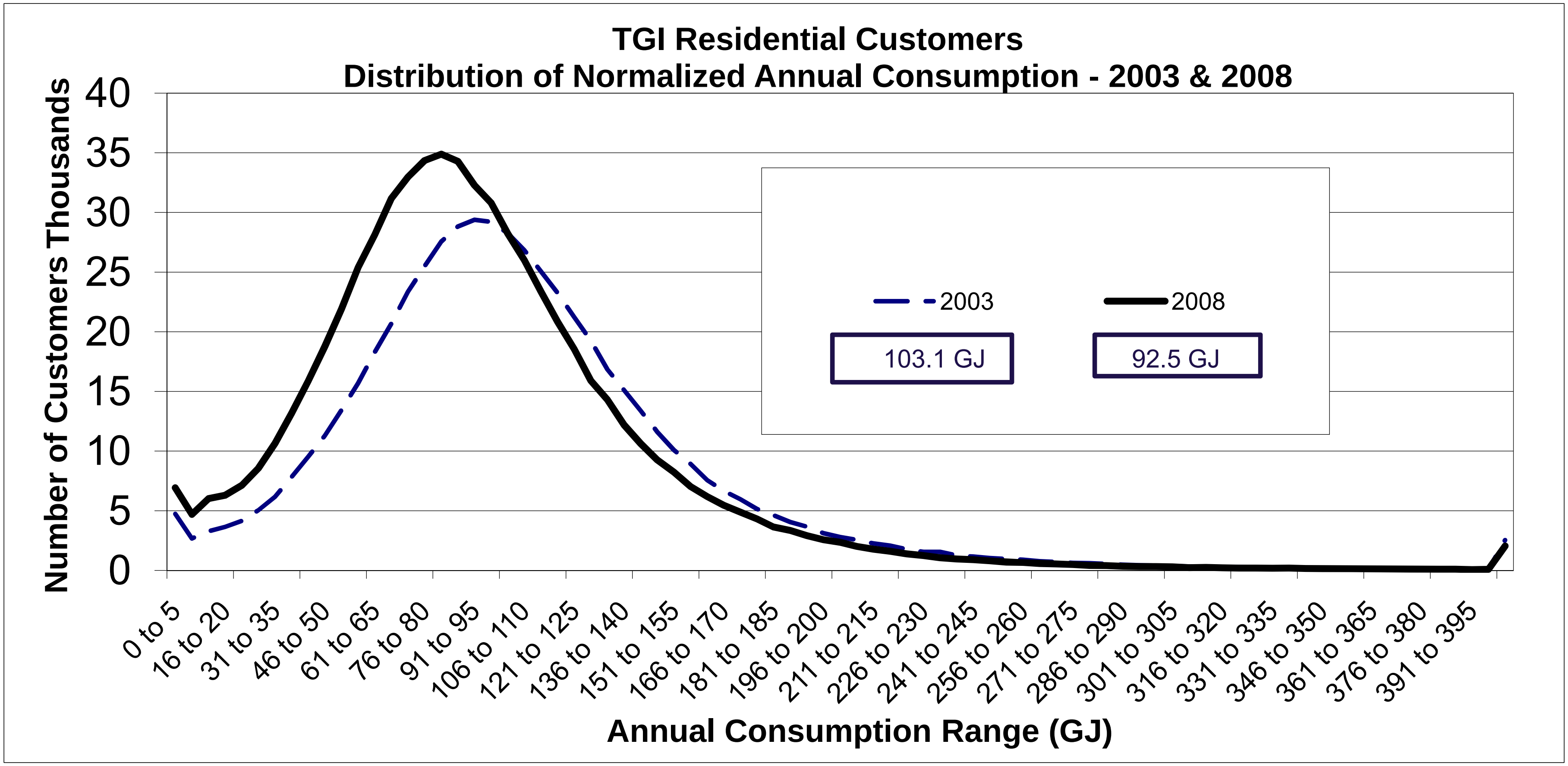

- Increased share of MFDs in the housing mix
- Retrofit of low & mid-efficient appliances
- 21% decline since 1999 (2.5% annually)
- Building codes and standards

Commercial Average use Per Customer

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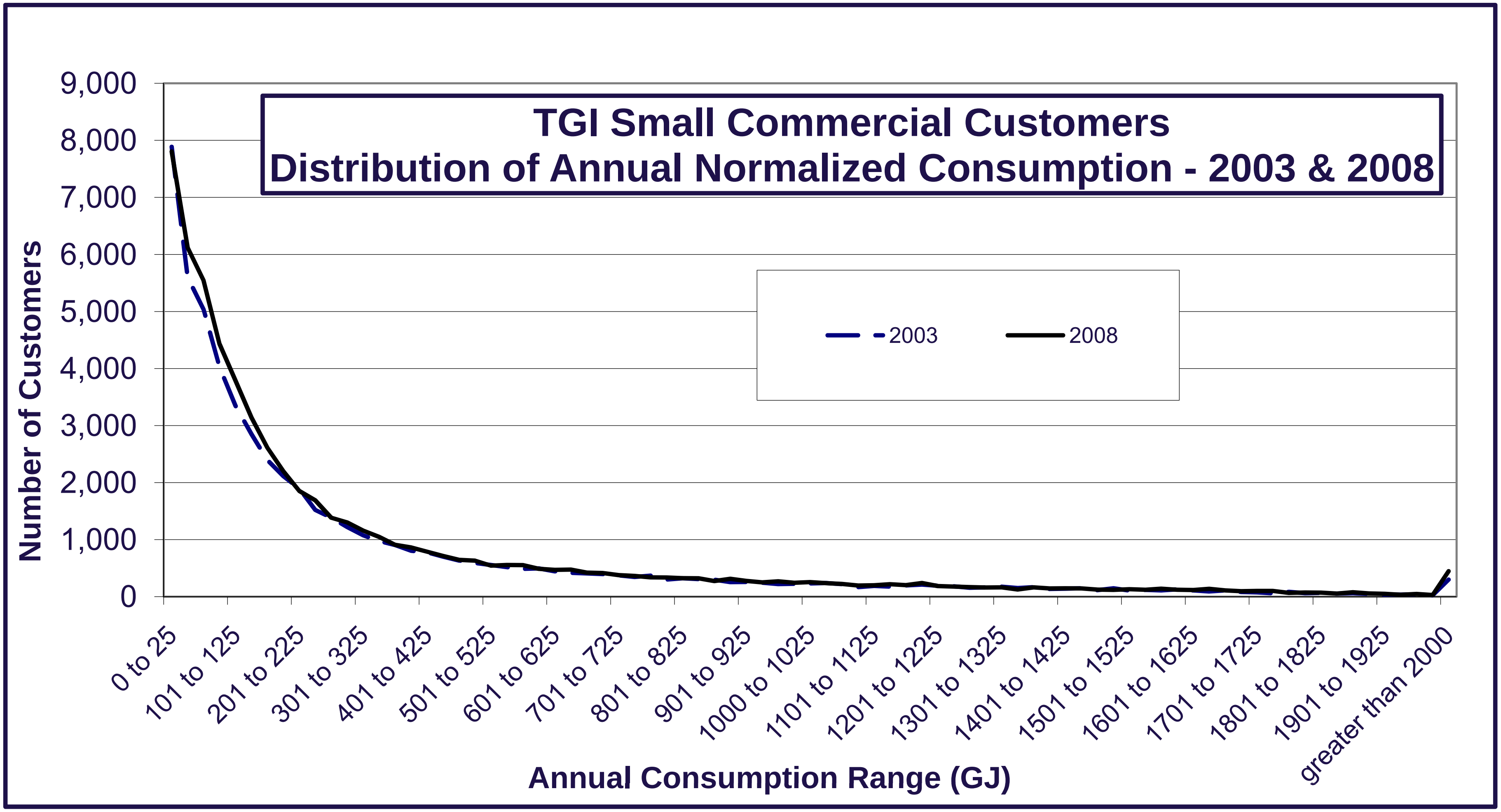

Top 5 sectors analyzed individually

Industrial Demand

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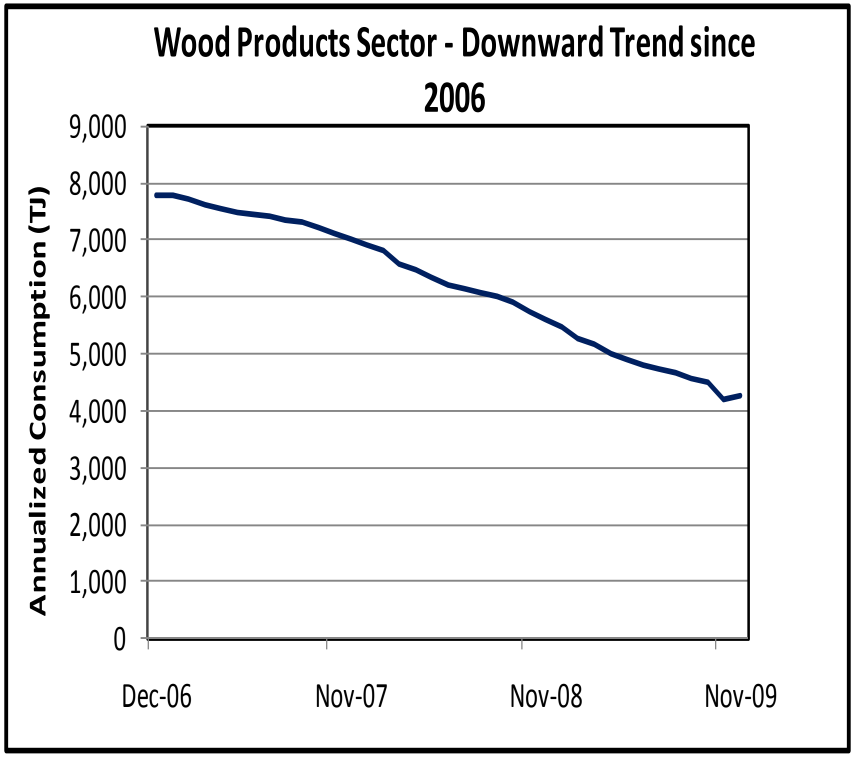
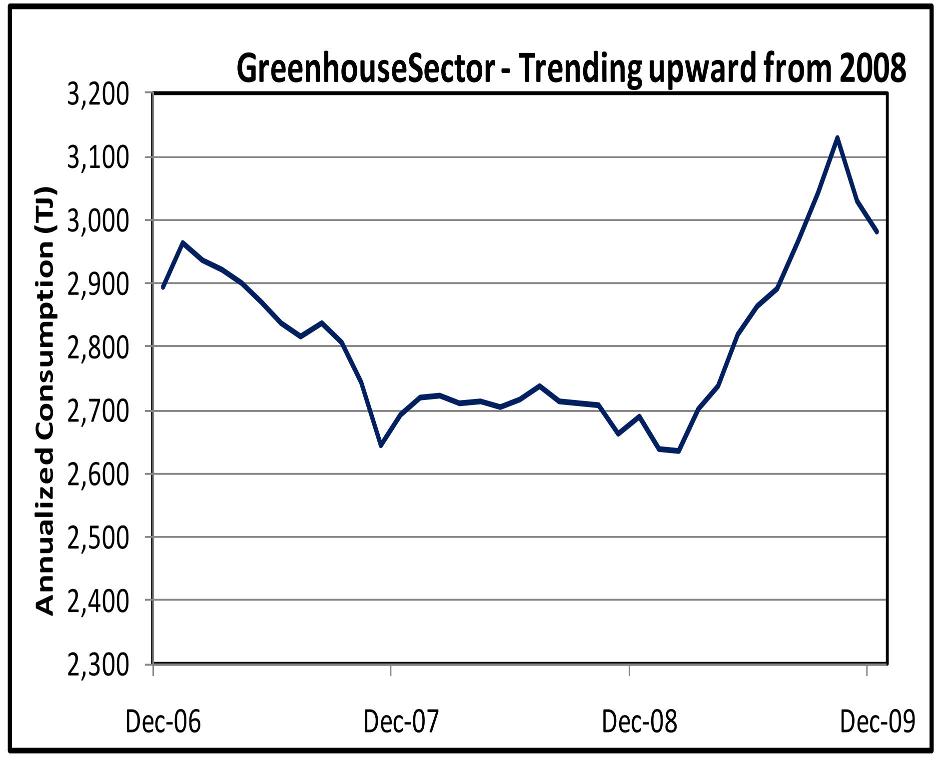
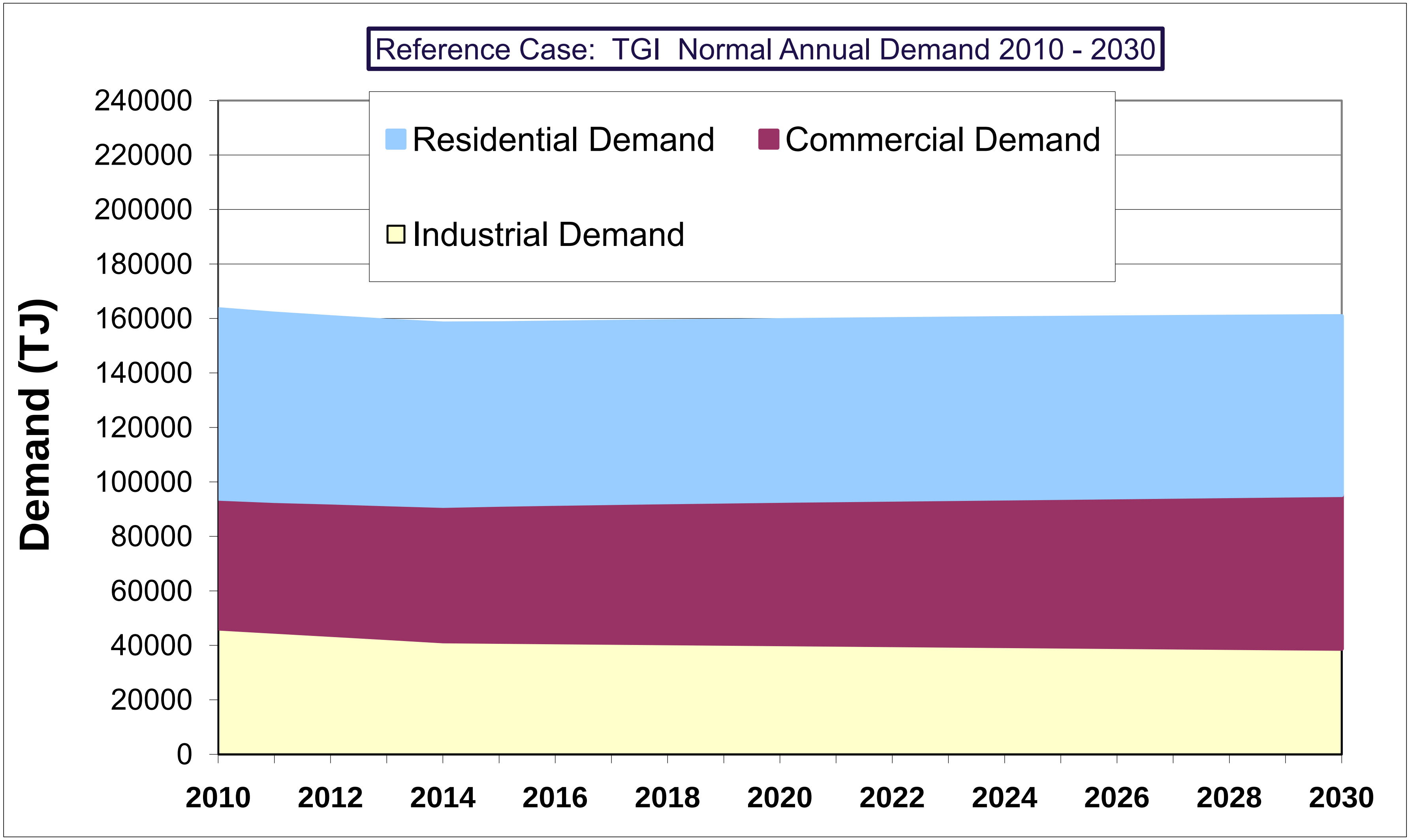




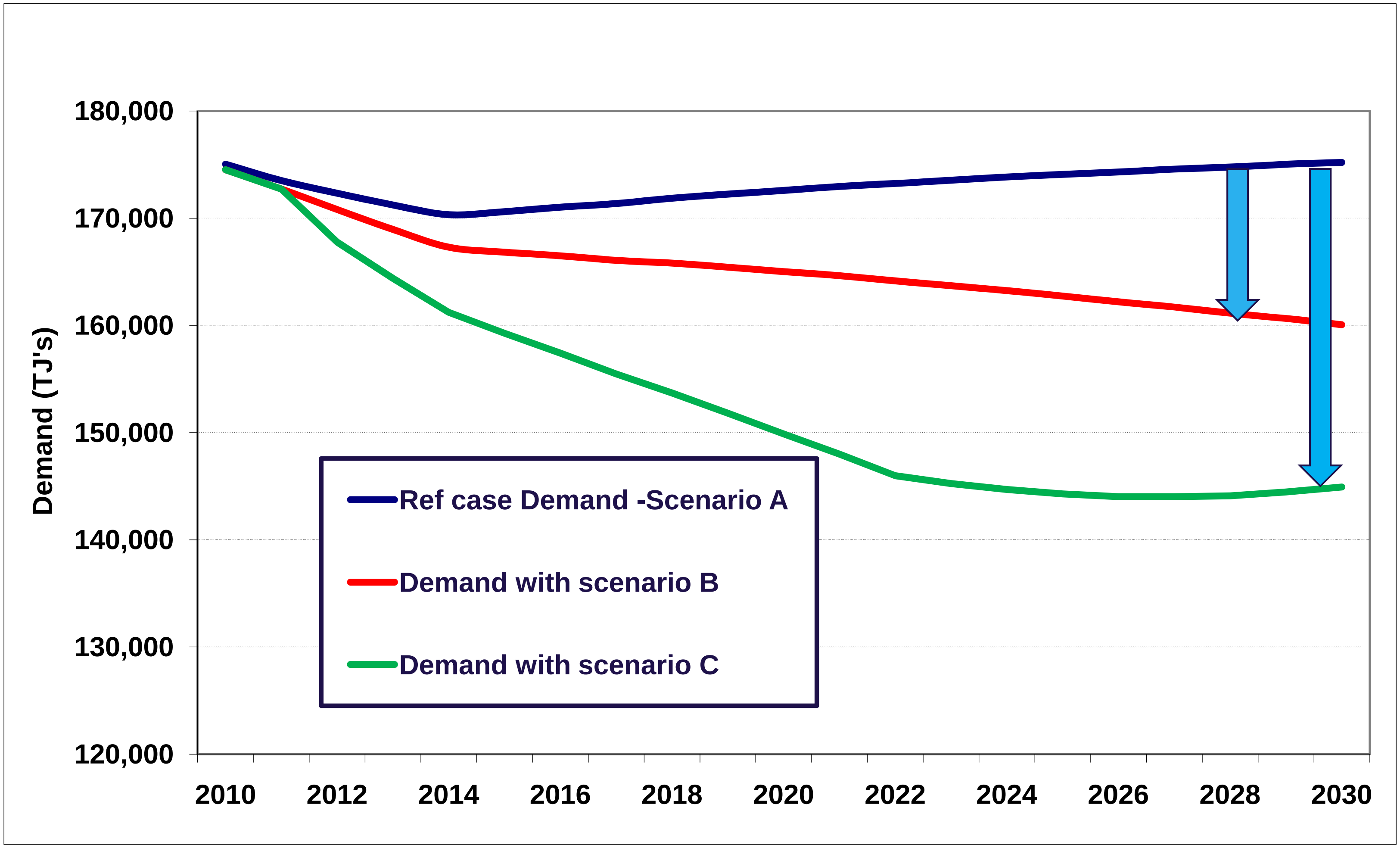
- **Wood Products sector continues to face challenges**
- **Greenhouse sector shows more variability due to fuel switching capabilities**

Reference Forecast – All Companies

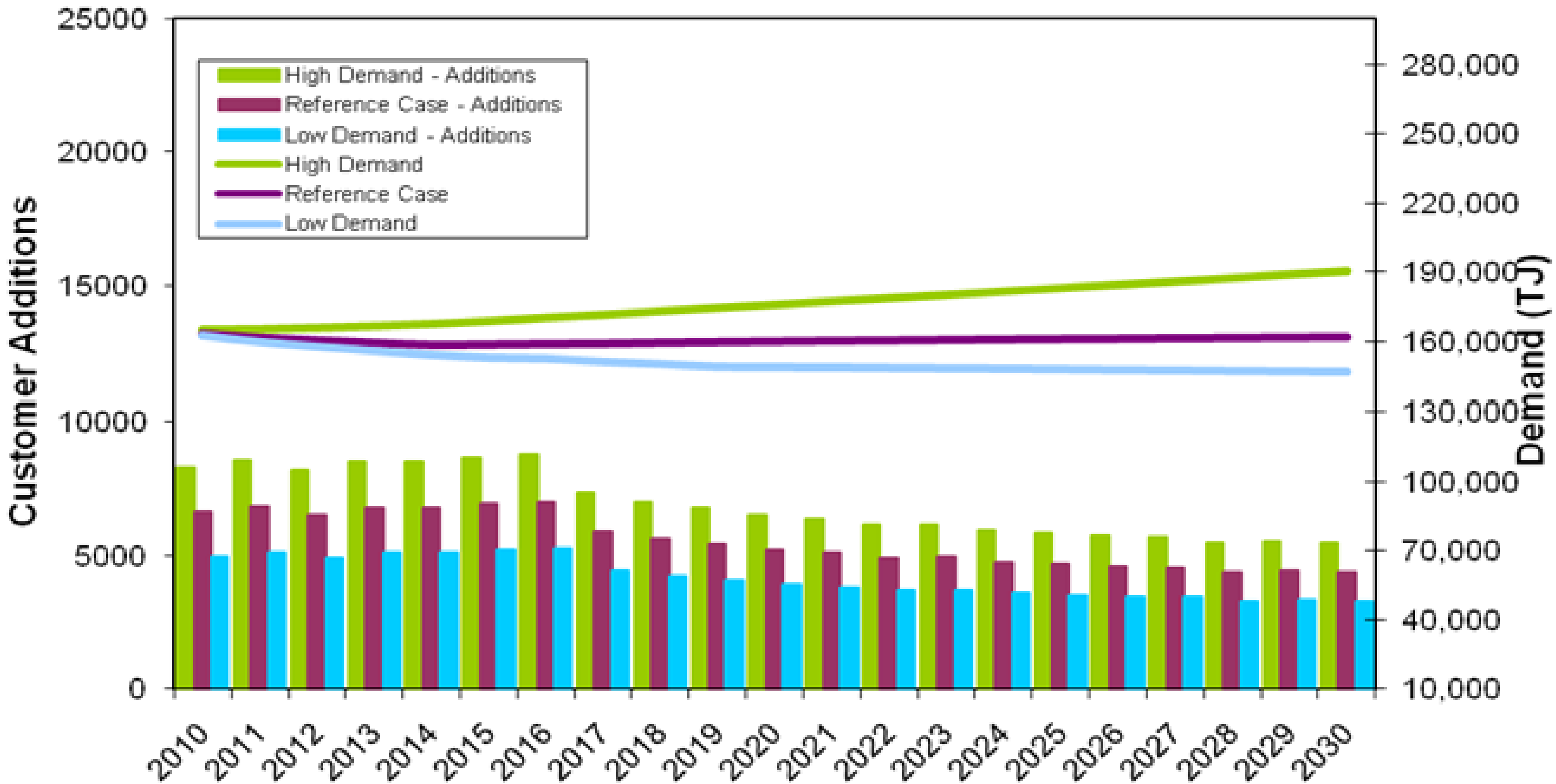


Energy Efficiency and Conservation

Terasen

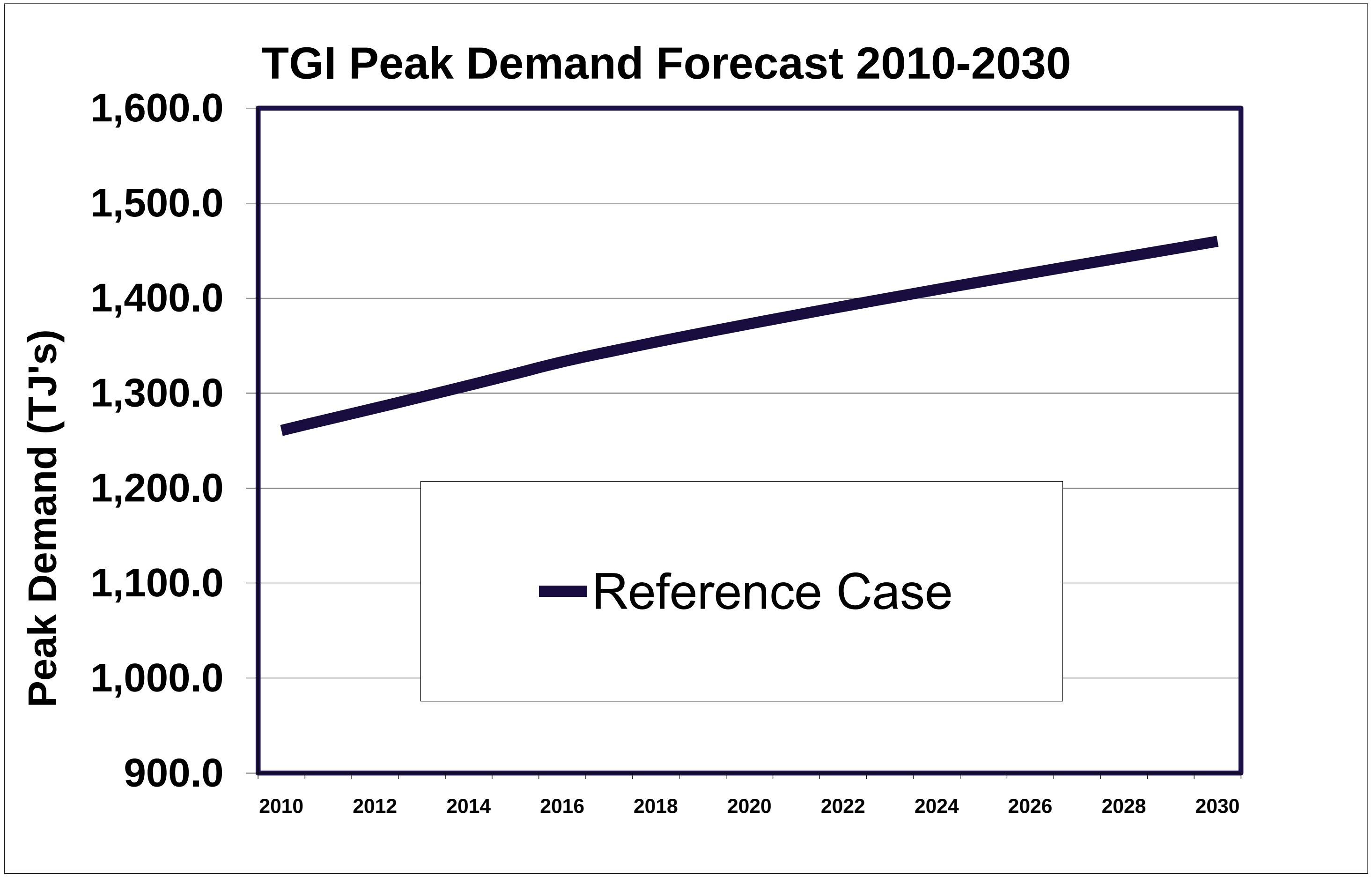


Reference Forecast – Scenario



Peak Day Demand

Peak Day Demand



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2009 peak use per customer to be held constant

Integrated energy solutions impact on peak /annual demand – not shown

Future of demand forecasting

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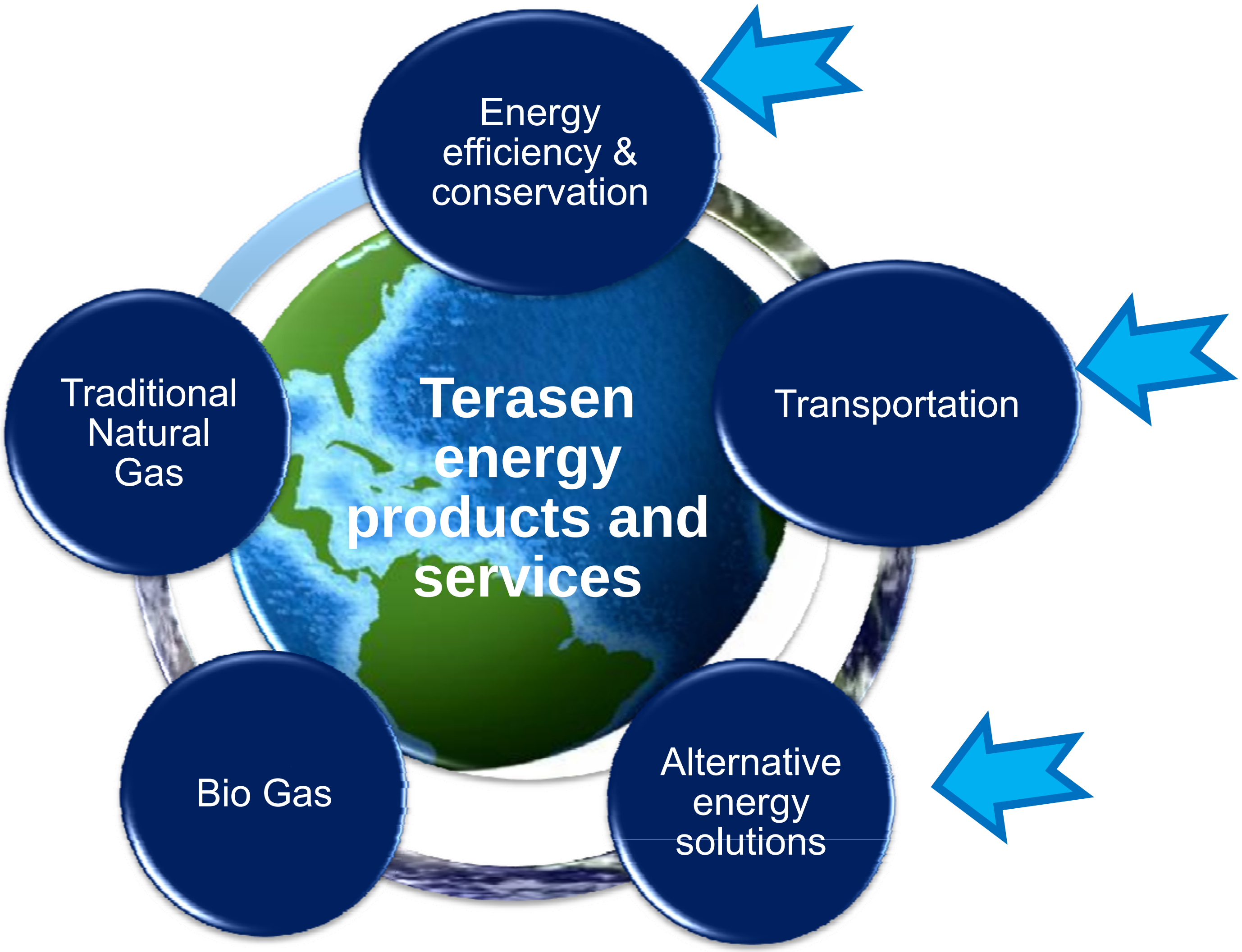

New Approach On Gas Demand

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New Customers

- New Home Construction
- ↓
- Housing Type
- ↓
- Choice of Appliances
- ↓
- Appliance Energy Choice
- ↓
- Appliance Efficiency

↔

Building codes and standards

Changing customer demand

Legislative policies

Existing Customers

- Choice of Appliances
- ↓
- Appliance Energy Choice
- ↓
- Appliance Efficiency

Lower Mainland Example

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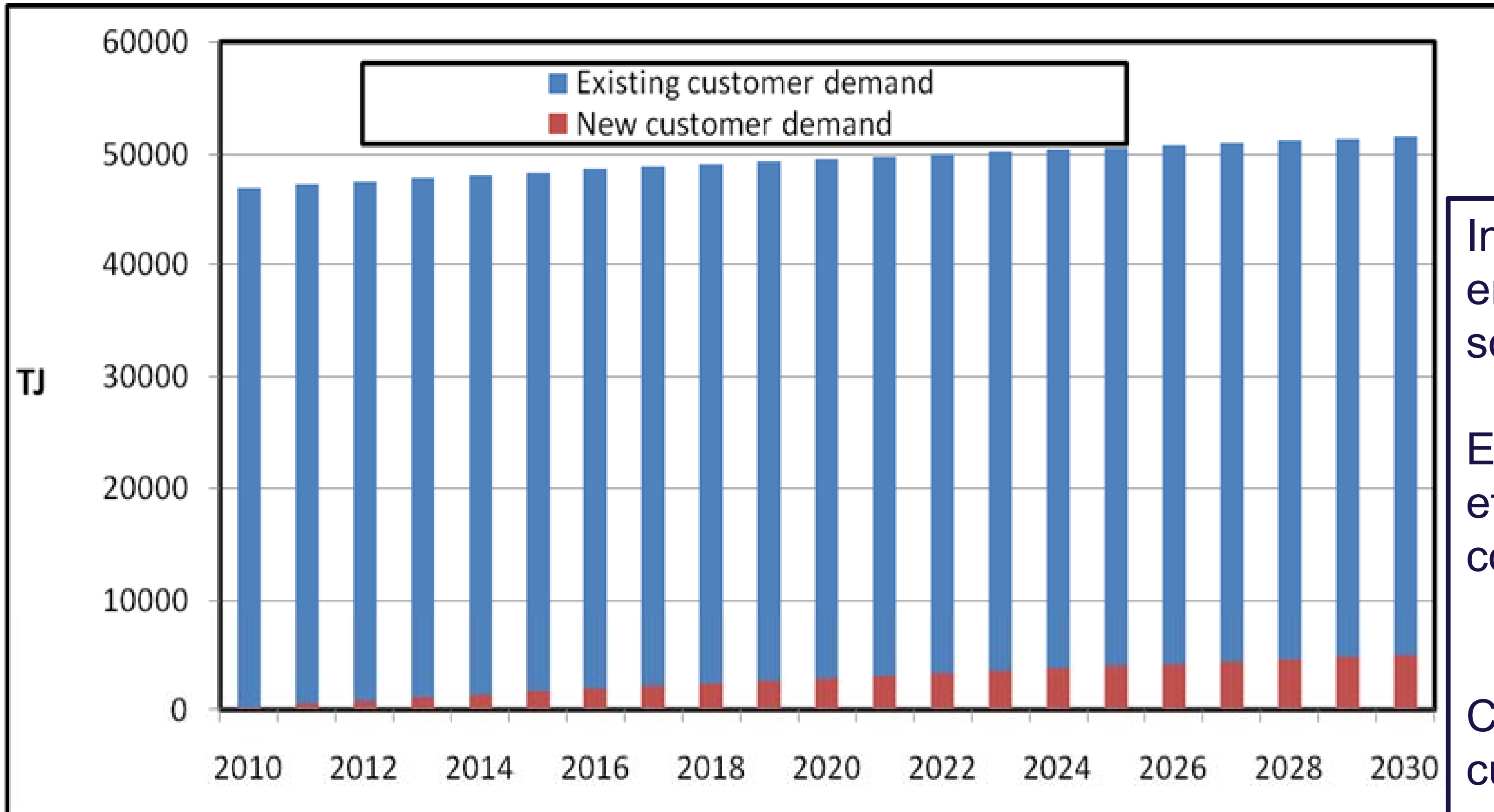
Annual Demand



Integrated energy solutions

Energy efficiency & conservation

Changing customer options

Example – Integrated Energy Solutions

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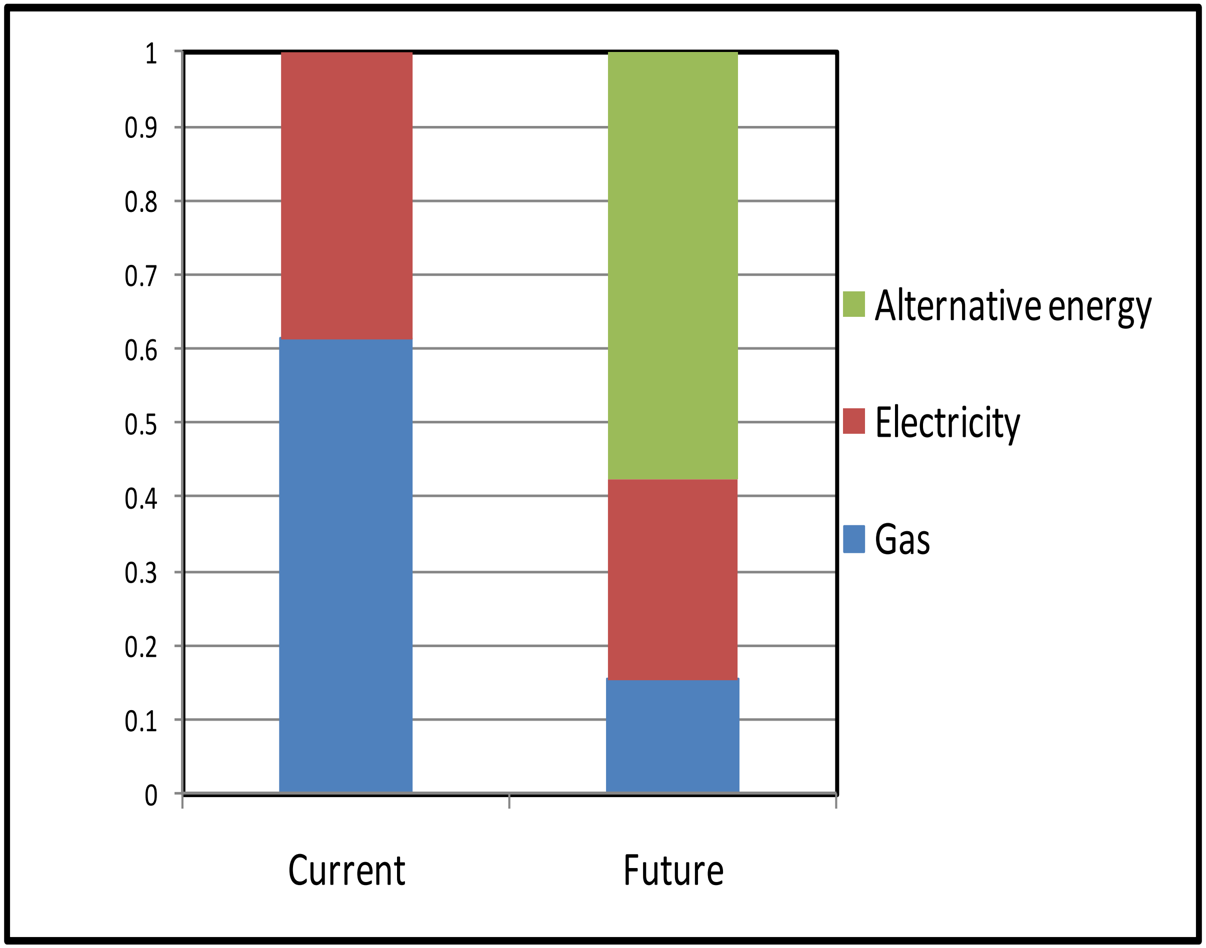
100 unit condo – thermal energy demand



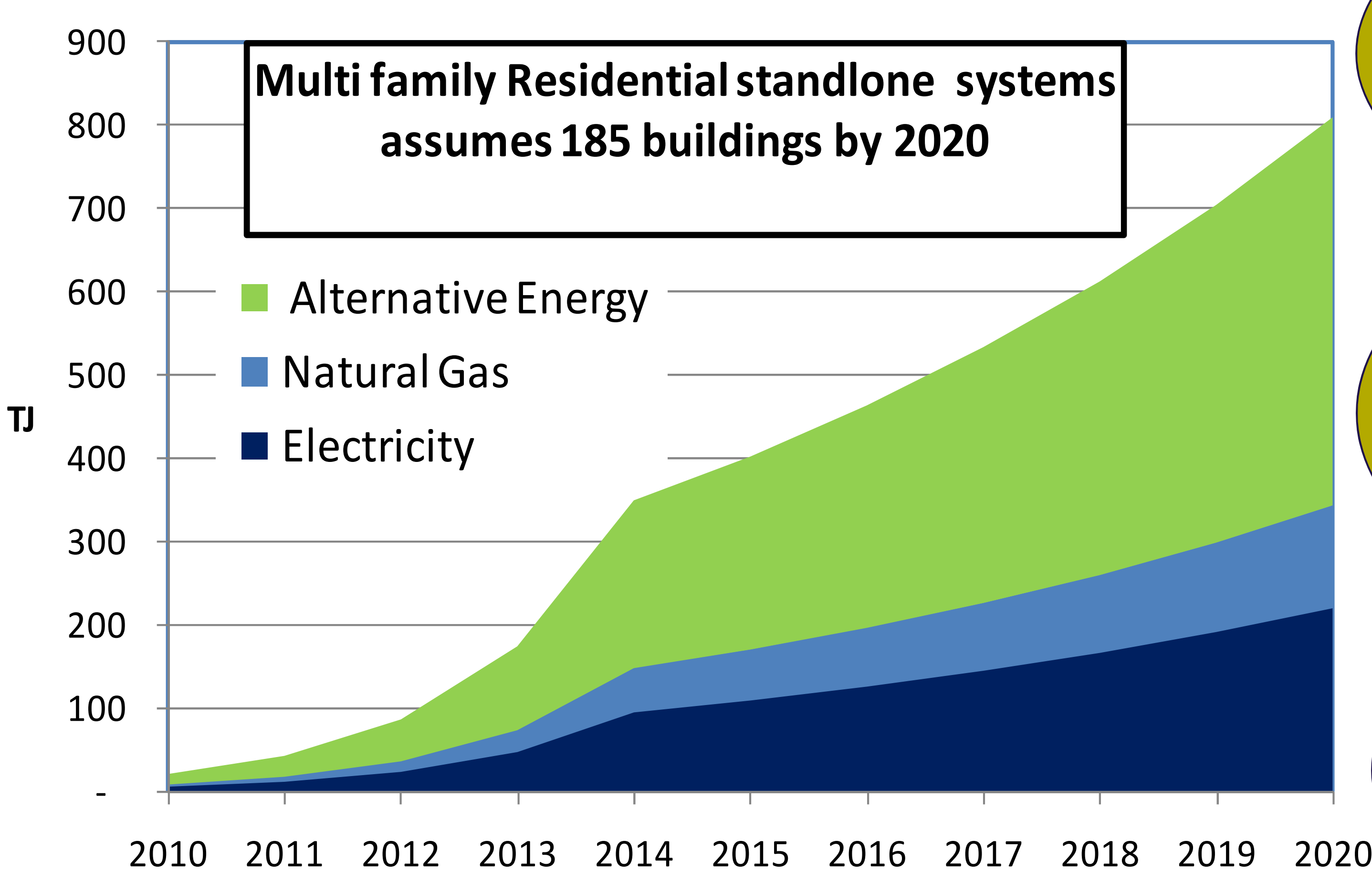
Electricity savings

Gas Savings

GHG Reduction

Peak /Annual demand

Example Continued
Alternative Energy Forecast



Electricity savings 134 GWh

NG savings 372,517 GJ's

GHG reduction 72%

BC Transportation sector- GHG

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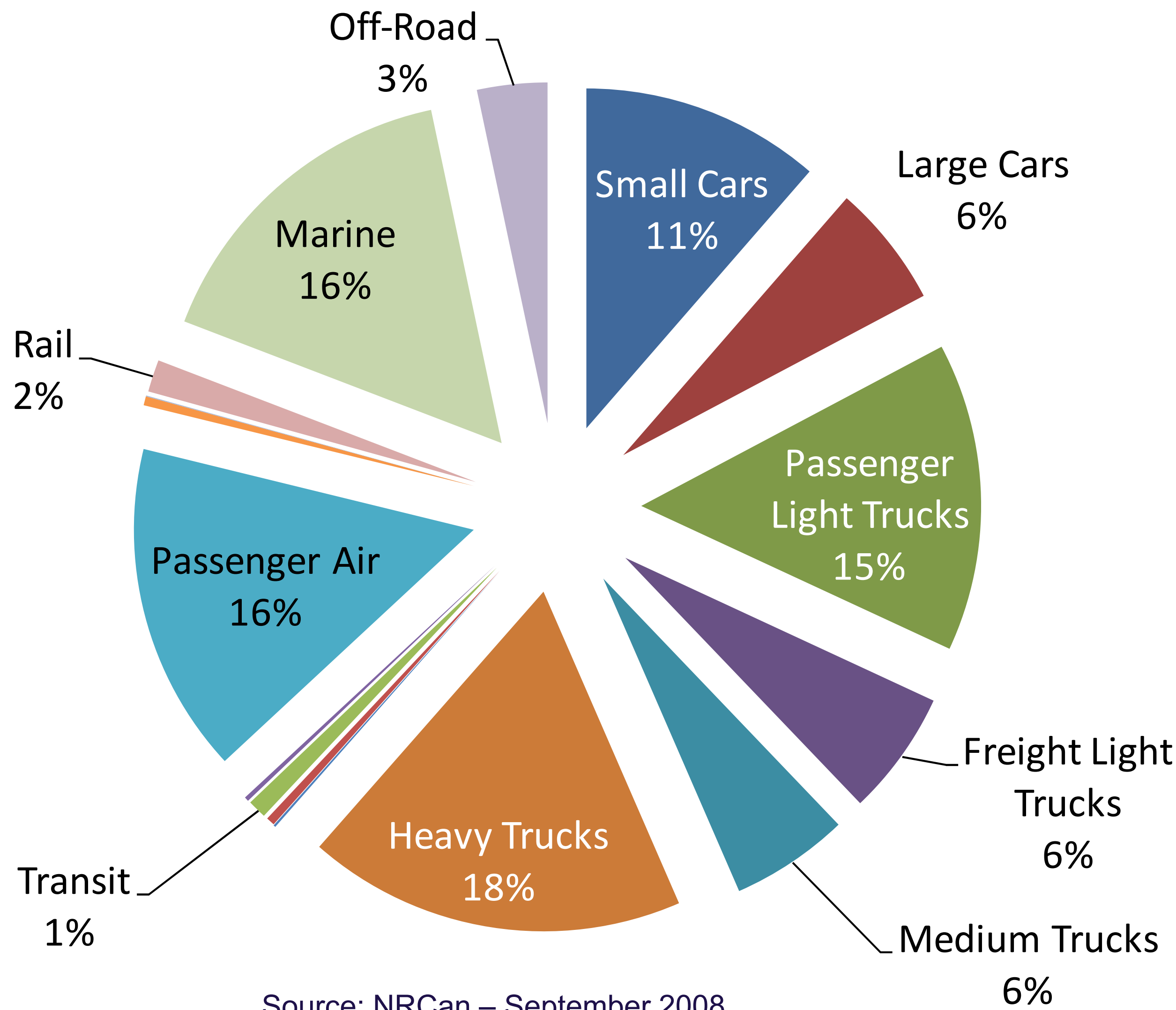

Source: NRCan – September 2008

Transportation Demand

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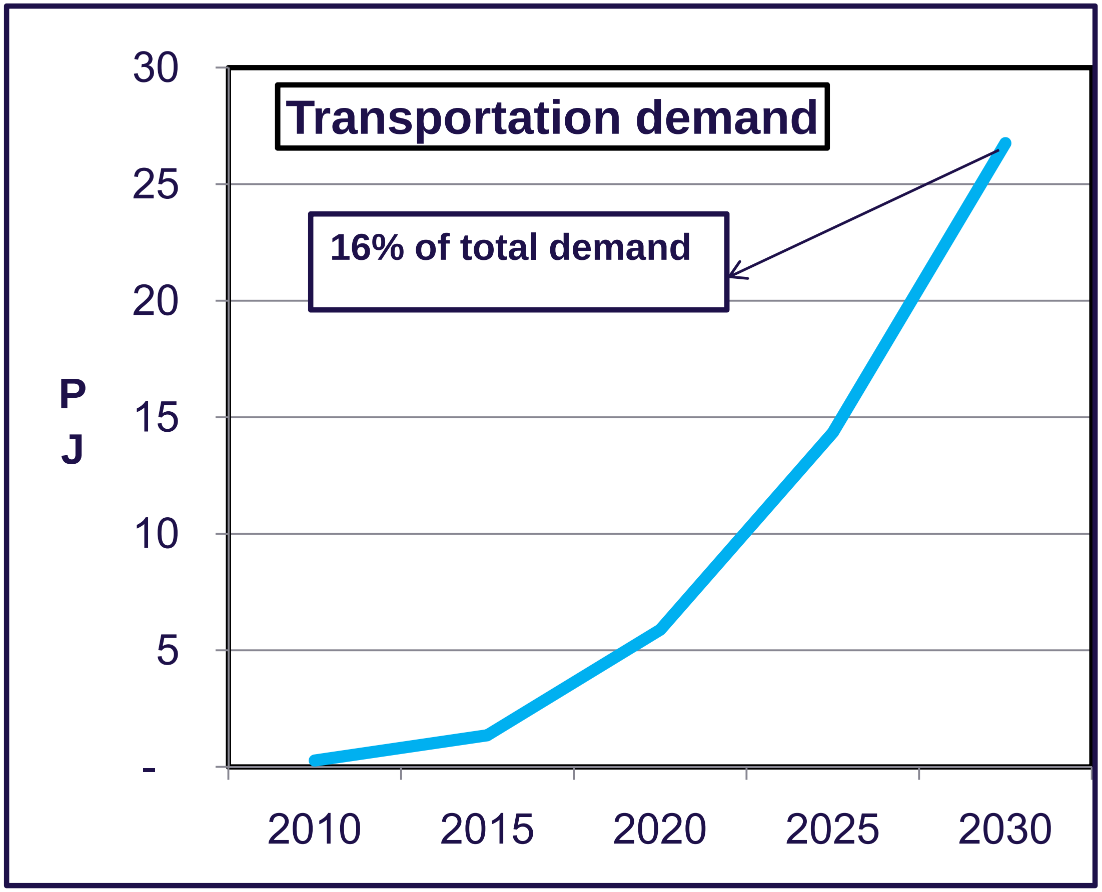
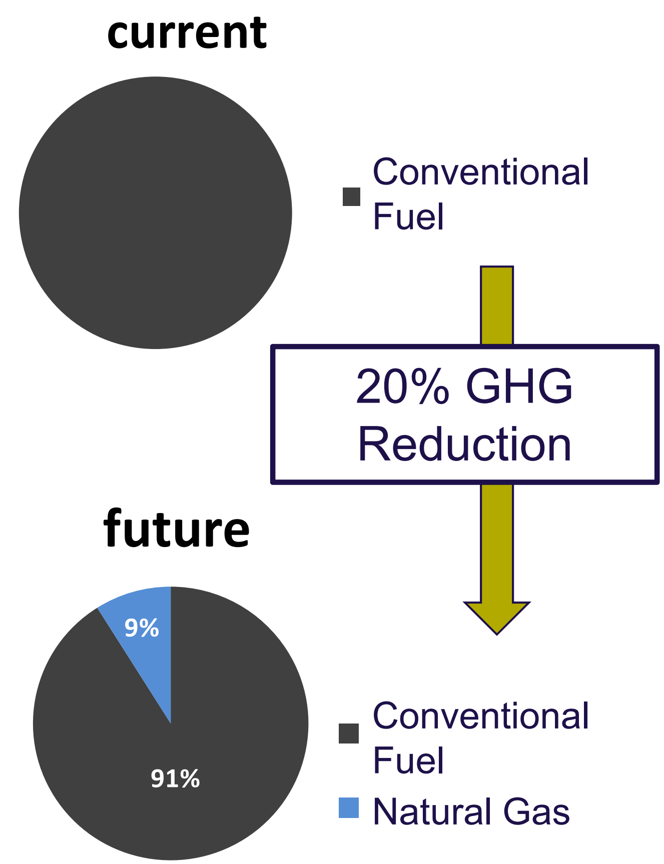
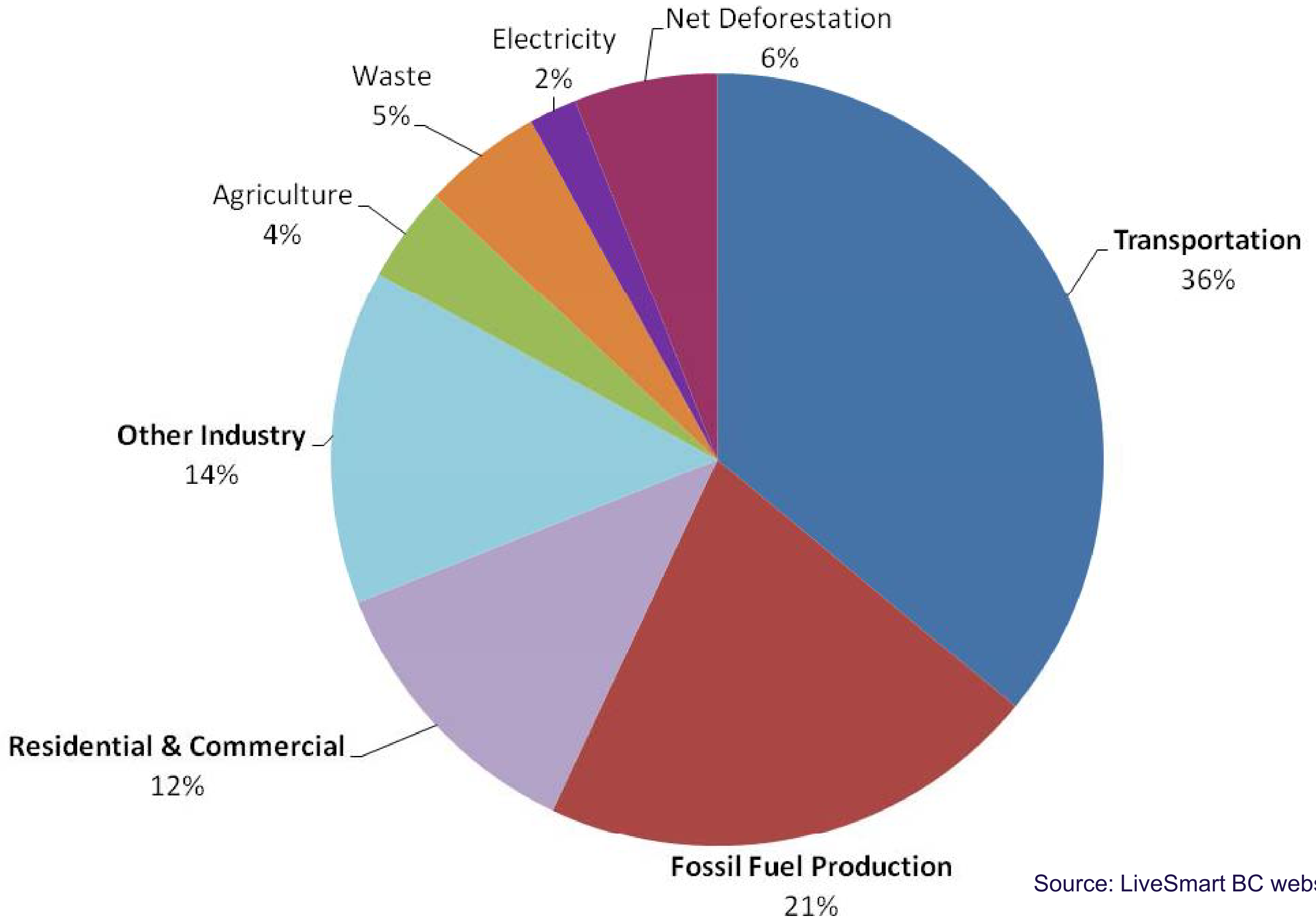
Heavy duty, medium duty, light duty, marine, transit bus applications





GHG Profile in BC
Opportunities to Reduce



Source: LiveSmart BC website (2006)

Reduced Carbon Intensity Future

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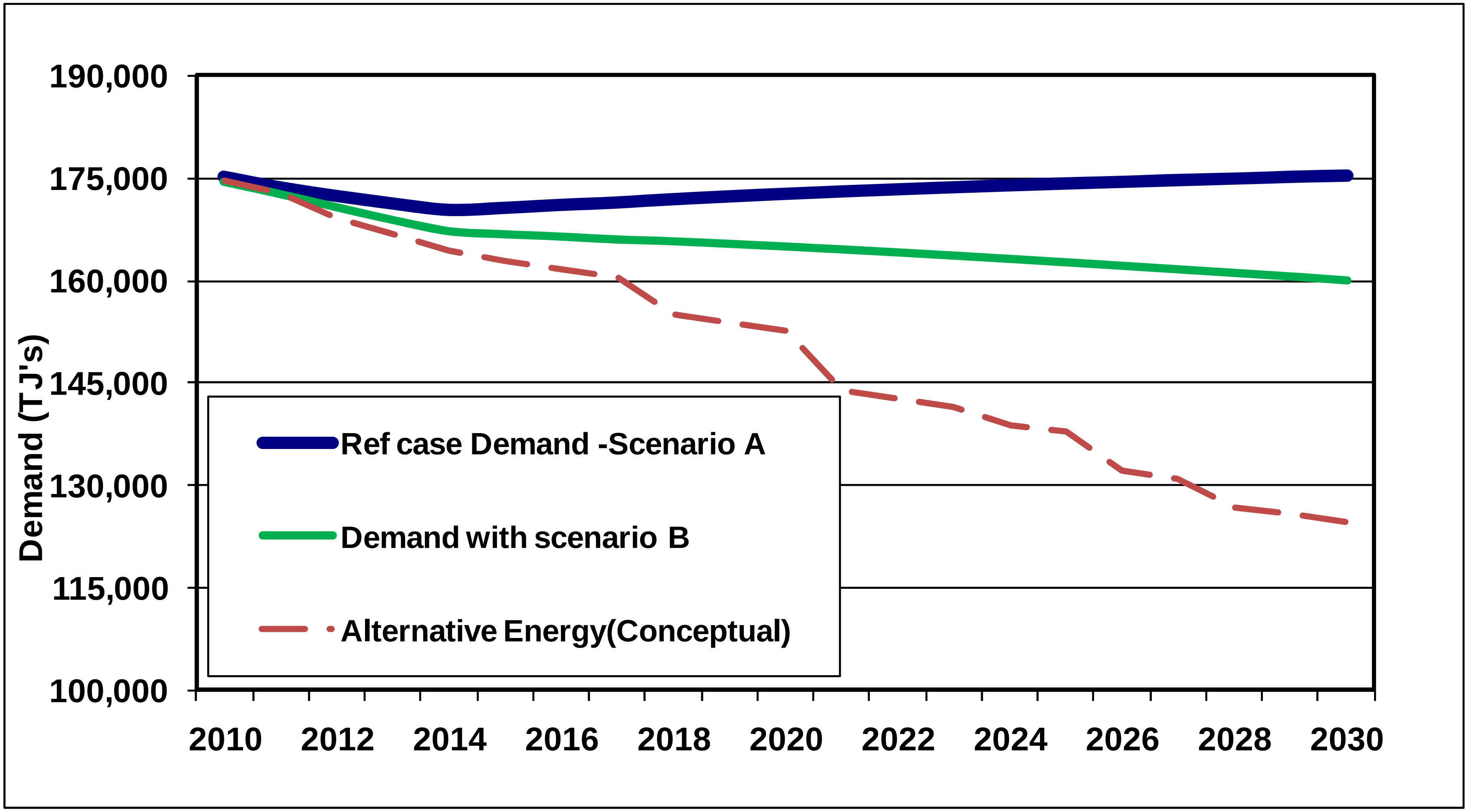
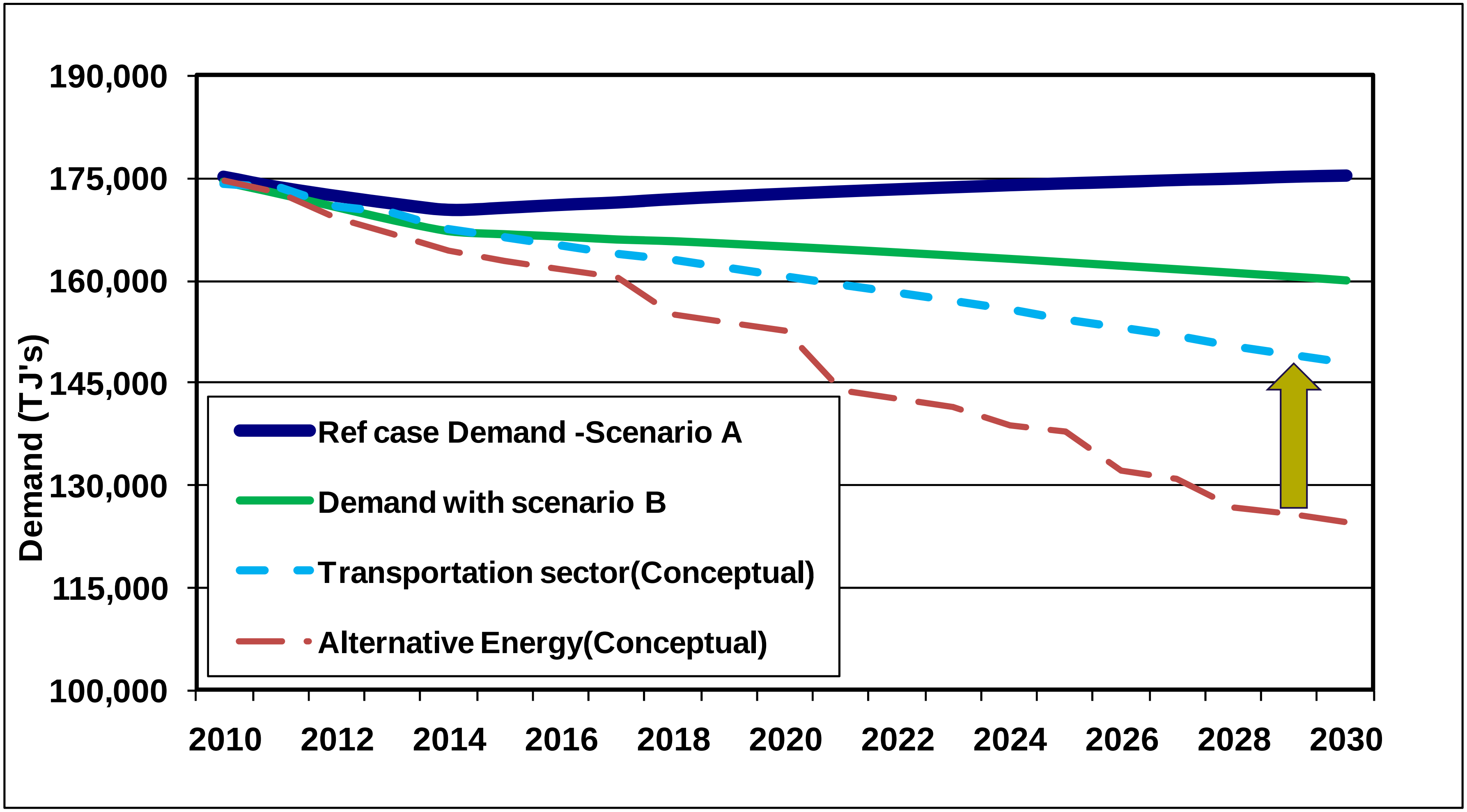


Reduced Carbon Intensity Future

terasen



Conclusion

terasen

- Traditional Natural Gas Demand
  - Demand to remain relatively stable
  - EEC will continue to help customers use energy efficiently
  - Increased impact from building codes and standards
- Exploring methodologies to meet forecasting needs for broad range of energy products and services

Questions / Discussion?

Natural Gas Supply

2010 Long Term Resource Planning Workshop

May 27, 2010

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Key Messages for Gas Supply

- North America - unconventional gas supply has changed future supply outlook
- BC unconventional supply – large part of the solution for Western Canadian declining gas reserves
- Pacific Northwest - expansion required now in the region to meet growth
- Terasen - opportunities to increase supply from BC to markets

North American Supply Basins

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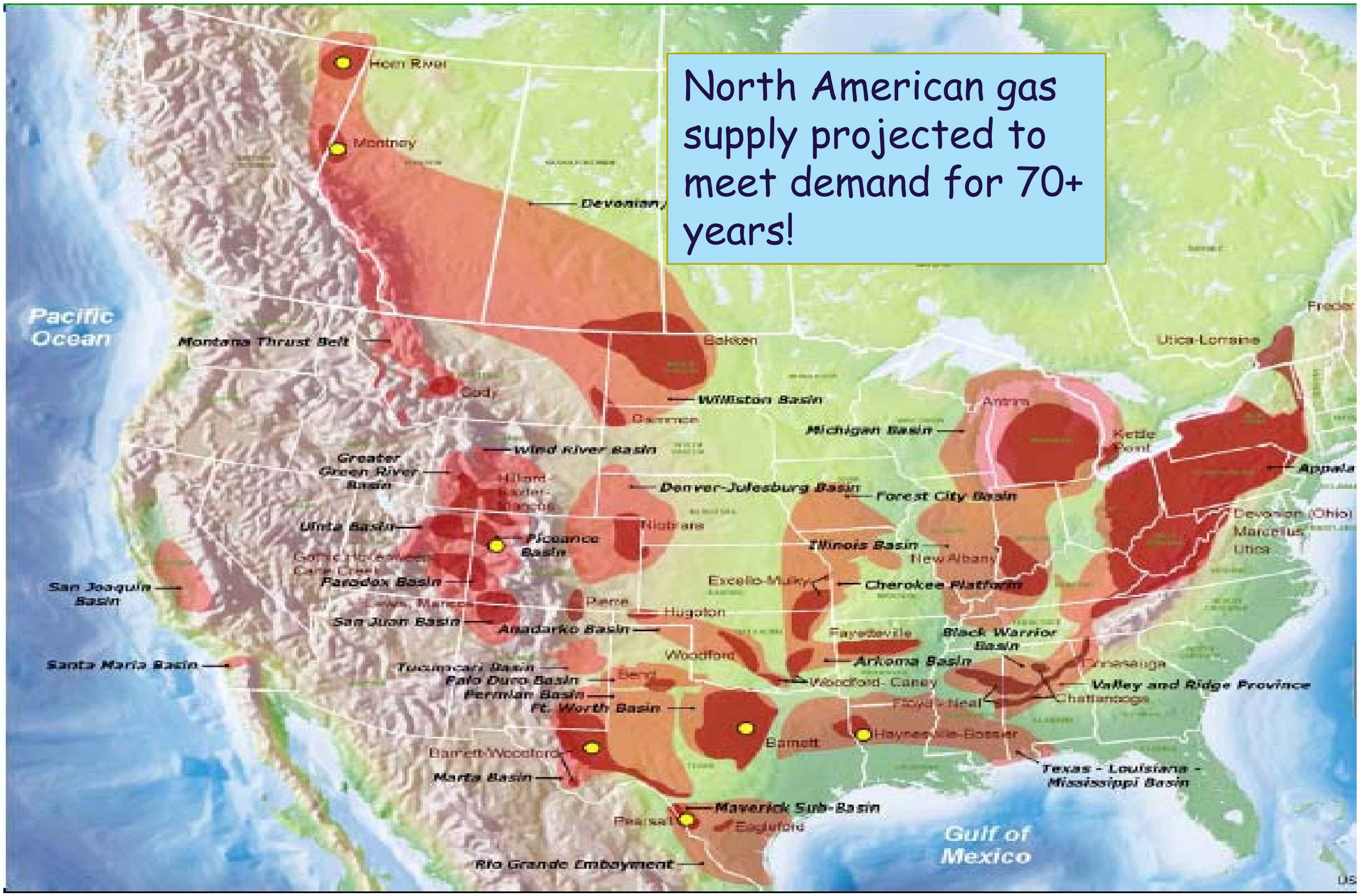

Attachment 55.0

Competing Fuel Prices

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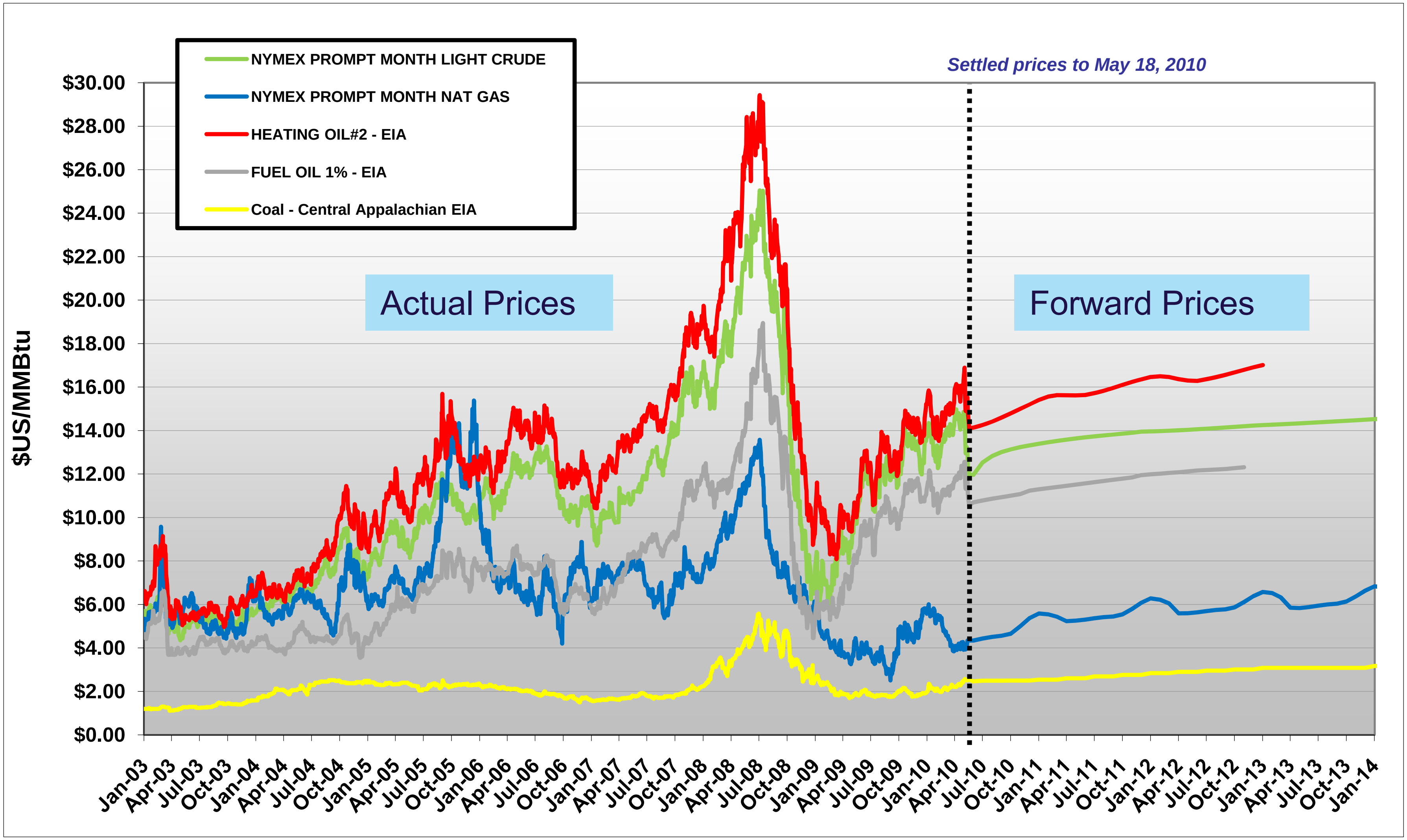
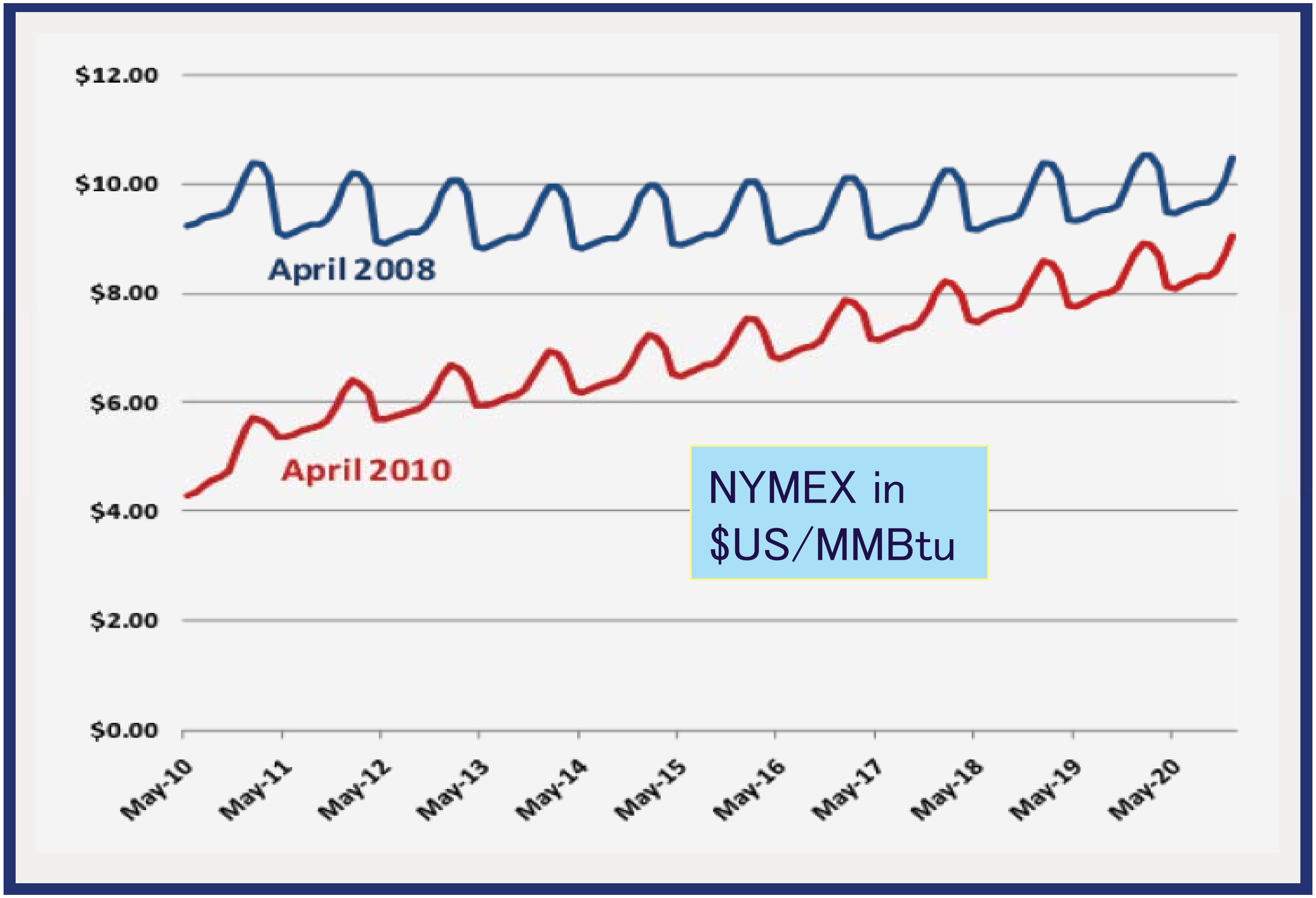


Gas Price Forecasts - 2010 vs. 2008

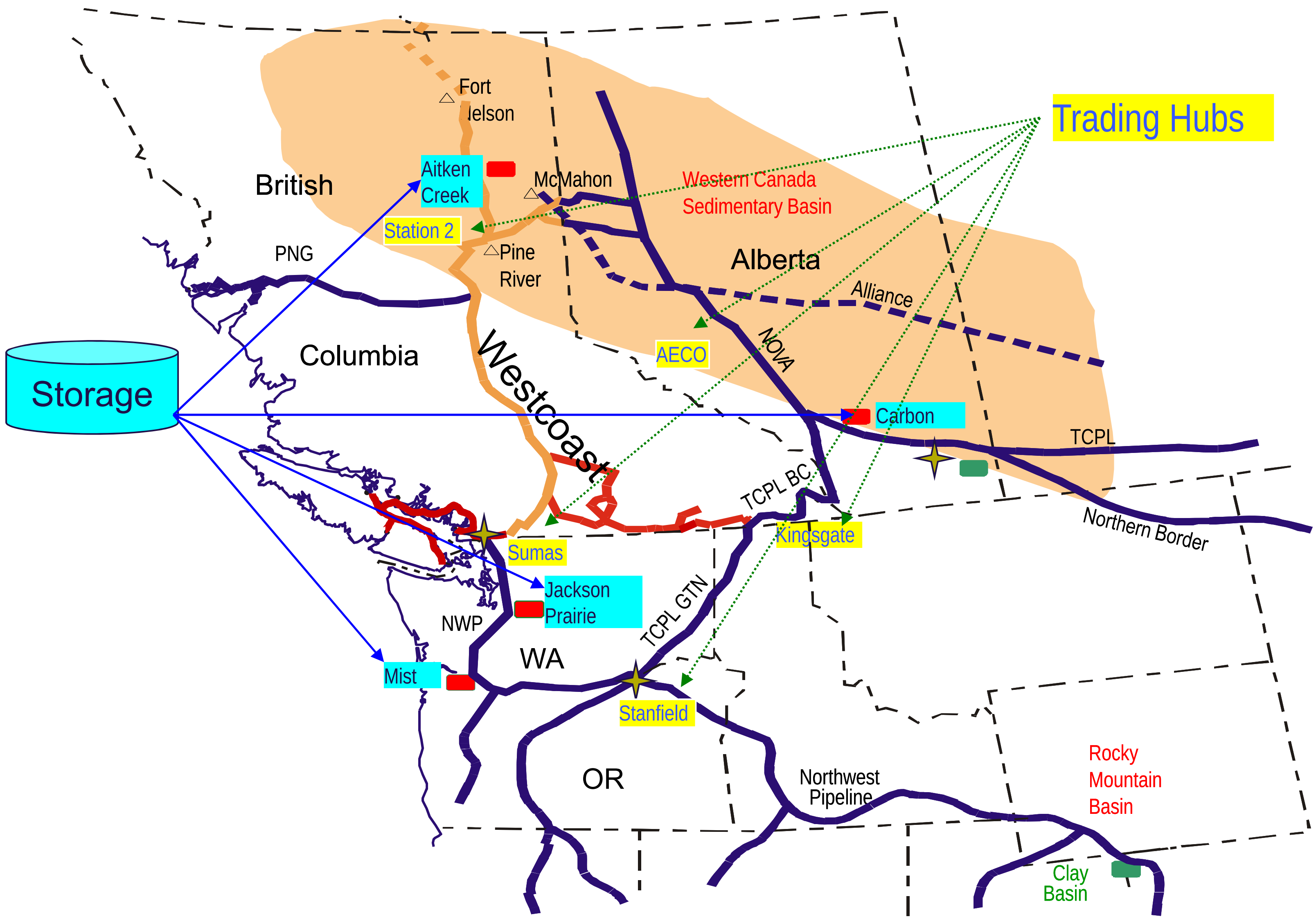


New unconventional supply reserves in North America greatly softening pricing forecasts for natural gas

Source:
NAVIGANT Consulting NGMarket
Notes: How Shale Gas Affects Strategy in the Northwest, May 2010, page 2.

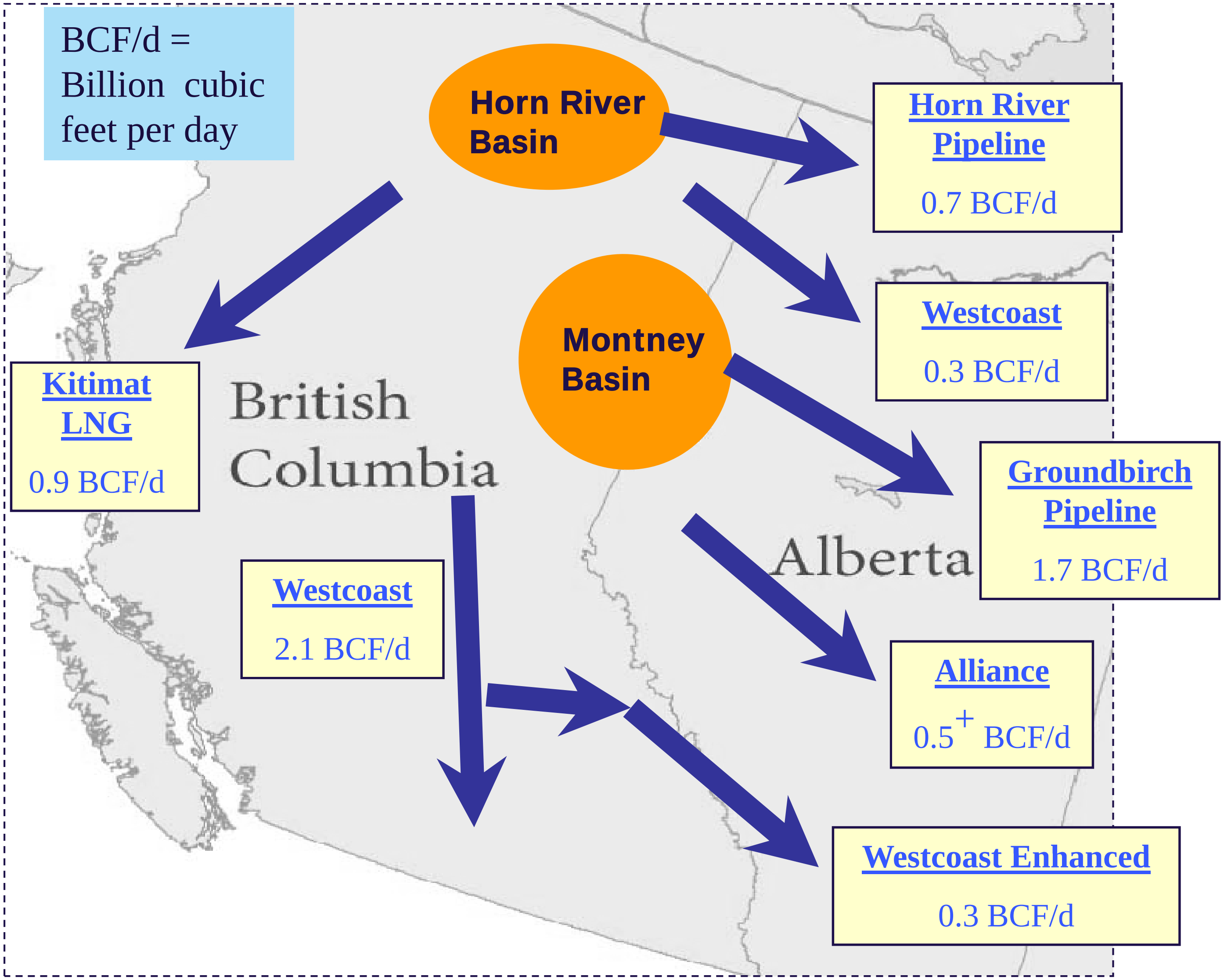
Terasen's Regional Market

terasen



BC Take Away Capacity By 2015

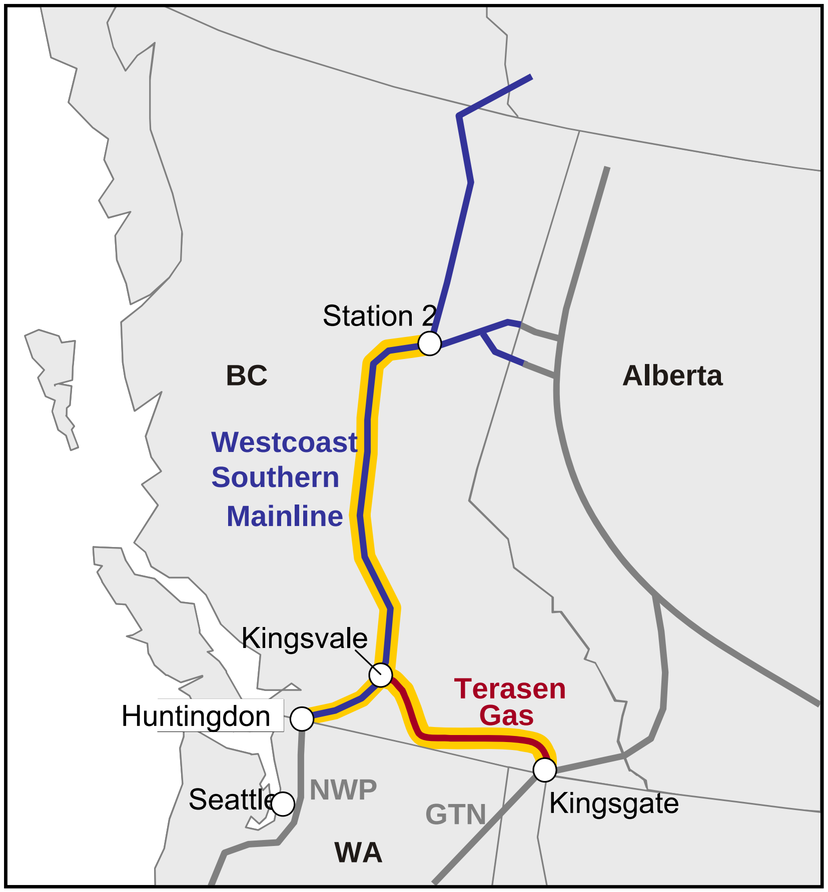
Terasen



- BC – will move over 6.5 BCF/d by 2015 (Terasen peak day forecasted @ 1.2 BCF/d)
- Alberta – steep declines in production
- Oil sands - demand to increase substantially
- Producers want access to liquid markets

Westcoast's T-South Enhanced Service

Terasen



- Westcoast Energy utilizing part of Terasen's system
- Allows BC supply to move within the province to markets
- 2 year pilot May 1, 2010 - April 30, 2012
- 87 MMCF/d available in total
- Minimum $8.6 MM net benefit to Terasen's customers over 2 years

Terasen's Regional Expansion Proposal

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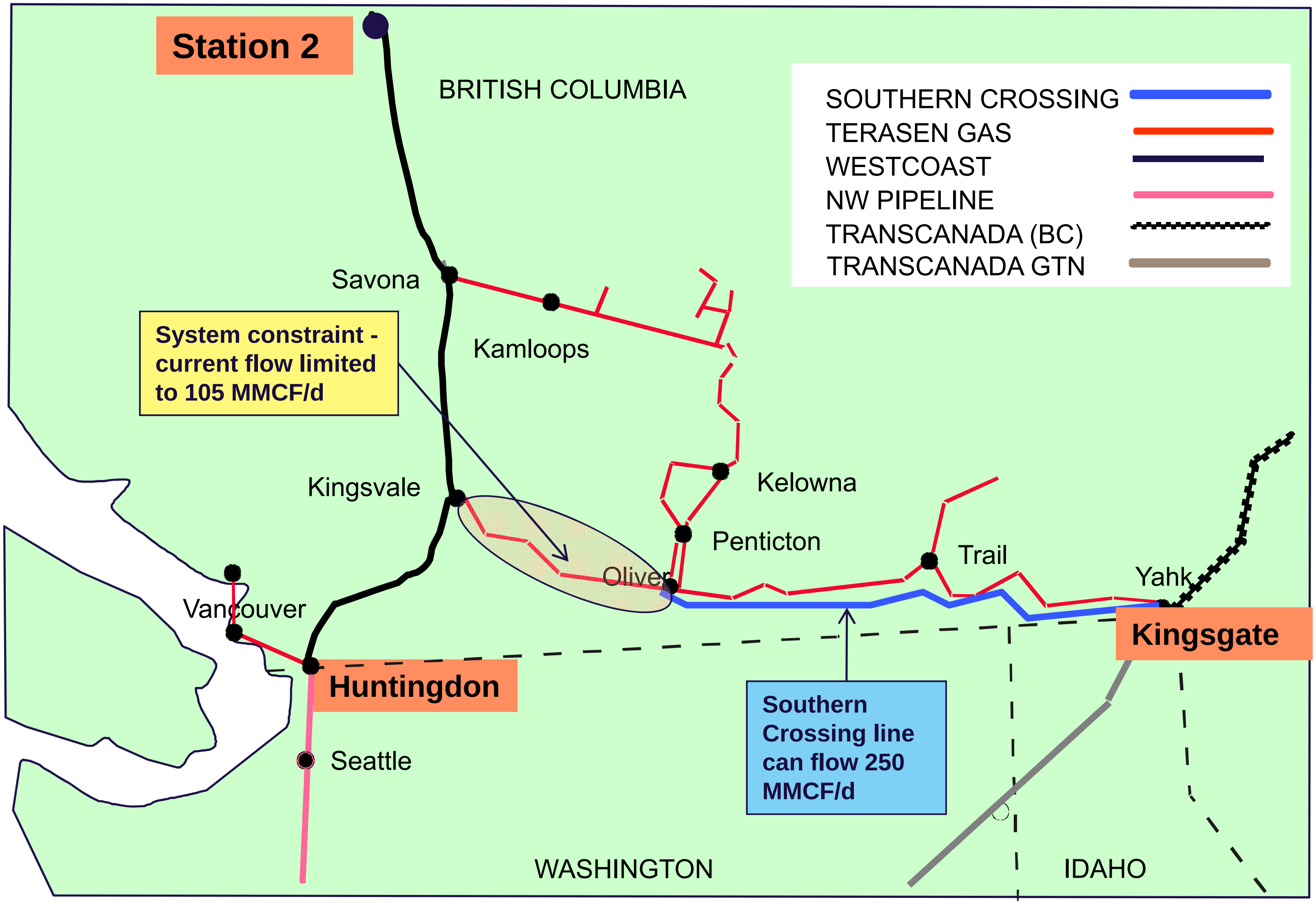
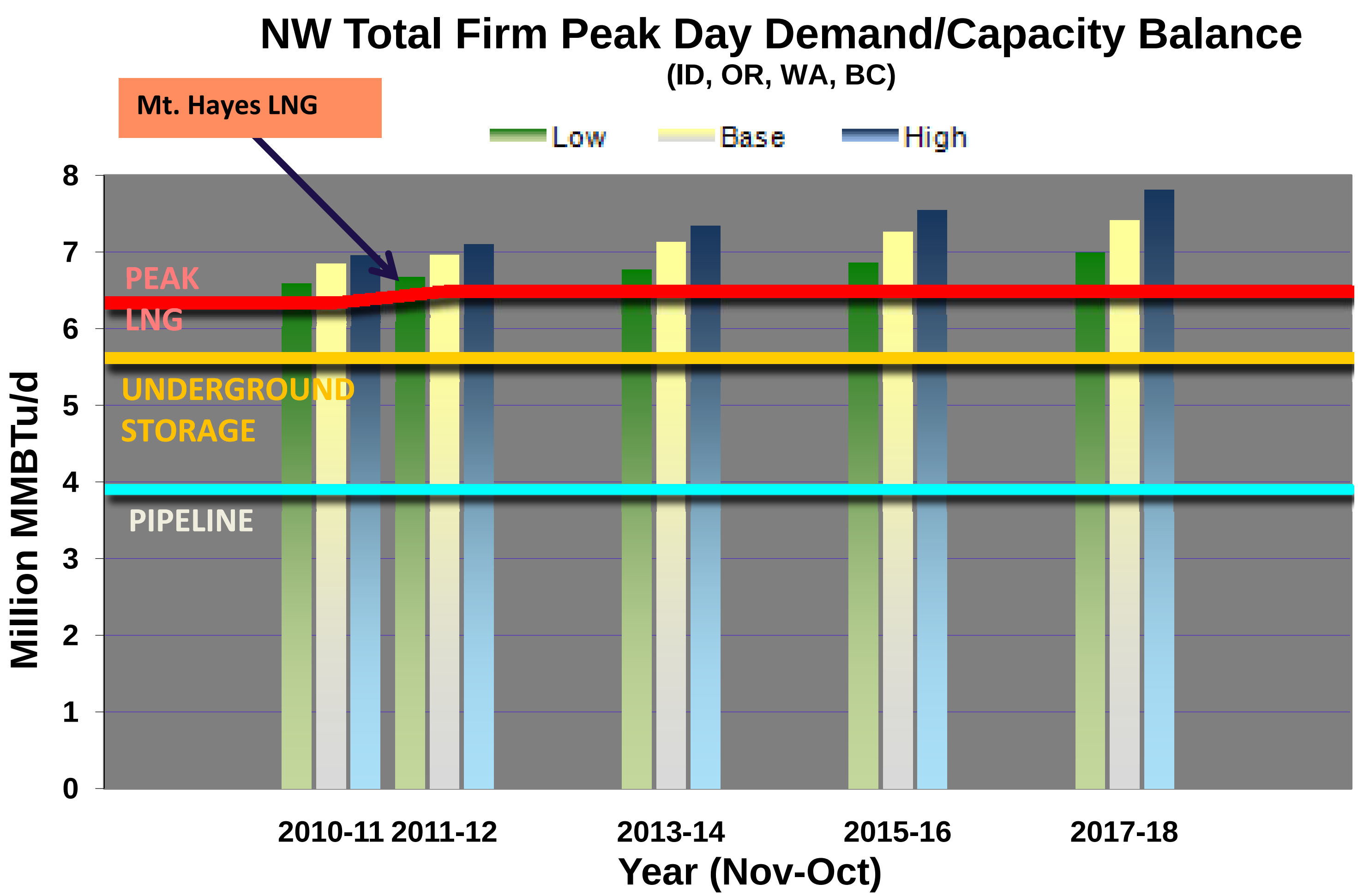


Regional Peak Day Demand vs. Capacity



Peak day capacity is constrained in the I-5 region

Proposed Regional Infrastructure

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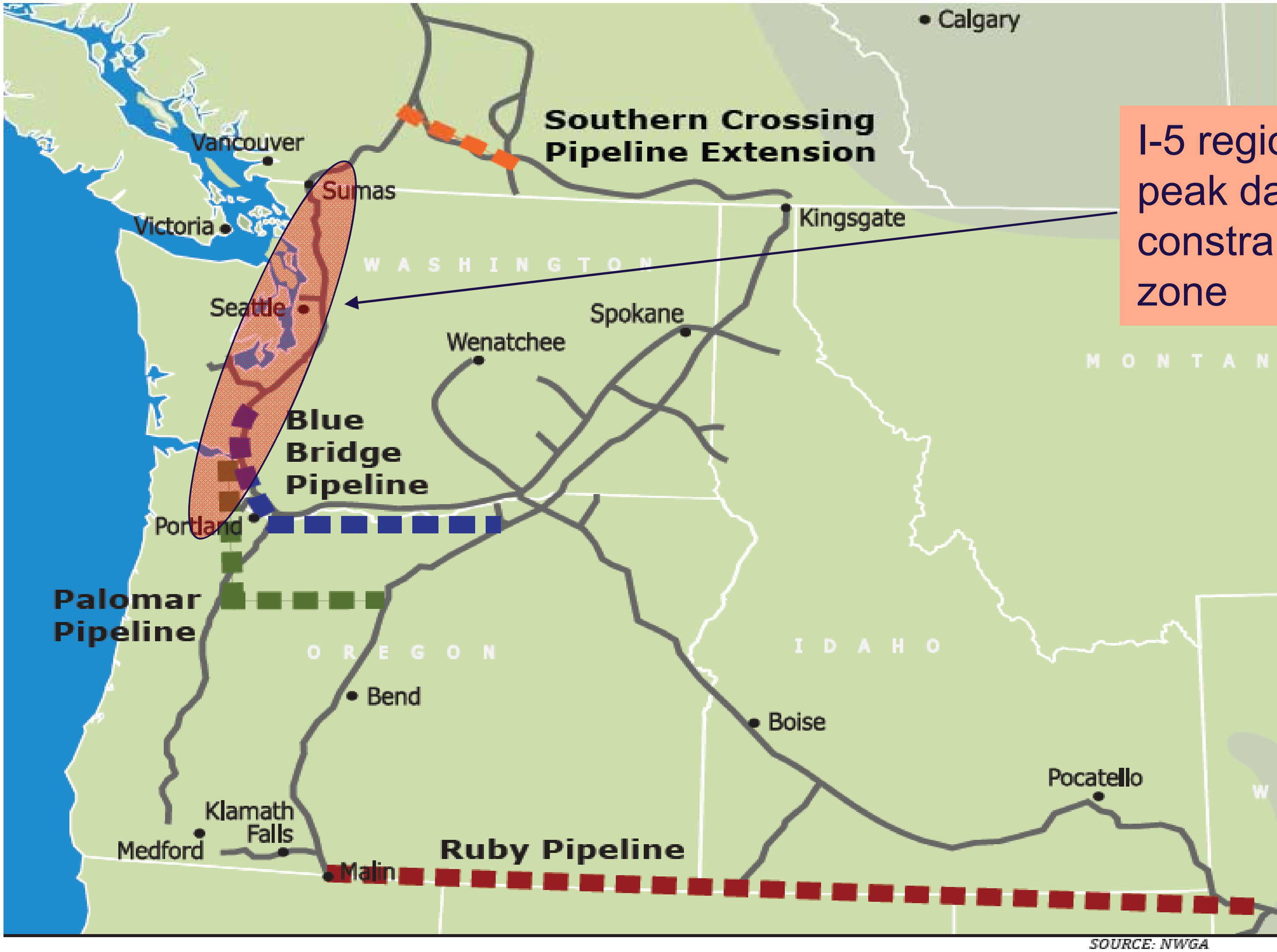


I-5 region peak day constraint zone

Source: NWGA 2010 Outlook

Summary

- North American Supply – abundance of gas supply for at least next 70 years
- Gas Prices – softening largely due to availability of long term gas supply across North America
- BC Supply - to play a larger role in Western Canadian basin
- Infrastructure Expansion - required now in the Pacific Northwest region to meet peak demand
- BC Market – well positioned to benefit from developments

Long Term System Planning

2010 Long Term Resource Planning Workshop

May 27, 2010

Contact Information

Edmond Leung
Manager, Transmission Assets & Improvements

E-mail: edmond.leung@terasengas.com
www.terasengas.com

Key Messages

Terasen Gas needs a long term comprehensive Asset Management strategy to both expand and sustain its gas assets.

This long term strategy will support safe, reliable, environmentally responsible and economical gas delivery services to its customers now and in future.

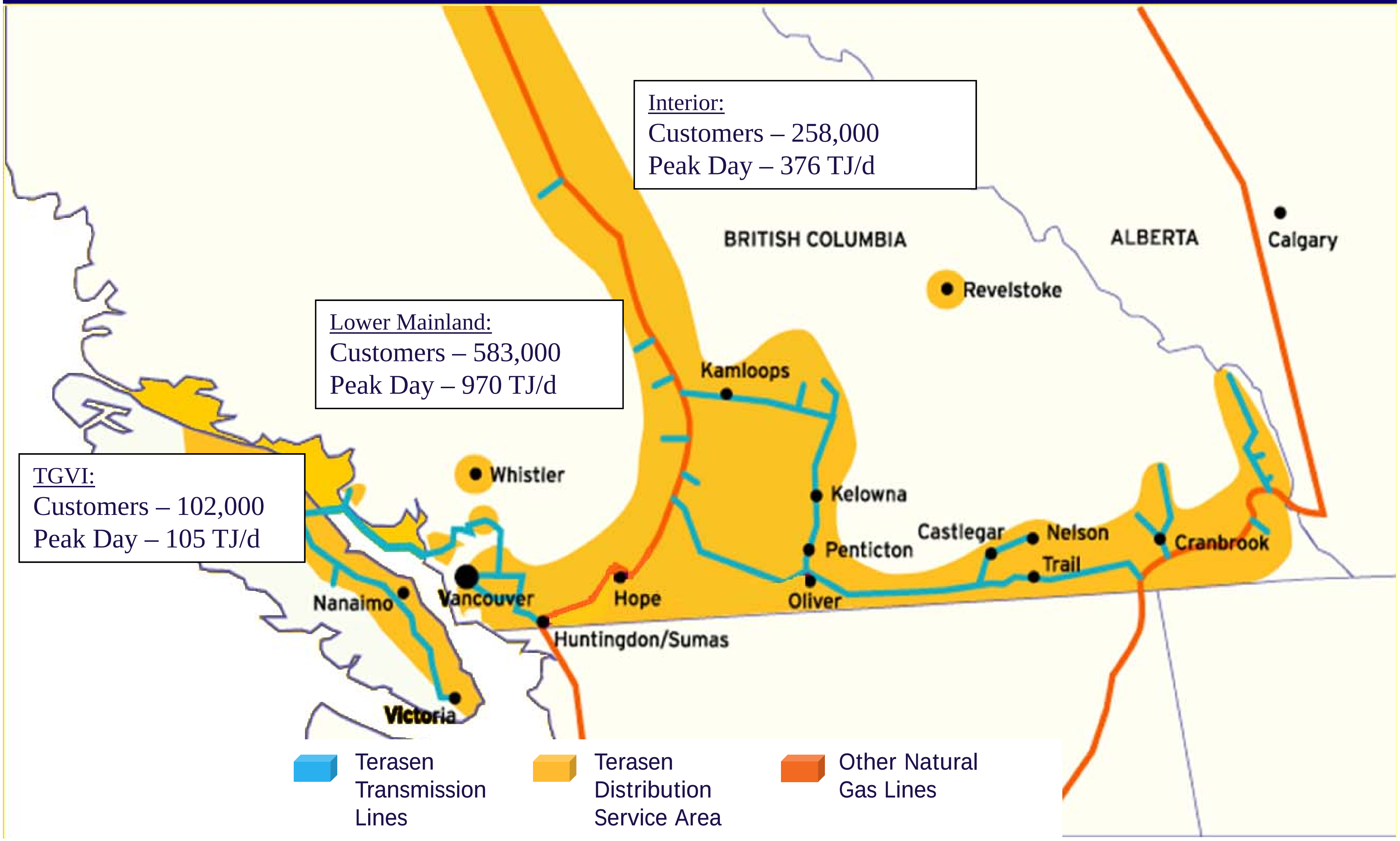
Long Term System Expansion Plan

Terasen

3 Major Transmission Systems (Vancouver Island, Coastal, Interior)

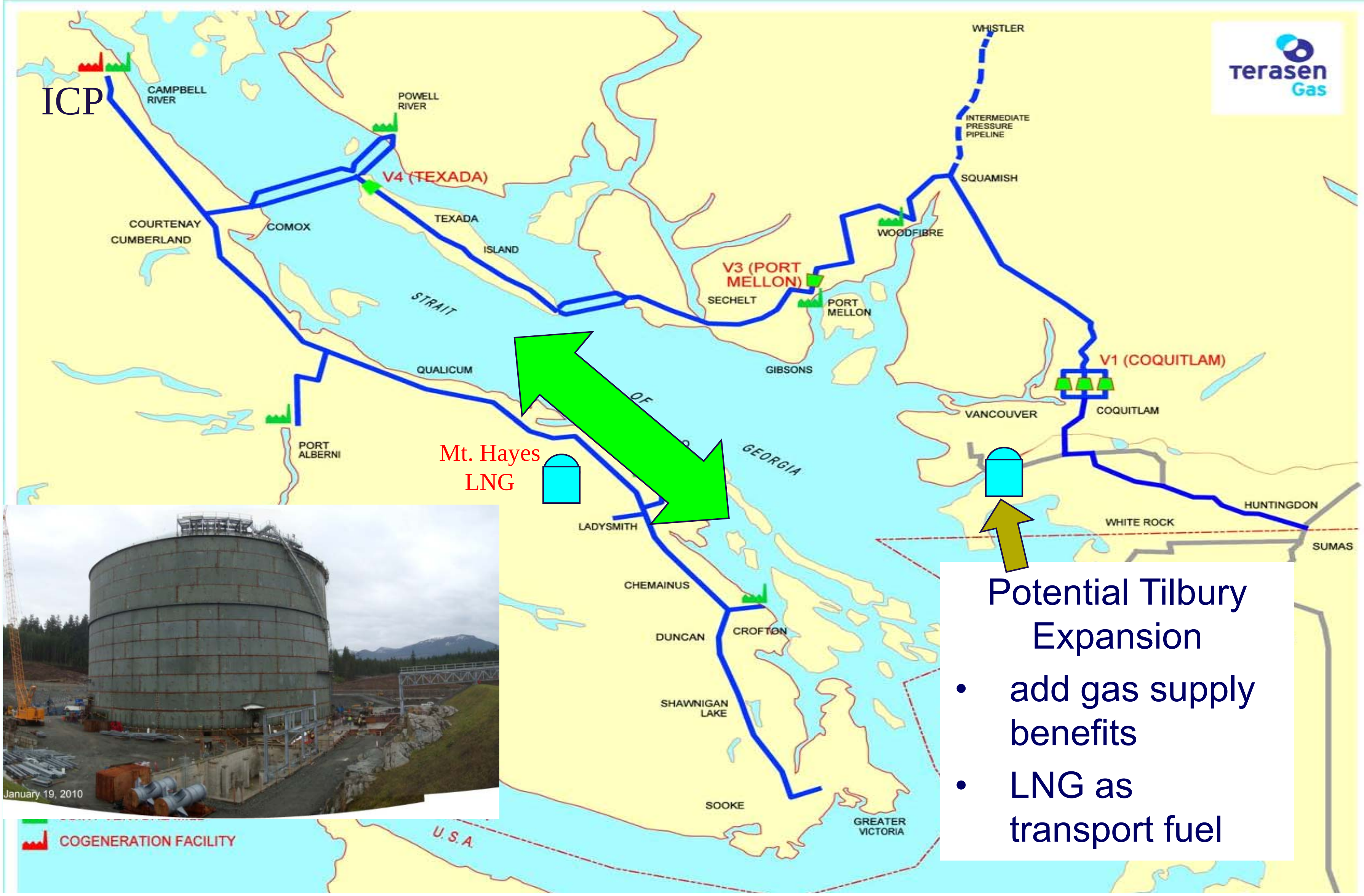
- Drivers for infrastructure resource additions
- Anticipated constraints and timing for reinforcement
- Resource options

Terasen Gas System Overview



Attachment 55.0

Vancouver Island and Coastal Systems

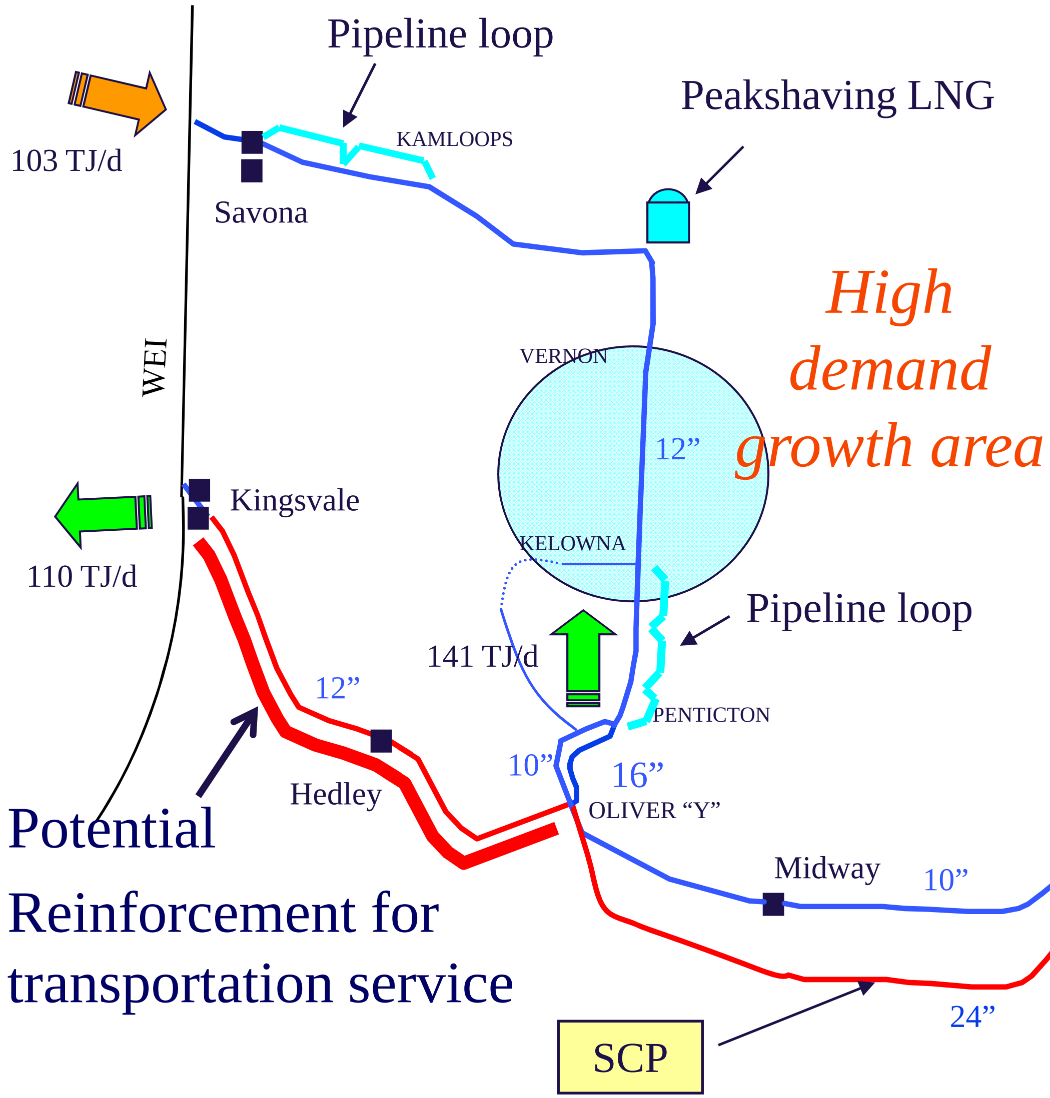


Potential Tilbury Expansion

- add gas supply benefits
- LNG as transport fuel

Interior Transmission System

Terasen



Potential Reinforcement for transportation service

- Additional system resource required in 2017+ to meet demand growth
- System addition schedule could be advanced due to:
  - new industrial demand in Okanagan

System Expansion to meet Growth

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- Terasen Gas (Vancouver Island)
  - Mt. Hayes LNG facility under construction, in service for 2011 winter
  - No further major expansion before 2021
- Terasen Gas Inc – Lower Mainland
  - No expansion requirement due to customer growth
  - Potential expansion of Tilbury LNG for additional supply benefit or LNG as transportation fuel
- Terasen Gas Inc – Interior
  - Expansion required by 2017 due to customer growth in the Okanagan
  - Expansion schedule could be accelerated due to:
    - New industrial demand in Okanagan

Long Term Sustainment Plan

Terasen

Sustaining existing assets

– Challenge

– Response

Factors Affecting Service Life of Assets

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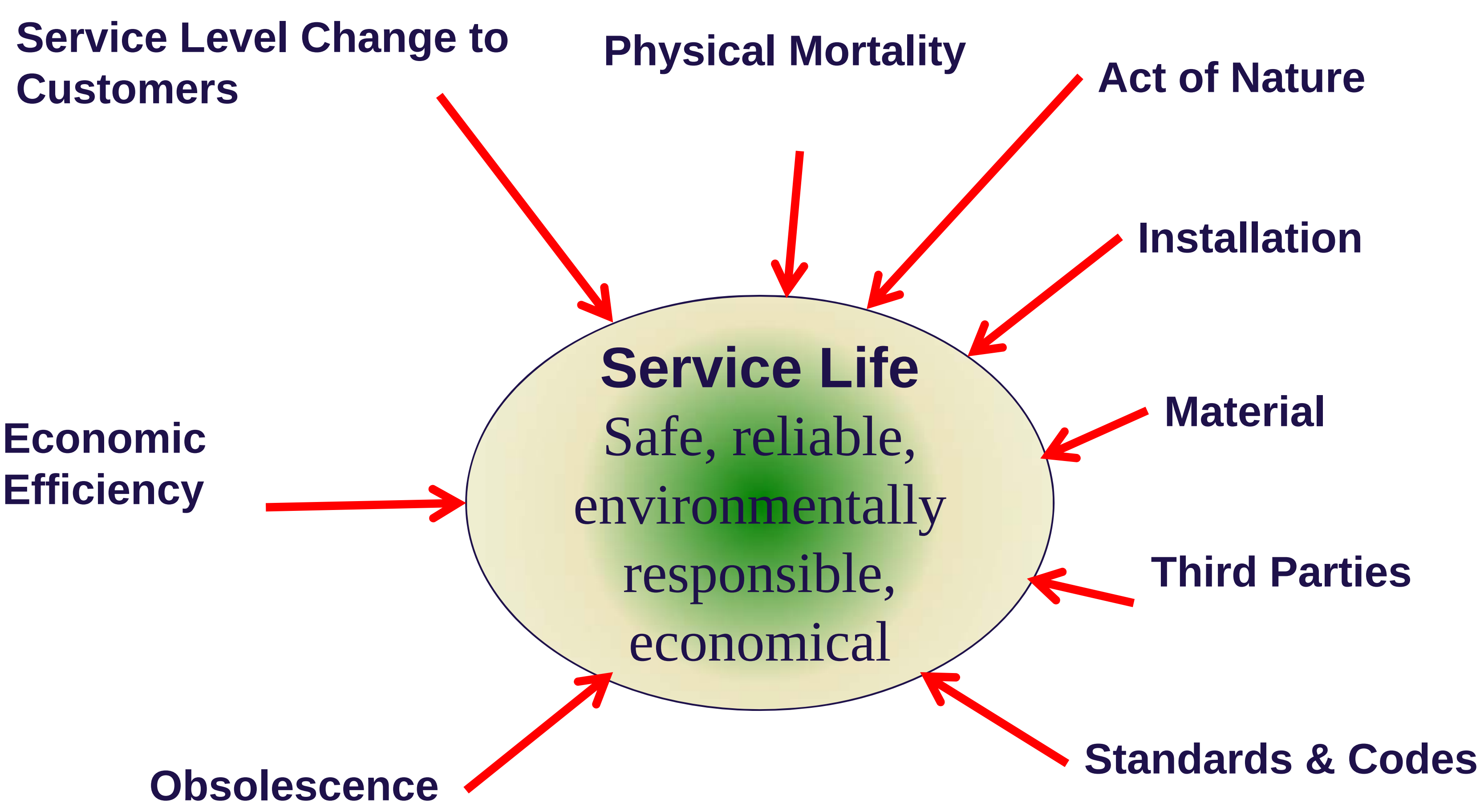
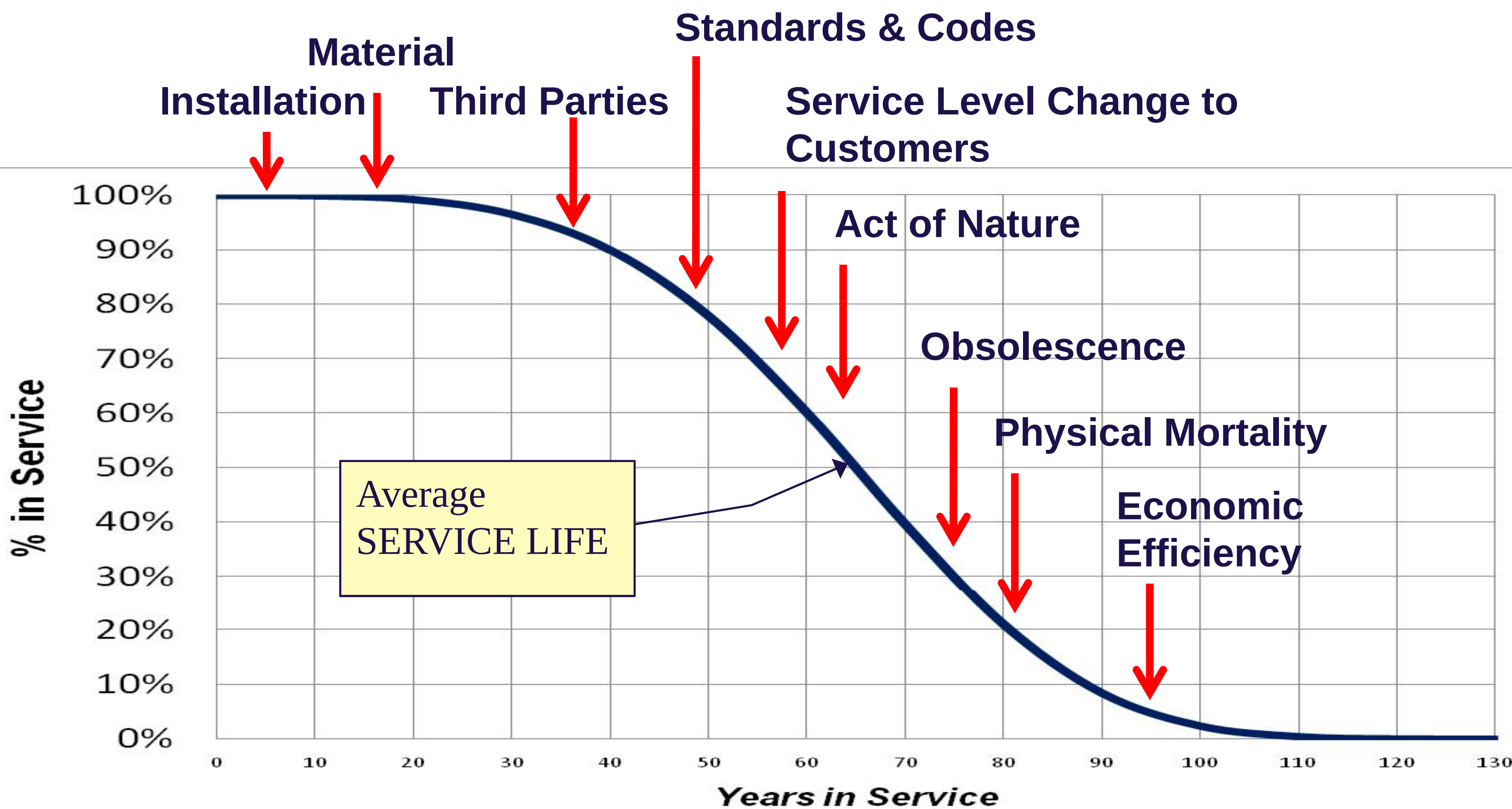


Service Life Considerations

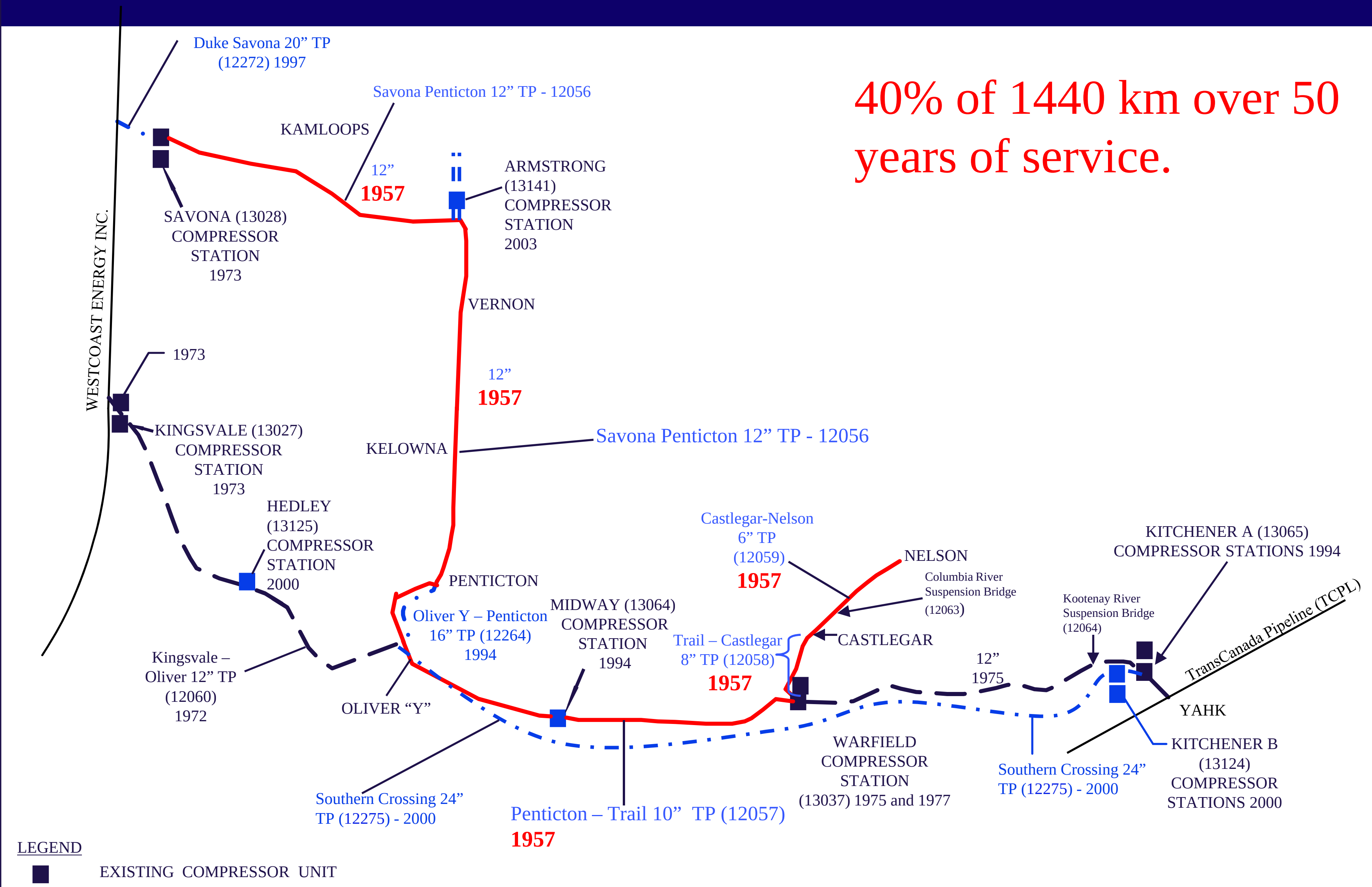


Survivor Curve - based on depreciation study (typical for pipelines)

Interior Transmission System

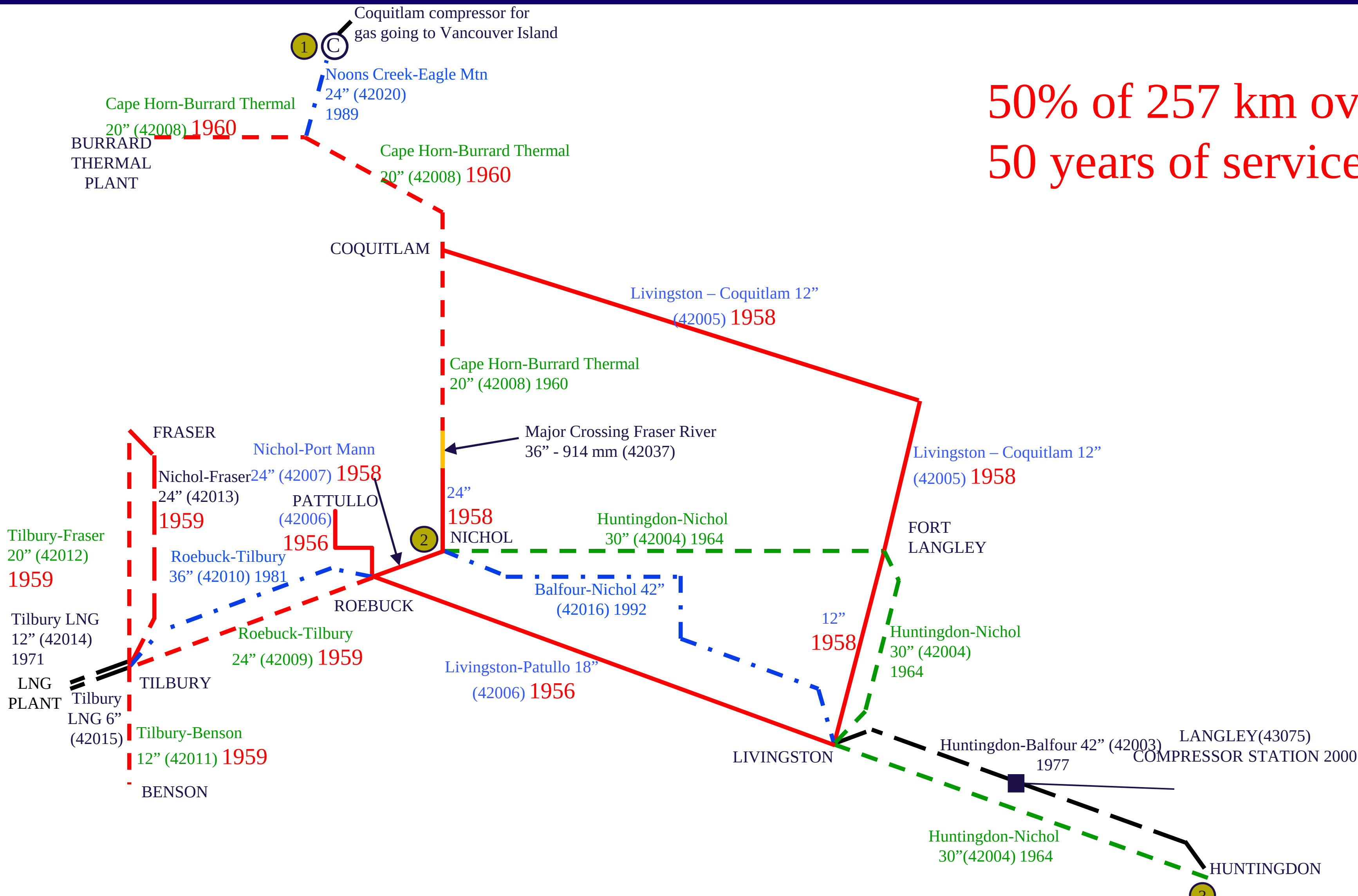
Terasen

40% of 1440 km over 50 years of service.



Coastal Transmission System

Terasen



50% of 257 km over 50 years of service

Vancouver Island Transmission System

Terasen

664 km

21 years in service

What problem are we facing?
- a wave of asset retirements is coming

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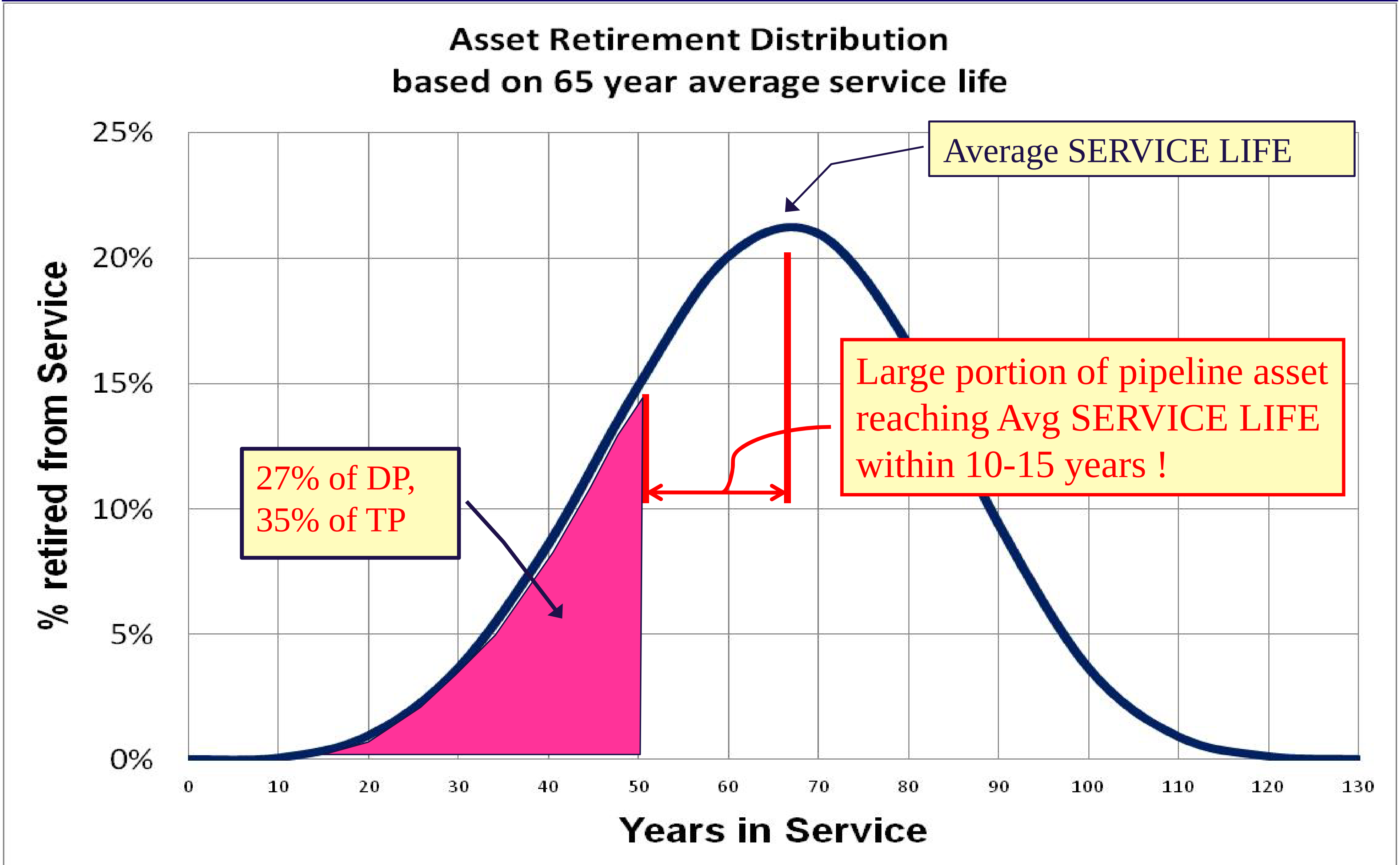
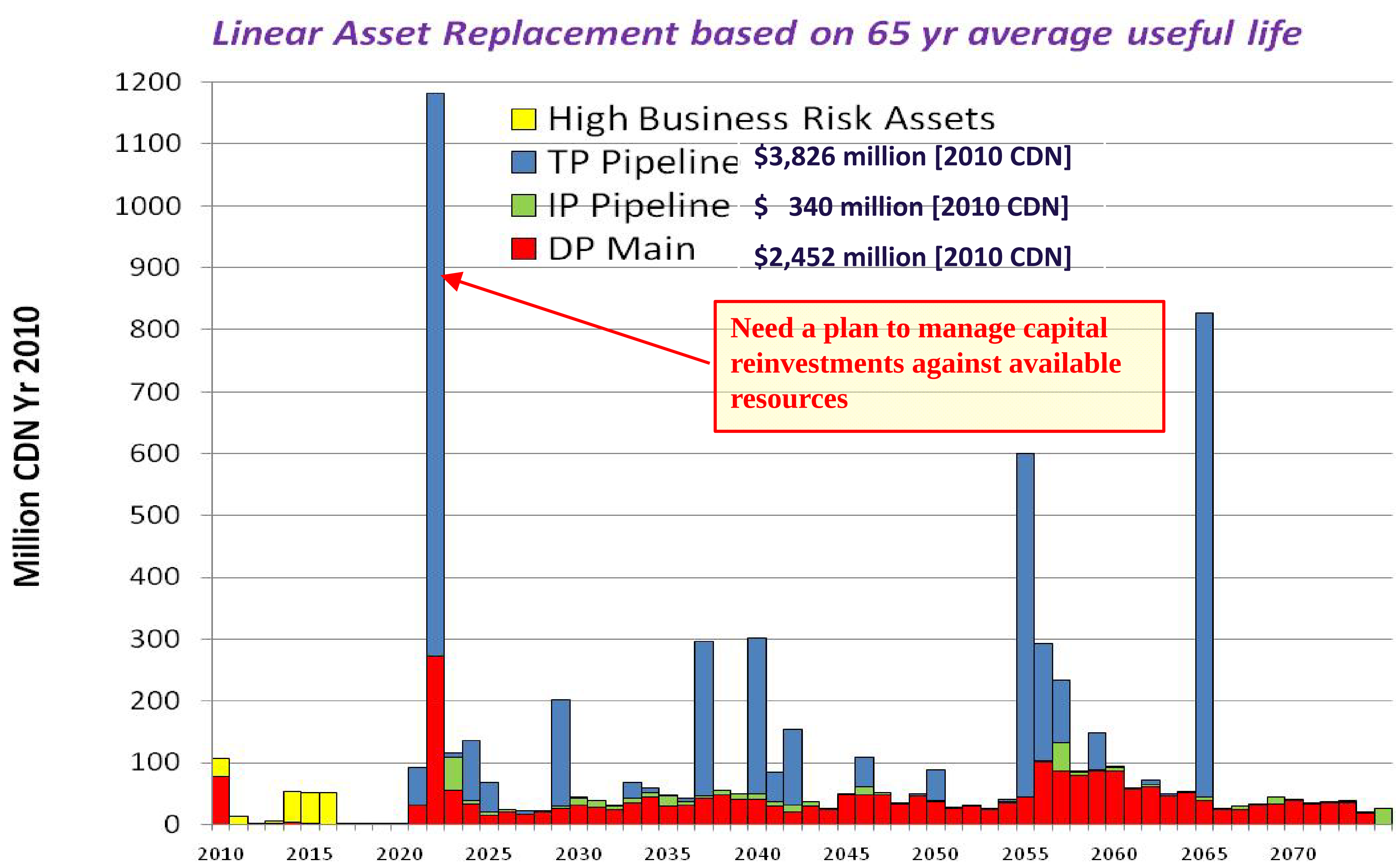


Major increase in capital required

Terasen



Our Business Challenge

- Need to manage factors that impact the service life of assets
- Need to manage increased risks as service life ends
  - Safety, reliability, environment, & economics in service deliveries
- A large portion of aging assets amplifies our business challenge – looming major capital reinvestments are required

➢ Need to plan for regulatory approval & to ensure resource availability

Develop a long term sustainment plan
- applying asset management practices

terasen

Continuous Improvement Process

Asset Registry → Business Values → Asset Health Review → Business Cases → Capital Planning

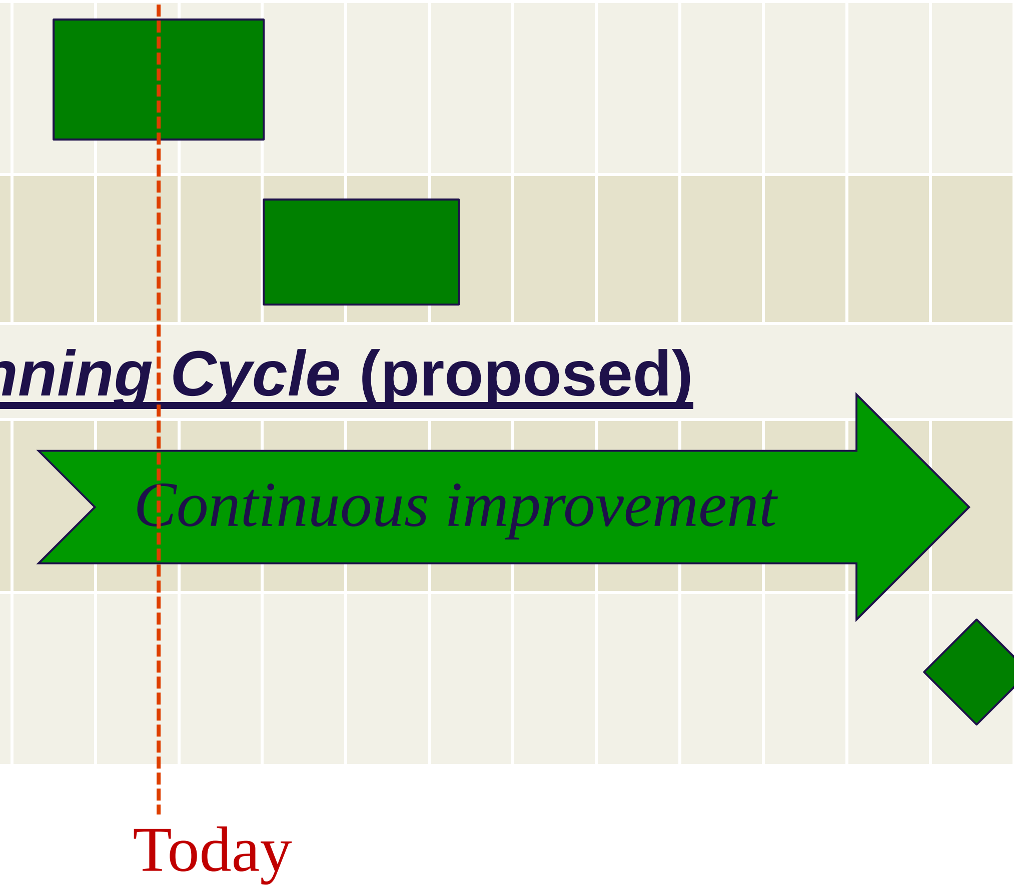
Long Term Asset Management Plan

System Sustainment Plan	System Expansion Plan	O&M Plan
▪ programs ▪ Projects	▪ programs ▪ projects	▪ programs ▪ tactics

Progress on long term sustainment plan

Terasen

ACTION PLAN	2010	2011	2012
1st System Sustainment Planning Cycle (underway)			
Asset registry / Business Values / Asset Health Review			
Identify Higher Risk Projects			
2nd System Sustainment Planning Cycle (proposed)			
Continuous Improvement on AM Steps			
Submit Long Term Sustainment Plan			



Summary

Terasen Gas needs a long term comprehensive Asset Management strategy to both expand and sustain its gas assets.

This long term strategy will support safe, reliable, environmentally responsible and economical gas delivery services to its customers now and in future.

2010 LTRP Action Plan

2010 Long Term Resource Planning Workshop

May 27, 2010

Ken Ross
Integrated Resource Planning Manager

Contact: 604-576-7343
ken.ross@terasengas.com

www.terasengas.com

Terasen. A Fortis company.

Proposed 2010 LTRP Action Plan

Terasen

- Continue developing new energy forecast approaches
  - Provincial thermal energy demand baseline forecast
- Establish an external Resource Plan Advisory Group
- Continue to collaborate on energy policy and planning
- Pursue carbon reduction strategies:
  - Integrated energy solutions, NGV services, renewable biomethane supply
- Develop / implement asset management program enhancements
- Plan and implement near-term system improvements, monitor long term system expansion needs
- Develop regional natural gas supply and infrastructure solutions

Feedback from this Workshop

Please provide any written feedback you have electronically by June 15th, 2010 to:

IRP@terasengas.com

For more information about Terasen's LTRP as this process proceeds, please visit:

www.terasengas.com/IRP

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2010 Long Term Resource Plan

Terasen Gas

Thank You

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RESOURCE PLAN WORKSHOP – May 27th, 2010
VANCOUVER BC

List of Acronyms

AES	Alternative Energy Services
Bcf/d	Billion cubic feet per day (In total Terasen typically delivers 0.5 Bcf/d to all of its customers on an average winter day.)
BCUC	British Columbia Utilities Commission
CMHC	Canadian Mortgage and Housing Corporation
CNG	Compressed Natural Gas
DES	District Energy System
DLE	Diesel Litre Equivalent
DP	Distribution Pressure (refers to pipeline pressure)
DSM	Demand Side Management
EEC	Energy Efficiency & Conservation
EF	Energy Factor
EIA	U.S. Energy Information Administration
GHG	Greenhouse Gas
GJ	Gigajoule (On average, a Terasen Gas Inc. residential customer uses 95 gigajoules each year)
GSHP	Ground Source Heat Pump
GWh	Gigawatt hour
I-5 Corridor	The energy service areas that surround the Interstate 5 highway from Vancouver BC to Portland Oregon
IP	Intermediate Pressure (refers to pipeline pressure)
IRP	Integrated Resource Plan
LNG	Liquefied Natural Gas
LTRP	Long Term Resource Plan
MFD	Multi Family Dwelling

RESOURCE PLAN WORKSHOP – May 27th, 2010
VANCOUVER BC

List of Acronyms

MMBTU	Million British Thermal Units (One MMBTU is equivalent to 1.055 gigajoules)
MMcf/d	Million cubic feet per day (In total Terasen typically delivers 500 MMcf/d to all of its customers on an average winter day.)
MOP	Maximum Operating Pressure
MoT	Ministry of Transportation
NEB	National Energy Board
NGT	Natural Gas for Transportation
NGV	Natural Gas for Vehicles
NPV	Net Present Value
NWGA	Northwest Gas Association
O & M	Operations and Maintenance
PJ	Petajoule (one petajoule is equivalent to one thousand terrajoules).
PNG	Pacific Northern Gas (a natural gas utility serving northern BC)
PNW	Pacific Northwest (generally considered to be British Columbia, Washington, Idaho and Oregon)
RRA	Revenue Requirement Application
SFD	Single Family Dwelling
TGI	Terasen Gas Inc.
TGVI	Terasen Gas (Vancouver Island) Inc.
TJ	Terrajoule (one terrajoule is equivalent to one thousand gigajoules)
TP	Transmission Pressure (refers to pipeline pressure) (TP > IP > DP)
TRC	Total Resource Cost Test (measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant’s and the utility’s costs)

RESOURCE PLAN WORKSHOP – May 27th, 2010
EVALUATION SURVEY & FEEDBACK FORM

Please take a few minutes to evaluate this workshop and identify areas in which improvements could be made.

1. The meeting room facilities met all of my needs.

Strongly disagree → **Strongly agree**

1 2 3 4 5

Comments: ______________________________

2. The material presented was clear and easy to understand.

Strongly disagree → **Strongly agree**

1 2 3 4 5

Comments: ______________________________

3. I found the workshop discussions valuable & informative.

Strongly disagree → **Strongly agree**

1 2 3 4 5

Comments: ______________________________

4. I feel that I had sufficient opportunity to ask questions & provide input.

Strongly disagree → **Strongly agree**

1 2 3 4 5

Comments: ______________________________

5. The length of the workshop was appropriate.

Strongly disagree → **Strongly agree**

1 2 3 4 5

Comments: ______________________________

6. Terasen's integrated energy solutions provide important energy and climate change solutions for BC.

Strongly disagree → **Strongly agree**

1 2 3 4 5

Comments: ______________________________

RESOURCE PLAN WORKSHOP – May 27th, 2010
EVALUATION SURVEY & FEEDBACK FORM

7. Terasen's evolving approach to energy demand forecasting will help inform energy choices in BC.

Strongly disagree → **Strongly agree**

1 2 3 4 5

Comments: ______________________________

8. I am interested in participating in Terasen's proposed Resource Planning Advisory Group on ongoing energy resource planning issues.

Yes ☐ **No** ☐

Contact Information (optional – you can also submit this information separately, via email to irp@terasengas.com):

Name: ______________ Organization: ______________

Phone: ______________ email: ______________

Additional Comments:

Please provide any additional comments you would like regarding either the workshop itself or the topics discussed – include additional sheets as necessary.

Topics include: Integrated Energy Solutions and Projects • Efficiency and Conservation Programs • Demand Forecasting • Natural Gas Supply Issues • Natural Gas System Expansion and Sustainment Planning

Thank you for taking the time to discuss these important issues and provide input.

If you are unable to complete this survey before leaving the workshop and would still like to submit comments, please forward them by June 15, 2010 to:

Terasen Gas
16705 Fraser Highway
Surrey, B.C. V4N 0E8

Attention: Ken Ross
Integrated Resource Planning Manager
604-576-7343
ken.ross@terasengas.com