Diane Roy
Director, Regulatory Affairs

FortisBC Energy
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

July 31, 2014

Via Email
Original via Mail

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130. Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Utilities[1] (FEU)

2014 Long Term Resource Plan (the Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 2

On March 25, 2014, the FEU filed the Application as referenced above. In accordance with the British Columbia Utilities Commission Order G-56-14 setting out the Regulatory Timetable for review of the Application, the FEU respectfully submit the attached response to CEC IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

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[1] comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.

1. Reference: Exhibit B-5, CEC 1.3.1

> 1.3 Does FEU differentiate between customer groups with respect to what may be considered 'lowest reasonable cost'?
>
> **Response:**
>
> The concept of cost effectiveness applies to all customers but will differ depending on the particular circumstances.

1.1 Please provide a discussion of the types of circumstances that could serve to differentiate 'lowest reasonable cost' as it applies to Commercial customers from 'lowest reasonable cost' that is applicable to residential customers and industrial customers.

Response:

The FEU elaborated on the referenced response in CEC IR 1.1.5: "The FEU do not differentiate the general definition of cost effectiveness among customer groups because the term is adaptable to each circumstance, which in a particular context may involve different considerations for different customer groups." In addition, the FEU provided a discussion of cost-effectiveness in response to BCUC IR 1.8.1, where they discuss consideration of project characteristics such as reliability, dispatchability, timing, and location as well as cost or price.

As such, differing characteristics of a potential project may have differing impacts on residential, commercial and industrial customers. This will be entirely dependent on the specifics of the project. As an example, residential customers in a community situated nearby a new compressor station may be concerned about noise and traffic. At the same time, industrial customers in the same community may see the benefits of the increased system reliability and not have the same concerns as the residential customers, since they are not located nearby the station. In this example, the lowest reasonable cost for the residential customers includes additional cost to mitigate noise and traffic, while the lowest reasonable cost for the industrial customers does not. Since commercial customers include a broader range of business segmentation and business needs – for example the restaurant owner might also be concerned with noise and traffic while the dry cleaner might not be – these considerations may both weigh in on the consideration of lowest reasonable cost for commercial customers.

2. Reference: Exhibit B-5, CEC 1. 2.1

> 2.1 Please describe whether or not FAES is a FortisBC utility and whether or not it provides services that compete with the natural gas delivery service for customers needing heating services.
>
> **Response:**
>
> FortisBC Alternative Energy Services Inc. is a regulated affiliate of FEI and subsidiary of Fortis Inc. FAES provides tailored, thermal energy solutions that may either compete with or complement FEU's natural gas delivery service. Please refer to Appendix B-2 of the 2014 LTRP to further understand how a renewable thermal energy system can impact a customer's need for conventional energy service.

2.1 Do the FEU have a forecast of the heating market and the market share for electricity, natural gas alternative thermal energy systems, propane, biomass, etc.

Response:

The FEU assume this question is asking for the total heating market in BC and market share portion of that total market for electricity, natural gas alternative thermal energy systems, propane, and biomass. The FEU do not have a forecast of the total heating market provincially and as such cannot provide a breakdown of the market share by system type or fuel as requested. The FEU believe that such a forecast should be done in collaboration with other utilities. While the FEU have discussed the possibility of developing a province wide forecast of demand for thermal energy with other utilities, no such initiative has been conducted to date. The FEU's consideration of competing energy system types and fuels is limited to that of its own customer base.

2.1.1 If so, please provide.

Response:

Please refer to the response to CEC IR 2.2.1.

2.1.2 If not, please explain why not.

Response:

Please refer to the response to CEC IR 2.2.1.

2.2 Given the information in Appendix B-2, with regard to the potential for thermal energy systems to increase the degree to which natural gas service is focused on supplying peak heating requirements, has the FEU determined at what point the penetration of alternative thermal energy systems in the market may require perceptible responses from the utilities to the peak requirements?

Response:

The FEU continue to monitor the progress with which thermal energy systems are adopted by customers and, at this time, has not determined the penetration level at which changes to current FEU planning processes need to be adjusted. Planning groups within the FEU work closely with customers, developers, communities and internal business development groups to characterize these gas loads. Ongoing annual review of local communities served by the FEU is used to determine gas infrastructure needs to meet peak demand.

2.2.1 If so, please explain.

Response:

Please refer to the response to CEC IR 2.2.2.

3. Reference: Exhibit B-1, Appendix B-2, Page 2

> Modelling energy demand for commercial and industrial thermal end-uses is more complex since demand is subject to market cycles and trends that differ from those impacting the residential sector. Furthermore, district and discrete energy systems are more complicated than conventional energy systems since each system can vary in size, technology, energy combinations and end-use applications depending on individual customer or community needs.

3.1 Does FEU intend to model energy demand for commercial and industrial thermal end uses in the future?

Response:

Given the quoted preamble from the 2014 LTRP's Appendix B-2, "Renewable Thermal Energy," the FEU understand the question to pertain to modeling renewable thermal energy demand for commercial and industrial thermal end-uses. To the extent possible, the potential impact of renewable thermal energy solutions on the FEU's demand for natural gas in the commercial and industrial customer groups has been modelled and will continue to be modelled in the End Use Annual Demand Forecast. The description of how these impacts were considered in the End Use model is provided in Appendix B-3 of the 2014 LTRP.

3.1.1 If so, when does FEU intend to develop this information?

Response:

Please refer to the response to CEC IR 2.3.1.

4. Reference: Exhibit B-5, CEC 1.3.3

> In addition, through the FEU's Community Consultation workshops, the FEU have identified specific customer and stakeholder interests that have included:
>
> - Finding solutions to reduce GHG emissions;
> - Understanding FAES service offerings such as district energy systems;
> - Exploring options to pursue NGT and biomethane opportunities;
> - Programs to help customers and communities manage energy costs and emissions including EEC and High Carbon Fuel Switching;
> - Advanced metering and billing options;
> - Understanding gas pricing trends; and
> - Coordinating activities between utilities and municipalities.

4.1 Please describe any plans FEU has to develop advanced metering and billing options.

Response:

At this time the FEU have no firm plans to implement an advanced metering infrastructure (AMI) solution or billing options contingent upon the technology. The FEU continue to monitor the implementation of advanced meter reading by electric and gas utilities and to evaluate customer attitudes toward advanced gas meters. While evidence to date indicates that there is interest in the potential benefits of advanced gas meters, the FEU have not at this time developed plans to implement such a program.

The Continuous Optimization and EnerTracker programs for FEU's commercial customers, makes interval metering data available to customer through an energy management information system. This additional detailed consumption data assists participating commercial customers to track the performance of their buildings and any energy saving practices they may have implemented.

4.1.1 Please explain the expected impact of such programs.

Response:

The energy management initiative described in the response to CEC IR 2.1.4 is expected to result in energy savings and GHG emission reductions that are or will be reported on in the EEC Annual Report. Besides energy savings and emission reductions, potential future advanced

metering and billing solutions would be expected to result in other yet-to-be-determined customer benefits that will need to be shown to be cost effective before being implemented.

4.2 Please confirm that the natural gas system and system costs are sensitive to peak demand.

Response:

Confirmed, the natural gas system and system costs are sensitive to peak demand. Transmission and distribution pipeline systems are installed and upgraded as needed to reliably deliver peak demand volumes.

4.2.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 2.4.2.

4.2.2 What demand side management activities does the FEU offer that could serve to reduce the peak?

Response:

In parts of the FEU's systems where reduction in demand is advantageous in order to avoid costly upgrades or to improve system reliability for core customers, the FEU actively employ demand side management activities such as:

- During periods of cold weather: curtailment of interruptible customers;
- During periods of low delivery pressure on transmission laterals: curtailment of interruptible customers; and

- During periods approaching cooler conditions: the FEU actively contact customers that have alternative fuel sources or are able to "store" thermal energy in order to reduce their gas consumption over the peak periods.

In general, the only demand side management activity that the FEU have identified to date with the ability to reliably reduce peak load is curtailment.

4.2.3 Could advanced metering and billing options include programs or provide additional information that would be of assistance in reducing the peak?

Response:

To date, the FEU have not identified reductions in peak demand from advanced metering or billing options. Furthermore, the FEU do not have a widely deployed advanced gas metering infrastructure that could be used to address peak demand reductions. The FEU believe future advanced metering and billing options may provide additional information on customer peak hour consumption patterns, which may be useful in designing effective peak reduction programs Please also refer to the response to CEC IR 1.8.3.

4.2.3.1 If so, please explain.

Response:

Please refer to the response to CEC IR 2.4.2.3.

4.2.3.2 If not, please explain why not.

Response:

Please refer to the response to CEC IR 2.4.2.3.

4.2.4 What additional options, if any, are available or will likely be available to reduce peak demand.

Response:

To date, the FEU have not identified any additional options that will help to reduce peak demand, but will continue to explore potential options and technologies that may have this potential.

4.3 Please describe any programs FEU has or intends to develop to assist customers in understanding gas pricing trends.

Response:

The FEU's Home Energy Calculator communicates to residential customers the current cost to operate natural gas appliances and the cost in comparison to other energy options. Existing rates for each of the Companies are provided by the FEU as the default setting for customers. However, customers also have the ability to input, on their own, a future price. The FEU do not provide future price forecast for customers due to the inherent variability of such forecasts.

The Customer Choice Program also provides a venue for customers to compare various natural gas prices so that customers can choose whether to purchase gas from an independent gas marketer or from the FEU. Natural gas is offered at a fixed rate over a term of one to five years; rates remain the same for the duration of the agreement regardless of any energy price fluctuations.

4.3.1 Please provide FEU's expectation as to how these might influence demand in each sector.

Response:

The response to CEC IR 2.4.3 referred to the Home Energy Calculator and the Customer Choice program. The FEU cannot comment on how these might influence demand in each sector since the FEU are not able to determine the specific investment criteria unique to each customer when a customer chooses to install a natural gas appliance or enrol in the Customer Choice program.

4.4 How does FEU coordinate its activities with municipalities?

Response:

The coordination of the FEU's activities with municipalities is an established and ongoing process that assists in identifying common areas where both the FEU and municipalities have work planned which may result in an opportunity for both organizations to realize synergies by working together. The FEU coordinate their activities with municipalities through the sharing of capital plans (by both organizations) and maintaining ongoing communications with those municipalities.

5. Reference: Exhibit B-1, Page ES-2

> The dynamic nature of these planning environment factors makes it difficult to predict with certainty how these factors may influence the demand for natural gas or its competitive position over the 20-year planning horizon. The FEU therefore examine a number of planning environment outcomes to identify a range of future scenarios for which to plan. The long term integrated resource planning process assists the FEU to remain alert and agile in order to overcome any challenges, capitalize on opportunities to add new system load, and continue to serve the Utilities' customer needs for safe, reliable and cost-effective energy in an evolving energy marketplace.

5.1 Please discuss any special strengths that FEU considers it has to enable it to meet challenges and address opportunities.

Response:

This response also addresses CEC IR 2.5.2. The FEU cannot present all of its strengths and weakness with regard to the challenges and opportunities it may face over the 20 year planning horizon as this will depend very much on the specific nature of each opportunity and challenge.

In general, to meet the challenges and address the opportunities identified in the LTRP, the FEU consider their strengths to be their people, customer relationships, industry partnerships, involvement in the communities served by the FEU, system infrastructure, knowledge of the energy industry and regulatory environment in B.C and more. Being a regulated utility is also a strength in that it provides customers with transparency and oversight, and enables the Utilities to invest in longer term solutions for their customers.

Often, the strengths that an organization has to meet some challenges may be weaknesses in meeting other challenges. A couple of noteworthy aspects of the FEU that could become weaknesses in facing some of the opportunities and challenges ahead include:

- the inability to know precisely what will happen and when, in terms of factors that may affect the energy planning environment or exogenous factors that may influence the FEU's system (i.e. the FEU cannot predict the future), and
- the length of time and amount of procedure involved in getting regulatory approvals to undertake projects and initiatives that can allow the FEU to take advantage of opportunities or address challenges.

5.2 Please discuss any weaknesses that FEU would consider as potentially limiting its ability to respond to challenges or capitalize on weaknesses.

Response:

Please refer to the response to CEC IR 2.5.1.

5.2.1 Please provide an overview of any plans FEU has to minimize these weaknesses.

Response:

The FEU consider this as a strategic corporate planning issue that is not part of the review of the 2014 LTRP.

5.3 Please provide a list of the key opportunities and key challenges facing FEU over the planning time frame.

Response:

The FEU cannot provide an exhaustive list of the key opportunities and challenges as it is impossible to know all opportunities or challenges that may affect the FEU over the planning horizon. Some examples of opportunities include the opportunity to add new customers, particularly industrial customers, due to a low natural gas price environment; and the opportunity to contribute to reducing B.C.'s road transportation emissions,. Some examples of challenges are increased regional competition for access to natural gas supply; higher capital costs for natural gas appliances and installation; changing customer use of natural gas; and energy and environmental policies that serve to decrease natural gas demand.

All of these opportunities and challenges may present themselves for a limited period or throughout the planning period. The specific timeframe, likelihood of occurrence, key success factors or impact of risk throughout the planning period are all factors that are not fully known due to the uncertainty around these opportunities and challenges. Nevertheless, the FEU actions to capitalize on and mitigate risk from these opportunities and challenges are identified and discussed in Sections 2 and 9, as well as Appendices A-7 and A-8 of the 2014 LTRP.

5.4 Please provide a chart listing each of the opportunities FEU identified over the planning horizon, when the opportunity might be available, the estimated potential benefit, key success factor or conditions; and the actions FEU could undertake to identify capitalize on the opportunity as depicted below.

Opportunity	Conditions	Time Frame	Est. Potential	Key Success Factors	FEU Actions to Identify and Capitalize
Natural gas sector is 30% of Transportation market	Low NG price; OEM offerings available; declining capital cost premiums; provincial policy support				
LNG Projects develop					

Response:

Please refer to the response to CEC IR 2.5.3.

5.5 Please provide a chart depicting potential challenges FEU faces over the planning horizon; including the risk, the likelihood of occurrence including the events that would precipitate the challenge; the potential impacts of the risk; and the actions FEU could undertake to mitigate the risk.

Risk	Conditions	Time Frame	Likelihood	Estimated Risk Size/Impacts	Actions to Mitigate
Commercial demand declines	Economy contracts;				

Response:

Please refer to the response to CEC IR 2.5.3.

6. Reference: Exhibit B-2, BCUC 1.9.1

> Given the above, the objective of the LTRP submission is to put forward a range of forecasts of gas use and the "at the time" resources that would be required to meet the forecast. The forecasts provide a band (upper and lower) that future use can be expected to fall within. The resources planned for should be acquired/built to meet the full range of the band of possible forecast (both high and low).
>
> The FEU do not believe that minimization of risk should be an explicit resource planning objective because the LTRP is only a broad planning document and is not proposing final investment decisions and is not seeking approval of resources that will affect rates. Further consideration for minimizing risks is included in all decision making at the FEU from safe work practices through to the development of large infrastructure projects. The objective "ensure a safe, reliable and secure energy supply" includes the idea of minimizing risks, for example. The consideration of risks and types of risk associated with alternative resource options occurs at the project / initiative planning and application stage.

6.1 Does FEU propose to monitor circumstances to determine which scenario is unfolding for future decision-making?

Response:

No. For the purpose of the LTRP it is important to continuously monitor the planning environment to be able to provide a new planning environment analysis with updated assumptions for the next LTRP. Since the resource planning process is ongoing, and the FEU are continuously monitoring both the planning environment and the Companies' customer and system needs, there is no need to look back at previous LTRPs to determine if a particular scenario has unfolded.

Please also refer to the response to CEC IR 2.22.2.

6.1.1 If so, has FEU identified markers that it can use to determine which scenario is unfolding?

Response:

Since the resource planning process is ongoing as explained in the response to CEC IR 2.6.1, the FEU have not set markers that will allow it to look backward and determine if a particular scenario developed in the past has unfolded. Instead, the FEU continuously monitor parameters such as customer additions, use per customer, system capacity, customer attitudes, public policy and many more which are discussed in the 2014 LTRP to determine if future

course adjustments are needed. A person driving a car does not generally look at the fence posts in the rear view mirror to determine if they are still on the road and travelling at a safe speed.

6.1.1.1 If so, please identify the markers FEU will use.

Response:

Please refer to the response to CEC IR 2.6.1.1.

6.1.2 If so, please explain how FEU will report which scenario it considers to be developing.

Response:

Please refer to the response to CEC IR 2.6.1.

6.1.3 If not, please explain why not.

Response:

Please refer to the response to CEC IR 2.6.1.

6.2 Please explain in what ways, if any, FEU undertakes a proactive approach to minimizing potential threats to the utilities and/or the services they provide to their customers.

Response:

Please refer to the responses to CEC IRs 2.5.5, 2.6.1, and 2.6.1.1.

6.3 Given that the FEU do not believe that minimization of risk should be an explicit resource planning objective, do they believe that risks are unimportant to planning?

Response:

No, the FEU do not concur with this simplification.

6.3.1 Do the FEU have any contingency plans for events that may have a probability of impacting the natural gas system or their customers?

Response:

Yes. The LTRP is a broad planning tool that estimates potential long-term demand for natural gas and identifies a portfolio of options to meet that long-term demand. The FEU consider the LTRP's scenario planning and analysis to inherently contain contingency planning, as the scenarios identify a range of possible future demand estimates and incorporate a number of factors that impact customer demand for natural gas. In this way, the FEU's LTRP contingency plan is to plan to acquire the resources necessary to ensure that the natural gas system can meet the demand expected across a range of future scenarios and continuously monitor both the planning environment and the system conditions to make any necessary timing adjustments for those resources.

7. Reference: Exhibit B-5, CEC 1.5.1

> 5.1 Please define the FEU interpretation of the 44.1 (8) (d) in regard to the definition of the interests of persons who receive or may receive service from the public utility.
>
> **Response:**
>
> The FEU interpret 44.1 (8)(d) to give direction to the Commission to consider the interest of a utility's customers and potential customers when deciding whether to accept or reject a long term resource plan. For the purposes of resource planning, the "interests" of persons who receive or may receive service from the public utility include delivery of reliable and safe energy services.

7.1 The FEU has said that the interests of persons who receive or may receiver service from the public utility include delivery of reliable and safe energy service. Please complete the list.

Response:

The FEU believe that a definitive list of interests does not exist, since the interests of customers may change over time. However, in addition to reliable and safe energy services, the interests of persons who receive or may receive service from the public utility commonly include security of energy supply, integrity and stability of the service provider, rate stability and implementing cost-effective energy solutions.

7.2 Would FEU agree that customer and potential customer interests include predictability of pricing over the long term?

Response:

Please refer to the response to CEC IR 2.7.1 for a description of how the FEU characterize the interests of existing and potential future customers for the purposes of long term resource planning.

7.2.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 2.7.2.

7.3 Would FEU agree that customer and potential customer interests include achieving the lowest possible pricing, subject to appropriately managing the public interest issues which the company needs to incorporate into its planning?

Response:

Please refer to the response to CEC IR 2.7.1 for a description of how the FEU characterize the interests of existing and potential future customers for the purposes of long term resource planning.

7.3.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 2.7.3.

7.4 Would FEU agree that customer and potential customer interests include adequate service levels?

Response:

Please refer to the response to CEC IR 2.7.1 for a description of how the FEU characterize the interests of existing and potential future customers for the purposes of long term resource planning.

7.4.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 2.7.4.

7.5 Would FEU agree that customer and potential customer interests include the long term stability of the energy provider?

Response:

Please refer to the response to CEC IR 2.7.1 for a description of how the FEU would characterize the interests of existing and potential future customers for the purposes of long term resource planning.

7.5.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 2.7.5.

8. Reference: Exhibit B-5, CEC 1.6.3

> 6.3 Please explain in detail how natural gas can be used to provide a firm back-up for renewable energy.
>
> **Response:**
>
> Because wind and solar are intermittent sources of electricity, there is a need for other generation assets to respond to load requirements when intermittent sources are not available. Natural gas is an ideal source of energy to provide firming power since gas is the most flexible in in terms of deployment: gas turbines can be turned on and off quickly to meet fluctuating power demands.

8.1 What are the forecasts for intermittent renewable energy in BC over the LTRP planning horizon, and what if any of these might affect the FEU?

Response:

From the preamble above, the FEU assume that this request is referring to the use of intermittent renewable resources to generate electricity. The FEU have not undertaken or acquired forecasts for intermittent renewable energy (wind and solar generated electricity) in BC over the LTRP planning horizon as the FEU do not expect BC's intermittent solar and wind electricity to have a significant impact on natural gas demand over the planning horizon, given the current planning environment. The FEU believe that natural gas is an ideal source of energy to provide firming power to intermittent renewable energy sources and would look to provide natural gas as a backup fuel to intermittent renewable energy sources should BC's energy policy allow for increased use of natural gas in balancing the variability of these energy sources.

8.2 Please explain how the FEU natural gas load could be expected to vary with respect to the implementation of additional intermittent renewable energy in BC.

Response:

BC's energy policy limits the extent to which natural gas can be used to firm intermittent renewable energy in BC and the FEU understand that hydroelectric resources are used to firm BC's intermittent renewable energy (wind and solar generated electricity). Therefore, the FEU do not expect additional intermittent renewable energy in BC to change the FEU's natural gas load given the current planning environment – please also refer to the response to CEC IR 2.8.1.

8.3 Please explain in what ways provincial policy regarding intermittent renewable energy could positively influence the demand for natural gas on the FEU system.

Response:

A provincial energy policy that would allow natural gas to provide backup power for intermittent renewable electricity generation could increase the demand for natural gas on the FEU's system. Section 3.3.9, page 61 of the LTRP discusses the potential addition of large new industrial loads, of which a natural gas fired generation facility could be one such load, to the FEU's annual demand.

9. Reference: Exhibit B-5, CEC 1.7.3

Response:

For the purposes of this planning exercise, conditions that would make the abundance of known natural gas reserves inaccessible include stricter environmental policies and poor producer economics. Stricter environmental policies and regulations would limit the volume and pace of natural gas development and therefore limit natural gas production. Poor producer economics could occur either in a depressed gas price environment or in an over-supplied environment where there is a lack of market demand for natural gas. Currently, there is a low probability that a change in environmental policies will occur that could limit natural gas production in B.C. as the provincial government is actively promoting the use and export of natural gas.

Shale gas is abundant in North America and different supply basins will be developed depending on their specific economics, which is tied to the price of natural gas over the long term. Natural gas resources located in B.C. compete with other supply basins throughout North America to meet domestic demand and export markets such as LNG.

Current natural gas forward prices and producer breakeven costs indicate that producers are likely to continue producing at least in the near future. Since B.C. has a large natural gas resource and the provincial government is actively supporting the development of natural gas production, the overall risk of having limited natural gas supply in B.C. is considered low at this time.

9.1 For how many years would FEU consider the 'near future'?

Response:

The FEU consider the 'near future' to be the next 3 to 5 years.

10. Reference: Exhibit B-5, CEC 1.7.4

> 7.4 What evidence do the FEU have that there may be a limitation of natural gas supply?
>
> **Response:**
>
> Evidence of a potential limitation or reduction in the production of natural gas can be seen in examples of restrictions on natural gas development in other jurisdictions in North America. The experience of New York provides a good example of how the use of environmental regulations have limited natural gas production there following a statewide hydraulic fracturing moratorium introduced in 2008 while the state conducts a study of the environmental impact of shale gas development.
>
> For North America as a whole, however, the current natural gas price environment and producer breakeven costs indicate that producers are likely to continue with maintaining production levels at least in the near future.

10.1 Please confirm that this evidence is more consistent with those of Scenarios A and C than it is with Scenarios B and D.

Response:

The FEU agree that conditions specific to production of natural gas in the region are more consistent with Scenarios A and C, but also point out that factors other than gas production could come into play over the planning horizon that could push annual demand toward Scenario B or D. While conditions for gas production appear positive into the future, the FEU do not believe that this factor alone makes the annual demand resulting from Scenarios A or C more likely over the planning horizon than the annual demand from Scenarios B or D. Rather, the range of annual demand that results from the scenarios that the FEU have examined provides insight into the opportunities and risks facing the FEU and helps to inform the assessment of resource needs for those resources not specifically designed for meeting peak demand.

10.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 2.10.1.

10.1.2 If confirmed, would FEU agree that at this point, Scenarios A and C could be considered as more likely than Scenarios B and D.

Response:

Not confirmed. Please refer to the response to CEC IR 2.10.1.

10.1.2.1 If not, why not?

Response:

Please refer to the response to CEC IR 2.10.1.

10.2 Please describe the hydraulic fracturing concerns which could give rise to a moratorium for supply constraint or limitation.

Response:

The above reference to New York was provided as an example of a jurisdiction that changed regulations on natural gas development. As part of the scenario planning exercise, a variety of factors were input into the models and scenarios that have an effect, positive or negative, on the resources required to deliver natural gas to our customers; gas supply constraints are but one of many factors considered. The specific factor that causes either an increase or decrease in the ability to deliver natural gas to our customers is not what is relevant to the LTRP process. Rather, the relevant aspect of these concerns to the FEU's 2014 LTRP is whether or not the FEU have appropriately addressed the degree to which these factors may constrain/increase, or loosen/decrease, the costs of future natural gas pipe, compression and gas supply resources. The FEU submit that their models and scenarios have produced reasonable results and the FEU have described the relevant resources required to serve customers under these different outcomes that are reasonably expected to occur.

With respect to hydraulic fracturing specifically, please refer to the responses to BCPSO IRs 1.1.1 and 1.1.2.

Additionally, a potential moratorium in BC is unlikely given the well-established industry guidelines that govern the use of hydraulic fracturing in this province. It is also unlikely to be restricted given the fact that a significant portion of natural gas produced in BC is only possible because of hydraulic fracturing and because any limitation on its use in BC as a means of extracting natural gas would likely result in a higher commodity cost. The FEU monitor developments affecting the use of hydraulic fracturing in this province by remaining informed about it, which is important to ensuring that we are in a position to educate customers about the processes it involves and the benefits it provides.

10.2.1 Please describe what the FEU are doing to avoid seeing this threat develop in BC?

Response:

Please refer to the response to CEC IR 2.10.2.

11. Reference: Exhibit B-5, CEC 1.7.9

> 7.9 What is the FEU estimate of the probability of having an abundance of natural gas versus the probability of having limited natural gas?
>
> **Response:**
>
> Current evidence suggests that there is an abundance of natural gas supply and production across North America and therefore the probability of having limited natural gas is low. The FEU do not have a forecast and do not have an estimate of probability of either abundance or limited natural gas. The forecasting process does not attempt to attribute probability to any one event or scenario occurring. Depending on the pace of future natural gas infrastructure development to move the supply to markets, it is possible to encounter pipeline capacity constraints and regional price spikes from time to time. However, over the long term, as more infrastructure is built to keep up with demand, a return to a more balanced supply and demand environment where sufficient natural gas is available will occur.

11.1 Would FEU agree that the pace of natural gas infrastructure development is likely related to the price and abundance of natural gas?

Response:

The FEU believe the pace of development of natural gas infrastructure is primarily driven by the demand for natural gas given the vast supply resources available. However, the market price of natural gas as well as environmental regulations and supply constraints are also factors that influence the pace of natural gas infrastructure development.

11.1.1 Please explain why or why not.

Response:

Please refer to the response to CEC IR 2.11.1.

11.2 Would FEU agree that the pace of natural gas infrastructure development represents a significant threat or risk? Please explain.

Response:

The pace of natural gas infrastructure development can represent a significant threat or risk, especially for parties whose planning does not adequately consider the impact of these threats. For example, an electric utility relying on interruptible gas pipeline service during peak demand periods to fuel its power plants may be at risk of not receiving its required gas supply to serve its customers as demand grows. The FEU, on the other hand, continuously monitor and address risks that threaten its ability to serve its customers so that it has the appropriate gas supply resources available. The Annual Contracting Plan includes an annual review of regional infrastructure and sets out the appropriate level of resources, such as storage and pipeline capacity, to meet customers' needs. Also, the FEU actively monitor regional infrastructure developments that could potentially affect the FEU's access to supply. The FEU are regularly involved in third party pipeline discussions and actively participate in regulatory proceedings to help ensure continued access to secure gas supply at fair market prices.

Ultimately, if there is sufficient demand to warrant it, infrastructure additions, such as storage or pipeline expansions, can reduce this threat or risk over time. Typically, new infrastructure is added if it is backed by longer term commitments by the infrastructure users, which helps to reduce the risk for these new additions. However, as it can take several years to build or significantly expand infrastructure, constrained infrastructure and market price spikes can occur for a period of time.

11.3 What evidence does FEU have that the infrastructure will or will not develop at a pace to avoid regional price spikes?

Response:

There is some evidence that infrastructure is not developing at a pace to avoid regional price spikes during certain times of the year. For example, during the peak winter demand of 2013/14, market gas prices in the northeastern US spiked to their highest levels in many years as the existing infrastructure was not sufficient to meet demand. In the FEU's own region, Sumas market prices often spike during peak winter periods as demand on the Spectra T-South pipeline system reaches capacity. Looking forward, if natural gas demand continues to grow as expected, infrastructure expansion will likely also occur in the form of storage and/or pipeline capacity expansions.

11.4 Please explain, in what ways, if any, FEU is able to influence the pace of natural gas infrastructure development, and explain what the FEU are doing.

Response:

Please refer to the response to CEC IR 2.11.2.

11.5 How would FEU propose to moderate regional price spikes should they occur?

Response:

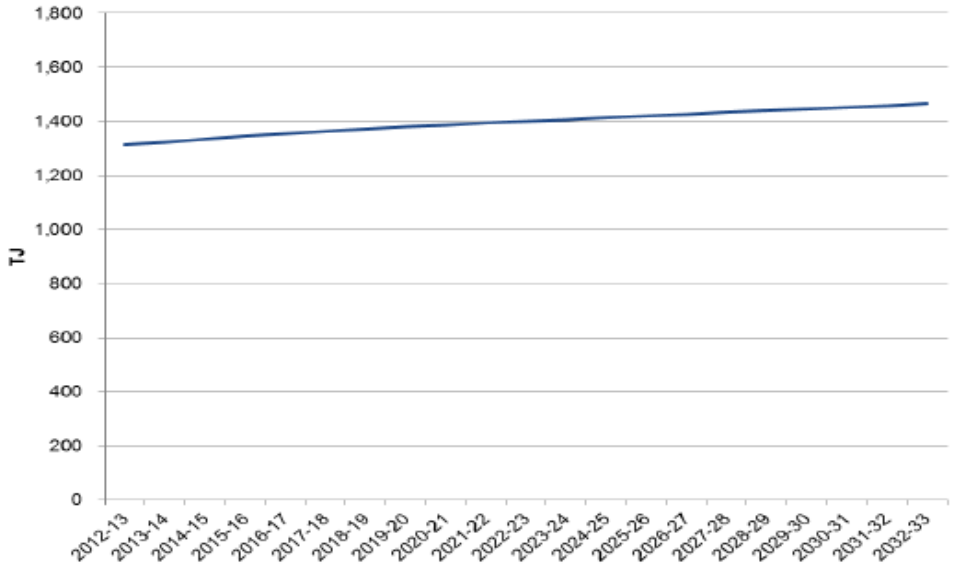
Regional price spikes are typically an indication to the market that new infrastructure, such as storage or pipeline capacity, is required to meet demand. This enables infrastructure additions to occur in an efficient manner by avoiding the over-building of capacity that may never be required or not needed for a considerable period of time.

The FEU take a number of actions to moderate regional price spikes. These include the development of a diversified gas supply portfolio that ensures an appropriate balance of cost minimization, security, diversity and reliability for customers. The portfolio includes purchasing gas from market supply hubs such as Station 2 and AECO/NIT, which are less prone to price spikes than the Sumas market hub. It also includes contracting for third-party storage capacity as well as using the FEU's own on-system LNG storage facilities to lessen the reliance on market purchases and regional pipeline infrastructure. In the past, the FEU have also used financial tools such as Sumas/AECO swaps to reduce the risk of regional prices spikes. The FEU will continue to consider both physical and financial tools (with the appropriate approvals) as part of its own going gas supply portfolio and price risk management activities.

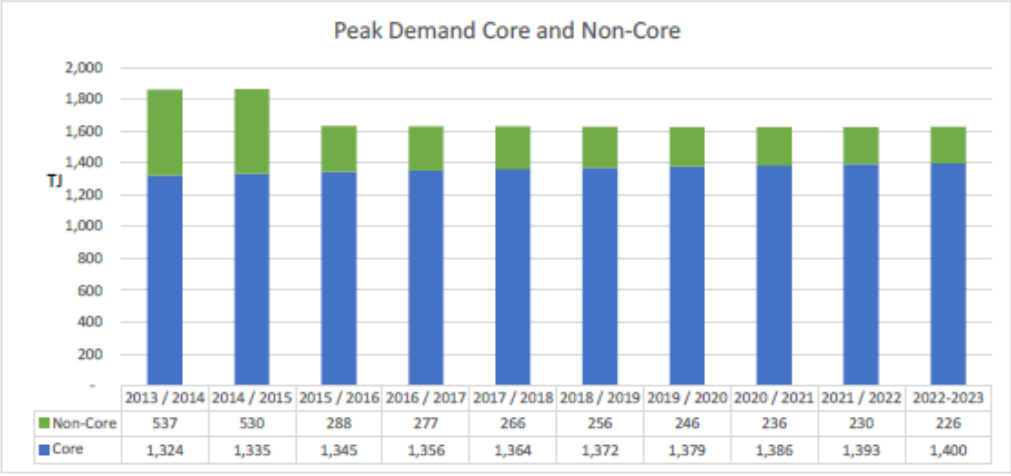
12. Reference: Exhibit B-1, Pages ES-4 and 5; Exhibit B-5, CEC 1.8.1

term with industrial demand returning to 2011 levels. Shown in Figure ES-2 below, the FEU expect to see modest growth in Core[3] peak day demand over the next 20 years, which stems from modest growth in customer additions.

Figure ES-2: FEU Core Peak Day Demand



Transportation customers in Rate Schedules 22 – 27 are not included as part of the core (Rate Schedule 1 to 7) market customers. The chart below shows the relative magnitude of the non-core peak demand (including power generation customers) to the core peak demand.



12.1 Please explain how the FEU plan for and service the non-core peak demand and please explain what the total peak is that the FEU plan for?

Response:

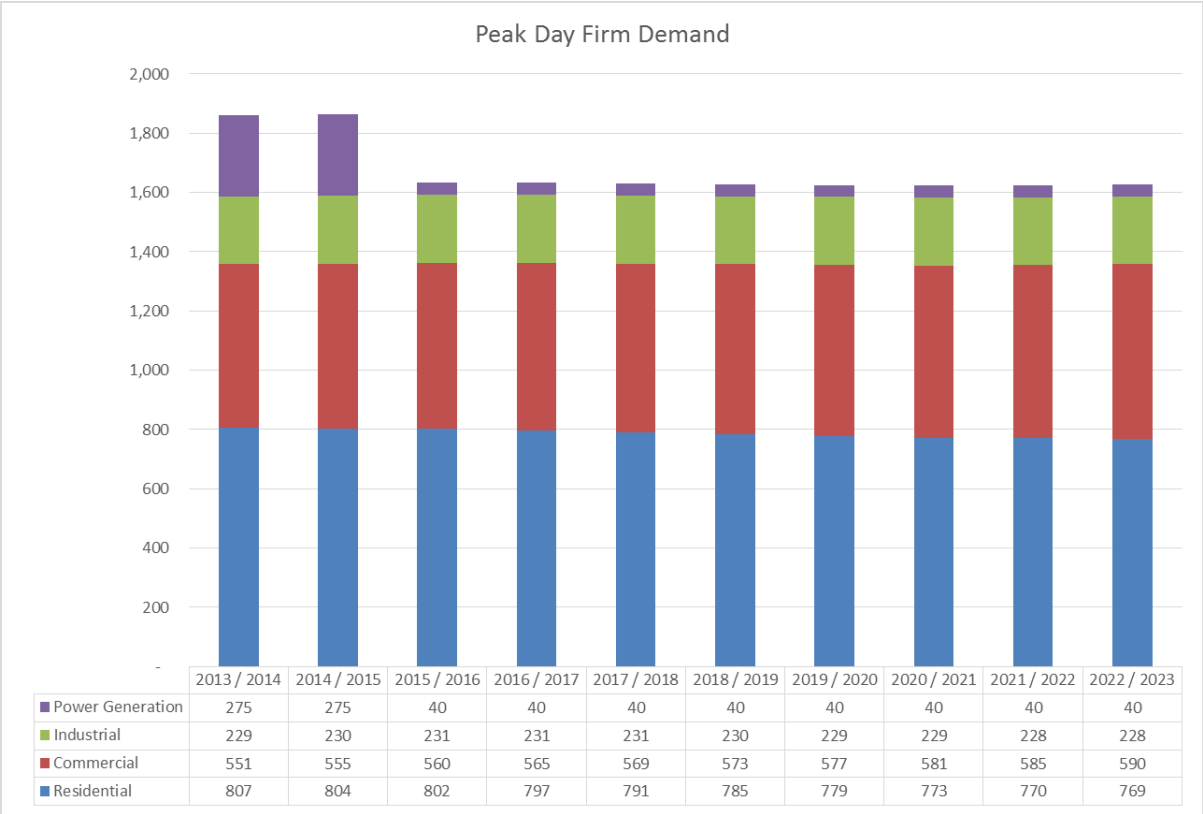
From a system planning perspective there are two components the FEU plan for related to serving peak demand: gas supply to meet the peak demand of core customers, and infrastructure (pipelines, compression, storage) to deliver the combined peak demand of core customers and firm non-core customers.

For core customers the FEU plan for and acquire gas supply to meet peak demand as set out in Figure ES-2 and ensure that sufficient infrastructure is available to deliver the peak demand . For non-core customers gas supply needs are met by a third party (ie. Marketers) and the FEU plan for and ensure that sufficient infrastructure is available to deliver any firm non-core peak demand. From the perspective of infrastructure requirements the FEU plan to meet the requirements of core peak demand and the non-core peak demand as set out in the second graph provided in the preamble.

12.2 Why is the non-core peak demand (transportation customers in Rate Schedules 22-27) expected to decline by about 45% between 2014 and 2015?

Response:

Further to the response to CEC IR 1.76.1, the estimated decline between 2015 and 2016 is from the power generation rate group. The estimated contract demand for Burrard Thermal is expected to be reduced from 275 TJ/day to zero in 2015/16.



	2013 / 2014	2014 / 2015	2015 / 2016	2016 / 2017	2017 / 2018	2018 / 2019	2019 / 2020	2020 / 2021	2021 / 2022	2022 / 2023
Power Generation	275	275	40	40	40	40	40	40	40	40
Industrial	229	230	231	231	231	230	229	229	228	228
Commercial	551	555	560	565	569	573	577	581	585	590
Residential	807	804	802	797	791	785	779	773	770	769

12.3 Why is the non-core peak demand expected to decline slowly over the next decade or so?

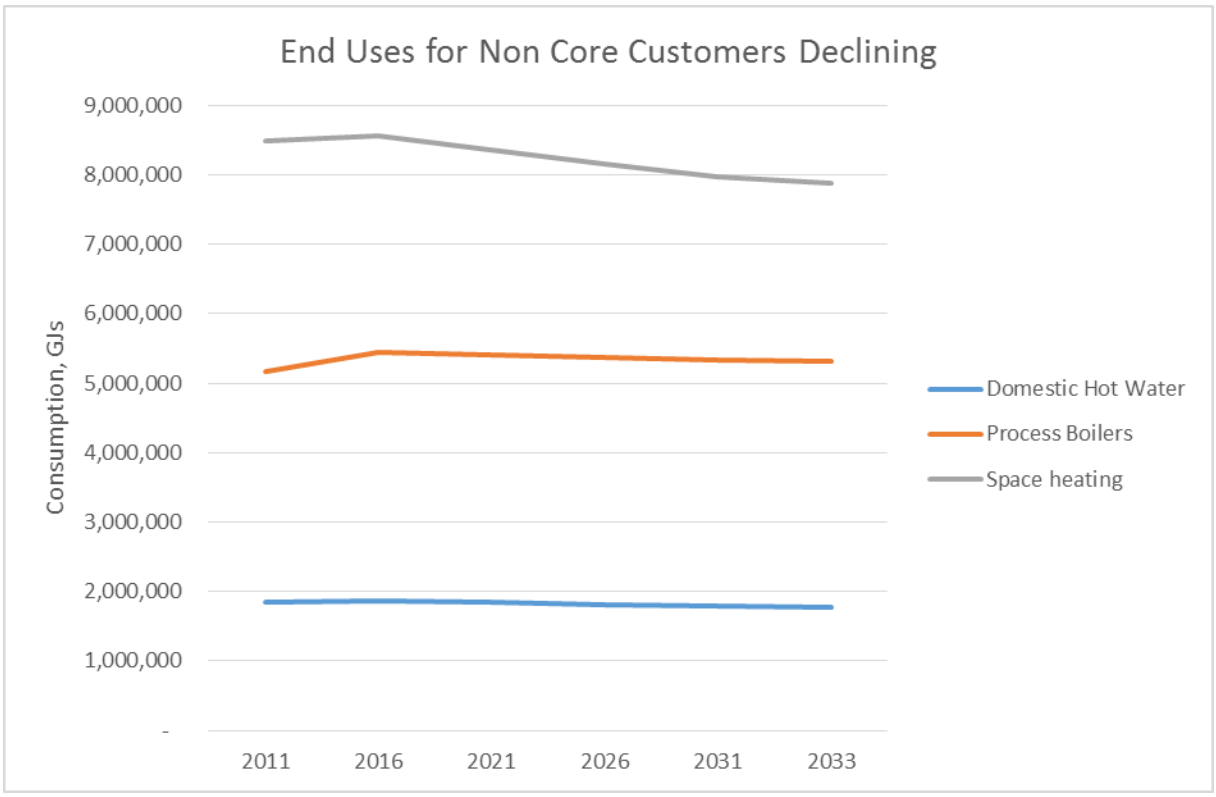
Response:

The non-core peak demand is expected to decline in parallel with the forecast decline of the annual load for the transportation customers in Rate Schedules 22-27. The top end uses for these customers include space heating and process boiler load, both of which are forecast to decline slowly over the next decade, in line with the expected decline in peak load. This decline is expected to be caused by continued improvements in end use efficiency over this period.

12.3.1 Is such a trend expected to continue over twenty years? Please explain why or why not.

Response:

Yes. As indicated in the response to CEC IR2.12.3, the anticipated decline is expected to continue given improvements in efficiency that are expected to carry on over the foreseeable future. The major contributing end-uses to this decline are set out in the figure that follows.



12.4 Please provide a discussion as to how FEU planning and investment is influenced by considerations of core peak versus non-core peak.

Response:

Please refer to the response to CEC IR 2.12.1.

12.5 Please confirm that NGT, LNG or any of the emerging potential markets is not included in either the Core Peak and Non-core Peak.

Response:

Confirmed. NGT and LNG or any of the emerging potential market forecast as described in Section 3.3.7 and Appendix A-8 in the Application is not included in the Core Peak and Non-core Peak in this analysis. Consequently, the incentives the Company are currently permitted to provide under the GGRR and the corresponding impact on the peak and the annual load are dealt with in the 2014 LTRP separately, outside of the Peak Day demand analysis.

12.5.1 If not confirmed, please illustrate the differences.

Response:

Please refer to the response to CEC IR 2.12.5.

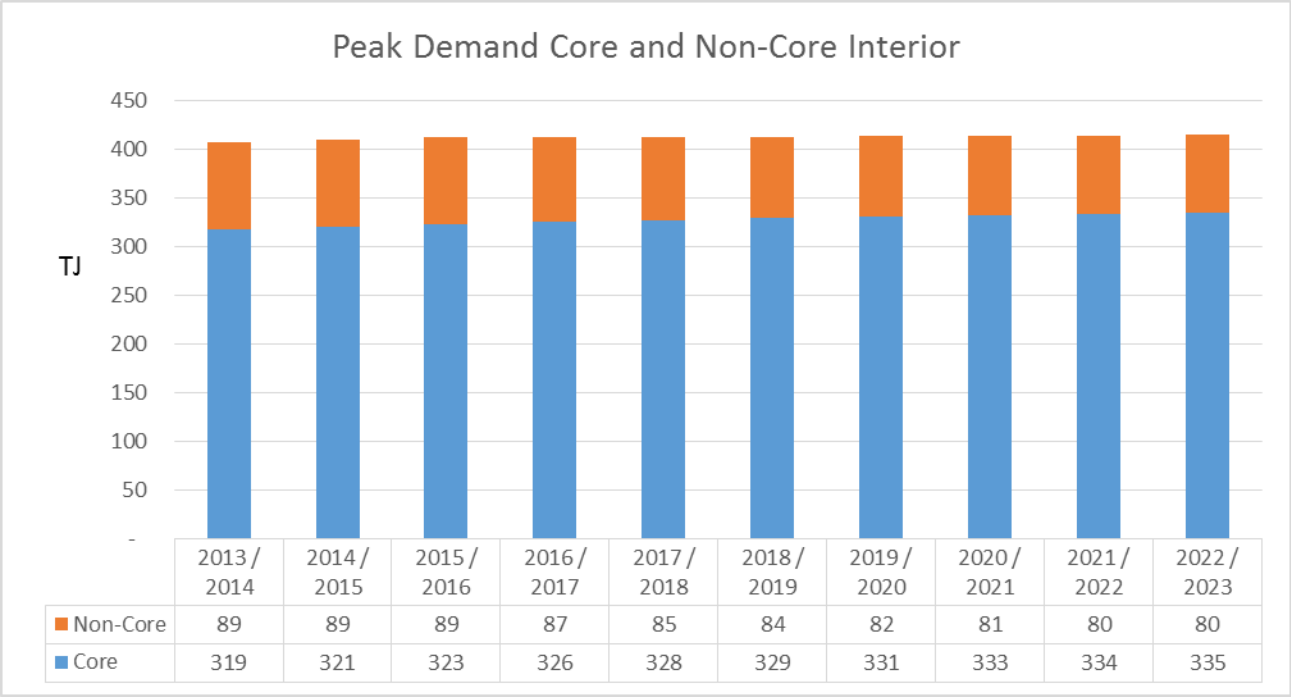
13. Reference: Exhibit B-5, CEC 1.8.2

> 8.2 Please relate the Core Peak Day Demand to the Peak Design Day for the natural gas delivery system showing all components required to explain any difference.
>
> **Response:**
>
> The Core Peak Day Demand shows aggregated loads across the entire FEU system, essentially total flow rates into the system during Peak Demand. Peak Demand used for design is region specific and is determined for individual gas systems independently based on forecasts of localized Core Peak demand and other transportation customers (e.g. rate schedules 22-27) as required.

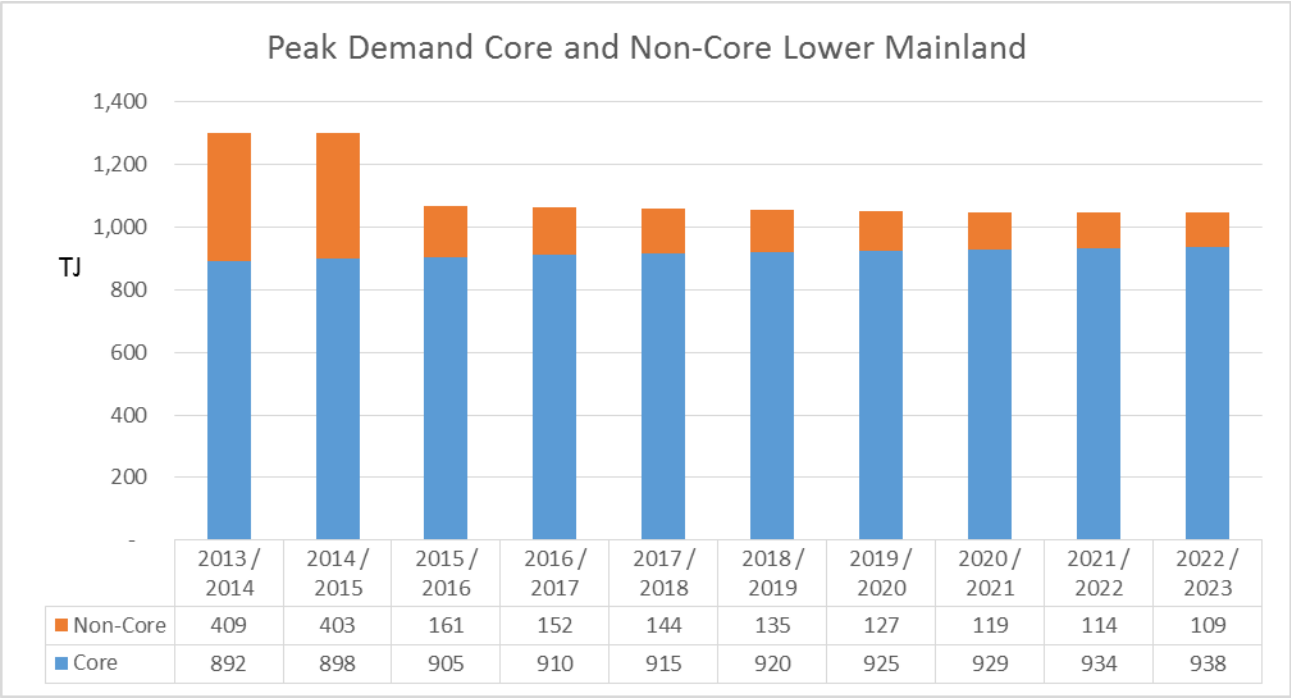
13.1 Please provide the forecast Peak Day demand for both core and other transportation customers (until 2033), disaggregated into regions.

Response:

The forecast Peak Day demand for core and other customers are provided below by region. Note FEW Peak Day demand only includes core customers.

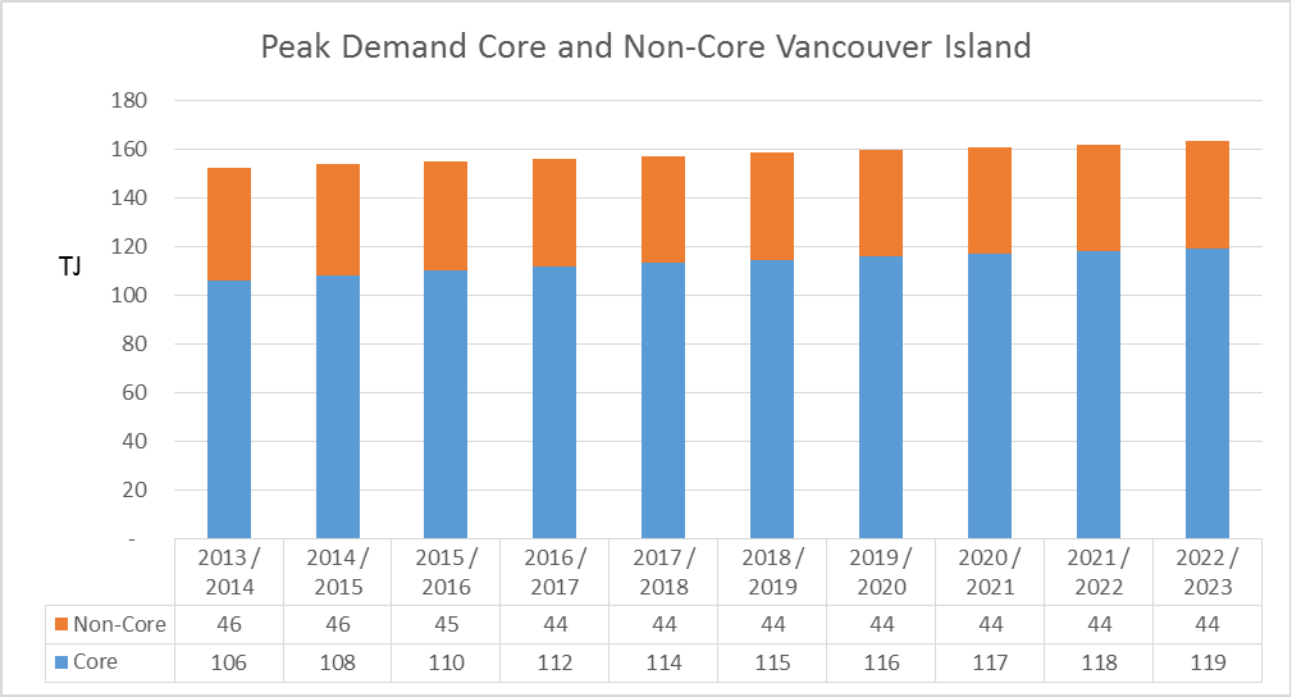


	2013 / 2014	2014 / 2015	2015 / 2016	2016 / 2017	2017 / 2018	2018 / 2019	2019 / 2020	2020 / 2021	2021 / 2022	2022 / 2023
Non-Core	89	89	89	87	85	84	82	81	80	80
Core	319	321	323	326	328	329	331	333	334	335



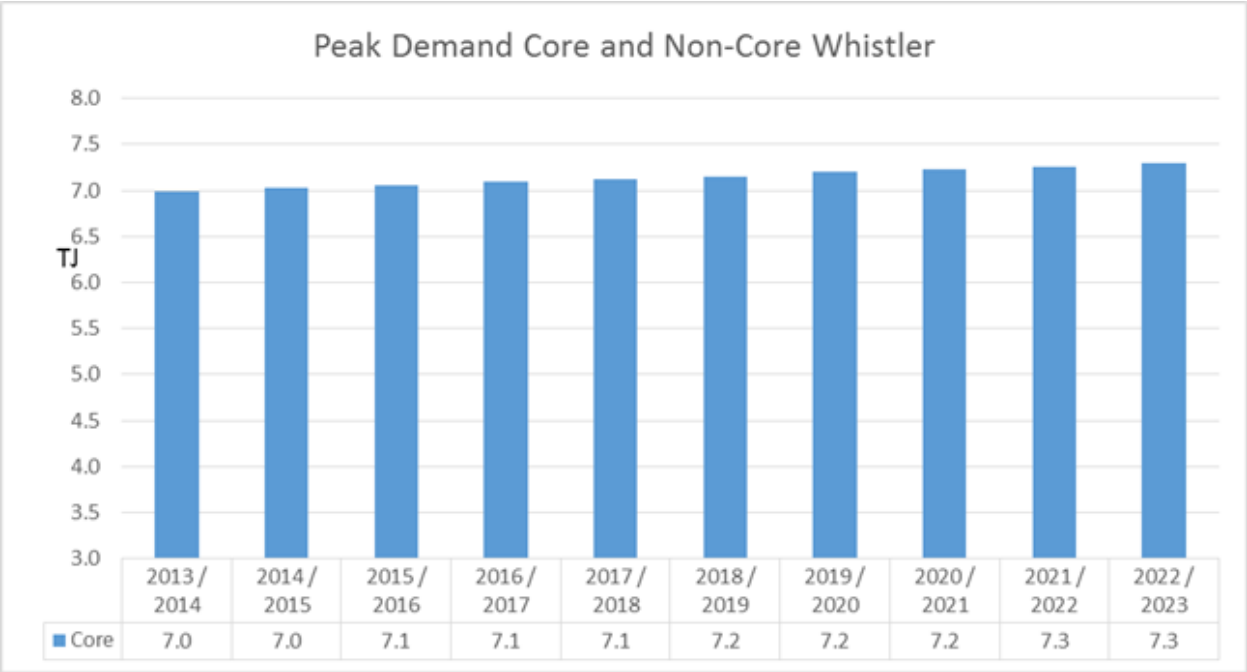
	2013 / 2014	2014 / 2015	2015 / 2016	2016 / 2017	2017 / 2018	2018 / 2019	2019 / 2020	2020 / 2021	2021 / 2022	2022 / 2023
Non-Core	409	403	161	152	144	135	127	119	114	109
Core	892	898	905	910	915	920	925	929	934	938

1



	2013 / 2014	2014 / 2015	2015 / 2016	2016 / 2017	2017 / 2018	2018 / 2019	2019 / 2020	2020 / 2021	2021 / 2022	2022 / 2023
Non-Core	46	46	45	44	44	44	44	44	44	44
Core	106	108	110	112	114	115	116	117	118	119

2


Peak Demand Core and Non-Core Whistler
TJ
8.0
7.5
7.0
6.5
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2013 / 2014
2014 / 2015
2015 / 2016
2016 / 2017
2017 / 2018
2018 / 2019
2019 / 2020
2020 / 2021
2021 / 2022
2022 / 2023
Core
7.0
7.0
7.1
7.1
7.1
7.2
7.2
7.2
7.3
7.3

14. Reference: Exhibit B-5, CEC 1. 8.4

> 8.4 Please define what if any peak demand 'demand side measures' may be possible and potentially feasible.
>
> **Response:**
>
> Please refer to the response to CEC IR 1.8.3. The FEU are not currently aware of any gas demand side measures other than curtailment that can reliably reduce peak demand on the FEU's systems, but will continue to examine measures that may have the potential to do so.

14.1 Please provide a discussion of the costs that are attributable to serving peak demand relative to non-peak service.

Response:

The FEU interpret the question to be a general question pertaining to cost drivers.

Gas transmission and distribution infrastructure is designed to meet a defined peak demand with sufficient capacity to ensure forecasted increases in peak demand on the system can be met economically into the future. Generally costs attributable to peak demand are capacity related and are fixed costs that that do not change in the short term when energy load changes. Generally, costs attributed to serving non-peak demand are not capacity related.

14.2 Would the ability to reliably reduce peak demand either overall or in specific regions result in savings for customers? Please explain why or why not.

Response:

The FEU agree in principle that the ability to reliably reduce peak demand over the long term could potentially result in savings for customers and, as such, the FEU continue to examine opportunities to reduce peak demand. These savings could materialize through avoiding or deferring capital expenditures required for system capacity improvement projects in systems where capacity constraints are forecast. The FEU can foresee that in some systems a reduction in peak demand has the ability to influence the timing of improvement projects by a number of years. In other systems where the load growth during the planning period remains within the local available capacity a reduction in peak demand will provide little or no savings. A meaningful way of quantifying customer savings via reductions in peak demand across the entire FEU is not currently available.

As discussed in the FEU response to CEC 1.8.3, to date the FEU have not identified any reliable measures other than curtailment to reduce peak demand. However, the use of advanced metering technology might help the FEU better characterize peak demand and help customers to better understand and manage their consumption patterns. Advanced metering technology is currently in the exploration phase and has not yet been proposed or deployed. For these reasons quantifying savings from peak demand reduction would be highly speculative.

In addition, the FEU continue to explore ways to increase the non-peak base load demand on the system. Securing interruptible customer load and markets such as NGT and new large industrial demand provide opportunity to increase the overall efficiency of the system and the distribution of costs amongst customers.

14.2.1 If reducing peak demand could create savings, what reductions would be necessary to create a meaningful change?

Response:

Please refer to the response to CEC IR 2.14.2

14.2.2 If reducing peak demand would create savings, please provide examples illustrating the magnitude of savings that would occur for varying levels of peak demand reductions.

Response:

Please refer to the response to CEC IR 2.14.2

14.3 What technologies or programs are currently being investigated that may have the potential to reduce peak demand in the future? Please provide a brief discussion of each.

Response:

Please refer to the responses to CEC IRs 2.4.2.2 and 2.4.2.3.

15. Reference: Exhibit B-5, CEC 1.9.1

9.1 Please confirm that to service the low scenario for NGT that the FEU would not require the Tilbury LNG plant expansion.

Response:

Not confirmed. As approved under Special Direction No. 5, the FEU are proceeding with Tilbury LNG plant expansion. NGT is only one of many industries seeking LNG. Other customers or industries that are seeking LNG include but are not limited to off system communities, utilities in BC, Washington State, Hawaii, Yukon and Northwest Territories, as well as niche export markets. The FEU expects that the liquefaction capacity will be subscribed and justify the expansion of the facility.

However, the FEU believe that the low NGT demand is unlikely and that NGT demand above the low scenario will materialize.

15.1 What indications has FEU received from other customers or utilities that suggest that the liquefaction capacity will be fully subscribed?

Response:

Discussions with potential customers for LNG service are confidential and, until firm contracts have been signed, subject to change. Therefore, the FEU cannot provide any further details about such discussions.

15.1.1 Please provide FEU's expectations as to when these customers are likely to require service and at what levels.

Response:

These customers may each require service within the next five years. The details of such potential service are confidential.

Please refer to the response to CEC IR 2.15.1.

15.2 Please describe whether or not temporarily un-utilized capacity of the Tilbury plant expansion can be used to lower gas portfolio costs and if so, by how much and with what benefit to customers?

Response:

Please refer to the response to BCUC IR 2.22.2.

16. Reference: Exhibit B-5, CEC 1.9.3

> 9.3 Please provide what conditions would be required to exist for a 30% scenario to be realized.
>
> **Response:**
>
> There are a number of factors that will need to persist for the 30% scenario to materialize. Namely, the following conditions will likely be required:
>
> 1. OEM engine offerings for a wide range of natural gas applications;
> 2. Declining capital cost premiums (i.e. economies of scale) for CNG and LNG engine offerings;
> 3. Widely available fuelling infrastructure covering a broad geographic area; and
> 4. Relatively low natural gas price environment relative to crude oil and diesel that would make switching to natural gas economic for fleet operators.

16.1 Please provide further details as to what FEU would consider as adequate OEM engine offerings for a wide range of natural gas applications.

Response:

The FEU refer to a wider range of OEM offerings in the following context. At the moment, the heavy duty hauling market segment, which is particularly suited in BC for the power and torque requirements provided by the 15L Cummins diesel engine, does not have a suitable engine replacement. The Cummins-Westport 15L natural gas engine has been discontinued from production leaving a void in this particular market application. The FEU are aware of Volvo developing a suitable natural gas engine replacement for the 15L engine, but are unsure when this engine will be available to market.

For other natural gas applications, Cummins-Westport is also developing a 6.7L natural gas engine to supplement with their current engine offerings. The 6.7L engine is particularly suited for light and medium duty applications such as medium-duty trucks, some school buses, and some vocational vehicles. This engine is expected to be available some time in 2015 but no firm timelines are known to the FEU at the moment.

Until a wider range of OEM engine offerings are available to the market looking to switch to natural gas, the FEU expect that consistent and dependable growth in NGT demand will be limited.

16.2 Would FEU agree that the price of natural gas will be influential in the pace of the development of OEM offerings? Please explain why or why not.

Response:

The FEU do not have any insight into the strategy and development of OEM engine offerings however the FEU can acknowledge that the price of natural gas *relative* to the price of incumbent fuels will continue to play an influential role in the pace of development of OEM offerings.

OEM engine suppliers are aware of the opportunities presented by abundant economic supplies of natural gas. Caterpillar for example has a very active development program to develop natural gas engine products across its product line which extends to include locomotive engines and mine haul truck engines. Development of new engines is however a very capital intensive endeavour and it takes time to develop and introduce these engines to the market. Caterpillar's offerings for example are expected to be introduced to the market in 2017.

16.3 Does FEU believe that there are presently declining capital cost premiums for CNG and LNG engine offerings? Please provide evidence to support the answer.

Response:

The FEU would like to clarify that capital cost premiums in the question refers to the chassis with CNG/LNG engine and the body with tanks and fuel systems. The FEU do not have enough data at this time to conclusively state that capital cost premiums are declining for CNG/LNG Engine offerings. The FEU have only data from the two rounds of funding in 2012 and 2013 for waste haulers, transit buses, heavy duty tractors and vocational truck type vehicles. The data suggests that the capital cost premiums for the same type of truck, model and specification is relatively flat. It should be noted that for capital cost premiums to come down the OEM's of engines and tanks have to realize certain economies of scale on a global scale and not just with the impact in the BC market.

16.4 What level of reduction in the capital cost premium would FEU consider as adequate for the 30% scenario to materialize.

Response

The FEU do not have any conclusive data to state the level of reduction in capital cost premium to achieve the 30 percent scenario. The FEU would point out that the capital cost premium of a natural gas engine is but one factor that influences the decision to adopt natural gas as a transport fuel. In order to increase natural gas adoption, all or a combination of some of the above noted factors will need to occur rather than just one of the factors.

Generally speaking capital cost premiums are expected to decrease as economies of scale are achieved, but FEI is unsure by how much they need to reduce by in order to achieve the 30 percent scenario.

16.5 Please define FEU's view as to 'widely available fuelling infrastructure covering a broad geographic market.'

Response:

The FEU's view of a widely available fueling infrastructure covering a broad geographic market is in reference to fueling stations that can be easily accessed by natural gas vehicle operators, similar to how gasoline and diesel are widely available today. At present, the FEU have constructed natural gas fueling stations on customer sites and are generally exclusive use of that customer. However, there are some fueling stations that are being used by third parties. For instance, Ledcor is fueling their LNG trucks at the Vedder LNG station, and the FEU are working with Waste Management to make their CNG fueling station open to third parties as well.

For natural gas demand for transportation to increase substantially, fueling infrastructure will need to be more widely accessible across a wider geographic area. The FEU's role in helping achieve this is to first secure return-to-base anchor fleet tenants and then make that fueling station open to third parties. As access to natural gas fueling is broadened, the FEU project that demand for NGT will continue to grow.

16.6 Would FEU consider an extensive fuelling infrastructure within BC to be sufficient to impact the BC NGT market? Please explain why or why not.

Response:

An extensive fueling infrastructure would be necessary but would not be sufficient by itself to solely impact the BC NGT market. As stated, the four factors listed in the preamble would need to occur in conjunction to have a material impact on the BC NGT market.

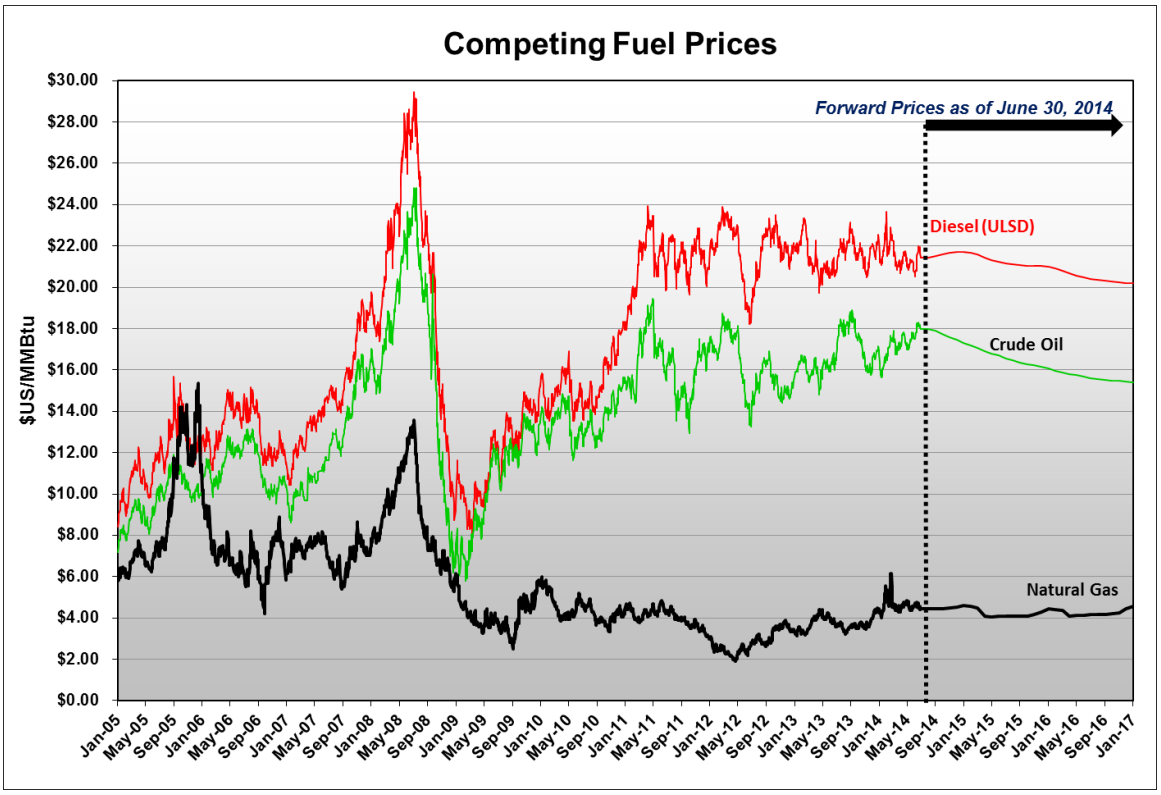
16.7 Please define FEU's view as to what constitutes 'relatively low natural gas price environment relative to crude oil and diesel that would make switching to natural gas economic for fleet operators'.

Response:

At present, natural gas prices are relatively lower than diesel and crude oil prices relative to historical prices. The figure below illustrates that on a $/MMBtu basis, natural gas prices are significantly lower than comparable diesel and crude oil prices. In the FEU's view such a price differential between natural gas and comparable diesel and crude oil have to exist to make it economical for fleet operators.

The figure shows settled prompt month prices for the past ten years and also shows the forward price curve settled on June 30, 2014 for the following three fuels:

1. New York Mercantile Exchange Natural Gas futures
2. West Texas Intermediate Crude Oil futures
3. US Low Sulphur Gulf Coast Diesel futures



It should be noted that the prices in the figure above are not burner tip or retail prices, but rather prices settled on the applicable exchanges and delivered to the applicable locations.

16.7.1 Does FEU believe this condition currently exists or will exist within the next five years? Please explain why or why not.

Response:

Please refer to response to CEC IR 2.16.7.

16.8 Please explain all the ways in which FEU believes the provincial and/or national government could stimulate the development of the NGT market.

Response:

The FEU believe that the following, but not limited to, list of initiatives would help continue to stimulate the development of the NGT market in BC:

- Continued promotion and increase awareness of the economic and environmental benefits of using natural gas for transportation.
- Provincial and/or federal policies/initiatives/incentives to mandate the phasing out of more carbon intensive fuels for cleaner burning fuel alternatives.
- Provincial and/or federal promotion and support for technological advancement of alternative fuels (i.e. the Westport LNG Technology Center and Demonstration Program).
- Tax (or other financial) incentives for manufacturers of OEM alternative fuels engine manufacturers.
- Provincial and Federal standardized codes and standards and guidelines for implementing safety practices for CNG and LNG as transport fuel.

16.9 Please describe the crude oil and diesel supply in North America and the world with respect to whether or not oil prices might decline and represent a threat to the FEU NGT business.

Response:

Please refer to the response to CEC IR 2.16.7. At present, the futures price expectations for diesel and crude oil are such that prices are expected to reduce slightly from current prices over the next number of years. However, diesel and crude oil prices are not expected to reduce materially enough to erode the economic advantage that natural gas currently has over these two fuels.

Additionally in the current fuelling station rate that customer's pay, commodity only represents 20 – 25 percent of the overall cost. Even if the commodity were to double from today's prices the overall net impact to a customer's fuelling rate is approximately 20 percent. This is a marginal cost increase when compared to the impact on the fuel pump if gasoline/diesel prices were to double by the same proportion.

17. Reference: Exhibit B-5, CEC 1.9.4

> 9.4 Please provide what the FEU are doing to enable the 30% scenario to be realized and describe any impediments the FEU see in realizing the 30% scenario.
>
> **Response:**
>
> The FEU can play an integral part in helping to enable the various scenarios presented. For instance, customer education and raising awareness through various media outlets will help fleet operators with decision making among the other variables that fleet operators must consider. The GGRR is also playing a vital role in the FEU continuing to develop NGT demand; however there exist a number of variables that are not in the FEU's control or influence.
>
> The FEU's influence on realizing any of the scenarios presented is limited to factors that are in direct control of the FEU. For instance, if there are delays in OEM engine offerings or if gas prices increase to levels that make switching to natural gas uneconomic, these factors would impede the FEU in realizing the 30% scenario.

17.1 Given the provincial policy with respect to natural gas and LNG economic development and the province's policy with respect to greenhouse gas reductions, do the FEU see a potential threat to the continued use of natural gas for its customers? Please explain.

Response:

Given the preamble to this request, the FEU interpret the question to refer specifically to the use of natural gas for its NGT customers. The public policies with respect to the use of natural gas in transportation are quite favorable in BC to reduce GHG emissions in that sector. The FEU recognize that there are a number of potential threats to the continued use of natural gas for its customers due to factors outside its control. In particular for NGT customers, the response provided to CEC IR 1.9.3 (included below) summarizes four potential threats to the continued use of natural gas for NGT customers.

9.3 Please provide what conditions would be required to exist for a 30% scenario to be realized.

Response:

There are a number of factors that will need to persist for the 30% scenario to materialize. Namely, the following conditions will likely be required:

1. OEM engine offerings for a wide range of natural gas applications;
2. Declining capital cost premiums (i.e. economies of scale) for CNG and LNG engine offerings;
3. Widely available fuelling infrastructure covering a broad geographic area; and
4. Relatively low natural gas price environment relative to crude oil and diesel that would make switching to natural gas economic for fleet operators.

Any delay in OEM engine offerings, increase in capital cost premiums of natural gas engines, reduction in availability of fueling infrastructure, and/or increased natural gas prices relative to gasoline or diesel are potential threats to the continued use of natural gas for NGT customers.

18. Reference: Exhibit B-5, CEC 1.9.6

> **Response:**
>
> Each of the 45%, 60% and 75% market share scenarios referenced in this question are unlikely to occur. However, if each of the conditions detailed in the response to CEC IR 1.9.3 were to occur, but at a greater magnitude, this may enable market growth of 45%, 60%, and 75%. Further, a number of external factors which are out of the control of the FEU may also favorably impact the FEU's market share. These include but are not limited to ongoing incentive funding for the purchase of CNG and LNG vehicles, penalties for operators of diesel and gasoline fueled vehicles and social pressure for fleet operators to convert to CNG and LNG vehicles.

18.1 Please explain why ongoing incentive funding for the purchase of CNG and LNG vehicles is not in the control of FEU.

Response:

At present, the FEU are permitted to provide financial incentives under the Province's GGRR regulation. However, if the FEU wish to provide financial incentives beyond the expiration of the incentive funding period under the GGRR, which is presently set to March 31, 2017, the FEU will require regulatory approval in order to do so.

In that respect, the ultimate decision to continue to provide incentives beyond March 31, 2017 does not reside with the FEU.

18.2 If the incentive funding declines, will this impede the growth of the market? Please explain why or why not.

Response

The FEU would like to clarify that the "incentive funding declines" in the question refers to the mechanism in the legislation where incentive funding declines by 10 percent every year since the start of the program until 2017. The declining level of incentive funding may impede the growth of the market for those customer segments that can't justify paying a higher proportion of the capital cost premium due to the longer payback timelines. This is one of the many factors that may impede the growth of the overall market.

The declining scale for incentives was part of the overall program design. This specific factor was designed to encourage the market to adopt natural gas and an acknowledgment that as a market became familiar with natural gas a smaller incentive to change to is required. The declining scale has worked well in some segments such as refuse hauling but has not worked

as well re the heavy duty class 8 sector primarily because of the withdrawal of the 15L engine in the third round of the program.

18.3 Please provide a list of the NGT incentive programs currently or previously offered by FortisBC, with the costs and any pre-established objectives.

Response:

FortisBC has currently two incentive programs in place to assist individual owners and operators of fleet vehicles to adopt natural gas. One is the light duty vehicle program and the other is the GGRR authorized incentive program for medium and heavy duty fleets. The programs are described below

Light duty incentive program

BCUC Order G-98-99 approved changes to FEI's Rate Schedule 6 to allow FEI to provide grants to customers wishing to purchase factory built light duty natural gas vehicles (NGVs). In 2005, FEI applied to the Commission for changes to Rate Schedule 6 which would allow grants to be provided to customers who wished to convert their vehicles, as factory built vehicles were no longer readily available in Canada. This was approved by Commission Order G-16-05.

FEI's objective is to encourage the growth of the light duty natural gas vehicle market. FEI believes that the current Rate Schedule 6 grants are necessary to grow the NGV market as a whole, particularly for smaller light-duty vehicles. FEI anticipates that in the next few years the number of personal use vehicle conversions and new vehicle adoption will still remain quite low. However, with continued government support and legislation and the maturing of conversion technology, conversion activity is expected to increase as gasoline and diesel prices remain high relative to the price of natural gas. In addition, it is expected that fueling infrastructure will continue to develop as heavy duty fleets come into operation resulting in increased access to fueling stations for light duty vehicle operators.

GGRR Incentive Program

The GGRR authorized NGT incentive program currently offered by the FEU is designed to help heavy and medium duty fleet owners in British Columbia to adopt natural gas vehicles in their fleets. The goal of the program is to initiate a market transformation from high carbon fuels such as diesel fuel to lower carbon fuel natural gas across specified market segments. The program pays to offset part of the cost premium associated with natural gas vehicles relative to diesel fuelled vehicles. The program is targeted for fleet vehicles across the following market applications.

- Heavy duty trucks (eg. Class 8 tractors)
- Vocational vehicles (eg. Waste haulers)
- Marine vessels
- Mine haul truck
- Locomotives

The following table illustrates the total envelope of grants available under each category:[1]

Specified vehicles as described above	$41.9 million
Marine Vessels	$11 million
Administration, Marketing and Training	$3.1 million
Maintenance facilities	$6 million

18.4 Please provide the results of these programs and relate them to the goals.

Response:

The Rate Schedule 6 NGV Grant Program is designed to assist customers to purchase factory built light duty natural gas vehicles and also to assist customers who wish to convert their vehicles to natural gas. In 2012, FEI provided $9,501.84 to convert 4 vehicles to natural gas, and in 2013, FEI provided $18,370.50 to convert 8 vehicles to natural gas. This grant program has been successful in its goal of providing incentives to encourage customers to convert to natural gas fueled vehicles.

The GGRR program was designed to help heavy duty and return-to-base fleet operators offset the premium associated with purchasing a natural gas fuelled vehicle. When the program was introduced FEI projected that cumulative diesel fuel displacement over the course of the entire program would be approximately 74 million diesel litres/year and GHG emissions would be reduced by 91,000 tons/year. FEI is on track to achieve the goals of the funding program. To date FEI has made $29 million in incentive commitments to assist in the purchase of approximately 400 heavy duty vehicles and 5 marine vessels. These actions will displace approximately 33 million litres/year of diesel fuel consumption and reduce CO2e emissions by 37,000 tons/year.

[1] For the period ending March 31, 2017. Commitments for the grants must be made by this date to be captured within the GGRR program

18.4.1 Please explain how these incentive programs are funded.

Response:

The light duty incentive program is funded by the FEU and recovered in rates from all non-bypass customers. The costs are amortized over 5 years and captured in a separate deferral account.

The GGRR incentive programs are funded by the FEU and recovered in rates from all non-bypass customers. The costs are amortized over a 10 year period. This cost treatment and mechanism is no different than the company's energy efficiency and conversation programs.

18.5 Has FEU undertaken any planning or activities directed at stretching the market growth beyond the 30% identified and into the 45%, 60% or 75% range?

Response:

No, the FEU haven't undertaken any planning to stretch beyond the identified 30 percent.

18.5.1 If so, please provide a description of the planning activities FEU has undertaken to expand the market.

Response:

Please refer to the response to CEC IR2 18.5

18.6 Is it FEU's position that they are unable to influence societal views of CNG and LNG? Please explain why or why not.

Response:

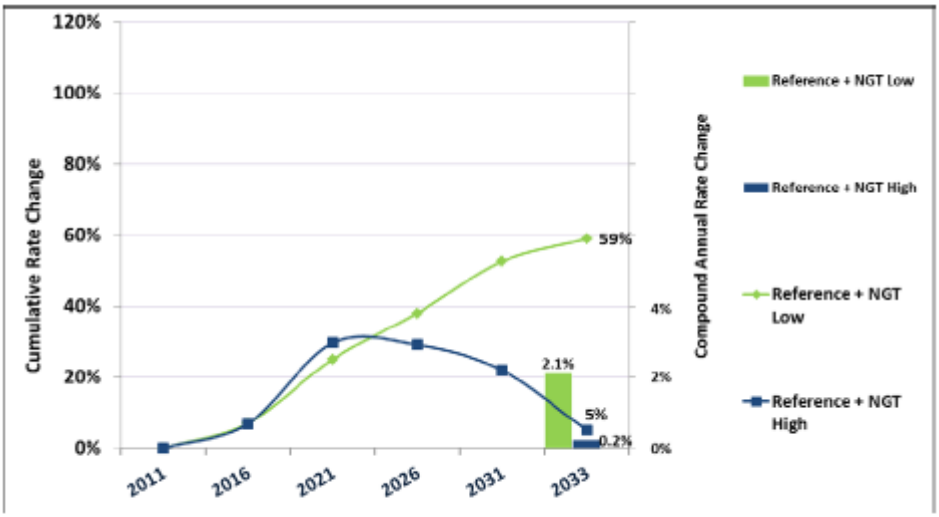
The FEU assume that the CEC is referring to the Companies' ability to increase public acceptance for using natural gas vehicles. To the extent that the FEU believe they can do so, that has already been considered in the demand forecasts presented in the 2014 LTRP.

18.6.1 If FEU is able to influence societal views, please explain what activities FEU undertakes to do so.

Response:

Please refer to the responses to CEC IRs 2.18.6, 1.9.4 and 1.26.2.

19. Reference: Exhibit B-5, CEC 1.10.2



19.1 Would the provision of additional incentives to the utility based on development of the NGT market create any changes in the activities of individuals or the activities of the utility as a whole to search out new opportunities? Please explain why or why not.

Response:

The FEU do not fully understand the broad nature of the question such that it can provide a response as to the actions of individuals or the utility at large. The FEU continue to explore potential new opportunities as they are identified and believe that it is important to continue exploring and developing programs that encourage the addition of new customers and load.

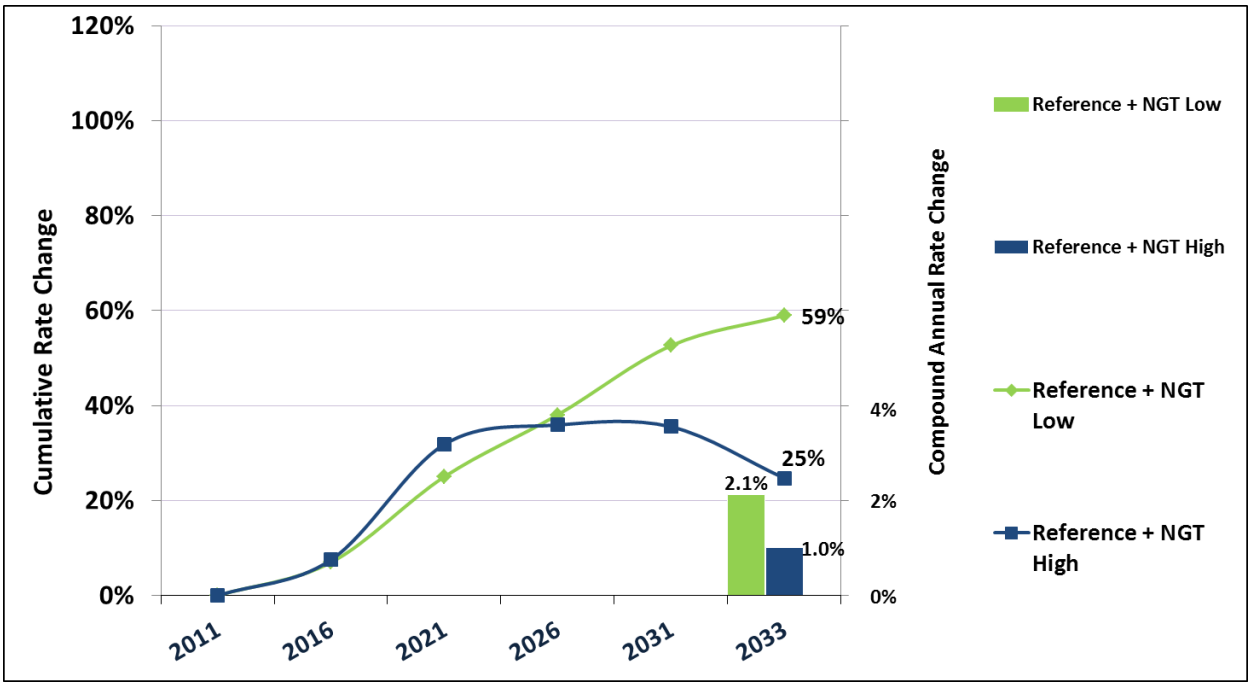
19.2 Please provide the above chart with the high NGT scenario occurring five years earlier than identified by the forecasting model.

Response:

In responding to CEC IRs 2.19.2 and 2.19.3, the FEU identified an error whereby some of the incremental LNG production costs were omitted from the analysis and, consequently, the response to CEC IR 1.10.2. Below, the FEU have reproduced the figure submitted in the

1 response to CEC IR 1.10.2 with this correction, and from which the analysis for the responses to
2 CEC IRs 19.2 and 19.3 are developed.

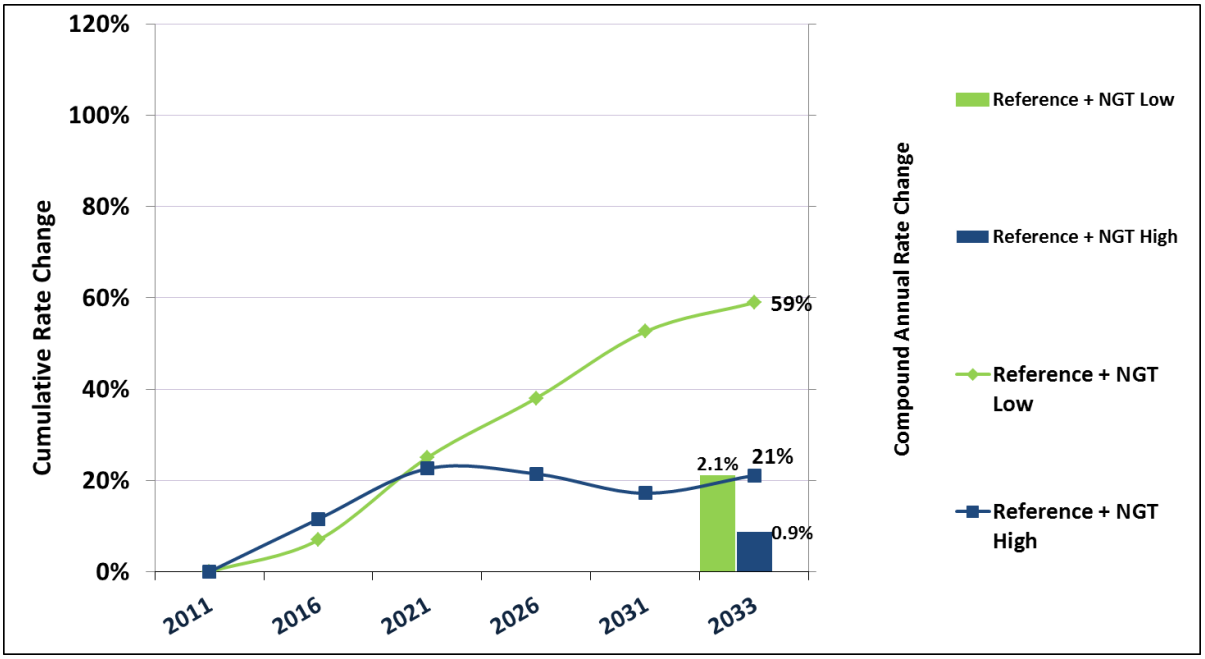
3 **CEC 1.10.2 figure, reproduced including omitted LNG production costs**



4

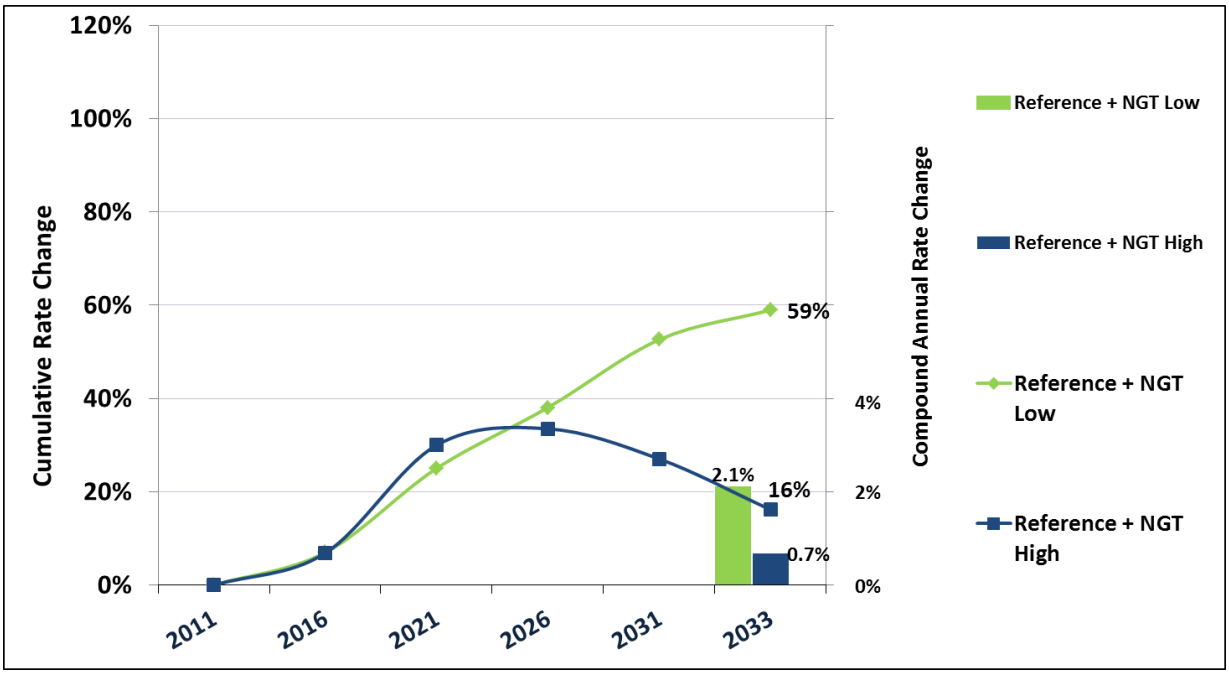
The following figure assumes that 2011 NGT High Volume is unchanged, 2021 NGT High Volume occurs in 2016, 2026 NGT High Volume occurs in 2021, 2031 NGT High Volume occurs in 2026 and 2033 NGT High Volume is unchanged. The figure pulls forward by five years the financial assumptions, such as incentives, underpinning the volume growth. The result is that customers may experience the benefits of load growth earlier.

NGT High Growth occurring 5 years earlier



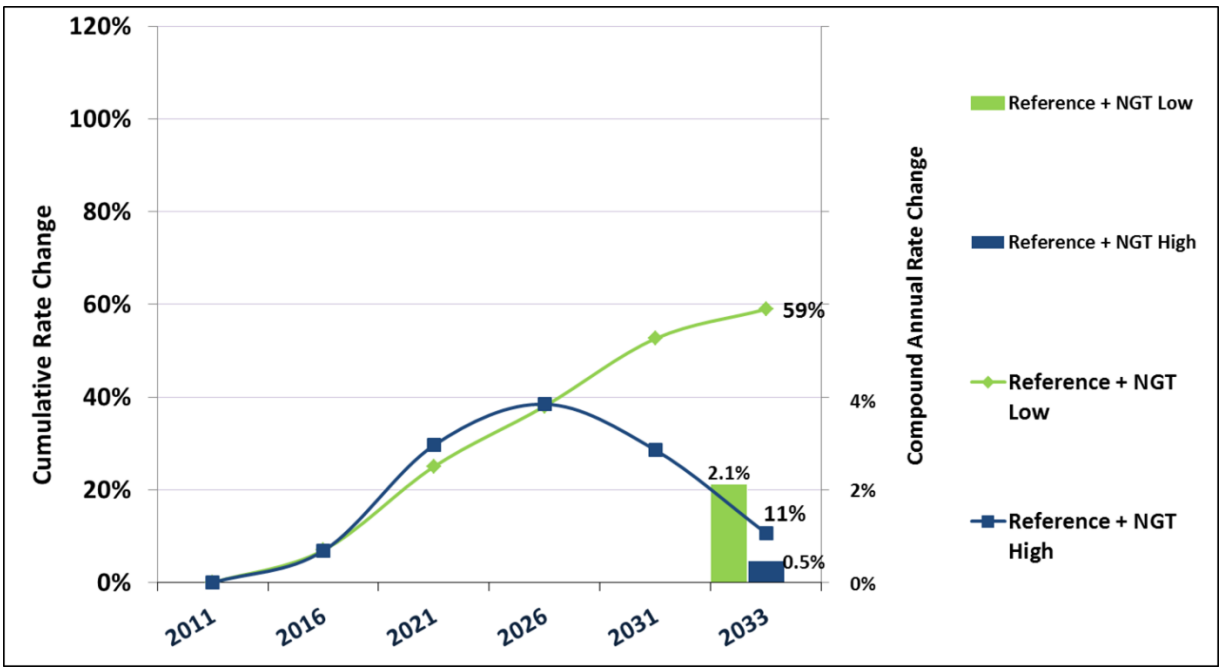
The following three figures assume that the FEU captures 45 percent, 60 percent and 75 percent of NGT market share. The analysis includes changes to LNG production facilities to accommodate the additional market served by FEI. The results indicate that at a high level the incremental margin from capturing a greater market share offsets the costs to produce LNG and CNG for the NGT market.

45 Percent Market Share



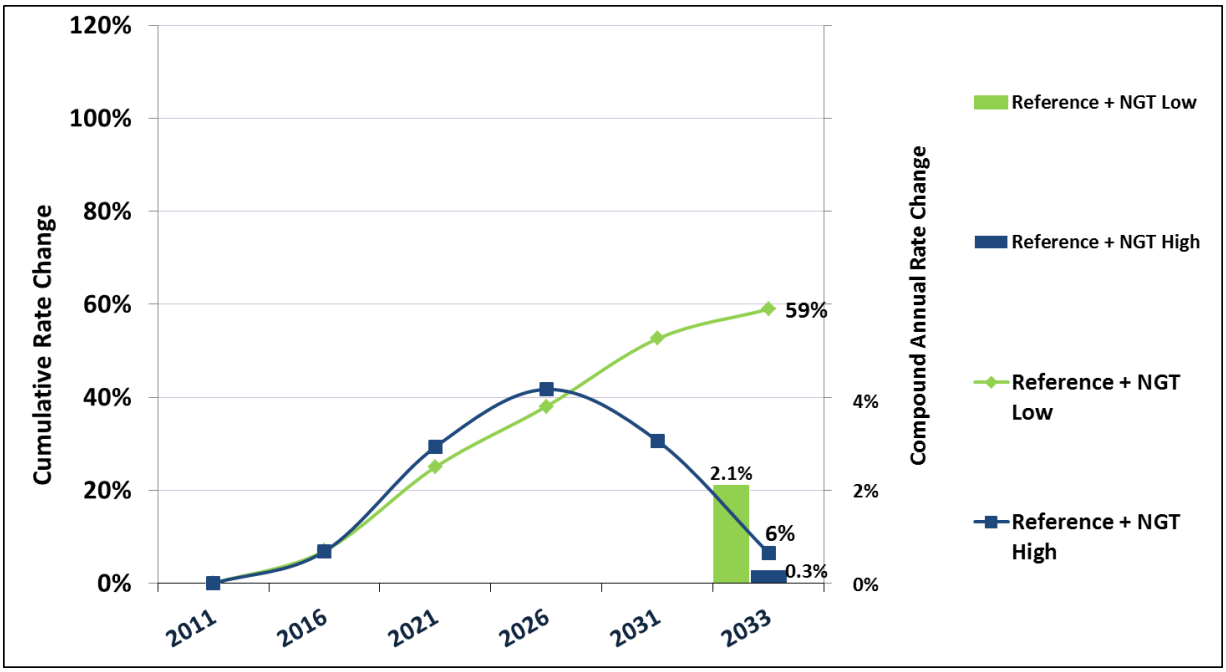
1

2 **60 Percent Market Share**



3

4 **75 Percent Market Share**



19.3 Please provide the above chart illustrating cumulative rate change with NGT demand occurring at 45%, 60% and 75%.

Response:

Please refer to the response to CEC IR 2.19.2.

20. Reference: Exhibit B-5, CEC 1.10.9

> 10.9 Please describe whether or not there are additional opportunities for expansion of the Tilbury Island LNG plant and under what conditions this might occur during the planning horizon.
>
> **Response:**
>
> Beyond the $400 million expansion allowed under Special Direction 5, the FEU are looking at additional opportunities for expansion of the Tilbury facility. At this time, the FEU do not have any firm commitments, however it is very possible that further expansions could occur during the planning horizon to meet both domestic (principally NGT and remote communities) and niche market or short haul export markets. In addition to the liquefaction capacity additions permitted under Special Direction 5, various parties have indicated interest in liquefaction capacity of up to 300,000 GJ/day.

20.1 Is 300,000 GJ/day a figure that is a combination of that received from various parties, or the maximum indicated by any one party?

Response:

Interest in liquefaction capacity has been both a combination from various parties for a total of 300,000 GJ/day as well as 300,000 GJ/day from a single party.

20.1.1 If not the combined figure, what would be a total combined figure for which FEU has received interest in liquefaction capacity?

Response:

Due to confidentiality agreements the FEU are unable to respond to CEC 2.20.1.1.

21. Reference: Exhibit B-5, CEC 1. 11.1

> 11.1 Does this mean that the FEU will not be working in the next 4 years with any LNG export opportunities?
>
> **Response:**
>
> No - working on opportunities to add new customers and demand is an important day to day business activity for the FEU and is not something that gets singled out as an action item in the LTRP. However, the 2014 LTRP has considered the impact of potential new industrial load on its infrastructure that could result from these ongoing business activities. The FEU continue to examine all opportunities that may result in increased load on the natural gas delivery system.

21.1 Please identify all other significant opportunities for adding load to the system in addition to NGT; LNG export opportunities; and natural gas feedstock for industrial and chemical processes that FEU is pursuing.

Response:

Other than the types of opportunities identified in the request, the FEU are not currently pursuing any other opportunities.

22. Reference: Exhibit B-5, CEC 1.12.2; Exhibit B-2, BCUC 1.1.5

12.2 What are the regulatory implications of an acceptance of the plan?

Response:

Once accepted, the Commission is required to consider the LTRP in subsequent applications under sections 44.2, 46 and 71 of the *UCA*. Please refer to the response to BCUC IR 1.1.5 for additional information.

would be little to no impact on future applications if the Commission accepts this submission. If the Commission does not accept or only partially accepts the FEU's 2014 LTRP, the FEU believe that information and statements of planned extensions contained in the 2014 LTRP could still be used to provide context for future CPCN applications as acceptance is not a condition required to use such information. In addition, the 2010 LTRP (accepted on February 1, 2011) and the Companies' Five-Year Capital Plans could be relied upon, if necessary, for submitting any future applications. Any future applications would contain information updates necessary for the Commission to make an informed decision at that time.

22.1 If the LTRP were not approved, would FEU consider modifying the plan for Commission approval or does FEU consider the process complete by having filed the plan?

Response:

Please see sections 44.1(6) and (7) regarding the Commission's "acceptance" (not "approval") of the Plan.

The FEU consider submission of the LTRP to the BCUC as one step in an ongoing, iterative long term resource planning process. If the Commission were to not accept or accept a portion of the LTRP, a decision to either modify the 2014 LTRP for resubmission or to address Commission concerns in the next iteration of the LTRP would depend largely on the Commission's reason for decision and any directives contained therein. Please also refer to the response to BCPSO IR 2.1.1.

22.2 If approved, will FEU be accountable for ensuring its future applications are in accordance with the LTRP scenarios? Please explain why or why not.

Response:

As described in Section 3 of the 2014 LTRP, the scenarios identified in the LTRP are based on key uncertainties—such as an abundance or limitation of natural gas supply, or centralized

versus decentralized energy delivery systems—that may unfold over the planning horizon. The scenarios incorporate varying assumptions for gas commodity and carbon prices, the policy environment, and the development of renewable thermal energy systems.

It is unclear what is meant by the question since the scenarios are intended to represent the range of alternative demand scenarios that could reasonably be expected to unfold over the 20-year planning horizon. The planning scenarios do not form the justification of any future expansion. They are a point in time planning view of what could reasonably occur 20 years into the future. The FEU use the range of scenarios in order to ensure that the Companies have the appropriate resources in place to meet customer needs across the range of potential demand. It is also important to note that a future LTRP would likely use different scenarios that are reflective of the planning environment at that time. Therefore it is not necessary or warranted to ensure that future applications are "in accordance" with the LTRP scenarios. If future applications such as CPCN's are made, and if the Commission accepts this LTRP, the Commission would have to consider the LTRP as part of that process as set out in section 46(3.1) of the Utilities Commission Act. The scenarios are simply a step to get to the resource planning needs, not an end unto themselves.

22.3 Would FEU be obligated to update the LTRP if it became clear that any or none of the scenarios were unfolding as expected? Please explain.

Response:

Please refer to the responses to CEC IRs 2.6.1, 2.6.1.1 and 2.22.2. The LTRP is submitted on a regular basis and is therefore updated on a regular basis.

23. Reference: Exhibit B-1, Appendix 1, Page 3; Exhibit B-5, CEC 1.13.2

Table 1-1: 2012 FEU Service Statistics

	FEI Lower Mainland	FEI Interior	FEVI	FEW
Number of Customers	583,979	257,484	101,098	2,612
Annual Demand (TJ)	120,378	59,355	33,926	652
Peak Day Demand (TJ/d)	887	316	104	7
Length of Transmission Pipeline (km)	260	2,071	626	N/A
Length of Distribution Pipeline* (km)	11,155	8,413	3,533	99

** Includes both low and intermediate pressure pipelines*

13.2 Please explain why the Peak Day Demand per customer is about 50% higher for FEI Lower Mainland than it is for FEI Interior.

Response:

The FEU note that Peak Day Demand per customer is 24% higher for FEI Lower Mainland than it is for FEI Interior, and not 50% higher.

The Lower Mainland experiences a higher Peak Day Demand per customer due to the higher proportion of industrial customers in the region that have much higher daily demand requirements than other customer groups. For FEI Interior the ratio of industrial demand to total demand is half that of the Lower Mainland.

23.1 Please explain why FEI Lower Mainland Peak Day demand is approximately 50% higher than it is for FEVI.

Response:

The FEI Lower Mainland Peak Day demand is actually 753 percent higher than that of FEVI. The FEU are assuming that the CEC is intending to question the difference in peak day demand per customer, and in this case the FEI Lower Mainland peak day demand per customer is 48 percent higher than that of the FEVI.

The Lower Mainland experiences a higher Peak Day Demand per customer due to the immature nature of the FEVI utility, and thus a relatively newer proportion of gas customers on the island. In many cases these customers do not have the same proportion of gas appliances and gas equipment as customers in the Lower Mainland do. For example, residential customer demand on Vancouver Island results in a lower peak load per customer when compared to the Lower Mainland due to the higher proportion of residential space heating served by electricity

instead of gas on Vancouver Island. As a result of lower gas appliance and equipment saturation on FEVI relative to the Lower Mainland a lower FEVI peak day demand per customer results.

24. Reference: Exhibit B-5, CEC 1.14.1

> Given the complexity of the commercial and industrial sectors and the level of detail in this information request, significant additional analysis would be required to speak to the advantages and disadvantages of natural gas and competing alternatives for each sector.

24.1 Please provide a high level overview of the financial and other trade-offs made in selecting natural gas for commercial cooking versus other alternatives.

Response:

Some of the financial and other trade-offs made in selecting natural gas for commercial cooking versus other alternatives include higher capital and installation costs, additional regulatory requirements such as venting, space considerations for natural gas equipment and venting, the ability to generate instant heat and more precise heat control.

24.1.1 Would FEU agree that natural gas is perceived as a preferred fuel source for commercial cooking? Please explain why or why not.

Response:

In 2011, the Canadian Gas Association (CGA) released results of a national survey that showed that 80 percent of Canadian Executive Chefs prefer cooking professionally with natural gas due to the speed and "outstanding" quality of natural gas.[2]

24.2 Please provide a high level overview of the financial and other trade-offs made in selecting natural gas for commercial domestic hot water versus other alternatives.

Response:

The financial and other trade-offs made in selecting natural gas for commercial space or water heating vary by commercial business purpose and scale. For example, large scale facilities such as hospitals encounter a different set of financial decisions and trade-offs than a small

[2] Canadian Gas Association. News Release: "Canada's Top Chefs Cook with Natural Gas," June 13, 2011.

restaurant. Some trade-offs may include higher capital and installation costs for natural gas than for electric appliances, additional venting or space requirements, the cost of natural gas versus alternative energy sources, energy efficiency of each option, any available incentives as well as environmental considerations.

24.3 Please provide a high level overview of the financial and other trade-offs made in selecting natural gas for commercial space heating.

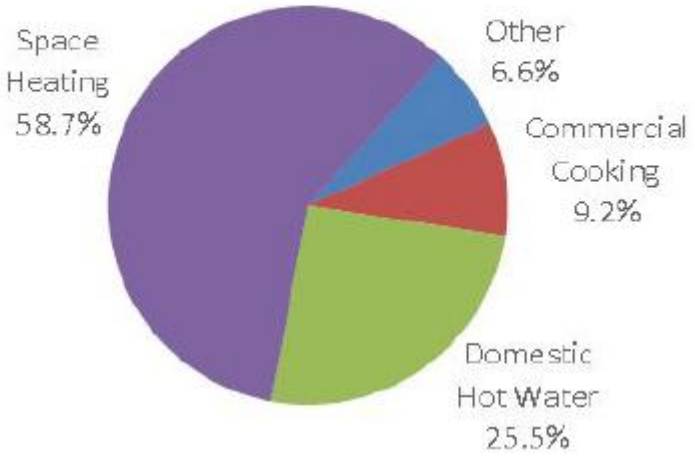
Response:

Please refer to the response to CEC IR 2.24.2.

25. Reference: Exhibit B-5, CEC 1.14.1

Exhibit 12 Base Year (2010) Natural Gas Consumption by Sub Sector and End Use for the Total FortisBC Service Area 2010 (GJ/yr.)

SubSector	Commercial Cooking	Domestic Hot Water	Space Heating	Other	Grand Total
Large Office	41,589	146,068	1,250,960	83,177	1,521,793
Medium Office	22,100	69,616	782,651	44,201	918,569
Large Non-Food Retail	40,558	104,378	1,249,447	20,279	1,414,662
Medium Non-food Retail	50,411	59,055	819,613	25,205	954,284
Food Retail	73,870	63,880	341,118	18,467	497,335
Large Hotel	115,311	337,389	362,190	69,187	884,077
Medium Hotel	42,615	169,779	219,372	42,615	474,382
Hospital	143,002	586,786	2,001,013	510,721	3,241,521
Nursing Home	114,557	317,906	781,546	133,650	1,347,659
Large School	82,352	168,135	1,237,559	20,588	1,508,633
Medium School	26,856	109,663	1,058,248	13,428	1,208,195
University/College	194,744	364,370	1,841,340	340,803	2,741,257
Restaurant	2,091,691	1,195,252	1,220,606	46,482	4,554,031
Warehouse/Wholesale	4,083	15,559	199,639	16,330	235,610
Large Apartment	166,335	3,491,420	4,728,026	665,338	9,041,119
Medium Apartment	50,714	1,883,367	2,775,717	304,285	5,014,084
Small Commercial	-	-	-	-	16,815,434
Recreation and Other	-	-	-	-	4,357,305
Whistler	-	-	-	-	247,757
Grand Total	3,260,788	9,072,621	20,869,245	2,354,758	56,977,907



25.1 Please provide a description of the types of the businesses that are included in 'small commercial'.

Response:

The following sectors are used in the End Use Model for the small commercial rate class:

Food Retail
Hospital
Large Apartment
Large Hotel
Large Non-food Retail
Large Office
Large School
Medium Apartment
Medium Hotel
Medium Non-food Retail
Medium Office
Medium School
Nursing Home
Restaurant
University/College
Warehouse/Wholesale

25.2 Please explain either why FEU did not provide, or does not have a breakdown of the small commercial sub-sector by end use, given that it is the largest sub-sector and represents nearly 30% of the total commercial sector of natural gas consumption.

Response:

The table referenced in the question was prepared by a consultant and presented in the 2010 Conservation Potential Review fully four years ago. In the above table Small Commercial was reported as a sub sector by the consultant. The table being referenced was not prepared using results from the End Use Model.

25.2.1 Please explain when FEU plans to acquire this information and how it will be provided to customers and the commission.

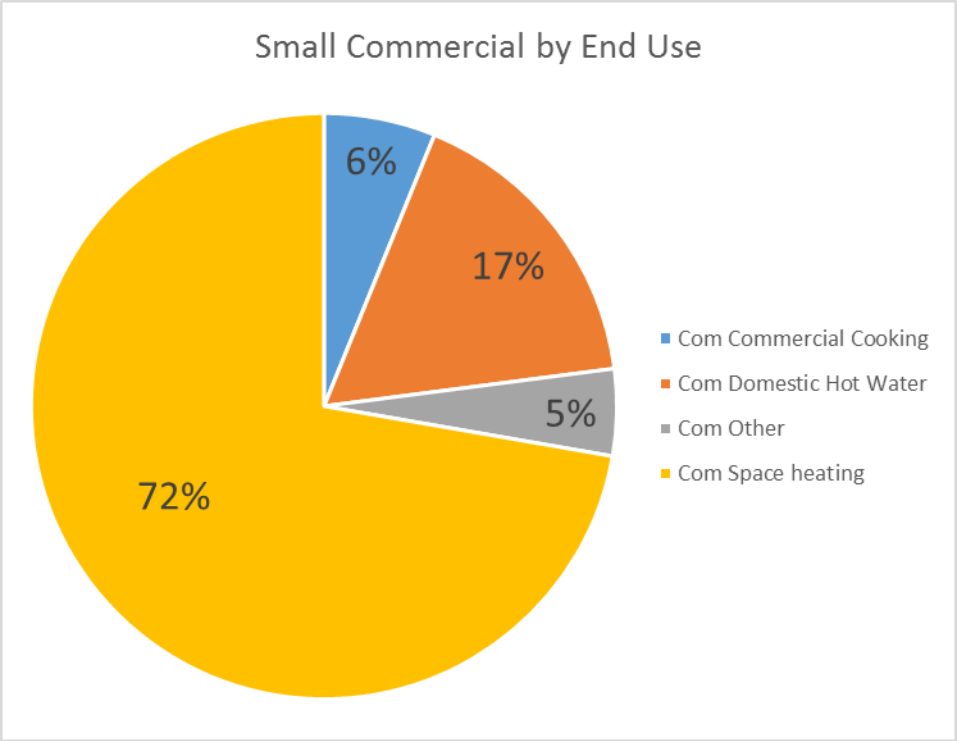
Response:

The table referenced above was prepared by a consultant and presented in the 2010 Conservation Potential Review fully four years ago. No further changes are anticipated to that document so the above referenced table will not be changed. That said, the data fully exists in the End Use Model and is easy to report on.

25.3 Please provide any breakdowns of the small commercial sub-sector by end use that FEU does have.

Response:

The four end uses modeled in the End Use Model for the small commercial sub sector include Commercial Cooking, Domestic Hot Water, Other and Space heating. The breakdown is shown below.



26. Reference: Exhibit B-5, CEC 1.15.1

A 90% efficiency factor was used in Figure 2-5, and was correctly noted in the LTRP, Footnote 16 in Section 2, page 19:

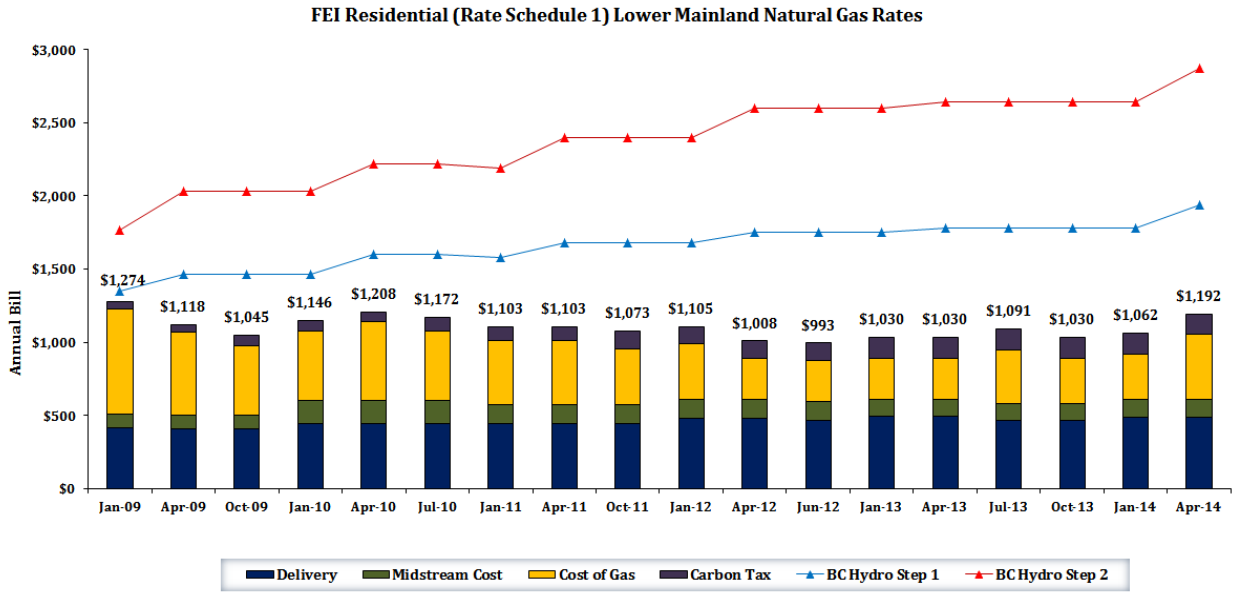
> *"[16] This illustration assumes natural gas use of 95 GJ and the efficiency of gas equipment is 90% relative to 100% for electric equipment. FEI amount includes the basic charge; BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use."*

It is important to note that the comparison in Figure 2-5 is not to a new gas furnace, but a generalized comparison of electricity bills and natural gas bills giving consideration for newer appliances that a customer may or may not have, and a generalized efficiency adjustment of 90% was used as an estimate to represent natural gas equipment as a whole. The comparison in Figure 2-5 is not intended to be an appliance specific comparison to a new natural gas furnace.

26.1 Please provide Figure 2-5 including the basic electric charge.

Response:

Please refer to the figure below which updates Figure 2-5 to include the basic electric charge.



Assumptions:
*Natural gas use of 95 GJ
*Efficiency of gas equipment is 90% relative to 100% for electricity
*FortisBC Energy amount includes the basic charge
*BC Hydro rates are inclusive of a 5% rate rider and the basic charge

26.2 Please provide a discussion of the key technologies that may arise in the future to improve the efficiency of natural gas equipment.

Response:

The maximum thermal efficiency attainable in any natural gas combustion appliance is 100 percent. There are some designs of natural gas condensing equipment available now that are in the range of 96 percent to 98 percent efficiency. This is the current ceiling for natural gas combustion efficiency. The technologies that allow efficiency improvements above 90 percent in condensing equipment are better materials, better design, better controls, better manufacturing, and quality control.

While FEI is not a research and design firm and is not in a position to know what technologies will arise in the future, there could be technologies that increase performance beyond the ceiling of combustion efficiency. FEI is aware of natural gas absorption air exchange and geo-exchange heat pumps that provide a co-efficient of performance of approximately 1.4 in heating and 0.60 in cooling. These systems are called absorption heat pumps. Theoretically this technology can also be leveraged for water heating. However, to the best of FEI's knowledge, there are no product lines available or installations in British Columbia at this time.

26.3 Please provide FEU's expectation for BC Hydro electric rates over the next 20 years.

Response:

Please refer to the response to COPE IR 1.2.1 which explains the FEU's current knowledge of BC Hydro's forecast electric rates.

26.4 Please provide the FEU's understanding of whether or not the financial impact of Site C, were it to be built, is in any of BC Hydro's electricity rate forecasts.

Response:

Please refer to the response to CEC IR 2.26.3.

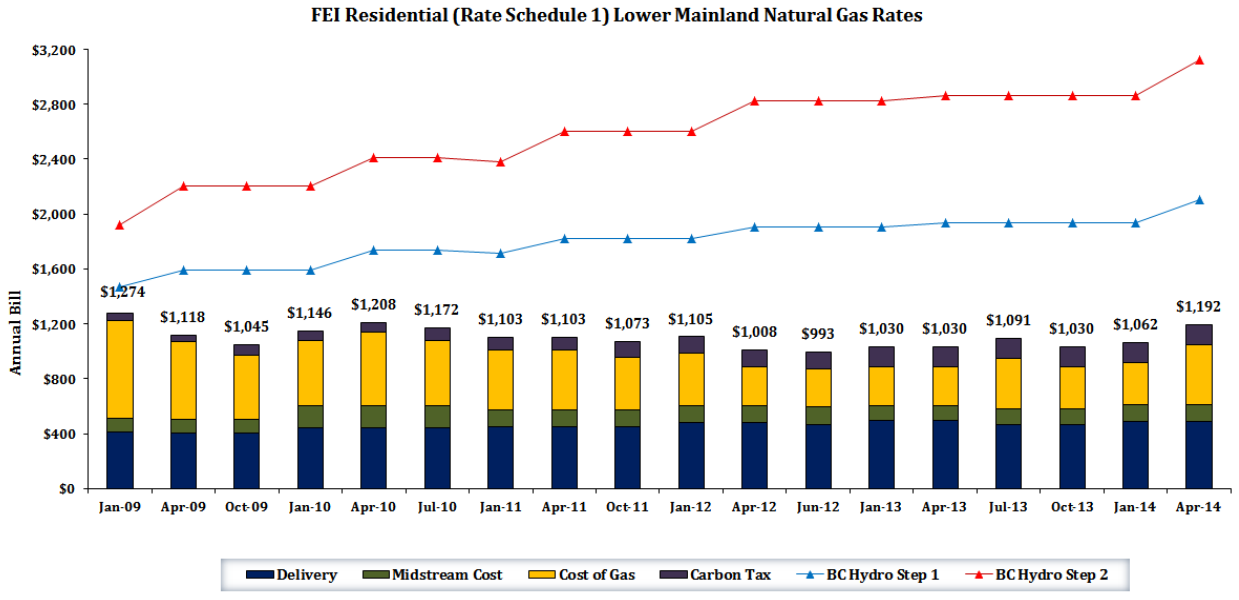
27. Reference: Exhibit B-5, CEC 1.15.2.1

> **Response:**
>
> The upper end of efficiency for new natural gas furnaces for residential use is 98%.

27.1 Please provide Figure 2-5 incorporating the 98% efficiency of a new natural gas furnace, and the BC Hydro base charge.

Response:

Please refer to the figure below which incorporates the 98 percent efficiency of a new natural gas furnace into the BC Hydro Step 1 and Step 2 data points, and the BC Hydro basic charge. It is important to note, as explained in the response to CEC IR 1.15.1, that the original comparison in Figure 2-5 was not to a new gas furnace, but a generalized comparison of electricity bills and natural gas bills giving consideration for newer appliances that a customer may or may not have, and a generalized efficiency adjustment of 90 percent was used as an estimate to represent natural gas equipment as a whole. The comparison in Figure 2-5 was not intended to be an appliance specific comparison to a new natural gas furnace and should not be taken out of context.



Assumptions:
*Natural gas use of 95 GJ
*Efficiency of gas equipment is 98% relative to 100% for electricity
*FortisBC Energy amount includes the basic charge
*BC Hydro rates are inclusive of a 5% rate rider and the basic charge

27.2 Please provide the Marginal cost of a gigajoule of electricity at 100% efficiency and the marginal cost of gas at 90% and 95% efficiency.

Response:

Please refer to the table below which provides the marginal cost of electricity and cost of gas at the requested efficiencies.

	FortisBC Energy Inc.[1]	FortisBC Energy Inc.[1]	BC Hydro[2]
Efficiency	***90%***	***95%***	***100%***
Long Run Marginal Cost per gigajoule	$5.92 - $7.79	$5.65 - $7.44	$23.61 - $27.78
	(range)	*(range)*	*(range)*

[1] Exhibit B-1, Appendix A-1, Section 5.1, page 26 (2020 forecast).
[2] The British Columbia and Power Authority (BC Hydro) 2013 Residential Inclining Block (RIB) Rate Re-pricing Application, page 2-4, line 8.

Conversion factors

1 gigajoule = 277.78 kWh

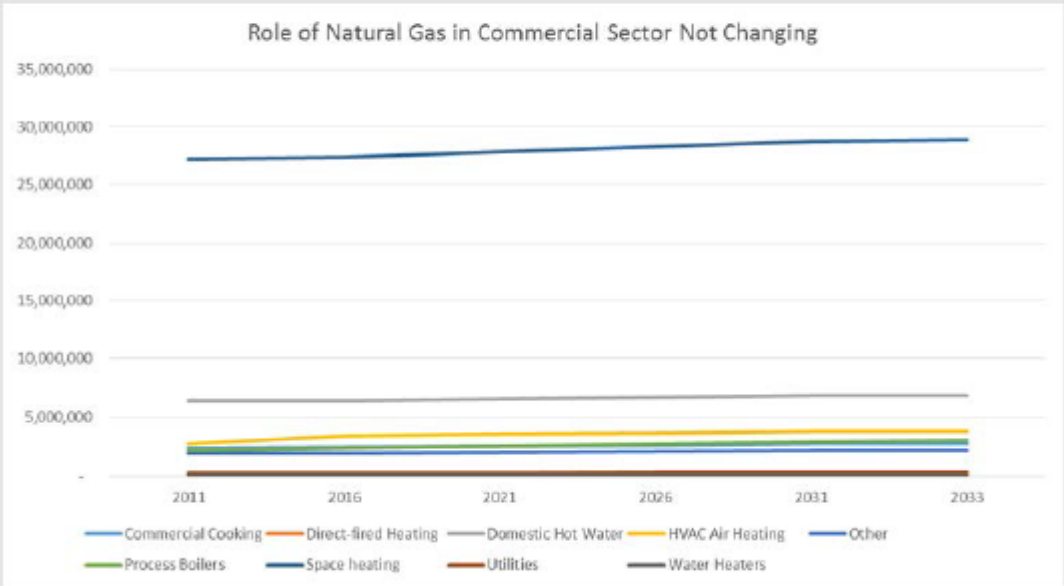
1 gigajoule = 1.055056 MMBTU

$US/$CAN Exchange Rate - 1.0742

1 **28. Reference: Exhibit B-5, CEC 1.30.1**

Response:

The chart below, from the Reference case of the end-use forecast, shows that the predominant role of natural gas in the commercial sector has been and will continue to be for space heating. The FEU do not expect this role to change or evolve over time.



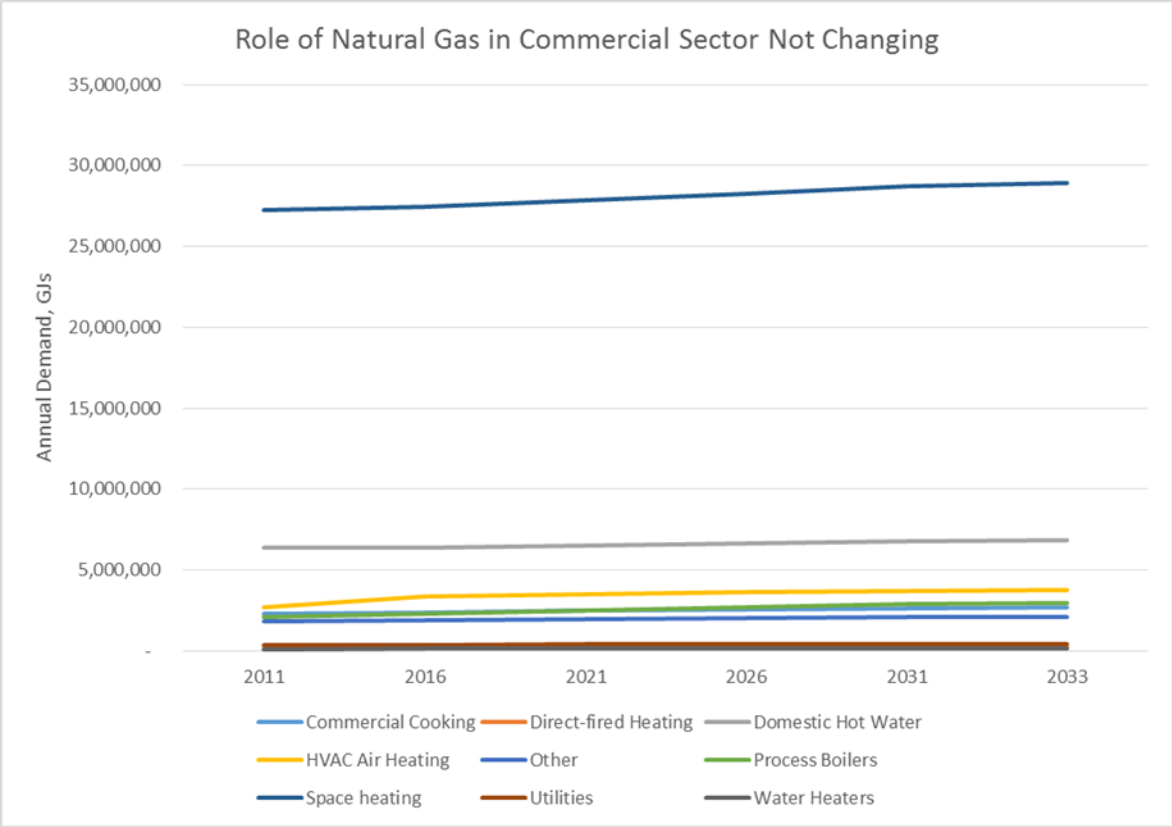
2

3 28.1 Please provide the label for the y axis.

4

Response:

A revised chart is provided below.



28.2 Does FEU see the Greenhouse Gas reduction program as a significant risk to the demand for natural gas? Please explain why or why not.

Response:

The FEU are unclear as to which “Greenhouse Gas reduction program” the question refers to. Since BC’s energy objectives outlined in the Clean Energy Act are aimed at aggressively reducing the province’s GHG emissions, the majority of BC’s energy policies, regulations and programs pose a risk to the demand for natural gas. One exception is BC’s *Greenhouse Gas Reduction (Clean Energy) Regulation* that aims to convert higher carbon transportation fuel users to natural gas. Another exception is British Columbia’s *Energy Objectives Regulation*, which recently modified Section 2 (c) of the *CEA* by adding, "other than electricity to serve

1 demand from facilities that liquefy natural gas for export by ship," between “at least 93 percent
2 of the electricity in British Columbia" and “be generated from clean or renewable resources.”

29. Reference: Exhibit B-5, CEC 1. 31.1.3

		2009	2010	2011	2012	2013
Customers	Residential	846,231	855,429	859,091	855,997	865,148
	Commercial	92,328	92,560	92,392	88,272	89,697
	Industrial	1,072	976	907	905	883
Demand (TJs)	Residential	75,488	76,573	74,252	73,598	72,184
	Commercial	55,168	56,133	55,330	56,233	55,012
	Industrial	60,363	59,922	65,540	68,552	68,105
Revenue (Million)	Residential	$962.21	$876.32	$903.35	$803.90	$771.92
	Commercial	$571.80	$516.61	$528.30	$457.49	$435.90
	Industrial	$136.21	$129.68	$132.58	$135.38	$137.12
FEU	Customers	939,631	948,965	952,390	945,174	955,728
	Demand	191,019	192,629	195,122	198,383	195,301
	Revenue (Million)	$1,670.22	$1,522.62	$1,564.22	$1,396.78	$1,344.94

29.1 Please provide the above chart dating back to the year 2000.

Response:

Please see the table below. Further to the response to BCUC IR 1.18.6, the billed consumption database which formed the basis for the forecast can only provide actual data from 2007 and thus data is provided starting from 2007.

		2007	2008	2009	2010	2011	2012	2013
Customers	Residential	827,190	838,508	846,231	855,429	859,091	855,997	865,148
	Commercial	90,365	91,875	92,328	92,560	92,392	88,272	89,697
	Industrial	1,157	1,103	1,072	976	907	905	883
Demand (TJs)	Residential	75,285	73,186	75,488	76,573	74,252	73,598	72,184
	Commercial	53,857	54,031	55,168	56,133	55,330	56,233	55,012
	Industrial	69,704	66,118	60,363	59,922	65,540	68,552	68,105
Revenue (Million)	Residential	$1,002.76	$1,117.30	$962.21	$876.32	$903.35	$803.90	$771.92
	Commercial	$576.36	$632.39	$571.80	$516.61	$528.30	$457.49	$435.90
	Industrial	$138.16	$138.03	$136.21	$129.68	$132.58	$135.38	$137.12
FEU	Customers	918,712	931,486	939,631	948,965	952,390	945,174	955,728
	Demand	198,845	193,335	191,019	192,629	195,122	198,383	195,301
	Revenue (Million)	$1,717.28	$1,887.72	$1,670.22	$1,522.62	$1,564.22	$1,396.78	$1,344.94

29.2 Please provide FEU's expectation as to the revenues that would be generated under each scenario for each customer group over the forecast time period.

Response:

The following table uses the volumes from Figures 3-7, 3-8 and 3-9, End Use forecasts by sector, and for the years 2016 through 2033 multiplies those volumes by the 2014 average annual revenue per TJ by sector for each scenario as described in Table 3-1 of the Application. For 2011, the revenues are derived by multiplying the 2011 volumes from by the average annual revenue per GJ by sector for 2011.

As indicated in the response to CEC 1.35.2, the FEU note that this is not an accurate representation of a long term revenue forecast. As discussed in the response to BCUC IR 1.46.4, the FEU do not prepare a twenty year revenue forecast because it would not provide meaningful information.

REVENUES ($000)	2011	2016	2021	2026	2031	2033
Reference						
Residential	812,718	734,152	706,747	699,750	694,623	689,788
Commercial	481,968	444,396	459,442	474,558	490,802	498,527
Industrial	109,221	95,942	95,075	94,022	93,104	92,594
Scenario A						
Residential	812,718	723,275	689,526	675,321	662,433	654,149
Commercial	481,968	442,420	450,729	455,607	463,557	468,194
Industrial	109,221	97,545	98,053	98,250	98,760	98,831
Scenario B						
Residential	812,718	725,607	693,135	680,669	668,093	659,809
Commercial	481,968	432,213	432,081	424,519	463,557	468,194
Industrial	109,221	87,808	86,875	85,460	84,435	83,926
Scenario C						
Residential	812,718	734,856	711,231	704,274	701,821	698,061
Commercial	481,968	451,406	477,755	508,290	542,101	557,582
Industrial	109,221	98,237	99,869	101,443	103,161	103,740
Scenario D						
Residential	812,718	723,415	692,592	676,568	664,836	657,105
Commercial	481,968	436,025	446,948	457,186	470,598	477,390
Industrial	109,221	88,470	87,126	85,625	84,390	83,800

30. Reference: Exhibit B-5, CEC 1.34.1

> 34.1 Is it FEU's expectation that there will be no significant change in the number of industrial customers through to 2033?
>
> **Response:**
>
> The FEU have not incorporated an expectation for a significant change in the number of industrial customers. Though interest from potential new industrial customers in acquiring gas service has increased recently, at the time the long term forecast was prepared there were no firm commitments for new industrial customers to take natural gas service or for existing customers to close their accounts. Hence, no growth or decline in industrial customers has been forecasted. The LTRP is updated on a regular basis. Any new industrial customers with firm commitments will be added as part of the regular update cycle.
>
> 34.1.1 If not, please provide an overview of FEU's high level expectation of the industrial sector customer growth (decline) over the next 20 years.
>
> **Response:**
>
> Please refer to the response to CEC IR 1.34.1. Please refer to Section 3.3.2 and Appendix B-3 of Exhibit B-1 for a description of how the FEU have modelled potential future changes in industrial demand outside of forecasting customer additions.

30.1 Do the FEU believe that 20 year long term resource planning must necessarily be based on firm commitments for new industrial customers at the time it is preparing its long term forecasts?

Response:

A review of the industrial customer counts since 2000 produces a plot that looks like this:

In the last decade industrial account totals have been on a very consistent decline. In 2013 there were fewer customers than at any other time this millennium. As a result, and without information on firm commitments from new customers, the FEU believe they would be imprudent to forecast an increase in industrial customers. The FEU believe that holding the 2013 total constant is appropriate pending the next update of the long term forecast.

For the purposes of long term resource planning, the FEU have considered the impact of the potential addition of large new industrial customer loads outside of the End Use Annual Demand Forecast as described in Sections 3.3.9, page 61 and 3.4.3 of the 2014 LTRP and on peak demand in Sections 5.1.2.1, 5.1.2.2 and 5.1.2.3.

30.1.1 Why would the FEU not find it useful planning to anticipate scenarios for additional industrial loads?

Response:

Please refer to the response to CEC IR 2.30.1. The FEU have found the manner in which they have considered the potential addition of new industrial loads both appropriate and useful.

31. Reference: Exhibit B-5, CEC 1.35.1

Response:

The traditional annual demand forecast methodology simply advances the trends observed in the historic data into the future. Therefore the traditional methodology forecasts a continuation of the commercial demand growth, assuming all the intrinsic factors in that demand growth will continue.

The FEU believe that the end-use forecast model is a better tool to examine a range of potential futures that can have different long-term implications of annual natural gas use in the commercial sector. The FEU's response to CEC IR 1.30.1 provides a discussion on how the role of natural gas in the commercial sector is not expected to shift substantially over the planning horizon. As such, the FEU believe that the key factor important for growing and maintaining commercial customer load will be related to the economy (i.e. a stronger economy will in general support a growing commercial sector), but that the FEU also needs help to influence commercial customer choices on energy through the types of initiatives described in response to CEC IR 1.45.2.2.

31.1 Please explain in what ways the 'FEU also needs help to influence commercial customer choices on energy' and from where this assistance might be anticipated and/or developed.

Response:

The list of activities that the FEU have provided in the response to CEC IR 1.45.2.2 contains all of the information that the FEU can provide at this time with regard to the means and nature of assistance to influence commercial customer energy choice.

1 **32. Reference: Exhibit B-5, CEC 1.35.3**

35.3 Would FEU agree that as broad characterizations, residential may be considered a declining market; commercial may be considered a growth market and industrial may be considered a stable market?

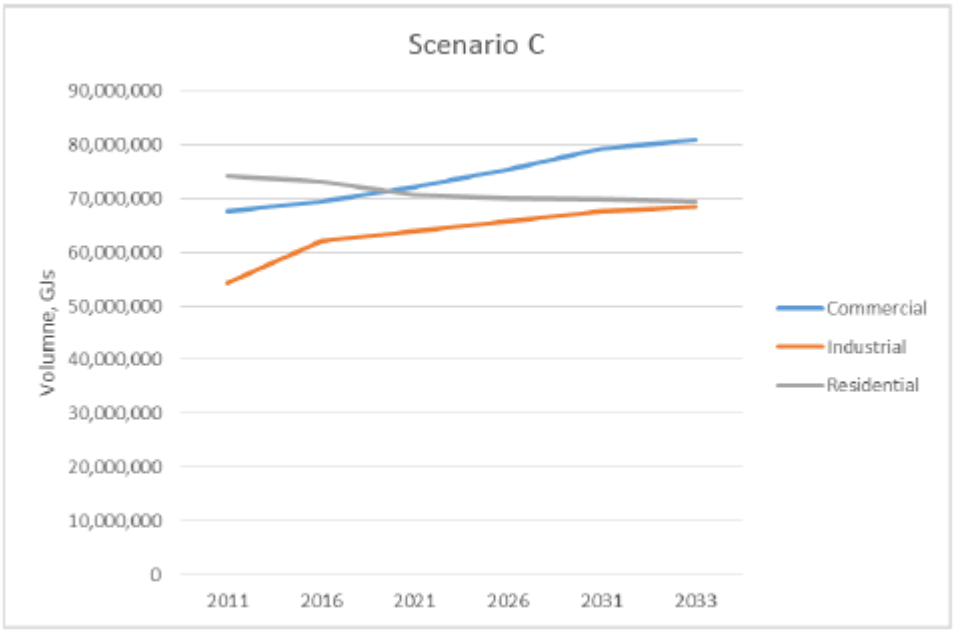
Response:

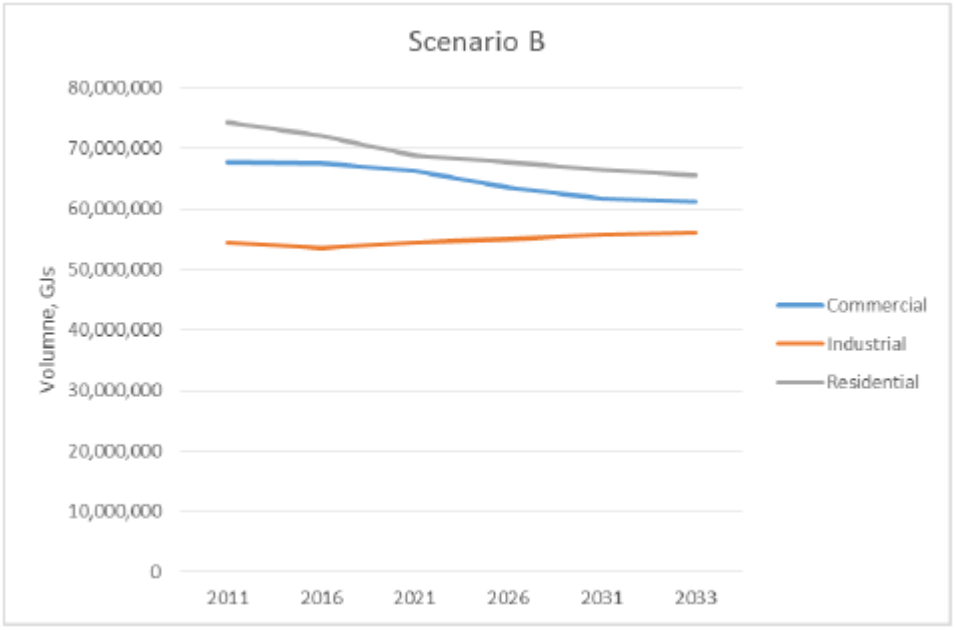
Based on the traditional forecast of energy (which is based on recent history), residential may be considered a declining market, commercial may be considered a growth market and industrial may be considered a stable market.

However based on the more sophisticated end use model, and depending on which scenario ends up most closely reflecting reality, these broad characterizations would not apply. For example, Scenario C from the end use model suggests a similar characterization as the traditional forecast while Scenario B suggests a trend where the commercial sector is stable. A chart is provided below for both of these scenarios to demonstrate the varying trends across different scenarios.

Note that these characterizations of market described in the question are in all cases based upon long term forecasts that individually may or may not occur. For example, an expanded LNG export market could change the characterization of industrial to be a growth market. Therefore these "broad characterizations" are very general and should not be taken literally.

2





32.1 The Charts provided indicate a significant directional difference for Commercial volumes in Scenarios C and B, which is not characteristic of the Residential and Industrial demand. Would FEU agree that positively influencing Commercial demand would make a significant difference to the utility core market demand over time?

Response:

The FEU does not assign probabilistic outcomes to the end use scenarios. The fact that the lowest scenario declines slightly and the highest scenario increases slightly demonstrates the range of possible commercial scenarios for which the FEU is prepared. Influencing (either positively or negatively) any single rate group over time could be expected to make a difference to the overall demand and is not unique to the commercial rate group.

32.2 Does FEU perceive the potential loss of Commercial revenue over the long term as a possible threat or the potential improvement in Commercial revenues as a potential opportunity, or do they not anticipate any change? Please explain.

Response:

Obviously the FEU perceive the potential loss of revenue over time as a threat regardless of the rate group, just as we perceive the potential improvement of revenues from any rate group as a potential opportunity. Nothing in this line of questioning is unique to the commercial rate group.

33. Reference: Exhibit B-5, CEC 1.45.2.2

> 45.2.2 If so, please identify which segments FEU has influence over consumption patterns and provide a description of the activities FEU would expect to undertake to maximize consumption in those sectors.
>
> **Response:**
>
> As stated in the response to CEC IR 1.45.2, the FEU believe that they currently have the most influence over the consumption patterns of their residential customer group, andr commercial customer groups, however the FEU do not have empirical evidence to suggest its ability to influence groups is high or low. The Companies believe that it is important to continually examine and adopt new ways of educating customers on energy choices, promoting the benefits of natural gas and providing innovative energy solutions that will meet their needs and ultimately influence their consumption patterns. Some of the activities the FEU are undertaking to this end are:

33.1 Would FEU agree that a proper understanding of the utilities' ability to influence residential and commercial demand would be an important start in managing risk and capitalizing on opportunities?

Response:

It appears from this request that the CEC have misinterpreted the responses to CEC IRs 1.45.2 and 1.45.2.2. The FEU agree with the statement that the CEC have made in this request, but clarify that they do have an understanding of the utilities' ability to influence residential and commercial customers, and they are far beyond the step of starting on the activity of managing risk and capitalizing on opportunities as is implied. However, the nature of how to influence these customer groups is complex and ever changing, given the wide range of customer needs and other customer characteristics involved, combined with an ever changing planning environment. As such, while the FEU do believe that continuing efforts to improve their understanding of how to influence these customer groups are very important, they do not purport to have perfect information on which to plan nor that acquiring perfect information is actually achievable. In addition to the continuous feedback that the Companies seek from customers through various means, the FEU are undertaking residential and commercial end use studies that will inform the next CPR and should offer updated insights into how to influence these customer groups.

33.2 If so, what plans does FEU have to develop such information, particularly for the Commercial market?

Response:

Please refer to the response to CEC IR 2.33.1.

33.2.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 2.33.1.

34. Reference: Exhibit B-5, CEC 1.35.4.1

> As a result of this end use pattern it is FEU's opinion that over the short term, commercial customers are not price sensitive. Commercial customers that use natural gas for space heating are weather sensitive and do not typically adjust thermostat settings based on gas prices. However, over the long term, although the literature on price elasticity for the commercial sector is limited, what is available suggests a value of approximately -0.5. Thus, a 5% increase in gas prices would tend to decrease commercial consumption by approximately 2.5% over the long term. Please refer to the commercial tables for each scenario in Appendix B-3 of Exhibit B-1 for a discussion of how this was accounted for in the end use annual demand forecasting methodology.

34.1 Would FEU agree that the price insensitivity of the commercial sector is likely to be significantly determined by the inability to substitute electricity easily and at reduced costs?

Response:

The FEU do not have the necessary empirical data to either support or refute whether or not price insensitivity is determined significantly by a customer's ability to substitute electricity for natural gas easily and at reduced costs. Over the longer term, the FEU believe that many factors have potential to influence the energy decisions that commercial customers will make.

34.1.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 2.34.1.

34.1.2 If so, would FEU agree that the future of electricity prices relative to natural gas will play a significant role in securing the demand for natural gas in the Commercial sector?

Response:

The FEU believe that the relative difference between electricity and natural gas costs for the customer is one factor that will affect the demand for natural gas in the Commercial sector. Other factors such as government policy, societal perceptions, new technologies and the economy could also play an important role.

34.2 Please explain how FEU factored in the forecast of electricity prices into its Commercial demand scenarios.

Response:

Please refer to the response to BCUC IR 2.18.2.

35. Reference: Exhibit B-5, CEC 1.35.4.1 and CEC 1.45.4

> As a result of this end use pattern it is FEU's opinion that over the short term, commercial customers are not price sensitive. Commercial customers that use natural gas for space heating are weather sensitive and do not typically adjust thermostat settings based on gas prices. However, over the long term, although the literature on price elasticity for the commercial sector is limited, what is available suggests a value of approximately -0.5. Thus, a 5% increase in gas prices would tend to decrease commercial consumption by approximately 2.5% over the long term. Please refer to the commercial tables for each scenario in Appendix B-3 of Exhibit B-1 for a discussion of how this was accounted for in the end use annual demand forecasting methodology.
>
> 45.4 Please confirm or otherwise explain why there are mitigating circumstances between sectors for each scenario such that a worst case scenario would not arise or a better case scenario would not arise.
>
> **Response:**
>
> There is no directional consistency between sectors because key assumptions are not equally significant to all sectors. For example, economic growth is a much stronger driver in industry than it is in the residential sector. Similarly, price sensitivity has a much larger effect on commercial demand than it has on residential volume. Whereever two influences exist that push in opposite directions (in terms of an expected consumption effect), their net effect will not be the same for all sectors. This is not an intentional mitigating factor. It is simply the result of the best interpretation FEU can make of the effects that the scenario assumptions have in each sector; the FEU believe that this interpretation of the scenario assumptions leads to realistic and plausible results. On the other hand, the arbitrary combination of highs and lows solely for the purpose of creating more extreme upper and lower bands is unrealistic and results in a less precise range than the model is capable of delivering.

35.1 Please reconcile the statements that commercial customers are not price sensitive over the short term, and that limited literature is available for long term elasticity assessment, with the statement that price sensitivity has a much larger effect on commercial demand than it has on residential volume.

Response:

As discussed in the response to CEC IR 1.35.4.1 the long term elasticity used for commercial was -0.5. A 5 percent increase in gas prices would result in a 2.5 percent decline in long term commercial consumption.

The long term elasticity used for residential customers was -0.2. A similar 5 percent increase in gas prices would result in a 1 percent decline in long term residential consumption.

-0.5 is 2.5 times larger than -0.2 so price sensitivity has a much larger effect on commercial demand than it has on residential demand. The FEU do not believe there is a contradiction between the two IR responses as suggested in the question.

36. Reference: Exhibit B-5, CEC 1.36.1

> 36.1 What drivers other than those listed also contribute to a lower of the UPC on the residential side?
>
> **Response:**
>
> The main drivers of lower residential use rates are shown. FEU does not have nor require specific data on the drivers or their impact because all drivers are implicit in the historic data we use to prepare future forecast. The "not limited to" clause is intended to account for any and all intrinsic factors that we may not be specifically aware of. The forecast is updated on a regular basis so all drivers and their precise effects are always captured in the recent historic data used.

36.1 Does FEU expect the UPC to continue to decline over the planning horizon or expect it to stabilize over the next several years? Please explain.

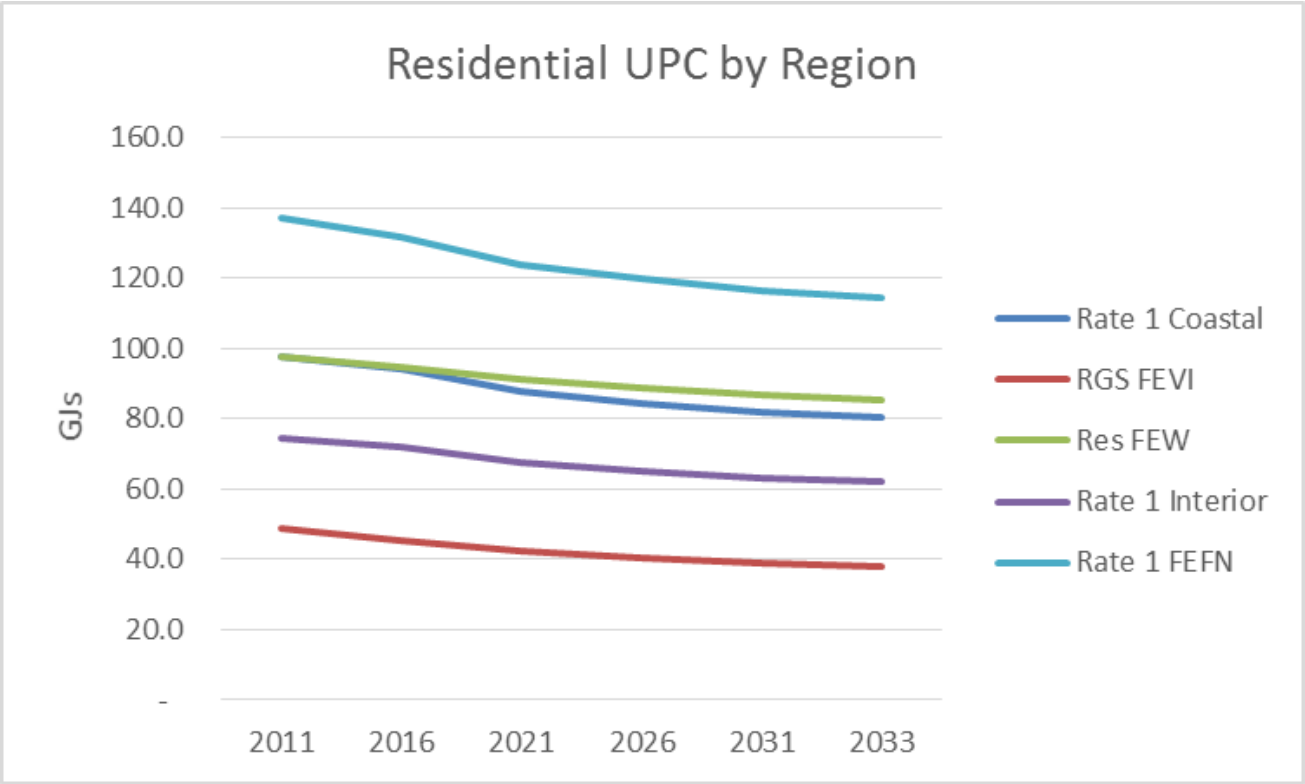
Response:

Please see the twenty Demand Forecast Tables in Appendix B-1 of the filing. These tables present UPC forecasts for all rates, all regions, all scenarios and all years.

36.2 Please provide a chart depicting the Use Per Customer (UPC) for each of the FEU regions.

Response:

Please see the chart below.



36.3 Are there different factors influencing UPC trends in each region?

Response:

Future regional UPC trends are affected by the initial pattern of housing types and the differences in expected customer additions.

For example, the End Use Forecast used information from the Residential End Use Study (REUS) focusing on homes built since 2006 that suggested new dwellings on Vancouver Island commonly do not use gas for space heating or domestic hot water. The REUS also suggested the primary gas end uses included only a fireplace and/or barbecue. The End Use Forecast assumed that new houses being built there would continue to follow that pattern and therefore use less gas than older homes in the same region. The REUS did not show that new houses in other regions were nearly as commonly lacking a furnace and gas DHW. As a result, the end use forecast shows UPC falling more quickly in the Vancouver Island region as more and more of these new houses without furnace and DHW get added to the model. The UPC in other regions declines relatively slower, reflective of these factors in the end use model.

In addition, there are also predictable changes in the individual end uses that would vary by region. For example, the average efficiency of furnaces is lower in the Lower Mainland than it is in Whistler. Therefore, as old furnaces get replaced by new ones, with a mandated efficiency of at least 90 percent, the reduction in UPC observed in the Lower Mainland will be relatively larger.

36.3.1 If so, please provide a discussion of the factors influencing UPC in each region and how the FEU predicts these to change over time.

Response:

Please refer to the response to CEC IR 2.36.3.

36.4 Does FEU consider declining residential UPC to be a significant risk factor over the planning horizon? Please explain why or why not.

Response:

Yes. Declining residential UPC contributes to less throughput on the FEU's system and puts upward pressure on customer rates.

36.5 Does FEU expect that there are limitations on the factors that contribute to declining UPC such as saturation of multifamily dwellings?

Response:

The FEU do not have any expectations about limitations to the factors that contribute to declining UPCs. The forecast is informed by frequent updates and data from our own customers. As such expectations of limitations are not required. We measure, survey and update the model. The model provides the results and those results are used for planning. If an expectation of a limitation existed it could be seen as conspiring against the purpose of the modelling activity.

36.5.1 If so, what are they?

Response:

Please refer to the response to CEC IR 2.36.5.

36.5.2 What factors would FEU expect could contribute to a reduction in the declining residential UPC?

Response:

The FEU expect that factors such as large-scale residential customer additions; construction of larger, more energy-intensive dwellings with gas space and water heating; reduced uptake of efficient residential gas appliances; policies to encourage the use of natural gas; policies that allow for electric-to-gas fuel switching; and lower natural gas prices could serve to reduce the declining residential UPC.

37. Reference: Exhibit B-5, CEC 1.40.1

> The scenario descriptions provided in Table 3-1 of Exhibit B-1 describe the implications for how complementary and competing energy sources will impact natural gas demand in each of the future scenarios. Complementary energy sources such as renewable thermal energy systems combined with natural gas systems at the end use will result in less demand growth for natural gas than will conventional natural gas systems. Though not specifically described in Table 3-1, the use of natural gas in distributed combined heat and power situations would increase demand. The use of natural gas as a generation fuel to back up or complement renewable types of generation in larger generating stations would be considered a new large industrial customer and was considered outside of the residential, commercial and industrial annual demand forecast scenarios. Competing energy sources, primarily electricity generated by other means or fuels than natural gas, would serve to decrease the demand for natural gas to a greater or lesser extent within the different scenarios.
>
> In order to include these implications in the end use annual demand forecasting model – for example the degree to which renewable thermal energy would displace natural gas – judgments were made about the extent to which natural gas demand would be impacted up or down in each of the scenarios. These judgments were made exogenous to the model, converted to model inputs and followed up with a check for reasonability as to the model outputs. This work was conducted in partnership with the FEU's forecasting model consultants. Appendix B-3 of Exhibit B-1 contains a complete description of how the scenario descriptions were converted to model assumptions and entered into the end use forecasting model.

37.1 Please provide the quantitative impacts modelled in Appendix B-3 and indicate whether or not the FEU consider these impacts to be important and/or meaningful to the FEU natural gas business over the planning time frame.

Response:

The FEU are unclear as to what "quantitative impacts" are requested in this question. The data provided in Appendix B-3 was used to create the long term annual demand forecasts by scenario shown in Figure 3-6 in the 2014 LTRP. Thus, the quantitative impacts modelled in Appendix B-3 are presented in Figures 3-6 through 3-11 and Appendix B-1 of the LTRP. The FEU consider the long term annual demand forecasts as an essential tool to ensure that the Utilities have the appropriate resources in place to meet customer needs across the range of future demand scenarios over the planning period.

38. Reference: Exhibit B-5, 1.45.2.2

- Establishment of the FortisBC Trade Ally Network, through which the FEU presently assist customers in finding local, qualified contractors that can safely install and service energy efficient natural gas appliances (for residential and commercial customers);
- A review of the Main Extension test involving customers and other stakeholders to identify potential updates that reflect the needs of current and future customers in pricing connection services (for all customers);
- Providing customers with incentives to promote the adoption of natural gas for transportation applications (for commercial and industrial customers);
- Offering a Renewable Natural Gas program to provide customers with an option to purchase a biomethane-blended natural gas supply (for residential and commercial customers);
- Offering high carbon to low carbon fuel switching incentives (Switch n Shrink) to encourage conversion from propane and fuel oil to natural gas (residential customers);
- An energy calculator to assist customers in understanding their natural gas consumption (for residential customers);
- Advertising that promotes the benefits of using natural gas (for residential and commercial customers);
- Enhancing customer experience in conducting business with the FEU; and
- Exploring advanced metering technologies that could improve customer experience and help them manage their own consumption patterns.

38.1 What types of potential updates does Fortis anticipate for the Main Extension test? Please explain.

Response:

The FEU are currently engaged with stakeholders, including CEC, in a review of the Main Extension (MX) test. Any potential updates to the MX will depend on the input from stakeholders involved in the MX test review process that is underway.

Thus far, two workshops have been completed resulting in the creation of a term of reference and guiding principles document that was forwarded to CEC following the second workshop on June 18, 2014. A third workshop is planned for October 2014.

At the end of the consultation period, the FEU have tentatively planned to submit an MX application to the Commission.

38.2 What is the total estimated annual cost of providing these activities?

Response:

The FEU point out that the Long Term Resource Plan is not seeking approval for any costs related to the activities listed above. Further, the FEU do not track their costs in a manner that allows for a full breakout of costs specifically for these activities. The FEU note, however, that these activities are managed within the Energy Solutions and External Relations department. This department had operating and maintenance expenses of approximately $19 million in 2013.[3]

38.3 How does the energy calculator promote the use of natural gas for residential customers?

Response:

The energy calculator serves to educate residential customers about the energy use and related costs to operate various appliances in a home. The Company believes that this type of education leads to more informed decisions by customers.

For example, customers are able to determine by using the energy calculator than a high efficiency natural gas furnace is less expensive to operate than electric baseboards. In this example, the information available from the energy calculator would thereby promote the use of natural gas for space heating over the electric alternative.

38.4 What activities does FEU undertake to improve the capture of multifamily dwellings?

Response:

As discussed in the PBR application, FEU Energy Solutions managers work with the builder/developers from building permit stage to determine the specific energy requirements for their specific building. FEU offers recommendations that incorporate natural gas equipment to

[3] See Exhibit B-1-5, Table 1, FEI 2014-2018 PBR Application, Evidentiary Update dated February21, 2014.

meet the builder's technical requirements along with offering programs such as individual metering of suites and Piping to Suites (The FEU own a portion of the piping that runs between the meter and the exterior of each suite). The FEU also offer marketing collateral to support the builder/developer's sales team when talking to a prospective buyer about the features and benefits of natural gas equipment. The FEU also work with many of the builders/developers to develop testimonial material of projects that incorporated natural gas equipment.

While these efforts are proving to be effective, this market segment continues to be a significant challenge due mostly to the fact that competing heating and hot water equipment fueled by electricity costs significantly less to install when compared to natural gas.

38.5 Has FEU established any targets for increasing the capture of multifamily dwellings?

Response:

This response covers CEC IRs 2.38.5 and 2.38.5.1.

Yes. Targets are set in relationship to the level of annual market capture. Our current annual capture rate on multifamily buildings is approximately 30 percent. Since the construction of large multifamily project is quite lengthy, our target is to raise the natural gas annual capture rate to 50 percent.

Annual capture rate is defined as the amount of completed new buildings in a given year as compared to the number of completed new buildings with gas service.

38.5.1 If so, please provide.

Response:

Please refer to the response to CEC IR 2.38.5.

39. Reference: Exhibit B-5, CEC 1.46.6

> 46.6 Does FEU propose to revise its long term end-use demand forecast based on changes in policy or other inputs as they arise?
>
> **Response:**
>
> Confirmed.

39.1 How will the Commission and customers be made aware of changes to the long term end-use demand forecasts?

Response:

The Commission and customers (if interested) are made aware of changes to the long term end use annual demand forecasts in the same way that they have been made aware in the past of changes to the traditional long term annual demand forecast; through the long term resource planning process and the Long Term Resource Plan submission.

39.2 To the extent that the Commission must consider the LTRP in its approval of future applications, will the Commission and customers be able to evaluate changes made to the end-use demand forecast?

Response:

Please refer to the response to BCUC IR 2.39.1.

40. Reference: Exhibit B-5, CEC 1.47.2

> 46.2 Please confirm or otherwise explain that FEU intends to retain the traditional method for short-term planning purposes.
>
> **Response:**
>
> Confirmed. Please refer to the response to CEC IR 1.42.1.

40.1 What is the longest time frame FEU would consider as being part of 'short term' planning, such that they would employ the traditional method?

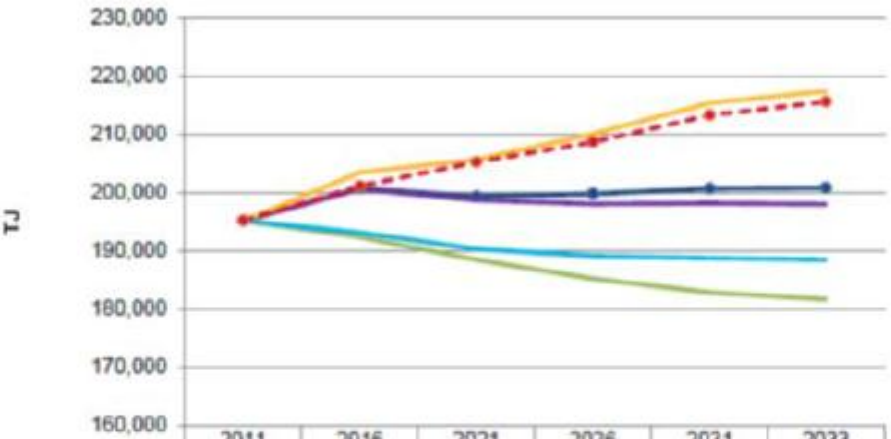
Response:

The longest timeframe the FEU would consider as being part of short term planning is 5 years.

To clarify, the FIS model is used for short term volume and revenue forecasts of 5 years duration or less. As confirmed in the response to CEC IR 1.46.2, the FEU intend to retain the traditional method in the FIS model.

41. Reference: Exhibit B-1, Page 56; Exhibit B-5, CEC 1.47.1

Figure 3-12: Traditional Versus End-Use Demand Forecast Results – Total Demand, All Regions



	2011	2016	2021	2026	2031	2033
Reference	195,122	200,735	199,304	199,777	200,679	200,817
Scenario A	195,122	200,577	198,662	198,022	198,136	197,961
Scenario B	195,122	192,333	188,399	185,148	182,773	181,608
Scenario C	195,122	203,393	205,630	210,022	215,388	217,430
Scenario D	195,122	193,094	190,242	189,060	188,709	188,378
Traditional	195,122	201,083	205,183	208,653	213,293	215,604

47.1 Please provide FEU's interpretation of the meaning and/or usefulness of Scenarios B and D given their divergence from the traditional trajectory in the short term.

Response:

Any model that is capable of producing a range of results will by definition deviate from a model that is incapable of producing such a range. The traditional model produces a single line. The end use model produces multiple lines. They cannot all lie on top of one another. The range of volumes from the End Use forecast are simply the results of the best interpretation FEU could make of the effects the scenario assumptions have in each sector.

Each of the scenarios permits the FEU to explore the implications of a different set of economic circumstances to the Companies' physical infrastructure. In devising the scenarios, the FEU in consultation with its advisory group, wanted to explore the range of possible circumstances in which it may have to operate in the future. Each of the scenarios provides insight into how customers are likely to respond to a different possible future environment. These insights

41.1 Given the proximity of the 'traditional' method forecast to Scenario C, is it FEU's view that the 'traditional scenario' effectively represents the upper bound of what is reasonably likely to occur over the next twenty years, excluding NGT and LNG?

Response:

No, this is not the FEU's view.

41.1.1 If not, please explain why not.

Response:

The Traditional forecast was computed for the purpose of establishing the reasonableness of the End Use Model as per Commission Order No. G-14-11. Given that the Traditional model results lie between the highest and lowest case of the End Use Model it is the FEU's belief that the End Use Model is reasonable.

The Traditional Model does not support the specific use rate changes for each end use and the FEU believe this results in an over estimation of the base case for the 2014 LTRP.

Owing to the entirely different methodologies employed by the two models, the FEU do not see the value of making any other comparisons.

The FEU intend to continue to collect the best and most current end use information directly from our customers through the use of end use surveys. The results from those surveys will continue to be used to improve the predictive capability of the end use model. Scenario development will continue without any preconceived notion of where we want the results to fall. The FEU believe that a combination of robust inputs with an equally robust model perturbed by a range of reasonable scenarios of how the future could unfold will lead to the best and most realistic estimate of future demand.

The FEU do not intend to arbitrarily limit the upper bound of future forecasts to the results from the Traditional model.

41.1.2 If so, please confirm that FEU does not intend to conduct long range planning for possibilities of demand significantly above the traditional scenario.

Response:

Please refer to the response to CEC IR 2.41.1.

41.2 If FEU were using the 'traditional method' for its long range forecasts, would FEU consider the ramifications of higher demand as part of its sensitivity or risk analysis?

Response:

The FEU refer the reader to the 2010 LTRP in which the traditional methodology was used and the End Use Model was not. In the 2010 LTRP a high and low scenario were applied to the base case results from the Traditional model.

All modelling, whether Traditional, End Use or some other method should be able to start with a base forecast and then perturb that forecast with what should be reasonably plausible scenarios. The scenarios developed for the Traditional method were not as robust or well informed as those developed for the End Use Model. Further, only two scenarios in addition to the base case were developed for the Traditional method and those were understood ahead of time to be the "high" and "low" case. With the End Use Model the scenarios are described and coded. There was no preconceived notion of which one would produce the highest or lowest result and that is a distinct advantage of the End Use Model.

41.3 Please provide the sensitivities that FEU would previously have likely applied to the traditional forecast for its planning purposes, i.e., +/- 20%.

Response:

The FEU again refer the reader to the 2010 LTRP in which the Traditional Annual Demand forecast methodology was used and the End Use Model was not. The High and Low annual demand scenarios in the 2010 LTRP resulted in a high case that was 19 percent higher than the base case and a low case that was 13 percent lower than the base case at the end of the 20 year planning horizon. The FEU do not intend to use the traditional methodology for the base case or high and low variations going forward.

42. Reference: Exhibit B-1, Page 102; Exhibit B-5, CEC 1.66.1

the primary service is required. Figure 5-2 shows the peak demand and capacity balance for FEVI with 2012 base case long range forecast, Core design day demand, and daily transportation requirements for VIGJV mills (12 TJ/d, 2013 onwards) and BC Hydro's IG (50 TJ/d, 2014 onwards). Since the daily demand from natural gas vehicles is forecast to be small relative to other loads, it does not show up in the demand graph. This graph shows a capacity constraint on the FEVI transmission system by 2028.

66.1 Please provide a graph and the annual data points for the VIGJV contract demand for the last 15 years.

Response:

The requested information is provided below.

VIGJV Contract Demand History	
Jan-96	40.0 TJ/day
Nov-98	36.0 TJ/day
Apr-00	37.6 TJ/day
Jan-05	20.0 TJ/day
Jan-06	12.5 TJ/day
Apr-07	9.1 TJ/day
Aug-08	8.0 TJ/day
Nov-12	12.0 TJ/day

42.1 Why does FEU expect the VIGJV Contract demand to remain at 12.0 TJ/day from 2013 onwards when it has varied quite significantly over the last ten years? Is it because BC Hydro is anticipating a significant surplus of energy into the future?

Response:

For planning purposes, the FEU have assumed that the VIGJV Contract Demand will remain at 12 TJ/day based on the terms of the current agreement with VIGJV. Any reinstatement of Contract Demand above 12 TJ/d will be on an annual renewal basis and as such, cannot be determined at this time. The current agreement is in place until December 31, 2017.

43. Reference: Exhibit B-5, CEC 1.68.1

> 68.1 Please confirm that amalgamation will turn the storage and delivery agreement between FEIV and FEI into an allocation between rate classes not regions. Please discuss.
>
> **Response:**
>
> Although FEI is still in the process of determining the final details of Amalgamation, it is expected that the costs of the Mt. Hayes LNG facility that are currently allocated to gas costs for FEVI and FEI will continue to be included as part of gas costs in the combined gas supply portfolio. This means that these costs will be treated as a midstream component; there will be no regional allocation of midstream costs however midstream costs will be allocated between rate classes on a demand-related basis.

43.1 Please confirm that the demand-related basis will be directly proportional to demand on the basis of volume.

Response:

Confirmed.

43.2 If not confirmed, how would FEU allocate the costs between rate classes?

Response:

Please refer to the response to CEC IR 2.43.1.

44. Reference: Exhibit B-1, Page 150

> The FEU's long term vision is to be B.C.'s trusted energy provider for safe, reliable and cost-effective natural gas delivery services to their customers, and to be a healthy, growing contributor to B.C.'s economy and to the well-being of B.C.'s communities. As such, the FEU have examined a broad range of future potential conditions under which it must realize this vision. The FEU's approach has been to identify a set of resources to acquire that will meet the range of potential futures analysed rather than to attempt to predict a most likely future and plan only to that future, since the likelihood of correctly predicting the future is low.

44.1 Has it been FEU's practice in the past to attempt to predict a most likely future plan and plan only to that future?

Response:

No, the FEU's practice in the past has been to attempt to predict a most likely future scenario (Reference Case) and to plan within the range of a Robust Growth and Low Growth scenarios around the reference case. To develop these additional scenarios, input assumptions from the Reference Case forecast were altered to illustrate the effect of additional or less consumption that could occur beyond the level set by the Reference Case.

44.1.1 If not, how has FEU managed to plan for a variety of circumstances in the past?

Response:

Please refer to the response to CEC IR 2.44.1.

44.2 Do any of the Scenarios A, B, C or D include anticipation of new LNG export demand in the lower mainland area?

Response:

No, the consideration of potential new large industrial demand could not be gleaned from the end use trends of our existing customers and so was considered separately from the scenarios of residential, commercial and industrial demand. Consideration of new large industrial demand

on annual demand expectations is presented in Section 3.3.9, page 61 of the 2014 LTRP and the discussion of the impact of potential new large industrial demand on peak demand expectations is presented in Section 5.1.2.1, page 105; Section 5.1.2.2, page 113; and Section 5.1.2.3, page 119 of the 2014 LTRP.