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June 19, 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. 1

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. 1.

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)

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

1. Reference: FEU Exhibit B-1, Executive Summary page ES-1

> The long term vision of the FortisBC Energy Utilities (FEU, Utilities or Companies)[1] is to be B.C.'s trusted energy provider for safe, reliable and cost-effective natural gas delivery services, and to be a healthy, growing contributor to B.C.'s economy and to the well-being of B.C.'s communities. This 2014 Long Term Resource Plan (LTRP) presents a long term view of how the FEU will meet future demand and reliability requirements at the lowest reasonable cost to customers over the next 20 years.

1.1 Please provide FEU's definition of lowest reasonable cost.

Response:

In this context, the FEU define the phrase 'lowest reasonable cost' to be synonymous with 'cost-effective'. Please refer to the response to BCUC IR 1.8.1 for discussion of cost effectiveness.

1.2 Please provide FEU's interpretation of 'lowest reasonable cost' with respect to cost recovery, return on equity and return of capital.

Response:

The cost component of the cost-effectiveness consideration takes into account the recovery of the costs themselves and, if applicable, a return on the costs calculated at the Companies' approved return on equity. Please also refer to the response to CEC IR 1.1.1.

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.

1.3.1 If so, please explain how FEU differentiates between customer groups with respect to lowest reasonable cost.

Response:

Please refer to the response to CEC IR 1.1.3.

1.3.2 If not, please explain why not.

Response:

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.

1.4 Please define 'growing contributor to BC's economy'.

Response:

The FEU aim to be a growing contributor to B.C.'s economy in the sense that, as an energy services provider that is located in B.C., operates in B.C. and provides services in B.C., the FEU aim to grow the Companies' business by adding new customers, growing the Utilities' service offerings, and providing jobs to citizens in B.C. and taxes to municipal and provincial governments, supporting communities and conducting business within BC.

1.5 Please define FEU's view of the measure of the well-being of BC's communities.

Response:

Consideration of the term "well-being" in this context refers to the role that the FEU can play in ensuring the provision of safe, reliable and cost effective energy services that meet the needs of communities as well as contributing economically to communities by conducting business in those communities and employing people who live in those communities. The term is not intended as criterion against which a detailed list of measurements is applied.

The FEU are committed to building strong relationships with customers, communities, stakeholders and Aboriginal groups by providing cost effective energy solutions, promoting energy safety, giving back to communities and caring for the environment. The FEU connect with communities across the FEU's service area through public safety and community giving programs. For example, the FEU support educational campaigns in schools, such as the "Energy is Awesome" campaign designed to educate children aged eight to eleven about natural gas and electricity safety and conservation. The FEU's "give where you live" program and Community Giving Days encourage employees to volunteer for social and environmental projects in their communities. Through the FEU's Community Investment Program, the FEU provides funding for a variety of community initiatives. The FEU also work closely with First Nation and Aboriginal communities through programs such as the REnEW program, which works with community groups throughout B.C. to train marginalized individuals to work in the field of energy efficiency retrofitting.

1.6 What plans does FEU have to contribute to the well-being of BC's communities.

Response:

Please refer to the response to CEC IR 1.1.5.

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

> The long term vision of the FortisBC Energy Utilities (FEU, Utilities or Companies)[1] is to be B.C.'s trusted energy provider for safe, reliable and cost-effective natural gas delivery services, and to be a healthy, growing contributor to B.C.'s economy and to the well-being of B.C.'s communities. This 2014 Long Term Resource Plan (LTRP) presents a long term view of how the FEU will meet future demand and reliability requirements at the lowest reasonable cost to customers over the next 20 years.

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.

3. Reference: FEU Exhibit B-1, Executive Summary page ES-1

> The FEU's resource planning process proceeds through several planning stages: examining the planning environment, forecasting energy needs, examining demand-side management potential and options to meet needs for system growth and sustainment, conducting portfolio analyses and ultimately, developing a four-year action plan to act on the plan's recommendations. Throughout this iterative and on-going process, the Utilities engage customers and stakeholders in order to capture valuable insight and to help ensure that customer and stakeholder needs are met.

3.1 Please confirm that the submission of the LTRP is the final step in the resource planning process.

Response:

Not confirmed. BCUC acceptance of the LTRP is the final step in the LTRP process. Nevertheless, the FEU view resource planning as an iterative and ongoing process. Any insight gained from engaging customers and stakeholders in the previous resource planning process, or through the regulatory review process of the current plan, will inform the next planning process.

3.1.1 If not confirmed, what additional steps will be undertaken after the review of the Long Term Resource Plan process to finalize the resource planning process?

Response:

Please refer to the response to CEC IR 1.3.1.

3.2 How does FEU propose to make use of the LTRP internally?

Response:

Generally, the LTRP and relevant analyses conducted to prepare the LTRP are used internally to inform business planning decisions, the identification of business and market risks and opportunities, decisions on demand and supply side resource needs, corporate strategy and to identify areas of additional research and analysis that will assist the business in making the above mentioned decisions.

3.3 Please list the customer and stakeholders needs that have been identified throughout the iterative process.

Response:

Through the iterative LTRP process, customer needs have been identified as follows:

- Delivery of safe, secure and cost-effective energy supply;
- Access to innovative energy services;
- Access to demand-side resources to assist in reducing consumption and managing energy costs.

The FEU's Resource Planning Advisory Group (RPAG) also identified the need to develop reasonable assumptions in the 2014 LTRP analysis such as identifying critical uncertainties that led to development of scenario inputs for the end-use annual demand forecasting approach. The RPAG also provided input to FEU's consideration of the potential market transformation of NGT activities in B.C. and many other valuable insights through questions and discussions during RPAG workshops.

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.

3.4 Please explain how each of the customer and stakeholder needs was addressed.

Response:

From a long term resource planning perspective, customer and stakeholder needs were addressed by examining a range of plausible future annual and peak demand scenarios and identifying appropriate demand and supply resources that will ensure that the FEU can provide safe and secure energy supply and innovative, responsive energy services through the planning horizon.

4. Reference: Exhibit B-1, Page ES-1

energy services. The FEU's resource planning objectives are to:

- Ensure a safe, reliable and secure energy supply;
- Provide innovative and cost-effective energy solutions;
- Provide cost-effective energy efficiency and conservation initiatives;
- Contribute to provincial energy objectives and emission targets; and
- Consider a range of possible future conditions.

4.1 Please describe whether or not the FEU's planning objectives involve identifying potential risks and or prevention and mitigation plans to manage risk.

<u>Response:</u>

Please refer to the response to BCUC IR 1.9.1.

4.2 If the planning objectives were to include identifying and managing risks please provide a complete and comprehensive list of the risk areas which may be of concern.

<u>Response:</u>

Please refer to the response to BCUC IR 1.9.1.

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

> The FEU submit this 2014 LTRP under Section 44.1(2) of the *Utilities Commission Act* (*UCA* or *Act*) and are not seeking approval of any particular elements of the plan. Any requests for approval of specific resource needs that are identified within this plan will be further evaluated and brought forward at the appropriate time for approval under different sections of the *Act*.

For convenience the portion of the UCA Section 44.1 (2) is provided below as a reference for the questions that follow.

Long-term resource and conservation planning

44.1 (1) [Repealed 2010-22-65.]

(2) Subject to subsection (4), a public utility must file with the commission, in the form and at the times the commission requires, a long-term resource plan including all of the following:

(a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

(e) information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);

(f) an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures;

(g) any other information required by the commission.

(3) The commission may exempt a public utility from the requirement to include in a long-term resource plan filed under subsection (2) any of the information referred to in paragraphs (a) to (f) of that subsection if the commission is satisfied that the information is not applicable with respect to the nature of the service provided by the public utility

(4) [Repealed 2010-22-65.]

(5) The commission may establish a process to review long-term resource plans filed under subsection (2).

(6) After reviewing a long-term resource plan filed under subsection (2), the commission must

> (a) accept the plan, if the commission determines that carrying out the plan would be in the public interest, or
>
> (b) reject the plan.

(7) The commission may accept or reject, under subsection (6), a part of a public utility's plan, and, if the commission rejects a part of a plan,

> (a) the public utility may resubmit the part within a time specified by the commission, and
>
> (b) the commission may accept or reject, under subsection (6), the part resubmitted under paragraph (a) of this subsection.

(8) In determining under subsection (6) whether to accept a long-term resource plan, the commission must consider

> (a) the applicable of British Columbia's energy objectives,
>
> (b) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,
>
> (c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and
>
> (d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(9) In accepting under subsection (6) a long-term resource plan, or part of a plan, the commission may do one or both of the following:

> (a) order that a proposed utility plant or system, or extension of either, referred to in the accepted plan or the part is exempt from the operation of section 45 (1);
>
> (b) order that, despite section 75, a matter the commission considers to be adequately addressed in the accepted plan or the part is to be considered as conclusively determined for the purposes of any hearing or

proceeding to be conducted by the commission under this Act, other than a hearing or proceeding for the purposes of section 99.

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.

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

> Energy and climate policy provides the framework through which the Utilities deliver customer energy needs and, at the same time, can heavily influence the energy choices that customers make. As policymakers balance economic concerns with a previous, ambitious climate policy agenda, today's policy and regulatory context de-emphasizes carbon pricing and focuses more heavily on sustainable energy solutions. As a result, natural gas is increasingly viewed as a fuel that can be used to help reduce greenhouse gas (GHG) emissions by displacing more carbon-intensive fuels (such as diesel and gasoline in transport applications and coal in power generation), provide firm backup for renewable energy, as well as present the ability to mitigate customer rate impacts from electric rate increases.

6.1 Please provide the evidence for using natural gas as a firm backup for renewable energy.

Response:

Natural gas is commonly known to be a cost-effective, reliable firm back-up for renewable intermittent electricity sources such as wind and solar. For example, the Center for Climate and Energy Solutions (C2ES) in its June 2013 report, "Leveraging Natural Gas to Reduce GHG Emissions," (cited in the 2014 LTRP and filed in response to BCSEA IR 1 11.12) states:

> *"Natural gas can provide baseload, intermediate, and peaking electric power, and can thus meet all types of electrical demand. It is an inexpensive, reliable, dispatchable source of power that is capable of supplying firm backup to intermittent sources such as wind and solar."* (pg. 25)

> *"In fact, wind and gas benefit from each other because they both mitigate each other's worst problems. For wind, intermittency is a problem, and for natural gas, price volatility has been a problem historically. It turns out that the ability for natural gas power plants to serve as rapid response firming power is an effective hedge against wind's intermittency. And, it turns out the fixed fuel price (at zero) of wind farms is an effective hedge against natural price volatility. Thus, they are complementary partners in the power markets."* (pg. 31)

The Northwest Gas Association "2014 Natural Gas Outlook" (Exhibit A2-1) also notes:

> *"A significant driver in the region's gas-fired generation growth has been the development of wind generation. The Renewable Portfolio Standards (RPS) of Oregon, Washington and California catalyzed the construction of nearly 8,000 MW of wind generation in the Northwest. Intermittent renewable resources – like wind and solar – require backup generation that can deliver electricity on demand. Public policy directly and indirectly limits options for consistent generation resources like coal and nuclear facilities while natural gas generation meets emissions and other environmental standards.*

Permitting a natural gas power plant is fairly straight forward and the costs of construction are predictable. The ability to produce natural gas from shale formations has yielded an abundant natural gas resource along with lower, more stable natural gas prices forecast well into the future.

When these dynamics are taken together, it's no wonder we are relying more and more on clean, safe and plentiful natural gas to fuel the generation of electricity. In fact, gas-fired generation has come right along with wind development in the region.

Due to limits on the Northwest hydropower system, the task of balancing wind generation is increasingly falling to natural gas generation units." (pg. 11)

As noted in Appendix B-2 of the FEU's 2014 LTRP, conventional natural gas is also used as a firming source for renewable thermal applications. Thermal energy solutions include renewable energy systems such as geo-exchange, waste heat, recovery and solar thermal energy. Designing a thermal energy system to meet demand on every single day of the year, including the coldest day, is cost-prohibitive. Therefore, such systems are typically designed to meet thermal energy demand for approximately 50% to 70% of peak day requirements, including a portion of the base load. This type of system can therefore serve approximately 80% to 90% of a customer's annual demand, and less in colder years. The remaining demand is then supplemented by conventional energy systems, which the FEU believe is best met by natural gas where it is available.

6.2 Please explain whether or not by renewable energy the FEU mean renewable electric energy or just renewable thermal energy or both and or something other than those as well.

Response:

The statement in the preamble is a general statement that applies to renewable electricity and renewable thermal energy applications.

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.

Designing a renewable thermal energy system to meet demand on every single day of the year, including the coldest day, is cost-prohibitive. Therefore, such systems are typically designed to meet thermal energy demand for approximately 50% to 70% of peak day requirements, including a portion of the base load. For renewable thermal applications, conventional natural gas boilers and furnaces can be integrated with the renewable thermal system to provided firm thermal energy when required. For additional information, please refer to Appendix B-2 of the 2014 LTRP.

7. Reference: Exhibit B-1, Page ES-2 and Page ES-3

> Advanced production methods and technologies have unlocked the potential of North America's vast shale gas deposits which has led to significant growth of natural gas supply and a low price environment. As a result, various interests including government and industry across B.C., the Pacific Northwest (PNW),[2] and North America more broadly are looking to take advantage of the economic, environmental and social benefits of using natural gas.

> As directed by the BCUC, the FEU have developed a new approach to modelling the 20-year horizon which will provide a more insightful forecast of the long term range of potential demand. This approach uses a number of future scenarios that allow the FEU to examine changes in natural gas demand at the end-use level. A reference case is based on the 2010 Conservation Potential Review, recent customer additions data and market research, while four additional future scenarios examine a range of alternative demand scenarios. These scenarios 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 and incorporate varying assumptions for gas commodity and carbon prices, the policy environment, and the development of renewable and district energy systems.

7.1 Does the first excerpted section suggest that there is an abundance of natural gas in North America?

Response:

Yes, the resource potential in North America is significant and improved production technologies have helped to provide for abundant supply that is expected to be sufficient to meet future gas demand.

7.2 Does BC have an abundance of natural gas?

Response:

Yes, B.C. has an abundance of natural gas and is expected to have a sufficient amount of gas to meet future demand.

7.3 Under what future conditions would BC not have an abundance of natural gas?

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.

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.

7.5 Please provide the estimates of the natural gas potential in BC and the Western Sedimentary Basin.

Response:

According to the National Energy Board (NEB), the estimated ultimate potential for marketable natural gas in the Western Canadian Sedimentary Basin (WCSB) by the end of 2012 was 821 trillion cubic feet (Tcf), with 400 Tcf of this amount from B.C.[1]

7.6 Please describe the NEB role in authorizing export of natural gas and whether or not the NEB would compromise the availability of natural gas to the domestic markets.

Response:

Pursuant to section 117 of the National Energy Board Act (NEB Act) the NEB is authorized to issue licenses for the export or import of oil or gas from or to Canada. An application for an export license requires:

- identification of the source and volume of gas to be exported;
- a description of gas supplies, including Canadian gas supply, expected to be available to the Canadian market (including underlying assumptions) over the requested license term;
- a description of expected gas requirements (demand) for Canada (including underlying assumptions) over the requested license term; and
- implications of the proposed export volumes on the ability of Canadians to meet their gas requirements.

Pursuant to section 118 of the NEB act, "on an application for a license to export oil or gas, [NEB] shall satisfy itself that the quantity of oil or gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada." The NEB assesses the merits of an application for export through a surplus

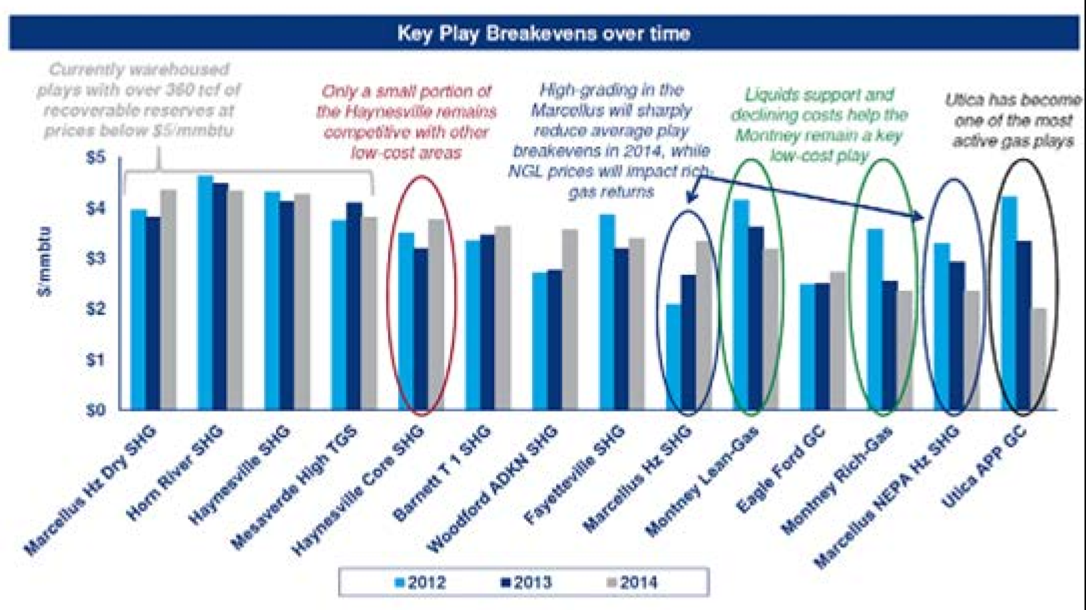
[1] NEB Report - November 2013 - The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta – Table 4. http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.html

determination procedure known as the Market-Based Procedure (MBP) to ensure the sufficient availability of natural gas for domestic markets.

7.7 Please provide information on the expected cost of lifting natural gas out of Northeastern BC and any variation over time which may be expected.

Response:

The FEU interpret cost of "lifting" natural gas as the breakeven cost for gas production in northeastern B.C. Producer break even costs have generally improved over time, contributing to lower natural gas prices. As illustrated in the below graph, northeastern BC, particularly the Montney region, is a key low cost play whose break-even costs have steadily decreased in the recent past, largely due to the recovery of liquids.



Source: Wood Mackenzie, North American Gas Service Cost of Supply Update – May 2014

Producer break even costs going forward will be determined by such factors as any further advances in drilling, associated liquids and production technology and any potential environmental regulations.

7.8 Please confirm that at reasonable costs (please define the reasonable costs) of providing natural gas supply the FEU do not expect the availability of natural gas supply during the planning period to become limited such that long term prices for natural gas would be materially affected.

Response:

For the purposes of this question, FEU would define "reasonable costs of providing natural gas supply" as the being the breakeven costs of production including a minimum level of return on investment as shown in the figure provided in the response to the previous question (CEC IR 1.7.7).

The current natural gas forward prices and producer breakeven costs indicate that producers are likely to continue with at least maintaining production levels in the near future. The latest long-term price forecasts, as indicated in the response to BCUC IR 1.11.1, indicate that Henry Hub gas prices could range between $6.86 and $8.12/MMBtu by 2030. The response to CEC IR 1.7.7 indicates that producer break even costs lie between $2 and $5/MMBtu. Therefore, the FEU expect there to be an abundance of gas supply available during the planning period of the 2014 LTRP.

While the FEU do not expect the availability of natural gas supply to become limited in North America during the 2014 LTRP planning period, the ability and costs to transport gas from the supply regions to demand areas is also an important factor to consider. Therefore, more pipeline infrastructure will likely be needed in the future to better link supply with demand.

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.

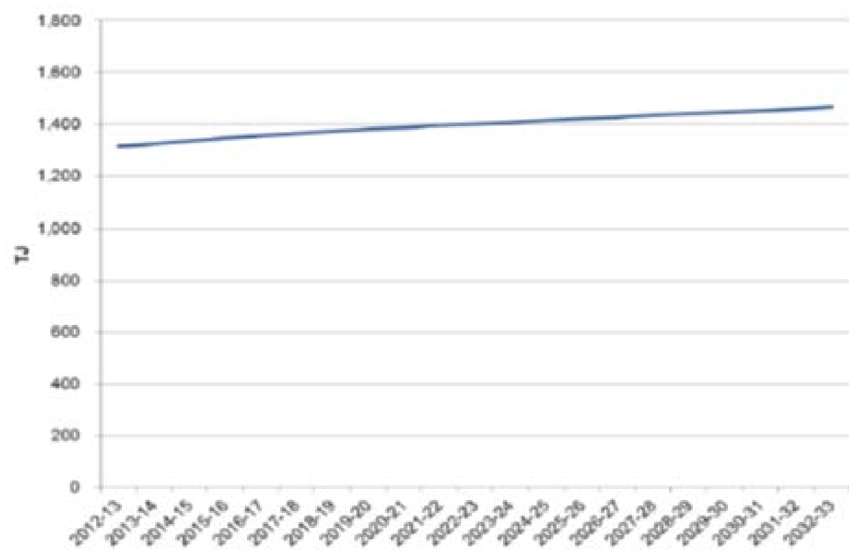
7.10 Please identify the major factors that might cause the conditions that may limit natural gas supply over the planning period and provide the FEU estimate of the probability of any of these factors occurring.

Response:

Please refer to the response to CEC IR 1.7.3.

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

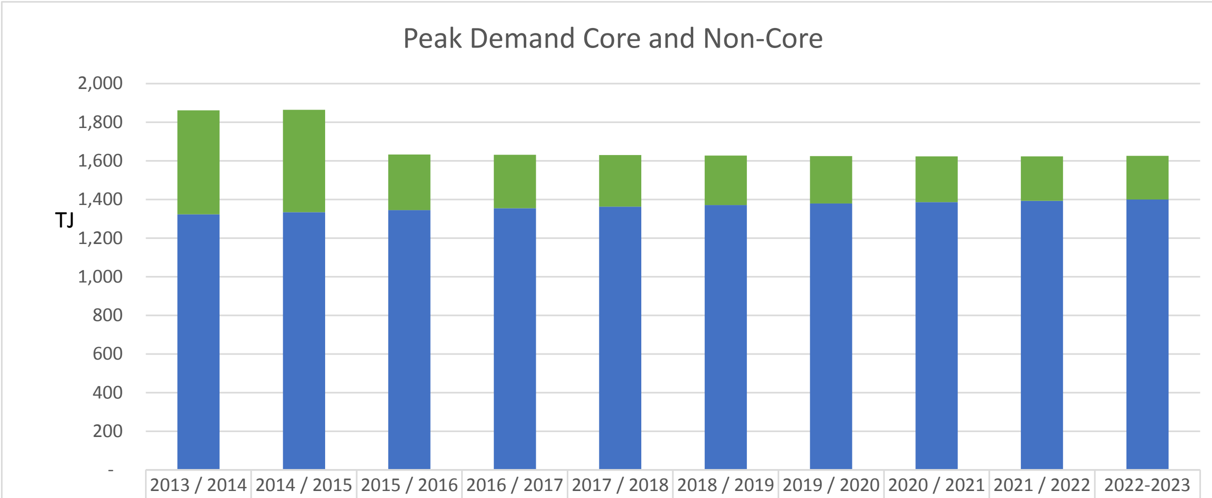
Figure ES-2: FEU Core Peak Day Demand



8.1 Please explain what is not included in the Core Market and relate the approximate magnitude or range of magnitudes for the peak day demand requirements for each.

Response:

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.



	2013 / 2014	2014 / 2015	2015 / 2016	2016 / 2017	2017 / 2018	2018 / 2019	2019 / 2020	2020 / 2021	2021 / 2022	2022-2023
Non-Core	537	530	288	277	266	256	246	236	230	226
Core	1,324	1,335	1,345	1,356	1,364	1,372	1,379	1,386	1,393	1,400

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.

<u>Response:</u>

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.

8.3 Please advise what if any demand side measures the FEU take to reduce the peak day demand and or the peak design day demand for the system.

<u>Response:</u>

The FEU do not currently undertake any EEC measures specifically to reduce peak (or design day/hour) demand. As outlined in Section 5.1.1.2 of the LTRP (pages 98 and 99), EEC activities lead to an overall decrease in annual consumption but may or may not affect peak demand. Some types of EEC activities may lead to an increase in peak demand. Set-back thermostats, for example, could potentially reduce yearly gas consumption but lead to concentrating gas demand at specific times during the day, while tankless water heaters likely lead to a reduction in total annual gas consumption but potentially require shorter periods of higher consumption, which could increase peak instead. Please also refer to the responses to BCUC IRs 1.48.1 and 1.48.1.1 for a discussion of how EEC measures may or may not impact peak demand and how the impacts of EEC are currently considered in forecasting peak demand.

To date, the FEU have not identified any demand side measures other than curtailment that can reliably reduce peak demand. Curtailment is an operational measure available through agreement with some of the FEU's industrial customers and is not an EEC program. As well, the ability to curtail is already considered in the core peak demand figure in the preamble. The FEU will continue to examine new technologies or innovative program designs for opportunities to reduce peak demand. If such opportunities are identified and proven out, the FEU will consider their potential impact on long term peak demand forecasts in future LTRPs.

8.4 Please define what if any peak demand 'demand side measures' may be possible and potentially feasible.

<u>Response:</u>

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.

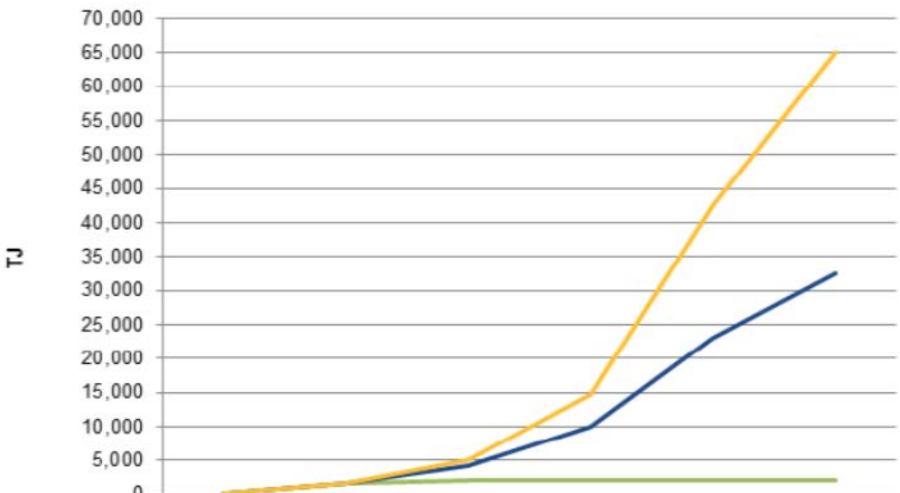
8.5 Please define what conditions may need to exist in order to enable cost-effective use of demand side measures for the peak demands on the system.

<u>Response:</u>

The details of specific equipment installations and the interaction of multiple installations would need to be known and be proven to result in an overall reduction in peak demand in order to design an EEC program around a measure or measures designed specifically to reduce peak demand. Please also refer to the response to BCUC IR 1.48.1.

9. Reference: Exhibit B-1, Page ES-6

Figure ES-3: NGT Annual Demand



	2010-2011	2016	2021	2026	2031	2033
Low	195	1,676	2,168	2,168	2,168	2,168
Reference	195	1,676	4,267	9,946	23,183	32,522
High	195	1,676	5,075	14,689	42,518	65,045

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

<u>Response:</u>

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.

9.2 Please provide the proportion for how much of the Tilbury LNG plant expansion capability would be needed to serve the planning horizon NGT demand for the 15% reference case scenario and the 30% high case scenario.

Response:

Please refer to the response to CEC IR 1.10.9 for discussion on potential Tilbury LNG expansion scenarios. There is a range of possible expansion scenarios that can be accommodated at the Tilbury site so the percentage of the expansion capacity used to meet different NGT demand scenarios would be dependent on the expansion scenario selected. Please note that the NGT volumes in the scenarios portrayed include both CNG and LNG volumes (please refer to the response to BCUC IR 1.24.1 for the breakdown of CNG and LNG amounts in each of the scenarios). It is also possible that LNG facilities providing supply to the BC NGT market may be developed by other parties elsewhere on the FEU's system or in other jurisdictions. As an example, a daily liquefaction capability of approximately 80 mmscfd would be required to serve the anticipated 2033 NGT loads in the Reference scenario and twice that amount or about 160 mmscfd would be required to serve the 2033 forecast annual demand from the High scenario. The potential expansion capability at Tilbury can handle these liquefaction quantities but it is possible that portions of those amounts will come from other sources of LNG supply.

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.

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.

9.5 Please provide the FEU estimate of the probability of achieving the 30% scenario, and the 15% scenario.

Response:

The FEU did not assign probabilities to its annual demand scenarios; however, generally speaking, the FEU has more confidence that that it could achieve the 15% NGT Annual Demand scenario. This scenario was built based on FEU's NGT program results to date, as well as a reasonable forecast of future demand based on the current market conditions.

The 30% scenario is presented to illustrate the upper limit of what FEU believes the NGT Annual Demand could potentially be.

9.6 Please provide the conditions that would have to exist to enable a 45% scenario, a 60% scenario and a 75% scenario.

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.

9.7 Please provide the additional facility capacities that would be required to service the higher scenarios.

Response:

Higher demand scenarios would require additional liquefaction facilities and potentially additional LNG storage tanks to accommodate maintenance schedules. Depending upon the magnitude of the demand, looping the Nichol to Roebuck transmission pipeline would also be required.

9.8 Please provide any technology developments that are expected to be required to reach either the reference 15% scenario or the 30% high scenario.

Response:

There are a number of technological developments that would aid in the development of NGT demand. For instance, in terms of on-road heavy duty trucking, the market is awaiting a suitable engine replacement for the discontinued Cummins-Westport 15L HPDI LNG engine. The discontinuation of this engine, which was ideally suited for the BC market (i.e. terrain and power requirements), has put downward pressure on LNG demand in this segment.

In terms of mass adoption, the higher upfront capital cost of a CNG or LNG vehicle over a comparable gasoline or diesel vehicle is also a limiting factor. As economies of scale are achieved through higher demand, this capital cost differential is expected to decrease and thus make CNG and LNG vehicles more attractive to potential customers.

9.9 Please identify what if any demand side measures the FEU are planning for the NGT customers.

Response:

The NGT effort itself is a demand side measure in that by adding NGT customers to the natural gas system the system is used more efficiently and all things equal rates would decrease over time. However, if the question is asking what conservations activities the FEU are undertaking, the FEU are not planning any demand side (conservation) measures for NGT customers at this time as the NGT program is designed to encourage existing fleet operators to switch from diesel to natural gas and add throughput into the system.

Demand side measures applicable to NGT customers may include technological changes such as the development of more fuel efficient CNG and LNG engines. However, these are technological developments that must be made by the engine supplier, and are out of the FEU's control. Additionally NGT customers operate in a competitive market, and as such are motivated to undertake demand side measures on their own to ensure that they consume the least amount of fuel possible.

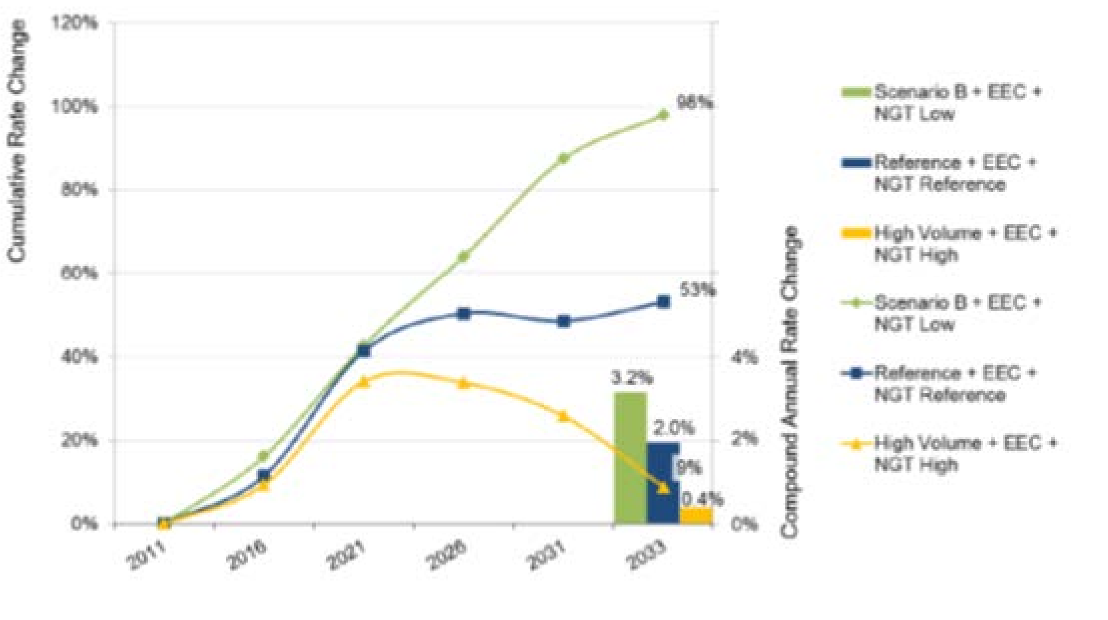
9.10 Please identify what if any demand side measures are possible for NGT customers and under what conditions they may be available and or feasible.

Response:

Please refer to the response to CEC IR 1.9.9.

10. Reference: Exhibit B-1, Page ES-13

Figure ES-6: Delivery Rate Direction – All Rate Classes, EEC and NGT



10.1 Please clarify whether or not the High NGT is related to the reference scenario, one of the lettered scenarios or a 'high volume' scenario and advise whether and how the high volume scenario is different from other scenarios.

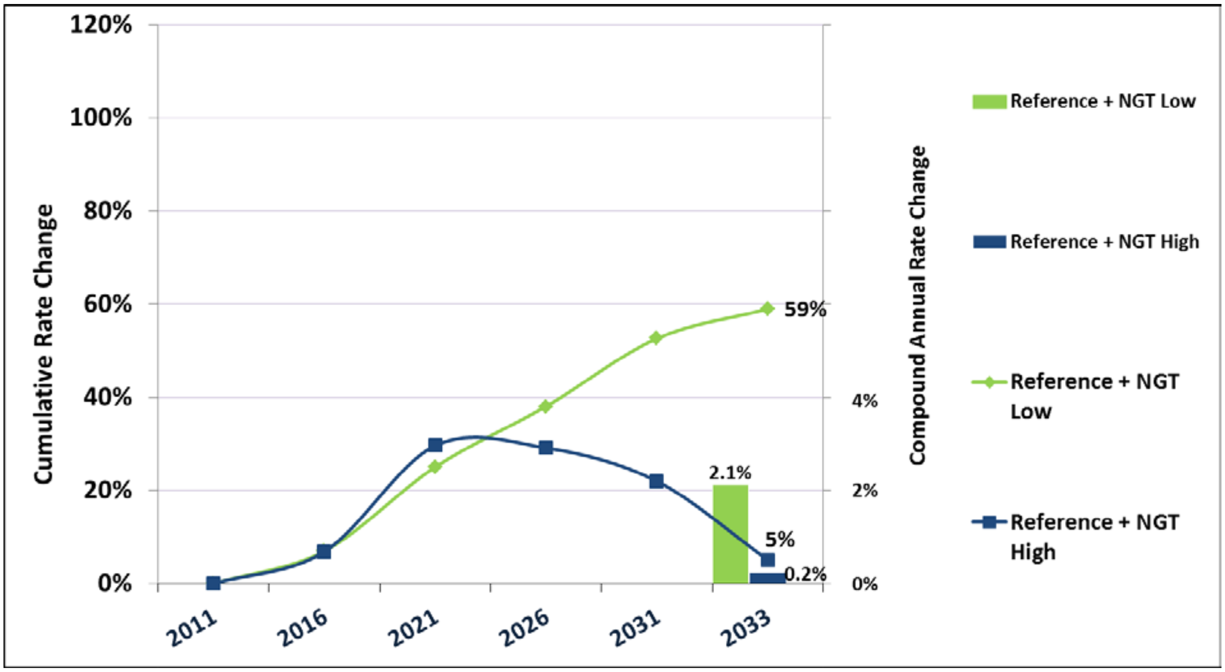
Response:

The "High Volume" scenario refers to the annual demand that would occur if Scenario C (for residential, commercial and industrial demand) were to unfold over the planning horizon. The FEU recognizes that they should have substituted the term 'Scenario C' for 'High Volume' in the referenced figure for clarity.

10.2 Please provide this same graphic with the high and low NGT scenarios applied to the reference case.

Response:

The graph included in this response excludes EEC and includes the Reference case plus NGT Low scenario (green line with diamond markers), and Reference case plus NGT High scenario (blue line with square markers).



10.3 Please confirm or otherwise explain that because the FEU are committed to building the Tilbury LNG plant expansion that a low NGT scenario is highly unlikely.

Response:

Demand for liquefaction of the current build out of the Tilbury facility (See also CEC IR 1. 73.1) is driven by local NGT, off system communities, other utility needs in BC/Yukon/NWT, as well as niche market exports. This spreads the risk and cost of liquefaction need amongst a variety of options with NGT being a portion of that demand.

10.4 Please explain why the rate reference case scenario increases significantly from 2011 to 2021 and then flattens out, is this the impact of the reference NGT 15% scenario.

Response:

To clarify, the rate reference case scenario reflects a compound annual rate change of approximately 3% per year between 2011 and 2021. Commencing in approximately 2021, the expected growth in NGT volumes produces delivery margin recoveries that largely offset other cost pressures, creating a flatter curve.

10.5 Please explain the title delivery rate direction.

Response:

FEI used the term delivery rate direction to clarify that the rate changes represented in the graph are not all encompassing forecasts, but rather an indication of the expected direction of delivery rates in the context of the potential impacts of the EEC and NGT programs on the Reference case.

10.6 Please provide the working spreadsheets that give rise to these scenarios.

Response:

Please refer to Attachment 10.6 for a working excel version of Figure ES-6.

10.7 Please explain whether or not there are any other types of demand changes on the natural gas delivery system that can have the effect of moderating delivery margin pricing pressures.

Response:

Generally, any demand growth that results in an incremental cost which is less than the existing average cost will serve to moderate delivery margin upward price pressures. New large industrial demand as discussed Section 3.3.9, page 61 of Exhibit B-1 is an example of demand that could have the effect of moderating delivery margin. The FEU cannot model the impacts of such a load however, as the load described in that section remains speculative and no rate information exists that could be modelled.

10.8 Please provide a quantitative analysis of the potential effect of the addition of LNG export facilities in the Lower Mainland, Vancouver Island areas.

Response:

While the FEU have had interest from potential customers seeking to construct LNG facilities in the Lower Mainland and Vancouver Island to attach to the FEU system, these discussions are confidential and in a development stage; as such these opportunities and associated forecasts are not included in the LRTP.

However, developments such as PEC/WoodFibre, Tilbury expansion, and additional customers seeking transmission service for LNG, and large scale industrial requirements, are expected to provide significant benefit to existing customers through better utilization of the natural gas system. FEU's existing assets are geographically well-positioned for LNG opportunities for markets domestically and abroad. Transmission and liquefaction requirements in these areas could exceed the annual existing throughput on the FEU system. Even accounting for additional infrastructure required to serve these new large loads, the net effect would be a reduction in rates for existing customers, all else equal.

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.

10.10 Please describe whether or not there is a potential for the BC Hydro electric system to need peaking capacity resources into the Lower Mainland, Vancouver Island area and whether or not any such facilities might impact demand on the FEU natural gas delivery system.

Response:

With the planned 2015 in service date of BC Hydro's (BCH) Interior to Lower Mainland (ILM) transmission project and the government order that BCH's Burrard Thermal power generation plant be shut down by 2016 there is a reduced potential for BCH to require gas supply and transmission capacity on the FEU's system to support peaking capacity resources for electrical production.

10.11 Please describe whether or not there are any potential industries that may use natural gas as a feedstock that may potentially locate where there may be requirements on the FEU natural gas delivery systems.

Response:

The FEU have had interest from large scale industrial customers seeking transmission service in the lower mainland, interior and Vancouver Island. These customers would use natural gas as a feedstock for the production of methanol, fertilizer and gas to liquids production. At present none of these discussions are far enough along to result in forecasts of either load or system expansions required to serve the customer.

11. Reference: Exhibit B-1, ES-14

> The actions that the FEU intend to pursue over the next four years based on the information and evaluation provided in this Resource Plan are to:

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.

11.2 Does this mean that the FEU will not be working in the next 4 years with any natural gas generation or peaking plant opportunities?

Response:

No. Please refer to the response to CEC IR 1.11.1.

11.3 Does this mean that the FEU will not be working with TES opportunities that would limit natural gas growth?

Response:

Due to the AES Inquiry Decision, the FEU limit their involvement in TES opportunities to the delivery of natural gas services.

11.4 Does this mean that the FEU will not be working with other than NGT LNG requirements?

Response:

The FEU are uncertain what is meant by the term “other than NGT LNG requirements”. Please refer to the response to CEC IR 1.11.1.

11.5 Does this mean that the FEU will not be working with any potential customers who might require natural gas feedstock for their industrial or chemical processes?

Response:

No. Please refer to the response to CEC IR 1.11.1.

12. Reference: FEU Exhibit B-1, Executive Summary page ES-1 and page 5

> The FEU submit this 2014 LTRP under Section 44.1(2) of the *Utilities Commission Act* (*UCA* or *Act*) and are not seeking approval of any particular elements of the plan. Any requests for approval of specific resource needs that are identified within this plan will be further evaluated and brought forward at the appropriate time for approval under different sections of the *Act*.

> In determining whether to accept a long term resource plan, Section 44.1(8) of the *UCA* requires the Commission to consider the applicability of B.C.'s energy objectives, whether the plan shows that the utility intends to pursue adequate, cost-effective demand-side measures, and the interests of the utility's existing or potential rate payers. The FEU believe that these considerations support the Commission accepting this LTRP.

12.1 Please confirm that FEU is requesting the Commission to accept the LTRP, but not necessarily provide approval of any of the forecasts or other information contained in the plan.

<u>Response:</u>

The FEU seek to have the LTRP accepted pursuant to section 44.1(6)(a) of the *Utilities Commission Act*. Strictly speaking, the *Act* does not treat the LTRP as an "application"; rather, it is something that the utility must "file with the commission", and the plan is either accepted or rejected. The FEU confirm that no specific approvals are being sought with this LTRP. Please also refer to the response to BCUC IR 1.1.5.

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

<u>Response:</u>

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.

12.3 If parts of the Plan are rejected by the Commission will FEU make amendments to the plan in this planning cycle and re-submit or does that depend on the Commission order? Please explain.

Response:

If parts of the LTRP are rejected by the Commission, and depending upon the nature of the rejection, the FEU would incorporate the Commission's directives into the next planning cycle. However, the FEU believe the Commission should accept the LTRP because it has met all of the requirements of the *Utilities Commission Act* (see Table 1-2 of the LTRP, Exhibit B-1, for information on each *UCA* requirement and where the requirement is addressed in the 2014 LTRP), it meets the Commission's directives provided in the 2010 LTRP Decision (see Table 1-3 of the LTRP, Exhibit B-1) and the FEU have followed the BCUC Resource Planning Guidelines, as appropriate, in preparing the 2014 LTRP.

13. Reference: FEU Exhibit B-1, Introduction page 3

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*

13.1 Please explain why the Annual Demand/customer for FEVI about 50% higher than it is for FEI Lower Mainland.

Response:

In Table 1-1, the inclusion of large volume industrial customers within a comparatively smaller customer base in the FEVI service territory results in an overall Annual Demand / Customer value that is higher for FEVI than for FEI Lower Mainland.

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.

14. Reference: FEU Exhibit B-1, pages 19 through 22

> In the past, low electricity rates have contributed to a competitive challenge for natural gas in B.C. but the decline in gas commodity cost and increases to electricity rates in B.C. in recent years has helped to improve the competitiveness of natural gas. Figure 2-5 provides a historical comparison of natural gas bills (based on consumption of 95 GJ/year and 95% efficiency) with comparable electricity bills (assuming 100% efficiency) for an FEI residential customer in the Lower Mainland. This chart demonstrates that today's natural gas rates are cost competitive with electricity rates.

14.1 FEU provides a discussion of natural gas and its competitive position in the residential market on pages 19 through 22 and in Appendix A-3. Please provide a similar overview of natural gas use in the Commercial and Industrial sectors in BC, including a discussion on the typical uses of natural gas, the advantages and disadvantages of natural gas and competing alternatives including prices, the relevant history and any other key issues for each sector. Please provide the relevant charts and graphs for illustration.

Response:

Although the commercial market is diverse both in scale and in the type of business, natural gas is used for many of the same purposes as in the residential sector – space heating, domestic water heating and cooking. There are a few additional sector-specific uses such as swimming pools in condos, apartments and hotels.

The information below is reproduced from the FEU's 2010 Conservation Potential Review (CPR) and shows the consumption for each commercial sub-sector and end use. As seen below, small commercial is the largest sub-sector and space heating is the largest end use. The information below also shows industrial consumption by major end use and sub-sector. The primary industrial sector end use is for boilers and the largest sub-sector is pulp and paper.

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.

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

Sub Sector	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	199,839	16,330	235,810
Large Apartment	166,335	3,481,420	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

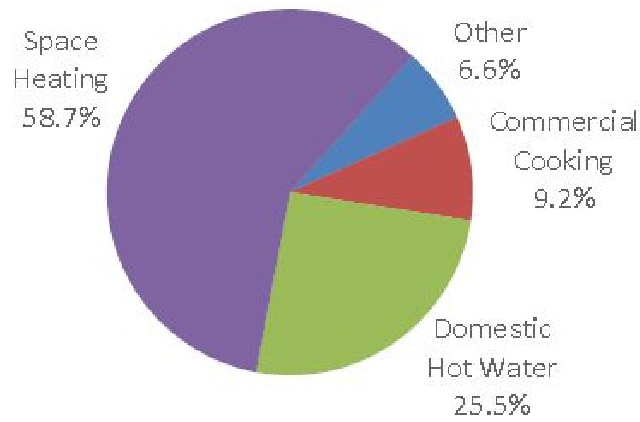


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Exhibit ES 2 Base Year 2010 – Industrial Natural Gas Consumption by Major End Use – All Service Areas

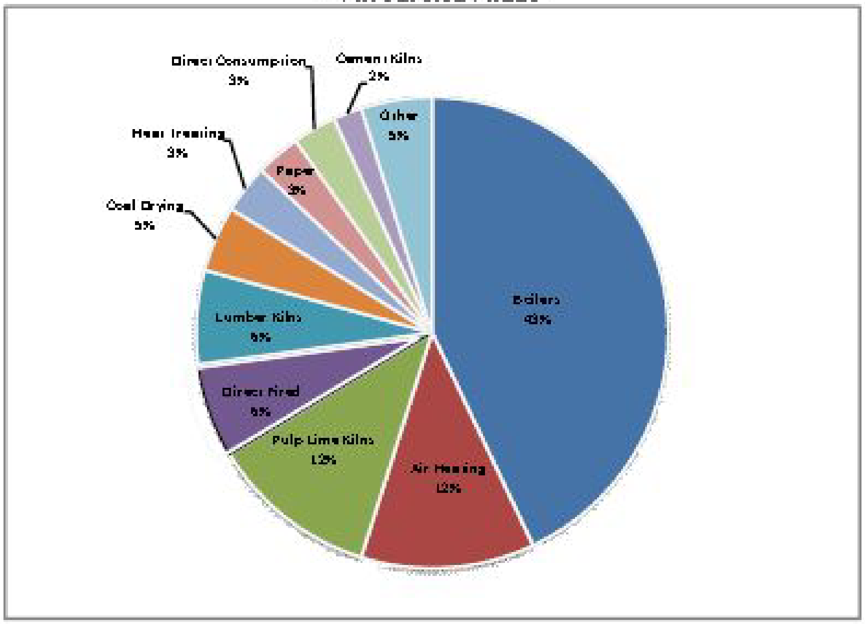
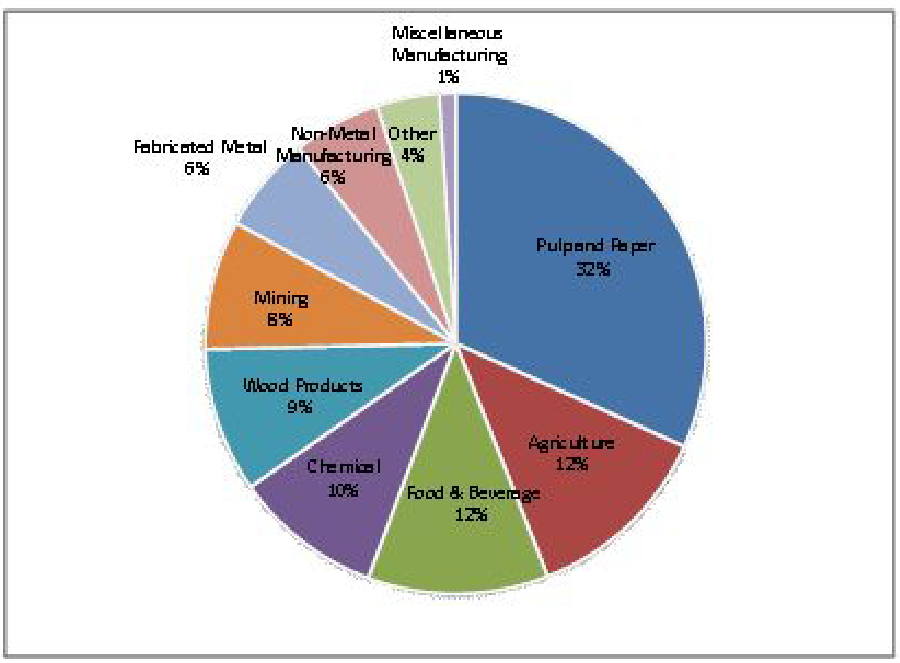


Exhibit ES 3 indicates the distribution among the sub sectors. The Pulp and Paper sector dominates at 32%, followed by Agriculture, Food & Beverage at 12% each, Chemical at 10%, Wood Products at 9%, Mining at 8% and Fabricated Metal at 6%.

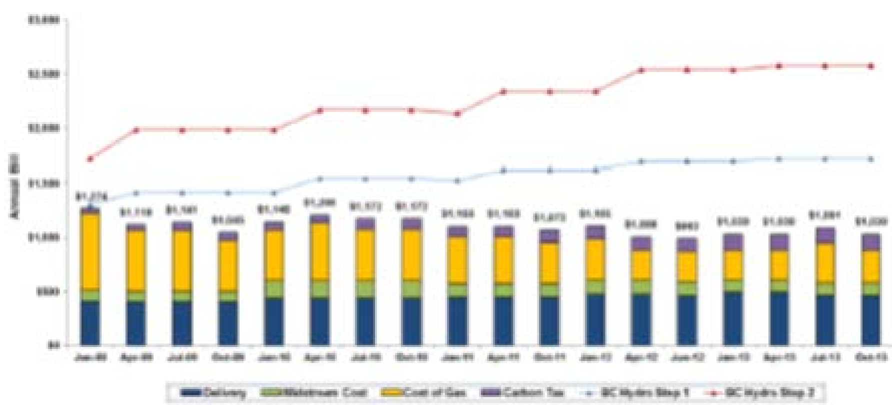
Exhibit ES 3 Base Year Industrial Natural Gas Consumption Distribution of Use by Sub Sector



15. Reference: FEU Exhibit B-1 pages 19 and 20 and Appendix A-3, page 1

> In the past, low electricity rates have contributed to a competitive challenge for natural gas in B.C. but the decline in gas commodity cost and increases to electricity rates in B.C. in recent years has helped to improve the competitiveness of natural gas. Figure 2-5 provides a historical comparison of natural gas bills (based on consumption of 95 GJ/year and 95% efficiency) with comparable electricity bills (assuming 100% efficiency) for an FEI residential customer in the Lower Mainland. This chart demonstrates that today's natural gas rates are cost competitive with electricity rates.

Figure 2-5: FEI Lower Mainland Residential Natural Gas Rates[18]



> efficiencies in order to provide a direct comparison to natural gas. For example, when looking at space heating for new customers, the electric equivalents include adjustments to the BC Hydro Step 1 and Step 2 rates of 90%, which is representative of the efficiency of a new gas furnace.

15.1 Please reconcile the use of the 95% efficiency figure in the comparison with electricity rates, with the 90% efficiency of a new gas furnace.

Response:

FEI would like to first make a correction with respect to the narrative provided preceding Figure 2-5. The narrative in the 2014 LTRP (Exhibit B-1), Section 2, page 19 stated:

"Figure 2-5 provides a historical comparison of natural gas bills (based on consumption of 95 GJ/year and 95% efficiency) with comparable electricity bills (assuming 100% efficiency) for an FEI residential customer in the Lower Mainland."

This should be corrected to read:

*"Figure 2-5 provides a historical comparison of natural gas bills (based on consumption of 95 GJ/year and **90%** efficiency) with comparable electricity bills (assuming 100% end-use efficiency) for an FEI residential customer in the Lower Mainland."*

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.

The reference in the preamble after Figure 2-5 is from Appendix A-3 of Exhibit B-1: Cost Competitiveness of Natural Gas and Electricity, page 1. The paragraph states:

> *"The natural gas burner tip rates are compared to electric equivalents. These electric equivalents are based on BC Hydro rates which have been adjusted for various appliance efficiencies in order to provide a direct comparison to natural gas. For example, when looking at space heating for new customers, the electric equivalents include adjustments to the BC Hydro Step 1 and Step 2 rates of 90%, which is representative of the efficiency of a new gas furnace."*

The charts contained in Appendix A-3 include more specific natural gas and electric appliance comparisons, and in Figure 2 on page 5, a comparison of FEI New Space Heating with BC Hydro Step 1 and Step 2 rates is provided, using a 90% efficiency factor to represent the average efficiency of a new gas fired furnace.

15.2 Could 95% be appropriately considered the upper bound of natural gas efficiency for residential use?

Response:

Please refer to the response to CEC IR 1.15.1, which corrects the narrative in the 2014 LTRP (Exhibit B-1), Section 2, to 90%. The FEU are aware of residential natural gas furnaces with manufacturer's efficiency ratings as high as 98.5% and residential boilers as high as 95.6%, therefore the upper bound of end-use energy efficiency for residential use is theoretically above 95%.

15.2.1 If not confirmed, please provide the upper end of efficiency for natural gas use.

Response:

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

15.3 Please provide the average efficiency level of the key uses for natural gas in the residential market.

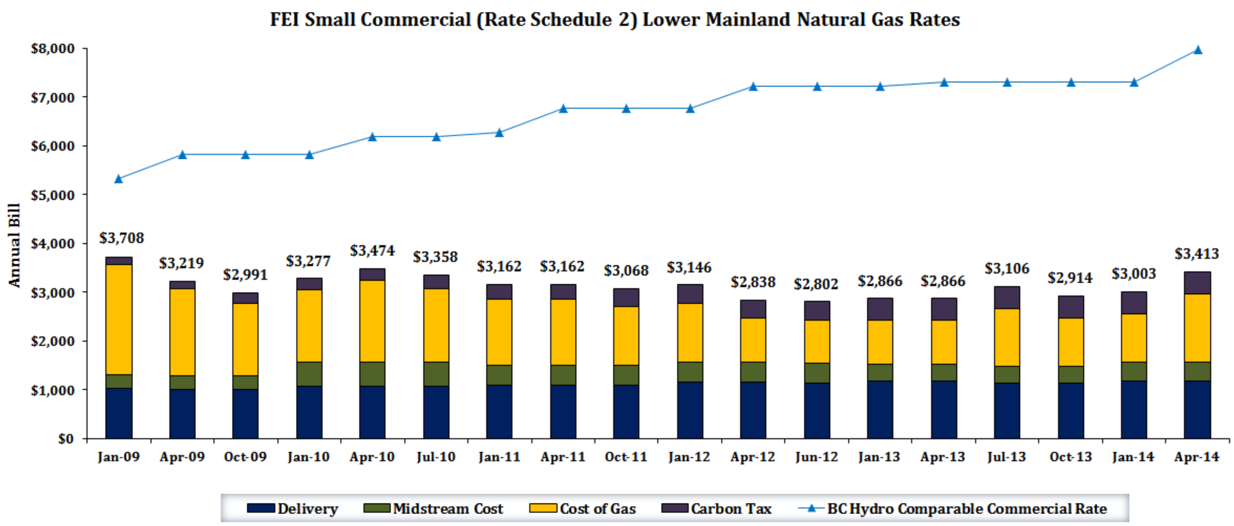
Response:

The average efficiency levels for existing customers are assumed to be 75% for space heating and 60% for water heating.

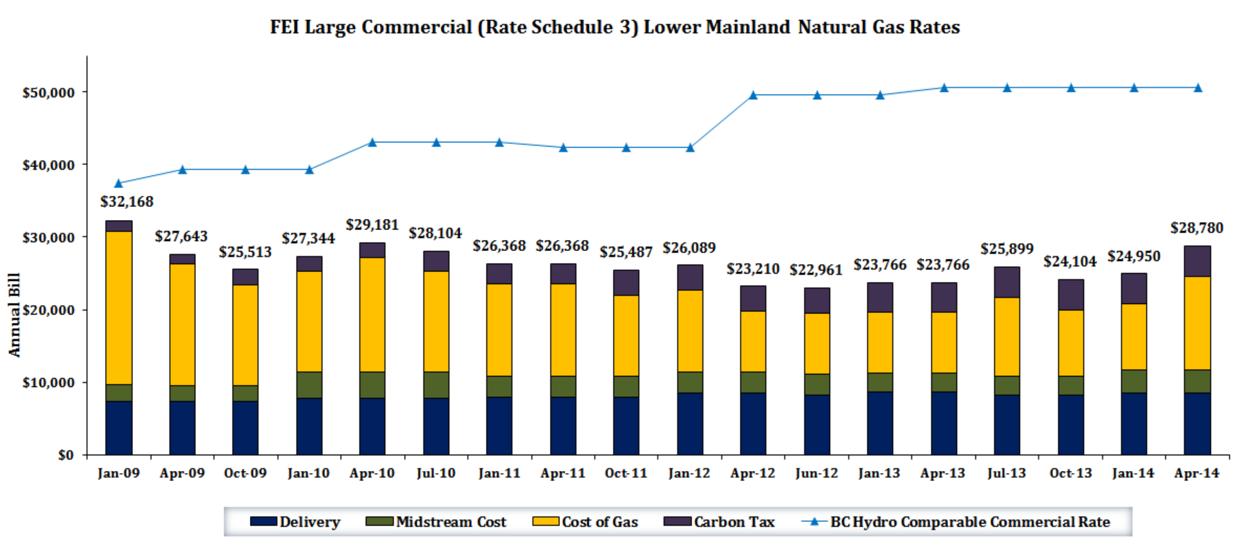
15.4 Please provide the relative efficiencies and comparison to electricity prices for the commercial market.

Response:

Please refer to the charts below for comparison of electricity prices for the commercial market. As stated in the response to CEC IR 1.15.1, the comparison is intended to be representative of a comparison of natural gas and electricity bills, therefore an efficiency adjustment of 90% has been used for natural gas equipment. It is also important to note that these two charts represent a generalized comparison of natural gas and electricity using rates for FEI under Rate Schedule 2 (Small Commercial) and Rate Schedule 3 (Large Commercial). Without comparing a specific commercial customer's natural gas consumption and demand relative to the specific BC Hydro rate class they would be classified under for process load only, a more definitive comparison is not possible. Thus, the gas vs electricity competiveness for commercial customers will be specific to each customer's own situation.



Assumptions:
*Natural gas use of 300 GJ
*Efficiency of gas equipment is 90% relative to 100% for electricity
*FortisBC Energy amount includes the basic charge
*BC Hydro rates are based on BC Hydro Rate Schedule 1300, inclusive of a 5% rate rider and exclusive of the basic charge



Assumptions:
*Natural gas use of 2,800 GJ
*Efficiency of gas equipment is 90% relative to 100% for electricity
*FortisBC Energy amount includes the basic charge
*BC Hydro rates are based on the Average Medium Commercial rate as per the Hydro Québec Annual Comparison of Electricity Prices in Major North American Cities, for each applicable time period

16. Reference: FEU Exhibit B-1, page 20-21

> Capital costs related to natural gas equipment (such as furnaces, ducting and hot water tanks) tend to be costlier than those relating to electric equipment (such as electric baseboards and hot water tanks). In retrofit situations, new and more complicated ducting requirements for high efficiency equipment are making the installation of natural gas equipment more difficult and costly. In addition, it is often not the end user that makes decisions regarding energy sources installed in the home: builders and developers are the primary decision makers regarding the choice of energy and equipment used in new construction. As builders and developers do not ultimately pay operating costs, they tend to be more influenced by capital costs alone. In addition, builders and developers typically aim to maximize the useable square footage available in a development to maximize the return on investment, particularly for multi-unit residential developments. Thus, capital cost savings and the ability to sell more useable living space incents developers and builders to install electricity equipment over natural gas equipment in new developments. The upfront capital cost difference for installing natural gas

16.1 Please confirm that natural gas may offer advantages other than operating cost savings in several applications such as cooking and fireplace units, and that these are also relevant to the customer decision, whether they are an end-user or a builder.

Response:

Natural gas does provide many other advantages other than operating cost savings in appliances such as cooking and fireplace units. For instance, builder/developers such as Quadra Homes, a large developer of luxury condos and high-end townhomes operating in BC have reported they will market to their target customers how natural gas cooking units allow for better temperature control over electric cooking units, and natural gas fireplaces provide a more comfortable form of heating than electric fireplaces. Many customers also prefer the ambience of a natural gas fireplace to that of an electric unit.

16.2 Please confirm, or otherwise explain that the inclusion of natural gas heating and/or appliances is considered a selling feature in the housing market relative to electric, for which a premium may or may not be attached.

Response:

The inclusion of natural gas heating and/or appliances can be a selling feature depending upon the type of housing stock and the buyer demographic. Individual builder/developers will have their own criteria for determining the premium potential of natural gas heating and /or appliances relative to electric. In turn, the builder/developer will make appliance decisions based on the expected return on investment of those appliances. For example, if a natural gas appliance has a higher installed cost, the builder/developer will need to sell the dwelling for a premium relative to electric to recoup the incremental capital investment. If the builder/developer's market research shows that the premium cannot be supported, the builder/developer will choose another appliance.

17. Reference: FEU Exhibit B-1, page 21

Table 2-1: Capital Cost Difference for Space and Water Heating – Natural Gas vs. Electricity[18]

	Space Heating	Water Heating
Capital costs for natural gas	$9,000	$2,000
Capital costs for electricity	$4,320	$1,023
Upfront capital cost premium for natural gas compared to electricity	**$4,680**	**$977**
Annual difference in capital costs[19]	$446.68	$113.32
Annual maintenance costs	$50.00	$0.00
Total annual difference in capital and maintenance costs	**$496.68**	**$113.32**
Energy consumption per year (GJ)	50 GJ	20 GJ
Difference in cost between natural gas and electricity over measureable life ($/GJ)	**$9.93/GJ**	**$5.67/GJ**

[17] American Gas Association. Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges, page 32.
[18] Assumptions based on the new construction of a 3,000 sq. ft. home in the Lower Mainland.
[19] Represents the difference in capital costs per year, assuming a stream of equal annual payments with an interest rate of 6% and measurable life of 17 years for a space heating furnace and 13 years for a hot water tank.

17.1 The energy consumption from space heating and water heating combined is 70GJ. Please provide the average consumption in a typical new 3,000 square foot house in the Lower Mainland.

Response:

The average natural gas consumption for a typical new 3,000 square foot house in the Lower Mainland is 92 gigajoules based on data from the Company's 2008 Residential End Use Study.

17.2 Please provide the average number of appliances and fixtures, by type, that use natural gas that would be included in a 3,000 square foot home in the Lower Mainland. Please differentiate by new home or existing home if appropriate.

Response:

On average, this hypothetical home would have approximately three natural gas appliances. The most common appliance combinations are a furnace, water heater and a fireplace.

17.3 Please provide a breakdown and explanation of the capital cost assumptions for electricity and natural gas for both space heating and water heating.

Response:

The breakdown of the installed cost for electric baseboards is a load of 12kW at $360 per kW for a total of $4320 while that of a 90% efficient natural gas furnace is $2,300 capital cost plus $6,700 for installation, ducting and venting costs for a total of $10,000.

An electric hot water tank is approximately $600 in capital costs with $400 in installation costs for a total of $1000 while a base efficiency tank natural gas water heater is $700 in capital costs and $1,300 in installation and venting costs for a total of $2000.

17.3.1 Please confirm that the installation and ducting costs consider the economies from implementing more than one natural gas appliance/fixture

Response:

Yes, the installation and ducting costs do consider economies from implementing both a furnace and water heater at the same time. There are also minor economies for natural gas piping/venting and other appliances.

17.3.2 If not confirmed, please recalculate the costs of space heating and water heating with consideration for the economies of multiple natural gas appliances in a 3,000 square foot house and provide the assumptions utilized.

Response:

Please refer to response to CEC IR 1.17.3.1.

17.4 What is the expected life of the ducting and installation expenses?

Response:

The expected life of ducting ranges between 30 and 50 years. Please refer to CEC IR 1.17.3 for installation expenses.

17.5 Please confirm or otherwise explain that the ducting and other expenses related to bringing natural gas into a residential space may have a significantly longer life than the appliance to which it is attached.

Response:

Ducting usually does outlast the lifetimes of natural gas furnaces and water heaters of approximately 17 years and 13 years respectively, while ducting should last between 30 and 50 years with regular maintenance. Lifespan of other appliances varies depending upon usage, and quality etc.

17.6 Please confirm or otherwise explain that the decision to incorporate natural gas into a home would consider all the applications for which natural gas could be used.

Response:

The decision to put natural gas into a home is made by the home owner or the builder/developer. From the perspective of the builder/developer, the decision to incorporate natural gas into a home is largely dependent on the return on the capital cost investment that the builder/ developer anticipates. For the home owner, the decision could be capital related or personal preference or desire. For either the home owner or builder/developer all, or only specific, applications may be considered.

17.7 Please recalculate the difference in natural gas and electricity on a $/GJ basis assuming the average consumption of a 3,000 square foot house and all the appliances that would contribute to that consumption.

Response:

Based on FortisBC's 2008 Residential End Use Study, average consumption for natural gas end uses other than space and water heating are as listed below.

End Use	Average Consumption per Household (GJ/year)
Decorative Fireplace	4.2
Heater Fireplace	7.8
Range, Cook Top, Oven	1.4
Barbeque	1.0
Dryer	0.2
Pool	1.0
Hot Tub	0.5

However, average capital costs for these other appliances are not readily available as they can have a wide range of prices depending on many factors, including size of retailer, make and model, quantity purchased and discounts offered. Hence, an analysis of the difference in natural gas and electricity for other appliances besides space heat and hot water is not available at this time.

18. Reference: FEU Exhibit B-1, page 21

> The higher upfront capital cost of natural gas end-use applications erodes the cost advantage of natural gas compared to electricity and plays an important role in influencing customer energy choice. The FEU expect the capital cost difference between natural gas and electricity to continue into the foreseeable future, which highlights the need to develop solutions (such as working with key energy influencers, discussed in Section 2.3.3) to address this challenge.

18.1 Please confirm or otherwise explain that existing homes that already utilize natural gas would not face the same capital cost trade-off with electricity as would be required in a new home.

Response:

Existing homes that already utilize natural gas still face a similar capital cost trade off with electricity as new homes. For existing homes, the replacement costs of natural gas equipment at end of lifetime are still higher than electrical equipment, even though ducting and venting are sunk costs and therefore would not be incurred.

18.2 Please confirm or otherwise explain that once natural gas is established in a residential dwelling, it would be unlikely for a homeowner to switch to electric appliances, and/or space or water heating.

Response:

Switching from natural gas to electric appliances is always a possibility depending on the preferences of the homeowner. There are few barriers to switching from natural gas to electric appliances. For example, there is no venting or ducting required for electric space and water heating, making it relatively easy for a homeowner to switch. Another example of the threat of switching is the use of plug in electric heaters or electric heat pumps which displace the use of natural gas.

18.2.1 If confirmed, would FEU agree that the decision with respect to residential energy choice is primarily in new housing?

Response:

Not confirmed. The decision with respect to residential energy choice is in both new and existing (retrofit) housing. As discussed in the response to CEC IR 1.18.2, there are few barriers to switching from natural gas to electric appliances for existing homes with natural gas service.

18.2.1.1 If not confirmed, please explain why not.

Response:

Please refer to the responses to CEC IRs 1.18.2 and 1.18.2.1.

18.3 Please confirm or otherwise explain that natural gas appliances and heating may be mixed with baseboard heaters and area plug in heaters.

Response:

Yes, natural gas appliances and heating may be mixed with baseboard heaters and area plug in heaters. For example, new homes can install natural gas furnaces for the downstairs levels and electric baseboards for upstairs. Electric plug in heaters can also easily be used to augment the heating requirements in any room of a home.

19. Reference: FEU Exhibit B-1, Appendix A-3 page 4

> However, the inclusion of the upfront capital costs (from Table 1) associated with the installation of a gas furnace (indicative of a customer that directly incurs the upfront capital costs of installing gas over electric appliances) reduces the competitive position of natural gas against electricity. From January 2004 to about January 2010, FEI's burner tip rate plus the capital cost of about $9.93/GJ put the total cost per GJ above the Step 2 electric equivalent. From July 2010 to present, FEI's burner tip rate plus capital cost is above the Step 1 electric equivalent rate but below the Step 2 electric equivalent rate. Therefore, it is a more economic option to use natural gas for residential customers with larger home sizes and who consume more energy for space heating (i.e. those who would incur the Step 2 electricity rate). However, for residential customers with smaller home size and consume less energy for space heating (i.e. those who would therefore incur the Step 1 electricity rate), it is a more economical option to use electricity.

19.1 Please confirm that the gas customer profiled in the decision discussion is that of an owner, developer or builder of a 3,000 square foot home in the Lower Mainland.

Response:

Yes, the gas customer profiled is that of an owner, developer or builder of a 3,000 square foot home in the Lower Mainland.

19.2 Would the capital costs be lower for a smaller single family home than for a larger home? Please explain why or why not and provide examples.

Response:

While the capital costs of a smaller single family home are generally lower than a larger home, it also depends on other factors such as insulation levels and number of occupants. For example, a smaller home that is less well insulated than a larger home might still need a larger and more expensive furnace to produce the same heating output. Similarly, a smaller home with more occupants will require a larger hot water tank than a larger home with fewer occupants.

19.3 Please confirm that the owner/developer/builder of a 3,000 square foot home in the Lower Mainland would consider many factors in the choice of natural gas versus electric heating in addition to the capital costs and please explain what they would be.

Response:

For a builder/developer, margin, which is affected by capital costs, drives key decisions. For owners, capital cost may or may not be a key consideration. Depending upon each project's requirements, cost may just be one factor in the decision criteria. Other factors that an owner/developer/builder might consider include comfort and reliability, usable square footage, customer demographic, competing capital requirements (granite counter tops for example) operating costs and accessibility to the energy supply.

19.3.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.19.3.

19.4 Would FEU agree that the builder /developer of a multi-family dwelling would be more cost-sensitive in evaluating the comparative cost of electricity and natural gas than would be a developer of a single family home?

Response:

The cost sensitivity of builder/developers with respect to the installation of electrical or gas appliances will depend on the type of development they are pursuing. For example, developments targeted at first time home buyers who are more price sensitive will require the builder/developer to be more cost sensitive than a high end development targeted at higher socio economic customers.

Generally speaking, developers are indifferent to the operating costs (commodity/delivery) of either natural gas or electricity as these costs are only incurred by the end use buyer of the property not the builder/developer. FEU research has shown that most customers do not understand the costs of natural gas and electricity and therefore customers do not ask for one or the other in a new home because of the price difference in these commodities. However, as evidenced by feedback from customers over two tiered electrical rates, customers are beginning to become aware of the higher cost of electricity.

19.4.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.19.4.

19.5 Please provide an analysis of the cost decision between electricity and gas including the capital cost per unit facing a builder of a multi-family dwelling in the Lower Mainland; and provide all assumptions.

Response:

Each individual builder and developer undertakes their own analysis, each with their own drivers and needs, to arrive at a decision on heating appliances. As such it is not possible to provide an analysis as requested in the question.

The FEU are in the middle of a study to analyze the cost decision between electricity and gas, including the capital cost per unit, facing a builder of multi-family dwellings. This study is expected to be completed at the end of 2014.

In general, smaller multi-family dwellings often have electric appliances installed by builder/developers due to the lower capital and installations costs relative to natural gas appliances, the smaller square footage requirements and less complicated installation requirements. In general, unless a builder or developer can recover their capital costs, and thereby increase their margin, or sell the property more quickly, thereby reducing carrying costs, a developer will install electric equipment. For some builder/developers, the installation of gas equipment is seen as a differentiator and either facilitates a quicker sale or increases the developer margin. Often the decision for gas appliances only occurs after significant sales effort on the part of FEI.

19.6 Would FEU agree that saleability is also a key issue for the developer/builder of Lower Mainland multi-family units?

Response:

Yes, saleability, and time to sale, is a key issue for developers/builders of all kinds of properties, including multi-family units in the Lower Mainland.

19.6.1 Please identify the other factors that FEU considers influences the decision between electricity and gas for developers of multi-family units in the Lower Mainland.

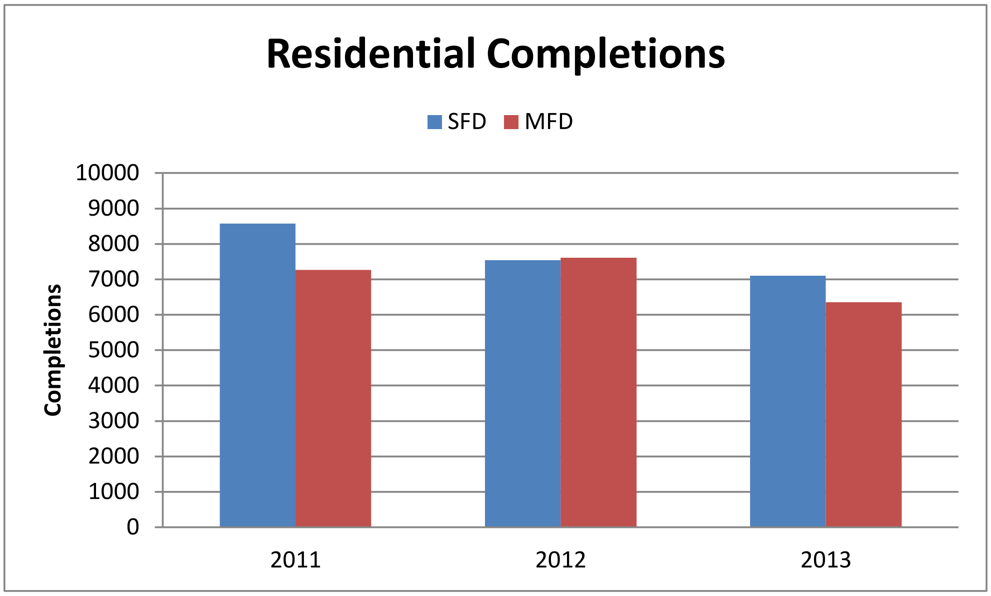
Response:

Please refer to the response to CEC IR 1.19.5.

19.7 Please provide the current multi-family dwelling versus single family dwelling market additions profile and that expected over the planning horizon and please provide FEU's existing and expected capture rate for both.

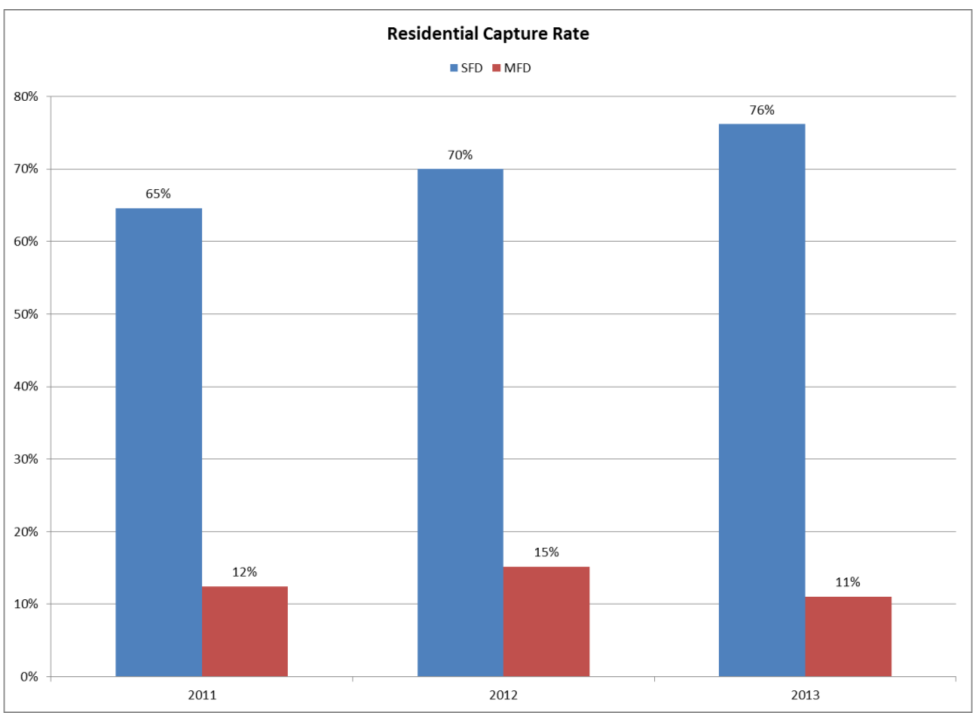
Response:

Based on BC Assessment housing completions data, the historical multi-family dwelling (MFD) versus single family dwelling (SFD) market additions is provided below.



Based on Canada Mortgage and Housing Corporation's report on "Housing Market Outlook – British Columbia Region Highlights (First Quarter 2014)", the 2014 growth in housing starts is excepted to be nearly four percent compared to the 2013 level.

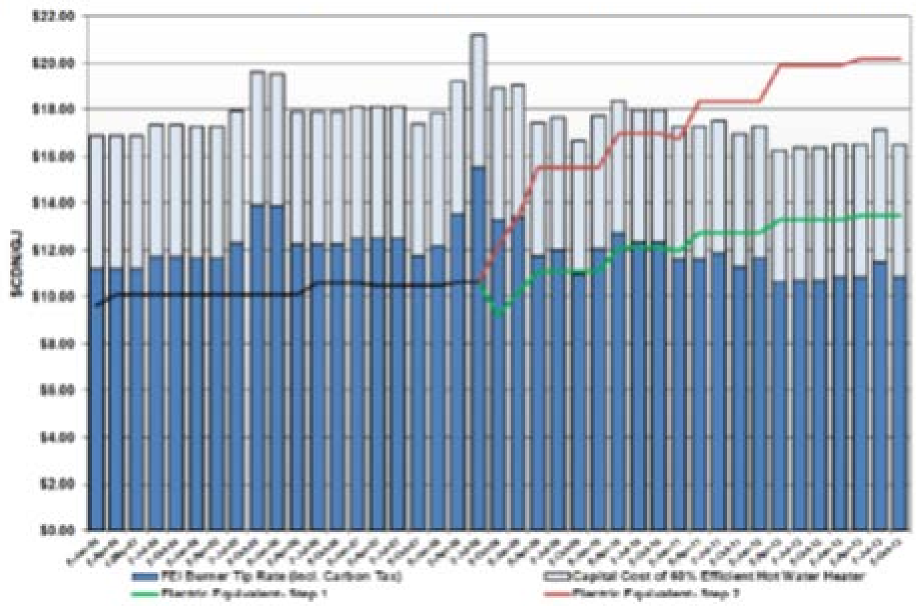
The chart below shows FEU's historical capture rates for MFD and SFD in recent years. As can be seen below, FEU has a much higher capture rate for SFD versus MFD.



20. Reference: FEU Exhibit B-1, Appendix A-3 page 6

> Illustrated in Figure 4, the inclusion of the upfront capital costs associated with the installation of a gas hot water heater dramatically reduces FEI's competitive position against the electric equivalents. From January 2004 until approximately January 2011, FEI's burner tip rate plus the capital cost of about $5.67/GJ put the total cost per GJ above both the Step 1 and Step 2 electric equivalents.

Figure 4: FEI New Water Heating – Burner Tip Rate and Capital Cost vs. Electric Equivalents[7]



20.1 Please confirm that the capital cost of $5.67/GJ is representative of the capital costs for new hot water heating for a 3,000 square foot home in the lower mainland.

<u>Response:</u>

Yes, the capital cost of $5.67 /GJ is representative of the capital costs for new hot water heating for a 3,000 square foot home in the Lower Mainland.

20.2 Would FEU agree that the differential capital costs of a natural gas hot water heater versus electric are unlikely to be a significant factor in the construction of a new 3,000 square foot house in the lower mainland?

Response:

No. The capital cost differential between natural gas and electric hot water heater is a key consideration for builder/developers when deciding on this appliance. Decisions made by a developer are driven by the margin a developer makes when selling a new building. If profit margins are eroded when more expensive natural gas appliances are purchased and installed, builders/developers will opt for less expensive electric installations.

21. Reference: FEU Exhibit B-1, Appendix A-3, page 7

> **3.3 SUMMARY**
>
> The results presented above for space and water heating show that, historically, electricity costs have compared favourably to natural gas when capital costs are taken into consideration. It is only recently, in the context of the lowest natural gas commodity prices in a decade that the price competitiveness of natural gas has improved. However, if the higher natural gas commodity price forecasts of industry experts materialize (as presented in Appendix A-1), FEI's current price competitiveness in certain applications with electricity will again be eroded.

21.1 Please confirm that a reduction in capital costs and/or efficiency improvements in new natural gas appliances could improve the price competitiveness of natural gas vis a vis electricity.

<u>Response:</u>

A hypothetical reduction in capital costs or an increase in efficiency in new natural gas appliances would improve the price competitiveness of natural gas vis a vis electricity, all else being equal (note that the efficiency of gas appliances is near 100% and therefore there is little room for efficiency improvements in new natural gas heating equipment). Efficiency improvements in new natural gas appliances would reduce the total amount of energy required and therefore lower the total energy bill for a consumer. However, an improvement in natural gas appliance efficiency could also mean higher capital cost of that appliance (as is currently the case with both water and space heating gas appliances), thereby hindering the price competitiveness (capital cost plus operating cost) of natural gas vis a vis electricity.

21.2 What strategies are the FEU considering to manage this potential issue and what are the cost/benefit implications of each?

<u>Response:</u>

As described in FEI's 2014-2018 PBR Application, Ex. B-1, Section C3.6.4, pages 160-162, and CEC IR 1.45.2.2 the FEU are pursuing a number of initiatives to manage this potential issue, including the following:

- **Customer Education, Awareness, and Outreach Programs**

  This initiative is aimed at increasing preferences and demand for natural gas use through comprehensive customer education, awareness and outreach programs. These programs are critical in mitigating the market shift in demand, in particular for natural gas space heating and domestic hot water use. Growing demand for natural gas products, through educating customers of the benefits of using natural gas in managing their energy portfolio will continue to be a critical element to the Company's future success.

- **Advancing Natural Gas end-use Technologies and Applications**

  This initiative is aimed at advancing gas end-use technologies to support the efficient use of gas applications in the residential, commercial and industrial market and ensuring they are more affordable and widely available, by working collaboratively with key stakeholders, including industry and the Canadian Gas Association (CGA). The advancement of these technologies and applications is necessary to support the future of natural gas use in residential, commercial and industry markets and align with evolving codes and standards, as FEI has limited influence in these future regulation changes. For example, through advancing the commercialization of efficient natural gas water heating equipment, this initiative will provide for a stable solution to mitigate the further decline in natural gas domestic hot water use, and will provide customers with the opportunity to reduce their energy costs.

- **Incentive Programs**

  Incentive programs are needed to mitigate the threats associated with the competitiveness of natural gas, in particular the higher upfront capital costs of the equipment and the installation. These programs encourage behaviour changes to attract and retain customers. Also, new technology is generally more expensive for customers to purchase and an incentive can be successful in starting market transformation toward, for example, on-demand hot water heaters. This program will leverage the successes of the high carbon fuel switching program.

- **Community Investment in Education**

  This initiative is for FEI to build and foster relations amongst educational institutions in the province, as these establishments are becoming increasingly influential in municipal and provincial policy changes.

22. Reference: FEU Exhibit B-1, page 22

> solutions. The FEU need to continue to understand how these renewable thermal solutions are impacting natural gas demand (outlined in Section 8) and how they are changing the way the Utilities' customers are using natural gas. These growing changes indicate that the traditional utility model may potentially shift over the long term.

22.1 In what ways will the traditional utility model need to shift to accommodate the changing way that customer are using natural gas? Please explain with examples where possible.

Response:

Renewable thermal energy solutions, and distributed generation technologies in general, are beginning to penetrate the energy marketplace and may eventually drive a market transformation. Although distributed energy currently represents a small fraction of lost load for both electric and gas utilities, energy policies and consumer demand are driving increases in installed distributed generation capacity. If distributed generation technologies capture increasing market share and begin to erode demand for energy from utilities, all things equal, consumption of utility energy would decrease but the costs to provided delivery service would stay the same or increase. The effect of this would be increasing rates which would encourage more customers to install distributed generation (Note that EEC initiatives also have the same effect of reducing demand or load on the natural gas system while decreasing utility revenue, which places upward pressure on utility rates). The adoption of distributed generation technologies impacts how energy is produced and consumed, and may transform the traditional utility business model in terms of how both gas and electric utilities create value for customers and shareholders.

There are a number of ways that the traditional utility model may need to shift to accommodate the changing way that customers are using natural gas:

- Utilities must continue to innovate and ensure that their business model offers new products and services that complement distributed generation systems. While the FEU do not provide integrated renewable thermal energy services, the FEU can continue to investigate opportunities to provide innovative solutions that may include EEC programs, metering solutions, customer service initiatives, and rate design.
- Utilities must focus on increasing customer knowledge and understanding of the way customers are using distributed energy in order to be able to forecast output from installed distributed generation systems as well as potential output from future systems.

At present, the FEU will continue to monitor advancements in distributed energy systems and will continue to investigate opportunities to provide innovative solutions that may include metering solutions, customer service initiatives, rate design or gas supply and price risk management.

23. Reference: FEU Exhibit B-1, page 25

> In the U.S. PNW, natural gas plays a prominent role as a source of base load, peaking and reserve demand. The use of natural gas for electricity generation has grown significantly in recent years and natural gas holds a growing share of generation supply. The Northwest Gas Association (NWGA) forecasts an average annual growth rate of 2.6 percent in gas use for generation, up from 1.0 percent in 2012.[27] At the same time, with the exception of Idaho, PNW states use renewable portfolio standards to promote renewable energy generation. Wind power is considered the most available and cost-effective resource to meet these mandates thus
>
> [27] Northwest Gas Association, "2013 Gas Outlook," April 9, 2013.

23.1 Does FEU expect the 2.6 percent annual growth rate for generation to continue beyond 2013? Please explain why or why not.

<u>Response:</u>

The annual generation growth rate in the last five NWGA Outlooks has varied from 1% to more than 3%. The variations are due to a number of factors including market uncertainties and shifting public policy. Weather and water conditions, evolving carbon and renewable energy policies, California's changing resource landscape and a variety of other factors add complexity to the region's generation forecasts. Natural gas-fired generation is the marginal resource in the U.S Pacific Northwest; it is one of a limited number of large scale, dispatchable resources available for future development and, going forward, it is expected that the region will utilize more natural gas for both its energy and capacity requirements. For these reasons, the NWGA updates the growth rate for generation annually in the Gas Outlook publication.

Since the 2014 LTRP was submitted for BCUC acceptance, the NWGA has issued its 2014 Gas Outlook which includes updated forecasts incorporating a 3.3 percent annual growth rate for generation through 2023. The FEU accept this forecast as reasonable based on the factors described above.

23.2 Please provide any longer term predictions that are available for the growth rate for competing generation types.

<u>Response:</u>

The Northwest Gas Association does not produce any longer term predictions for the growth rate for competing generation types. However, the 2014 Northwest Regional Forecast, prepared by the Pacific Northwest Utilities Conference Committee, provides a long term forecast for competing generation types. The following table sets out the 10-year resource projection of power generation for the Northwest Region.

Table 1: *Northwest Region Requirements and Resources – Annual Energy* shows the sum of the individual utilities' requirements and resources for each of the next 10 years. Expected firm load and exports make up the total firm regional requirements.

Annual Energy (MWa)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Firm Requirements										
Load 1/	20,536	20,756	20,976	21,189	21,379	21,572	21,733	21,909	22,067	22,232
Exports	700	650	615	600	590	584	579	527	523	523
Total	21,236	21,406	21,591	21,789	21,969	22,156	22,311	22,436	22,590	22,754
Firm Resources										
Hydro	11,435	11,443	11,402	11,402	11,398	11,398	11,398	11,398	11,398	11,398
Small Therm & Misc.	-	-	-	-	-	-	-	-	-	-
Natural Gas	3,885	4,253	4,272	4,296	4,311	4,347	4,457	4,467	4,420	4,368
Renewables-Other	194	194	194	194	195	194	193	187	185	184
Wind	1,232	1,280	1,280	1,280	1,280	1,280	1,279	1,279	1,232	1,228
Cogeneration	70	70	55	55	41	38	34	17	17	17
Imports	721	822	811	810	813	816	819	821	824	827
Nuclear	878	1,030	878	1,030	878	1,030	878	1,030	878	1,030
Coal	3,730	3,677	3,620	3,712	3,703	3,681	3,500	3,216	3,213	3,221
Total	22,145	22,770	22,513	22,779	22,619	22,784	22,557	22,415	22,167	22,273
Surplus (Need)	**909**	**1,364**	**922**	**990**	**650**	**628**	**246**	**(21)**	**(423)**	**(481)**

1/ Loads net of conservation.

Source: Pacific Northwest Utilities Conference Committee, "2014 Northwest Regional Forecast", March, 2014.

24. Reference: Exhibit B-1, page 26

> Since using natural gas for space heating and thermal applications is more efficient than using it to generate electricity for use in these same applications, utilities such as Puget Sound Energy and Avista Utilities (which provide both electricity and natural gas), promote the direct use of natural gas to avoid new electricity demand—even in service territories where other utilities may benefit from increased natural gas demand.[29,30] The NWGA also advocates policies to promote the direct use of natural gas since gas is seen as a pillar of the region's electricity resource strategy to reduce the use of coal-fired generation and allows integration of a growing fleet of intermittent renewable resources.[31]

24.1 Would FEU consider it appropriate to develop a joint BC Hydro and FEU resource plan to manage the issues where the two energy forms interact?

Response:

No, the FEU do not consider it appropriate to develop a joint resource plan with BC Hydro. The resource planning requirements of a vertically integrated electric utility and a natural gas transmission and delivery utility are very different, making the development of a joint resource plan between the two separately owned and managed companies difficult and impractical.

The FEU do collaborate with BC Hydro in a number of areas that influence long term resource planning, including energy efficiency and conservation activities, understanding the energy services each utility needs or may need in the future from the other and participating in the other's respective resource planning advisory committee/group. The two utilities also plan to collaborate on the next Conservation Potential Review, which will inform both utility's future resource plans.

However, closer alignment on energy policy and customer outcomes should be encouraged between utilities. For example, FEU's proposal to encourage direct use of natural gas for heating applications would have a direct impact on the electricity requirements of BC Hydro, preserving BC's clean electric supply for better end uses. A move to encourage natural gas direct use for heating could be a lower cost resource portfolio option for BC hydro than current portfolios. This has broad implications that can affect Provincial competiveness, disposable income and standard of living.

24.1.1 Please explain why or why not.

Response:

Please refer to the response to CEC IR 1.24.1.

25. Reference: FEU Exhibit B-1, page 28

> such as gasoline and diesel. Nevertheless, the *CEA* does not promote the use of natural gas over electricity where gas is more efficient such as in thermal applications; in fact, the *CEA* defines "demand-side measure" in B.C. to specifically exclude any fuel switching activities that lead to an increase in GHG emissions. Excluding electricity-to-gas fuel switching as a demand-side measure may cloud customer and public perception of natural gas as an efficient fuel. This, combined with heavy government and media emphasis on B.C.'s electricity as a clean, renewable energy source, may contribute to customer and stakeholder confusion regarding the role of natural gas.

25.1 Please provide more details as to why FEU believes excluding electricity to gas fuel switching as a demand-side measure may cloud customer and public perception of natural gas as an efficient fuel.

Response:

The FEU believe that using natural gas instead of electricity for uses such as space heating and hot water where it is appropriate can avoid the use of higher cost electricity for those same uses. The conserved clean electricity would then be available for higher and better uses both in BC and in neighboring jurisdictions. Higher and better uses would include offsetting the need for additional hydro and gas fired generation in BC and gas and coal fired generation outside of BC. From a site-to-source (energy system) perspective, the direct use of natural gas in homes and businesses is a more efficient use of this energy than is using natural gas to generate electricity for use in those same space heating and hot water applications. The FEU believe that the government's policy in not allowing incentives for 'demand-side' measures to encourage electricity conservation in this way provides signals to customers that cover up this efficiency benefit.

Please also refer to the responses to BCSEA IRs 1.11.1 and 1.11.2.

25.2 Please confirm that the CEA exclusion of electricity to gas fuel switching from demand side measures does not preclude FEU from promoting any of the advantages, environmental or otherwise, of switching from electricity to natural gas outside of DSM programs.

Response:

The FEU confirm that outside of the its EEC programs, the FEU can and do promote the advantages of natural gas, environmental or otherwise. The FEU believe that natural gas offers both good economic value but is also a low GHG energy option (please refer to the response to CEC IR 1.45.2.2 for a description of marketing efforts the FEU is currently undertaking)

25.2.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.25.2.

26. Reference: FEU Exhibit B-1, Page 31

> In November 2013, the B.C. Government issued Special Direction No. 5 to the BCUC under Section 3 of the *UCA*. The direction exempts from review expenditures on an expansion of the Tilbury LNG facility up to $400 million and effectively lowers the LNG dispensing rate to $4.35 per GJ. These developments are likely to lead to increasing NGT demand, however, the changes are currently under analysis to determine the potential impact on the forecast of annual NGT demand. While the effect of these recent developments is not considered in the NGT demand forecasts of this LTRP, the potential effect of adding NGT load is considered in determining future system resource needs and alternatives (Section 5).

26.1 When does FEU intend to complete its analysis of the potential impact of Special Direction No. 5 on the forecast of annual NGT demand?

Response:

The FEU have completed the initial analysis of the potential impact of the Special Direction and the forecasts presented in the PBR Evidentiary Update incorporated the change. For reference, the table below was filed in the FEI PBR Evidentiary Update, which was filed February 21, 2014.

Table H-4: FEI Natural Gas Demand (GJ/Year) Forecast for NGT

Load Addition (Cumulative)	2013A	2014F	2015F	2016F	2017F	2018F
Vocational trucks (CNG)	119,753	163,763	221,763	310,763	410,763	486,763
Buses (CNG)	-	-	72,000	82,000	86,000	86,000
Class 8 tractors (LNG)	194,729	442,729	442,729	466,729	858,729	1,302,729
Mining (LNG)	-	-	-	68,000	136,000	136,000
Rail (LNG)	-	-	-	-	60,000	60,000
Marine (LNG)	-	-	-	550,000	550,000	550,000
Total NGT Fleet	314,482	606,492	736,492	1,477,492	2,101,492	2,621,492

26.2 Please identify the activities that FEU intends to undertake to promote the development of NGT demand over the next five years.

Response:

In the NGT segment, FEI's primary objective in the next five years is to create awareness for the use of CNG/LNG across targeted customer segments and to enable customers to make the transition from conventional fuels to CNG/LNG. FEI's strategy to date has been to work with leaders in the target segment and use them as an anchor tenant to build the infrastructure and demonstrate that there are considerable savings by switching from diesel to natural gas. This then encourages other customers to follow these early adopters. This approach has been successful in both the CNG and LNG segments since the enactment of the GGRR.

In the CNG segment, FEI has been able to penetrate the refuse and transit markets as these are ideal customer segments that consume large amounts of fuel, travel intra-city and return back to base. To replicate this success, FEI is conducting research and market analysis on other types of applications best suited for regional haul and intra-city travel that fit a similar profile as that of waste haulers and transit buses. This research will allow FEI to focus on the carriers that will help expand the market, and will also build transportation corridors for future potential customers.

In the LNG segment, FEI has had strong initial success in heavy B train transportation applications (vehicle combinations with a gross combination weight of 140,000 pounds) However, further penetration in this segment is not possible until there is a suitable replacement for the Westport 15 Litre High Pressure Direct Injection (HPDI) from OEM suppliers. In the meantime FEI is conducting research and exploring alternative market segments which could be potential adopters of LNG in transportation applications. For example FEI is in discussions with two marine vessel operators to convert a number of marine vessels to operate on LNG, and also with mine truck operators to develop LNG for use in mine haul truck applications.

Additionally FEI will use channels such as internal sales, website marketing, participation in industry events, print media and working closely with OEM suppliers and dealerships to create awareness and promote the NGT program.

26.3 Please provide any high-level forecasts that FEU currently has with respect to the NGT demand due to Special Direction No. 5.

Response:

Please refer to the response to CEC IR 1.26.1.

27. Reference: FEU Exhibit B-1, page 25 and page 32

> In the U.S. PNW, natural gas plays a prominent role as a source of base load, peaking and reserve demand. The use of natural gas for electricity generation has grown significantly in recent years and natural gas holds a growing share of generation supply. The Northwest Gas Association (NWGA) forecasts an average annual growth rate of 2.6 percent in gas use for generation, up from 1.0 percent in 2012.[27] At the same time, with the exception of Idaho, PNW states use renewable portfolio standards to promote renewable energy generation. Wind power is considered the most available and cost-effective resource to meet these mandates thus

> Such rules include mandatory pre-piping for future installation of roof-mounted solar energy generating equipment, in addition to infrastructure that will facilitate the installation of electric vehicle charging stations. According to the City of Vancouver, by 2020, all new homes will consume up to 33% less energy, and by 2030, all new homes will be carbon neutral. In a similar manner, the City of Surrey is building a district energy system and to ensure adequate customer levels, Surrey's *District Energy System By-Law* requires all city centre buildings of a specified size to be built with a hydronic system such that they will be compatible with the district energy system for space heating and hot water heating.[39] **The actions by local governments to encourage adoption of a variety of renewable energy sources carry significant negative implications for natural gas demand and future throughput on FEU's systems.**

27.1 Could a transition away from traditional gasoline vehicles to electric vehicles have a positive indirect effect on the demand for natural gas through its use in generation? Please explain why or why not.

<u>Response:</u>

The proliferation of electric vehicles is not expected to have a material impact on natural gas demand, particularly in BC. Electricity generation in BC, primarily supplied by BC Hydro, is overwhelmingly produced using hydro-generation.

28. Reference: FEU Exhibit B-1, page 33

> Following the BCUC Alternative Energy Solutions Inquiry in 2011-2012, FEI's new initiatives in thermal energy service projects are being undertaken by a separate, regulated FEI affiliate.[40] Nonetheless some customers continue to demand efficient, low carbon, integrated end-use energy solutions.
>
> Although the FEU are no longer delivering renewable thermal energy alternatives, the Companies are enabling a number of customer solutions through programs to promote energy efficiency and conservation (discussed in Section 4), provide natural gas as a transportation fuel alternative, capture carbon neutral biomethane sources to displace conventional natural gas, explore advanced metering solutions and improve the competitive position of natural gas service to better meet the needs of builders, developers and end-use customers. The initiatives

28.1 Please confirm that due to the AES decision FEU is not permitted to offer integrated end-use energy solutions, but that the regulated FEI affiliate is permitted to do so.

Response:

The AES Inquiry Report uses various defined terms in setting out its guidelines, recommendations and directives, such as "Alternative Energy Services" and "Thermal Energy Services" (see Appendix A to the Report). The AES Inquiry Report does not use the phrase "integrated end-use energy solutions", and so the FEU is not sure how to answer this question. See the "Principles and Guidelines for Determining Business Structure and Use of Monopoly Resources" in section 2.3 of the Report for further discussion on this subject matter.

28.2 Please provide a discussion of the customer group(s) requiring integrated end-use energy solutions.

Response:

Customers in the FEU's general residential, commercial and industrial groups may require integrated solutions as described in the response to CEC IR 1.28.1; however, it is generally customers in the residential and commercial customer groups who seek energy solutions in which renewable thermal or district energy systems are integrated with natural gas service.

29. Reference: Exhibit B-1, page 36

2.3.3 Other Activities

The Utilities are improving customer engagement through education and awareness of the benefits of natural gas use, along with providing customers with energy management tools facilitated through multiple communication channels. As such, the Companies continue to explore ways to engage a wider network of builders and developers along with other influencers of residential gas use including architects, engineers, contractors, manufacturers, dealers and homeowners. This activity is aimed at building natural gas load, mitigating declining market share in some sectors, and improving customer and stakeholder engagement through opportunities to promote natural gas education, awareness and training.

29.1 Please provide a description of the energy management tools that FEU is offering its customers.

Response:

Currently, the FEU have an online home energy calculator that provides customers with a cost comparison, energy comparison and related savings for operating various space and water heating appliances using different fuel types including electricity, natural gas, propane and fuel oil. In addition, the FEU's contractor program is designed as a tool to assist customers in finding local, qualified contractors that can safely install and service energy efficient natural gas appliances.

The FEU also offer energy management tools through the Companies' EEC programs. For example, through the Energy Specialist program, the FEU assist large commercial customers to develop and execute projects that result in natural gas savings. Through the Continuous Optimization Program, commercial building owners obtain access to energy efficiency funding and an energy management information system to assist in tracking building performance. The Industrial Energy Audit program provides funding towards helping customers conduct a comprehensive energy audit by a certified energy manager or professional engineer. The FEU consider EEC incentives to encourage customers across all sectors to promote energy conservation and efficiency as important tools to manage energy consumption.

The FEU continue to examine other energy management tools including a customer engagement and energy visualization tool that will provide customers with neighbour energy comparisons if they so wish.

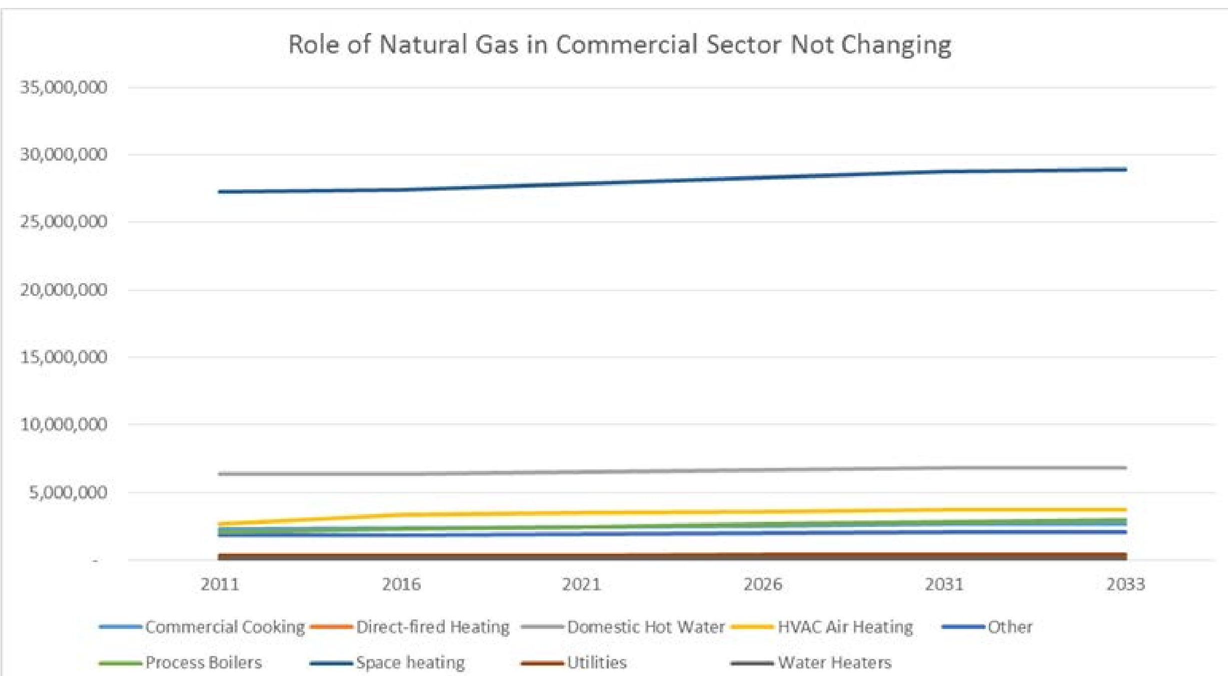
30. Reference: FEU Exhibit B-1, page 36

> Although the decline of natural gas commodity rates has improved the fuel's price competitiveness against electricity on an operating cost basis, this decline has been offset by increases in B.C.'s carbon tax along with the relatively higher capital, installation and maintenance costs for natural gas equipment. Furthermore, the role of natural gas in its traditional use of space and water heating, which makes up over 80 percent of residential natural gas throughput, continues to be challenged by changing environmental policies, appliance standards and regulations. These declining trends negatively impact throughput and load growth, and increase the importance of the Utilities' actions to mitigate this pressure. Though the evolving natural gas marketplace presents a number of utility challenges, the FEU are also presented with opportunities to capitalize on new areas to add new system load.

30.1 Please provide a discussion as to how the role of natural gas is expected to evolve in the Commercial sector.

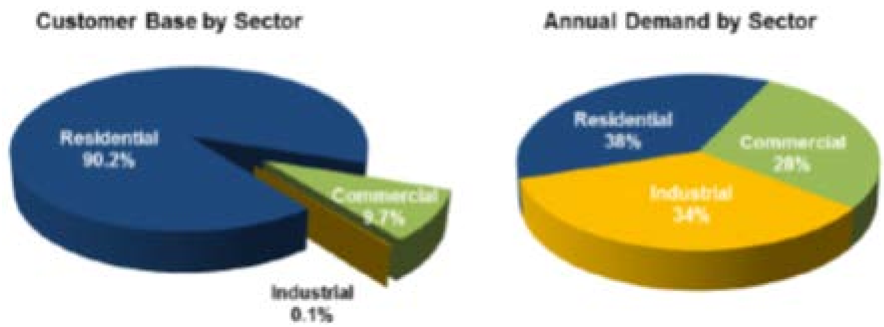
Response:

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.



31. Reference: FEU Exhibit B-1, page 39

Figure 3-1: FEU Customer Base and Demand Overview, 2011



31.1 Please confirm that 'Customer Base by Sector' represents the number of customers, while the Annual Demand by sector is based on volume.

Response:

Confirmed.

31.1.1 Please provide the relevant figures for the pie charts.

Response:

Please refer to the table below for the 2011 customer base and demand data respectively.

2011 FEU

Rate Group	Customer Count	Demand (TJs)	Percent Customer Count	Percent Demand
Residential	859,091	74,252	90.2%	38%
Commercial	92,392	55,330	9.7%	28%
Industrial	907	65,540	0.1%	34%
Total	**952,390**	**195,122**	**100.0%**	**100%**

31.1.2 Please provide the Annual Revenues by Sector and by volume if not already provided.

Response:

Please find the customer counts, volumes and revenues by sector for 2011 in Table 1.31.1.2 below. The annual demand by sector shown in the referenced Figure 3-1 from the 2014 LTRP correlates with the annual volumes and revenue by sector shown in the table below.

Table 1.31.1.2: 2011 FEU Volume and Revenues by Sector

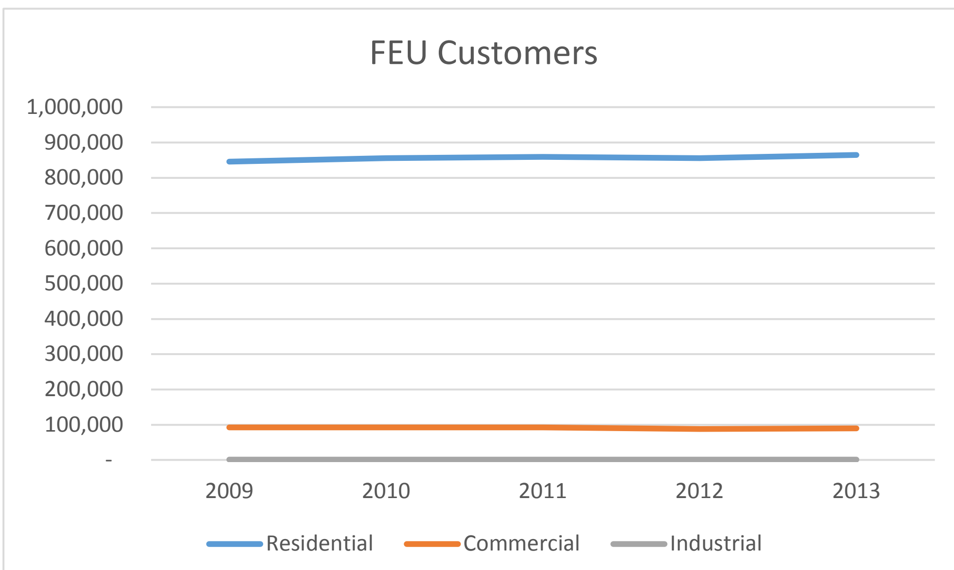
		2011
Customers	Residential	859,091
	Commercial	92,392
	Industrial	907
Demand (TJs)	Residential	74,252
	Commercial	55,330
	Industrial	65,540
Revenue ($Million)	Residential	903.35
	Commercial	528.30
	Industrial	132.58

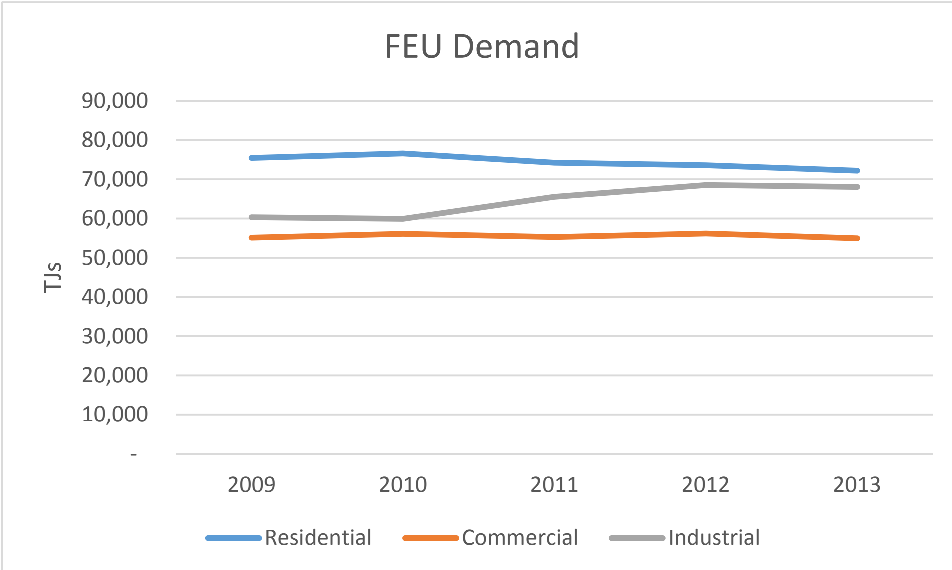
31.1.3 Please provide depictions and the relevant figures the Customer Base by Sector, Annual Demand by Sector by TJ, and Annual Revenues for the years 2009, 2010, 2011, 2012 and 2013.

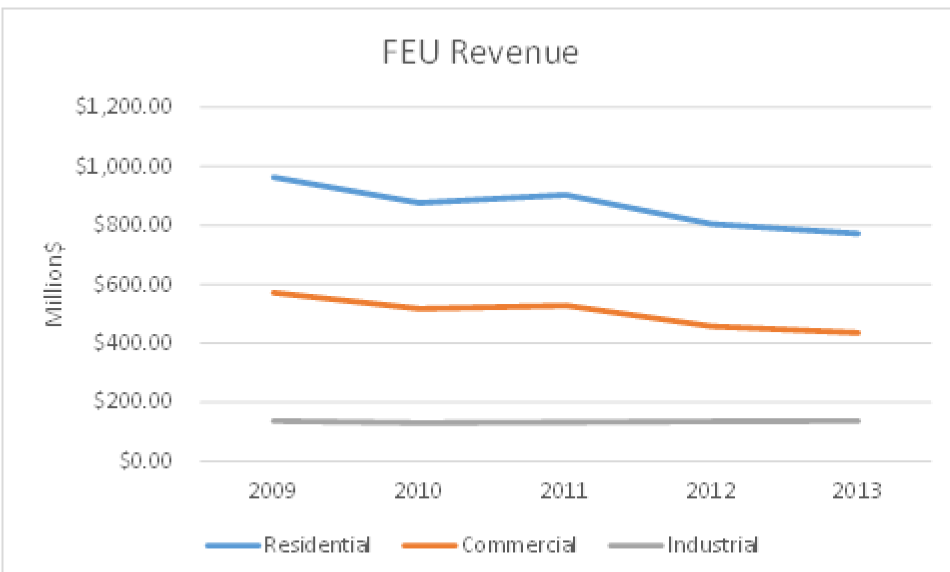
Response:

Please find below customer base, demand and annual revenue for FEU by respective rate groups and respective percentages.

		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




FEU Demand
TJs
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
2009
2010
2011
2012
2013
Residential
Commercial
Industrial


FEU Revenue
Million$
$1,200.00
$1,000.00
$800.00
$600.00
$400.00
$200.00
$0.00
2009
2010
2011
2012
2013
Residential
Commercial
Industrial

32. Reference: FEU Exhibit B-1, page 40

> **3.2 CUSTOMER ADDITIONS FORECAST**
>
> The FEU use a well-established methodology to forecast customer additions that remains consistent with previous LTRP filings. The forecast of residential customer additions is grounded in the Conference Board of Canada housing starts forecast for British Columbia, while commercial customer additions are forecast based on recent trends in growth for the commercial customer group. The customer additions forecast by rate class for each of the milestone years is included in Appendix B-1.

32.1 Please explain in what ways the residential customer additions forecast is 'grounded in the Conference Board of Canada forecast housing starts and what additional considerations are applied to develop the final forecast.

<u>Response:</u>

Residential customer additions and the existing residential customer totals are a key input in the residential demand forecast. The customer count (including additions) is multiplied by the average use per customer to form the residential demand forecast.

In order to forecast customer additions, the FEU continue to use the housing starts forecasts from the Conference Board of Canada (CBOC). The forecast provides separate single family and multi-family residential estimates.

The residential net addition forecast consists of a single and multi-family dwelling forecast. These two forecasts are based on our FEU's internal customer mix for these dwellings as well as the CBOC forecast for growth in these two housing types. Once the separate forecasts are completed the accounts are combined for the two housing types and become the Rate Schedule 1 residential accounts forecasts.

32.2 Please confirm or otherwise explain that the customer additions forecast are developed using the same methodology in each region.

<u>Response:</u>

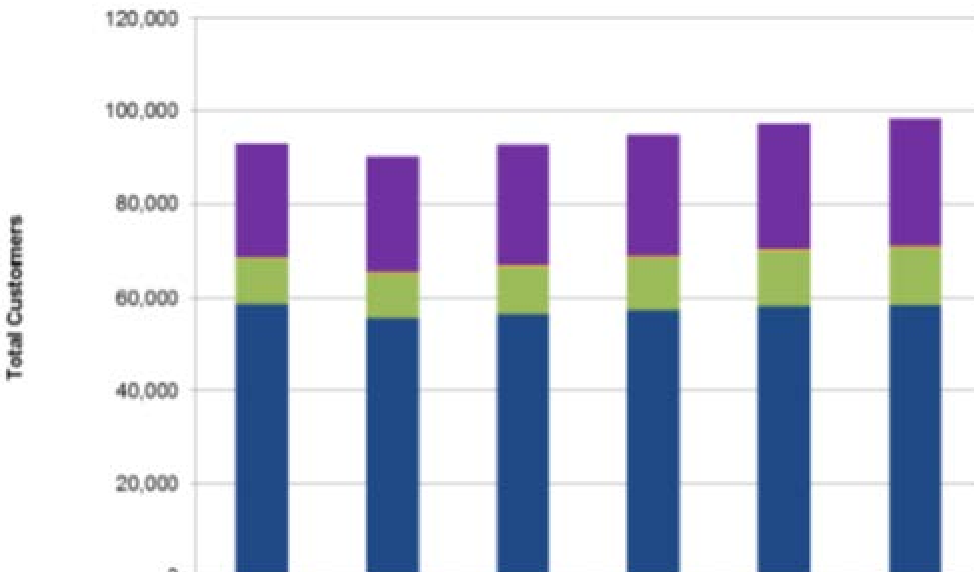
Confirmed.

33. Reference: FEU Exhibit B-1 page 41 and Figure 3-3

Commercial

Recent trends in commercial customer additions are used to predict future additions. The net customer additions are estimated based on actual additions in the latest three years. Recent additions are not as strong as in previous years, averaging in the range of 400 per year. The long term account forecast for commercial rate schedule customers is shown in Figure 3-3 for each of the FEU's service regions.

Figure 3-3: Long Term Account Forecast by Region – Commercial



	2011	2016	2021	2026	2031	2033
Interior	24,329	24,423	25,388	26,269	27,123	27,486
Whistler	353	373	412	447	486	502
Vancouver Island	9,534	9,530	10,205	10,853	11,539	11,839
Lower Mainland	58,632	55,708	56,565	57,368	58,139	58,440

33.1 Please provide a more detailed discussion as to how the commercial forecast is developed and identify any other considerations that are included in generating the long term commercial forecasts by region.

<u>Response:</u>

Given the preamble, the FEU interpret this request to refer specifically to the commercial customer additions forecast. Commercial customer additions and the existing commercial customer totals are a key input for the commercial demand forecast. The total customer count (including additions) is multiplied by the average UPC to form the commercial demand forecast.

The forecast of Commercial customer additions is based upon an analysis of recent trends in the Commercial rate class.

Commercial additions are volatile and the FEU believe there is no one numerical method that can provide a consistently accurate long term insight into the future commercial additions due to the multiple factors involved. In the absence of a better alternative, the FEU use a simple 3 year average approach with a goal to update the forecast on a regular basis to capture any deviations from the existing trend. The average is taken on the actual net additions which incorporate the net trend from new installations, rate switching and customer churn.

Other factors that go into the long term annual demand forecasts other than customer additions are provided in Sections 3.3.2, 3.3.3 and 3.3.4, as well as Appendix B-3 of Exhibit B-1.

33.2 According to Figure 3-3, FEU expects the Commercial sector account forecast in the Lower Mainland to decline between 2011 and 2016 by 5%, while the other regions are forecast to remain steady or increase. Please provide an explanation as to why FEU has this expectation, and provide any relevant context for why this is expected to occur.

<u>Response:</u>

Commercial customer additions for 2016 through 2033 were forecast using actual data from 2010, 2011 and 2012. As a result, the commercial sector account forecast was affected by the customer count adjustment that resulted from the introduction of a new SAP based Customer Information System (CIS). The customer count adjustment was a one-time amendment effective January 1, 2012. Although the adjustment affected all of the FEU's regions, its impact on the Lower Mainland was more pronounced relative to the other regions, resulting in a decrease of 4,527 commercial customers or almost 8 percent.

This one-time adjustment decreases the commercial customer count in the 2011-2016 period. The impact of this one-time adjustment has been properly examined and accounted for in order to ensure the adjustment does not adversely deflate the true trend in the commercial additions forecast for the years subsequent to 2012.

Account growth in the commercial sector is forecast to be positive but modest with new additions ranging around 0.3% of the total account on an annual basis. Given the magnitude of change due to the SAP customer count adjustment in 2012, the commercial sector account total for the Lower Mainland is not forecast to return to its pre SAP level until after 2033.

More detail on the customer count adjustment can be found in FEI 2014-2018 PBR, Ex. B-1-1, Appendix E4.

33.3 According to Figure 3-3, FEU expects that the Long Term Commercial Account Forecast in the Lower Mainland will not recover its 2011 standing even by 2033 while the other regions are growing. Please provide an explanation as to why this phenomenon is expected to occur.

Response:

Please refer to the response to CEC IR 1.33.2.

34. Reference: FEU Exhibit B-1, page 42

Industrial

The FEU had 909 industrial customers in 2011. 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.

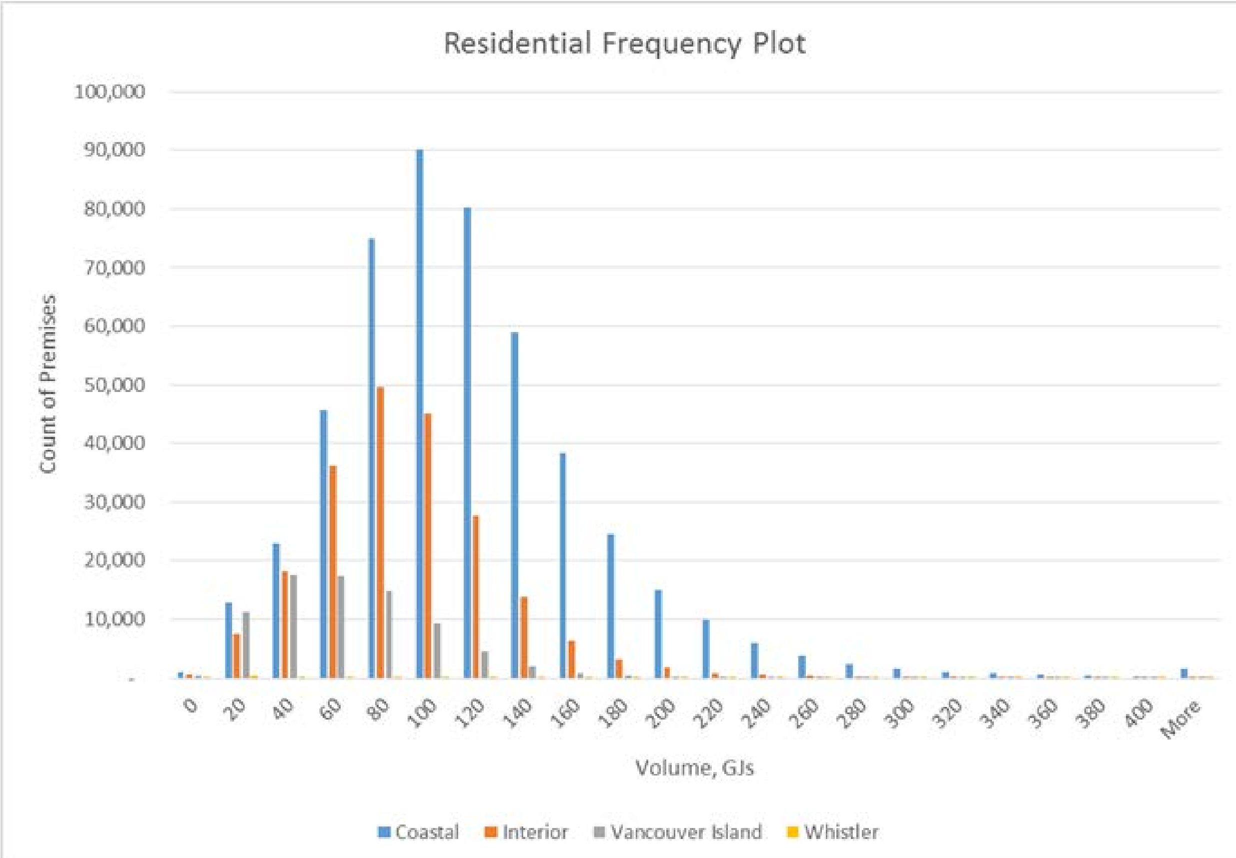
34.1 Is it FEU's expectation that there will be no significant change in the number of industrial customers through to 2033?

Response:

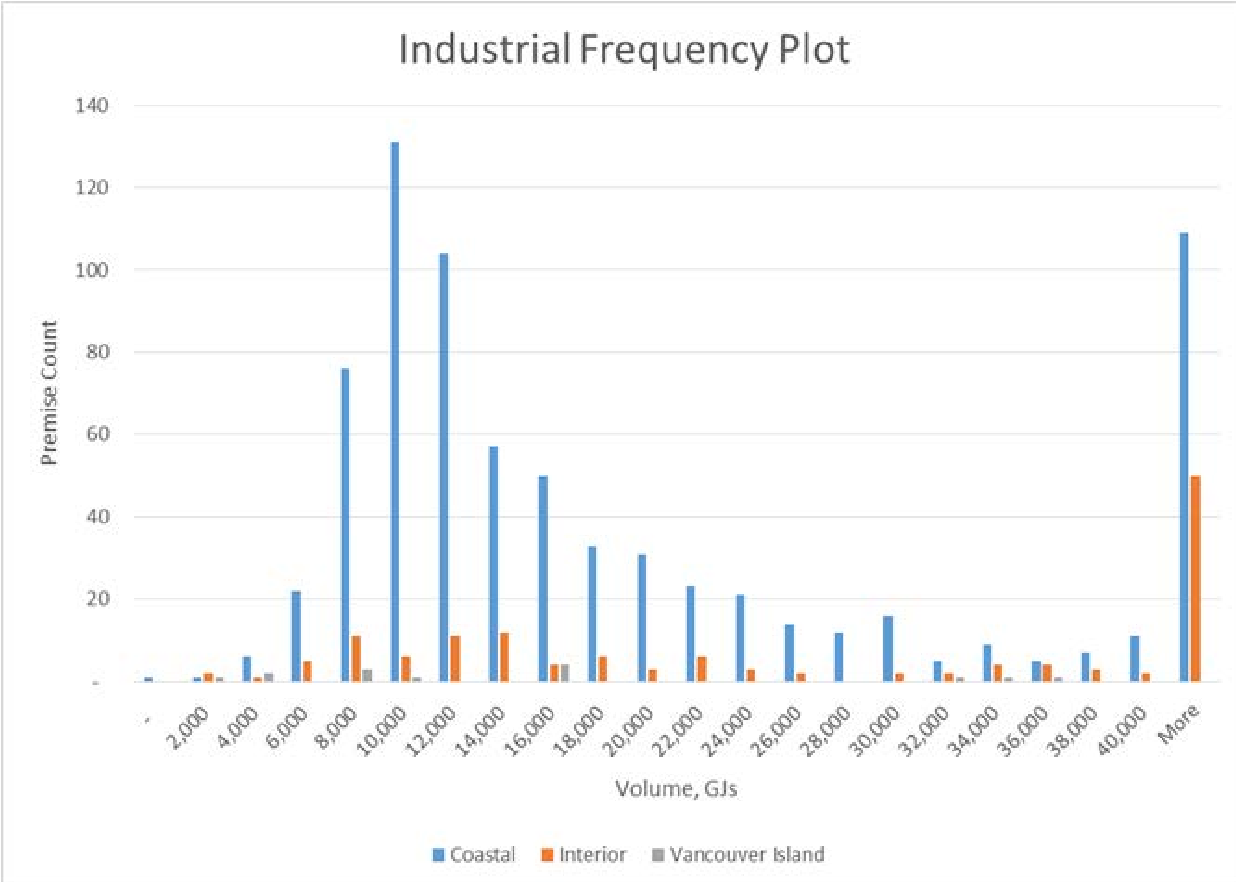
The FEU have not incorporated an expectation for a significant change in the number of industrial customers. Though interest from potential new industrial customers in acquiring gas service has increased recently, at the time the long term forecast was prepared there were no firm commitments for new 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.

As compared to industrial customers, adding new residential and commercial customers to the forecast does not require that we know their individual expected volumes. They are added to the appropriate rate class and assumed to consume the rate class average. Industrial customers on the other hand are not forecasted using average use rates, and without specific knowledge of a new industrial customer it is not reasonable to apply an average consumption to determine a demand forecast.

A frequency plot for residential customer shows the consistency for this rate class:



On the other hand a similar plot for industrial customers shows that the second most popular class is "more" and the bin size is fully 2,000 GJ. The wide range of demand values for industrial customers means that FEU cannot just add an "average" industrial customer as we do with the residential and commercial classes. The industrial frequency plot also demonstrates why it is important for the accuracy of the forecast to only add individual customers once we have firm commitments.



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.

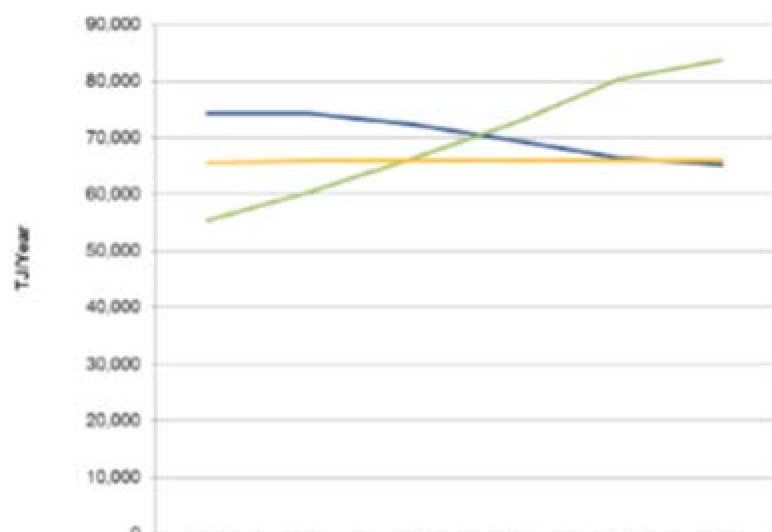
34.2 Please provide insight into and an explanation of the recent increase in industrial customer inquiries about natural gas service.

Response:

The FEU have seen a recent increase in industrial customer inquiries about natural gas service as a result of favourable commodity prices and large natural gas reserves within the province. Such inquiries remain confidential.

35. Reference: FEU Exhibit B-1, page 44

Figure 3-4: Long Term Annual Demand by Rate Class – Traditional Methodology



	2011	2016	2021	2026	2031	2033
Residential Traditional	74,252	74,277	72,345	69,408	66,434	65,259
Commercial Traditional	55,330	60,308	66,353	72,760	80,373	83,859
Industrial Traditional	65,540	66,008	65,996	65,996	65,996	65,996

35.1 According to the traditional methodology, Commercial demand is expected to outpace industrial demand by 2021 and also residential demand by 2026. Please provide a discussion of the key factors that FEU considers will be important in maintaining and growing Commercial demand over the next 20 years

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.

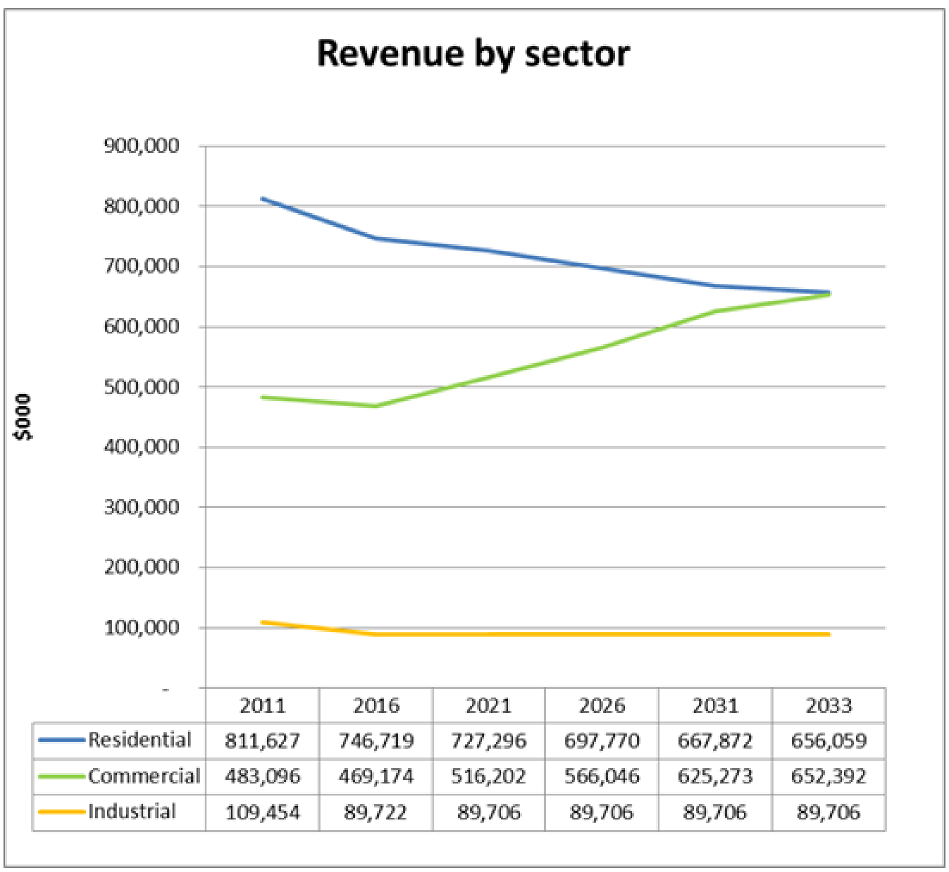
The FEU believe that the end-use forecast model is a better tool to examine a range of potential futures that can have different long-term implications of annual natural gas use in the commercial sector. The FEU's response to CEC IR 1.30.1 provides a discussion on how the role of natural gas in the commercial 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.

35.2 Please provide Figure 3-4 Long Term Annual Revenue ($ per year), assuming the average current $/TJ for each sector.

Response:

As requested, the following graph uses the volumes from Figure 3-4: Long Term Annual Demand by Rate Class – Traditional Methodology, and for the years 2016 through 2033 multiplies those volumes by the 2014 average annual revenue per TJ by sector. For 2011, the revenues are derived by multiplying the 2011 volumes from Figure 3-4 by the average annual revenue per GJ by sector for 2011.

Although prepared as requested, 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, FEU do not prepare a twenty year revenue forecast because it would not provide meaningful information.



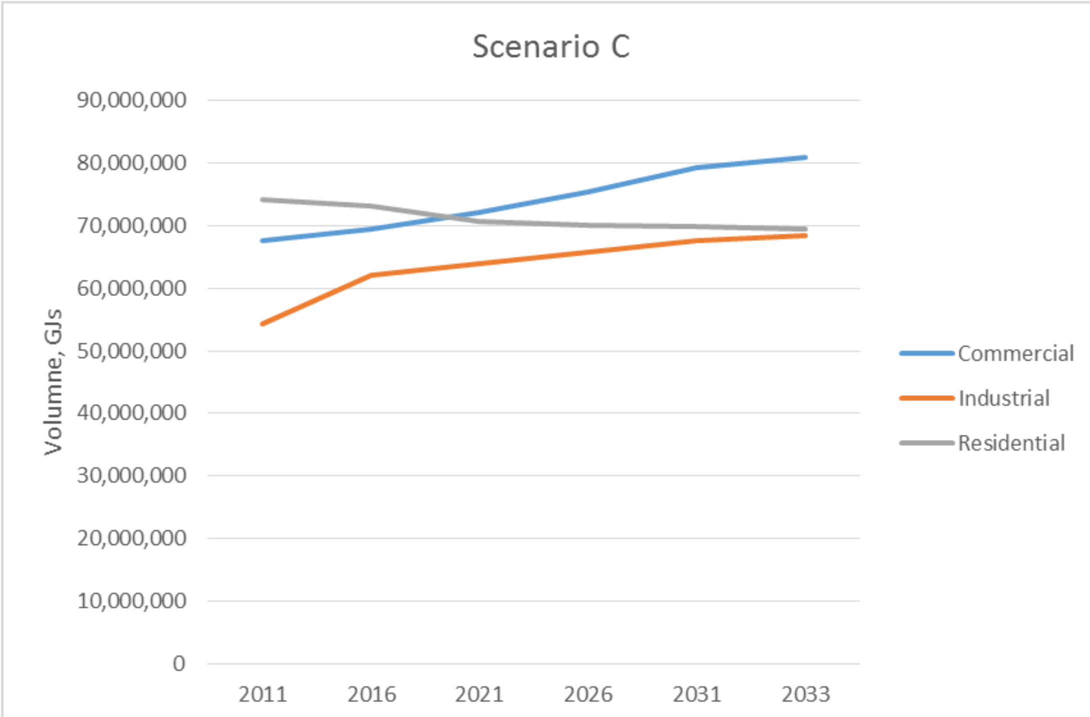
35.3 Would FEU agree that as broad characterizations, residential may be considered a declining market; commercial may be considered a growth market and industrial may be considered a stable market?

Response:

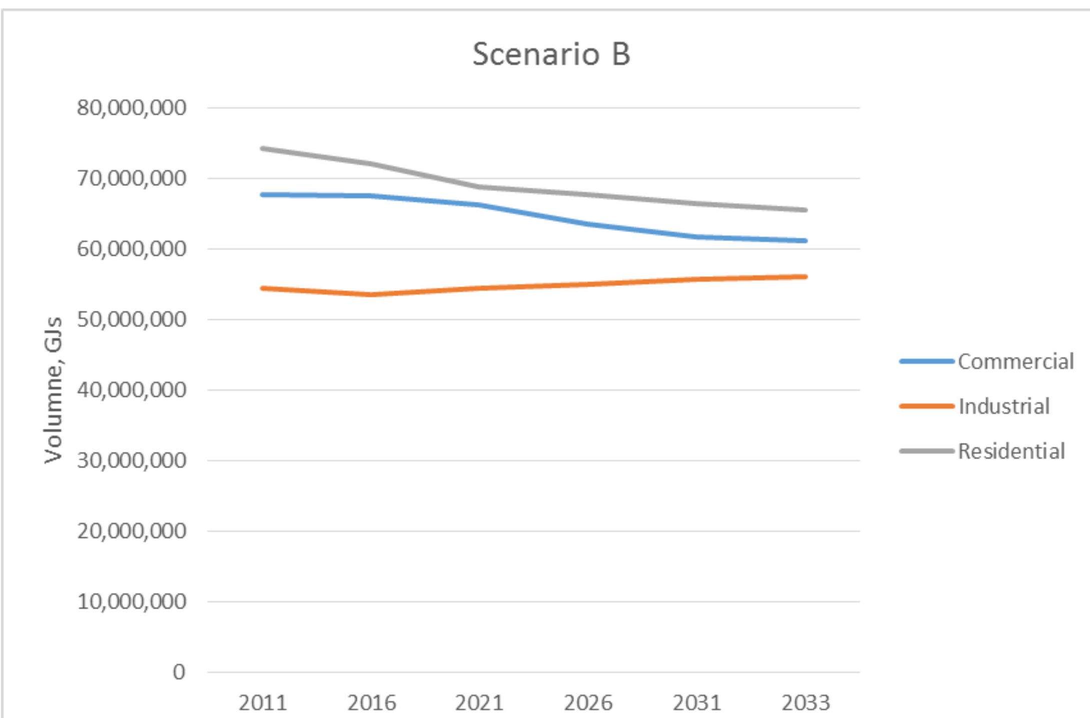
Based on the traditional forecast of energy (which is based on recent history), residential may be considered a declining market, commercial may be considered a growth market and industrial may be considered a stable market.

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.



Scenario C
90,000,000
80,000,000
70,000,000
60,000,000
50,000,000
40,000,000
30,000,000
20,000,000
10,000,000
0
Volumne, GJs
2011
2016
2021
2026
2031
2033
Commercial
Industrial
Residential



Scenario B
80,000,000
70,000,000
60,000,000
50,000,000
40,000,000
30,000,000
20,000,000
10,000,000
0
Volumne, GJs
2011
2016
2021
2026
2031
2033
Commercial
Industrial
Residential

35.3.1 If not, please explain why not and provide an alternate view.

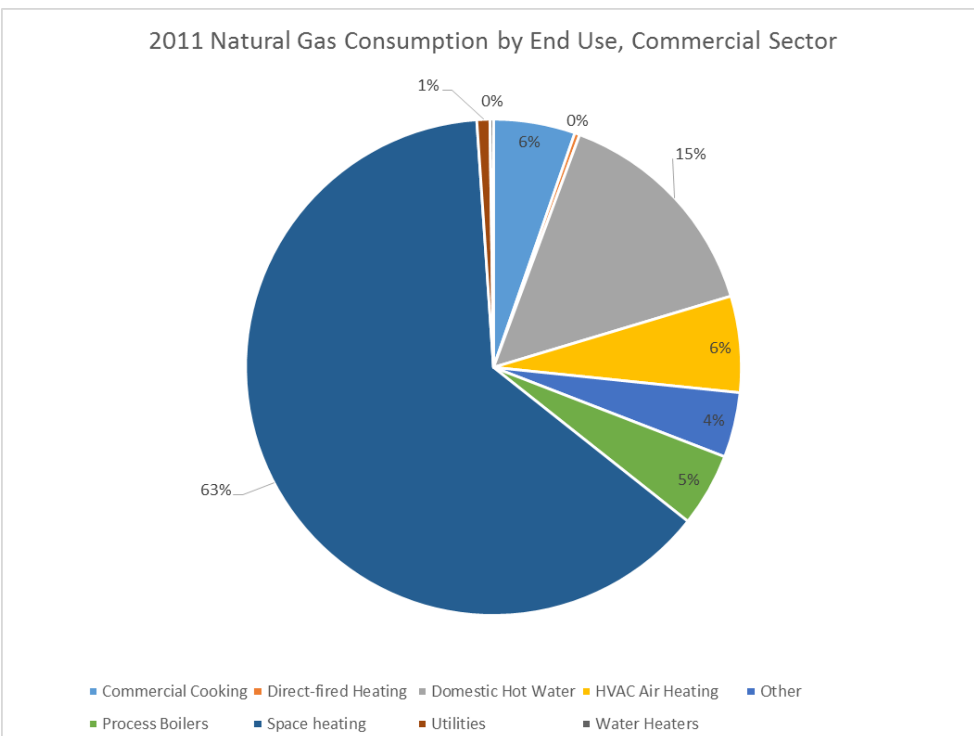
Response:

Please refer to the response to CEC IR 1.35.3.

35.4 Please provide a discussion of FEU's view of the price-sensitivity of the Commercial sector.

Response:

The following plot from the end use model for the base case, 2011, all commercial rate classes, shows that the predominant use of natural gas in the commercial sector is for space heating.



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.

35.4.1 At what prices might different growth scenarios be expected for the commercial sector?

Response:

Please refer to the response to CEC IR 1.35.4. The commercial sector tables in Appendix B-3 of Exhibit B-1 contain assumptions about how different price forecasts will impact future annual demand using the end use forecasting methodology.

35.4.2 Please provide a price range and the relevant growth scenarios which might be expected for each price.

Response:

Please refer to the responses to CEC IRs 1.35.4 and 1.35.4.1.

36. Reference: FEU Exhibit B-1, page 45

> Declining residential use per customer in the FEU's service territories is resulting in an overall decline in residential annual demand, even though the FEU continues to add residential customers through the forecast period. This decline in residential use per customer is now a common occurrence affecting mature natural gas utilities across North America. The Companies believe that the drivers lowering UPC include, but are not limited to, efficiency improvements, changes in building stock, changes in appliance uptake and switching between energy sources (from gas to electric). Efficiency improvements include the retrofit of older, less efficient appliances with new high efficiency units, and also upgrades to insulation, window, doors, and more generally speaking, building shells. Efficiency improvements are driven by a number of factors such as technological advances, construction of smaller, less energy-intensive multifamily dwellings, natural gas prices, public policies and programs and the state of the economy. This declining trend is expected to continue through the planning period.

36.1 What drivers other than those listed also contribute to a lower of the UPC on the residential side?

<u>Response:</u>

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.

37. Reference: FEU Exhibit B-1, page 45

> **Commercial Demand**
>
> In the traditional forecast method, the recent demand increases seen in the commercial rate classes are assumed to continue into the long term and thus, commercial demand grows significantly over the 20 year planning horizon. Increases in commercial annual demand drive the overall increase in the traditional forecast of annual demand shown in Figure 3-4.

37.1 Please provide FEU's views of the key drivers for the growing Commercial demand and the sustainability of those drivers throughout the planning period.

Response:

The FEU's commercial customer group has a wide range of commercial sectors within it. Drivers for overall commercial demand are a mix of different factors that are specific to each commercial sector. The drivers for each individual sector may act differently under different future conditions. For instance, a recession may reduce demand in one sector while increasing demand in another sector. In this respect it is difficult to identify key drivers that would be affecting all different sectors of commercial demand simultaneously. For this reason the FEU do not break out sector or industry drivers for the purposes of forecasting demand.

For the purposes of forecasting, the FEU do not require specific data on the drivers and their impact on the traditional annual demand forecast because all drivers are implicit in the historic data the FEU use to prepare the future forecast. The forecast is updated on a regular basis so all drivers and their precise effects are always captured in the recent historic data used.

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 1.35.1 discusses the key factors for growing commercial demand and the response to CEC IR 1.45.2.2 describes the types of initiatives the FEU believe they need to undertake to influence commercial customer energy choice.

38. Reference: FEU Exhibit B-1, page 46

> To undertake this new annual demand forecasting methodology, the FEU turned to their best source of existing end-use demand characteristics for the development of a base year data set, the 2010 Conservation Potential Review. This base year data set has been enhanced by more recent customer additions data and additional market research undertaken since preparation of the 2010 CPR. The FEU also engaged ICF Marbek (who prepared the 2010 CPR) to repurpose their CPR modelling software with FEU base data to apply it to a long range demand forecasting effort. This partnership provides an effective combination of knowledge about the customer base data from the FEU and expertise in modelling end-use energy consumption within the B.C. marketplace from the consultant. The exercise resulted in an extensive raw data set provided to the FEU, on which the FEU is able to conduct further analysis of potential future demand implications.

38.1 Please confirm or otherwise explain that the new annual demand forecasting methodology is limited to addressing end-use consumption and does not affect the service line additions forecast nor average number of customers forecasts as would be provided under PBR.

<u>Response:</u>

Confirmed. The end use methodology affects use rates only. Instead of specifying a single premise level UPC for a Rate Schedule 1 residential customer, for example, the end use model allows the FEU to specify end use rates for each appliance in the premise. As such the end use method does not affect or attempt to forecast service line additions.

A long term account forecast is prepared and in conjunction with the end use scenarios produces the long term forecast of demand. In comparison, the short-term forecast that will be utilized to forecast demand in FEI's annual filings under PBR continues to use the traditional method of forecasting.

38.1.1 If not confirmed, please provide a discussion as to how the service line additions and average customer count will likely be affected by the revised forecasting methodology.

<u>Response:</u>

Please refer to the response to CEC IR 1.38.1.

39. Reference: FEU Exhibit B-1, page 46

> The Reference Case began with the development of a base year, in this case 2011. The FEU provided a database of accounts with normalized consumption data for their service territory categorized by region, rate class, and industry (for industrial and commercial customers). To further subdivide natural gas consumption by end use, ICF Marbek drew on the detailed customer knowledge assembled for the 2010 CPR, including end use consumption, market saturation[48] and gas share.[49] Some of this information has been derived from end-use surveys commissioned by the FEU, while other aspects emerged from detailed building modeling. In the residential sector, a new category of dwellings built since 2005 was added to the model to reflect the results of a recent survey of new homes. The resulting model, calibrated to the actual normalized sales of natural gas in the FEU's service territory, is subdivided as follows:

39.1 Why did FEU use 2011 as the base year for the reference case rather than 2012 or the most recent information available?

Response:

Please refer to the response to BCUC IR 1.19.5.

39.2 Please confirm that 'normalized consumption' refers to weather normalized.

Response:

Confirmed.

39.2.1 If not confirmed, please explain what 'normalized consumption' refers to.

Response:

Please refer to the response to CEC IR 1.39.2.

39.3 Why did FEU select 2005 as the demarcation year for a new category of dwelling to be added to the model?

Response:

The "results of a recent survey of new homes" in the preamble refers to the 2008 REUS study completed by Sampson Research. In that research the author was directed by FEU to consider homes constructed since 2006 independently of the rest of the population. The REUS data was reused in the End Use forecast and as a result the same 2005 demarcation was used.

40. Reference: FEU Exhibit B-1, page 47

> *Theme 1 - Abundance or constriction of natural gas supplies. This theme is not about whether there are enough gas reserves in the ground to serve customer needs, but rather whether or not market factors will occur that make accessing those supplies easier (less costly) or more difficult (more expensive). For example, technological improvements that allow safe, year-round drilling and processing of gas in northern climates will act to make access to supply easier and therefore less costly, whereas opposition to pipelines, more stringent rules for gas drilling and production, or greater competition for supply will increase the cost of accessing gas supplies. The scenarios that have been developed do not attempt to identify specific causes, but instead examine the impact on demand if access to supply becomes more or less constricted.*

40.1 Please explain how FEU factored in changing technology in competing and/or complementary energy sources such as wind and solar energy, and their effects on the relative costs and market size of natural gas.

<u>Response:</u>

This excerpt is from Section 3.3.4 of the 2014 LTRP which discusses the development of alternative future scenarios that informed the range of future annual demand scenarios presented in Section 3.3.5. The consideration of alternative competing or complimentary fuels is better described in Theme 2, which also informed the scenarios:

> Theme 2 – Centralization versus decentralization of energy delivery systems. Centralized energy systems can be explained as the type of grid-based electric and natural gas energy services that have been in place for many decades, and for which the energy supply and maintenance costs, safety controls and customer service conditions are shared across large customer bases. Decentralized energy systems are characterized by an accelerated movement toward off-grid, or end-of-grid energy production and utilization where the end-use customer or their representative takes a greater role in developing and maintaining the energy equipment.

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.

The FEU note that the traditional long term annual demand forecasting methodology has no flexibility with which to include the consideration of such trends.

40.2 Please explain how FEU factored in the potential for significant technological advancements in energy efficiency.

Response:

Technology advancements in energy efficiency would act to decrease growth in natural gas demand, or even cause declining annual demand. The FEU addressed the implications of such a trend through modelling the impacts of higher amounts of natural conservation before EEC, high participation rates in EEC and higher levels of displacement of natural gas by renewable thermal energy systems. These trends are not necessarily assumed to be cumulative within the scenarios. Please refer to the scenario descriptions in Table 3-1 and Appendix B-3 of Exhibit B-1 for the specifics of how these considerations were included in the annual demand forecast modelling. The extent to which these trends could be significant depends on the interpretation of the term "significant", however, the FEU believe that they have modelled a range of reasonably plausible impacts for energy efficiency technology improvements. Please also refer to the response to CEC IR 1.40.1.

40.3 Please provide historical trends on gas access costs.

Response:

The FEU do not track historical natural gas production costs but understand that they fluctuate over time based in part on basin location, local geology, gas composition, operating and overhead costs, development and production costs, the cost of capital, royalties and production taxes, and the market price for natural gas.

Although production costs vary from basin to basin, and even within a basin, in general, technological enhancements in horizontal drilling and multistage hydraulic fracturing has allowed for a surge of gas production across North America because these enhancements have helped to make it economically attractive to access natural gas located in shale plays.

Please also refer to the response to CEC IR 1.7.7.

40.4 Please provide a range of cost impacts that might affect gas availability and/or price with specific data.

Response:

Please refer to the response to CEC IR 1.40.3.

41. Reference: FEU Exhibit B-1, page 45

> Using historical trend data to forecast future consumption is a common and accepted industry practice, particularly for short-term analysis or decision making where historical data is used to forecast a few years into the future. This methodology provides a high level of confidence for near-term business decision making. All short-term revenue requirement forecasting at FEU has successfully been conducted in this way and this method is embedded in the short-term Forecast Information System, which has been in use for over a decade.

41.1 Please confirm that FEU continues to consider the predictive capabilities of the traditional method to be adequate for short term business making decisions.

Response:

Confirmed.

The traditional method of using recent historic use rates and the CBOC housing starts forecast to prepare a forecast of the next 1-2 years has proven adequate. In addition the traditional method (as implemented with the short term FIS system) also performs the full range of tariff calculations. The short term model provides a forecast of demand and revenue whereas the new end use methodology provides a forecast of demand only.

41.1.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.41.1.

42. Reference: FEU Exhibit B-1, page 45

> However, as described in Section 2, ongoing changes in the end-use energy solutions available to customers and the way in which customers are using energy means that historical trends no longer provide the best basis on which to forecast the long term potential range of future demand. For this reason, the FEU proposed in the 2010 LTRP to consider an approach to demand forecasting that involves examining different ways that end-use trends in energy use could potentially impact future demand for natural gas. The new end-use approach was encouraged by the Commission and interveners during the regulatory review of the 2010 plan.

42.1 Is it FEU's position that the traditional method is sufficiently inaccurate as a predictor of long term consumption that it should not be relied upon and should be replaced with the end-use method? Please explain.

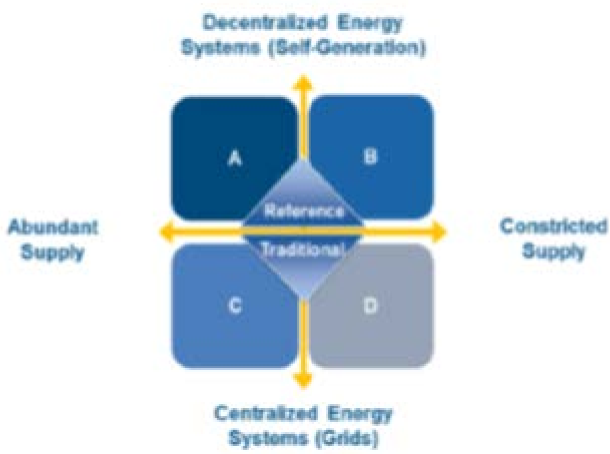
Response:

Owing to a lack of long term actual results the FEU are unable to confirm that the traditional method is an inaccurate predictor of long term consumption. However the FEU's position is that the end use methodology is an improvement on the traditional method. The end use methodology allows the FEU to repurpose data collected for the 2010 CPR and this end use data is considered more appropriate than the assumptions in the traditional model. As discussed in the response to CEC IR 1.41.1 the traditional methodology as implemented in the FIS system provides additional and necessary benefits in terms of support for tariffs and revenue calculations. The traditional method as implemented in the FIS system will continue to be used for short term revenue and demand forecasting. The FEU do intend to continue to use the end use methodology introduced in this LTRP in the future. The FEU do not intend to continue using the traditional method for long term annual demand forecasting beyond this 2014 LTRP.

43. Reference: FEU Exhibit B-1, page 48

> Applying the two themes of abundance or constriction of natural gas supplies and centralization versus decentralization of energy delivery systems results in a matrix of four scenarios as shown in Figure 3-5. Figure 3-5 includes the Reference Case, or starting point for the end-use demand forecast scenarios, and the traditional methodology demand forecast, which provides a point of comparison for the end-use methodology. General scenario descriptions follow.

Figure 3-5: End-Use Demand Forecast Scenario Development



43.1 Please confirm that the Reference case is not the same as the Traditional, but instead presumes a continuation of the status quo while the Traditional method relies on continually revising inputs.

<u>Response:</u>

The FEU can confirm that the Reference case is not the same as the Traditional, but do not confirm that the Reference Case is a simple extension of the status quo. Please refer to the response to BCUC IR 1.21.1, for further explanation.

44. Reference: FEU Exhibit B-1, page 51

> The model results for Scenarios A through D have the same level of granularity as the Reference Case, with results available for the same set of milestone years. Note that the FEU does not predict which scenario will unfold in the future. Rather, the five scenarios considered together provide a reasonable range of possible future demand that the FEU will need to serve over the next 20 years.

44.1 Why does FEU not undertake to identify which of the five scenarios is most likely to occur?

Response:

Please refer to the response to BCPSO IR 1.2.3.

44.2 Would FEU propose to revise its forecasts if it became evident that one of the scenarios was more clearly appropriate than the others?

Response:

As discussed, the new end use model supports multiple scenarios. In future LTRP filings the FEU may decide to update one or more of the current scenarios depending on the conditions prevailing at the time the forecast is developed. The LTRP forecast is updated frequently so the FEU have the ability to respond and adjust to any scenario that develops in a timely manner. The purpose of the forecasts is to come up with a range or band of reasonable forecasts that would likely occur over the twenty year period. The FEU plan their resources to fit within that band. The purpose of the forecasts is not to pick a scenario and resultant forecast that is most likely.

44.2.1 If not, please explain why not.

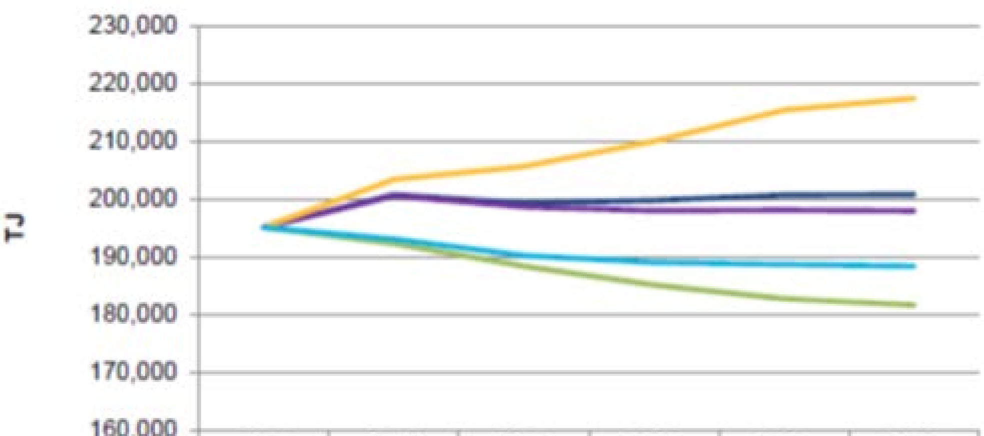
Response:

Please refer to the response to CEC IR 1.44.2.

45. Reference: FEU Exhibit B-1, pages 51 Figure 3-6 and pages 52-53 Figures 3-7 through 3-9

- For all of the five scenarios (including the Reference Case), an overall decrease in annual residential demand is predicted. The degree of each decline depends on the assumptions used for each planning environment.
- The potential exists for commercial demand to grow or decline, though continued growth can be observed in most of the scenarios.
- Industrial demand based on the current customer base also has the potential to grow or decline over the planning period. Three of the forecasts, including the Reference Case, assume that recent increases in actual demand persist, while two see this increase as short term with industrial demand returning to 2011 levels.

Figure 3-6: Total End-Use Forecast, Annual Demand by Scenario – 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

From Figure 3-7, Residential End Use Forecast Annual Demand All Regions

50,000

	2011	2016	2021	2026	2031	2033
Reference	74,252	73,027	70,301	69,605	69,095	68,614
Scenario A	74,252	71,945	68,588	67,175	65,893	65,069
Scenario B	74,252	72,177	68,947	67,707	66,456	65,632
Scenario C	74,252	73,097	70,747	70,055	69,811	69,437
Scenario D	74,252	71,959	68,693	67,299	66,132	65,363

From Figure 3-8 Commercial End Use Forecast Annual Demand All Regions

50,000

	2011	2016	2021	2026	2031	2033
Reference	55,330	57,123	59,057	61,000	63,088	64,081
Scenario A	55,330	56,869	57,937	58,564	59,586	60,182
Scenario B	55,330	55,557	55,540	54,568	54,199	54,232
Scenario C	55,330	58,024	61,411	65,336	69,682	71,672
Scenario D	55,330	56,047	57,451	58,767	60,491	61,364

From Figure 3-9 Industrial End Use Forecast Annual Demand All Regions

50,000

	2011	2016	2021	2026	2031	2033
Reference	65,540	70,584	69,946	69,171	68,496	68,121
Scenario A	65,540	71,763	72,137	72,282	72,657	72,709
Scenario B	65,540	64,600	63,913	62,872	62,118	61,744
Scenario C	65,540	72,272	73,473	74,631	75,895	76,321
Scenario D	65,540	65,087	64,098	62,994	62,085	61,651

45.1 Would FEU agree that the difference in the End-Use forecast trajectory is primarily driven by the growth or decline in the Industrial and Commercial sectors; and that the residential impact is expected to be relatively modest given that there is little variability in the expected decline?

Response:

Confirmed.

45.1.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.45.1.

45.2 Does FEU believe it has any more influence over the consumption patterns of any segment more than any other?

Response:

In general, among the customer groups included the cited figures (residential, commercial and industrial), the FEU consider that they currently have more influence over residential customer consumption patterns, with less influence over commercial customer consumption patterns. Residential customer HVAC requirements are more homogenous and in general residential customer knowledge of HVAC options are less than that of industrial customers. Therefore the ability of the FEU to influence the consumption patterns of this group is higher. Commercial customers HVAC requirements are a little more unique than residential customers as there may be manufacturing heating requirements in addition to space heating. Commercial customers may also be more sophisticated. Industrial customers are the most sophisticated customer group whose natural gas requirements are generally unique to their industry sector or business. In addition, natural gas, or energy usage may or may not be a deciding business decision factor. As such, the FEU has the least influence over the consumption patterns of the industrial sector.

45.2.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.45.2.

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:

- 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.

The FEU believe that these types of customer retention and acquisition initiatives are important for influencing customer choice, maintaining customer growth and countering the risk of declining annual demand depicted in the lower portion of the range of future demand scenarios outlined in Figure 3-12, page 56 of Exhibit B-1. The FEU will continue to explore additional service initiatives through the planning period as part of its day to day business activities.

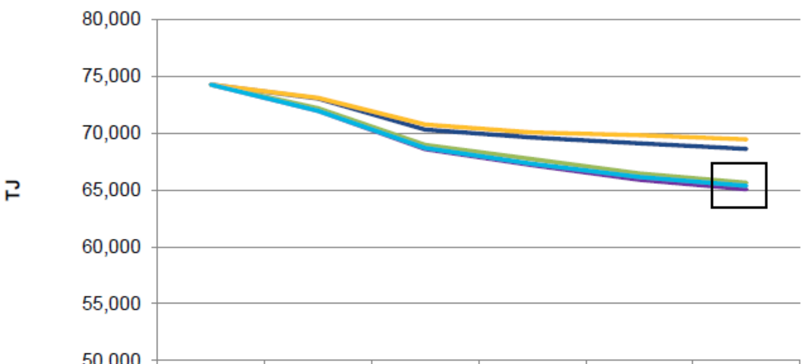
45.3 According to the above, the lowest long term result would theoretically arise from a combination of scenario A occurring in the residential sector; Scenario B occurring in Commercial sector, and scenario D occurring in the Industrial sector. Please explain why the scenarios are not consistent directionally between sectors.

Response:

In the aggregate plot in Figure 3-6, scenario C represents the upper bound of the annual demand forecast while scenario B represents the lower bound.

When considering residential demand alone (Figure 3-7), scenario A shows the lowest demand but it is less than 0.9% lower than the demand shown in scenario B. FEU does not believe that a variance of less than 0.9% twenty years into the future constitutes a directional difference. The similarity between scenarios A and B is evident in the plot from Figure 3-7 (highlighted by the rectangular box, below):

Figure 3-7: Residential End Use Forecast, Annual Demand – All Regions

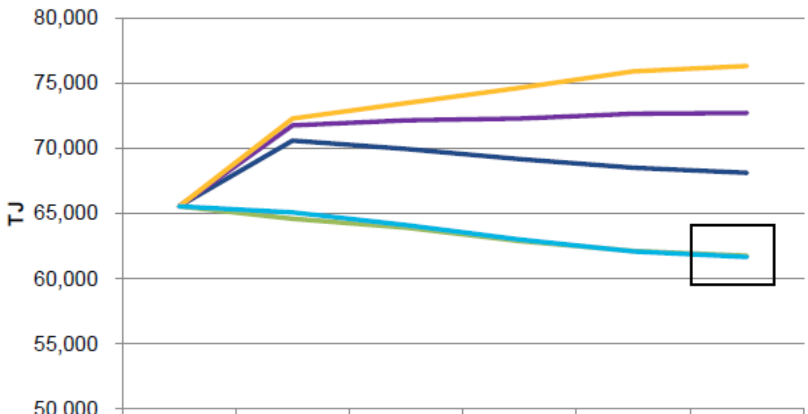


	2011	2016	2021	2026	2031	2033
Reference	74,252	73,027	70,301	69,605	69,095	68,614
Scenario A	74,252	71,945	68,588	67,175	65,893	65,069
Scenario B	74,252	72,177	68,947	67,707	66,456	65,632
Scenario C	74,252	73,097	70,747	70,055	69,811	69,437
Scenario D	74,252	71,959	68,693	67,299	66,132	65,363

When considering commercial demand, scenario B shows the lowest volume as pointed out in the preamble.

When considering industrial demand, scenario D shows the lowest demand but the variance to scenario B is only 0.15%. Again, the FEU do not consider a variance of 0.15% twenty years in the future as a directional difference. The similarity between scenarios D and B is evident in the plot from Figure 3-9 (highlighted by the rectangular box, below):

Figure 3-9: Industrial End-Use Forecast, Annual Demand – All Regions



	2011	2016	2021	2026	2031	2033
Reference	65,540	70,584	69,946	69,171	68,496	68,121
Scenario A	65,540	71,763	72,137	72,282	72,657	72,709
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Scenario C	65,540	72,272	73,473	74,631	75,895	76,321
Scenario D	65,540	65,087	64,098	62,994	62,085	61,651

Please also refer to the response to CEC IR 1.45.4 regarding the validity of arbitrarily combining sector results from different scenarios.

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.

46. Reference: FEU Exhibit B-1, pages 55

> The FEU have found implementation of the end-use demand forecasting methodology to be both successful and useful, and intend to continue using this methodology for long term planning and analysis purposes. Before retiring the traditional method and to satisfy the Commission directive to compare the new end-use forecasting methodology and results with the traditional forecasting approach and results, a comparison of the two methodologies is necessary. Figure 3-12 shows the demand forecast results (all regions) from the traditional methodology compared to the results of the new end-use methodology for the Reference Case and four alternative scenarios. Since the forecast using the traditional methodology falls within the highest and lowest boundaries of the end-use methodology results, the FEU are confident in the ability of the new methodology to provide a reasonable long term demand forecast.

46.1 Please confirm or otherwise explain that FEU intends to retire the traditional method for long-term planning and analysis purposes.

Response:

Please refer to the response to CEC IR 1.42.1.

46.1.1 If so, when does FEU intend to retire the traditional method?

Response:

Please refer to the response to CEC IR 1.42.1.

46.1.2 Does FEU require Commission approval to retire the traditional method? Please explain why or why not.

Response:

No. There is no specific requirement to seek approval to use or abandon the use of a particular forecasting methodology under section 44.1 of the *Utilities Commission Act*, or any other sections of the Act. In the 2010 LTRP Decision, the Commission issued certain directives under section 44.1(2)(g) of the Act relating to the use of a new end-use forecasting methodology, but the FEU do not interpret those directives as requiring approval to retire the "traditional method" of demand forecasting.

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.

46.2.1 If so, for how many years out will FEU rely on the traditional method as its planning method?

Response:

The FEU do not intend to rely on the traditional method for future long term forecasting.

46.3 Please explain why having the traditional forecast fall within the upper and lower boundaries of the end-use forecast provides confidence in the 'ability of the new methodology to provide a reasonable long term demand forecast' and please consider that highly divergent scenarios could equally provide for the traditional method to fall within the upper and lower boundaries.

Response:

The alternative to having the traditional methodology bounded by the limits of the end use method is to have the traditional method outside the bounds of the end use method. In that case the FEU would say that it had less confidence in the end use method to produce a reasonable forecast.

the FEU are confident in the ability of the end use method to produce a reasonable forecast, given that:

- The end use method parameters were repurposed from the 2010 CPR;

- The four end use scenarios were reasonable and reviewed by the Resource Planning Advisory Group; and
- The traditional method resulted in a forecast between the upper and lower end use scenarios.

46.4 Please confirm that it is FEU's opinion that the End-Use model is a better predictor of the demand than the traditional method.

Response:

Please refer to the response to CEC IR 1.42.1.

46.4.1 If so, please provide the basis by which FEU makes this decision and explain whether or not it has been tested against actual results.

Response:

Please refer to the response to CEC IR 1.42.1.

46.4.2 If not, please explain why FEU has relied upon the reference model for the bulk of the capacity planning discussion in the LTRP.

Response:

Please refer to the response to CEC IR 1.42.1.

46.5 Would FEU consider it appropriate to continue testing both the traditional and the End Use models to determine which model, and which scenarios are better predictors of future demand.

Response:

No, the FEU will not be doing any further testing of the traditional long term model. The FEU does not intend to continue using the traditional method for long term annual demand forecasting.

The ability of the end use model to produce a range of future outcomes makes it more appropriate for use as a long term planning tool. The FEU will continue using the end use method and will continue to update the data as new CPR studies and other reliable market data becomes available. In addition the FEU will continue to update and adjust the scenarios as part of the ongoing resource planning process.

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.

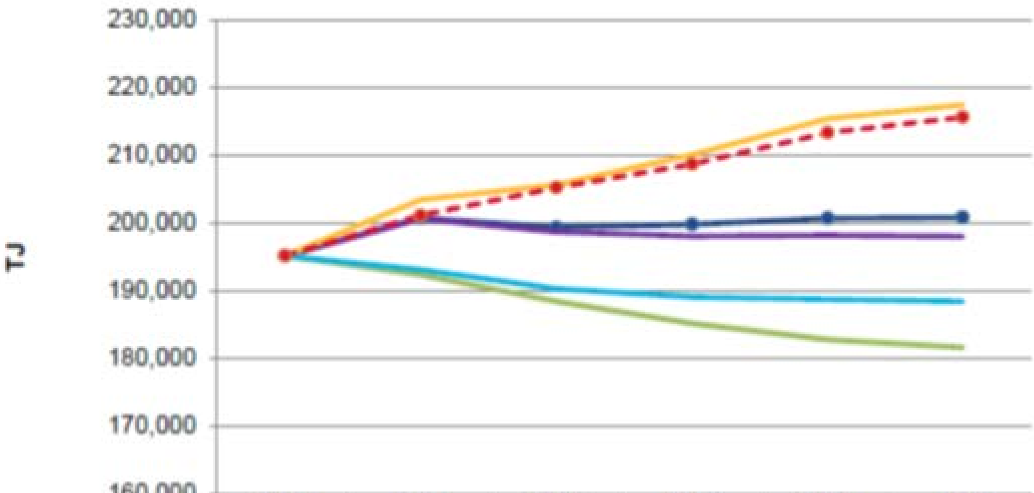
46.6.1 Please explain why or why not.

Response:

Please refer to the response to CEC IR 1.46.6. The FEU chose to use the end use methodology so that the impact of this type of future change in policy, and other future changes, on annual demand could be more readily modelled.

47. Reference: FEU Exhibit B-1, page 56

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 provide value beyond the simple risk management that one high and one low scenario would offer.

47.2 Please explain why the reference case does not track with the traditional method.

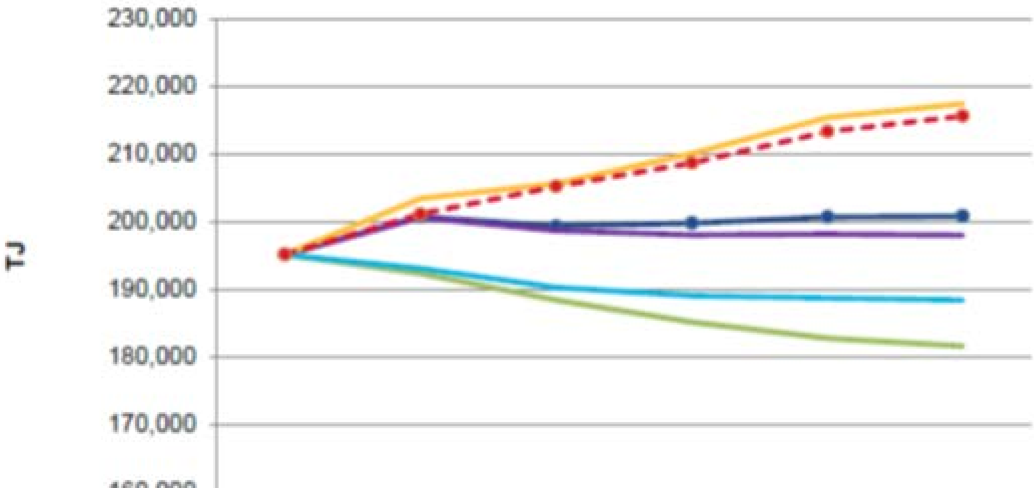
Response:

Please refer to the response to BCUC IR 1.21.1.

48. Reference: FEU Exhibit B-1, page 50 and page 56

The model results for Scenarios A through D have the same level of granularity as the Reference Case, with results available for the same set of milestone years. Note that the FEU does not predict which scenario will unfold in the future. Rather, the five scenarios considered together provide a reasonable range of possible future demand that the FEU will need to serve over the next 20 years.

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
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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

48.1 Please confirm that long term planning for the five scenarios and the traditional scenario would be the most likely result in planning for the upper bounds or Scenario C in order to ensure available energy supply.

Response:

Not confirmed. The annual demand scenarios developed for the LTRP are not intended to identify a most likely result. Implying that one result is more likely than any other would imply that the end use model is capable of prioritizing, ranking or predicting which scenario is most likely and that those outcomes would actually occur. Rather the scenarios are intended to provide a range of future outcomes.

The end use annual demand model shown in Figure 3-12 is the appropriate forecast to use for identifying future opportunities and risks facing the Companies over the long term with respect to annual demand.

However, it is not the appropriate forecast to use for ensuring available energy supply. While the end use method provides long term annual demand visibility, the detailed gas supply requirements are forecast and presented for core customers in the Annual Contracting Plan (ACP). The forecast used for the ACP is shorter term in nature and the methodology is not end use based or related to the end use methodology.

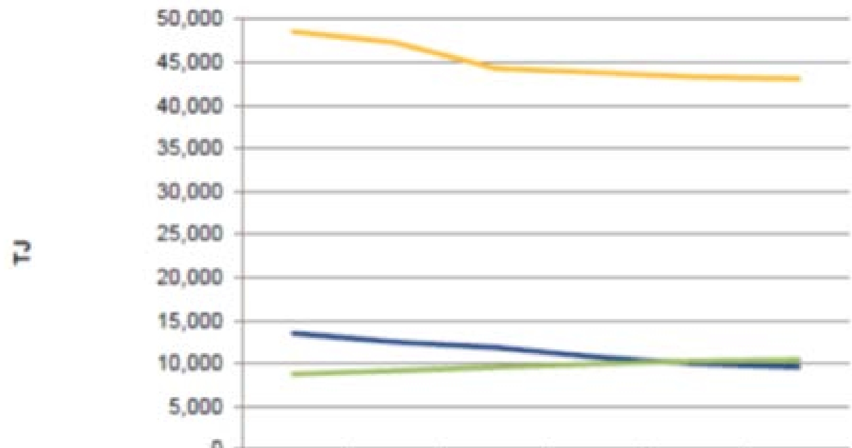
48.1.1 If not confirmed, please explain how FEU proposes to synthesize the information into expected demand on an on-going basis.

Response:

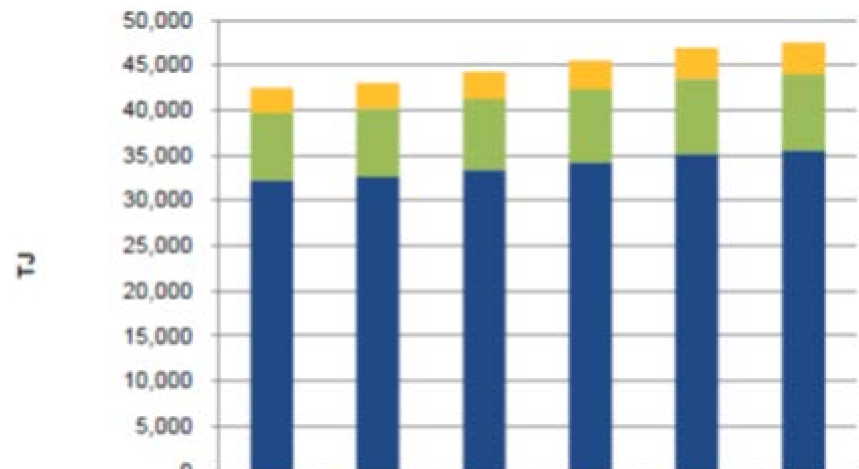
The FEU do not propose to synthesize the range of long term annual demand forecast scenarios into a single expected forecast for the purpose of gas supply planning. The long term annual demand forecast provides insights about the opportunities and risks facing the FEU with respect to annual demand. While the end use method provides long term annual demand visibility, the detailed gas supply requirements are forecast and presented for core customers in the Annual Contracting Plan (ACP). The forecast used for the ACP is shorter term in nature and the methodology is not end use based or related to the end use methodology.

49. Reference: FEU Exhibit B-1, page 54 and 55

Figure 3-10: Reference Case Demand for Three Largest Residential End-Uses by Consumption – All Regions



	2011	2016	2021	2026	2031	2033
Domestic Hot Water	13,496	12,495	11,871	10,738	9,955	9,584
Fireplace	8,745	9,159	9,573	9,941	10,282	10,416
Space Heating	48,566	47,322	44,295	43,819	43,293	43,076



	2011	2016	2021	2026	2031	2033
Commercial Cooking	2,765	2,883	3,036	3,195	3,373	3,451
Domestic Hot Water	7,426	7,555	7,804	8,059	8,342	8,468
Space Heating	32,246	32,622	33,433	34,254	35,167	35,580

49.1 Please explain why the trend in domestic hot water is rising in the Commercial sector while rapidly declining in the residential sector.

Response:

Efficiency increases incorporated in the commercial sector affect both tertiary load and water heating efficiency. The efficiency increases are not as large as the improvements in the residential sector, and they are smaller than the growth in commercial floor space. As a result energy consumption for domestic hot water usage is rising in the commercial sector.

Significant reductions in tertiary load, mostly because of increased efficiency from clothes washers and dishwashers, are present in the residential sector. In addition (and as reported in the 2010 REUS study) a trend to install 80% efficient tankless and condensing water heaters has developed in new homes. These two effects result in a 35.7% reduction in residential DHW UPC by 2031. This reduction outpaces the forecast increase in number of dwellings (14.6% to 2031). Therefore the net effect is a decrease in DHW for residential of 26.2% by 2031.

50. Reference: FEU Exhibit B-1, page 56 and page 57

> At the time of writing, the B.C. Government issued a special direction to the BCUC to exempt from review expenditures on an expansion of the Tilbury LNG facility of up to $400 million and to effectively lower the LNG dispensing rate to $4.35 per GJ. The government also amended the GGRR to include trains and mine-haul trucks, provide tanker-truck delivery services to trucking, mining and marine transportation customers. These developments are likely to lead to increasing NGT demand, however, these recent developments are not considered in Figure 3-13 and the three NGT scenarios described below.

> The second part of the NGT demand forecast covers the period from 2018 to the end of the planning period (2033), with 2018 being the point at which the NGT demand scenarios begin to diverge based on market share capture assumptions. The 2033 transportation market size was calculated by projecting 2010 NRCan data for the transportation market to the end of the forecast period. This exercise focused solely on the market for heavy duty and return-to-base vehicles that could reasonably be expected to utilize natural gas, and did not include the personal vehicle market. A total for medium trucks, heavy trucks, school buses, urban transit,

50.1 Please confirm that FEU did not provide alternative market size scenarios for NGT based on the potential for changing market directions as was undertaken in the core.

<u>Response:</u>

Confirmed. The FEU did not provide alternative overall market size scenarios for NGT, as the total size of the transportation market is not anticipated to increase as a result of the NGT program. The purpose of the NGT program has been to encourage fleet owners and operators to purchase natural gas fueled vehicles as opposed to diesel vehicles once their current vehicles reach the end of their useful life.

Therefore the NGT program is displacing diesel vehicles, not introducing new vehicles and demand into the market. It is anticipated that the total transportation market will continue to increase at 2% per year, irrespective of the type of fuel used to power a vehicle.

50.1.1 If not, why not and is it FEU's expectation that the total market size will not change as a result of market conditions?

<u>Response:</u>

Please refer to response to CEC IR 1.50.1.

50.1.2 If FEU did consider a change in market size as a result of changing market conditions, please provide the relevant scenarios.

Response:

Please refer to response to CEC IR 1.50.1.

50.2 Would the likely impact of the special direction be to increase FEU's market share capture rate rather than to influence the overall market?

Response:

No. Part of the purpose of the Special Direction was to influence the overall vehicle market to adopt natural gas as a fuel. Over the long term the Special Direction will permit further penetration into the heavy duty class 8 segment and other vehicle markets by providing supply and rate certainty.

50.2.1 If yes, would the impact most likely be felt after 2018? Please explain why or why not.

Response:

FEI believes that 2018 is reasonable timeframe to demonstrate savings for operators, address the adoption barriers, generate awareness and build the infrastructure across strategic corridors to enable further growth and adoption. However, this also has to be accompanied with the availability of OEM engine offerings for different types of applications.

In the near term, there are market impacts that are impeding the growth of the LNG Class 8 heavy duty market due to the lack of an available OEM engine offering. However, over the long term (i.e. beyond 2018), FEI expects that market responses such as OEM engine offerings and expanded networks of fuelling infrastructure will enable further market share growth of natural gas vehicles. To the extent that this occurs, annual demand from NGT may tend toward the higher NGT annual demand forecast.

50.3 Why did FEU exclude the personal vehicle market from its analysis?

Response:

The FEU's NGT strategy is to target large return-to-base fleets that have high fuel consumption. This will justify the fuelling station economics and provide the customer with a reasonable payback on their investment. This strategy also allows the FEU to drive growth and increase system throughput while managing risk, as customers are required to commit to certain volumes. Additionally the customer segments that FEI targeted such as the waste haulers, urban transit, and long haul highway tractors have OEM engine offerings and support available to make the transition easier.

For the personal vehicle market there are numerous challenges that FEI views as limiting factors to the continued growth of this market. Factors such as the availability of OEM engine offerings for personal vehicles, lack of public fuelling infrastructure and relatively low consumption resulting in longer pay back periods for the customer are viewed as limiting factors.

However the FEU will continue to monitor the adoption of personal natural gas vehicles across other jurisdictions and as the external market circumstances change, it may look into the possibility of entering this market segment in the future. Since there is no basis on which to forecast such demand, the FEU have not included it in the NGT demand forecast at this time.

50.4 What are FEU's expectations with respect to the personal vehicle market? Please provide any forecasts that FEU has available.

Response:

Please refer to the response to CEC IR 1.50.3.

51. Reference: FEU Exhibit B-1, page 57 and Appendix A-1, page 19

> personal vehicle market. A total for medium trucks, heavy trucks, school buses, urban transit, freight rail, and marine from the 2010 NRCan data was scaled up by a 2% annual growth rate to reach an applicable 2033 total vehicle market size. In FEI's service territory, the three natural gas vehicle forecasts in 2033 reach 1% market share in the Low case, 15% market share in the Reference Case, and 30% market share in the High case. The latter two scenarios assume that LNG liquefaction, storage and dispensing facilities are expanded and do not limit the amount of LNG available to serve the transportation sector. The three NGT scenarios are presented in Figure 3-13 and described below.

> From the period 2008 to 2010, natural gas demand for NGVs rose at a rate of about 13% per year as natural gas prices were, and continue to be, more competitive over traditional fuels such as diesel and gasoline.
>
> According to the forecast for NGT gas demand presented in the figure below, U.S. gas demand is expected to grow from about 0.1 Bcf/d in 2013 to about 2.7 Bcf/d by 2030. While significant for the NGT market, overall NGT demand is expected to represent only about 2% of total U.S. gas demand by 2030.

51.1 Please confirm that FEU expects the market for NGT to grow for the period between 2011 and 2033 dependent upon relative fuel price advantages and capital cost investment and market transformation assistance.

<u>Response:</u>

The FEU assume that the market transformation assistance referenced in the preamble refers to the GGRR incentive program, and clarifies that it expects the NGT market share will grow for the period between 2011 and 2033. The FEU expect the market share of natural gas vehicles within the overall vehicle market to grow faster than the overall vehicle market for the relevant vehicle types.

The FEU expect the NGT market share to continue to grow based on the following assumptions:

1. GGRR incentives in the short term will help kick start the market and support the build out of the infrastructure. Beyond the GGRR period, FEU assumes that financial incentives are no longer a necessity to make the economic justification of switching to natural gas vehicles.

2. Relative price advantage of natural gas over diesel will continue to persist over the long run;

3. Economies of scale will reduce the higher upfront capital cost of natural gas vehicles opposite diesel vehicles; and

4. Fuelling infrastructure will be constructed in a manner that will allow a broad area of coverage to a number of NGT customers.

The FEU assume the overall transportation market for the relevant vehicle types will grow at 2% per year.

51.1.1 If not confirmed, please provide any further expectations FEU might have with respect to the rate of growth of the NGT market over the next five and ten years.

Response:

Please refer to response to CEC IR 1.51.1.

51.2 Why did FEU not provide alternative scenarios to estimate market size based on market changes as was undertaken for the core demand?

Response:

Please refer to the response to CEC IR 1.50.1.

51.2.1 Please provide a high level discussion as to how FEU might expect the NGT market to perform based on each of the four scenarios used to forecast the core market.

Response:

Table 3-1, presented on page 49 and 50 of Exhibit B-1 provides a high level discussion regarding the NGT market based on each of the four scenarios that were used to forecast demand for the residential, commercial and industrial customer groups. The table is provided below for reference. The conditions described in Table 3-1 relating to NGT were not converted into direct inputs to the long term forecasts because the NGT market share growth is still new and the same type of historic base year information is not available for the NGT customer base from which to model NGT in a similar fashion to the residential, commercial and industrial customer base. Instead, these descriptions were used to make reasonable judgments in combining the reference, high and low NGT scenarios with the appropriate residential, commercial and industrial scenarios.

Table 3-1: Alternative Future Scenario Descriptions

Scenario	General Theme	Policy Expectations	Directional Implications for Demand[1]
Scenario A (Abundant Supply, Decentralized Energy Markets)	Abundant natural gas supply and corresponding low natural gas prices are tempered by high carbon prices and a policy environment focused on GHG emission reductions. There is a transition to decentralized energy markets, more so than centralized energy markets, and as such there is a moderate amount of renewable energy uptake. Overall, this scenario shows a change in the energy mix such that renewable thermals and electricity are favored by policy and carbon pricing, but low natural gas prices mitigate substantial fuel switching.	The policy focus is on carbon emission reductions. Energy strategies are consistent within regions, but may be disparate among regions. For example, the Western Climate Initiative or an alternative cap-and trade program could proceed in this scenario, but other Canadian provinces or U.S. states and the federal government would not necessarily follow suit or put in place similar carbon pricing programs.	We may expect to see significant demand for natural gas for transportation because of the low cost and the resulting emission reductions associated with switching from diesel/gasoline, although the additional natural gas load is offset by some fuel switching to electricity (the main low-carbon alternative) and an increase in decentralized renewable thermal options, particularly district energy, geo-exchange, and additional new technologies. The market penetration of renewable thermal technologies, while moderate, is not high because the low cost of natural gas makes alternative technologies somewhat less competitive. There is moderate participation in EEC initiatives, due to a drive to reduce fossil fuel use, although the low cost of natural gas acts as a barrier to substantial EEC uptake.
Scenario B (Constricted Supply, Decentralized Energy Markets)	Natural gas supply is constrained and new, decentralized technologies emerge rapidly to meet future energy needs. Carbon policy is not a driver in this scenario and B.C.'s carbon tax is held constant at 2012 levels; rather, generalized environmental policies contribute to constricted natural gas supply and support renewable thermal development.	Policy is focused on the environmental impacts of energy as a whole, not specifically carbon impacts. Additionally, there are coordinated energy strategies among regions and all levels of government, which allows for the creation of a national energy strategy.	With a moderate to high price for natural gas and no carbon-specific regulations in place, there is likely little uptake in natural gas for transportation, and the price of natural gas does cause consumers to look for alternatives to natural gas for thermal applications. This scenario would likely drive fuel switching to decentralized renewable thermal applications, and potentially a corresponding overall decrease in demand for natural gas. There is moderate to high participation in EEC initiatives as customers who do not switch fuels are looking for ways to reduce their energy consumption in response to high natural gas prices.

Scenario	General Theme	Policy Expectations	Directional Implications for Demand[1]
Scenario C (Abundant Supply, Centralized Energy Markets)	Natural gas supply is abundant while energy technology remains centralized, leaving natural gas as an important means to meet long term energy needs. Overall, natural gas is viewed positively and is perceived as an integral part of B.C.'s energy picture.	Policy is focused on economic growth rather than environment, carbon, or climate issues, and energy strategies are disparate among regions and levels of government, meaning that other jurisdictions may or may not implement carbon pricing, renewable thermal subsidies, etc.	Abundant supply results in a low gas price, and coupled with current technologies and a policy environment that is not focused on carbon emission reductions, the scenario drives an increase in overall demand for natural gas. In particular, low gas prices likely drive an increase in Industrial demand. A high fuel cost differential between oil and natural gas paves the way for higher than expected uptake in NGT. Convincing customers to participate in EEC programs will be more difficult, as the low fuel costs and abundant supply create less incentive for consumers to focus on saving energy. The conditions in this scenario also mean that renewable thermals will likely play a smaller role in the energy picture in B.C.
Scenario D (Constricted Supply, Centralized Energy Markets)	Natural gas supply is constricted and a slower economy minimizes technological development and decentralization, limiting the energy alternatives available to meet consumers' long term needs. Overall, energy is expensive in this scenario and customers are looking to reduce their energy needs.	Policy is focused on economic growth, with some advancement of carbon regulations, while the energy strategies among regions and levels of government are disparate and uncoordinated.	Overall demand for natural gas is likely low as natural gas supply is constricted and prices are correspondingly high. Demand for NGT is also potentially minimal, as the fuel costs are higher and will not pay back the conversion cost quickly. EEC is likely to see extremely high participation rates, as consumers are paying high energy prices and do not have technology alternatives. Renewable thermals are not likely to obtain a substantial market share as technology is more centralized, but may see some uptake because they are more cost-competitive with higher natural gas prices.

51.3 The US NGV demand grew at 13% from 2008 to 2010, and is expected to grow at a rate of approximately 20% CGR between 2013 and 2030. Please explain why FEU assumed a 2% annual growth rate from the 2010 NRCan data. Please provide any evidence that FEU has to support its assumptions.

Response:

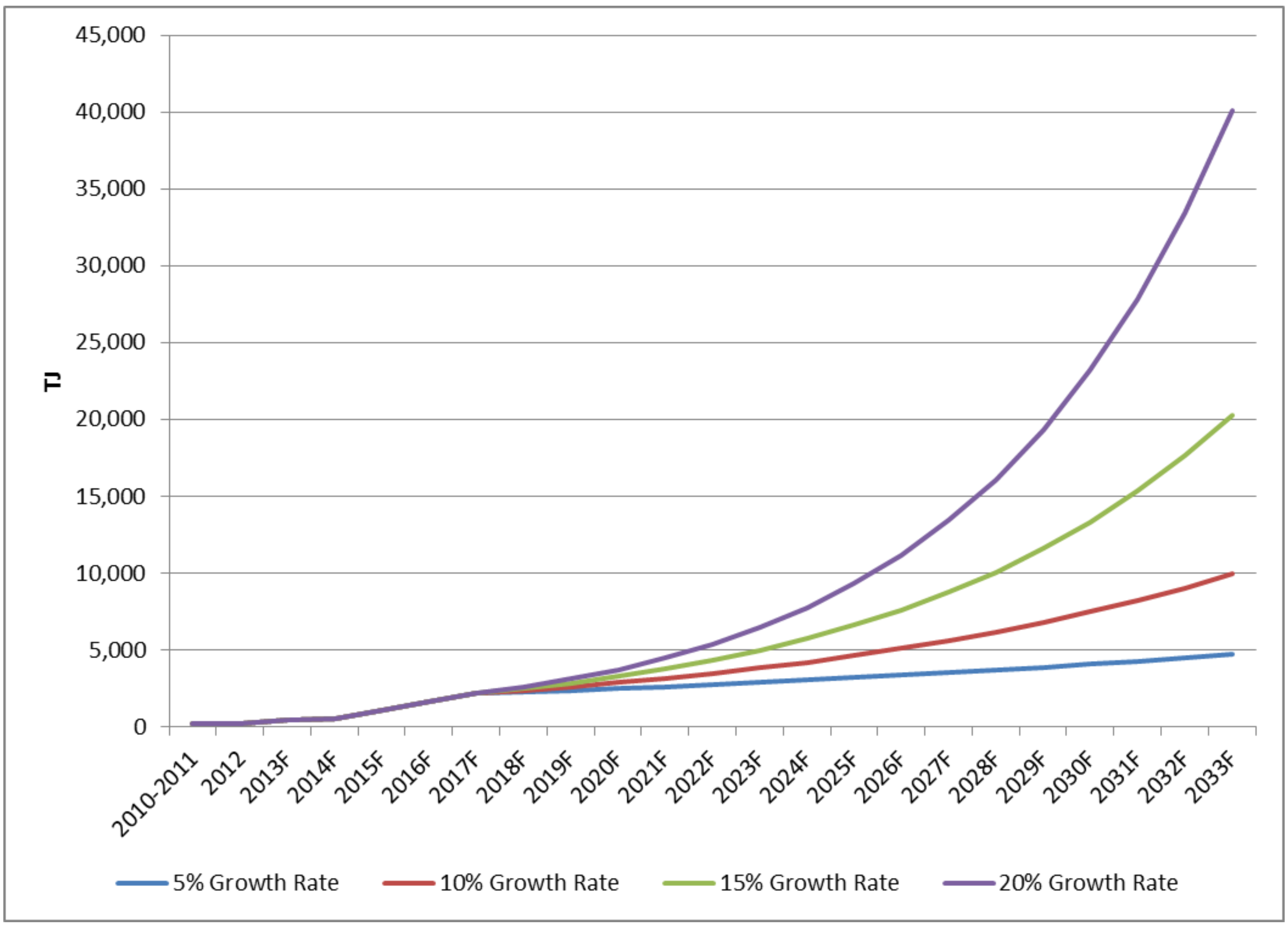
The reference in the preamble to demand growth of 13% from 2008 to 2010 and 20% between 2013 and 2030 refers specifically to growth in the NGT portion of the overall transportation market.

The FEU's annual growth rate of 2% per year between 2013 and 2033 refers to the growth of the *overall transportation market*. In the Reference Case scenario of the NGT forecast presented in the Application, the FEU assumed an annual growth rate in NGT demand of about 18.4% per year from 2018 to 2033, which is in line with the growth rate in US NGV demand.

51.3.1 Please provide forecasts for the Reference, High and Low cases based on a 5%,10%, 15% and 20% annual growth rate.

Response:

The FEU interpret this request to be seeking four additional scenarios to the Reference, high and Low scenarios prepared by the FEU. Please refer to the graph and table below. Please note that for all scenarios all growth rates remain the same through the GGRR period. After the GGRR period ends in 2017 the scenarios begin to diverge from 2018 to 2033 based on the four growth rates in the above question. Please also note that the 20% growth rate requested compares closely to the growth rate of 18.4% resulting from the FEU's reference case forecast.



Total Load (TJ/yr)	2010-2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
5% Growth Rate	195	247	424	511	1,108	1,676	2,168	2,277
10% Growth Rate	195	247	424	511	1,108	1,676	2,168	2,385
15% Growth Rate	195	247	424	511	1,108	1,676	2,168	2,494
20% Growth Rate	195	247	424	511	1,108	1,676	2,168	2,602
Total Load (TJ/yr)	**2019F**	**2020F**	**2021F**	**2022F**	**2023F**	**2024F**	**2025F**	**2026F**
5% Growth Rate	2,391	2,510	2,636	2,767	2,906	3,051	3,204	3,364
10% Growth Rate	2,624	2,886	3,175	3,492	3,841	4,226	4,648	5,113
15% Growth Rate	2,868	3,298	3,793	4,361	5,016	5,768	6,633	7,628
20% Growth Rate	3,122	3,747	4,496	5,396	6,475	7,770	9,324	11,188
Total Load (TJ/yr)	**2027F**	**2028F**	**2029F**	**2030F**	**2031F**	**2032F**	**2033F**	
5% Growth Rate	3,532	3,709	3,894	4,089	4,293	4,508	4,733	
10% Growth Rate	5,624	6,187	6,805	7,486	8,234	9,058	9,964	
15% Growth Rate	8,772	10,088	11,601	13,342	15,343	17,644	20,291	
20% Growth Rate	13,426	16,111	19,334	23,200	27,840	33,409	40,090	

51.4 FEU discusses the natural gas vehicle market share in FEI's service territory. Please confirm that the markets from the FEVI and FEW regions are expected to be similar.

Response:

Not confirmed. In FEI's view, NGT markets on FEVI and FEW are more regional in nature and as such there are limits to the growth of the NGT program in FEVI and FEW. Although the FEU do not expect that FEVI and FEW will capture the same market share rate as the FEI transportation market, the FEU do expect to capture a portion of the existing transportation market.

FEVI has already added a CNG customer named ColdStar. Coldstar is based on Vancouver Island and has converted 10 of its vehicles from Diesel to CNG.

51.5 If not confirmed, please explain why not and provide the estimates for the other service territories.

Response:

Please refer to the response to CEC IR 1.51.4. The FEU do not have data available that provides an overall market size specific to only FEW or FEVI. The NRCan data provides the total market size for the entire province of BC, but not for specific regions.

51.6 On what basis did FEU assume a 15% market share for the Reference Case? Please provide any evidence that FEU used to arrive at this assumption.

Response:

The FEU assumed a 15% market share of the overall transportation market based on an anticipated annual growth rate in NGT vehicle adoption of 18.4%. The NGT program is relatively new, and there is limited historical data available. However, the FEU believes an 18.4% growth rate is a reasonable estimate based on vehicle conversions to date under the NGT program.

The FEU note that the 18.4% growth rate in the reference case is similar to the 20% growth rate presented by the CEC in their IR 1.51.3.

51.6.1 Does FEU consider 15% market share to be the most likely scenario to arise? Please explain why or why not.

Response:

The FEU do consider a 15% market share to be the most likely scenario to arise as a result of the NGT program. Please refer to the response to CEC IR 1.51.6 for the assumptions supporting the 15% market share scenario.

51.7 On what basis did FEU assume a 30% market share in the High Case? Please provide any evidence that FEU used to arrive at this assumption.

Response:

The FEU chose to present the High Case scenario of a 30% market share of the total applicable vehicle market in 2033 as that market share is exactly double the 15% market share that FEI is expecting in its Reference Case scenario. The 30% scenario represents higher than anticipated NGT demand growth due to the operating cost advantages of natural gas over gasoline and diesel fuels and increasing availability of fueling stations.

The FEU also took into consideration feedback received from the Resource Planning Advisory Group in deciding to examine a forecast that is double the FEU's expectations.

51.8 Is it FEU's position that 30% market share is the highest possible market share that natural gas vehicles could reasonably be expected to achieve. Please explain why or why not.

Response:

It is not the FEU's position that a 30% market share is the highest possible market share that natural gas vehicles could reasonably be expected to achieve. The 30% scenario was intended to represent an upper range of the NGT demand forecast in comparison to the Reference Case assumption of the FEU capturing 15% of the transportation market by 2033.

52. Reference: FEU Exhibit B-1 page 58

From Figure 3-13

	2010-2011	2016	2021	2026	2031	2033
Low	195	1,676	2,168	2,168	2,168	2,168
Reference	195	1,676	4,267	9,946	23,183	32,522
High	195	1,676	5,075	14,689	42,518	65,045

52.1 Please provide the total current market size and the projected market size by 2033.

<u>Response:</u>

Please refer to Attachment 52.1.

53. Reference: FEU Exhibit B-1, page 58

NGT Reference Case Annual Demand Scenario:

Market expands, volumes increase to meet demand

The Reference Case NGT scenario is based on the anticipated outcome of the NGT Incentive Program, and includes anticipated market expansion and a subsequent increase in demand volumes. It is expected that the popularity of NGT vehicles will increase due to the operating cost advantages of natural gas over gasoline and diesel fuels and increasing availability of fueling stations. In the Reference Case scenario, the number of heavy duty and return-to-base fleet NGT vehicles scale up to a 15% market share by 2033.

53.1 Please explain how the anticipated outcome of the NGT Incentive Program influences the Reference case forecast.

Response:

The NGT incentive program is designed to kick start the transformation process from diesel fuel to CNG/LNG by reducing adoption barriers for fleet operators. FEI's strategy was to look at fleets across various sectors that consume high amounts of diesel fuel, travel intracity and return back to base.

FEI is on track to put 400 CNG/LNG vehicles on the road since the start of the incentive program, and has made considerable progress in establishing the fuelling infrastructure required for those fleets.

During the remaining term of the program FEI anticipates making further inroads across new market segments, and plans to build or support the development of infrastructure and demonstrate that converting to natural gas is good for fleet owners and operators. The outcome of this incentive program will increase the adoption of natural gas vehicles, and forms the basis for developing the reference case forecast.

54. Reference: FEU Exhibit B-1, page 58 and 59

Market expands during incentive reward period, volumes stabilize

In the NGT Low Case, the level of demand at the end of the GGRR approval period is assumed to remain stable as existing customers continue to renew their fleet of natural gas vehicles, but the market is not assumed to continue growing. Although it is expected that NGT vehicles will increase in the marketplace, the possibility remains that without incentive funding beyond 2018, firms will not purchase additional natural gas fueled vehicles regardless of the fuel cost savings that can be achieved. This assumption results in a level demand forecast (neither growing nor declining demand beyond 2017) thus the heavy duty and return-to-base fleet NGT vehicles remain at a 1% market share by 2033. This Low case represents the lower bound of NGT demand that the FEU believe could reasonably be expected to occur over that time.

54.1 Is it FEU's view that incentive funding is crucial to growing the overall market; or that incentive funding will predominantly drive FEU's market capture rate? Please explain.

Response:

The objective of the NGT program is to kick start the transformation from diesel to natural gas fuelled vehicles. To the extent that this occurs, the incentive funding will drive market share capture rate of natural gas vehicles within the overall vehicle market rather than growing the overall market size of the applicable vehicle types.

As outlined in the response to CEC IR 1.50.1, the FEU do not anticipate that the NGT program will increase the overall size of the transportation market. Rather the NGT program will displace diesel fuelled vehicles with natural gas fuelled vehicles.

54.2 What strategies is FEU planning to follow to develop the NGT market?

Response:

Although not an exhaustive list, the following are some of the strategies that the FEU is planning to follow to develop the NGT market:

1. Actively engage with OEM engine manufacturers to express the need for suitable engine offerings;
2. Raise awareness of the FEU's NGT Program by actively participating in industry trade shows, events, and conferences and through internal sales channels;

3. Conduct case studies on existing NGT customers to demonstrate feasibility and success of switching to natural gas;
4. Conduct research to identify newer market segments and corridors best suited for CNG/LNG applications based on existing OEM offerings; and
5. Work closely with dealerships and other associations such as CNGVA, BCTA to raise awareness and promote natural gas for transportation.

Please also refer to the response to CEC IR 1.26.2.

55. Reference: FEU Exhibit B-1, page 59 and page 59

> increase in the marketplace, the possibility remains that without incentive funding beyond 2018, firms will not purchase additional natural gas fueled vehicles regardless of the fuel cost savings that can be achieved. This assumption results in a level demand forecast (neither growing nor declining demand beyond 2017) thus the heavy duty and return-to-base fleet NGT vehicles remain at a 1% market share by 2033. This Low case represents the lower bound of NGT demand that the FEU believe could reasonably be expected to occur over that time.
>
> *Market expands rapidly, volumes increase to meet demand*
>
> The High NGT scenario is based on a higher than anticipated level of NGT demand growth This scenario anticipates that the popularity of NGT vehicles will increase dramatically due to the operating cost advantages of natural gas over gasoline and diesel fuels and increasing availability of fueling stations. In the High case, by the end of the forecast period in 2033, the FEU is expected to capture a 30% market share of B.C.'s heavy duty and return-to-base fleet NGT.

55.1 Please clarify if the term 'market share' references the heavy duty and return to base fleet NGT vehicles as a portion of the total vehicle market, or FEU's market share capture of the heavy duty and return-to-base fleet NGT vehicles

Response:

The term 'market share' references market share that natural gas fueled vehicles capture out of the total applicable heavy duty and return-to- base segment of the transportation market in BC.

55.2 Please provide the full data set illustrating the forecast for total market size, the forecast for heavy duty and return-to-base fleet NGT vehicles and the expected market capture rate for FEU.

Response:

Please refer to Attachment 55.2 for the full data set.

55.3 Please provide a high level analysis of competitors and their expected actions under each scenario.

Response:

The FEU assume this request is referring to competing fuels in the relevant transportation market, such as gasoline and diesel that currently hold almost 100% of the market share or hydrogen and electricity that are still experimental. It can be reasonably assumed that under the FEU's low demand scenario, existing competitors would likely take little or no action, whereas under the FEU's high demand scenario, competitors would likely respond with a strategy designed to protect their market share. The nature of that strategy is not known to the FEU. The FEU expect that experimental fuel developers will continue efforts to find viable market entrants, but do not expect see this occur in the foreseeable future, though they will remain vigilant.

55.4 Please provide the full data set illustrating the current situation and forecast for marine market.

Response:

At present, the FEU are in advanced discussions with two marine vessel operators that will be taking receipt of a total of 5 liquefied natural gas (LNG) marine vessels beginning in 2016. The forecast presented in FEI's PBR Evidentiary Update, dated February 21, 2014, provided a five-year forecast of natural gas demand, including demand from the marine sector. Please refer to CEC IR 1.26.1 for that forecast.

Please also refer to the response to CEC IR 1.55.2 for the full data set.

55.5 Please provide the full data set illustrating the current situation and forecast for the rail market.

Response:

Please refer to response to CEC IR 1.55.2.

56. Reference: FEU Exhibit B-1, page 59

> *Market expands rapidly, volumes increase to meet demand*
>
> The High NGT scenario is based on a higher than anticipated level of NGT demand growth This scenario anticipates that the popularity of NGT vehicles will increase dramatically due to the operating cost advantages of natural gas over gasoline and diesel fuels and increasing availability of fueling stations. In the High case, by the end of the forecast period in 2033, the FEU is expected to capture a 30% market share of B.C.'s heavy duty and return-to-base fleet NGT.

56.1 What is FEU's expectation as to the likelihood of the High NGT scenario occurring? Please provide any evidence that may be available.

Response:

The likelihood of the High NGT demand scenario occurring is relatively low. However, it was presented to represent the upper range of expectation that the FEU had with respect to overall NGT demand over the long run. The FEU view that the reference case at 15% of market share by 2033 represents a realistic expectation of overall NGT demand over the long run.

56.2 Would FEU agree that in the event that the popularity of NGT vehicles increases dramatically due to operating cost advantages of natural gas over gasoline, that the entire market would also grow?

Response:

The FEU do not agree that in the event that the popularity of NGT vehicles increases dramatically due to operating cost advantages that the entire market would also grow. The FEU expect to displace diesel and gasoline use with natural gas use and thus would imply that the overall market is not growing, but the shift is occurring away from diesel and gasoline to more natural gas use. Hence it is the NGT share of the transportation market that would grow more quickly.

The FEU expect that the transportation market will continue to grow at a steady and predictable rate, but within this overall market size, the share of demand provided by natural gas use is expected to continue to grow into the future.

56.2.1 If so, please provide FEU's expectations with respect to how the market might grow under a rapid market expansion scenario.

Response:

Please refer to response to CEC IR 1.56.2.

56.3 Please confirm that if the market were to expand rapidly that FEU would still predict a 30% market share capture rate.

Response:

Confirmed. However, the FEU note that the transportation market is not expected to expand rapidly over the long term.

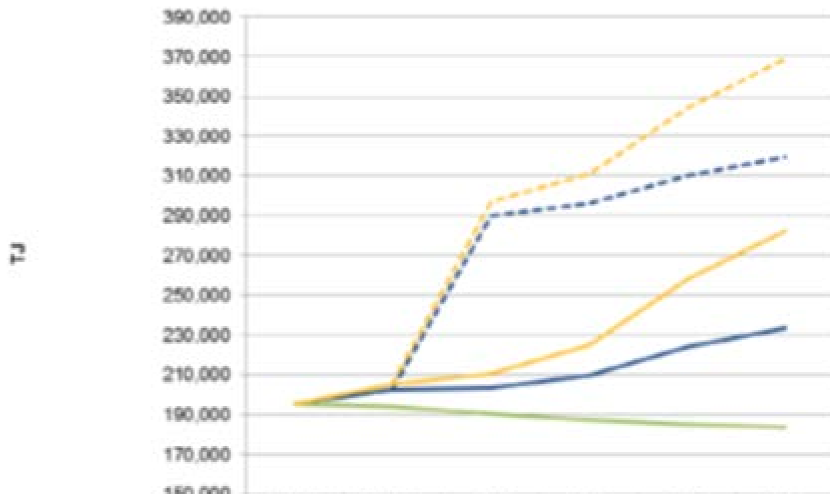
56.3.1 If not confirmed, please provide any modifications to the market share that FEU expects to capture under such as scenario and explain why.

Response:

Please refer to response to CEC IR 1.56.3.

57. Reference: FEU Exhibit B-1, page 62 and Appendix A- page

Figure 3-16: Total Annual Demand Including NGT and Woodfibre Example



	2011	2016	2021	2026	2031	2033
Ref + NGT	195,317	202,426	203,586	209,738	223,877	233,353
Ref + NGT + Woodfibre	195,317	202,426	289,986	296,138	310,277	319,753
Scen B + NGT	195,317	194,010	190,567	187,316	184,942	183,777
Scen C + NGT	195,317	205,099	210,734	224,741	257,935	282,504
Scen C + NGT + Woodfibre	195,317	205,099	297,134	311,141	344,335	368,904

If all of the projects that have been announced publicly were to proceed, a total LNG volume approaching 19 Bcf/d would be exported. To date, only seven of these projects, the Kitimat LNG, BC LNG, Pacific NW LNG, Prince Rupert LNG, WCC LNG, Woodfibre LNG and LNG Canada, have received National Energy Board (NEB or the Board) approval to export up to 14.8 Bcf/d of LNG. A number of market analysts predict that between 1 bcf/d[3] (Wood Mackenzie)

and 4.8 bcf/d[4] (Goldman Sachs) of gas are likely to be exported by the end of the decade to markets in Asia.

57.1 Would FEU agree that there is a substantial likelihood that a new load such as that expected from Woodfibre will likely be added over the next decade?

Response:

The FEU believe that there is a fair likelihood of the addition of a large new industrial load such as that of Woodfibre over the next decade, such that FEU has considered the possibility of it occurring sometime between 2016 and 2021 in Figure 3-16 of Exhibit B-1. As noted in response to CEC IR 1.73.1, the FEU are speaking to a number of customers that are either seeking additional liquefaction from Tilbury or seeking transmission service for their own LNG facilities. It is recognized that not all these potential customers will proceed but that if only two or three of these proceed, additional load similar to Woodfibre could be expected.

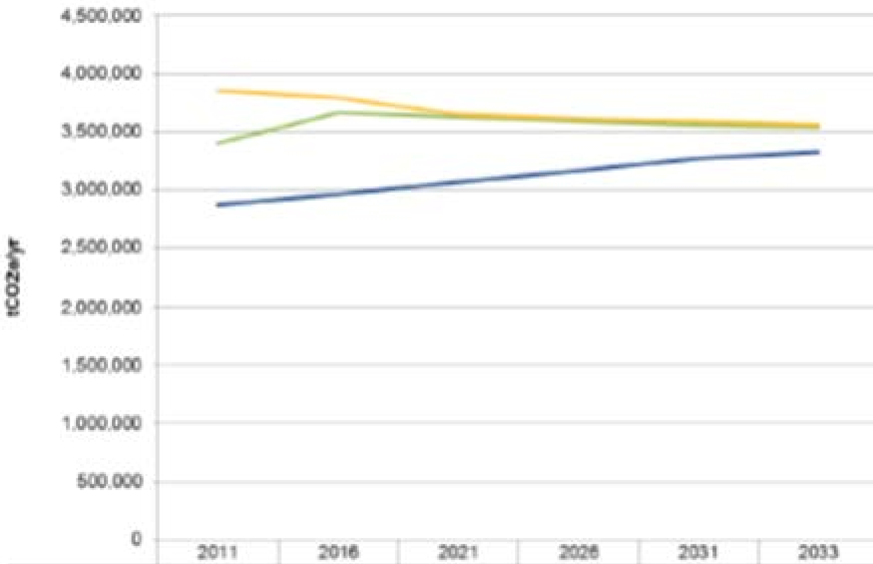
57.2 Please provide a list of other sites where opportunities for NG export are being explored that might use the FEU natural gas system.

Response:

FEI is in discussions with a number of large industrial customers who would use the FEI natural gas system. These customers are looking at locations primarily within the lower mainland system and would use the natural gas to either produce LNG or other products that require natural gas as a feedstock. These negotiations are confidential and FEI is unable to provide a list of sites/locations or customers.

58. Reference: FEU Exhibit B-1, page 68

Figure 3-22: GHG Emissions From End-Use Gas Consumption – FEU



	2011	2016	2021	2026	2031	2033
Commercial	2,869,029	2,961,987	3,062,286	3,163,059	3,271,298	3,322,803
Industrial	3,398,468	3,660,017	3,626,922	3,586,726	3,551,749	3,532,290
Residential	3,850,171	3,786,685	3,645,328	3,609,244	3,582,784	3,557,850

58.1 Please confirm that Figure 3-22 is illustrative of the Reference case.

Response:

Confirmed.

58.1.1 If not confirmed, please provide the Reference case.

Response:

Please refer to the response to CEC IR 1.58.1.

59. Reference: FEU Exhibit B-1, page 89

> - Conduct a new Conservation Potential Review starting in 2015 to provide new conservation potential data for natural gas in B.C. with which to design EEC programs beyond 2018. The purpose of a CPR study is to examine available technologies and determine their conservation potential, which includes the amount of energy savings that can be achieved through energy-efficiency and conservation programs over the study period. A request for approval of the funding for the CPR and ongoing supporting studies that are important for the design of EEC programs is contained in the 2014-2018 EEC Plan and PBR application.

59.1 When would FEU expect the new Conservation Potential Review to be complete?

Response:

In the 2014-18 FEI PBR application, the FEU stated they intended to conduct the next Conservation Potential Review (CPR) in 2015 and are planning to do so in collaboration with FortisBC Inc. (electric) and BC Hydro. The FEU have just recently started discussions with BC Hydro and FortisBC Inc. on how this collaboration will operate. At this time, the FEU do not have an agreed upon timeframe for completion of the CPR.

60. Reference: FEU Exhibit B-1, page 90

- **Load Management:** Programs that may either reduce peak demand or shift demand from peak to non-peak periods. Since the largest portion of natural gas demand in B.C. is for space and water heating which are more difficult to shift, and because the natural gas system acts to store energy allowing it to be drawn down over a longer period of time than with electricity, programs that reduce or shift peak demand for natural gas are more challenging in B.C. However, increasing the load factor by adding customers who use natural gas in a flat manner helps to manage the system. Transportation customers are an example of this type of customer, as are other manufacturing customers such as those in fertilizer production or LNG for export.

60.1 Would FEU expect that the load management issues will slowly become less relevant as the load from residential water and space heating diminishes and the load from NGT increases and other industrial load such as that which might come from Woodfibre are added to the system? Please explain why or why not.

<u>Response:</u>

Although the relative proportion of energy demand for residential water and space heating will decrease with the addition of large baseload customers, load management issues will not become less relevant.

Increasing the load factor (LF) by adding large baseload customers results in increased utilization of installed system capacity. By running the system more fully there will be less on system storage (via line pack) available for load management. This means that operational response times to address peak demand will likely decrease – that is, faster operational responses would be required to deal with changes in demand.

61. Reference: FEU Exhibit B-1, page 91

> The impact of the High Carbon Fuel Switching Program, NGT activities, firm contracts for large new industrial customers, as well as every day sales activities for natural gas demand is already incorporated into the energy demand forecasts (Section 3), and therefore, their potential impact on system infrastructure is inherently considered in the system capacity and gas supply analysis discussions in Sections 5 and 6 respectively. The main goal, consequently, is to present them here as examples of load management strategies that the Companies should continue to explore, implement and expand where they are found to be in the interests of customers by adding throughput to the natural gas system thereby reducing rates while also helping to achieve government energy and emissions reduction objectives. GHG emission reductions from demand-side activities other than EEC are discussed in Section 8.

61.1 Does FEU consider itself a market leader or market follower in natural gas?

Response:

Given that the FEU is the largest natural gas provider in BC, it is a market leader.

For the purposes of this response, the FEU defines a market leader as, "The company selling the largest quantity of a particular product[2]" and, a market follower is defined as, "A company which enters a particular product market after another firm has become well established in that market.[3]"

61.2 Please provide a discussion of the everyday sales activities referenced including the focus of the sales activities and their objectives.

Response:

The focus of everyday sales activities is on retaining our existing customers and attracting new customers. Retention activities and objectives relate, in part, to educating customers and facilitating the participation in Energy Efficiency and Conservation (EEC) programs. Attracting new customers, in general, involves working with builders and developers to promote the advantages of using natural gas in their development.

[2] www.oxforddictionaries.com
[3] www.investorwords.com

62. Reference: FEU Exhibit B-1, page 95

> **Pipelines**
>
> To increase throughput capacity, an existing pipeline can be replaced by a larger diameter pipeline (increasing the flow area and decreasing the gas velocity) or it can be twinned with a parallel pipeline. Twinning pipelines is called "looping".

62.1 Please provide a discussion of the advantages and disadvantages of providing larger diameter pipeline and looping.

<u>Response:</u>

Since looping pipelines results in a second flow path, it has the advantage of providing operational flexibility. If one of the pipelines needs to be taken out of service, then the second pipeline can be used (although not at the full capacity of the two pipelines combined) to continue to provide gas delivery. Interconnecting the pipelines and controlling the pressure on either or both of the pipelines can control the flow through one of the specific pipelines which is of great utility when controlling gas velocity during Inline Inspection (ILI) runs. Disadvantages for looped pipelines include: the requirement of finding sufficient property and installation space to accommodate a second pipeline, two physical assets that have to be managed (a doubling of record keeping, inspections, etc.) and more infrastructure that is exposed to damage.

Larger diameter pipes have the advantage of increasing capacity usually within existing running lines or Rights of Way (ROW) without necessitating finding additional space for installation. Some disadvantages include: welding procedures on larger diameter pipelines can be time consuming, larger fittings (elbows, bends, etc.) which require additional space, and larger equipment is required to move and work on these pipelines. A single uni-directional (i.e. without a back-feed source) larger diameter pipeline generally offers less operational flexibility when compared to a looped pipeline (due to the reduced ability to manipulate the gas flows).

63. Reference: FEU Exhibit B-1, page 99

> installations. The FEU believe that a reasonable approach to consider the effect of EEC and changing end-use trends assumes that these effects offset one another in the Reference Case peak demand forecast and otherwise should be captured within the expected potential range of peak demand variation using high and low demand sensitivities. This approach explains why the recommendations in this section for system capacity related resources are not replaced by demand-side measures, thus addressing Section 44.1(2)(f) of the *UCA*.

63.1 What approach has the FEU traditionally employed to consider the effects of EEC?

Response:

With regards to the effect of EEC on peak demand forecasts, FEU carries out an annual review of customer usage patterns across the entire province. For heat sensitive loads the methodology used for this review consists of correlation of all customer billed consumption data against ambient temperature to determine the forecast peak demand by customer, by rate class and by region. To capture trends in customer usage a three year averaged Use Per Customer (UPC) is determined based on the historical billed consumption data. Changes in customer usage caused by EEC or other factors (e.g. increased space heat demand caused by installing larger furnaces for additions to residences, or addition of other appliances) are captured through this annual process.

For customers where hourly flow measurement data is available, traditionally the historical peak consumption would be used as peak demand for that customer. These historical peak consumption values are reviewed regularly to ensure that the historical value is representative of current peak consumption. If, for example, an industrial customer with hourly flow measurement implements EEC measures resulting in a reduction in their peak demand, then the historical value would be used as the peak demand until sufficient data has been collected to confirm a reduction in their peak load. In some cases where the customer account managers are aware of changes in load, then this is communicated directly with the planning group and changes in peak demand forecast can be made.

63.2 As the high demand scenario is similar to that of the traditional method, and the Reference case has a lower trajectory, would FEU agree that planning to the Reference case and the high and low demand sensitivities results in no additional margin or advantage above the traditional method?

Response:

With regards to annual demand forecasting discussed in Section 3, the new end-use methodology (encompassing the low Scenario B, reference and high Scenario C cases) provides significant benefits over the traditional method. Since it is possible to run end-use methodology with different scenarios using specific parameters that can be changed, a greater range of "what-if" scenarios can be analyzed looking at different potential future states. This is of great use to assess which changes in end use energy patterns would have the greatest impact and benefit. While annual demand forecasts are important for planning purposes (gas supply portfolios, strategic direction, effect of EEC programs, etc.), infrastructure planning is designed to meet peak demand.

However, the LTRP excerpt referenced in the preamble discusses peak demand, or the demand expected on the coldest day/hour. The end use methodology is not employed for forecasting peak demand. Infrastructure (e.g. capacity) planning requires a peak demand forecast. Peak demand analysis is based upon a low, reference and high demand peak forecast by region. This specific analysis is required to ensure that the gas system assets are of sufficient capacity to meet the peak demand within the planning horizon. The low and high peak demand cases provide an indication of when increased planning or field evaluation (e.g. of pressures, flow rates, etc.) are required such that project schedules can be created. Section 5, System Resource Needs and Alternatives on page 95 of Exhibit B-1 provides additional information.

63.2.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.63.2.

64. Reference: FEU Exhibit B-1, page 100

5.1.2.1 FEVI Transmission System

A potential capacity constraint has been identified on the FEVI Transmission System late in the planning period for which both operational and infrastructure solution options exist. This system serves Vancouver Island, the Sunshine Coast and feeds the communities of Squamish and Whistler. It consists of 626 km of high pressure pipelines including three twinned marine crossings of the Georgia and Malaspina Straits, three compressor stations, and the Mt. Hayes LNG storage facility in Ladysmith. Natural gas for FEVI customers is delivered from upstream sources on Spectra's Westcoast Pipeline system to the Huntingdon-Sumas trading point. From Huntingdon, FEVI contracts for transportation capacity across the FEI Coastal Transmission System (CTS) to the start of the FEVI system at Eagle Mountain in Coquitlam. The Mt. Hayes LNG storage facility has improved system reliability and enabled significant operational flexibility of the combined FEI CTS and FEVI systems.

64.1 Please provide a discussion of the potential capacity constraint and in what year it is likely to occur.

Response:

Forecast peak demand continues to grow on the FEVI system leading to a potential capacity constraint whereby existing gas system assets would not be able to meet the maximum contractual delivery of 50 TJ/d to Island Generation. This constraint is forecast to occur in 2028 without additional system reinforcement.

64.2 What are the operational and infrastructure options that exist to mitigate the capacity constraint?

Response:

Three main options have been identified on the FEVI system to mitigate this capacity constraint:

1. Increase Mt. Hayes Send-Out Allotment;
2. Add compression at Squamish V2; and
3. Renegotiate BC Hydro contract with Island Generation.

Further information discussing these options can be found on page 105 of the 2014 Long Term Resource Plan.

65. Reference: FEU Exhibit B-1, page 102 and page 102

> 31, 2013. For the 2013-14 winter, BC Hydro has indicated a contract demand of 40 TJ/d. Since this contract demand can be amended for the following year (i.e. for 2014-15) to a maximum value of 50 TJ/d, the FEU have analysed transmission requirements for FEVI based on the IG contract demand increasing to and remaining at 50 TJ/d from 2014 onwards. The VIGJV has

> Prior to installation of the Mt. Hayes LNG storage facility, the FEVI system was fully subscribed and relied upon a right to call back capacity to IG from BC Hydro during design weather events in order to serve its Core market design day, that is peak demand, requirements. Construction of the Mt. Hayes LNG storage facility was completed in 2011 and the facility entered service for the 2011-12 winter season. This "on-system" storage facility optimizes the existing system infrastructure by providing significant operational flexibility, regional storage resource benefits for both FEVI and FEI, and improved system reliability.

65.1 Does BC Hydro provide FEU with forecasts of its expected demand on an annual basis or for the longer planning horizon?

Response:

No, BC Hydro does not provide the FEU with forecasts of its expected demand on an annual basis. However, BC Hydro is required to provide a minimum 1 years notice for changes to the IG contract demand with all changes to take effect on the following November 1st or such later November 1st as designated by BC Hydro .

65.1.1 If so, please provide all the BC Hydro forecasts that would be relevant for predicting IG contract demand.

Response:

Please refer to the response to CEC IR 1.65.1.

65.2 Does FEU retain the right to call back capacity to IG from BC Hydro?

Response:

Yes, the FEU retains the right to call back capacity (the "Capacity Right") to IG from BC Hydro pursuant to the Peaking Agreement that was put in place at the same time as the Transportation

Service Agreement. The maximum curtailment volume that the FEU may use under the peaking agreement may not in aggregate exceed a total of 100 TJ/year.

65.2.1 If so, please provide a discussion of the conditions under which FEU can call back capacity from BC Hydro.

Response:

FEVI can exercise its Capacity Right under the Peaking Agreement in the event that it reasonably forecasts that there is insufficient capacity on the FEVI system to meet core market customer demand provided proper notification is given and all interruptible transportation has been curtailed. FEVI can also call on the capacity intraday if required to meet emergency situations, however in this case it is also required to take and pay for any gas BC Hydro has delivered to the system.

65.2.2 If not, is the call back an option that FEU could re-institute in future contracts? Please explain why or why not.

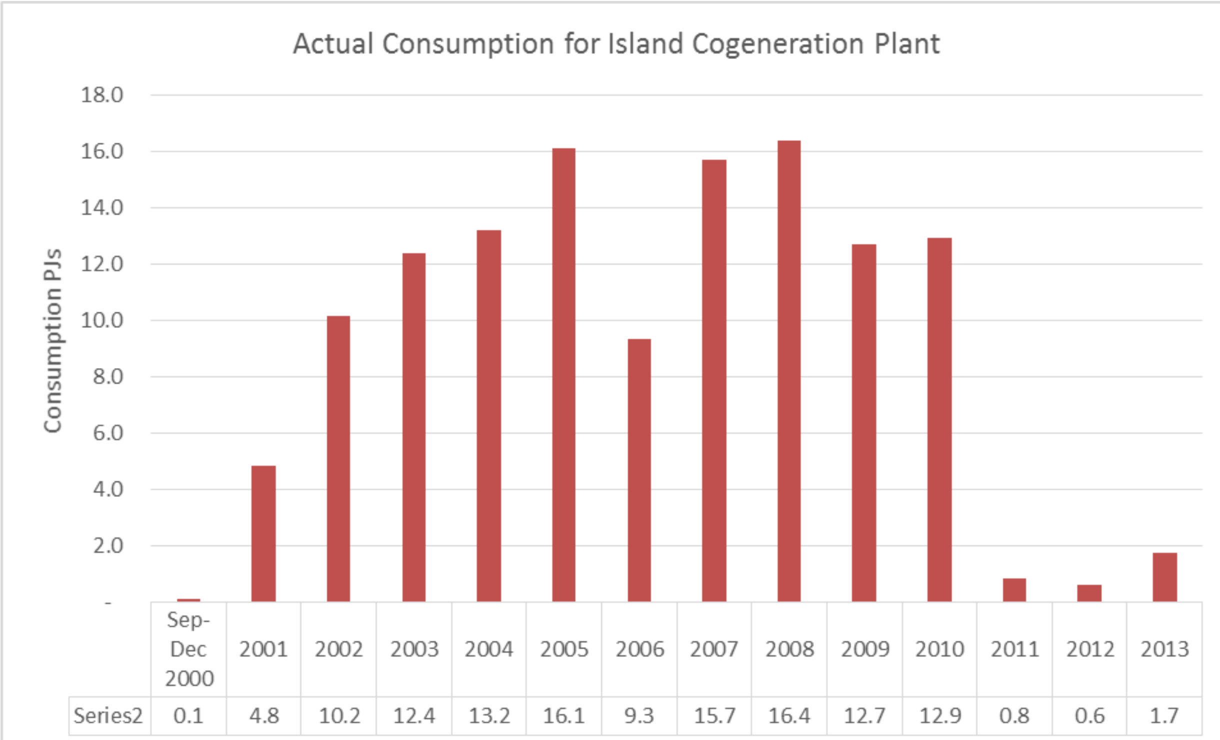
Response:

Please refer to the response to CEC IR 1.65.2.1.

65.3 Please provide a graph and the annual data points depicting the history of BC Hydro demand over the last 15 years.

Response:

The following graph shows annual consumption for the Island Cogeneration plant.



65.4 Is 50 TJ/day the maximum demand that BC Hydro is entitled to contract for the duration of the planning period?

Response:

Yes, 50 TJ/day is the maximum firm contract demand that BC Hydro can hold within the current Transportation Service Agreement in place with FEVI.

65.4.1 If not, please provide a discussion of BC Hydro's contractual options over the next 20 years.

Response:

Under the transportation service agreement, BCH has the right to adjust its contract demand at the beginning of each contract year (i.e. at November 1) up to 5 TJ/d with a minimum of 12 months notice. The contract demand cannot be more than 50 or less than 40 TJ/d. The initial term of the current agreement expires on April 12, 2022, however BC Hydro has renewal rights to extend one or more years to a maximum term of 35 years. BC Hydro also has early termination rights under the agreement on or after November 2015 by giving two years prior written notice.

65.5 What evidence does FEU have that BC Hydro will increase its contracted demand by 25% during the 2014-2015?

Response:

Under the term of the TSA, BC Hydro must give a minimum 12 months notice of any adjustment to the contract demand which would the come into effect the next November 1st. BC Hydro did not provide notice of any change and therefore the Contract Demand is expected to remain at 40 TJ/d for 2014/15 contract year.

66. Reference: FEU Exhibit B-1, page 102

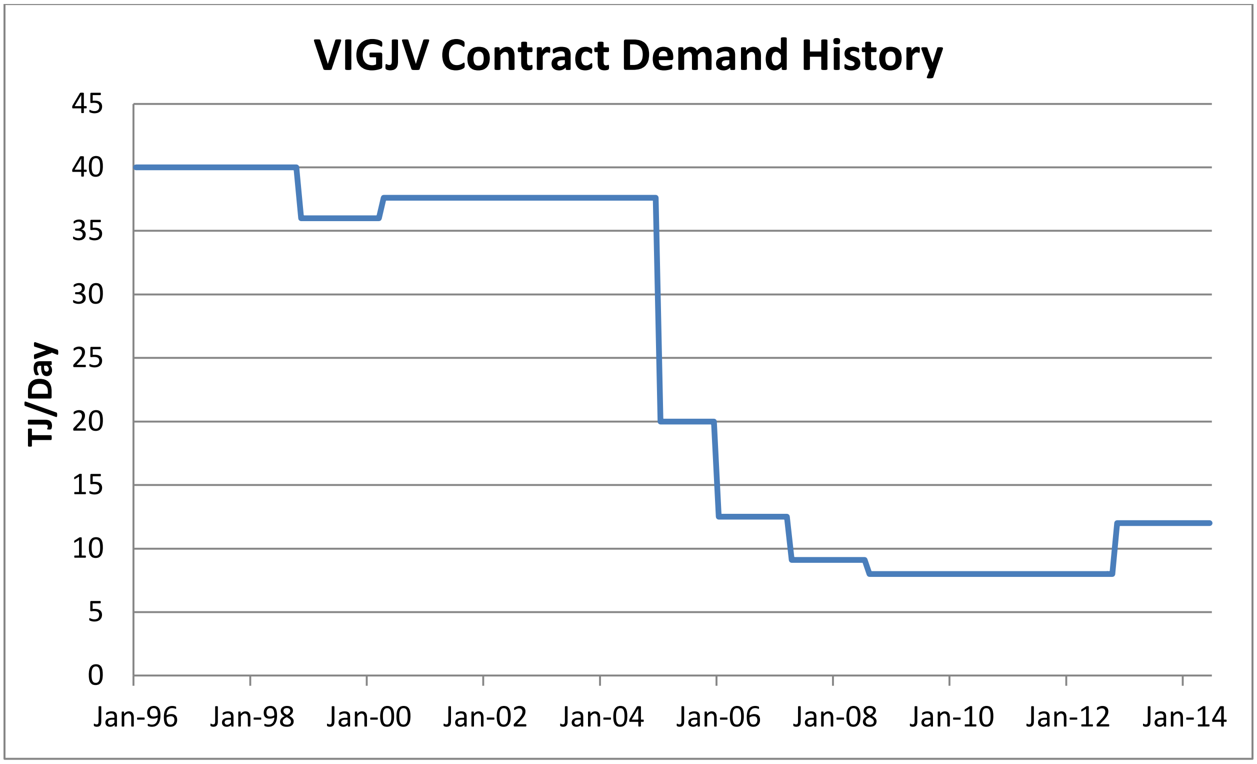
> contract demand increasing to and remaining at 50 TJ/d from 2014 onwards. The VIGJV has recently increased its contract demand from 8 to 12 TJ/d starting in the 2012-13 winter season. For demand and capacity modelling, it is assumed that VIGJV demand is fixed at 12 TJ/d from 2012-13 onwards. Future daily demand for natural gas as a transportation fuel in the FEVI

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



VIGJV Contract Demand History
TJ/Day
0
5
10
15
20
25
30
35
40
45
Jan-96
Jan-98
Jan-00
Jan-02
Jan-04
Jan-06
Jan-08
Jan-10
Jan-12
Jan-14

67. Reference: FEU Exhibit B-1, page 102

> 2012-13 onwards. Future daily demand for natural gas as a transportation fuel in the FEVI service region is determined by dividing the annual demand presented in Section 3.4.1 by 365 (days). As such, the daily demand for transportation is forecast to reach 0.04 TJ/day in 2033 in the Reference Case NGT demand forecast and is expected to be used primarily for compressed natural gas vehicles.

67.1 Please confirm that the Reference Case NGT does not reflect any increase in the NGT market size, but assumes a 15% share of an NGT market growing at 2% per annum.

Response:

Not confirmed. In response to this question it is important to clarify the following. First, market share is the share of the existing market for the vehicle categories that are captured by NGT. Second, it is the overall market for these vehicles that the FEU assumes is going to grow at a rate of 2% per year. The FEU's Reference Case NGT demand scenario presented in the LTRP results in an annual growth rate in NGT demand of about 18.4% per year from 2018 to 2033. The Reference Case NGT reaches a 15% market share of the overall vehicle market in 2033.

The overall vehicle market was calculated by taking 2010 Natural Resources Canada Transportation Statistics for Medium Trucks, Heavy Trucks, School Buses, Urban Transit, Freight Rail, and Marine and growing these figures by a 2% annual growth rate out to 2033. The overall vehicle market is comprised of all vehicle types (diesel, gasoline, etc.) and not solely NGT vehicles. Please also refer to the response to CEC IR 1.50.1.

68. Reference: FEI Exhibit B-1, page 102

> The Mt. Hayes facility has a storage capacity of 1.5 billion cubic feet (Bcf) (approximately 1,614 TJ[75]), of liquefaction capacity of 7.5 million standard cubic feet per day (mmscfd), and a send-out deliverability of 150 mmscfd (161 TJ/d). According to the storage and delivery agreement between FEVI and FEI, as part of its primary service, FEVI retains one third of the Mt. Hayes storage (i.e. 0.5 Bcf or 538 TJ) and send-out capabilities (50 mmscfd or 54 TJ/d) for supply and system capacity needs. FEI will contract the remainder of the storage and send-out capabilities for gas supply benefits. As part of the supplemental service, FEVI can put a portion of its one-third capacity to FEI, and has done so in the past. Further capacity constraints on the FEVI system are not expected until 2028, at which time additional Mt. Hayes send-out capacity above the primary service is required. Figure 5-2 shows the peak demand and capacity balance for

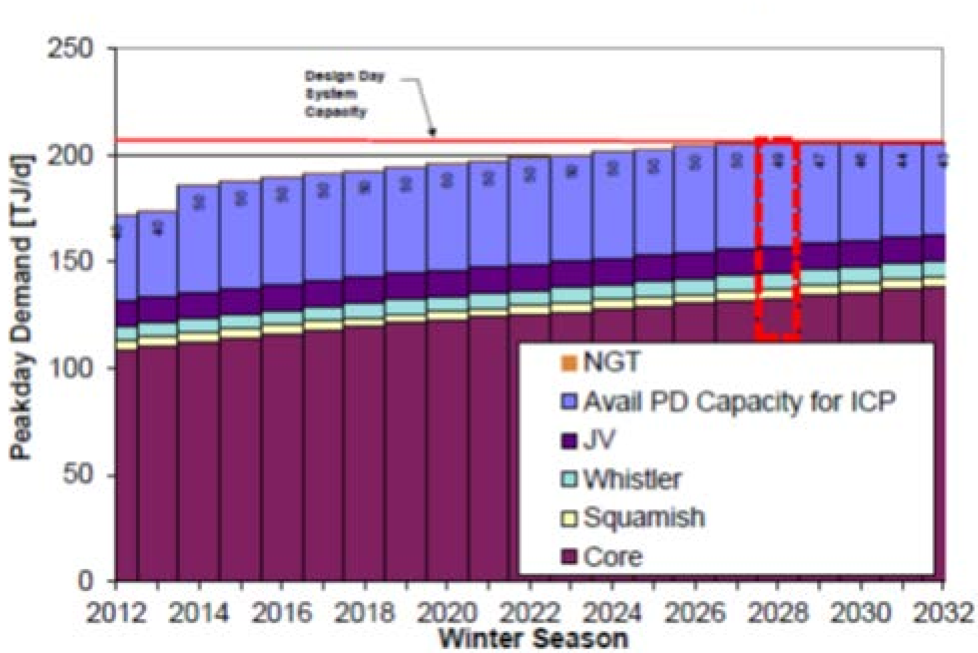
68.1 Please confirm that amalgamation will turn the storage and delivery agreement between FEIV and FEI into an allocation between rate classes not regions. Please discuss.

<u>Response:</u>

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.

69. Reference: FEU Exhibit B-1, page 103

Figure 5-2: FEVI Demand-Capacity Balance with the Mt. Hayes Facility (Reference Case)



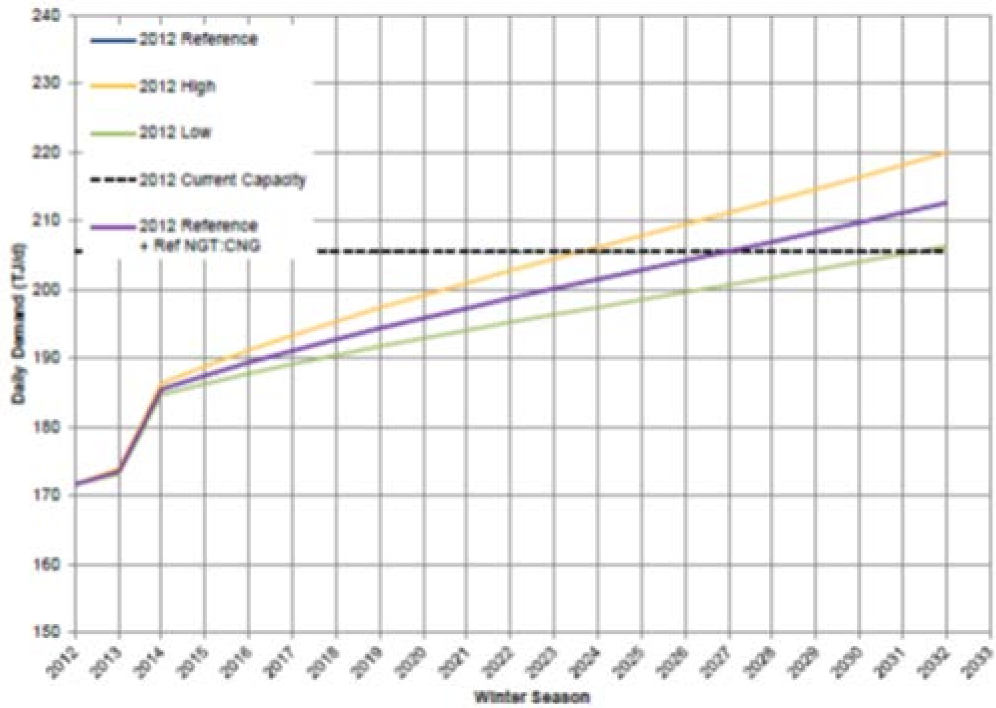
69.1.1 Please confirm that ICP refers to the BC Hydro Island Generation plant.

Response:

Yes, ICP refers to BC Hydro Island Generation Plant.

69.2 FEU Exhibit B-1 page 104

Figure 5-3: FEVI Facility Timing Using Reference, Low and High Peak Demand Scenarios



69.2.1 Please define and explain the current capacity determination.

Response:

The current FEVI capacity is the sum of the maximum deliverability from the Eagle Mountain supply from the FEI Coastal Transmission System via the pipeline and the maximum allowable Mt. Hayes LNG send out for the FEVI system.

69.2.2 Please confirm that the current capacity constraint appears to be reached just prior to 2027 under the Reference case due to the inclusion of CNG and not in 2028 as discussed elsewhere. (page 104)

Response:

In 2027 the FEVI system capacity just exceeds the forecast load; therefore, the capacity constraint would occur in the following year. Addition of the NGT loads on the FEVI system does not lead to advancement of this capacity constraint from 2028.

69.2.3 Please confirm that the Reference case is not visible because it is overlaid with the 2012 Reference plus Reference NGT:CNG

Response:

Confirmed.

69.2.4 Please confirm or otherwise explain that the significant increase occurring between 2013 and 2014 is as a result of the assumption that BC Hydro will contract for an additional 10TJ/day for the 2014-2015 period and please explain why.

Response:

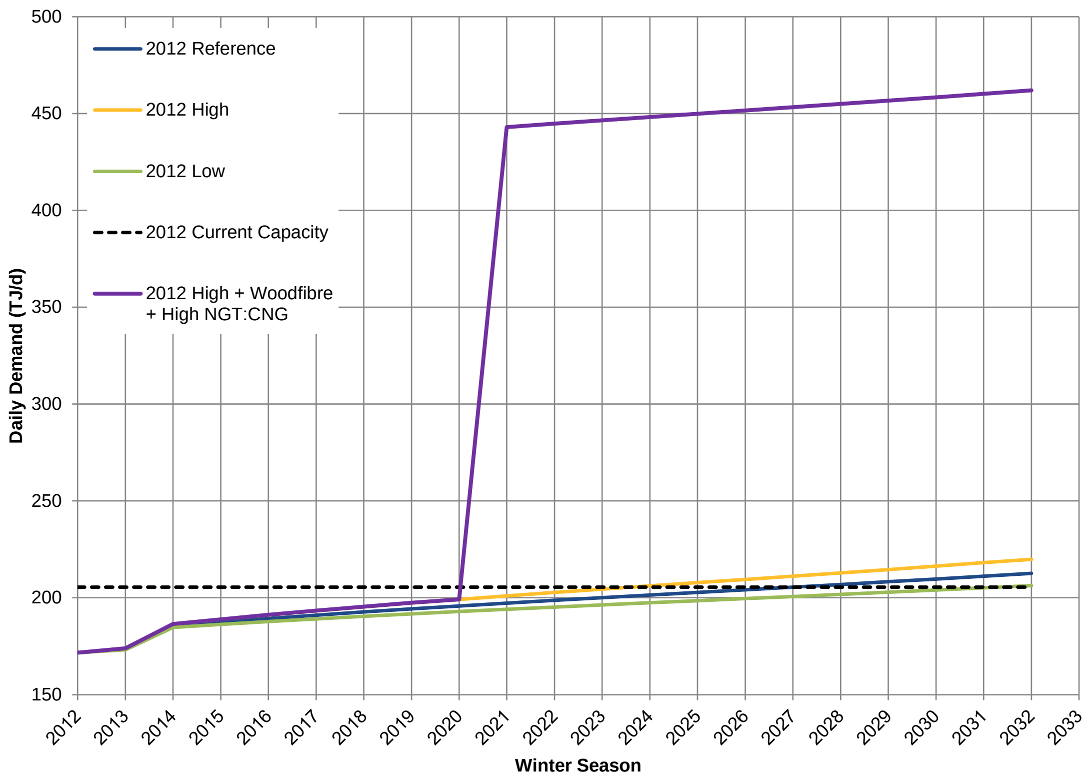
Yes, the significant increase in forecast demand between 2013 and 2014 is as a result of the assumption that BC Hydro will contract for an additional 10TJ/day for the 2014-2015 period. For clarity, the FEU have not received any notice from BC Hydro requesting an increase in contract demand from the current level of 40 TJ/d. From a planning perspective, to ensure that there is sufficient capacity on the FEVI system, it is assumed that the BC Hydro (BCH) Island Generation power plant increases its contracted demand to 50 TJ/d in 2014-2015. This is to ensure a conservative modeling approach is applied as that is the maximum firm contract demand that BC Hydro can hold under the Transportation Service Agreement.

69.2.5 Please provide Figure 5-3 utilizing the following scenarios:

a) High Scenario for core market plus high (30% market share) NGT plus the addition of Woodfibre occurring in 2021

Response:

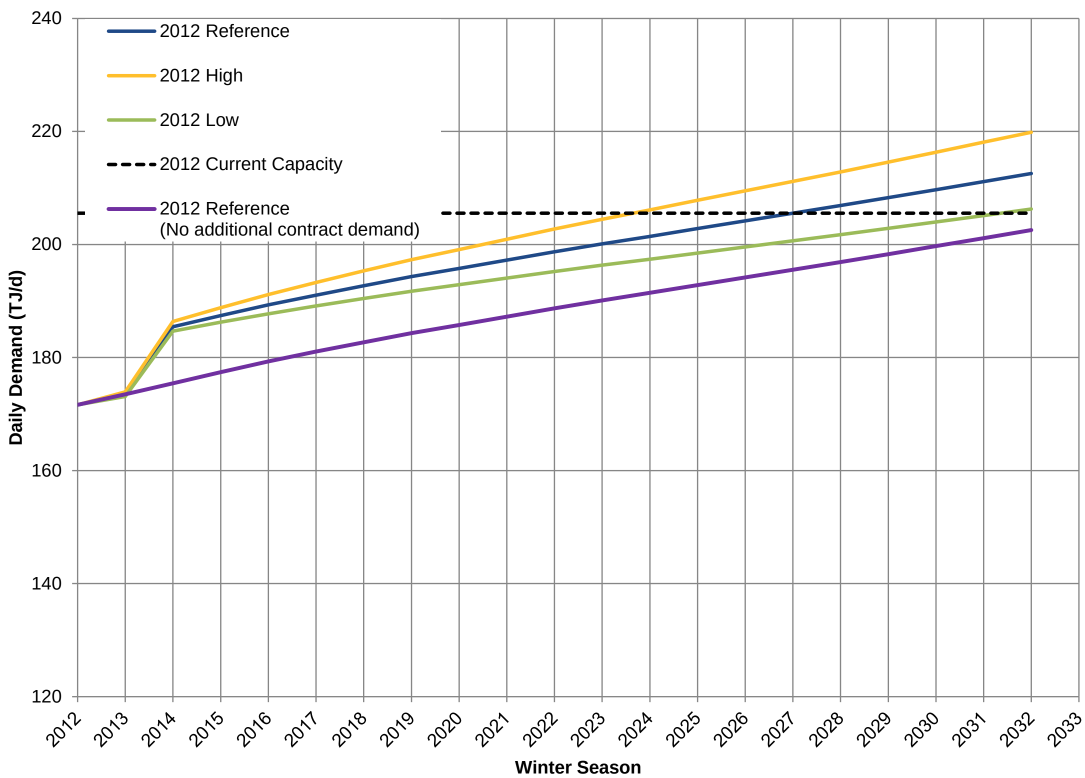
In the figure below, the FEU have reproduced Figure 5-3, replacing the "2012 Reference + Ref NGT:CNG" line with the requested scenario – high peak demand plus 30% NGT plus the addition of Woodfibre occurring in2021 (assumed at 242 TJ/d).



b) Reference case with no additional contract demand from BC Hydro.

Response:

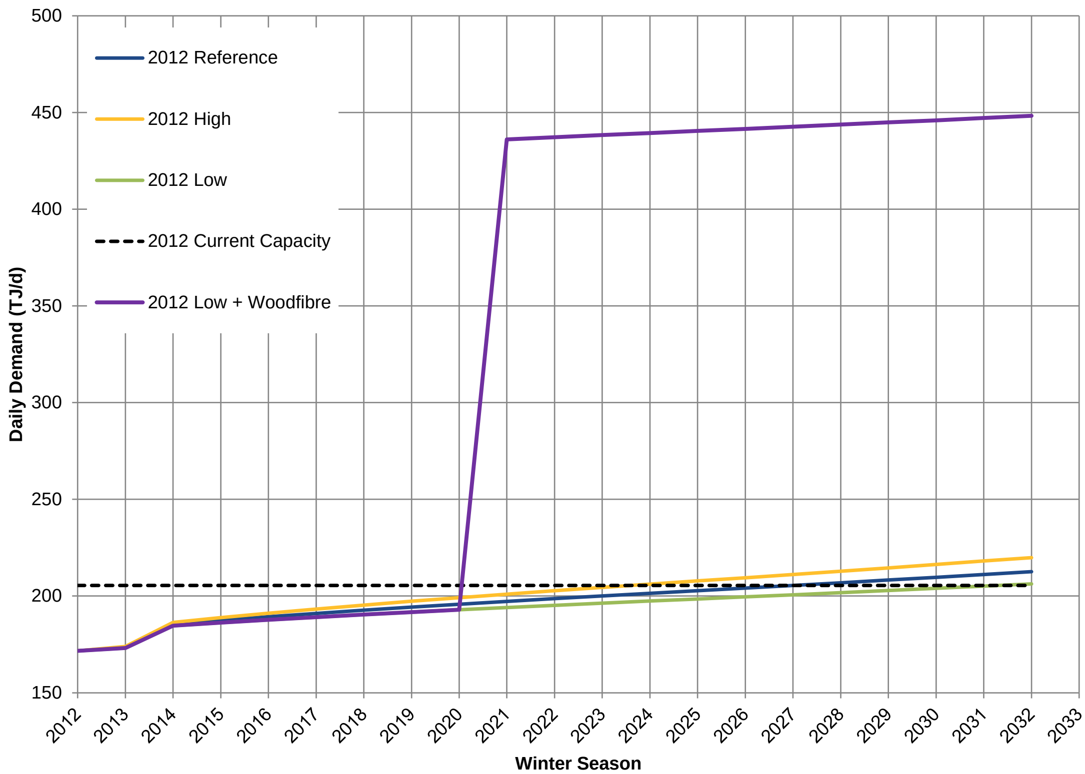
In the figure below, the FEU have reproduced Figure 5-3, replacing the "2012 Reference + Ref NGT:CNG" line with the requested scenario – reference peak demand but removing the additional BC Hydro Island Generation contract demand.



c) Low Scenario for core market plus the addition of Woodfibre occurring in 2021

Response:

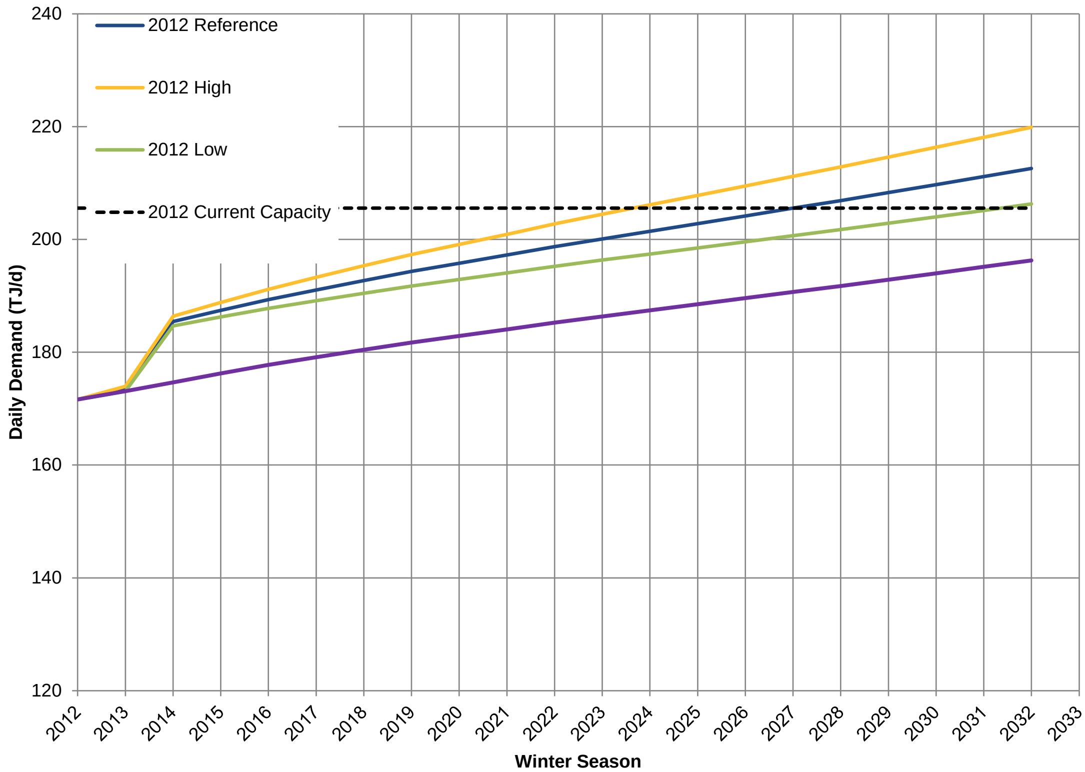
In the figure below, the FEU have reproduced Figure 5-3, replacing the "2012 Reference + Ref NGT:CNG" line with the requested scenario – low peak demand plus the addition of Woodfibre occurring in2021 (assumed at 242 TJ/d)..



d) Low scenario with no additional contract demand from BC Hydro.

Response:

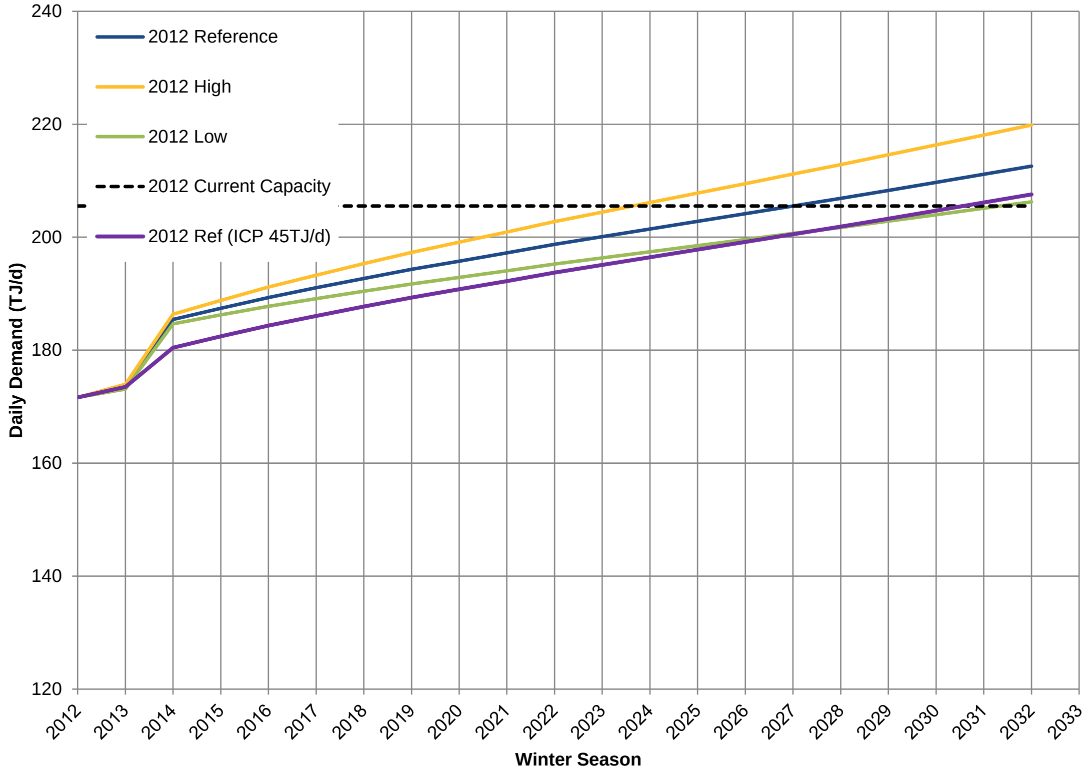
In the figure below, the FEU have reproduced Figure 5-3, replacing the "2012 Reference + Ref NGT:CNG" line with the requested scenario – low peak demand but removing the additional BC Hydro Island Generation contract demand.



e) Reference case with 5 TJ/day (rather than 10 TJ/day) of additional contract demand from BC Hydro

Response:

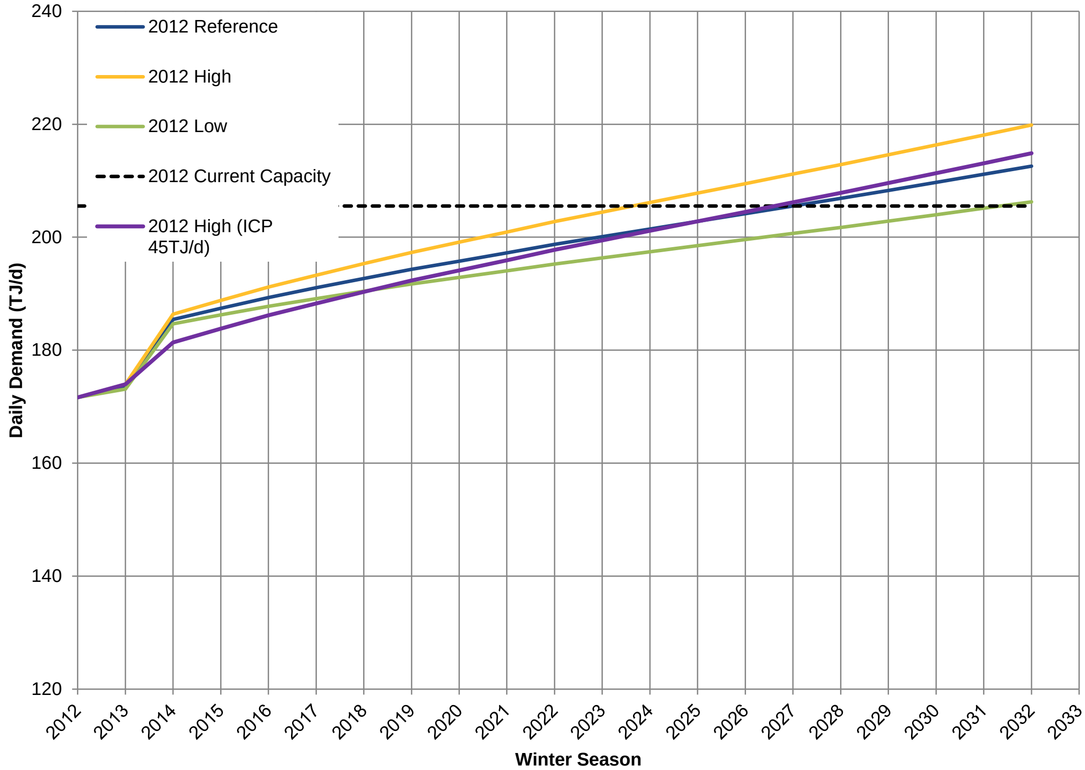
In the figure below, the FEU have reproduced Figure 5-3, replacing the “2012 Reference + Ref NGT:CNG” line with the requested scenario – reference peak demand but reducing the BC Hydro Island Generation demand by 5 TJ/d to a maximum of 45 TJ/d from 2014 onwards.



f) High Scenario with 5 TJ/day (rather than 10 TJ/day) of additional contract demand from BC Hydro

Response:

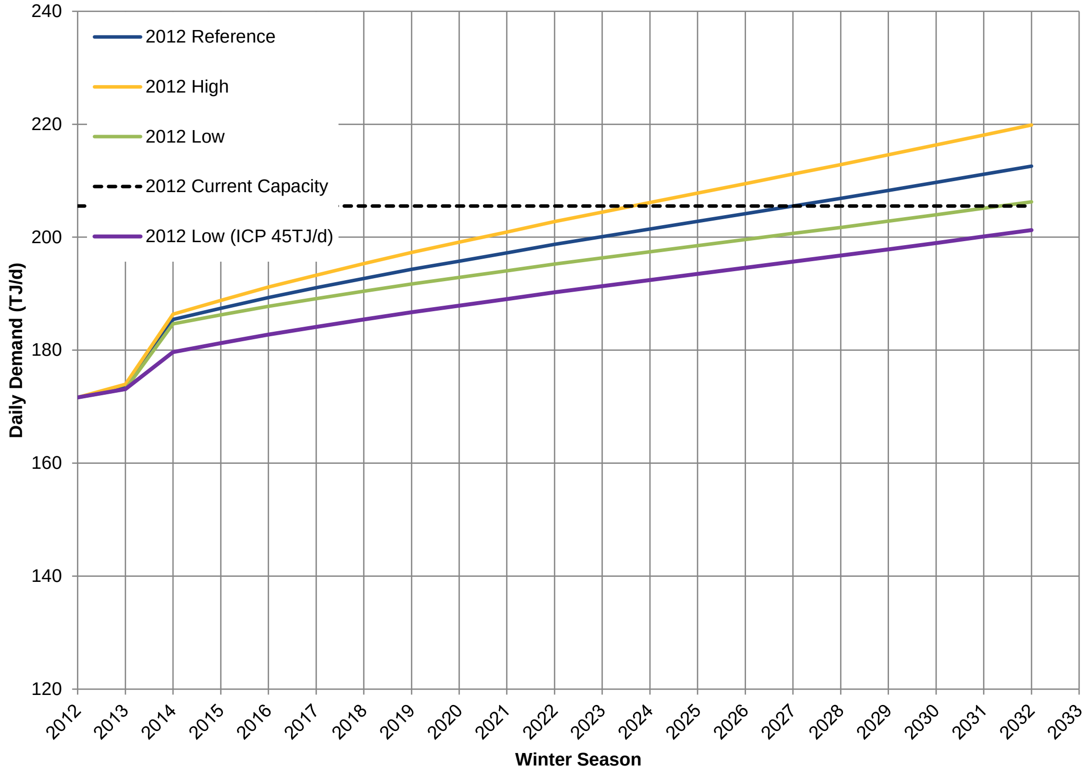
In the figure below, the FEU have reproduced Figure 5-3, replacing the "2012 Reference + Ref NGT:CNG" line with the requested scenario – high peak demand but reducing the BC Hydro Island Generation demand by 5 TJ/d to a maximum of 45 TJ/d from 2014 onwards.



g) Low Scenario with 5 TJ/day (rather than 10 TJ/day) of additional contract demand from BC Hydro

Response:

In the figure below, the FEU have reproduced Figure 5-3, replacing the “2012 Reference + Ref NGT:CNG” line with the requested scenario – low peak demand but reducing the BC Hydro Island Generation demand by 5 TJ/d to a maximum of 45 TJ/d from 2014 onwards.


240
220
200
180
160
140
120
Daily Demand (TJ/d)
2012 Reference
2012 High
2012 Low
2012 Current Capacity
2012 Low (ICP 45TJ/d)
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Winter Season

1

2

70. Reference: FEU Exhibit B-1, page 104

> **FEVI System Expansion Alternatives**
>
> The identified capacity constraint in 2028 (Figure 5-2) occurs six years after expiry of the FEVI - BC Hydro Transportation Service Agreement (TSA) for service to the IG. If the FEU and BC Hydro extend the TSA beyond 2022, based on current reference scenario forecast numbers, FEVI would have the following three resource options to manage forecast demand for the Core market customers and transportation requirements for the VIGJV and IG, and thus solve the capacity constraint that occurs in 2028:

70.1 Please provide a discussion as to the implications for the TSA and the need for capacity in the event that Site C is developed prior to 2028.

Response:

If the TSA agreement expires in 2022 and does not continue on, this could potentially free up some capacity on the FEVI system and defer the identified capacity constraint past 2028.

71. Reference: FEU Exhibit B-1, page 106

> In order to support PEC's timeline on the Woodfibre LNG Project, FEVI has developed a scope of work in the Pipeline Reinforcement Project, which outlines the system reinforcement requirements that are necessary in order to transport the additional load required by the export terminal. FEVI would need to reinforce its existing system with pipeline looping and add compression on the system to meet PEC's natural gas transportation service requirement; this infrastructure expansion would exactly match the firm transportation capacity contracted by PEC. With additional firm contract daily demand on the system, all else being equal, FEVI expects the Woodfibre LNG Project to help reduce costs for firm transportation on the FEVI system and thus provide benefits to FEVI's existing customers through lower rates.

71.1 What are the approximate expected costs of the Pipeline Reinforcement Project?

Response:

At this point in time, the Eagle Mountain – Woodfibre Gas Pipeline Project (previously referred to as the Pipeline Reinforcement Project) capital costs are expected to be in the range of $475 million to $600 million. The expected annual operating and maintenance costs are forecast to be approximately $1.5 million to $2.0 million per year.

Please note that the project remains in the development phase and further study and cost refinement will continue to occur as the project develops.

71.2 Are there additional opportunities to provide potentially needed infrastructure expansion at reduced cost by undertaking concurrent construction?

Response:

At this time FEVI cannot definitely state whether construction utilizing the same contractor for additional potentially needed infrastructure elsewhere within the FEI system will reduce costs. As part of the FEVI contracting strategy for the Eagle Mountain – Woodfibre Gas Pipeline Project (aka EGP or Pipeline Reinforcement Project), FEVI plans to investigate in detail whether combining construction work either concurrently or sequentially will yield lower costs.

71.2.1 If yes, please provide a discussion of these opportunities.

Response:

Please refer to the response to CEC IR 1.71.2.

72. Reference: FEU Exhibit B-1, page 109

> Reference Case peak demand for the entire CTS, shown in Figure 5-6, was analysed for Low and High scenarios by adjusting the Reference Case Core growth by 76% and 126% respectively. Again, these values were used to remain consistent with previous LTRPs in which high and low customer additions forecasts drove the peak demand sensitivities. The Low, Reference and High cases shown with the solid lines in Figure 5-6 include the current contractual firm demand for Burrard Thermal. The dashed lines in the same figure show the impact of phasing out the Burrard load from 2014 to 2016. With the inclusion of the Burrard Thermal load, Figure 5-6 shows that the Low and High cases delay the capacity constraint on the FEI CTS until 2032, or advance it forward to 2023, respectively. However, if Burrard Thermal is phased out, then Figure 5-6 shows that no capacity reinforcements are required in the 20-year planning window. In this graph, it should be noted that the Reference Case demand forecast and the Reference Case plus CNG transportation fuel demand are very close to one another.

72.1 Please provide Figure 5-6 with the 76% and 126% sensitivities for both the high scenario (Scenario C) and the Low Scenario (Scenario B).

<u>Response:</u>

The FEU are unable to provide the requested information. Scenarios C and B were used to generate the Total End-Use Forecast annual demand [TJ/yr] whereas Figure 5-6 deals specifically with peak demand [TJ/d] on the Coastal Transmission System (CTS). Annual demand and peak demand are computed using different methodologies and, at this time, it is not possible to directly relate forecast annual consumption to peak demand.

73. Reference: FEU Exhibit B-1, page 111

> Based on the FEI's natural gas demand forecast for NGT (refer to Section 3.3.7), the existing Tilbury facility can meet this demand until 2017, after which time demand is expected to outstrip the quantity of LNG available under the approved Rate Schedule 16 tariff. On November 28, 2013, the Government of B.C. issued Special Direction No. 5 to the BCUC to exempt from CPCN review an expansion of up to $400 million of the Tilbury LNG facility.[72] An LNG facility expansion is expected to be in place by mid-2016 to provide the fuel to meet expected LNG demand. The FEU's long term outlook must consider the system requirements for such an expansion.

73.1 Will FEU revise its expected expansion timeframes if the demand for NGT does not materialize as anticipated?

Response:

The FEU are proceeding with the expansion of the Tilbury facility which is expected to cost $400 million, with an in service date in 2016. Demand is materializing in the NGT market, small and remote communities, as well as niche export markets for the liquefaction capacity of this expansion. The FEU are also in discussions with other potential customers that could result in additional expansion of the Tilbury facility (Please also refer to the responses to CEC IRs 1.10.08 and 1.10.09).

73.1.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.73.1.

73.1.2 If so, please explain how FEU will determine when it would be appropriate to proceed with the Tilbury system expansion.

Response:

Please refer to the response to CEC IR 1.73.1.

73.1.3 What is the expected cost of the Tilbury system expansion?

Response:

Please refer to the response to CEC IR 1.73.1.

73.2 Please provide long term market expansion scenarios and potential future NNG expansion scenarios to match.

Response:

Long term NGT market expansion scenarios, in terms of forecast demand, have been presented in the executive summary, page ES-6. With regards to the Tilbury LNG facility expansion, the following table lists the minimum anticipated system expansions required to meet these forecasts:

Forecast Scenario	Annual NGT Demand in 2033 [TJ/year]	System Expansion
Low	2,168	Tilbury: + additional 34 TJ/d liquefier and 1,660 TJ storage
Reference	32,522	+ additional 68 TJ/d liquefaction + Loop: Cape Horn to Coquitlam + Loop: Nichol to Port Mann
High	65,045	+ additional 68 TJ/d liquefaction + Loop: Nichol to Roebuck + Increase diameter of lateral feeding Tilbury

74. Reference: FEU Exhibit B-1, page 112

> Under Reference (or expected) NGT market growth with Burrard Thermal still considered, the previously identified reinforcements of either Option 1 (looping Cape Horn to Coquitlam with a 30-inch line) or Option 3 (looping the Nichol to Port Mann pipeline with a single 36-inch pipeline) are feasible. Both options provide sufficient capacity for the 20-year planning window. However, the 36-inch pipeline replacement from Nichol to Port Mann provides the added benefit of allowing inline inspection from Nichol and the Fraser River crossing. Figures 5-5 and 5-6 depict the need for and timing of the 36-inch Nichol to Port Mann pipeline loop identified to solve this constraint. Option 2 (Provide Mt. Hayes LNG Support) could potentially be used to address

74.1 What is the difference in cost in the 36 inch pipeline looping option (Nichol to Port Mann) versus the 30 inch pipeline looping option (Cape Horn to Coquitlam)?

<u>Response:</u>

The difference in capital cost is estimated to be between 15 to 20%. A key benefit to installing the NPS36 pipeline is that a single Inline Inspection (ILI) run from Nichol to Cape Horn would be possible, resulting in reduced operating costs. These costs and other benefits would be examined further at the CPCN stage.

74.2 Has FEU already determined that the 36 inch pipeline option would be selected?

<u>Response:</u>

At this point no specific decisions regarding pipeline size (e.g. NPS 20 versus 36) nor location (e.g. looping Nichol to Port Mann or Cape Horn to Coquitlam) have been made. Transmission projects of this magnitude are often in excess of the $5 million threshold and require a CPCN application. An alternatives analysis forms part of this process and lays out the specific pros and cons for the different solutions.

75. Reference: FEU Exhibit B-1, page 110 and 112

> *Option 2: Provide Mt. Hayes LNG Support*
>
> The Mt. Hayes LNG storage facility could also alleviate the capacity constraint identified on the CTS for the duration of the planning period in two ways: Firstly, the Mt. Hayes facility reduces transport requirements to FEVI across the CTS as it provides on-system supply to FEVI during peak demand periods. Secondly, FEI contracts two thirds of the Mt. Hayes storage and deliverability capacity. Delivery of FEI's peaking supplies from the Mt. Hayes storage facility is largely through displacement, which leads to a further reduction in physical transport requirements to FEVI across the constraint on the Nichol to Coquitlam pipeline. Therefore, the capacity constraint on the CTS can be deferred beyond the planning period. Unlike option 1, the use of Mt. Hayes does not fully address Long Term Sustainment concerns.

> Tilbury. This option is not preferred as it presupposes that there is LNG send out available from Mt. Hayes on off peak days. Under the High NGT forecast, Figure 5-8 indicates that the *first*

75.1 Please explain why it would not be appropriate to rely on there being LNG send out available from Mt. Hayes on off-peak days to meet LNG requirements for at least some period of time.

<u>Response:</u>

Aside from peak days, Mt Hayes is also used on non-peak days to provide send-out in order to meet demand on the FEVI and CTS systems during cold weather events. The extent to which Mt Hayes can be used during these periods is somewhat uncertain because it is subject to a number of factors that change the capacity benefit it is able to provide the CTS system. Variability in forecast weather makes the timing of send-out to meet CTS capacity constraints uncertain. This weather uncertainly could also lead to the depletion of LNG inventory, which provides no assurance that sufficient LNG will be available to alleviate CTS capacity constraints when they occur. Given that Mt Hayes is used to meet core demand during cold weather events that may occur at any given time during the winter, it cannot be relied on to permanently alleviate the capacity constraints faced by CTS.

76. Reference: FEU Exhibit B-1, page 108 and 112

> With the November 2013 release of the BC Hydro Integrated Resource Plan (BCH IRP), BCH indicates that the Burrard Thermal power generation plant will be phased out of service by 2016 as other electrical system assets are brought online. From a gas capacity planning perspective, FEU is contractually obligated to reserve pipeline capacity to supply all six thermal power units at Burrard Thermal during peak demand conditions until a formal change to the contract is received. Based on this planning environment (e.g. assuming that firm gas capacity must still be reserved for Burrard Thermal) the peak demand and capacity balance for the Nichol to Coquitlam pipeline is shown in Figure 5-5.

> When the Burrard Thermal firm load is not included in the NGT analysis, both the Reference and Low NGT scenarios (dashed lines in Figure 5-8) do not need capacity reinforcement within the 20-year planning window. Conversely, the High NGT case would still require reinforcement in 2033 and would consist of one of the three options identified above.

76.1 When does FEU expect to have confirmation as to the requirement to service the Burrard Thermal load?

Response:

Although the Burrard Thermal load is expected to not be present past 2016 due to the government's order to shut this facility down for generation purposes, BC Hydro still contractually holds the capacity right and would have to determine whether or not to release this commitment. This contract expires on November 1, 2029 and BC Hydro has had the right to early termination with a minimum 1 years notice since November 2009. Any early termination would take effect on November 1st following the minimum 1 year notification that BC Hydro is required to provide pursuant to the current agreement. The FEU do not have any timing upon which it expects to have confirmation as to the requirement to service the Burrard Thermal load; however, if BC Hydro does not provide notification to the FEU to terminate the agreement before November 1, 2014, then the FEU will have confirmation that BC Hydro will retain this commitment for the November 1, 2015 to October 31, 2016 gas contract year.

77. Reference: FEU Exhibit B-1, page 117

> *Option 3 - LNG Storage Facility*
>
> The third alternative is an LNG storage facility located between Westwold and Grandview Flats close to Vernon. An LNG facility located closer to the load centre allows natural gas to be moved into storage in times of low gas demand when excess pipeline capacity is available, and provides on-system delivery to the region during periods of high demand. Since a high level cost analyses indicated that options 1 and 2 were less costly than an LNG facility, only the Reference Case demand was analysed for option 3.

77.1 Please provide the high level costs for Options 1,2 and 3.

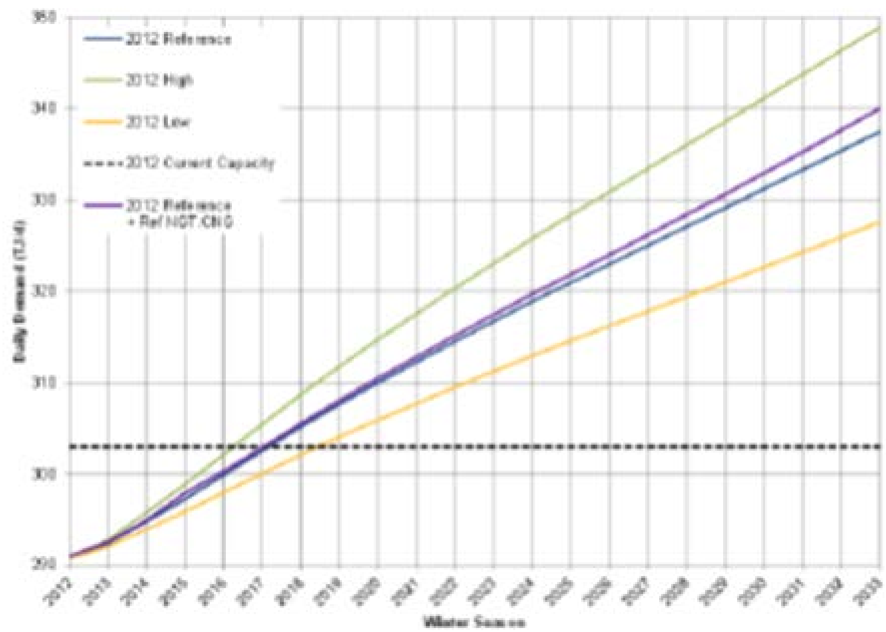
<u>Response:</u>

An order of magnitude cost estimate for each option is listed below.

Option	Description	Order of Magnitude Capital Cost
1	South Loop from Ellis Creek and Additional Compression	$66 million
2	North Loop from Savona and Kelowna Lateral	$81 million
3	LNG Storage Facility	$122 million

78. Reference: FEU Exhibit B-1, page 118 Figure 5-12

Figure 5-12: Location of Possible Interior Transmission System Reinforcement Options



78.1 Please provide the correct Figure 5-12: Location of Possible Interior Transmission System Options

<u>Response:</u>

This has been provided. Please refer to Exhibit B-1-1.

79. Reference: FEU Exhibit B-1, page

> Based on the 2012 FortisBC Inc. Integrated System Plan filed with the Commission in June 2011, a gas-fired power generating station was identified as one of three preferred build strategy options in the Okanagan area to meet growing peak electrical demand and avoid installing costly electrical transmission infrastructure. For the ITS, this or any other large additional industrial load that could arise would result in enough demand to drive the system reinforcement requirements described in this section (Section 5.1.2.3). The FEU would only include such new industrial demand in its peak demand forecast and conduct detailed system requirements analysis once a firm commitment is made by the customer for natural gas supply services. To date, the only formal proposal has been the gas-fired generating station mentioned above.

79.1 What was the expected timing of the FortisBC proposal for the generating station in the 2012 IRP?

Response:

The potential for gas fired power generation station was discussed in FBC's 2012 LTRP that was included as part of the Integrated System Plan. The FBC 2012 LTRP identified gas fired generation as one of several resource options to meet future capacity requirements that may be required by the mid to late 2020s.

79.2 When would FEU expect FortisBC to determine whether or not a gas fired power generating station would be undertaken?

Response:

The decision to proceed with a gas fired generating station depends on several factors including changes in forecast load requirements and forward market power prices compared to the cost of building a power generating plant. FBC will continue to evaluate resource options and load requirements in future resource plans. Given the current forecast timing of the project, FBC does not expect to begin planning for this project within the next five years.

80. Reference: FEU Exhibit B-1, page 120

> Cache Creek/Ashcroft Lateral has been identified to have insufficient capacity to meet the forecast demand throughout the 20 year planning horizon.

80.1 When would the Cache Creek/Ashcroft lateral expect to reach a capacity constraint?

Response:

Natural gas supply into the Cache Creek/Ashcroft lateral is from a tap on Spectra's mainline. The FEU have identified that with the minimum contractual tap pressure from Spectra there is sufficient capacity beyond the 20 year planning horizon for all core customers of the lateral with the exception of one large volume customer. This large volume customer is able to fully utilize the available capacity of the lateral when the tap pressure approaches the minimum contractual value. The FEU have an agreement in place with this customer to ensure the demand on the lateral remains within its capacity.

Current forecasts indicate little foreseeable growth of core customers on this lateral over the next 20 years. The FEU believe the current measures in place to monitor and manage demand on this lateral within the available capacity can avoid the need for pipeline capacity expansion indefinitely.

81. Reference: FEU Exhibit B-1, page 121

> FEI has identified Revelstoke's satellite propane system as a potential opportunity to convert the community from propane to natural gas. FEI has conducted an internal pre-feasibility study on using LNG from Tilbury for a possible conversion from propane to natural gas using a satellite LNG station at Revelstoke. After converting the existing propane distribution system to enable natural gas transmission, this off-grid LNG storage facility would accept shipments from Tilbury, re-gasify the LNG and then send it into Revelstoke's distribution network. The pre-feasibility analysis indicated that there could be a benefit to customers from converting to natural gas due to a lower cost of service and potential for a sustained lower delivered commodity price. The study focused on economic estimates and evaluations however, and did not identify specific challenges associated with converting from propane to natural gas. FEI will conduct further internal studies to refine conversion costs, review land availability and the logistics of transporting LNG infrastructure, and will also consult with Revelstoke stakeholders. FEI is planning to further examine the integration of this potential LNG opportunity with an overall LNG market assessment.

81.1 Please outline the costs and benefits that were identified to residential, commercial and industrial customers in the pre-feasibility study.

Response:

The costs identified in the pre-feasibility study were costs for LNG transport, storage, and re-gasification infrastructure, as well as upgrades to the propane distribution system and customer appliances. The FEU's conversion of the Whistler propane system to natural gas in 2009 was used as a baseline to calibrate estimated conversion costs for Revelstoke.

The benefits identified were as stated in the preamble in terms of reduced rates for service.

The magnitude of the net benefit is sensitive to assumptions used for future commodity price increases, as well as cost estimates described above. A further refinement of the assumptions used in the prefeasibility study is currently underway, with a view to increasing the certainty around any benefits that could be passed on to customers in Revelstoke.

82. Reference: FEU Exhibit B-1, page 123

> In the 2010 LTRP, the Utilities stated that they had embarked on a plan to enhance their asset management practices in order to be able to better manage the impacts of aging assets.[74] Through this exercise, the Utilities have gained a better understanding of asset condition and the impact of age, and have realized that age is not the causal factor that affects the probability of asset failure. Rather, the probability of failure is determined by the presence of threats such as corrosion or natural forces which act on the pipe. For example, corrosion is dependent on factors including coating and mitigating measures such as cathodic protection. Steel pipe that is properly coated and has effective cathodic protection has little threat of corrosion and can last virtually forever. Polyethylene pipe was expected to last 35 to 40 years when it was first installed in the early 1980s; however, samples of such pipe of this age removed from service in 2011 were tested by an independent laboratory and showed no degradation in performance. Thus, an asset's risk is dependent on the presence of threat factors which the asset management project team identified through literature, experience and expert knowledge. This approach ensures that the FEU's resources are allocated to where they are most effective at mitigating threats to pipe condition, which thereby maximizes the cost-effectiveness of each dollar spent and optimizes the service life of assets.

82.1 Has the FEU's understanding of threats, probability of failure and expected asset life resulted in an expectation of lowered costs for maintenance and asset management than were anticipated prior to undertaking the exercise? Please provide a high level discussion of the changes in management practice that will arise as a result of the improved understanding.

Response:

Costs for maintenance and asset management were (and still are) anticipated to change as a result of increased understanding of threats, probability of failure and expected asset life. The FEU believe that over the long-term, maintenance and asset management costs are likely to decrease, but over the near term are more likely to increase as opposed to decrease. The shift in philosophy to a more proactive nature and longer term view requires additional resources, especially over the near term, to enable the FEU to develop, implement, and support long-term plans. At the same time, as the FEU replace and/or upgrade assets considered high (relative) risk, it is expected there will be an overall reduction in the risk profile of its systems. As the overall risk profile of the systems are lowered, the likelihood of exposure to costs associated with responding to unplanned work (such as corrective repairs, emergency situations, or potentially even catastrophic events) will also decrease, as that work will be undertaken in a planned and managed manner (i.e. proactively replacing assets prior to failure or damage). Therefore, there are expectations of both increasing and decreasing maintenance and asset management costs arising as a result of the FEU enhanced asset management practices. And while over the long-term those costs are expected to decrease, the extent and timing of that decrease is uncertain. The FEU are confident, however, that through gaining a better understanding of threats, probability of failure, and expected asset life, the FEU have developed a relative risk framework that assists in the development of appropriate sustainment programs that minimize costs and ensure the ongoing safety and reliability of the natural gas delivery system.

82.2 Please provide the studies of this Revelstoke potential which have been done to date.

Response:

A pre-feasibility study to assess the opportunity for conversion of the Revelstoke propane system to natural gas is currently being prepared for internal review. Should FEI decide to proceed with the project, any internal studies would be included as part of the regulatory approval process, and would be available for review at that time.

83. Reference: FEU Exhibit B-1, page 125

> The FEU LTSP team has identified a limited number of high priority sustainment issues on the Lower Mainland IP System and the Coastal System. While projects at FEU are typically identified, budgeted and executed as discrete assets, in reality, the natural gas delivery system is a series of integrated assets and changing one asset impacts others. Correspondingly, planning projects and assessing the requirements for those projects must be done at a system level instead of at the asset level. This is especially true for the complex system in the large

83.1 Please provide an example of how changing one asset would impact others.

Response:

An example of how changing one asset would impact others is the replacement of a higher pressure gas line. When replacing a higher pressure gas line, factors such as pipe diameter and operating pressure are considered. Maintaining the existing operating pressure on the new gas line may not have any impact on other attached assets, such as stations, however an increase in operating pressure to accommodate a smaller diameter new gas line may require modifications to existing stations to ensure the continued safe, reliable delivery of natural gas.

83.2 Would FEU undertake to make several projects at once as a result of the integration, or would they continue to be kept separate. Please explain.

Response:

The FEU view its natural gas delivery system as a series of integrated assets. When projects are identified and developed for a particular asset or assets, further analysis typically determines whether or not any other assets may be impacted through that project, and if they are, the extent to which they may be impacted. It is through this process that opportunities to undertake several projects at once may be identified. Further analysis would then determine the feasibility of carrying out the projects concurrently, and whether or not design, construction or other infrastructure efficiencies may be achieved in doing so. In some cases, the FEU may deem it to be in the best interests of its customers to undertake several projects at once, while in other cases the FEU may deem it in the best interests of its customers to continue to keep execution of those projects separate.

84. Reference: FEU Exhibit B-1 page 127

Nichol to Roebuck pipeline loop. Although the Fraser Gate seismic upgrade project is listed below with an estimated at $3 to $4 million (therefore under the $5 million CPCN threshold), it is included here as it is an integral part of the assessment of the Lower Mainland natural gas delivery system. Additional inspection and analysis must be conducted before determining an appropriate course of action for Burns Bog.

762 mm Fraser Gate IP Pipeline	High risk of failure from seismic movement. Analysis indicates either replacement or stabilization of 700 m of the 762 mm pipeline is required. However, Coquitlam system capacity must be improved before addressing seismic risk.	Options to enable work on seismic upgrade: • Install a temporary bypass (not technically feasible due to a railway obstruction). • Reinforce/ increase back-feed capacity through the Coquitlam 508 mm pipeline. Estimated cost $3 to $4 million. This project is only feasible with increased capacity through the Coquitlam Gate IP pipeline.

84.1 Please confirm or otherwise explain that the costs for the Fraser Gate seismic upgrade will not be included in a CPCN application or as a portion of another CPCN.

Response:

Current cost estimates for the Fraser Gate IP Pipeline seismic upgrade are in excess of $5 million which is above the threshold that would necessitate a CPCN application. The FEU are currently evaluating other alternatives to address this seismic risk while minimizing overall estimated project cost. Once this options analysis has been completed and if the identified solution is above $5 million, the FEU will evaluate whether to file as a standalone CPCN application or to be incorporated as a portion of another CPCN.

85. Reference: FEU Exhibit B-1 page 128

Nichol to Coquitlam	In-line pipe inspections are required between Fergusson Station and Port Mann Station.	• Loop Nichol to Port Mann with 914 mm pipeline. Estimated cost $24 million. • Move the 610 mm receiver from Fergusson Station to Port Mann. Estimated cost $3 million.

85.1 Is moving the receiver from Fergusson Station to Port Mann only required s as a result of the Loop Nichol to Port Mann pipeline or is it required independently as well.

Response:

The FEU confirm the requirement to move the receiver from Fergusson Station to Port Mann is independent of the looping of the Nichol to Port Mann pipeline. Moving the receiver from Fergusson Station to Port Mann will enable the in-line inspection of an additional 1800 metres of the 610mm pipeline between Nichol and Port Mann that traverses a residential area. This will help ensure the continued safety and reliability of this portion of the transmission system.

85.2 Please explain what other system upgrades are or may be related to the Fraser Gate Upgrade.

Response:

To ensure the safety and reliability of the system downstream of the Fraser Gate Station, the Fraser Gate IP Pipeline seismic upgrade must be undertaken regardless of other system upgrades that are being considered. However, replacement of the 508mm IP Pipeline running through Coquitlam, Burnaby and Vancouver, with one of greater capacity, would facilitate undertaking the Fraser Gate IP Pipeline seismic upgrade.

86. Reference: FEU Exhibit B-1, page 140

> environment creates opportunities for longer term strategies. In the future, these could include consideration of longer term instruments or tools, such as fixed price purchases or investment in natural gas reserves. Not only do these provide long term cost certainty and help provide stability in rates, but they also ensure security of supply for customers.

86.1 Please explain how investment in natural gas reserves would provide price protection to customers relative to declining costs of alternative energy sources.

Response:

As discussed in the response to BCUC IR 1.60.1, a discussion on the potential benefits of investment in natural gas reserves will be included in the FEU's Price Risk Management Review Report expected to be filed with the Commission in mid-2014.

86.2 Please provide an approximate timeframe in which FEU would consider investment in natural gas reserves.

Response:

Please refer to the response to CEC 1.86.1.

86.3 What changes would be necessary, if any, to the utility and regulatory model if FEU were to invest in natural gas reserves. Please explain.

Response:

Please refer to the response to CEC 1.86.1.

87. Reference: FEU Exhibit B-1, page 153

> **Energy Efficiency Technologies**
>
> The impact of introducing and implementing programs that shift the market adoption of energy efficient technology has been addressed in the Companies' CPR and subsequent long term EEC planning analysis presented in Section 4.2. Figure 4.3 shows the results of that analysis by scenario. Although the FEU have not identified the extent of market transformation that will occur for each measure or technology, the analysis results do represent an estimate of the amount of energy efficiency that can be achieved by the Companies over the planning horizon.

87.1 Please explain why FEU did not address the issue of technology improvements occurring outside EEC planning.

Response:

The FEU have addressed technology advancements outside of EEC planning. The quoted excerpt is taken from Section 8.2 of the 2014 LTRP which provides a summary description of how the FEU have addressed the issue of Market Transformation within the plan—both within and outside of EEC planning. Other areas in which the FEU explored the extent of market transformation enabled by technology improvements are in NGT, renewable thermal energy, industrial demand and technologies that improve the efficiency of natural gas use.

By incorporating a range of examples of technology improvements that could either reduce or increase the demand for natural gas, the FEU have assessed the impact of different assumptions on market transformation in the 2014 LTRP.

Attachment 10.6

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 52.1

NRCan Market size (2010)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Heavy Duty Trucks	52.1	53.1	54.2	55.3	56.4	57.5	58.7	59.8	61.0	62.3	63.5	64.8	66.1	67.4	68.7	70.1	71.5	73.0	74.4	75.9	77.4	79.0	80.5	82.2
Medium Trucks	24.4	24.9	25.4	25.9	26.4	26.9	27.5	28.0	28.6	29.2	29.7	30.3	30.9	31.6	32.2	32.8	33.5	34.2	34.8	35.5	36.3	37.0	37.7	38.5
Urban Transit	4.3	4.4	4.5	4.6	4.7	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.5	5.6	5.7	5.8	5.9	6.0	6.1	6.3	6.4	6.5	6.6	6.8
School Buses	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5
Marine	48.8	49.8	50.8	51.8	52.8	53.9	55.0	56.1	57.2	58.3	59.5	60.7	61.9	63.1	64.4	65.7	67.0	68.3	69.7	71.1	72.5	74.0	75.4	77.0
Freight Rail	6.3	6.4	6.6	6.7	6.8	7.0	7.1	7.2	7.4	7.5	7.7	7.8	8.0	8.1	8.3	8.5	8.6	8.8	9.0	9.2	9.4	9.5	9.7	9.9
Total PJ	**137.5**	**140.3**	**143.1**	**145.9**	**148.8**	**151.8**	**154.8**	**157.9**	**161.1**	**164.3**	**167.6**	**171.0**	**174.4**	**177.9**	**181.4**	**185.1**	**188.8**	**192.5**	**196.4**	**200.3**	**204.3**	**208.4**	**212.6**	**216.8**
Annual Growth Rate		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Attachment 55.2

NRCan Market size (2010)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Heavy Duty Trucks	52.1	53.1	54.2	55.3	56.4	57.5	58.7	59.8	61.0	62.3	63.5	64.8	66.1	67.4	68.7	70.1	71.5	73.0	74.4	75.9	77.4	79.0	80.5	82.2
Medium Trucks	24.4	24.9	25.4	25.9	26.4	26.9	27.5	28.0	28.6	29.2	29.7	30.3	30.9	31.6	32.2	32.8	33.5	34.2	34.8	35.5	36.3	37.0	37.7	38.5
Urban Transit	4.3	4.4	4.5	4.6	4.7	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.5	5.6	5.7	5.8	5.9	6.0	6.1	6.3	6.4	6.5	6.6	6.8
School Buses	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5
Marine	48.8	49.8	50.8	51.8	52.8	53.9	55.0	56.1	57.2	58.3	59.5	60.7	61.9	63.1	64.4	65.7	67.0	68.3	69.7	71.1	72.5	74.0	75.4	77.0
Freight Rail	6.3	6.4	6.6	6.7	6.8	7.0	7.1	7.2	7.4	7.5	7.7	7.8	8.0	8.1	8.3	8.5	8.6	8.8	9.0	9.2	9.4	9.5	9.7	9.9
Total PJ	**137.5**	**140.3**	**143.1**	**145.9**	**148.8**	**151.8**	**154.8**	**157.9**	**161.1**	**164.3**	**167.6**	**171.0**	**174.4**	**177.9**	**181.4**	**185.1**	**188.8**	**192.5**	**196.4**	**200.3**	**204.3**	**208.4**	**212.6**	**216.8**
Annual Growth Rate		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
NGT Reference Case Load (PJ)		0.19	0.25	0.42	0.51	1.11	1.68	2.17	2.57	3.04	3.60	4.27	5.05	5.99	7.09	8.40	9.95	11.78	13.95	16.53	19.57	23.18	27.46	32.52
NGT Reference Case Market Capture		**0.14%**	**0.17%**	**0.29%**	**0.34%**	**0.73%**	**1.08%**	**1.37%**	**1.59%**	**1.85%**	**2.15%**	**2.50%**	**2.90%**	**3.37%**	**3.91%**	**4.54%**	**5.27%**	**6.12%**	**7.10%**	**8.25%**	**9.58%**	**11.12%**	**12.92%**	**15.00%**