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June 19, 2014

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Utilities[1] (FEU)

2014 Long Term Resource Plan (the Application)

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

On March 25, 2014, the FEU filed the Application as referenced above. In accordance with Commission Order G-56-14 setting out the Regulatory Timetable for the review of the Application, the FEU respectfully submit the attached response to BCUC 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 (e-mail only): Registered Parties

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

1.0 Reference: RESOURCE PLAN OVERVIEW

***Utilities Commission Act* (UCA), S. 44.1; Resource Planning (RP) Guidelines, pp. 1–2;**

BCUC 2013 Generic Cost of Capital, Exhibit B1-9-6, p. 46

Resource Plan Information

Section 44.1(2) of the UCA states "… a public utility must file with the commission … a long-term resource plan including all of the following: … (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;" (UCA, Section 44.1(2)).

The British Columbia Utilities Commission (BCUC, Commission) RP Guidelines state on pp. 1–2:

> "The Commission requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional and alternative supply sources (including 'BC Clean Electricity' as referred to in the Energy Plan), and those which focus on conservation of energy and Demand Side Management ("DSM"). Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run. … a resource planning process that assesses multiple objectives and the tradeoffs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service." [Emphasis Added]

In Exhibit B1-9-6 of the BCUC 2013 Generic Cost of Capital proceeding, FortisBC Energy Utilities (FEU) submitted in Appendix H, page 46: "…as opposed to [FortisBC Energy Inc.] FEI's core business of space and water heating."

1.1 Please provide a list of all FEU's products and services.

Response:

The FEU's products and services continually evolve to meet customers demand but in general, these products and services help customers make use of natural gas in an efficient, reliable and safe manner. Variations on the use of natural gas can be considered products or services. The FEU's products and services currently include (but are not limited to) the following:

- Natural gas delivery and sale including:
    - Construction services – installation or removal of gas service lines, installation and service removal).

- Customer education and safety awareness via website, bill inserts, marketing and media presence.
- Natural Gas for Transportation incentives.
- Residential high carbon fuel switching incentives.
- Energy Efficiency & Conservation programs.
- Renewable Natural Gas (RNG) offering.
- Emergency Line service.

- Services Include:
  - Home Energy Calculator.
  - Find A Contractor Program.
  - Call Before You Dig/BC OneCall.

1.2 In identifying 'the demand for a utility's product' for the purpose of preparing a Resource Plan, please identify which products/services FEU has included in the load forecast, and which it has not, and provide an explanation as to why.

Response:

The FEU have included information in the load forecast from the following products and services listed in response to BCUC IR 1.1.1: Natural gas delivery service, construction services, Energy Efficiency and Conservation Programs, Natural Gas for Transportation incentives and Residential High Carbon Fuel Switching incentives. From these products and services, the FEU use expected energy demand and energy demand savings, customer additions and expected load growth to inform the load forecast.

The Home Energy Calculator, Find A Contractor Program, Equal Payment Plan for home service, Call Before You Dig/BC OneCall, Emergency Line and customer education and safety awareness services are not products or services that directly impact customer load and are therefore not included in the load forecast. RNG is an important service offering that provides customers with a renewable gas alternative while maintaining load on the system, though it does not directly impact the FEU's overall load forecast.

1.3 Please identify and describe all resources (supply and demand side) available to FEU to meet British Columbia (BC) domestic demand for FEU's core business of space and water heating.

Response:

The FEU disagree with the general characterization of the FEU's core business as limited to space and water heating. The quotation referenced above from Exhibit B1-9-6 of the BCUC 2013 Generic Cost of Capital proceeding refers to the B.C. Government's focus on a "green economy" and the opportunity for job growth. In this context, the FEU intended to emphasize that the major applications for natural gas in the "green economy" would be for LNG in transport and export applications, rather than for space and water heating, which are currently the FEU's largest end-uses in both the residential and commercial sectors (please refer to Figures 3-10 and 3-11 in Section 3 of the 2014 LTRP).

The FEU's core business is to provide utility energy services, of which delivering energy for space and water heating is one. Those supply and demand side resources available to the FEU to meet our customers' needs for energy, and that are typically covered by integrated resource planning, generally include:

- On-system pipelines, compressors, storage facilities and other infrastructure needed to manage the delivery of natural gas.
- Natural gas purchases – the FEU can purchase natural gas through short and longer term gas supply portfolio management.
- Contracting for pipeline and storage resources external to the FEU for the purpose of managing natural gas supply and delivery.
- Natural gas reserves - the FEU is also exploring the potential for investing in natural gas reserves.
- Assisting customers to reduce natural gas demand – the FEU can educate customers on how to reduce natural gas demand and offer incentives to purchase more efficient natural gas space and water heating appliances (referred to as Energy Efficiency and Conservation activities).
- Other demand side activities such as load building and other load shaping activities.

1.4 Is a key purpose of a Resource Plan to "[assess] multiple objectives and the tradeoffs between alternative resource portfolios?" If not, please explain why not.

Response:

Generally speaking, yes, a key purpose of a utility resource plan is often to assess multiple objectives and the tradeoffs between alternative resource portfolios.

However, this aspect of a resource plan differs depending upon the nature of the utility. Key in this differentiation is how supply side resources are developed or acquired. A vertically integrated utility, such as many electrical utilities, must either acquire power and capacity from the market or produce their own power and capacity. In this regard, a resource plan examines the alternative resource portfolios to determine what might be the best mix of these resources. In other words, the resource plan reviews and assesses the trade-offs between various generation and electrical purchase options.

However, for a gas utility that does not own its own gas reserves and files for approval of its Annual Contracting Plan (in other words, acquires supply side resources from the market) and whose bill is disaggregated showing supply side resources (gas supply) costs separately, the purpose of the Resource Plan is not to assess resource portfolios. Rather, its purpose is primarily to assess energy delivery infrastructure requirements needed to deliver gas to end use customers on the natural gas utility system. To this extent, the Resource Plan examines forecasted load, the potential for demand side resources and the resulting options for adding additional pipe, storage and compression.

In summary, since there are no generation resources to include in alternative portfolios and since there are no alternative portfolios of energy efficiency measures that will have substantially different impacts on supply capacity resources, creating alternative portfolios and conducting portfolio analysis typical of vertically-integrated electric utilities does not make sense for the FEU.

1.5 Please describe what effect there would be, if any, on future FEU applications (over the next four years) if the Commission (i) accepts FEU's 2014 Long Term Resource Plan (LTRP) (Application), (ii) does not accept FEU's LRTP or (iii) partially accepts FEU's LTRP (for example, accepted FEU 2014 LTRP Chapters 3, 5 and 6 only).

Response:

The submission of the LTRP is a requirement of the *Utilities Commission Act* (the Act). The Act does not treat the LTRP, strictly speaking, as an "application"; rather, it is something that the

utility must "file with the commission", and the plan is either accepted or rejected. No specific approvals are being sought with this LTRP. The FEU seek to have the plan accepted pursuant to section 44.1(6)(a).

The 2014 LTRP is intended to meet the requirements under the Act and broadly to outline the planned resources for a 20 year period. The Commission should accept the LTRP because it has met all of the requirements of the Act (see Table 1-2 of the LTRP, Exhibit B-1, for information on each Act 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.

The LTRP, once accepted, is something that the Commission is required to consider in subsequent applications under sections 44.2, 46 and 71 of the Act. However, it is unclear to the FEU what the question is attempting to ascertain. If the LTRP were not accepted, this could be for any number of reasons and involve any number of scenarios in terms of what would happen subsequent to the plan not being accepted. As such, the FEU could only speculate on the impacts of the scenarios raised in the question above. With that caveat, the FEU believe there would be little to no impact on future applications if the Commission accepts this submission. If the Commission does not accept or only partially accepts the FEU's 2014 LTRP, the FEU believe that information and statements of planned extensions contained in the 2014 LTRP could still be used to provide context for future CPCN applications as acceptance is not a condition required to use such information. In addition, the 2010 LTRP (accepted on February 1, 2011) and the Companies' Five-Year Capital Plans could be relied upon, if necessary, for submitting any future applications. Any future applications would contain information updates necessary for the Commission to make an informed decision at that time.

2.0 Reference: RESOURCE PLAN OVERVIEW

Exhibit B-1, Application, Executive Summary, p. ES-7;

NW Natural 2013 IRP[1], pp. 4.1, 1.10; BC Hydro 2013 IRP[2], p. 3–13;

SEE Action Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency 2011[3], pp. 6–7

Benchmarking

FEU states in the Application: "The LTRP's EEC analysis assumes that current funding levels of approximately $35 million annually … continue over the planning horizon" (Exhibit B-1, p. ES-7).

NW Natural's 2013 Integrated Resource Plan (IRP) states:

> "NW Natural worked with the Energy Trust of Oregon (Energy Trust) to forecast the 20-year demand-side management (DSM) potential … A 'high' DSM sensitivity case was run using targeted levels from the 2011 Modified IRP in order to determine the impact of the lower cost-effective potential identified in this IRP" (pp. 4.1, 1.10).

BC Hydro, in their 2013 Integrated Resource Plan (p. 3-13), considered three DSM funding options.

A SEE Action (State and Local Energy Efficiency Action Network, facilitated by the US Department of Energy and the US Environmental Protection Agency) 2011 report titled 'Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures' states: "… the best IRPs create levelized cost curves for demand side resources that are comparable to the levelized cost curves for supply side resources … the best IRPs are developed after considering a range of possible future [environmental] regulations" (pp. 6–7).

2.1 Does FEU consider that the development of a levelized cost curve for demand side resources represents 'best practice' in the development of Resource Plans? If no, please explain why not.

Response:

The FEU agree that the development of levelized cost curves for demand side resources, as described in the 2011 SEEA report, may be appropriate for the development of some resource

[1] https://www.nwnatural.com/uploadedFiles/NWN_2013_IRP_3-27-13.pdf
[2] http://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html
[3] http://www1.eere.energy.gov/seeaction/pdfs/ratepayer_efficiency_irpportfoliomanagement.pdf

plans, and may even be considered a "best practice" under certain circumstances. For example, this may be an appropriate approach for a vertically integrated electric utility resource plan.

That said, the FEU do not believe that this is the appropriate approach for their resource plan. The FEU are not vertically integrated utilities that have a range of energy generation portfolios against which to compare demand side resources. Please also refer to the response to BCUC IR 1.1.4.

This is a fundamentally different situation than a vertically integrated electric utility such as BC Hydro. In the case of BC Hydro, the resource plan is truly integrated and must compare the costs of meeting demand with supply and demand-side resources as the rate-payer must cover the costs of building new supply sources. Investment in demand side resources can therefore reduce utility costs and customer rates if the demand side resources have lower levelized costs than building or acquiring new supply resources.

The planning process is inherently different for a non-vertically integrated utility. For the FEU, demand and supply side resources are not directly comparable as they are for an integrated electric utility. Levelized costs of natural gas DSM/EEC can be used as a planning tool for the natural gas utility. For example, when forecasting demand, assuming the customer will invest in the least-cost alternative, levelized costs can be used to estimate the conservation potential if all (or some) least-cost DSM/EEC measures were adopted. This conservation potential can then be used as an input in resource planning. In the 2014 LTRP, the FEU determined the uptake of economically efficient DSM/EEC measures while adhering to the Act and the BC Demand-side Measures Regulation in order to determine the impact of different DSM/EEC scenarios on future demand.

It should be noted that the BCUC resource planning guidelines do not distinguish between utilities that provide generation, transmission or distribution services; therefore, some items (such as portfolio analysis) apply more readily to vertically integrated electric utilities. Therefore, the BCUC reviews resource plans in context of the unique circumstances of the utility in question. (Please also refer to the response to BCUC IR 1.1.4).

2.2 In the development of levelized cost curve for demand side resources, would there be any significant difference in the ability to undertake this analysis between an electric utility such as BC Hydro and a gas utility such as FEU? If yes, please explain why.

Response:

Please refer to the response to BCUC IR 1.2.1.

The FEU believe that there would be no difference in the *ability* to undertake the analysis, but, being a non-vertically integrated utility, the approach is not appropriate to the FEU for the purposes of resource planning.

2.3 To what extent does FEU consider that a review of alternative portfolios with different levels of Energy, Efficiency and Conservation (EEC) investment is a useful way for stakeholders to be able to provide informed input on the trade-offs (such as bills/reliability/emissions) that may be required in selecting a preferred option? Please explain.

Response:

As stated in section 4.2 of the 2014 LTRP, the FEU have included alternative EEC portfolios in its 2014 LTRP. However, rather than being based on a top down examination of different funding levels as was analyzed in the 2010 LTRP, those alternative portfolios were based on all cost effective measures (as determined in the most recent CPR) that would be available to the FEU under the different future scenarios in which the demand for natural gas was examined.

The FEU examined the impact of different funding levels in the 2010 LTRP and have extensively reviewed appropriate funding levels through a series of EEC funding requests and regulatory proceedings. The Commission and Interveners were all involved in the discussions that led the Commission to approve the 2013 level of EEC funding. The 2014 to 2018 EEC Plan was also reviewed with the EEC Advisory Group who stated agreement that no major course corrections in the Plan were needed.

The analysis in the 2014 LTRP involves applying the CPR methodology to find all cost effective measures under different future scenarios, taking into consideration the requirements of the BC Demand-side Regulation. Based on the FEU's experience in delivering EEC programs through the ramp up period since 2009, EEC activity based on funding in the range of $35 million represents what the FEU believes the market can reasonably uptake. Cost effectiveness tests and market research together with stakeholder engagement are used to identify appropriate levels of incentives for driving EEC participation.

Furthermore, the FEU plan to undertake a new CPR during the recently applied for PBR period of 2014-2018. That CPR will examine any new technologies and trends that have come to market since the last CPR was done, and will consider the level of market transformation that has occurred as a result of EEC programs to date. As a result, updated economic and achievable energy savings levels will be identified. This new level of savings potential will be incorporated into future LTRPs and future EEC funding applications, making further analysis of

1 additional EEC scenarios with varying levels of funding at this time of little additional value to
2 customers and stakeholders.
3

3.0 Reference: RESOURCE PLAN OVERVIEW

Terasen Utilities (TGI) 2010 Long Term Resource Plan (2010 LTRP), Exhibit B-1, p. E-9; Decision accompanying Commission Order G-14-11, pp. 23–24

2010 LTRP

TGI's 2010 LTRP states: "The Terasen Utilities examined both energy saving and GHG emission reductions for different potential EEC funding scenarios, ranging from current approved funding only, to an ongoing increase in funding set at 5% of gross annual revenues (~$80 million annually) for the next 10 years" (TGI 2010 LTRP, Exhibit B-1, p. E-9).

The Commission states in the February 1, 2011 decision of the TGI 2010 LTRP (G-14-11):

> "…the 2010 LTRP, while accepted, is viewed as being just adequate. It falls short of our expectations that resource plans should provide a comprehensive 20 year view of a utilities trajectory and provide a strong support for programs and initiatives which will be filed with the Commission" (p. 23).

> "…the Commission Panel directs future LTRPs to include the following: … Greater coordination between EEC planning and the development of future resource plans. This will allow for a more detailed presentation of future EEC programs over a longer timer period with expected impacts to be included as part of the LTRP process. Development of a limited number of scenarios detailing the impacts of varying degrees of EEC Planning measures on the demand forecast an GHG emission reductions" (p. 24).

3.1 Please explain why FEU has not included alternative EEC portfolio options in the 2014 LTRP (or identified where options have been considered), given that options were included in the 2010 LTRP and the Commission directed, in Order G-14-11, greater coordination between EEC planning and the development of future resource plans.

Response:

The FEU has included alternative EEC portfolios in its 2014 LTRP. However, rather than being based different funding levels as was analyzed in the 2010 LTRP, those alternative portfolios were based on all cost effective measures (as determined using the most recent CPR) that would be available to FortisBC under the different future scenarios in which the demand for natural gas was examined. Since all cost effective measures were included, there were no additional measures that could be used in the creation of further additional portfolios and therefore no reason to compare one portfolio to another for the purpose of selecting a preferred

portfolio. Please refer to the responses to BCUC IRs 1.2.1 and 1.2.3 for a discussion of the appropriateness of using portfolios to compare demand-side and supply-side resources and for further analysis of varying levels of funding.

4.0 Reference: RESOURCE PLAN OVERVIEW

2012–2013 FortisBC Energy Utilities Revenue Requirements and Rates Proceeding, Decision accompanying Commission Order G-44-12, pp. 56–59

Staff Resources to Improve the Long Term Resource Planning Process

In the 2012–2013 FortisBC Energy Utilities Revenue Requirements and Rates proceeding FEU took the position that in order for them to comply with directives from the 2010 LTRP Decision and implement additional initiatives to improve the resource planning process, they would need an additional seven employees with a total corresponding cost of $2.7 million over 2012 and 2013. FEU stated on page 67 of the FEU Final Submission: "the additional staffing will be used to develop new end-use forecasting methods, prepare and report on new forecasts and compare new and existing forecast methodologies."

The Commission Panel approved additional funding totaling $1 million over 2012 and 2013. On page 59 of the Decision accompanying Commission Order G-44-12 the Commission Panel stated:

> "While the Panel accepts that there is substantial work to be completed, the lack of detail with respect to a work plan fails to persuade us that seven people will take two years to explore options and develop a plan detailing FEU's future resource needs. … While significantly reducing the FEU's proposal to fund the resource planning process, the Commission Panel notes that it has left $1 million dollars to support this process. This is a substantial amount and, if used appropriately and in an integrated fashion with the strategic planning process, can serve both processes concurrently and produce a sufficiently robust LTRP. We leave it to the FEU senior management to determine how these funds may be best used to achieve this end."

4.1 Please outline how this approved additional funding totaling $1 million was spent in each of 2012 and 2013 on the resource planning process and how, if at all, this process was integrated with the strategic planning process.

Response:

The FEU note that the Commission did not approve additional funding of $1.0 million annually for the LTRP. If read in context, the actual additional amount approved by the Commission is stated in the following excerpt from page 59 of the Commission's decision on the 2012-2013 RRA:

"…the Commission Panel will only approve additional funding in the amount of $400 thousand in 2012 and $600 thousand in 2013 for resource planning of the $1.2 million requested in 2012 and $1.5 million in 2013."

The FEU further note that if read in context, this additional funding is not solely for the preparation of the LTRP, but is also to aid in the integration of resource planning activities with the Companies' strategic planning activities. Additionally, while the Commission approved funding for a revenue requirement, under the UCA, it is then up to the utility to determine how to use its total revenue requirement. In other words, once part of the revenue requirement the utility uses its funding as it sees fit for whatever purpose it deems appropriate.

That stated, the FEU have utilized the approved additional funding to advance a number of improvements to the LTRP in the areas of stakeholder engagement, analyzing the planning environment, future scenario development, long term annual demand forecasting, long term EEC analysis and alternative forecast impact analysis.

The output of the LTRP planning activities (including those incremental activities listed below) informs the Utilities' strategic planning process. Further strategic business analyses are conducted based on this work which may ultimately feed back into the LTRP in the form of utility objectives, initiatives and resource options.

Significant incremental work performed in 2012 and 2013 on the LTRP includes the following:

- Improved future scenario development and an end use annual demand forecasting methodology that examines potential future changes in the planning environment rather than utilizing historic trends to predict a future range of demand potential.
- Inclusion of a total long-term thermal end-use demand forecast for FEU's customer base.
- Improved stakeholder, First Nations and community engagement throughout the Resource Planning process, including extensive input into the future scenarios and new long-term annual demand forecasting methodology.
    - The creation of an external Resource Planning Advisory Group that included participation from the Commission; and
    - Community consultation activities throughout BC.
- Additional examination of the energy planning environment in BC including assessing the potential impacts of emerging renewable thermal energy solutions on the demand for natural gas.
- Adaptation of the long term, end use, annual demand forecasting model to analyze the long term outlook for demand reductions from EEC activities based on all cost effective efficiency measures identified in the most recent CPR and the BC Demand-side Measures Regulation.

- Development of alternative, long term demand scenarios for natural gas used as a transportation fuel.
- Inclusion of the impact of potential addition of new large industrial customers on natural gas demand and FEU's infrastructure.
- Assessment of greenhouse gas (GHG) emissions from natural gas commodity sales and GHG reductions from FEU initiatives including EEC and NGT.
- Incorporation of system sustainment planning work into the LTRP.
- An assessment of the directional rate impacts of different future demand scenarios as well as the directional impact of EEC activities and NGT initiatives on rates.
- Inclusion to the extent possible of a long term vision for the FEU and an examination of the extent to which certain markets, such as the natural gas for transportation market, may be transformed and the impact such transformation could have on demand and the FEU's infrastructure.

The resource planning process is an ongoing process to which improvements are made with each iteration of the LTRP. The additional funding has been important for making additional improvements to the LTRP, but was not sufficient for the FEU to make improvements throughout the entire resource planning process within a single iteration.

5.0 Reference: PUBLIC INTEREST OBJECTIVES

Exhibit B-1, Application, Section 2, p. 12; TGI 2010 LTRP, Exhibit B-1, pp. E-2–E-3; BCUC 2013 Generic Cost of Capital, Exhibit B1-9-6, pp. 45, 46; NW Natural 2013 IRP, p. 4.17

Planning Environment

FEU states on page 12 of the Application: "While governments across North America were keen to introduce climate and green energy policies a number of years ago, today's setting is more tempered … B.C.'s Natural Gas and [liquefied natural gas (LNG)] Strategies suggest that natural gas will continue to play an important role in B.C.'s energy mix far into the Province's future" (Exhibit B-1).

The TGI 2010 LTRP Application states on page E-2 and E-3: "However, B.C.'s electricity grid cannot physically or economically meet all of these requirements. … In B.C. and the PNW [Pacific Northwest], as we progress towards a low carbon economy, natural gas is expected to act as the transition fuel for both electricity generation and direct use applications" (Exhibit B-1).

In Exhibit B1-9-6 of the BCUC 2013 Generic Cost of Capital proceeding, FEU submitted in Appendix H, pages 45 and 46:

> "On February 3, 2012, the BC Government released "British Columbia's Natural Gas Strategy … The Strategy does not, however, advocate a role for natural gas for space and water heating, which is the most significant source of throughput and margin on FEI's system. … The BC Government's focus on "green economy" is exemplified in its "BC Green Economy: Growing Green Jobs" document … The role of natural gas in this "green economy" is focused on LNG for transport and export, as opposed to FEI's core business of space and water heating."

NW Natural states on page 4.17 of its 2013 Integrated Resource Plan:

> "Although the details that will affect the natural gas utility business are not clearly established, a carbon constrained future is inevitable. In preparation for those regulations, the Company continues to strategize for the future. Examples of the Company's forward-thinking include its continued commitment to energy efficiency, its research into developing technologies including CHP and compressed natural gas vehicles, and its development of both the Smart Energy™ carbon offset program. NW Natural recognizes that the future of the fossil fuel industry is changing and the Company plans to change accordingly so that its customers will continue to have their water and space heating needs met in the best possible way." [Emphasis Added]

5.1 Does FEU concur with NW Natural's view of a carbon constrained future? Please explain.

Response:

The FEU agree that government policy further constraining the emissions of carbon during the planning horizon is a realistic possibility and have included consideration of the impact of such policy in their future scenarios and range of annual demand forecasts in Sections 3.3.4 and 3.3.5 of Exhibit B-1. The FEU's view is that it already operates in a carbon-constrained environment since B.C. currently has carbon tax of $30 per tonne on fossil fuel consumption that is intended to alter consumer behavior. The Companies do not expect the tax to be repealed in the near future as indicated in the B.C. government's June 26, 2013 Speech from the Throne. The degree to which carbon constraints will or will not be increased over the next 20 years is a matter of speculation and has been addressed by including varying levels of carbon costs in the scenarios developed and used in the 2014 LTRP. Please refer to the response to BCUC IR 1.5.3 for additional detail regarding carbon pricing assumptions in the various LTRP scenarios.

5.2 Does FEU consider that gas can be a transition fuel in BC in the move to a carbon constrained future? If yes, please describe (i) the type of applications it can be used for and (ii) when the transition period would be expected to end.

Response:

As stated in the response to BCUC IR 1.5.1, B.C. is already in a carbon-constrained environment. Natural gas can play a role in B.C.'s carbon-constrained environment by shifting users of higher carbon fuels to natural gas such as where diesel, marine bunker, heating oil and propane fuels are used. These opportunities are in return-to-base fleet vehicles, marine vessels and locomotives. Also, the use of natural gas as a fuel for electricity generation where appropriate, such as for use by LNG export facilities in the north, can preserve BC's cost-effective clean electricity resources for similar (such as LNG export facilities on the south coast) or higher and better uses elsewhere in the province.

Further, as also stated in the response to BCSEA IR 1.11.1, electricity is a commodity that B.C. trades regionally with other neighbouring jurisdictions including Alberta and U.S. PNW states where coal and natural gas play a prominent role in electricity generation. As such, avoiding electric load in B.C. by efficiently using natural gas in heating applications could offer an opportunity to reduce GHG emissions in other jurisdictions when B.C.'s clean electricity is made available for export. Climate change and reducing GHG emissions are global issues; the

physical location of where higher- to lower-carbon fuel switching activity takes place is irrelevant since GHG emissions transcend political and geographical boundaries. As a result, natural gas could also be used as a fuel in B.C. in the move to a carbon constrained future throughout the PNW region. The FEU will continue to explore opportunities to use natural gas to reduce GHG emissions while providing secure, reliable and cost-effective energy supply.

The FEU do not have a prediction about when the end of such a transition might occur, however, the degree to which natural gas demand may increase or decrease through the planning period has been considered in the range of future scenarios and annual demand forecasts examined in section 3.3.4 and 3.3.5 of Exhibit B-1.

5.3 Please provide a high-level overview of the steps, if any, FEU plans to take over the next 20 years to address the risk of a carbon constrained future.

Response:

To address the risk of a carbon constrained future, the FEU plan to continue:

- monitoring the energy planning environment for real and potential changes for either increasing or decreasing carbon constraints in the Companies' long term planning activities;
- offering innovative EEC programs as described in Section 4.2 of Exhibit B-1 that help customers reduce energy use and GHG emissions while supporting continued use of the natural gas delivery system;
- exploring and offering innovative service offerings that can help reduce GHG emissions such as those described in Section 4.3 of Exhibit B-1;
- examining system requirements as described in Section 5.1.2 of Exhibit B-1 for opportunities to serve new customers including large industrial customers who may be seeking natural gas supplies for uses that offset higher carbon uses in other jurisdictions; and
- advocating for the implementation of electric load avoidance where natural gas can be used for heating applications instead of electricity wherever it makes sense and the resulting conserved clean electricity can be moved to neighbouring jurisdictions for use in offsetting generation that relies on fossil fuels as discussed on page 26 of Section 2.2.3 of Exhibit B-1.

5.4 Does FEU still consider that the BC electricity grid cannot physically or economically manage a transition from natural gas to electricity for BC space and water heating? Please explain why or why not.

Response:

Yes, the FEU still consider that B.C.'s electricity grid cannot physically or economically manage a transition from natural gas to electricity for B.C.'s space and water heating. BC Hydro states on page 4 of its 2013 Integrated Resource Plan (IRP), "British Columbia's hydroelectric system is vast and reliable, but it will not be enough to meet the electricity needs of future generations." This statement is based on planning environment analyses conducted for the 2013 IRP which show that B.C.'s electricity system requires new investment; this capital spending will put upward pressure on electricity rates. Analyses in BC Hydro's 2013 IRP do not include a scenario of transitioning from natural gas use to electricity in B.C. In B.C., since approximately as much natural gas is currently used as electricity, the majority of which is for space and water heating, the FEU do not believe that B.C.'s electricity grid will ever be able to economically manage a complete transition from natural gas to electricity for space and water heating.

Transitioning from natural gas to electricity for space and water heating in B.C. is an impractical scenario since such a move would place extremely heavy demand on B.C.'s electricity infrastructure and would increase customer's energy costs substantially. At the same time the direct use of natural gas "delivers the most useful primary energy to the customer with the fewest system losses relative to other systems of energy delivery" ("Squeezing Every BTU", 2014 LTRP, Appendix A4, pg. 8). The report, attached in Appendix A4 of the LTRP reinforces this concept on page 8, "fuelling more homes and business directly with natural gas can help reduce new electric power requirements by easing demand on the electric power grid while reducing the need to construct expensive new electricity generating plants . . . Policymakers and regulators should establish energy policies that acknowledge that the direct use of natural gas provides a key option to help realize cost-effective efficiency and emissions goals."

5.4.1 If yes, by what date would this be expected to no longer be a constraint?

Response:

Please refer to the response to BCUC IR 1.5.4.

6.0 Reference: PUBLIC INTEREST OBJECTIVES

Exhibit B-1, Application, Section 1, pp. 8–9; TGI 2010 LTRP, Exhibit B-1, p. 6;

Primer on Gas Integrated Resource Planning, University of California[4], p. 37

Utility vs. Public Interest Objectives

FEU describes its resource planning objectives on page 8 and 9 of the Application. Page 6 of the TGI 2010 LTRP sets out the following objective: "Acting on Social and Environmental Priorities: It is important to incorporate environmental and socio-economic consideration into the selection process for demand and supply resources by examining the impact of resource selection alternatives on land-use, air emissions, the local economy, and First Nations and BC communities served" (Exhibit B-1).

A 1993 report prepared by the University of California for the National Association of Regulatory Utility Commissioners (NARUC) titled 'Primer on Gas Integrated Resource Planning' includes Table 3-1 on page 37 which illustrates how a utility and a public utility commission (PUC) can give different weightings to resource planning objectives.

6.1 It appears that the objective "acting on social and environmental priorities" is no longer in the 2014 LTRP. Please explain if FEU's position regarding this objective has changed in the 2014 LTRP compared to the 2010 LTRP. If so, please explain why.

Response:

The FEU's position to act on social and environmental priorities has not fundamentally changed. The FEU consider the objective of "Acting on Social and Environmental Priorities" to be inherent in all of the Companies' planning activities and therefore redundant as an explicit resource planning objective.

The Resource Planning Objectives in the 2014 LTRP were restated to reflect the current political, economic and regulatory environment. The 2014 LTRP contains the objectives to "Provide Cost-Effective Energy Efficiency and Conservation Initiatives," and "Contribute to Provincial Energy Objectives and Emission Targets," which include examining the impact of resource planning on GHG emissions. Furthermore, while not explicitly stated in the 2014 LTRP objectives, the FEU incorporates consideration of land-use, the local economy, First Nations, and local communities in planning decisions at the project level. This is evidenced by extensive First Nations and community consultations, and environmental and socio-economic impact analysis of all major projects.

[4] http://emp.lbl.gov/sites/all/files/REPORT%20LBNL-34144_0.pdf

Since the 2010 LTRP, the FEU have undertaken various Natural Gas for Transportation (NGT) and Renewable Natural Gas (RNG) initiatives, both of which contribute to the Companies' social and environmental priorities. At the same time, the Companies have been directed by the BCUC to conduct their low carbon thermal energy service projects through a separate business entity. The FEU continue to provide programs that target the Companies' social priorities such as the Residential Energy and Efficiency Work (REnEW) program, in which marginalized individuals receive training from the FEU and community partners around B.C. and the Energy Conservation Assistance Program, which provides assistance of various means to low income customers.

6.2 Please describe the steps taken by FEU to ensure that its resource planning objectives are reflective of public interest objectives. Specifically, to what extent was stakeholder input sought on (i) the development of FEU objectives (including 'acting on social and environmental priorities' objective), (ii) the development of portfolio options and (iii) the evaluation of portfolio options against objectives and the trade-offs made?

Response:

The FEU provides the following response.

(i) The FEU's Resource Planning objectives were presented to the external Resource Plan Advisory Group at resource planning workshops on at least two occasions – very early in the planning cycle and again nearing the conclusion of the planning cycle. The FEU considered feedback received from the RPAG, including comments from Commission staff, that resulted in some changes to the objectives on the first occasion. There were no comments raised about the objectives on the second occasion.

(ii) & (iii) Please refer to the response to BCUC IR 1.1.4 and Section 1.2.3, page 7 of Exhibit B-1 regarding the applicability of developing and evaluating alternative resource portfolios to the FEU's resource planning process. Since the 2014 LTRP appropriately did not weigh the trade-offs between alternative demand and supply side portfolios such as would be done by a vertically integrated electric utility evaluating different types of power generation; the weighting of objectives for the FEU was not beneficial to the resource planning process and is an activity better considered at the project planning stage.

Connecting with customers, communities and other stakeholders on long range planning issues is of critical importance to the FEU. The FEU's resource planning objectives for the 2014 LTRP are the product of an evolution through past Long Term Resource Plans, including the

stakeholder consultation processes that took place around those resource plans, and the Commission directives and intervener comments that came out of the review process for those plans. The FEU view resource planning as an ongoing process and use stakeholder input solicited through the FEU's resource planning stakeholder engagement efforts to inform the objectives of future long term resource plans.

The FEU also have a long history of community and stakeholder consultation for project planning. As noted in the response to BCUC IR 1.1.4, developing portfolio options and evaluating portfolio options against objectives and trade-offs does not make sense for gas utilities such as the FEU. Nevertheless, stakeholders are engaged early and throughout the project planning process via various avenues including meetings, focus groups, open houses and newsletters.

7.0 Reference: PUBLIC INTEREST OBJECTIVES

TGI 2010 LTRP, Exhibit B-1, p. 65;

Environment

The TGI 2010 LTRP Application states on page 65: "There are some reports that indicate carbon taxes may need to go up to $300 per tonne in order to have a meaningful impact on consumer behavior and therefore reduce GHG emissions" (Exhibit B-1).

7.1 To what extent does FEU consider that it should be responsible for actively supporting BC emission reduction targets? Please explain.

Response:

The FEU have not been tasked with responsibility for meeting all or any particular level of the BC emission reduction targets. However, the FEU consider that as an energy utility and provider of natural gas, the Companies should take steps to educate customers on the benefits of conserving energy and using natural gas efficiently, and also to provide services such as EEC programs, the NGT initiative, RNG offering and the Switch 'N Shrink program, all of which support the Province in meeting its GHG emission reduction goals by helping customers reduce their emissions.

7.2 Does FEU consider that the utility or the end-use customer (i) is responsible for the emissions generated from using natural gas for space and water heating and (ii) can take credit for the emission reductions generated from using natural gas to displace other fossil fuels?

Response:

Since the FEU do not own or control the appliances that the Utilities' customers use for space and water heating, the FEU consider that the end-use customer is responsible for the emissions generated from using natural gas for space and water heating. This would seem to be the BC Government's position as well, since the carbon tax is charged to the end-use customer.

The FEU support the Province's energy objectives and emission reduction targets by making energy efficiency and conservation programs and higher carbon to lower carbon fuel switching programs available to customers. If customers take steps on their own to reduce emissions, they may take credit for those reductions; however, if the customer takes advantage of FEU

1 incentives or takes action as a result of the Utilities' activities, then the FEU can take credit for
2 those emission reductions.

3

8.0 Reference: PUBLIC INTEREST OBJECTIVES

Exhibit B-1, Application, Section 1, p. 8; RP Guidelines, pp. 1, 3;

Efficiency objective vs. low rates

FEU include as a resource planning objective: "provide innovative and cost-effective energy solutions" (Exhibit B-1, p. 8).

The RP guidelines state: "Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run" (p. 1) and include as resource plan objectives: 'economic efficiency' and 'equal consideration of DSM and supply side resources' (p. 3).

8.1 Please explain how FEU defines 'cost effective' energy solutions — for example, cost effective to the customer, the utility or society?

Response:

The FEU believe that the definition of "cost effective" energy solutions, and evaluating cost effectiveness in general, will vary depending upon the perspective taken. It is the FEU's understanding that the Commission first clarified the distinction between "least cost" and "most cost effective" in its 2003 Decision on the Vancouver Island Generation Project (Order G-55-03, page 77) where it states:

> *"The principal distinction between most cost-effective and least-cost is the scope of considerations that are relevant. In the context of this Decision, most cost-effective includes consideration of project characteristics such as reliability, dispatchability, timing, and location as well as the cost or price, in the case of an EPA. Least-cost is taken to only include cost or price considerations."*

In making use of the term "cost effective" in this Application and others the FEU have been guided by the distinction set out by the Commission in the quote above.

As an energy provider, the FEU are tasked with balancing the multiple perspectives of the utility, customers and society, as guided by policy, regulation, and economic factors. As such, the FEU's LTRP aims to identify the resource options (note that vertically integrated companies will have different portfolio options than a non-integrated gas utility that is only looking as options for pipe, compression and storage. Please also refer to the response to BCUC IR 1.1.4) that will provide service solutions to the utility to meet potential future demand, help to manage rate impacts for customers and maintain public safety. The lowest cost solution to the utility, therefore, is not always the "most cost effective" given the competing perspectives.

There may be conflict between perspectives of what is considered "cost effective." For example, there is a potential conflict in the perceived cost effective level of EEC investment from the perspectives of the customer and society; the customer may see an increase in rates from

increased investment in EEC and society may see a reduction in emissions. In such a case the customer may be a member of society, but they may not hold the same perspective on what is cost-effective. Where such a conflict of perspectives exists, the balance of what is cost-effective would be worked out through the separate processes of setting rates and determining an appropriate level of investment in EEC activities. Negotiating the trade-offs inherent in providing energy services is ultimately a decision for society to contemplate and address through the various processes of policy, regulation, and individual economic and behavioral choices. In conducting long term resource planning and considering which energy solutions to provide, the FEU will continue to consider: policy, regulation, and economic factors; input from stakeholders; and, ultimately, the demands of customers.

8.2 Does FEU consider that a resource planning objective should include promotion of economic efficiency from a BC perspective? Please explain why or why not.

Response:

For the purposes of answering this question, the FEU assume that a "B.C. perspective" refers to a societal perspective. No, the FEU do not believe that 'promotion of economic efficiency from a BC perspective' needs to be an explicit resource planning objective as promotion of economic efficiency from the societal perspective is typically prescribed by government policy, legislation and regulation and is thus already inherent in the resource planning process. For example, the BCUC's Resource Planning Guidelines cite Bonbright, Danielsen and Kamerschen:

> *"Bonbright, Danielsen and Kamerschen, (Principles of Public Utility Rates, 1988, Ch.8, p.165) suggest that the rates set by utility commissions invariably involve some discretionary judgment about the extent to which broader social principles should influence ratemaking. Because of social and environmental impacts, the rates charged by utilities may be allowed to deviate from those that would result from a rate determination based exclusively on financial least cost."* (Footnote 2, pp. 3)

The FEU consider all relevant government policy, legislation and regulation when setting objectives for resource planning. Please refer to the response to BCUC IR 1.10.1 for additional detail as to how the FEU have considered government policy, regulation and the BCUC's Resource Planning Guidelines in developing the 2014 LTRP.

8.2.1 Does FEU consider that the economic efficiency could be defined as: (i) efficient customer investment and consumption decisions, (ii) efficient utility operational and investment decisions and (iii) innovation over the long term? Please elaborate.

Response:

The FEU's interpretation of this question is that it refers to three definitional components of economic efficiency: allocative efficiency, productive efficiency, and dynamic efficiency. The FEU do consider that allocative efficiency, productive efficiency, and dynamic efficiency are all definitional components of economic efficiency.

8.2.2 Does FEU consider that there should be co-ordination between BC Hydro and FEU in the setting of EEC/DSM incentives to ensure incentives do not inadvertently result in sub-optimal outcomes from a BC perspective? Please explain.

Response:

The FEU does consider that there should be coordination between BC Hydro and the FEU in the setting of EEC/DSM incentives to ensure incentives do not inadvertently result in sub-optimal outcomes from a BC perspective. The FEU recognize that collaboration and integration of EEC/DSM programming with BC Hydro, as well as FortisBC Inc. (the electric utility) and with other entities such as governments and industry associations, will maximize program efficiency and effectiveness and provide optimal EEC/DSM solutions to customers.

For example, customers may use many end-use appliances, both electric and natural gas and as a result of a DSM program by one utility, may be pushed into selecting an appliance using a different energy form rather than a more efficient appliance using the same fuel. This may not be the desired outcome from the Province as a whole. Additionally, customers may be making energy efficient investment decisions, such as building envelope retrofits, that will impact both gas and electricity demand. For these customers, it makes sense for the utilities to collaborate to offer an integrated program to the customer to meet their energy needs, avoid customer confusion over EEC/DSM offerings, and avoid duplication of administration and marketing expenses. For these reasons, since 2009 the FEU and BC Hydro have had in place a memorandum of understanding to work together on energy efficiency and conservation programs, have numerous joint programs in market, and continue to build on what is one of the most comprehensive voluntary joint utility energy efficiency and conservation initiatives in North America. Further, the three utility companies are in the planning stages of conducting a

combined electricity and natural gas Conservation Potential Review as explained on page 93 of the LTRP. Please also refer to the response to BCUC IR 1.8.2.2.1.

8.2.2.1 If yes, how does FEU ensure this occurs?

Response:

The setting of EEC incentives as described in response to BCUC IR 1.8.2.2 occurs at the program planning and design stage and is not part of the LTRP. However, the knowledge that is gained by the FEU through the cooperative efforts between BC Hydro and the FEU at that stage, for example around customer uptake and market barriers, help to inform the assumptions that are used in the long range EEC analysis conducted for the LTRP. The long range EEC analysis thereby inherently captures the consideration of optimal incentive levels to the extent possible. The inclusion of all cost effective demand side measures as identified by the most recent CPR ensures that economic efficiency and equal consideration for demand side resources are also addressed in the LTRP.

8.2.3 Does FEU consider that its rate structures promote efficient investment and consumption decisions by customers? Please explain why or why not, and any changes that are under consideration to address deficiencies.

Response:

The FEU consider that the current FEI rate structures promote efficient investment decisions by consumers. The commodity, midstream and delivery charges send easy to understand pricing signals to consumers to conserve – the more you use, the more you pay. As part of the Companies' approved amalgamation, these rate structures will be implemented starting January 1, 2015 for FEVI and FEW, and the current disparities in rate levels will disappear over the planned 3-year phase-in process to common rates. The Companies will file a Rate Design before January 1, 2017, that will review the multiple objectives and principles normally considered in a Rate Design process.

Further, the move to common rates will enable customers in the FEVI and FEW service areas to participate in natural gas programs and services previously only offered to FEI customers

including the RNG offering, NGT service, transportation service and the Customer Choice Program.

8.3 Does FEU consider that, in comparing different resource portfolios, the focus should be on (i) low rates, (ii) low customer gas bills, (iii) low total bills for customer space and water heating (gas, electricity, propane etc.) or (iv) encouraging efficient customer investment and consumption decisions from a BC perspective (including or excluding consideration of non-energy benefits)? Please explain.

Response:

Please refer to the response to BCUC IR 1.1.4 for discussion on comparing different resource options (as opposed to portfolios) in the gas utility context. In comparing different resource options, FEU consider that the focus should be on selecting the resource alternative with the "best overall outcome of expected impacts and risks for ratepayers over the long run," as outlined in the BCUC Resource Planning Guidelines (pg. 1). While specific resource options are identified in the LTRP, more detailed analysis of resource options and alternatives are examined in certificate of public convenience and necessity (CPCN) applications.

8.4 Does FEU consider that a resource planning objective should include equal consideration of EEC and supply side resources? If not, please explain.

Response:

Although not explicitly stated as a separate objective, the FEU believe that equal consideration of demand and supply side resources should be and are included among the FEU's resource planning objectives. The idea of equal consideration of demand and supply resources can be found throughout the FEU's objectives, although the specific term 'equal consideration' may be interpreted differently by different stakeholders. The FEU's approach to this balance is to fully consider both demand and supply side resources. Please refer to the response to BCUC IR 1.10.1 for a discussion of how this was done in the 2014 LTRP.

8.4.1 Does FEU consider that EEC, by its very nature, tends to put upward pressure on rates, and that a focus on limiting rate (rather than bill) impacts will result in preference being given to supply side resources over EEC? If not, please explain why not.

Response:

The FEU confirm that EEC, by its very nature, tends to put upward pressure on rates and all things equal would then put upward pressure on bills. This is one reason why it continues to be important for the FEU to continue pursue other demand side activities such as FEI's NGT initiative and the addition of new customers and their associated load.

The FEU do not believe that preference is given to supply side resources for the following reasons:

- The FEU have included all cost effective EEC measures available in the energy savings scenarios in Section 4.2.3.2 of the Resource Plan.
- Supply side resources are addressed primarily through a separate regulatory proceeding: the Annual Contracting Plan (also refer to the response to BCUC IR 1.1.4)
- The FEU purchase natural gas supplies from the market rather than developing those supplies themselves and so do not pit EEC against alternative sources of supply or the decision to build versus buy sources of supply (see also the response to BCUC IR 1.4).
- The FEU have explained on page 98 and 99 of the LTRP (Exhibit B-1) why system capacity resources are not replaced by EEC.
- Some supply side resources are needed for system sustainment rather than system capacity and so are required regardless of the energy savings that can be achieved through EEC.

8.5 Does FEU consider that, to ensure efficient utility investment and operational decisions, additional supply side infrastructure (such as system extensions to new residential developments) should only be considered where there is sufficient customer demand growth to support the added cost of service impacts associated with those resources? Please explain.

Response:

System extensions to new residential developments are an example of a distribution level utility investment that is part of the FEU's day to day business. Planning for this level of investment is conducted through the capital planning process rather than the resource planning process, and the economic test is applied at the project planning stage. The FEU would not consider system extensions to be "supply side infrastructure". For this purpose, the FEU currently use a system extension test approved by the Commission in Orders G-152-07 and G-06-08 to evaluate whether or not there is sufficient customer demand growth to support the added cost of service impacts associated with those resources. A review of system extension policies and test typically occurs in separate proceedings; either a Rate Design or separate System Extension Application.

8.5.1 Please briefly describe the FEU Mains Extension Test.

Response:

As discussed in the response to BCUC IR 1.8.5, all applications to extend the gas distribution system to one or more new customers are subject to a system extension test (referred to as an "MX Test") approved by the Commission. The MX Test formula develops a Profitability Index ("PI") which is the ratio of the discounted present value of all forecast net cash inflows over twenty years divided by the discounted present value of the capital costs of attaching customers in the first five years of the main extension.

While there are many components factored into the calculation of this ratio, the following formula provides a summary of the major components:

$$P.I. = \frac{\text{Net Present Value of Net Cash Inflows}}{\text{Net Present Value of Capital Costs}}$$

(Delivery Margin + Connection Fees – O&M - System Improvement Charge – Property Tax – Income Tax)

(Mains, Services, Meter Costs)

Accompanying the MX Test formula are the following FEI and FEVI MX Test threshold criteria that have been approved by the Commission under Order No. G-152-07:

- If an individual PI is 0.8 or greater, the system extension can proceed without the need for a customer contribution.

- If the PI is less than 0.8, a customer contribution is required to bring the PI up to the 0.8 threshold, before the system extension can be built.
- An aggregate threshold PI of 1.1 is to be used for the portfolio of main extensions completed on an annual basis.

8.5.2 Has FEU's monitoring of actual compared to forecast results of these financial feasibility tests indicated any concerns that FEU may not be making cost-effective supply side investment decisions? How is FEU planning to address these concerns (if any) and how does FEU ensure that the best overall outcome of expected impacts and risks for ratepayers over the long run is being achieved? Please explain.

Response:

No. The Companies are interpreting "supply side investment decisions" to mean distribution and transmission main extensions, and as discussed in the response to BCUC IR 1.8.5, the FEU employs the MX test approved by the Commission for determining cost-effectiveness of main extensions.

However, the FEU does have concerns about the MX test reporting requirements and the MX test itself. The existing reporting methodology requested by the Commission compares forecast to actual incorrectly. As such, results of this comparison are not meaningful. Further, the existing MX test has not kept up with changes to the marketplace, appliances, and housing stock. Consequently, the FEU is currently reviewing their system extension policies with stakeholders to ensure that they meet the needs of both existing and potential new customers.

On February 18, 2014, the Companies held an initial workshop designed to educate and inform stakeholders on the issues related to FEU's system extension policies. Commission Staff participated in this workshop and an electronic copy of the presentation materials was forwarded to the Commission on February 19, 2014.

The Companies have scheduled a second workshop for June 18, 2014 in order to determine the terms of reference of the project and the guiding principles of the system extension policies. Subsequent stakeholder workshops are anticipated to take place during the fall of 2014. In short, the purpose of these workshops will be to evaluate the existing MX test in relation to the guiding principles and to provide feedback on the development of any new MX test being considered.

9.0 Reference: PUBLIC INTEREST OBJECTIVES

Exhibit B-1, Application, Section 1, pp. 8–9; RP Guidelines, p. 3

Risk Management

FEU describes its resource planning objectives on page 8 and 9 of the Application. The RP Guidelines include on page 3 the following resource plan objectives: minimization of risks and preservation of the financial integrity of the utility.

9.1 Generally, does FEU consider that minimization of risks should be a resource plan objective, and if yes how should it be defined? For example, does FEU consider it should be interpreted as minimization of risks to the utility, or minimization of public interest related risks?

Response:

The resource plan is a submission that examines the potential future use of gas and its effect on resources (pipe, compression and storage) required at some time by the utility. The filing is not requesting that resources be approved or built to serve customers. Nor is the filing requesting approval of any pipe, compression and storage portfolio. A CPCN, RRA/PBR or other such filing would make such a request.

Given the above, the objective of the LTRP submission is to put forward a range of forecasts of gas use and the "at the time" resources that would be required to meet the forecast. The forecasts provide a band (upper and lower) that future use can be expected to fall within. The resources planned for should be acquired/built to meet the full range of the band of possible forecast (both high and low).

The FEU do not believe that minimization of risk should be an explicit resource planning objective because the LTRP is only a broad planning document and is not proposing final investment decisions and is not seeking approval of resources that will affect rates. Further consideration for minimizing risks is included in all decision making at the FEU from safe work practices through to the development of large infrastructure projects. The objective "ensure a safe, reliable and secure energy supply" includes the idea of minimizing risks, for example. The consideration of risks and types of risk associated with alternative resource options occurs at the project / initiative planning and application stage.

9.2 Please describe technology developments that FEU considers could influence the natural gas and heating markets over the next 20 years, and describe how

FEU has considered risks arising from potential technology developments in arriving at its recommended portfolio.

Response:

Please refer to the response to BCUC IR 1.1.4 and pages 7 and 8 of the LTRP (Exhibit B-1) for a discussion of why the FEU's 2014 LTRP did not culminate in a single recommended portfolio of supply and demand side measures. A discussion of how the FEU have considered new technologies in forecasting future demand using the end use demand forecasting methodology is included In Section 8 of the LTRP (Exhibit B-1) on pages 151 (NGT Market Transformation), 152 (Renewable Thermal Energy considerations), 153 (Energy Efficiency Technologies), and Section 8.5 (Potential Impact of New Technologies and Market Conditions on Demand). The FEU have not attempted to identify an exhaustive list of potential technologies that could impact demand over the next 20 years, but rather has used these very real examples to model a reasonable range of demand impacts. The value of this approach is that it allows the FEU to examine the influence that advancing technologies and market conditions can have on either increasing or decreasing demand over the planning period without the need to identify all possible technologies and tie a demand prediction to each of those specific technologies. This is the first time that the FEU's LTRP has examined the potential risks of decreasing demand associated with technology developments or market changes in this way.

The FEU recognize that the potential always exists for significant technology advancements to drastically change market conditions either positively or negatively over shorter periods. While the FEU remain vigilant for such major technology or market shifts in order to capitalize on market opportunities or address risks, including such an exercise in the resource planning process would not provide additional value since the high and low bounds of potential future demand would be too wide and too speculative to provide any useful information for future resource planning.

10.0 Reference: PUBLIC INTEREST OBJECTIVES

Exhibit B-1, Application, Section 1, pp. 8–9; RP Guidelines, p. 3

Other

FEU describes its resource planning objectives on page 8 and 9 of the Application. The RP Guidelines include as objectives: equal consideration of DSM and supply resources; minimization of risks; and compliance with government regulations and stated policies (p. 3).

10.1 Please elaborate how FEU has included (i) equal consideration of DSM and supply resources and (ii) compliance with government regulations and stated policies in its 2014 LTRP objectives.

Response:

The 2014 LTRP objectives guide the FEU to develop a plan that follows the BCUC Resource Planning Guidelines where applicable, meet the requirements of *UCA* Section 44.1(2) (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) and assist the province by contributing to provincial energy objectives and emission targets.

Please refer to the response to BCUC IR 1.2.1 for an explanation of why the FEU do not directly compare demand-side and supply-side resources. Instead, the FEU have included cost-effective demand-side measures in the analysis of different future demand scenarios for natural gas. Section 4 of the 2014 LTRP provides detail on how the FEU have included consideration of DSM resources and compliance with government regulations and stated policies in the 2014 LTRP.

Section 4.2 addresses the utility demand-side measures as defined by B.C. statute which are met through the FEU's Energy Efficiency and Conservation (EEC) activities, in addition to a plan for how the Utilities will move forward to try to achieve these demand reductions over the planning horizon. Section 4.2 thus addresses Sections 44.1(2)(b) and (c) of the *UCA*. Although there are no specific, government-mandated GHG targets for the FEU or the Companies' customers to meet, the emissions reduction estimates for each of the EEC scenarios are also presented.

Section 4.3 discusses demand-side management in the broader context of utility activities beyond B.C.'s limited definition of demand-side measure. The FEU's high carbon fuel switching, natural gas for transportation and exploration of new, large industrial customer demand are presented as examples of activities that, though they do not meet the provincial definition of demand-side measure and are therefore not eligible for EEC funding, are nevertheless important demand-side management activities for the Companies. These

activities assist the province by contributing to provincial energy objectives and emission targets.

In Section 5.1.1.2, the FEU provide an explanation of why the demand for energy to be served by supply resources are not planned to be replaced by demand-side measures. This section describes how EEC may or may not lead to changes in peak-demand. When the impacts of EEC on peak demand are taken into account, it becomes apparent that the effect of EEC and shifting end-use trends on peak demand cannot be predicted without knowing the specific details of equipment 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*.

The FEU also note that the BCUC Resource Planning Guidelines also suggest that resource planning objectives should include compliance with government regulations and stated policies. The above discussion describes how the FEU adhered to these regulations and policies in the 2014 LTRP, and yet stating such an objective as a separate, explicit objective would not add value to the FEU's resource planning process.

10.2 Please describe whether FEU also has an objective of promoting/ensuring: (i) customer satisfaction, (ii) social considerations (specifically low income and First Nations), (iii) BC economic development and (iv) rate stability (burner tip and burner tip excluding commodity). If not, please explain why not. If yes, please describe how FEU determines to what extent it should support these objectives.

Response:

Each of the listed objectives are very important considerations for the FEU in the way that they conduct their business and operations, but these have not been explicitly stated as separate objectives for the 2014 LTRP. Since the development and comparison of portfolios of demand and supply side resources is not appropriate for the FEU's resource planning process (please refer to the response to BCUC IR 1.1.4), and the LTRP presents a high level view of upcoming resource needs for which future applications will be made, the impact of resource decisions on these types of considerations is more appropriately assessed at the application stage for an individual project or initiative.

10.2.1 For rate stability, at what level of annual rate impact would FEU consider unacceptable for customers for (i) burner tip and (ii) burner tip excluding commodity.

Response:

For rate stability, the FEU examine burner tip rates faced by customers and consider that rate shock must be assessed considering the specific circumstances in each rate design proceeding. The 10% rule (bill increases greater than 10 percent per annum) and the "two times rule" (bill increases as a result of rate design changes greater than double the average bill increase for that customer class) are useful for assessing rate shock in the case of electric utilities where the electricity commodity is generated within the utility. However, in the case of gas utilities that source the natural gas commodity at market-based prices, commodity cost can introduce a further source of rate shock for customers. The FEU consider that rate shock should primarily be assessed at the burner tip including commodity, as the burner tip price represents the overall impact to customers and the commodity portion of the customer's bill is the most volatile.

FEI has conducted customer research regarding residential customers' tolerances for burner tip rate changes in the past. In February 2005, FEI engaged a research company to survey customers regarding their tolerance for rate volatility. The results of the Residential Customer Price Volatility Preferences Study, conducted in February 2005 by Western Opinion Research Inc. and submitted in the 2005-2008 Price Risk Management Plan, indicated that customers prefer rate stability. The survey results confirmed that customers will tolerate some volatility in rates but that there were limits largely based on household budget constraints. In addition to examining the study population as a whole, the study also examined how results might differ for respondents on tighter budgets versus those with higher budgets. The study revealed the following insights and preferences among residential customers:

- Natural gas bills are considered among the more significant monthly payments;
- Many customers cannot afford large increases in their natural gas bills;
- On average, the study respondents as a whole could tolerate annual natural gas billing changes of $169 (or 16% of average annual billing of $1033);
- For study respondents on tighter budgets (i.e. those with annual billings of less than $900), the average tolerable change was only $53 (or 11% of average annual billings of $482);
- For study respondents with higher budgets with annual billings of more than $900, the average tolerable change was $219 (or 17% of average annual billings of $1288); and

- 70% of the total study respondents could tolerate annual bill changes of $100 or less.

This last point indicates that 70% of customers may not be able to tolerate annual bill changes over $100. Based on FEI's current average total residential annual billing of about $1,050 (assuming 95 GJ consumed per year and a burner tip rate of $11.06/GJ based on FEI's commodity, midstream and delivery rates and fixed basic charge rate effective July 1, 2014 and excluding carbon tax) this level of $100 tolerable increase represents approximately 10% or $1/GJ. FEI's last commodity rate increase effective April 1, 2014 was about $1.37/GJ.

10.2.2 Will the recent approval of postage stamp rates for FEU decrease any need to reduce the level of cost effective EEC in order to mitigate competition and rate stability risks? Please explain.

Response:

Since Provincial regulation sets out how the FEU determine the cost-effectiveness of demand-side activities, the FEU interpret this question to mean whether the FEU see a need to increase or decrease EEC spending in general, to address changes in the competitive position of natural gas as a result of the approval of postage stamp rates. For Vancouver Island, the FEU expect the upcoming postage stamp rates to improve the competitiveness of natural gas against electricity. Therefore, reducing the level of EEC spending is not needed to mitigate competition and rate stability risk as a result of postage stamp rates. For FEI, a slight increase in rates as a result of postage stamp rates could slightly erode the competitive position of natural gas; however, the FEU do not expect this slight change to be sufficient to impact rate stability and therefore do not expect to reduce the level of EEC spending for this reason.

11.0 Reference: PLANNING ENVIRONMENT

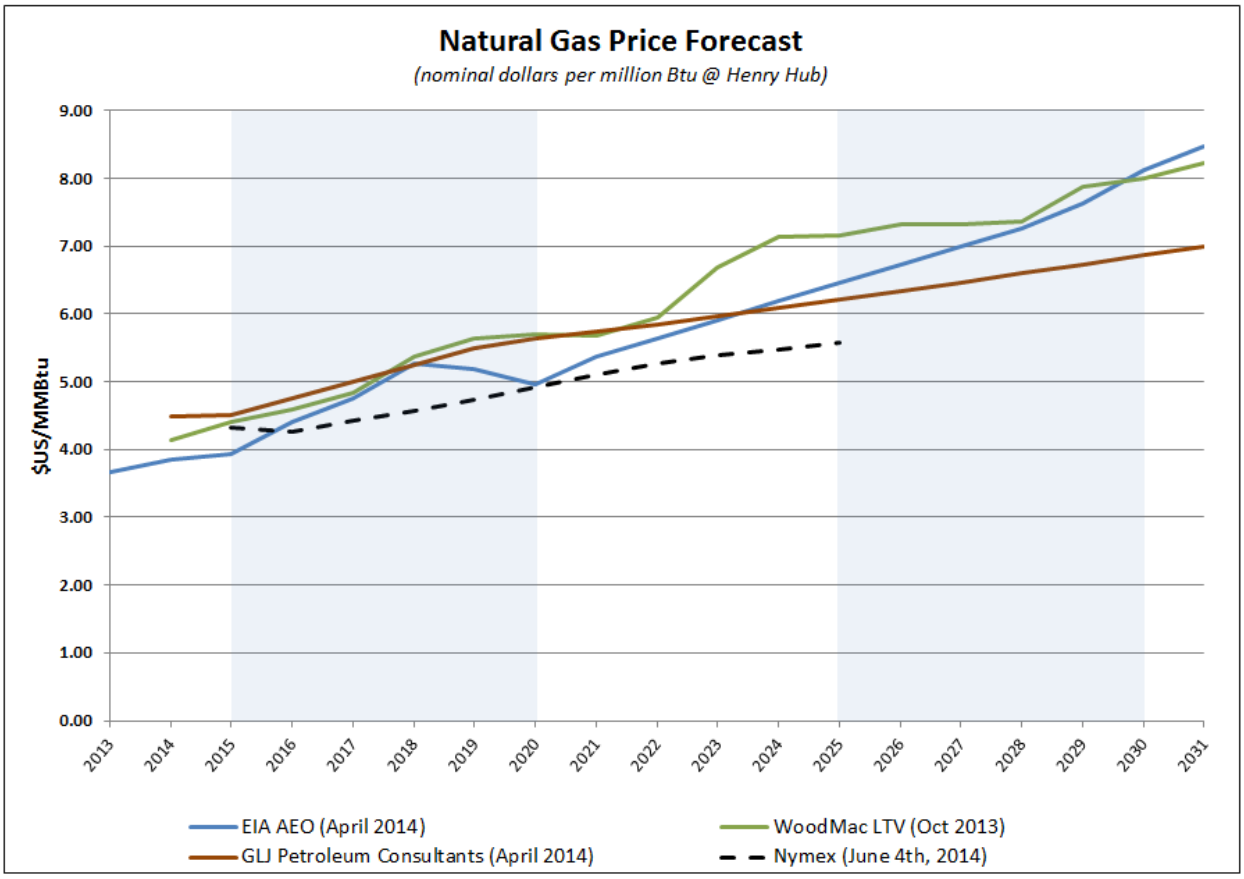
Exhibit B-1, Application, Section 2.1.1, Figure 2-3, p. 17

Market Dynamics and Commodity Pricing

11.1 Please provide an updated version of Figure 2-3: Natural Gas Price Forecast to reflect current price forecasts.

Response:

The following figure is an updated version of Figure 2-3 using the latest price forecasts available to the FEU and NYMEX futures prices as of June 4, 2014.



Source: FEU based on U.S. EIA Annual Energy Outlook, GLJ, Wood Mackenzie Long Term View and Nymex.

12.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Application, Section 2.1.2, pp. 17–18

Supply Infrastructure

On page 18 of the Application, FEU states: "The Kingsvale Oliver Reinforcement Project (KORP) is an example of one such opportunity to expand the FEU's transmission system to support gas flows south from northeast B.C. toward new base load markets that are emerging in the Lower Mainland and PNW [Pacific Northwest]" (Exhibit B-1).

12.1 How does the timing of the KORP differ, if at all, under the high, reference and low cases for the annual and the peak day demand forecasts? Is that timing affected by different levels of achieved conservation? If so, how?

Response:

The FEU expect a higher probability of KORP advancing on an earlier timeline in higher demand scenarios. The overall supply and demand dynamics in the region, along with the FEU demand, will be key considerations in the overall justification and timing for KORP. Within BC, the FEU do not expect their own EEC programs to have a significant impact on this timing (refer to Pages 98 and 99 of the LTRP, Exhibit B-1, and the response to BCUC IR 1.48.1 for an explanation as to why EEC is not considered to have a significant impact on capacity related resources). In the US Pacific Northwest, natural gas is generally considered to be a cleaner alternative to coal fired generation and using more expensive electricity for space heating and hot water, so other energy conservation or emission reduction programs in the Pacific Northwest could have some impact on the regional market dynamics in such a way as to advance the timing of KORP.

13.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Application, Section 2.3.2, p. 35

Renewable Natural Gas Offering

FEU notes on page 35 of the Application that the Renewable Natural Gas Offering provides customers the opportunity to elect to notionally replace a percentage of their traditional gas supply with biomethane and in footnote 43 on that page defines biomethane as derived from biogas, which is produced from decomposing organic waste from landfills or agricultural waste.

13.1 Please discuss the potential for expanding the renewable natural gas offering beyond biomethane and biogas, as defined in the current offering, at some point in the forecast period. Briefly address the barriers to injecting syngas into the natural gas distribution grid and to expanding the renewable natural gas offering to include syngas. Refer to experiences in other jurisdictions where appropriate.

Response:

The FEU have not considered the use of other renewable gases such as syngas as a means of expanding the current potential supply of renewable natural gas during the forecast period. The FEU cannot rule out using other sources of renewable gas over the forecast period, but at this time other gasses such as syngas are not interchangeable with natural gas.

The FEU are, however, aware that over the past few years, other jurisdictions have begun to investigate the use of natural gas pipelines for hydrogen storage. For example, Enbridge Gas has indicated on its website (under Alternative Technologies), that it is considering a project in partnership with Hydrogenics (a known hydrogen fuel cell and electrolyzer Company) that may utilize the natural gas grid to store and or transport hydrogen. Regardless, the FEU have found no evidence that other jurisdictions are using other forms of gas generated from biomass as a substitute or complement to natural gas as a means of offering customers a gas with lower carbon intensity (like the FEI renewable natural gas program).

Fundamentally, the FEU designed the renewable natural gas program around the premise that any injected gas was interchangeable with natural gas. Therefore, at this time, the FEU are limited to methane produced from organic sources. The FEU would consider obtaining supply from a source of biomass that produced syngas which was further processed to result in pure methane.

Gas derived from woody biomass, such as syngas, could be considered renewable. However, based on a limited evaluation of this type of gas, the FEU have identified several potential hurdles. These are listed here with a brief description of the potential issue.

1. Heating Value: The FEU understand that the heating value of syngas is significantly lower (less than 50%) than natural gas (and biomethane or RNG).

2. Raw syngas contains tars: Tars are a known contaminant that need to be removed in order to ensure longevity of natural gas assets.

3. Syngas often contains carbon monoxide: Carbon monoxide is toxic to humans and introducing it into a pipeline may put customers at risk.

4. Syngas often contains hydrogen: Under certain conditions and at certain levels, hydrogen may contribute to asset risk (material compatibility).

These issues can be addressed by further processing syngas. For example, carbon monoxide and tars can be removed with proper processing. The gas can also be further processed to convert it to methane. However, the FEU have not seen this done economically.

To reiterate, the FEU have not included other sources of renewable natural gas other than those indicated in the forecast period. However, the FEU acknowledge that during the forecast period progress will likely be made on commercially viable alternative means of producing the gas so these sources cannot be categorically excluded as potential future renewable supply sources.

14.0 Reference: PLANNING ENVIRONMENT

Dr. Specht et al, Storing Bioenergy and Renewable Electricity in the Natural Gas Grid[5]

Use of Gas Grid to Store Renewable Energy

In some jurisdictions around the world, in particular Germany, the use of the natural gas pipeline grid to store electricity in the form of hydrogen or methane from methanation of hydrogen is being considered. The paper titled "Storing Bioenergy and Renewable Electricity in the Natural Gas Grid" by Dr. Michael Specht et al describes how "Power to Gas" or "P2G" might provide, in addition to a means to store electricity that is produced from intermittent renewable sources such as wind or solar, the opportunity to make use of unused capacity in natural gas grids.

14.1 Is "P2G" likely to present FEU with the opportunity to develop innovative service offerings of this nature during the forecast period? Please discuss the barriers and potential benefits.

Response:

There are many emergent and emerging technologies that could have an impact, either positive or negative, on the use of gas. The Resource Plan is not intended as a document that examines any and all potential technology that could impact gas consumption. However, in the end use forecasts, consumption is forecast to increase or decrease based broadly on technology changes.

With this in mind, FEI provides the following broad general comments on the P2G technology. "P2G" might present the FEU with the opportunity to develop innovative service offerings of this nature in the future, if and when the technology becomes commercially available. The FEU understand that P2G is not yet commercially available, though FEU is aware of work in Ontario to determine if this technology is market ready and scalable. Extensive additional analysis would be required once this technology became commercially available to determine if it would be suitable in BC using the FEU's infrastructure, and whether the methane potentially produced synthetically using electricity would be employed as an electric resource or as an alternative natural gas supply resource. The cited article does not identify barriers that would need to be overcome. Potential barriers common to new technology and process applications include safety, cost, availability of technical expertise, policy and regulation, investor interest, and development of required partnerships, among others. If such technology were proven beneficial, reliable and cost effective, the result could be to increase the availability of natural gas supplies – a condition which the FEU have generally examined in the alternative future

5 http://www.etogas.com/fileadmin/user_upload/Publikationen/Wind2SNG_ZSW_IWES_SolarFuel_FVEE.pdf

planning scenarios included in the 2014 LTRP. Scenario C, for example, examines a future in which natural gas supply is abundant and an important means to meet long term energy needs (Table 3-1, Exhibit B-1).

15.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.2, pp. 40–42; Section 5.1.2.1, p. 103

Customer Additions Forecast — Residential

On page 40 of the Application, FEU states: "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…" (Exhibit B-1).

On page 103 of the Application, FEU states: "The FEVI system peak demand forecast shown in Figure 5-3 was analyzed against Low and High demand scenarios. The Low and High demand scenarios were determined by taking the incremental year-over-year increase in Core demand for FEVI and multiplying this value by 79% (in the Low scenario) or 125% (in the High scenario)" (Exhibit B-1).

15.1 Please provide a detailed explanation of the derivation of the residential customer additions forecast for each of the service regions. Be sure to include a discussion of the forecasted population growth and mix of residential buildings in each of the service regions, the renewal of the existing stock in each of the service regions and FEU's forecasted capture rate for each of the service regions.

Response:

The FEU use consistent methodologies to forecast the residential customer additions across all service regions. The FEU use the CBOC housing starts forecast to provide different province-wide growth rates for single family dwellings (SFD) and multi-family dwellings (MFD). Regional net customer additions are split based on regional SFD/MFD ratios and are then assumed to grow according to the growth rates derived from the housing starts forecasts. This approach incorporates and differentiates the different mix of residential buildings in each of the service regions while keeping the capture rate constant in the forecast years within each region. The FEU believe that the housing starts growth rate is a more relevant indicator than general population growth because our definition of a customer is closely associated with a premise/house. In addition, the correlation between the CBOC housing starts forecast and our own customer data are proven to be high.

15.2 Were low and high customer additions forecasts created for the traditional demand forecast methodology as was done for previous resource plans? If so,

please provide the low and high customer additions forecast totals including a breakdown by service region for each of the years in the planning period. This data should also be included in a functional Microsoft Excel file.

Response:

No. Low and high customers additions forecasts were not created for the Traditional Forecast.

As the Company is making the switch to the End Use annual demand Forecast methodology (with support from the Commission), and as discussed in Section 3.3.6, the Traditional annual demand Forecast was completed for the purpose of establishing the reasonableness of the End Use Forecast. The Traditional Forecast was not produced to serve as a base to be manipulated or changed to achieve different results. As discussed at the Resource Planning Advisory Group meetings, since this is the first LTRP using an End Use Forecast; the FEU believe it is important to be able to validate the new methodology against the methodology used previously. The FEU anticipated that the Traditional Forecast would produce results within the bounds of the upper and lower scenarios of the End Use Forecast. As shown in Figure 3-12 of the LTRP (Exhibit B-1) the demand from the Traditional Forecast does lie between the upper and lower bounds of the End Use Forecast.

The End Use method incorporates high and low forecasts as part of the scenario modeling and thus the methodology used in previous resource plans to distinguish high and low from the base forecast was not required.

Using the stated percentages (which were used to provide upper and lower bounds to the Vancouver Island regional peak demand forecast, and not specifically for customer additions) to inflate and deflate the customer additions forecast would not be appropriate. Since so many other factors play into the peak demand forecast other than just the customer additions, there is no logic to applying these parameters to customer additions. For clarity, please note that the annual demand and peak demand forecasting methodologies are separate and distinct processes conducted for different purposes as explained in Section 3.1 of Exhibit B-1.

15.2.1 If not, would it be appropriate to use the 79 percent and 125 percent values used to develop the FortisBC Energy (Vancouver Island) Inc. (FEVI) low and high peak day demand forecasts to also develop high and low customer additions forecasts for FEVI and FEI? If not please explain why not and provide appropriate values with accompanying derivations.

Response:

Please refer to the response to BCUC IR 1.15.2.

15.3 Would it be appropriate to multiply the traditional annual demand forecasts for FEVI and FEI by the factors that were used to create low and high customer additions forecasts to create low and high traditional annual demand forecasts? If so, please provide them. If not, why not?

Response:

Please refer to the response to BCUC IR 1.15.2.

15.4 How were low and high customer additions forecasts incorporated into the end-use forecast, if at all?

Response:

Low and high customers additions were not incorporated into the end use forecast. High and low ***demand*** forecasts were based on various scenarios as defined in the Scenario Explanation documents. There are twelve Scenario Explanation documents, one for each combination of sector and for each of Scenarios A through D. Customer additions were held constant across the scenarios.

15.4.1 If the low and high customer additions forecasts were replaced by capture rate or market share assumptions, please show if these assumptions were consistent with the growth in customer additions shown in the low, high and reference forecasts.

Response:

Please refer to the response to BCUC IR 1.15.4.

16.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.2, pp. 41–42

Customer Additions Forecast — Commercial

On page 41 of the Application, FEU states: "The net customer additions are estimated based on actual additions in the latest three years" (Exhibit B-1).

16.1 Please provide a detailed explanation of the methodology used to forecast commercial customer additions.

Response:

Similar to our residential customer addition forecast methodology, the forecast process for commercial customer additions starts with the base year actual additions data. However, unlike the residential methodology where the forecast additions are highly correlated to housing starts, commercial additions are very volatile and there is no one source of data that provides long term insight into future commercial additions. For this reason the FEU have adopted a simple methodology using a three year average by region and rate class to forecast commercial customer additions. The FEU believe this approach, when combined with frequent updates, produces a reasonable forecast.

16.2 The data illustrated in Figure 3-3 on page 42 begins at 2011. Please indicate which three years were used to determine the trend used to forecast commercial customer additions.

Response:

Figure 3-3 shows the milestone years consistently used for reporting all results. 2011 data is "actual" while 2016 through 2033 are forecast values.

Commercial customer additions for 2016 through 2033 were forecast using actual data from 2010, 2011 and 2012.

16.2.1 Is the residential forecast also based on actual additions in these three years? If not, please indicate the years used as the basis to forecast residential customer additions.

Response:

No. Residential additions are forecast using a different methodology that relies on year end actuals and the CBOC forecast by housing type. Please refer to the response to BCUC IR 1.15.1.

16.3 To what extent does a three-year period reflect growth over the much longer planning period that will normally include economic cycles?

Response:

Commercial customer additions are very volatile. The FEU believe there is no single numerical method that can provide accurate long term insight into the future commercial additions due to the volatility and multiple factors involved. Additionally, the FEU do not attempt to forecast economic cycles.

In the absence of a better alternative, the FEU used a simple three year average approach with the goal to update the forecast on a regular basis to capture any deviations from the existing trend.

17.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.2, p. 42

Customer Additions Forecast — Industrial

On page 42 of the Application, FEU states: "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" (Exhibit B-1).

17.1 Please confirm that the above preamble remains true. If not, please indicate the salient changes in the Energy Demand Forecasting section that would occur as a result of the current circumstances.

Response:

Confirmed.

18.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.3.1, pp. 43–44

Traditional Annual Demand Methodology — Additional Data

On page 43 of the Application, FEU states: "The analysis was conducted for each residential and commercial rate class, based on the most recent five years of data. The trends were then extended into the next 20 years for the purposes of providing a long term forecast" (Exhibit B-1).

18.1 Please describe the traditional annual demand methodology, and the key variables and inputs. For example is it a multiple linear regression analysis and if so what are the dependent variables? Also, if applicable, for each variable please describe the data period used.

Response:

Demand is not forecasted directly. UPC and accounts are forecasted and the product of those two forecasts is the demand forecast. Please refer to section 3.3.1 Page 43 of the filing (Exhibit B-1). As stated "The FEU's traditional methodology for forecasting residential and commercial demand involved determining an average UPC and multiplying it by the number of customers forecasted for each year of the study period."

18.2 Have there been any significant changes to the methodology or the inputs used — for example, basing the residential and commercial UPC trends on the most recent five years of data? If so, please elaborate.

Response:

A comparison summarizing the methodologies between the 2010 LTRP and 2014 LTRP is provided below. The core methodology to define the UPC and account forecast remain consistent as major data inputs remained the same such as housing data from Conference Board of Canada (CBOC) and the industrial customer survey. The modeling framework for residential and commercial rate classes is based on a time series which also remains the same. Although not considered a significant change, the FEU did base the 2014 UPC regressions on five years of data as opposed to three years used in 2010.

The significant change in 2014 was the introduction of the end use method which is not time series based.

	2010 LTRP	2014 LTRP Traditional
Residential		
UPC	Time series through a simple regression analysis based on three years of data combined with some parameters from 2008 REUS.	Time series through a simple regression analysis based on five years of data.
Account	Base year actual net additions escalated based on the growth rates from CBOC.	Base year actual net additions escalated based on the growth rates from CBOC.
Commercial		
UPC	Time series through a simple regression analysis based on three years of data.	Time series through a simple regression analysis based on five years of data.
Account	Average of the latest three years of data on net additions.	Average of the latest three years of data on net additions.
Industrial		
Demand	Customer survey	Customer survey

18.3 Please discuss the drivers which result in the increase in commercial annual demand seen in Figure 3-4 on page 44 of the Application.

Response:

In line with the traditional annual demand forecast methodology, the commercial demand forecast is a product of the commercial UPC and commercial net customer additions forecasts at the rate class level. Both of these components use a trending approach in which historical data is examined to identify a trend in the data. The trend is assumed to have all the drivers embedded in it and separating out each driver is not feasible.

18.4 Please provide a functional Microsoft Excel workbook containing tables of customer year end account forecasts, average use per customer forecasts and annual demand forecasts for each of the 20 years in the planning period, using the traditional demand forecast methodology. The data should be separated by service region (FEVI, FEW, FEI – Coastal Region and FEI – Interior) and each service region should be broken down into all relevant customer rate classes. Data for FEU totals broken down by major customer class (Residential, Commercial and Industrial) should also be included. Please include the previous five years of actual data from which these traditional forecasts were based.

Response:

Please refer to Attachment 18.4 for a functional Microsoft Excel workbook containing tables of customer year end account forecasts, average use per customer forecasts and annual demand forecasts for the milestone years in the planning period. The years between the milestone years can be read from the charts included in the attachment, or through simple interpolation.

18.4.1 Please provide charts for each of the service regions, as well as FEU totals, to clearly illustrate the information requested in the previous question. On each chart, please be sure to differentiate forecasts from actual data.

Response:

Please refer to the response to BCUC IR 1.18.4.

18.5 Please provide tables and graphs showing the actual year-end accounts, average use per customer and annual demand for each service regions for the past 10 years. For each service region please breakdown the data into major customer classes (Residential, Commercial and Industrial). Also provide a table and graph with FEU totals broken down into the major customer classes for each of the past 10 years.

Response:

Please refer to the response to BCUC IR 1.18.4.

18.6 Please provide a graph(s) showing past UPC data for the last 10 years, with labelled data points and include on the graph the regression lines and the resulting UPC forecasts for the planning period established with the traditional methodology.

Response:

Please refer to the response to BCUC IR 1.18.4 for the requested graphs. The billed consumption database which formed the basis for the forecast can only provide actual data from 2007 and thus, the UPC data are provided starting from 2007. Regression lines are included for applicable rate classes as requested.

18.6.1 Was a low and high UPC forecast created for residential and commercial customers? If so, please provide it. If not, why not?

Response:

A low and high annual UPC forecast for the Traditional Annual Demand Forecast was not created.

As described in Section 3.3.6 (Exhibit B-1), and discussed at Resource Planning Advisory Group meetings, the intention of the Traditional Annual Demand Forecast was only to provide a reasonability check for the End Use Forecast. The development of the upper and lower annual demand scenarios for the End Use Forecast followed a sophisticated process that examined changes in energy use at the more granular end-use level rather than at the customer level. Applying a simple factor to the Traditional Model to create an arbitrary high and low residential and commercial UPC forecast and then comparing those results to the more sophisticated End Use Model would not be a meaningful exercise and as such upper and lower UPC scenarios for the Traditional Model were not developed.

18.6.2 What would be a reasonable basis for low and high UPC forecasts?

Response:

Please refer to the response to BCUC IR 1.18.6.1.

19.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.1.2, p. 40; Sections 3.3.2 and 3.3.3, pp. 45–47

End-Use Annual Demand Methodology — Residential, Commercial and Industrial

On page 40 of the Application, FEU states: "Preparation of the new end-use forecast and the traditional long term forecast resulted in a data set comprised of nearly 20 million records. Due to the volume of data involved, it was necessary to prepare the LTRP forecasts at a series of milestone years, rather than on a year-by-year basis" (Exhibit B-1).

19.1 Please provide an estimate of the size of the data set, in terms of records, if only the traditional forecasting methodology was used.

Response:

The Traditional Annual Demand Forecast occupies less than 1,000 records in the database.

For the End Use Forecast, a record exists in the database for each scenario, region, rate, end use, building type, milestone year etc. The Traditional Forecast does not manage data at the level of granularity supported by the End Use Forecast so the storage requirements are significantly less.

19.2 Can these 20 million records be utilized in the end-use model to produce an annual demand forecast for each year from 2013 through to 2033, instead of only five milestone years (2016, 2021, 2026, 2031 and 2033)?

Response:

The 20 million records represent the output from the End Use Forecast model runs. The 20 million records are *not* the inputs to the model. Each output record includes the milestone year for the data in the particular row. Therefore the 20 million records cannot be used to produce an annual demand forecast.

For example below is a row (split into 4 parts for legibility) from the output file provided to the FEU by ICF/Marbek. This row is one of the 20 million rows loaded into the FEU's analysis database.

Dataset Identifier	Region	Fuel	Rate Class	Class Fraction	End Use	End Use Nick
ResScen0	Lower Mainland	Natural Gas	Rate 1	1	Space heating	Space heating

End Use Sum	Year	Ex/Reno/New	E/R/N Sum	Segment	Segment Nick
HVAC	2011	Existing	Existing/Reno	SFD/Duplex, gas heat, pre-1976	Older Gas Heated SFD

Segment Sum	Measure #	Measure	Measure Nick	Measure Sum	Units, Original Reference Case	Accounts, Original Reference Case
SFD	0	Enduse Consumption	Consumption	Consumption	193365.642	193365.642

End Use Count, Original Reference Case	Consumption, Original Reference Case
182794.5492	16009255.86

Values for any measure in any intervening year between two milestone years can be determined using simple linear interpolation as follows:

$$y = y_0 + (y_1 - y_0)\frac{x - x_0}{x_1 - x_0}$$

In this case

- x_0 is the first milestone year
- x_1 is the second milestone year
- y_0 is the value of the output being examined in the first milestone year
- y_1 is the value of the output being examined in the second milestone year
- x is the year in question
- y is the value of the output being examined at x.

For example if we wanted to know the total reference case energy for 2028 we would consider the total energy for the reference case o for 2026 and 2031. We have the following data from Figure 3-6:

Energy, TJs	2026	2031
Reference Case	199,777	200,679

To determine the energy for 2028 we would enter the above formula with the following values:

$$Energy_{2028} = 199{,}777 + (200{,}679 - 199{,}777)\left(\frac{2028 - 2026}{2031 - 2026}\right) = 200{,}138$$

The interpolated energy for the reference case for 2028 is thus 200,138 TJs.

Completing a linear interpolation to fill in all the years for all scenarios and measures would be time consuming and likely require additional consulting expertise. The dataset would conceivably grow to 100 million records while the accuracy of the results would not be improved.

19.2.1 If yes, please provide a functional Microsoft Excel spreadsheet containing tables showing the annual demand forecasts for each of the 20 years in the planning period, obtained via the end-use model. The data should be separated by service region (FEVI, FEW, FEI – Coastal Region and FEI – Interior) and each service region should be broken down into all relevant customer rate classes. Data for FEU totals broken down by major customer class (Residential, Commercial, and Industrial) should also be included. Please include the previous five years of actual data in each table.

Response:

Please refer to the response to BCUC IR 1.19.2.

19.2.1.1 Please provide charts for each of the service regions, as well as FEU totals, to clearly illustrate the information requested in the previous question. On each chart, please be sure to differentiate forecasts from actual data.

Response:

Please refer to the response to BCUC IR 1.19.2.

19.2.2 If not, what would be required in order to use the end-use model to produce annual demand forecasts for each year from 2013 through to 2033? Please elaborate on the analysis and calculations that, because of the size of the data set, restrict the end-use forecast to a handful of milestone years.

Response:

The forecasting model was a repurposing of a model more generally used for conservation potential review (CPR) studies, and which was used for the FEU CPR in 2010. The architecture of that model is designed with six milestone years including the base year, up to twenty end uses, and up to twenty-five building types. The ICF/Marbek model is Microsoft Excel based and at the current size stretches the capability of the Excel application. The current forecasting model had to be calculated and delivered to the FEU in multiple separate files. As a result the only feasible way to produce annual demand forecasts for each year at full granularity would be to use interpolation between the milestones.

The ICF/Marbek results are saved at the FEU in a corporate Microsoft SQL Server database. With approximately 20 million records in the SQL Server database the FEU estimate that approximately 80 million interpolations would be required.

Neither ICF/Marbek nor the FEU forecast analysts have, or are required to have, the Microsoft SQL Server expertise or programming skills required to complete such a project. As a result a separate IT consultant would need to be retained to complete the SQL Server interpolation programming. The SQL Server programming would then result in 80 million additional records being added to the dataset, expanding it to 100 million records. Without a statement of work and a proposal from one or more IT consultants it is impossible to estimate how much this would cost. Additional hardware resources might also be needed to house a database of this magnitude and those costs would also need to be estimated during the project.

It should also be noted that the additional work and costs discussed would not in any way improve the accuracy or precision of the model results. It is important to note that this LTRP submission is providing a broad range of forecast outputs for the purpose of planning resources into the future. The purpose of the resource planning it to plan resources to meet the range of forecast outputs. Any forecast looking out more than a year or two has significant potential for error or variance from what is expected. It is because of this that planning is conducted to meet the range of possible outcomes rather than purporting confidence that a specific forecast outcome will occur. As such, providing annual forecasts, in addition to being onerous and potentially costly, will not do anything to increase the accuracy of the long term forecast and in the opinion of the FEU would not be a good use of ratepayer dollars.

On page 46 of the Application, FEU states: “The process first involved the development of a reference case forecast. The reference case is based on end-use patterns observed

in the base year and keeps these patterns constant throughout the planning period" (Exhibit B-1). FEU further indicated that the base year in this case is 2011.

19.3 Please explain what FEU means by 'patterns'. Specifically are these variables that are held constant in the reference case but adjusted in the other scenarios?

Response:

"Patterns" in this context is meant to describe the current blend of end uses and associated use rates being installed across the system.

The reference case scenario was based on the reference case used in the 2010 CPR, but updated to start with a newer base year. The CPR reference case was created based on the best information available to the consultants about how end use energy consumption would evolve over the 20-year study period. Energy efficiency is not assumed to remain static, but instead evolves according to best estimates of natural conservation. These changes are further adjusted in each of the scenarios.

To explain further, the end use saturations – i.e., a percentage that indicates what fraction of a given type of facility has the given end use, such as the percentage of older Lower Mainland single-family dwellings that have dryers – is not assumed to change through the forecast period. It is also not varied between scenarios. Another example of a pattern would be fuel choice. The percentage of gas-heated older Lower Mainland single-family dwellings with a gas water heater is not assumed to change through the forecast period. This assumption is changed between scenarios, depending on the influence of gas pricing. Efficiency is another example of a pattern. In this case, maintenance of the pattern may not mean that the efficiency remains static. For example, in the reference case gas furnaces are assumed to fail and get replaced according to their normal life cycle. They get replaced with a furnace meeting the minimum efficiency regulations, and consequently the average efficiency of furnaces in the population of dwellings rises over the forecast period. The different scenarios incorporate different assumptions about the average efficiency of the replacement furnaces, and therefore the rate of improvement in average efficiency varies by scenario.

19.4 Please provide a table showing the assumptions and variables that underpin the reference case, assumptions used to mean factors that are not adjusted for any of the scenarios (including the reference scenario), and variables are factors that are adjusted.

Response:

The FEU provide the table below to show an example of the assumptions and variables underpinning the reference case forecast. This example shows the requested information for residential DHW in single family dwellings in the Lower Mainland, to demonstrate the level of detail involved in the models. The FEU are not able to provide a complete listing of all information for all variables and assumptions within the response time frame due to the large number of assumptions and variables by end use. Such a response would result in over 4,000 pages of information, take considerable time to prepare and be outsourced to our forecast modelling consultant. However, the forecast model has been designed in such a way that individual assumptions and variables can be examined fairly readily by the FEU.

The modeled estimate of the tertiary energy[6] requirement for DHW is built up from assumptions about the individual DHW end uses (clothes washing, dishwashing, showers, faucet use), which may vary by house type and over time because of differences in occupancy and the efficiency of the end use devices. Regionally, tertiary load will also vary somewhat depending on the average temperature of the ground, which affects water mains temperature. The consumption of natural gas for DHW per dwelling is a combination of tertiary load, efficiency of the DHW appliance, and gas share. Consumption per dwelling in each of the categories, which are also separated into existing, renovated, and new dwellings, is multiplied by the number of dwellings in each category, to estimate the total gas consumption for DHW in the dwellings. Total gas consumption in the base year for all end uses and dwellings in a region must ultimately calibrate to the FEU consumption figures for that rate class.

While the base year is the same for all of the scenarios, most of the values in the table can vary by scenario for the future milestone years. In fact, the values under Ref #2, Ref #3, and Ref #5 are the primary variables that were directly adjusted from one scenario to another, with other variables changing because they are calculated from those three. The totals in Ref #7 do not change, but there is some shifting between categories.

[6] Tertiary energy is defined as the useful energy delivered to accomplish the end use task; for example, for DHW it is the heat actually transferred into the water. Secondary energy for an end use is the energy delivered to the customer's home or business to fuel the end use appliance; for example, for DHW it is the energy content of the natural gas used by the water heater. For a natural gas water heater, secondary energy is tertiary energy plus the losses due to the efficiency of the water heater. Primary energy is the energy content of the natural gas that must come out of the ground in order to supply the ultimate end use, including all losses in between.

Ref #	Variable or Assumption?	Description	Dwelling Type	Value, 2011	Value, 2033	(Units)	Does it vary by scenario	Endogenous or exogenous?	Notes
1	Variable	Tertiary Load - the energy to do the DHW tasks in the home	Pre-2006 SFD, mainly gas heat	11,717	8,112	MJ	Yes, for milestones after the base year	Endogenous - back-calculated from the EUI and efficiency variables	2006 and later dwellings have higher occupancy, but also higher incidence of efficient clothes washers and dishwashers, according to the REUS. The occupancy difference assumption was not changed in the later milestone years, but the difference in appliance efficiency was assumed to disappear with time.
			2006 or later SFD, mainly gas heat	10,793	8,575	MJ			
			Pre-2006 SFD, mainly non-gas heat	11,717	8,112	MJ			
			2006 or later SFD, mainly non-gas heat	10,793	8,575	MJ			
2	Variable	Efficiency - the combustion efficiency of the appliance	Pre-2006 SFD, mainly gas heat	60%	64%	%	Yes, for milestones after the base year	Exogenous	2006 and later dwellings have higher incidence of tankless and condensing DHW, according to the REUS. Other dwellings were assumed to reach EF of 0.64 by the end of the forecast period, with 2006 and later staying at an average of 0.68. These efficiency gains varied by scenario.
			2006 or later SFD, mainly gas heat	68%	68%	%			
			Pre-2006 SFD, mainly non-gas heat	60%	64%	%			
			2006 or later SFD, mainly non-gas heat	68%	68%	%			
3	Variable	Gas Energy Utilization Index (EUI) - how much gas used by DHW if it is gas	Pre-2006 SFD, mainly gas heat	19,529	12,674	MJ	Yes, for milestones after the base year	Exogenous	Using FortisBC sales data, REUS data on the percentage of DHW supplied by gas, and assumptions (largely from the 2010 CPR) about how much energy is used by the different gas end uses, the base year values for gas EUI are adjusted to calibrate modeled gas consumption to match sales to the dwellings. Values in future milestones vary depending on assumptions about tertiary load and efficiency.
			2006 or later SFD, mainly gas heat	15,953	12,674	MJ			
			Pre-2006 SFD, mainly non-gas heat	19,529	12,674	MJ			
			2006 or later SFD, mainly non-gas heat	15,953	12,674	MJ			
4	Assumption	Saturation - what percentage of dwellings have this end use in any form	Pre-2006 SFD, mainly gas heat	100%	100%	%	No	Exogenous	All dwellings are assumed to have DHW. Saturations are not 100% for some of the other end uses. In general, we have not varied saturation by scenario.
			2006 or later SFD, mainly gas heat	100%	100%	%			
			Pre-2006 SFD, mainly non-gas heat	100%	100%	%			
			2006 or later SFD, mainly non-gas heat	100%	100%	%			
5	Variable	Gas Share - the percentage of energy used by the end use that is supplied by gas	Pre-2006 SFD, mainly gas heat	92%	92%	%	Yes, for milestones after the base year	Exogenous	The base year values are from the REUS. Base year values are the same for all scenarios. Gas share varies in future milestones in the different scenarios.
			2006 or later SFD, mainly gas heat	76%	76%	%			
			Pre-2006 SFD, mainly non-gas heat	69%	69%	%			
			2006 or later SFD, mainly non-gas heat	57%	57%	%			
6	Variable	Gas Use Per Unit - consumption of gas for DHW per dwelling, accounting for gas share	Pre-2006 SFD, mainly gas heat	18,025	11,698	MJ	Yes, for milestones after the base year	Endogenous - calculated from EUI * saturation * gas share	
			2006 or later SFD, mainly gas heat	12,193	9,687	MJ			
			Pre-2006 SFD, mainly non-gas heat	13,537	8,785	MJ			
			2006 or later SFD, mainly non-gas heat	9,157	7,275	MJ			
7	Variable	Number of units - dwellings in each category	Pre-1976 SFD, mainly gas heat	193,366	193,366	dwellings	Yes, for milestones after the base year	Exogenous	From FortisBC account totals, but divided up using REUS data. Existing dwellings, dwellings that undergo a major renovation, and new dwellings are tracked separately and can have different numbers for the above variables and assumptions, so the total consumption is not a simple multiple of Ref #6 times Ref #7. Total number of dwellings does not vary by scenario, but the split between dwellings that are primarily heated by gas and dwellings that use a different space heating fuel varies by scenario in the future milestone years.
			1976-2005 SFD, mainly gas heat	212,743	212,743	dwellings			
			2006 or later SFD, mainly gas heat	24,242	53,440	dwellings			
			Pre-1976 SFD, mainly non-gas heat	12,562	12,562	dwellings			
			1976-2005 SFD, mainly non-gas heat	13,820	13,820	dwellings			
			2006 or later SFD, mainly non-gas heat	5,967	13,153	dwellings			
8	Variable	Gas Reference Case - total consumption of gas for DHW in each category of dwellings	Pre-1976 SFD, mainly gas heat	3,485,456	2,262,061	GJ	Yes, for milestones after the base year	Endogenous	Calculated from multiplying the number of houses in each category (separating existing, renovated, and new) by the corresponding consumption for the end use. Base year consumption for all end uses for all dwelling types in a region must match the FortisBC data on gas sales to the residential rate class in that region.
			1976-2005 SFD, mainly gas heat	3,834,743	2,488,748	GJ			
			2006 or later SFD, mainly gas heat	295,584	463,559	GJ			
			Pre-1976 SFD, mainly non-gas heat	170,040	110,356	GJ			
			1976-2005 SFD, mainly non-gas heat	187,080	121,415	GJ			
			2006 or later SFD, mainly non-gas heat	54,634	85,681	GJ			

1

The table above is intended to illustrate the level of detail in the model. To list all the assumptions and variables in the reference case comprehensively, the table above would need to expand as follows:

- More of the details underlying the tertiary load and average efficiency estimates would be provided, such as the occupancy assumptions, percentage of high efficiency clothes washers, percentage of tankless and condensing DHW units, etc. Development of these estimates drew heavily on the REUS reports provided by FortisBC, but also used ICF Marbek's internal database of end use consumption information, incorporating data compiled from previous conservation potential studies.
- The table above would be replicated for 11 other end uses, each one treated somewhat differently
- The four milestones between 2011 and 2033 would be added (as additional columns)
- The existing, renovated, and new dwellings would be shown separately
- The table above shows information on only six dwelling types, condensed to four for some of the variables. There are 14 dwelling types in residential altogether.
- There are four other fuels in the residential model: electricity, other fossil, renewables, and district energy.
- There are five other regions.
- The comprehensive list of assumptions for the residential sector would therefore include four additional columns (for the other milestones) and would be 12 (end uses) x 3 (exist/reno/new) x 14/6 (dwelling types) x 5 (fuels) x 6 (regions) = approximately 2,500 pages long.
- The commercial and industrial models together would require approximately 1,900 pages of similar tables to the one above, but would also require a separate set of tables to describe how the consumption and numbers of accounts are divided up among the nearly 30 different rate classes that are tracked separately in the commercial and industrial sectors.

The assumptions above address only the LTRP portion of the model. The EEC portion of the model includes assumptions about the many energy efficiency measures that can be applied as part of energy efficiency programs, including their performance improvement, costs, current penetration, expected penetration under different program scenarios, and so forth. The EEC portion of the model relies heavily on the measure assumptions developed under the 2010 CPR study. The deliverables of that study provided detailed information on the assumptions used.

19.4.1 Of the above variables, which are adjusted endogenously and which are adjusted exogenously?

Response:

Please refer to the response to BCUC IR 1.19.4.

19.5 Please explain why 2011 was used as the base year.

Response:

The development of the End Use Forecast by ICF/Marbek started in 2012. At that time the most recent complete annual consumption dataset the FEU could provide was for 2011.

19.5.1 Could FEU have successfully used 2013 or 2012 as the base year? If not, why not?

Response:

No, the FEU could not have used 2012 or 2013 as the base year at the time the LTRP forecast was developed. The development of the End Use Forecast by ICF/Marbek started in 2012 and at that time the only complete base year dataset we could provide them with was for the most recent complete year which was 2011. A complete year of actual data is required for the base year. The FEU do not believe that using 2012 or 2013 data would result in a forecast that was more predictive than the version based on 2011 data.

19.6 Please discuss how easily and quickly the base year information can be updated to establish a new base year.

Response:

From the FEU's perspective the updating of the base year involves extracting premise level consumption data for the last complete year. The data is then aggregated to the annual level and delivered electronically to ICF/Marbek. This process takes two days for one person to complete.

ICF/Marbek would then receive the data from the FEU and begin the process of updating the model. Once the base year is updated the rest of the model and scenarios should also be updated to make sure results are consistent from one milestone year to the next and between scenarios. The complete work package for ICF/Marbek would take approximately 8 weeks to complete at an estimated cost range of $75,000 to $100,000.

Once the model runs are complete the results are sent in multiple files back to the FEU where they are loaded into the corporate database. This process and associated quality assurance and testing steps takes five days for two people.

19.7 Was the calibration done solely to actual normalized sales in a single base year (2011)? If so, how can ICF Marbek or FEU ensure that the model is structured such that the forecast results are reliable? Did ICF Marbek or FEU test the model to verify its predictive accuracy by, for example, taking a historic year as the base and using the model to predict the 2011 actual annual demand?

Response:

Yes, the calibration was done solely to the actual normalized sales in 2011. Rather than attempting to calibrate a single forecast, the approach has been to produce a range of forecasts under five different sets of scenario assumptions.

ICF Marbek did not test the model in the way suggested in this request. Testing the model with a historic base year would require making a second copy of the entire model and changing the starting year. The current budget estimate for running the full model for a different base year is in the range of $75,000 to $100,000.

Whether a model starting with a historic base year would accurately predict the 2011 actual demand would depend on the scenario assumptions used to run the model. It would be difficult to select a set of assumptions that would reflect the mindset of a team that would have been developing the model at the time of the historic base year. If, on the other hand, the results were bracketed in the same way that the FEU are doing with the current model, then certainly the actual results for 2011 would fall somewhere in the range of different scenario results. It's not

clear what value would be gained from this process. The FEU would still want to understand potential risks and opportunities by developing several scenarios based on a currently relevant range of assumptions.

The FEU's current plan is to continue the development of the model and renew it with new base years on a regular basis. The predictions for the first milestone year, 2016, can be compared from year to year to assess how well the model is performing. This feedback will facilitate continued improvements.

19.7.1 If not, please describe how the calibration of the model was carried out.

Response:

Please refer to the response to BCUC IR 1.19.7.

19.8 Based on the degree of rigor of the calibration of the end-use model as discussed above, how confident is FEU that the end-use model by itself will provide robust results over time and under a variety of economic conditions?

Response:

The FEU are very confident that the end use model will provide robust results over time under a variety of economic conditions. The inputs used by the model allow for a range of outcomes over time across the different scenarios out to 2033.

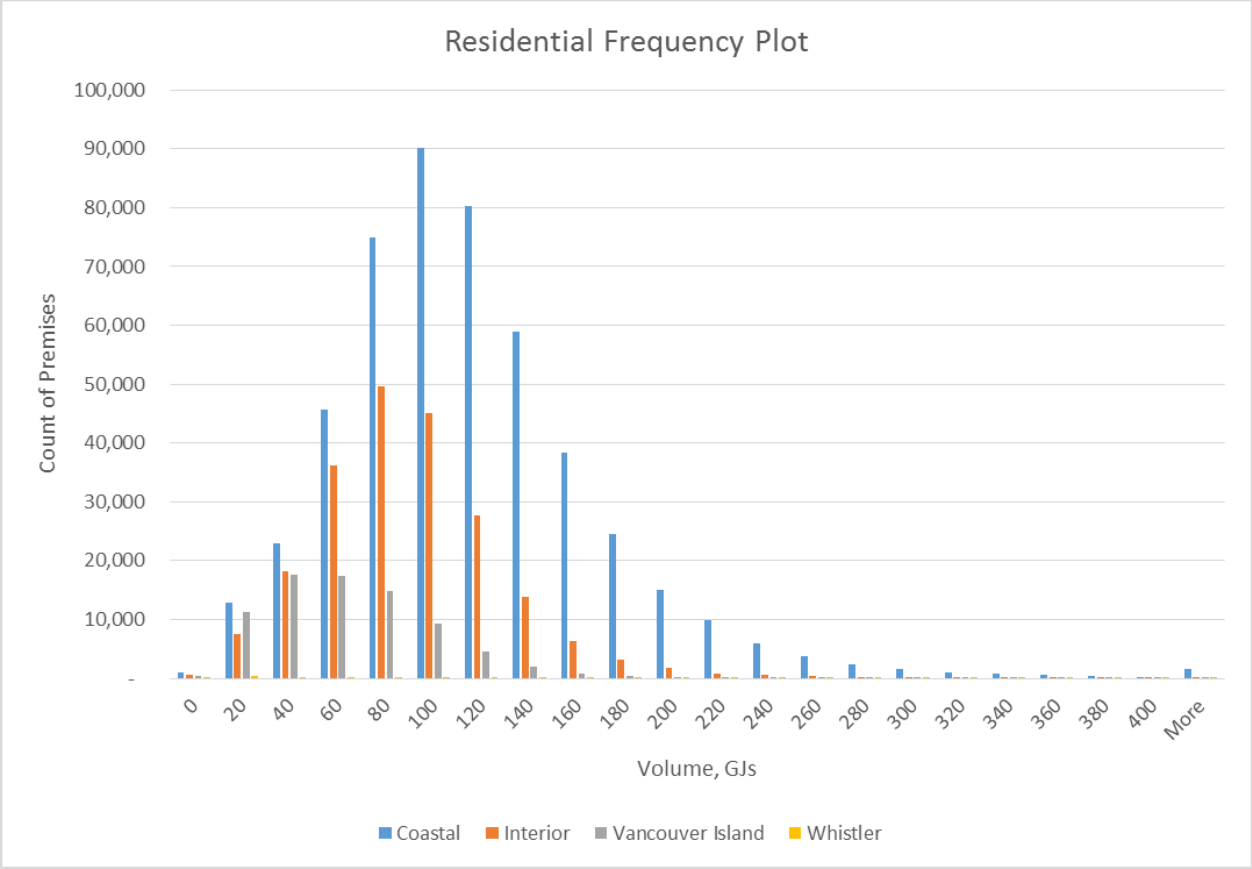
Please also refer to the response to BCUC IR 1.19.7.

19.9 For the base year, please provide UPC Frequency Distribution charts showing the frequency and the annual demand in gigajoules (GJ) for each service region and also broken down into the major customer class (Residential, Commercial and Industrial). Include a discussion with regards to the annual UPC based on

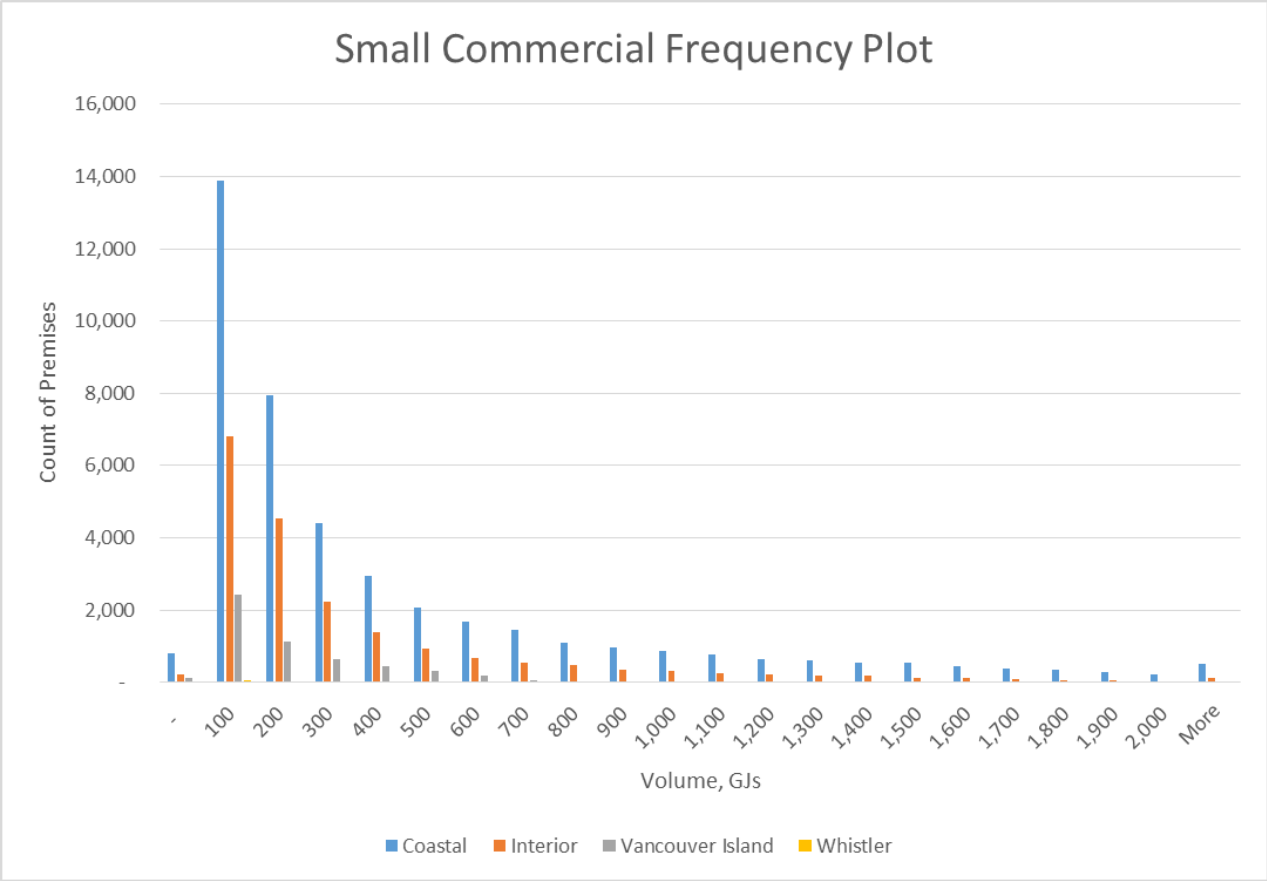
the differences, if any, noticed in the frequency distribution charts for the different service regions.

Response:

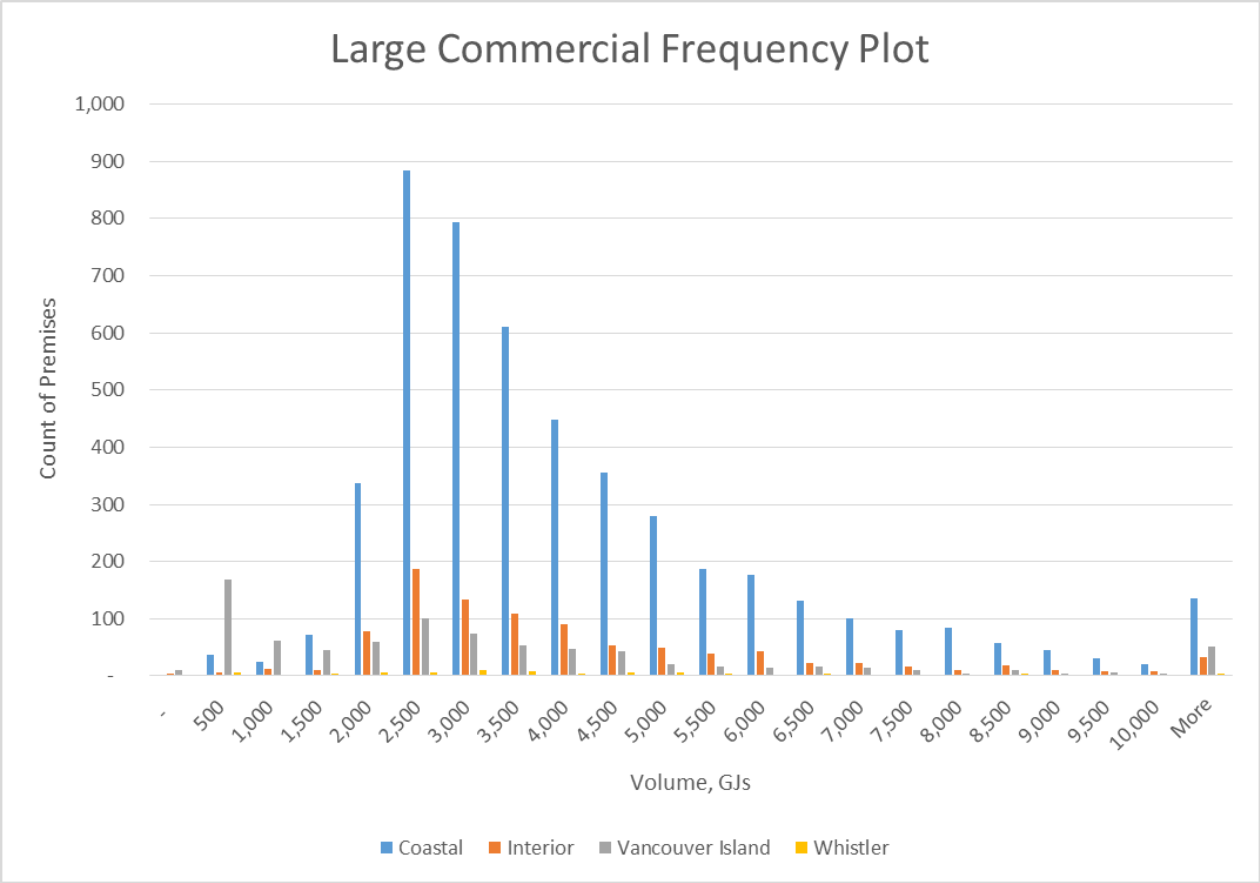
Frequency plots are provided below for residential, small commercial, large commercial and industrial. Plots were created for Coastal, Interior, Vancouver Island and Whistler. Only customers with 365 days of consumption in 2011 were considered. Considering customers with less than 365 days of consumption would skew the frequency plots to the left as partial consumption customers would be added to the smaller bins.



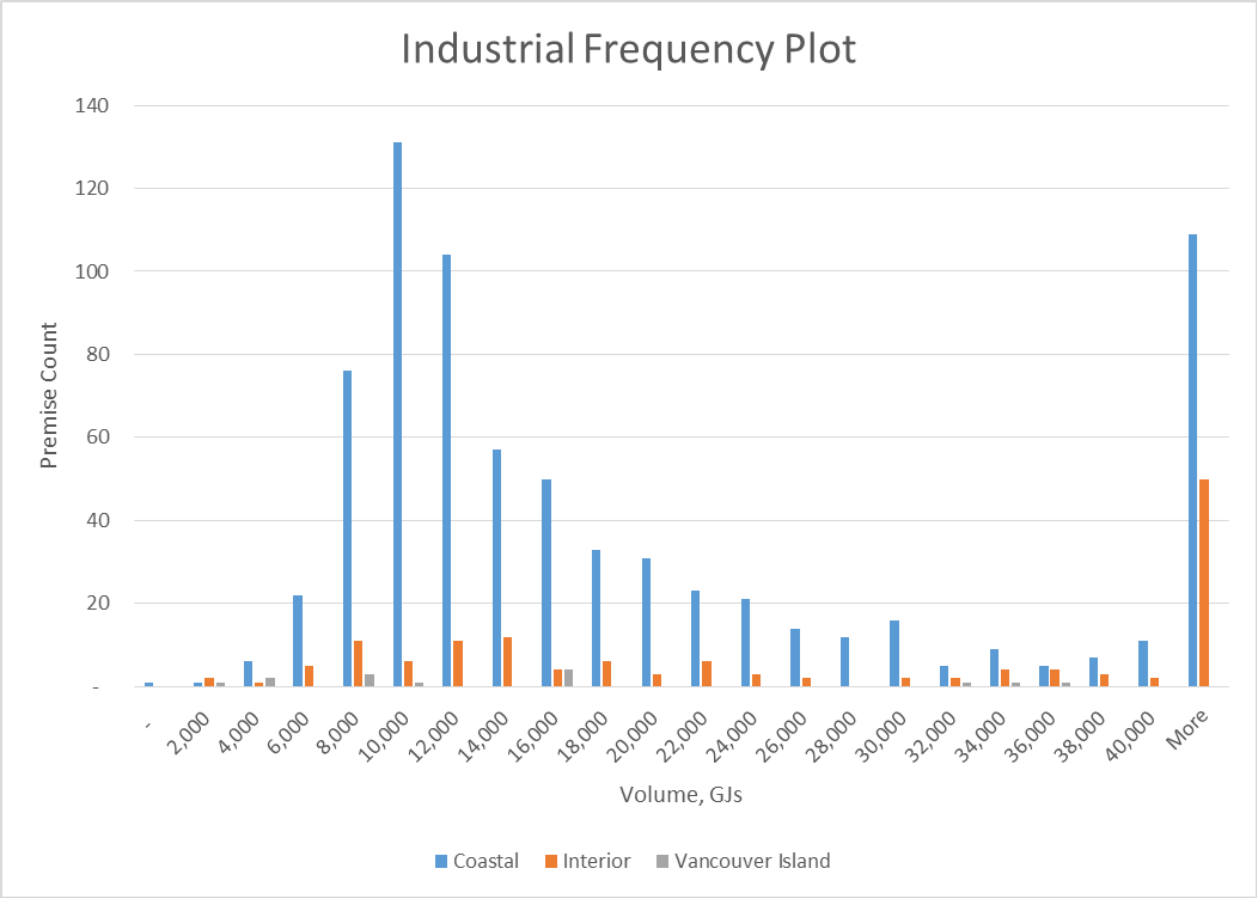
The residential plot shows that the modal class for Coastal customers is 100 GJs, whereas the modal class for the Interior is slightly less at 80 GJs. The modal class for Vancouver Island is 40 GJs. The modal class for Whistler is only 20 GJs per year. This could be attributed to the seasonal nature of many Whistler premises and the immaturity of that utility.



The small commercial plot shows that the modal class for Coastal, Interior and Vancouver Island and Whistler is 100 GJs. On Vancouver Island rate schedules LCS-1, SCS-1 and SCS-2 were considered small commercial. In Whistler rate schedules SGS-1C and SGS-2C were considered small commercial.



The large commercial plot shows that the modal class for both the Coastal and Interior regions is 2,500 GJs. Other than a large class at 500 GJs the second largest group on Vancouver Island is also 2,500 GJs. In this response large commercial refers to rate schedules 3 and 23 for FEI customers. On Vancouver Island rate schedules LCS-2 and LCS-3 were used for this plot.

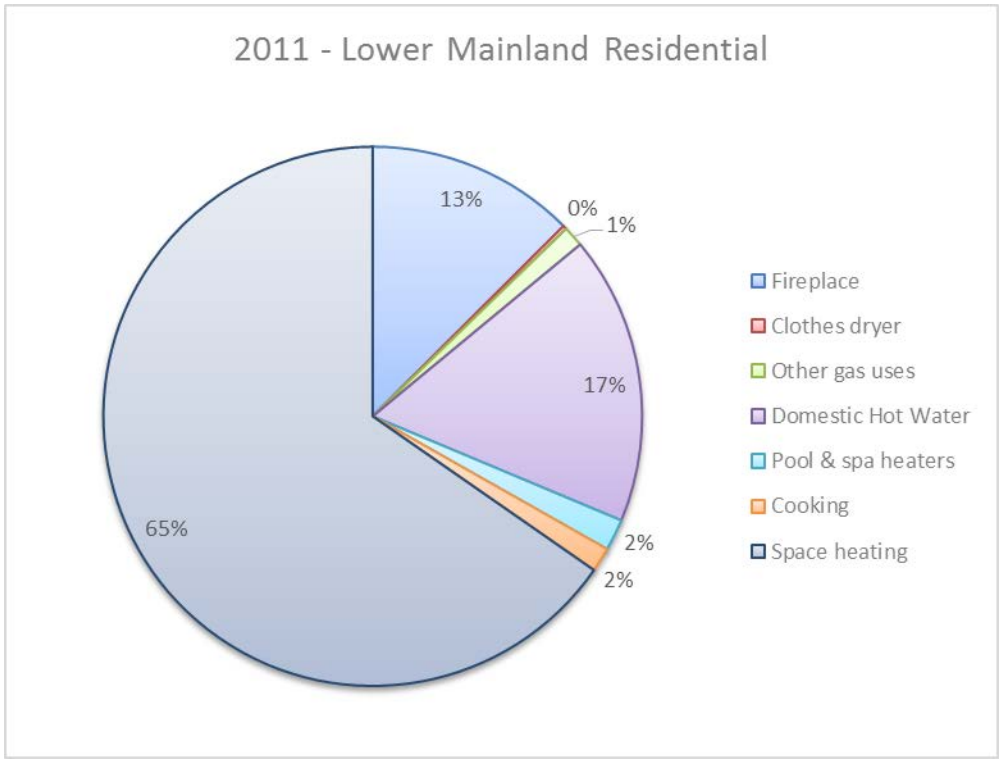


Industrial customers are difficult to categorize in a frequency plot due to the wide range in annual UPC values. This is clearly shown in the Industrial Frequency plot above where the second highest class for Coastal and the highest class for Interior are both in excess of 40,000 GJs per year.

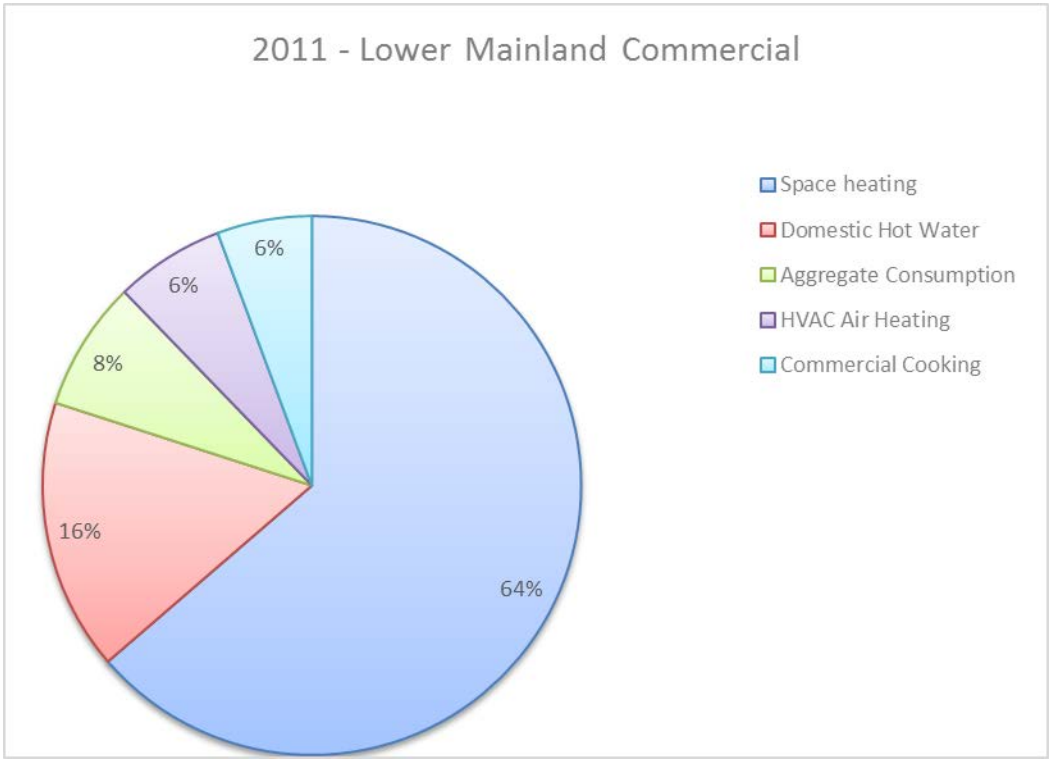
19.10 For the base year, please provide pie charts for <u>each service region</u> illustrating the breakdown of annual demand (GJ) into: (i) the seven residential end uses mentioned on page 47 of the Application and (ii) the five commercial uses mentioned on page 47 of the Application.

Response:

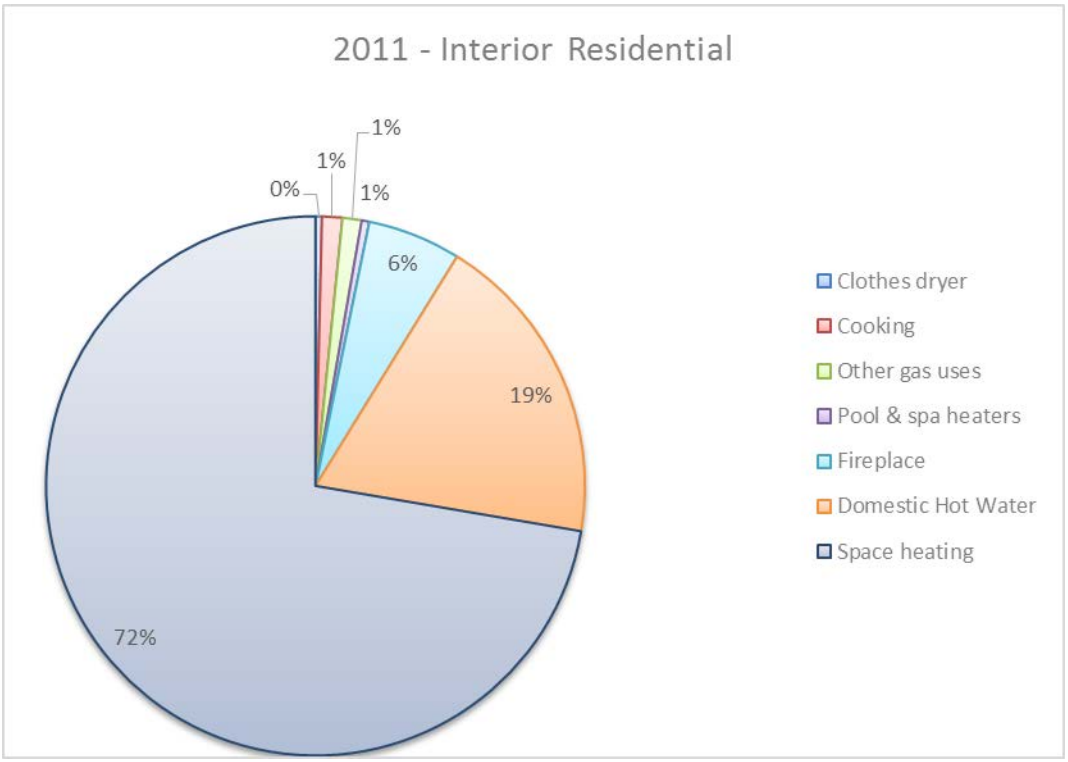
The requested charts are included below.


2011 - Lower Mainland Residential
13%
0%
1%
17%
2%
2%
65%
Fireplace
Clothes dryer
Other gas uses
Domestic Hot Water
Pool & spa heaters
Cooking
Space heating

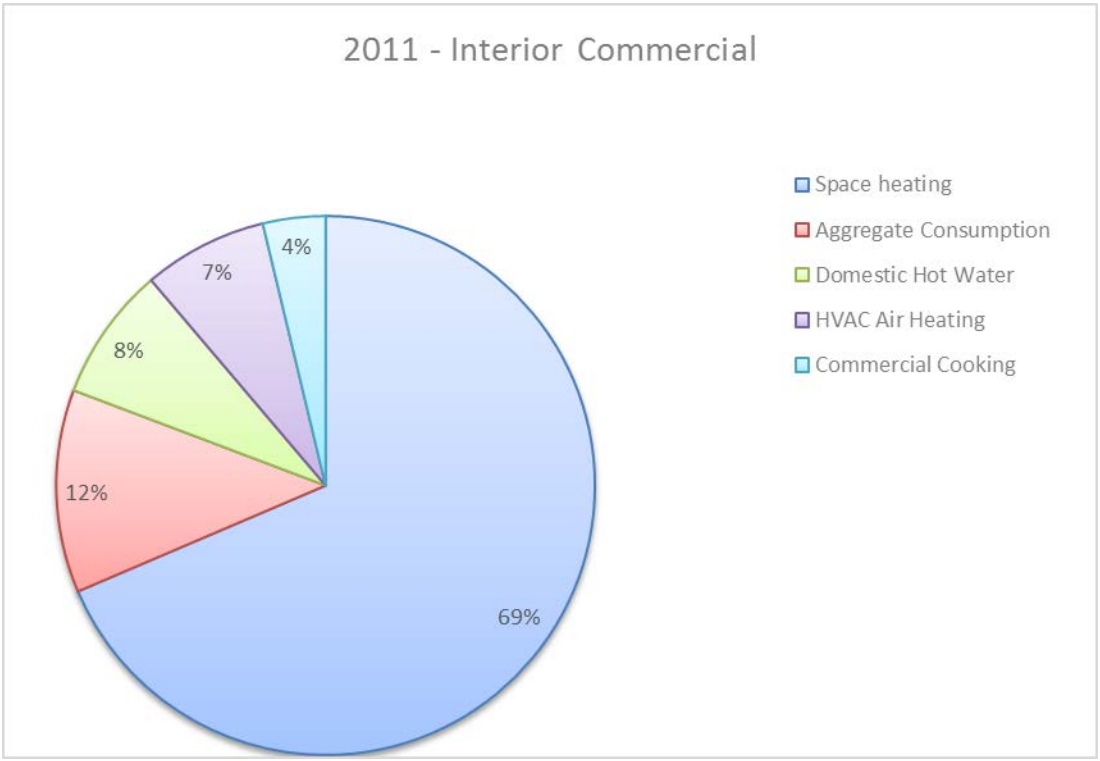
1


2011 - Lower Mainland Commercial
6%
6%
8%
16%
64%
Space heating
Domestic Hot Water
Aggregate Consumption
HVAC Air Heating
Commercial Cooking

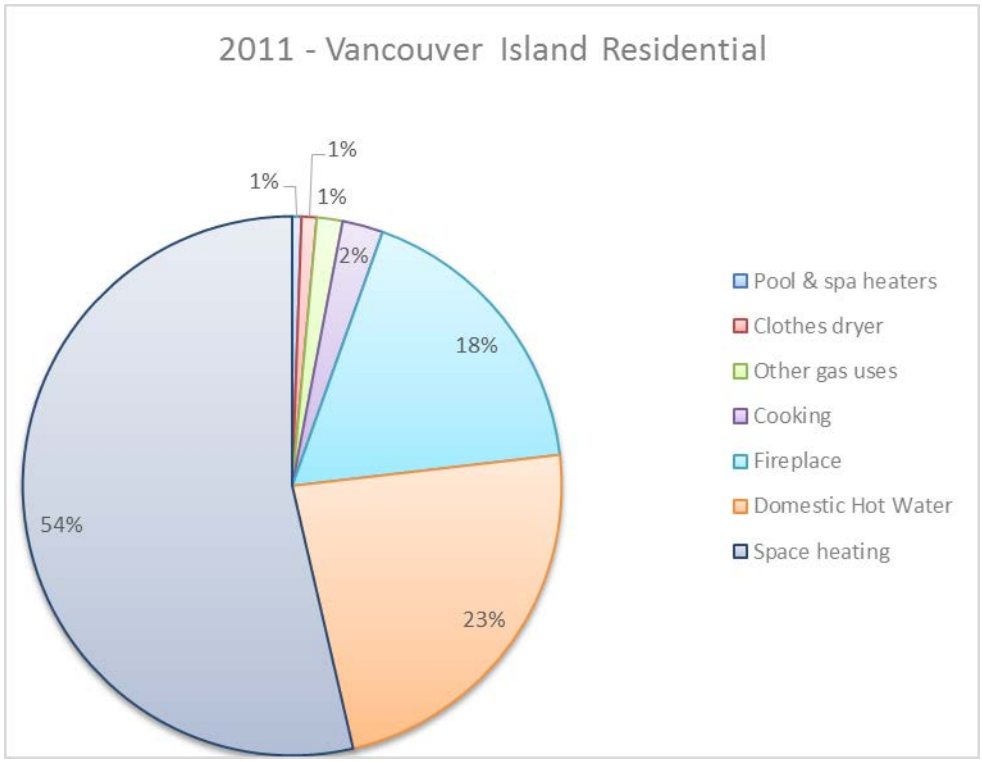
2


2011 - Interior Residential
1%
1%
0%
1%
6%
19%
72%
Clothes dryer
Cooking
Other gas uses
Pool & spa heaters
Fireplace
Domestic Hot Water
Space heating

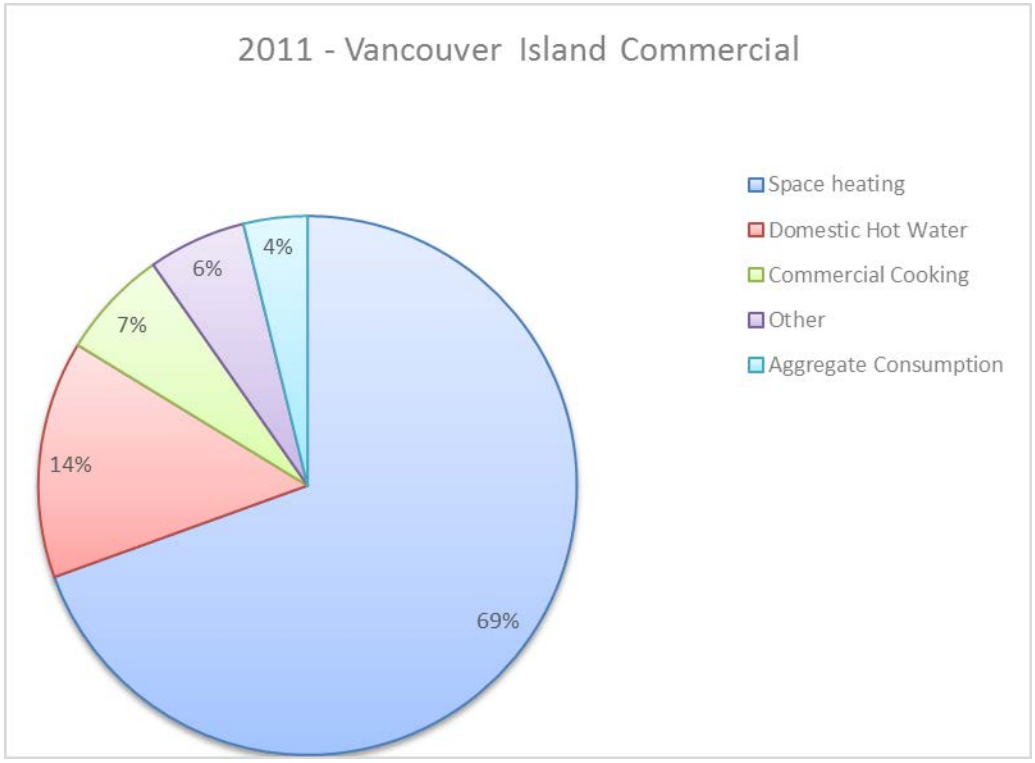
1


2011 - Interior Commercial
4%
7%
8%
12%
69%
Space heating
Aggregate Consumption
Domestic Hot Water
HVAC Air Heating
Commercial Cooking

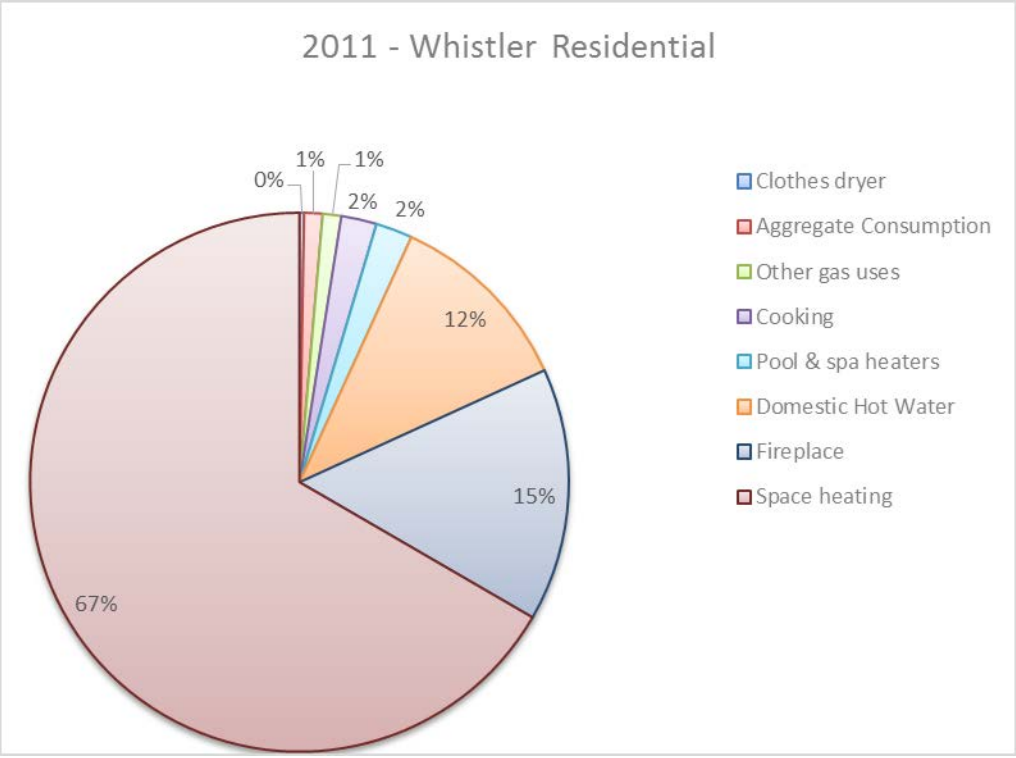
2


2011 - Vancouver Island Residential
1%
1%
1%
2%
18%
54%
23%
Pool & spa heaters
Clothes dryer
Other gas uses
Cooking
Fireplace
Domestic Hot Water
Space heating

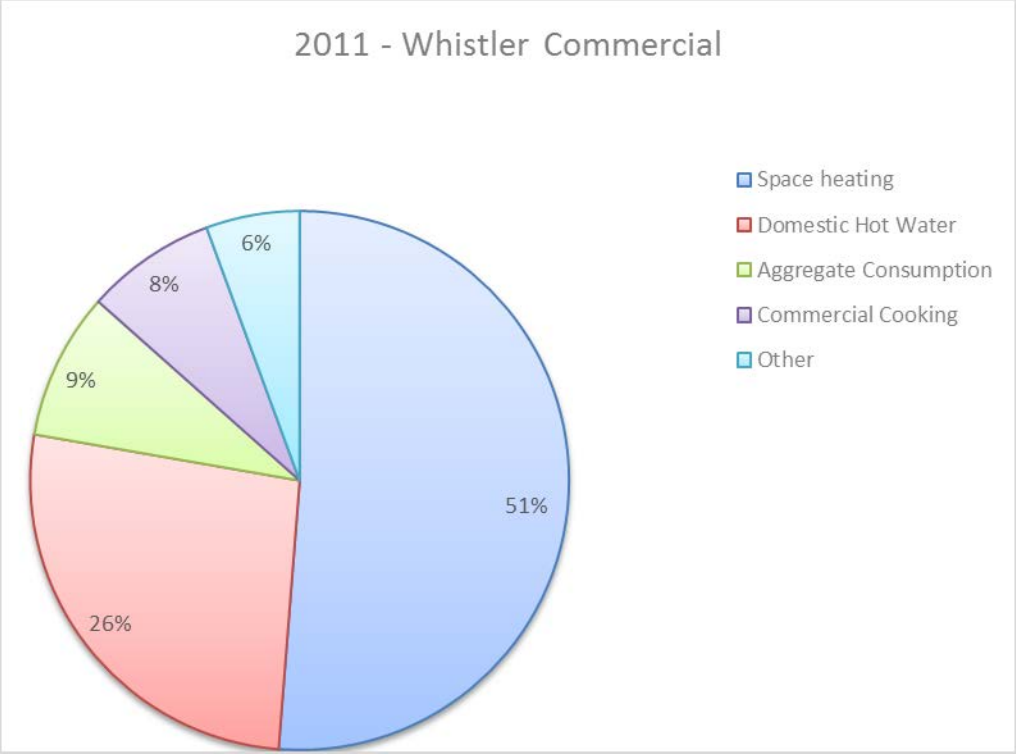
1


2011 - Vancouver Island Commercial
4%
6%
7%
14%
69%
Space heating
Domestic Hot Water
Commercial Cooking
Other
Aggregate Consumption

2


2011 - Whistler Residential
0%
1%
1%
2%
2%
12%
15%
67%
Clothes dryer
Aggregate Consumption
Other gas uses
Cooking
Pool & spa heaters
Domestic Hot Water
Fireplace
Space heating

1


2011 - Whistler Commercial
6%
8%
9%
51%
26%
Space heating
Domestic Hot Water
Aggregate Consumption
Commercial Cooking
Other

2
3

19.11 Please provide a copy of the end-use survey for each of the service regions and discuss how FEU encouraged participation in the survey.

Response:

Several steps were taken to encourage participation in the 2012 Residential End Use Study. The covering letter laid out the reasons for the survey and how the information will be used, and appealed to both the customers own interests (the design of energy efficiency programs) and the greater public interest (protect the environment by lowering greenhouse gas emissions). In addition all participants were entered into a draw for one of four $500 gift certificates. A card was sent out ten days after the initial survey mail out to remind people to participate.

Please refer to Attachment 19.11 for a copy of the REUS survey.

19.12 For each of the service regions please indicate the number of surveys that were targeted and the number of survey responses.

Response:

Region / Business Unit	Sample Population	Surveys Mailed	Completed Surveys	Response Rate (%)	Surveys Completed Online (%)
Lower Mainland (LM)	528,192	6,250	793	12.7	45.0
Interior (Inland and Columbia) (INT)	231,522	12,171*	1,707	14.0	41.7
Vancouver Island / Sunshine Coast (VI)	92,067	3,704	752	20.3	36.7
Whistler (W)	2,271	1,650	85	5.2	41.7
Fort Nelson (FN)	1,947	1,294	107	8.3	41.0
Total (FEI)	**855,999**	**25,069**	**3,444**	**13.7**	**41.3**

Survey response rates varied from over one-in-five (20.3%) in FEVI to a low of one-in-twenty (5.2%) for Whistler. The low response rate for Whistler is primarily due to the nature of the customer base with a high percentage of out-of-province residents and the placement of homes in rental pools. Customers are difficult to reach and there is little incentive for them to participate in the survey. Overall the response rate for the 2012 REUS (13.7%) was lower than the rate for the 2008 REUS (20%). The likely reasons are:

- The survey was sent later in the year (November versus October in 2008) which meant that the survey was delivered to customers in the pre-Christmas period.

- The survey was lengthy and fairly complex, especially for the combined gas and electric survey which was 24 pages.
- Changing demographics in the Lower Mainland with fewer native-English speaking customers.

19.12.1 Please discuss the accuracy and identify the confidence interval associated with the survey results for each service region.

Response:

The margin of error (accuracy level) for 2012 REUS questions varies by region and the degree of consensus. The table below summarizes accuracy levels at the 95% confidence level for a typical range of "yes-no" type questions for each of the five regions and FEU total, and also separately for FEI total. Comparable margins of error at the FEU level for the 2008 REUS survey are provided, as are margins of error for FEI totals (Lower Mainland, Interior and Fort Nelson) for 2012, 2008 and 2002. The degree of accuracy of the overall FEU results and those from the Interior, Lower Mainland and Vancouver Island is high. However, the degree of accuracy of the results for the smaller operating areas (Whistler and Fort Nelson) is somewhat compromised by the small sample size.

Accuracy Levels for Proportional Responses by Region (%)

Percent Plus or Minus at the 95% Confidence Level

Accuracy / Proportional Response	LM +/-	INT +/-	VI +/-	W +/-	FN +/-	FEU 2012 +/-	FEU 2008 +/-	FEI 2012 +/-	FEI 2008 +/-	FEI 2002 +/-
50%	3.5	3.6	2.4	10.6	9.6	2.4	3.2	2.6	3.5	2.4
40% or 60%	3.4	3.5	2.3	10.4	9.4	2.3	3.2	2.6	3.4	2.4
30% or 70%	3.2	3.3	2.2	9.7	8.8	2.2	3.0	2.4	3.2	2.2
20% or 80%	2.8	2.9	1.9	8.5	7.7	1.9	2.6	2.1	2.8	2.0
10% or 90%	2.1	2.1	1.4	6.4	5.8	1.4	1.9	1.6	2.1	1.5
Number of respondents (unweighted)	**793**	**1707**	**752**	**85**	**104**	**3441**	**2221**	**2604**	**1446**	**1610**

19.13 In the absence of a recent Conservation Potential Review, please provide an estimate of the breakdown of the costs associated with acquiring (including the end-use surveys), managing and analyzing all the data required to produce demand forecasts using the end-use methodology, and compare those with the costs associated with producing the annual demand forecasts using the traditional methodology.

Response:

The FEU conduct a range of customer and market research to meet a range of business needs, much of which helps to inform the LTRP and the long term demand forecast. Since the FEU do not envision a time when customer end-use data will not be vital information throughout the Company, these costs will be incurred irrespective of the end use annual demand methodology. One of the key benefits of the end use annual demand methodology is that it leverages information and modelling that is already available to the FEU making both the end use modelling and those studies that were already completed more cost effective, while solving the problem that the traditional annual demand methodology does not provide a means to address the changing nature of end use energy consumption patterns.

Absent the CPR, two key studies that are vital to the end-use methodology are the Residential End Use Study (REUS) and the Commercial End Use Study (CEUS). The most recent costs for these two studies provide insight into the costs of acquiring the background information that goes into the end use annual demand forecasting study. The cost of the 2012 REUS was $260 thousand. The 2010 CEUS cost $134 thousand These costs would still be incurred if the traditional methodology continued to be used.

19.14 Was the repurposing of the CPR modelling software by ICF Marbek necessary to produce long term demand forecasts using the end-use methodology?

Response:

Yes, the repurposing of the CPR modelling software by ICF Marbek was necessary to produce long term demand forecasts using the end use methodology.

The FEU considered other options, among which the repurposing of the CPR model by ICF Marbek was both the most efficient and cost effective. A further benefit of using the repurposed ICF Marbek CPR modelling was the further extension of the model for use in the long range EEC analysis included in the 2014 LTRP. The FEU consider the additional EEC analysis to have been cost effective as well.

19.14.1 Please provide the costs for this work carried out by ICF Marbek.

Response:

The cost to repurpose the CPR model and run the reference case, 4 alternative future scenario demand forecasts, transfer the results to the FEU and participate in QA/QC activities was $150,000. This does not include the additional costs of further extending the ICF Marbek model to examine alternative long range EEC scenarios (a further $80,000).

19.14.2 Will this process have to be repeated each time new base data is gathered to establish a base year data set for the end-use methodology? If not, please explain.

Response:

Confirmed. Each time a new End Use Forecast is prepared the FEU will need to provide ICF/Marbek with the most recent full year of actual consumption data.

ICF/Marbek will then use the actual data to create the base year, assuming the end use patterns in the actual data continue for the duration of the forecast.

19.14.3 Please elaborate on whether the traditional methodology could have been used to produce demand forecasts without repurposing the CPR modelling software?

Response:

Yes, the Traditional Method could be used to produce a demand forecast. The Traditional Method was used to prepare a demand forecast for the purpose of checking the validity of the End Use Forecasts. The Traditional Forecast does not require or make use of any of the data found in the CPR study.

Note however that the Traditional methodology cannot be used to produce an End Use Forecast.

19.15 Describe the advantages and disadvantages (including costs) related to using the existing Conservation Potential Review relative to developing an end-use model solely for the purpose of load forecasting.

Response:

Option	Advantages	Disadvantages
In House Development	• FEU would own the model • Would be able to re-purpose the results from the CPR, but not the CPR model itself, which FEU does not own. • FEU would be able to precisely specify the model inputs and outputs to work efficiently with our existing data sources.	• Highest cost. Development would be carried out by an IT contractor in close consultation with FEU staff. • Additional staff would be required to maintain and operate the model • Development would take considerable time
Repurposed CPR Model	• Lowest cost. The one-time cost to repurpose the CPR model, load the FEU actual consumption data and run the model was $150,000 • Future model runs will be significantly less costly. • Makes use of data collected in a prior study. • Leverages considerable expertise in the end use area from ICF/Marbek. • Makes use of ICF/Marbek data and experience gathered for other clients.	• FEU does not own the model

Development of a project scope document and solicitation of proposals from third party contractors would be necessary to accurately determine the cost to develop a proprietary long term model. This cannot be completed in the time allocated for response and therefore costs have not been included in the above analysis. In addition to the development cost the FEU would also need to allocate funds for ongoing maintenance, hardware and software support, etc. The model, once developed would only be used at most every other year.

20.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.3.4, pp. 47–51

Alternative Future Scenarios

FEU states on page 47 of the Application that four scenarios were developed based on critical uncertainties representing those future conditions that stakeholders felt could have the biggest impact on the FEU's business.

On page 48 of the Application, FEU states:

> "The modeling process involved turning each of these assumptions into concrete changes to the input numbers for buildings in the three sectors. For example, in response to higher or lower gas prices, adjustments were made to the number of new buildings using natural gas for specific end-uses, or to the number of existing buildings whose owners might opt to change fuels when equipment needs replacement. In response to higher or lower economic growth, adjustments were made to the heat demands of industry" (Exhibit B-1).

20.1 How, if at all, is the abundance of natural gas supplies linked to the forecast natural gas price?

Response:

The FEU note that the referenced paragraph is from page 51 of the Application, not page 48 as indicated in the preamble.

The abundance of natural gas supplies is intrinsically linked to price of natural gas and thus the natural gas price forecast. The price of natural gas is usually inversely related to the abundance of supply. The forecast of natural gas prices was conducted by the FEU exogenously from the model and provided to the external consultant, ICF Marbek. Future scenarios that included abundant gas supplies utilized a lower natural gas price forecast than those that included constrained natural gas supplies as explained in Appendix B-3 of Exhibit B-1.

20.1.1 How, if at all, are efficiency improvements and the changes in saturation and gas share adjusted to reflect possible changes in natural gas prices (either in isolation or relative to electricity?

Response:

Efficiency improvements and gas share are adjusted to reflect changes in natural gas prices. For example the far right column for Scenario B in Table 3-1: Alternative Future Scenario Descriptions states "With a moderate to high gas 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 is one of many examples where adjustments are made to reflect gas price changes.

In an abundant natural gas environment one could expect a higher proportion of new buildings utilizing natural gas over alternative energy sources, fuel switching occurring when equipment reaches the end of its life, and an uptake in demand for natural gas vehicles. Furthermore the model makes changes to fuel shares which are linked to price elasticity. These changes are described in some detail in the tables provided in the response to BCUC IR 1.38.1.

20.1.2 Please provide a table(s) showing the change in efficiency improvements, saturation and gas shares.

Response:

Please refer to the tables provided in the response to BCUC IR 1.38.1. The requested information can be found in the rows titled "Renewable Thermal and Energy Efficiency".

20.1.3 Which links in the model, if any, between natural gas supplies and gas price, and between natural gas prices and efficiency improvements, saturation and gas share are made endogenously and which are made exogenously?

Response:

The link between natural gas supplies and gas prices are entirely exogenous to the model. The changes in efficiency, saturation, and gas share were made manually and input into the input worksheets that feed the model. There was an iterative feedback process of making adjustments to these input assumptions and examining the resulting consumption changes to assess how it compared to expected price elasticity, but this was a manual process. The input

values themselves could therefore best be described as exogenous to the model. Appendix B-3 explains how these relationships were turned into model inputs.

20.2 How is the base data input into the model?

Response:

Scenario Explanation Documents were developed for each scenario and sector, to describe the assumptions involved in each scenario and the specific actions planned to implement these assumptions. Feeder workbooks are designed for rapid entry of changes (often as a percentage of the original reference value), so that global adjustments to an entire end use can be made quickly, but separate adjustments can also quickly be made if changes need to vary by building type, region, or vintage (new versus existing). These feeder workbooks supply the modified input assumptions for efficiency or gas share into a complete parallel set of model files for each scenario, at the same level of granularity as the original reference case.

As an example, if the client/consultant discussion concluded that the price change for Scenario X would result in a 5% decrease in commercial gas consumption to 2031, we would make manual adjustments to specific values in the feeder workbooks for space heating and DHW to the assumed percentage of fuel switching that would occur as equipment was replaced as well as the gas share in new construction. The feeder workbooks turn these values into gas share percentages by building type, region, and milestone year. The workbooks for the Scenario X part of the commercial model are then opened and updated, and then the new consumption results are harvested and collected in the large dataset from which tables and charts can be made. The resulting consumption numbers are compared to the original reference case. If the decrease of 5% has not been achieved, the input values are adjusted in the feeder workbooks (within limits of what is reasonable in the marketplace) and the results run through the model again.

20.2.1 How easily can the end-use model be updated or modified to run alternative scenarios such as a new industrial load, LNG load or higher utilization by power generating plants?

Response:

For a single, large, potential new customer, annual demand load assumptions can easily be added to the annual demand after the end use modelling is complete, as these are very large, distinct loads that will not behave in the same way through the scenarios as those customers included in the end use modelling. Figure 3-16, page 62 of Exhibit B-1 provides an example of this approach to potential new large industrial loads.

For smaller new industrial and commercial loads that would become part of the overall trend for these sectors, running additional scenarios is not particularly difficult, but would take a substantial amount of staff and consulting time. The end use model was built in a modular way. Every section can be changed independently. Parts can be re-figured in small or large blocks. The cost of creating a complete new scenario to add to the five already established has been estimated by the external consultant at approximately $26,000. It is somewhat less costly to make a change to one or two variables in an existing scenario and run it through all three sectors. A change that affects only one sector takes approximately one-third as much time as a comprehensive change. There are some economies from doing several changes at once.

21.0 Reference: ENERGY DEMAND FORECASTING

Decision for Commission Order G-14-11 regarding TGI 2010 LTRP, pp. 23–25;

Exhibit B-1, Application, Section 3.3.1, Figure 3-4, p. 44; Section 3.3.5, pp. 51–55; Section 3.3.6, pp. 55–56; TGI 2010 LTRP, Exhibit B-1, Appendix B-2

Comparing the Traditional and End-Use Methodologies

In the Decision for the TGI 2010 LTRP, the Commission states:

> "…Terasen is directed to include the following in future resource plans.
>
> - A description of the new end-use forecasting methodology, how it compares with Terasen's traditional demand forecasting approach, and reconciliation of the results of the two different approaches…" (Decision, TGI 2010 LTRP, p. 25)

Section 3.3.6 on pages 55 and 56 of the Application highlights the difference in reference case forecast results between the two methodologies.

21.1 Please provide an analysis explaining why the traditional methodology reference case forecast is different from the end-use methodology reference forecast (Exhibit B-1, Figure 3-12, p. 56).

Response:

The end use reference case scenario was based on the reference case used in the 2010 CPR, but updated to start with a newer base year. The CPR reference case was created based on the best information available to the consultants, subject to consultation and review by the client, about how end use energy consumption would evolve over the 20-year study period. Energy efficiency is not assumed to remain static, but instead evolves according to best estimates of natural conservation.

For example:

- People replace clothes washers and dishwashers with new ones. They cannot replace them with appliances that use the same amount of hot water as the old ones, so the demand for DHW decreases.
- People's DHW tanks wear out and they buy new ones that are more efficient. Again people cannot replace a worn out tank with one of the same efficiency. As a result the end-use methodology reference case shows a decline in DHW UPC.

- People build new houses, but they only build houses that look like the post-2006 ones, which tend to shift average efficiencies upwards.

The traditional model is based on recent historic trends and then projects those trends forward. No further efficiencies or reductions in use rates are incorporated into the future years of the traditional forecast. As a result the FEU expect the traditional forecast to be higher than most of the end use forecasts where improved efficiencies and reduced UPCs are part of the model.

There is no direct connection between the two methodologies. The traditional forecast was developed as a reasonableness test for the end use forecast. The fact that the traditional forecast lies within the range of results predicted by the end use forecast suggests that the end use forecast is reasonable. That the traditional methodology is higher than the end use methodology reference case can also be expected given the traditional methodology's inability to adequately consider changing end use energy consumption patterns.

The FEU have switched to using the end use methodology because during the 2010 LTRP process, the FEU and stakeholders generally agreed that newer customers on the FEU's system do not have the same end use demand characteristics as customers that they have been serving for a longer period of time and that the traditional methodology had no logical means to account for these changes. Additionally, the population of end use equipment in the province is changing over time as newer technologies and changing codes and standards come into effect. This is another trend that the traditional methodology could not address over the long term since it is a time series method that examines historical data in aggregate to predict the long range future. While the traditional methodology remains valid for near term annual demand forecasting, it has no flexibility with which to consider longer term changing trends. The Commission subsequently directed the FEU to include the end use forecast, a description of the new methodology and a comparison and reconciliation of the traditional and new approaches, all of which has been provided in the 2014 LTRP. Through the process of developing the new end use methodology, the FEU have gained confidence that the new methodology is a more appropriate tool with which to explore a range of long term potential future trends in end use annual demand for natural gas and is a superior method to the traditional methodology for this purpose.

21.1.1 Why is the traditional methodology reference case forecast similar in demand and trend to Scenario C, which is the highest forecast of the end-use methodology scenario results?

Response:

Please refer to the response to BCUC IR 1.21.1.

21.2 Should the traditional methodology and end-use methodology yield similar reference case forecasts? Please elaborate.

Response:

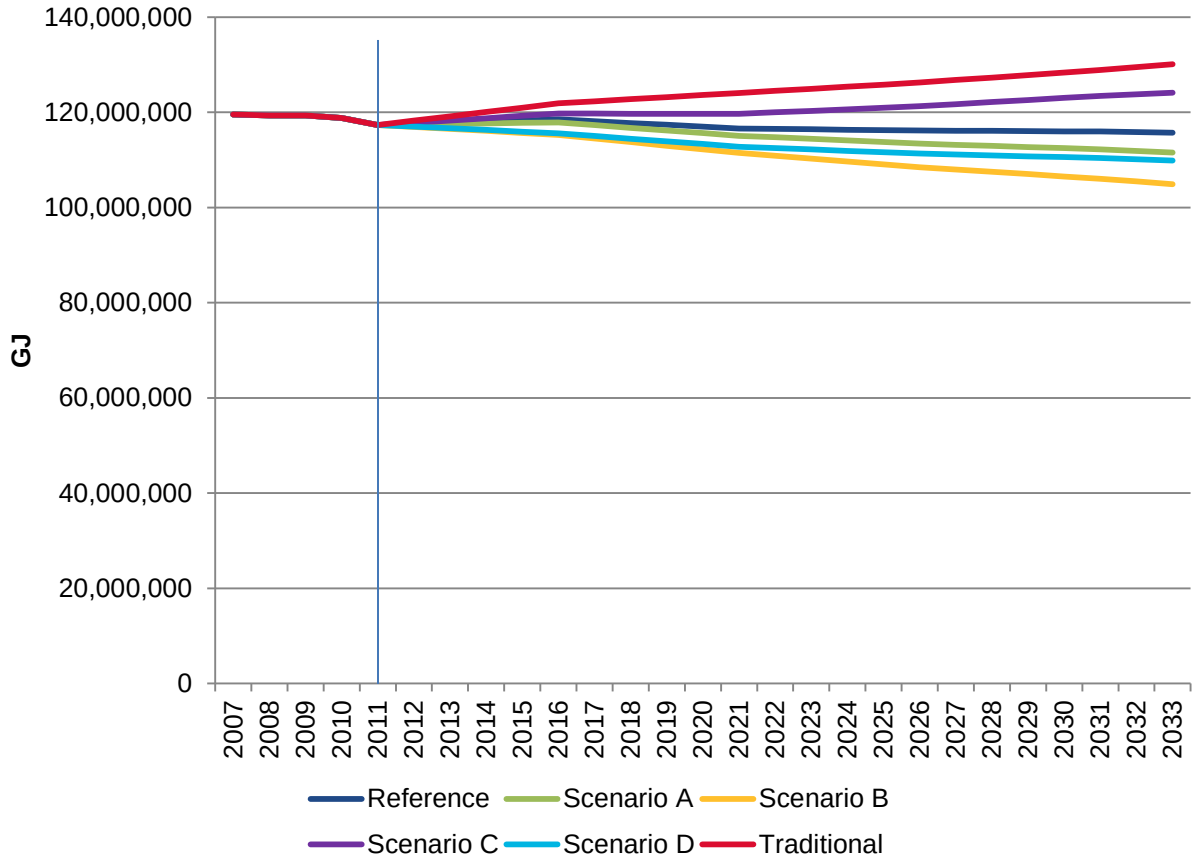
Please refer to the response to BCUC IR 1.21.1.

21.3 Please provide charts that graphically compare the reference cases for the traditional annual demand and the end-use annual demand forecasts and Scenarios A through D for each service region. Graphs should include data points for each of the twenty years in the planning period as well as actual data for the previous five years. Please be sure to distinguish actual data from forecasts.

Response:

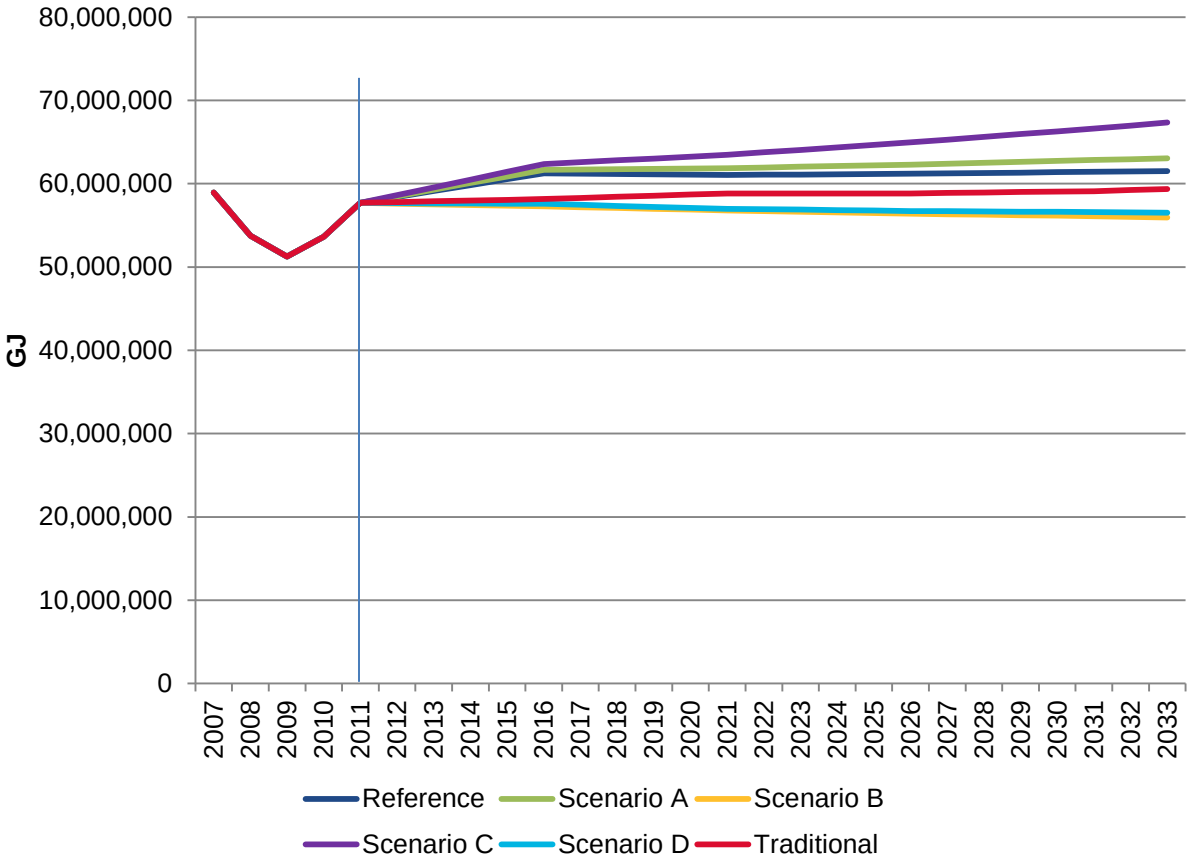
As discussed in the response to BCUC IR 1.19.2.2, intervening years between milestone years can be determined from simple interpolation, and this was the methodology for creating the four charts below. Actual data is presented from 2007 to 2011, and forecasted data from 2012 to 2033. The vertical blue line on the graphs separates the actual data on the left from the forecast data on the right.

1 *Lower Mainland*



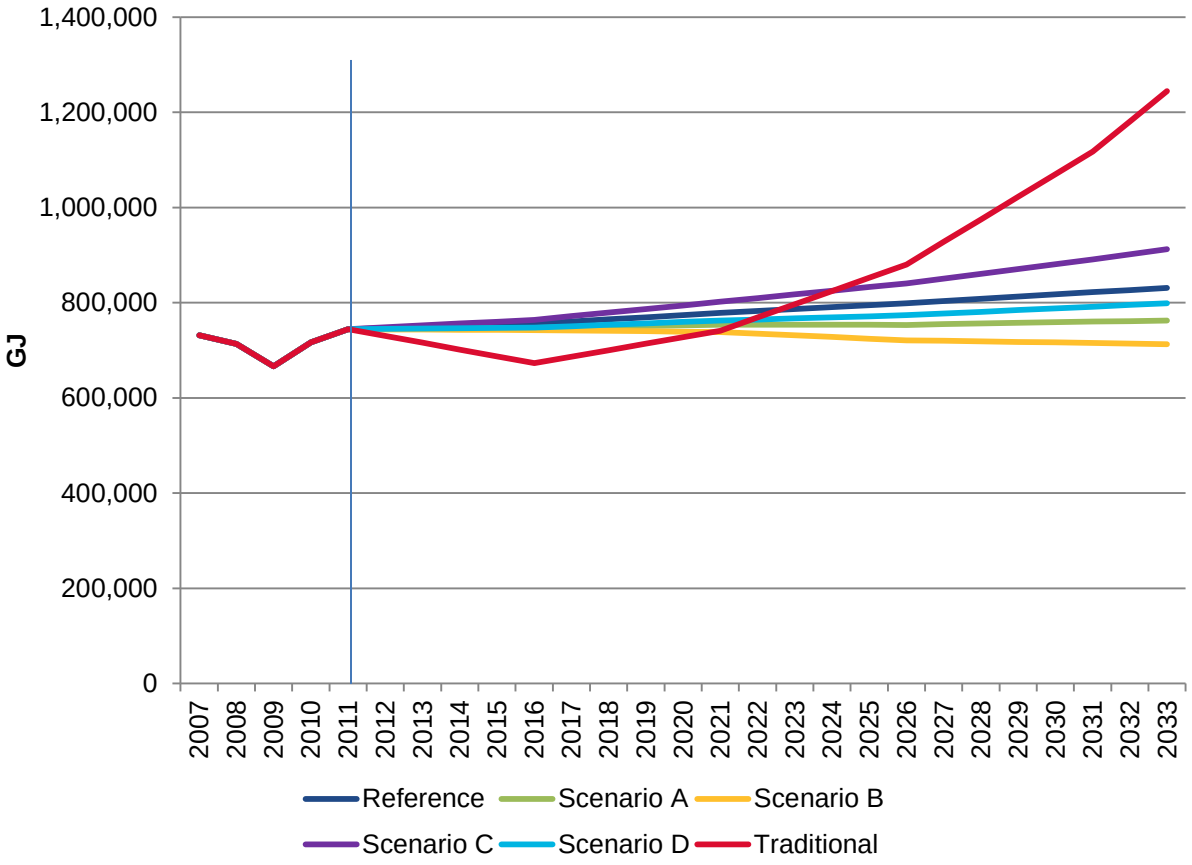
2

1 *Interior*


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
GJ
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Reference
Scenario A
Scenario B
Scenario C
Scenario D
Traditional

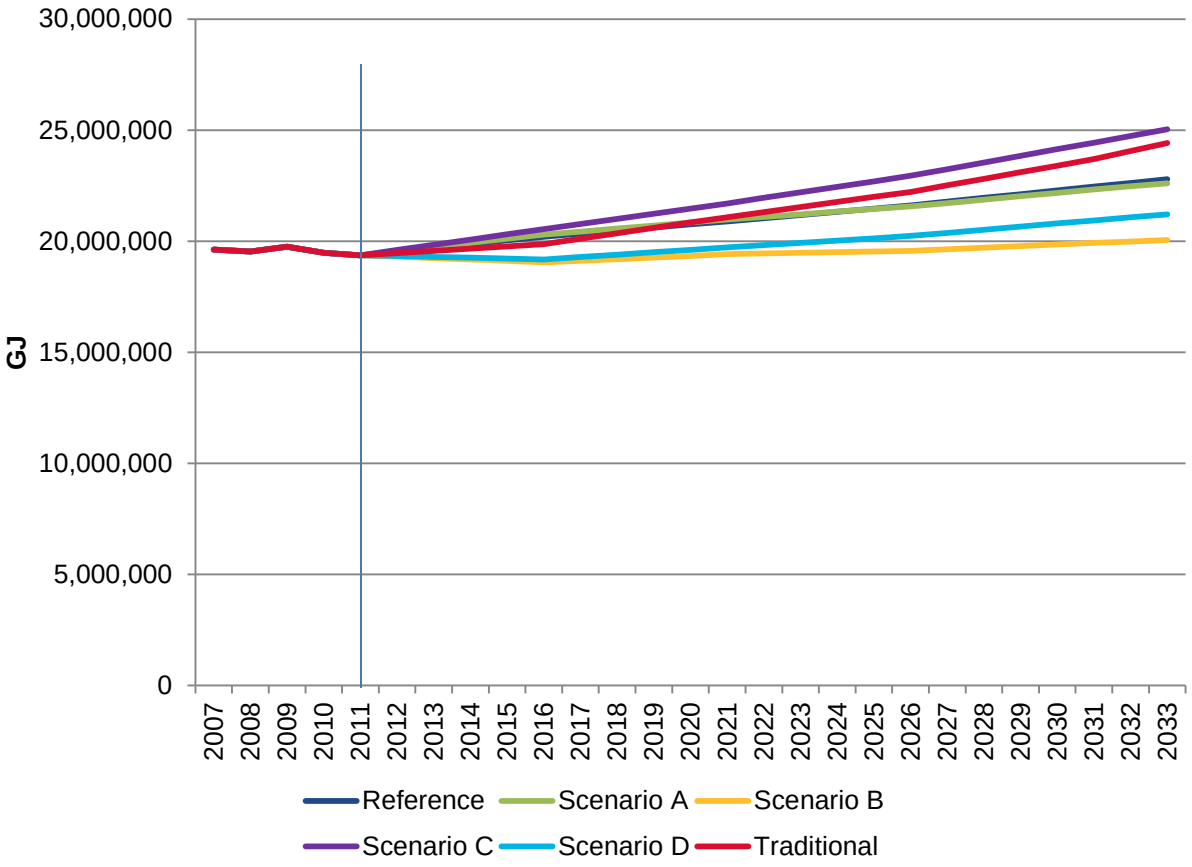
2

1 *Whistler*


1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
GJ
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Reference
Scenario A
Scenario B
Scenario C
Scenario D
Traditional

2

Vancouver Island



21.3.1 For each graph provide a qualitative analysis offering explanations for any difference in values and/or trends between reference case forecasts for the two methodologies.

Response:

The Lower Mainland region is a mature utility with significant efficiency improvements available as aging residential and commercial equipment is replaced. The traditional model does not have the same insight into the future conservation potential and results in a forecast that is higher than all the end use scenarios.

In the interior the End Use Method forecasts an increase in industrial demand compared to the current conditions that drive the traditional model. As a result the traditional model lies within the upper and lower scenarios but is positioned more towards the bottom of the range.

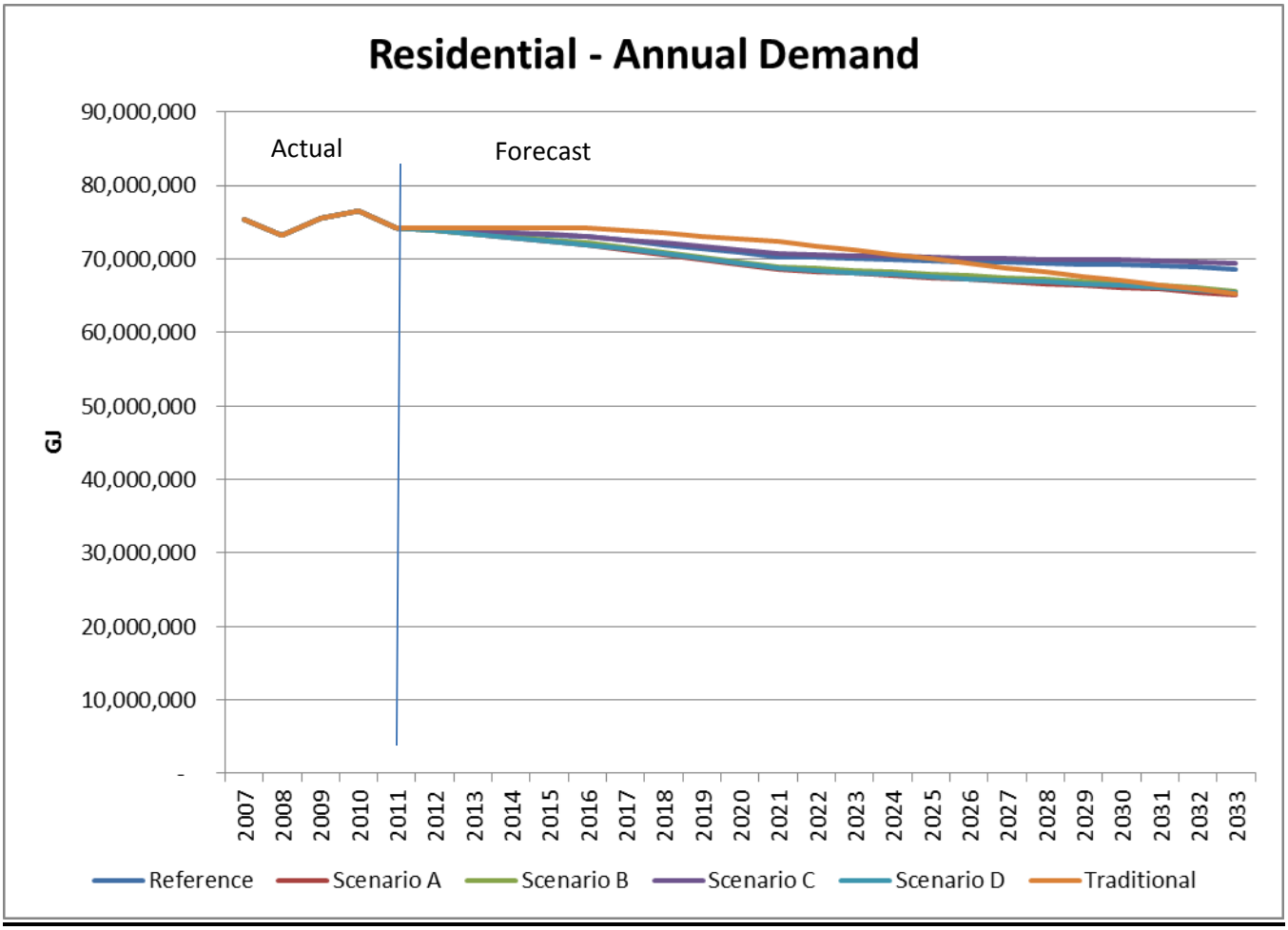
The total Whistler demand in 2011 was less than 0.75 PJs so the volatility present in the chart is not unexpected.

The Vancouver Island trend is as expected. FEVI is an immature utility so the opportunities for efficiency savings are not as significant as in the Lower Mainland. As a result the "business as usual" assumptions built into the traditional method follow the end use results more closely.

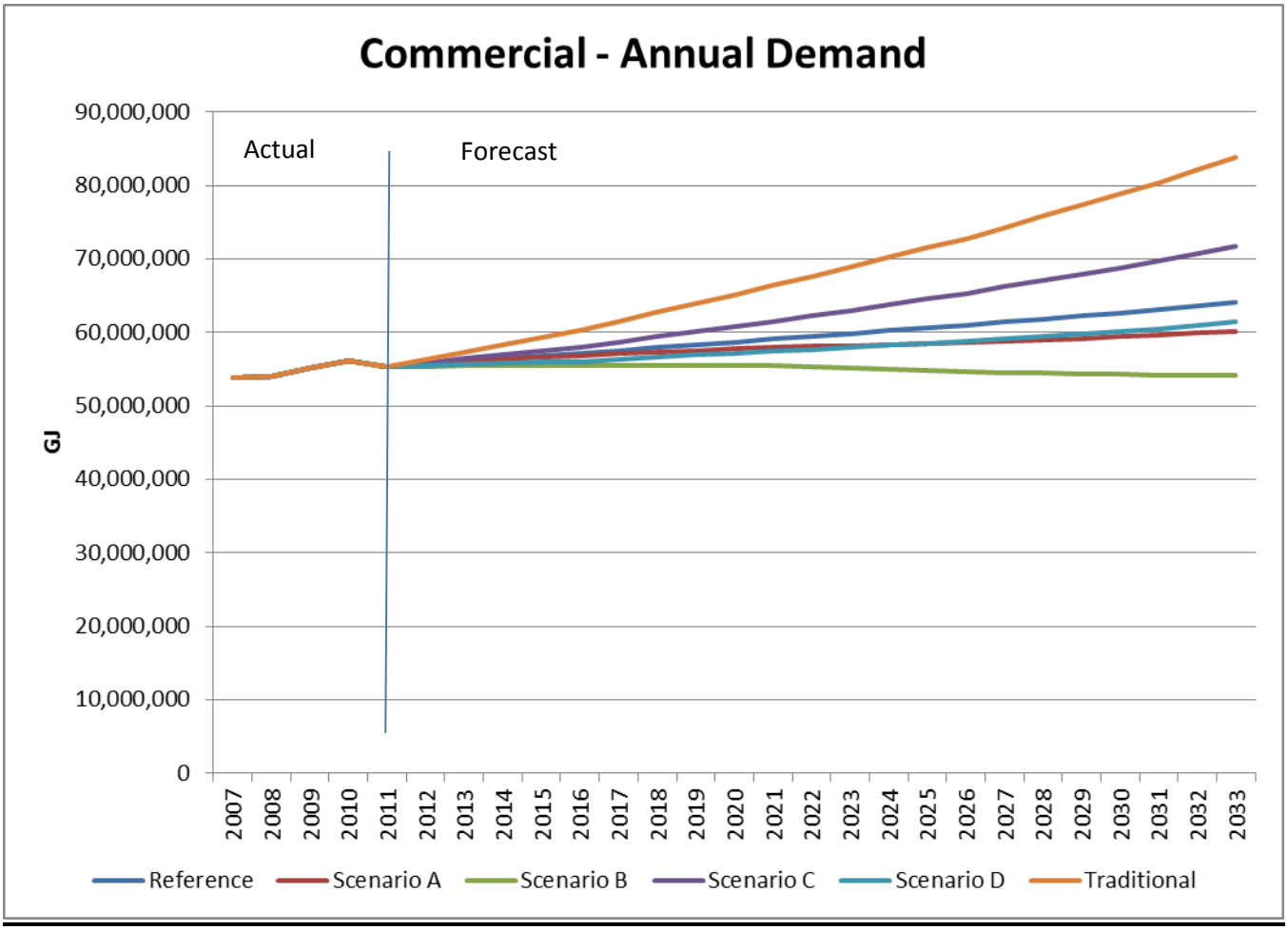
21.4 Please provide charts that graphically compare the reference cases for the traditional annual demand and the end-use annual demand forecasts and Scenarios A through D for each sector. Graphs should include data points for each of the twenty years in the planning period as well as actual data for the previous five years. Please be sure to distinguish actual data from forecasts.

Response:

Charts that graphically compare the reference cases for the traditional annual demand and the end-use annual demand forecasts and Scenarios A through D for each sector are provided below.


Residential - Annual Demand
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
-
GJ
Actual
Forecast
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Reference
Scenario A
Scenario B
Scenario C
Scenario D
Traditional

1


Commercial - Annual Demand
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
GJ
Actual
Forecast
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
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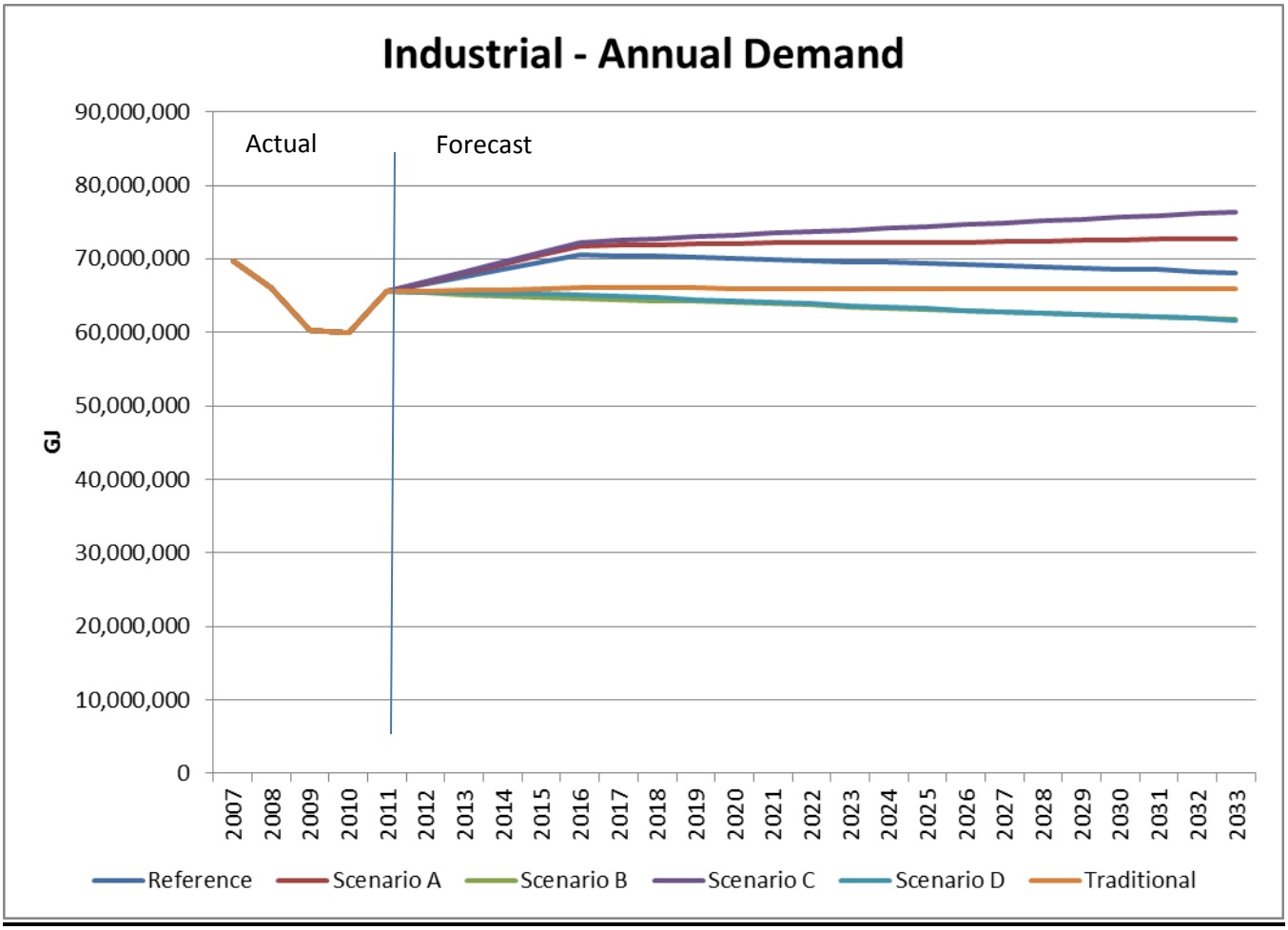
2029
2030
2031
2032
2033
Reference
Scenario A
Scenario B
Scenario C
Scenario D
Traditional

1



21.5 Has FEU surveyed the forecasting practices of other natural gas utilities with regard to their reliance on end-use versus traditional forecasting methods? If not, why not? If so, please discuss the results of the survey, and how the results informed FEU's decision to proceed with the forecasting methods that they used?

Response:

No. While the FEU are aware that various forms of end use demand forecasting methodologies are in use among other utilities, they have not conducted a survey to determine specifically which utilities are using them or in what context they are being used in. The FEU did not do such a survey because it was outlined in the 2010 LTRP that moving to an end use forecasting methodology was necessary to be able to examine the impact that newer end use demand

trends were having on annual energy demand, and that the traditional methodology could not do so. The FEU were subsequently directed by the Commission (on Page 25 of the Commission decision to the 2010 LTRP) to provide a description of the new end-use forecasting methodology, how it compares to the traditional methodology and a reconciliation of the two different approaches, all of which has been provided in the 2014 LTRP. The FEU's decision to proceed with the end use methodology was based on need, the availability of a cost-effective base model to work from and the ability of trusted external consultants to partner with on the project. The FEU believe that conducting such a survey would be of little practical value to this decision.

21.6 Is FEU aware of other utilities filing long term resource plans that include demand forecasts with milestone years only and that do not utilize a traditional forecast methodology? If so, please identify those utilities.

Response:

No, the FEU are not aware of other utilities that display their annual demand forecasts by milestone years rather than for each year of the study period. The fact that the FEU's end use demand forecast only stores and presents data for the milestone years does not mean that the model is ignoring all of the intervening years. The calculations within the model make the same assumptions and apply the same variables in each scenario to the intervening years. The database that results from the model, however, only contains data for the milestone years. Results for any measure for any intervening year can be determined thorough simple linear interpolation.

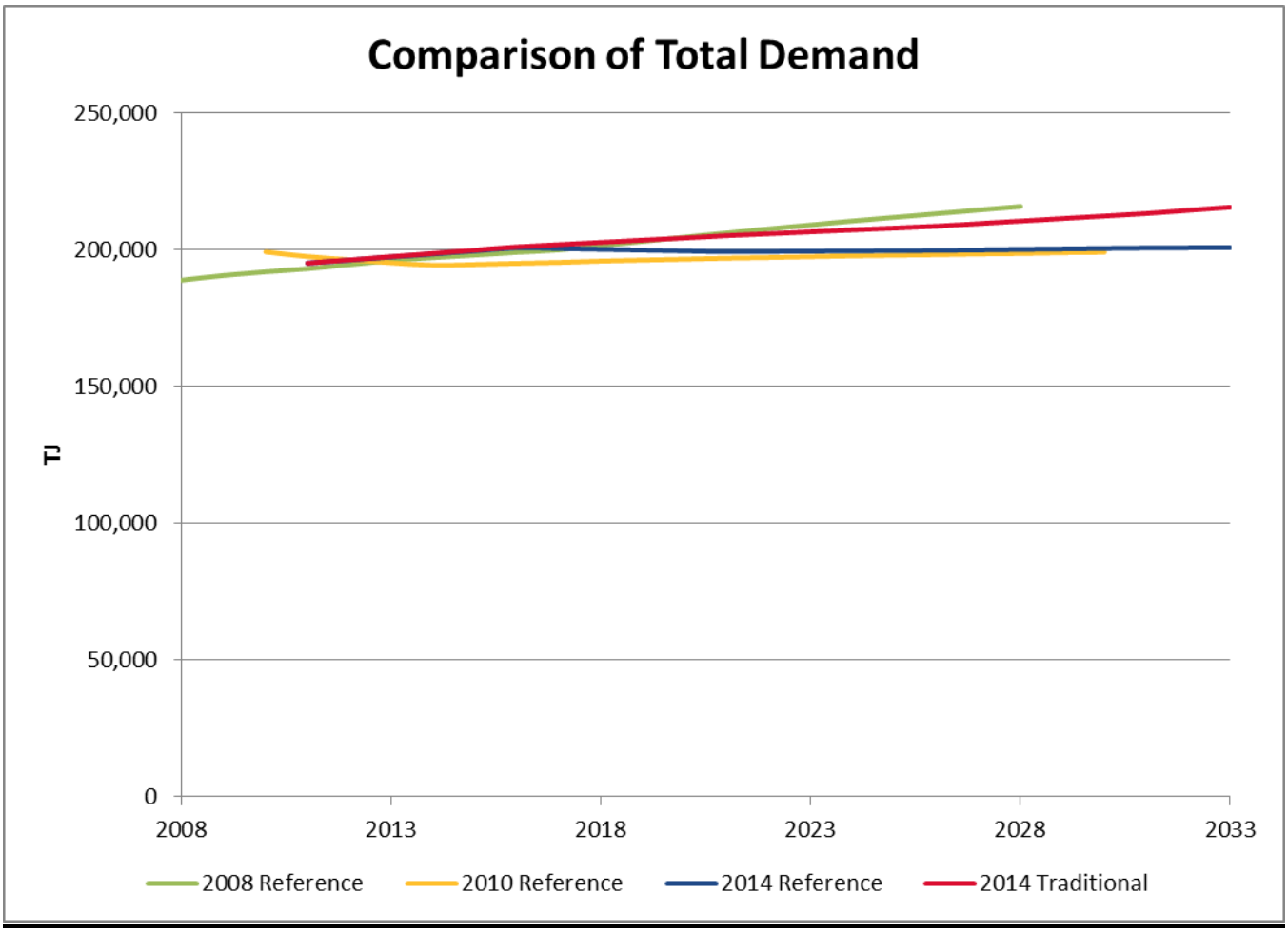
The FEU did not conduct a broad survey on how other utilities display their demand forecasts within their integrated resource plans as this was not considered a meaningful exercise in making a decision to employ the end use forecasting methodology. The ability of the model to consider future changes to end use energy consumption patterns among the FEU's customer base, however, was a key factor in making this decision and a significant amount of effort went into ensuring the model and the modelling process could meet this need.

21.7 Please provide one chart graphically comparing the reference cases for the traditional annual demand and the end-use annual demand forecasts with the long term annual demand forecasts from the two previous resource plans

(Terasen Gas 2008 Resource Plan and Terasen Utilities 2010 Long Term Resource Plan).

Response:

The chart graphically comparing the reference cases for the traditional annual demand and the end-use annual demand forecasts with the long term annual demand forecasts from the two previous resource plans is provided below.

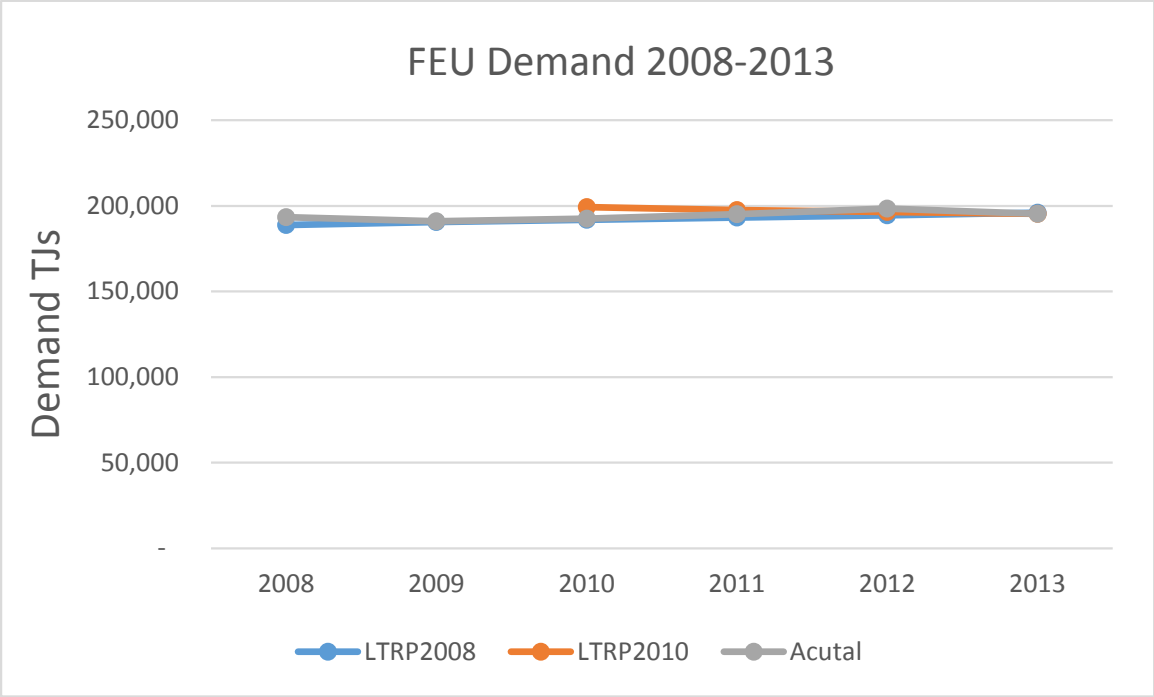


21.8 Please provide one chart graphically comparing the long term annual demand forecasts from the two previous resource plans (Terasen Gas 2008 Resource Plan and Terasen Utilities 2010 Long Term Resource Plan) with actual demand data from the period 2008 through to 2013.

Response:

The following chart shows:

- Normalized annual demand from the 2008 Long Term Resource Plan;
- Normalized annual demand from the 2010 Long Term Resource Plan; and
- Normalized actual annual demand from 2008 – 2013.



21.9 For each service region, please provide data tables with charts comparing forecasts of the Annual Use Rate per Customer (in GJ) obtained from (i) the end-use methodology used in the FEU 2014 LTRP; (ii) the traditional methodology used in the FEU 2014 LTRP and (iii) figures in Appendix B-2 of the TGI 2010 LTRP, for residential, small commercial and large commercial. Please plot these charts from 2010 through to 2033. Please discuss any significant differences between the plots and elaborate on the assumptions.

Response:

Please refer to Attachment 21.9. In regard to any significant differences between the plots please refer to the response to BCUC IR 1.21.1. Please be advised that forecasts from the 2010 LTRP exist from 2010-2030 and do not go out to 2033. Furthermore, Reference Case forecasts and Traditional forecasts from the 2014 LTRP are only available by milestone year (2011, 2016, 2021, 2026, 2031, and 2033). For annual data points for the 2014 Reference Case and Traditional Case graphs please visually reference the charts. Please refer to the response to BCUC IR 1.19.2 for an explanation as to why this is not presented for every year of the planning horizon.

22.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.3, pp. 42–62;

Exhibit A2-1, 2014 Gas Outlook, Appendix A2, p. 25

Annual Demand Forecast Comparison

FortisBC Energy Inc. has provided yearly Annual Demand Forecasts – Expected Case, in Dth (dekatherm), for BC Lower Mainland and Vancouver Island from 2013 through to 2023 in the 2014 Gas Outlook, compiled by the Northwest Gas Association (NWGA) and its members (Exhibit A2-1, p. 25).

22.1 Please indicate which forecasting methodology was used to derive these annual demand forecasts and why that method was chosen.

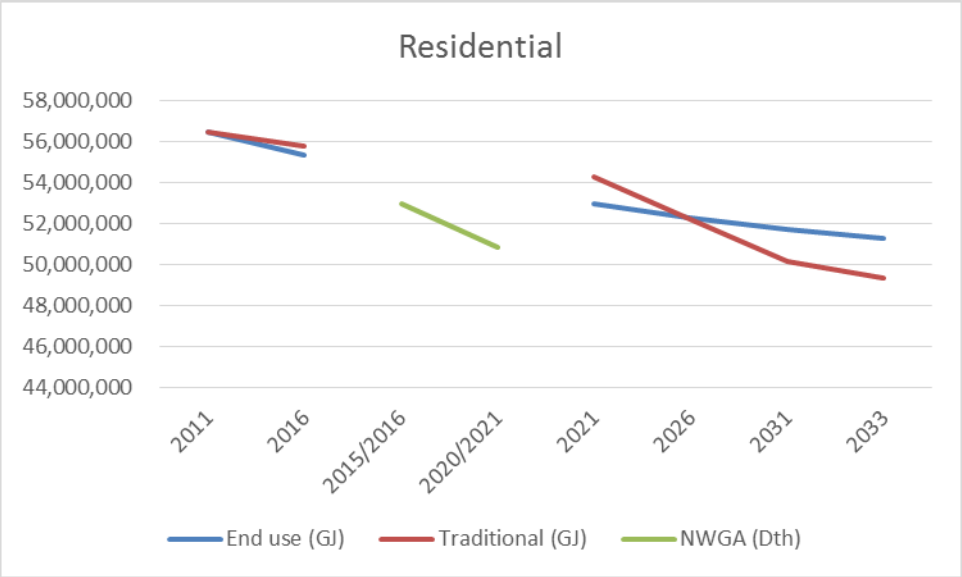
Response:

The forecasting methodology used to derive the annual demand forecasts for the NWGA was based on the new end use methodology. The FEU believe the new end use methodology provides better long term insights by having the ability to track changes at the end use level compared to the traditional methodology. Additionally the new end use methodology supports scenarios to model the amount of uncertainty within the long range forecast.

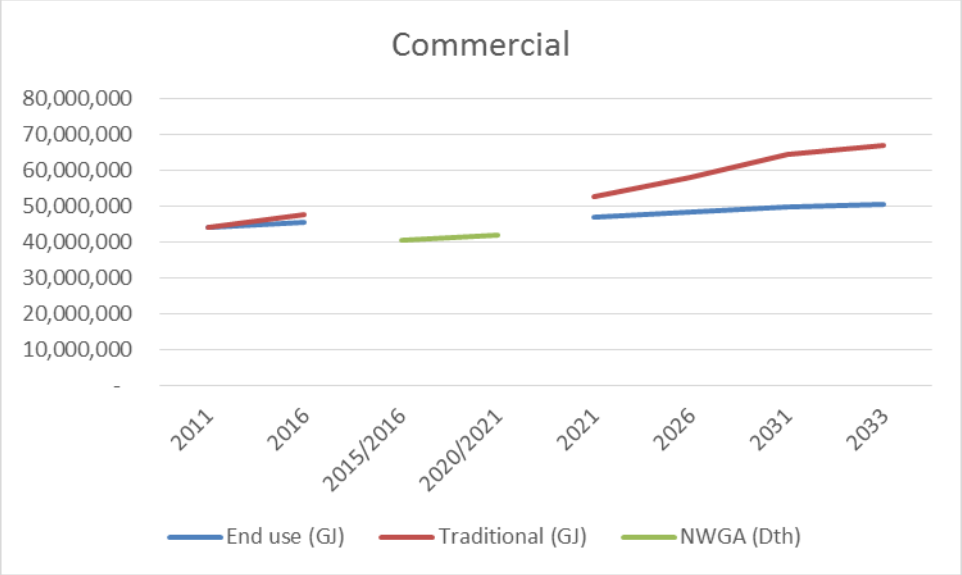
22.2 Please compare graphically the forecast mentioned in the preamble with both the traditional annual demand reference forecast and the end-use annual demand reference forecast for each of the years from 2013 through to 2023.

Response:

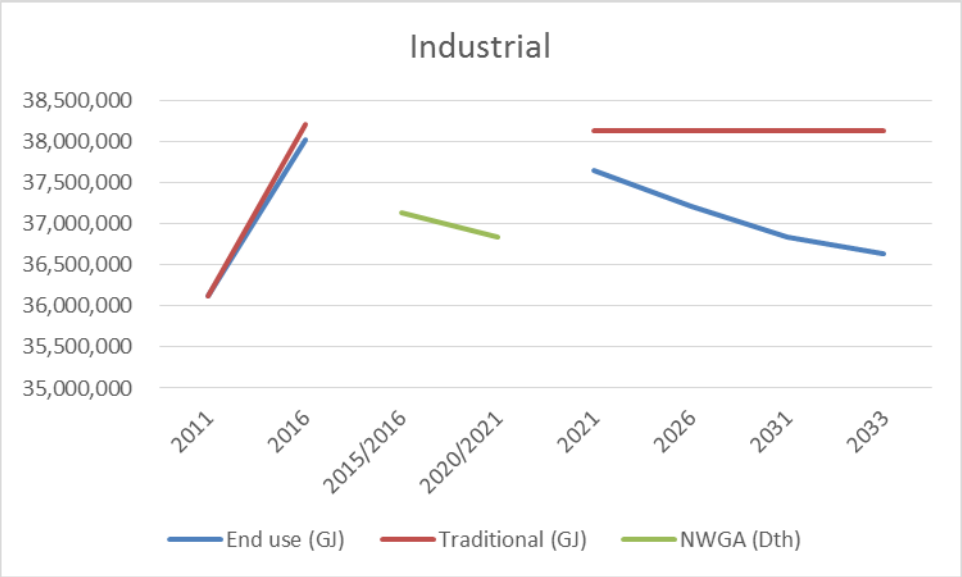
A comparison between Annual demand forecasts compiled by the NWGA and both the traditional annual demand reference forecast and the end-use annual demand reference forecast is provided below. As the traditional demand forecast and the end use annual demand forecast were developed for the milestone years, only the forecast years that overlap between the two sources were charted below. Note that the NWGA's 2014 Gas Outlook is based on a different unit such as Dth and is based on gas year, as opposed to the unit and the year system used by the traditional and end use annual forecast as part of the Application. The data provided for the purpose of filing the 2014 Gas Outlook for the NWGA were based on the end use forecast while the numbers were redistributed using a seasonality factor to accommodate the NWGA requirement of using a gas year instead of calendar year.


Residential
58,000,000
56,000,000
54,000,000
52,000,000
50,000,000
48,000,000
46,000,000
44,000,000
2011
2016
2015/2016
2020/2021
2021
2026
2031
2033
End use (GJ)
Traditional (GJ)
NWGA (Dth)

1


Commercial
80,000,000
70,000,000
60,000,000
50,000,000
40,000,000
30,000,000
20,000,000
10,000,000
-
2011
2016
2015/2016
2020/2021
2021
2026
2031
2033
End use (GJ)
Traditional (GJ)
NWGA (Dth)

2



22.2.1 Please explain the reason(s) for any significant differences between the values and/or the trends of the forecast included in the 2014 Gas Outlook and either of the traditional annual demand reference forecast and the end-use annual demand reference forecast seen in Section 3.3 of the Application.

Response:

Please refer to the response to BCUC IR 1.22.2 for the list of factors outlining the differences between the NWGA and the forecasts included as part of the Application.

23.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 9, pp. 164–166;

Exhibit A2-2, MISO Peak Forecasting Methodology Review Whitepaper, pp. 3–4

Qualities of a Good Forecasting System

Midcontinent Independent System Operator (MISO) describes the desirable characteristics of a good forecasting system as "understandability [transparency], credibility, accuracy, reasonable cost, maintainability and adaptability."

23.1 Using the descriptions of each characteristic provided on pages 3 and 4 of the whitepaper, please discuss each of these characteristics with regards to: (i) FEU's utilization of the traditional methodology and (ii) FEU's utilization of the end-use methodology.

Response:

The MISO document "provides information intended to assist those developing annual forecasts of the peak demand". It should be noted that neither the Traditional Method nor the End Use Method are used for forecasting peak demand.

On page 3 the document says "Much of the following was taken from a booklet prepared for the Edison Electric Institute by Charles River Associates, A GUIDE TO ELECTRICITY FORECASTING METHODOLOGY. While the publication is, from our current perspective, "old", its observations, comments, and conclusions remain valid." So the document is both old and is intended as a guide to peak electric forecasting.

The MISO document describes very complex forecasting approaches that are not justified for annual demand gas forecasting. In the response to BCUC IR 1.45.2 from the 2010-2011 RRA the FEU provided the following data:

The following table summarizes the regression results for TGI Residential customers.

Variable	Coefficient	R Square	Statistically significant
Vs GDP Growth in current year	-56,799.8	-8%	No
Vs GDP Growth in previous year	48.9	-9%	No
Vs HDD	27.0	88%	Yes
Vs Commodity prices in current year	-719.9	-9%	No
Vs Commodity prices in previous year	1.1	59%	No
Vs Account additions in current year	-0.3	-10%	No
vs Account additions in previous year	0.6	3%	No
Vs Electricity prices in current year	183,118.6	-13%	No
vs Electricity prices in previous year	760,424.4	4%	No
Vs Population growth in current year	605,524.2	22%	No
vs Population growth in previous year	1,069,032.7	65%	No

The following table summarizes the regression results for TGI Commercial customers.

Variable	Coefficient	R Square	Statistically significant
Vs GDP Growth in current year	-52,524.2	-3%	No
Vs GDP Growth in previous year	-5,386.4	-14%	No
Vs Heating Degree Days	18.0	86%	Yes
Vs Commodity prices in current year	-161.9	-14%	No
Vs Commodity prices in previous year	-127.4	-13%	No
Vs account additions in current year	1.7	10%	No
vs account additions in previous year	2.2	28%	No
Vs electricity prices in current year	5,722.4	-5%	No
vs electricity prices in previous year	11,877.8	20%	No
Vs Population growth in current year	540,819.3	52%	No
vs Population growth in previous year	723,232.6	68%	No

The only variable of any significance to our residential and commercial forecasts is weather. As a result we do not require forecasts at the level of complexity implied in the MISO document. One of the pitfalls the FEU try to avoid is developing forecast methodologies that are far more complex than the data available to put in them.

Nevertheless, the FEU have provided the requested table below, relying on MISO's definitions of the listed characteristics.

Characteristic	Traditional Forecast	End Use Forecast
Understandability	Forecast analysts are very familiar with the traditional method. Analysts have to implement the methods in Excel spreadsheets so understandability is 100%. However changing the forecast method because it is well understood is a dangerous consequence of too much familiarity.	The end use forecast is well understood by the author at ICF/Marbek. ICF/Marbek is making a significant effort to train additional staff on the inner workings and technical support of the model. FEU analysts fully understand the ramifications of the various inputs we provide. Quality assurance testing of the results was carried out primarily by FEU further enhancing our understanding of the model.
Credibility	Given the broad assumptions used in the Traditional Forecast FEU believes it is credible. FEU prepares a new long term forecast on a regular and frequent basis so any changes in the trends used to prepare the long term forecast are updated and adjusted regularly.	The ICF/Marbek forecast was developed based on the CPR model also developed by ICF/Marbek. The CPR model has been successfully used at multiple client sites including FEU for several years. Repurposing an already credible model results in a significant measure of credibility in the new model.
Accuracy	The accuracy of the traditional model is related to the continuation of past trends. If those trends continue then the traditional model will continue to produce accurate results. If trends in the short term deviate significantly from the five year average then the accuracy of the forecast will be compromised. By completing a new long term forecast on a regular basis FEU is able to respond to such short term demand pattern changes.	The accuracy of the end use method is enhanced by the ability to model different scenarios. No long term forecast will be accurate 20 years from now, but a forecast approach that models four scenarios and a reference case is more likely to capture the future state within its upper and lower boundaries.
Reasonable Cost	There is little to no cost to maintain the traditional model. It is not a standalone piece of software.	By repurposing a study already commissioned FEU saved the substantial cost of developing a new model. The limited expenditure repurposing the data to create the new model clearly lead to increased insight and flexibility. On page 1 of the MISO document the reader is warned that “Reinventing the wheel should be avoided” and FEU believes that repurposing the existing model achieves this goal.
Maintainability	The traditional model is housed in a collection of Excel spreadsheets. The methodology is simple enough that custom software development is not required.	The end use model is the proprietary property of ICF/Marbek. The model and the CPR “parent” model are maintained by ICF/Marbek. It is hoped that additional ICF/Marbek clients will make use of this modeling capability such that costs are reduced for all users.

Characteristic	Traditional Forecast	End Use Forecast
Adaptability	All forecast systems FEU is aware of take a series of inputs and based on those inputs prepare a set of output results. Both the traditional and end use forecasts can use different input values to produce different output values.	

Further to the characteristics outlined in the MISO document, the end use methodology is fully transparent as evidenced by the descriptions contained in Appendix B-3 of the LTRP (Exhibit B-1), which explain fully how the assumptions made for each scenario were incorporated into the forecasting model. Any assumption that has been made can be traced through the model in order to understand how the assumption became an input to the model and how the model used that input to produce the results.

23.2 Please compare the two methodologies by looking at each characteristic and highlighting the benefits and challenges of using one method versus the other.

Response:

Please refer to the response to BCUC IR 1.23.1.

23.3 Considering the response to the preceding IRs regarding the traditional and end-use methodologies, the comparison of the two and the qualities of a good forecasting system, as described by MISO, please justify Action Plan item 3, on page 164 of the Application, which proposes that FEU discontinue use of the traditional forecasting methodology for all sectors and use an updated 2012 base year with the end-use methodology in future long term forecasting work.

Response:

The accuracy measure from the MISO guidelines and the response to BCUC IR 1.23.1 supports Action Plan item 3.

Both the traditional gas method and the end use gas method meet the MISO peak electric forecast guidelines, assuming peak electric forecast guidelines are relevant to annual gas forecasts. The FEU believe that the scenario modeling capability and the ability to repurpose

1 detailed end use data will result in more accurate upper and lower boundaries than the high and
2 low percentages previously used with the traditional method.

3

24.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.3.7, pp. 56-59; Section 3.3.8, p. 61

Forecast of Annual Natural Gas for Transportation (NGT) Demand

On page 56 of the Application, FEU states:

> "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." (Exhibit B-1)

24.1 Please provide NGT data in the manner outlined in the table below up to the year 2033. Please break down the NGT forecasts into service regions, showing a further breakdown into all rate schedules associated with NGT, including rate schedules 16 and 46. For rate schedules involving both CNG and LNG, please show these figures separately.

NGT - Annual Demand Forecast (GJ)											
Region	Actual 2011	Actual 2012	Actual 2013	2014	2015	2016	2017	2018	2019	2020	.....
FEVI Total											
(List Applicable Rate Schedules here)											
FEW Total											
(List Applicable Rate Schedules here)											
FEI - Lower Mainland Total											
(List Applicable Rate Schedules here)											
FEI - Interior Total											
(List Applicable Rate Schedules here)											
Grand Total											

Response:

Please refer to Attachment 24.1 which includes 2011-2013 actual NGT consumption by rate class and region, a CNG and LNG forecast breakdown for each of the three NGT scenarios, and a forecast of consumption by vehicle type and by region for each of the three NGT scenarios (low, reference and high). In the forecast table by region and vehicle type please

note that Marine could not be broken down into the four regions (Interior, Lower Mainland, FEVI, and FEW).

Notes:

- The historical data requested is shown in a separate table from forecast data.
- In the forecast table by region and vehicle type please note that Marine is not broken about by region.
- The very early years of the forecast period in Whistler include small volumes that do not represent full vehicle demand due to the Whistler loads being an allocation of the total forecast demand.
- The forecast data for CNG demand cannot be broken out further by rate class then shown since future CNG customers may fall into different rate classes and the forecast was not prepared by rate class, but rather by vehicle type.

For clarity Rate Schedules 16 and 46 are only LNG sales tariffs. CNG is sold to NGT customers under existing rate schedules under which each customer qualifies. As such, forecasts presented in the 2014 LTRP with respect to Class 8 heavy duty trucking, marine, and other high horsepower applications are all LNG demand forecasts, and by extension Rate Schedule 46 sales forecasts. Rate Schedule 16 will expire on December 31, 2014 and all future sales of LNG will be from Rate Schedule 46.

24.1.1 Does FEU expect the recent developments mentioned in the preamble to significantly add to the annual NGT demand forecasts? If so, please provide updated NGT forecast figures which include these developments, in a manner similar to the question above, and describe the impact of additional FEU LNG production facilities anticipated over the forecast period.

Response:

No. Since the long term NGT demand scenarios targeted a market share percentage at the end of the forecast period, these short term changes would not substantially impact the long term demand forecast for NGT. The short term demand forecast was updated for these developments when FEI submitted its February 21, 2014 evidentiary update in its 2014-2018 PBR Application (PBR Evidentiary Update); however, this would have little impact to the long term NGT demand forecast. It should be noted that the NGT demand in 2016 (the only mutual milestone year between the updated short term forecast and the long term forecast) is actually lower in the PBR Evidentiary Update than in the 2014 LTRP reference case.

If the provincial government's changes to the GGRR do result in stronger growth through the study period (which may occur due to the additional vehicle categories included), actual NGT demand would be expected to track above the reference case demand and closer to the high demand scenario. This is exactly the reason that the FEU have included a range of potential future NGT demand scenarios.

The next iteration of the LTRP will take into account actual demand growth and changes in market share that occur between now and when that long term NGT demand forecast is prepared (within two to three years) to the extent possible.

For reference, the table below was filed in the PBR Evidentiary Update.

Table H-4 from PBR Evidentiary Update, Page 9

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

24.1.2 Please explain how the regional NGT demand forecasts in Figure 3-15 on page 61 were developed.

Response:

The regional NGT demand forecasts in Figure 3-15 on page 61 of the LTRP were developed in the following manner: The basis for the overall NGT demand forecast is presented on pages 57 through 59 of Exhibit B-1. In order to estimate the regional breakout of NGT demand for Figure 3-15, the overall NGT forecast was allocated to the four regions (Lower Mainland, Interior, Vancouver Island, and Whistler) in the same ratios as the overall volumes for FEI's residential, commercial, and industrial annual demand forecasts. This methodology was used as it was deemed the best way of allocating future NGT growth to the various regions given that NGT market share growth is in its infancy and there is little historical market data that would otherwise provide insight into how this demand will be distributed within each of the service areas, beyond the expectation that, as is represented in Figure 3-15, the majority of NGT load will come onto the system in the Lower Mainland.

On page 57 of the Application, FEU states: "For this period (2013 to 2017), the FEU have received expressions of interest from potential CNG and LNG customers and have therefore based their NGT demand forecast on the projected number of vehicles in each class of eligible vehicle, multiplied by the typical fuel consumption for each respective vehicle type" (Exhibit B-1).

24.2 Please confirm that the vehicle types analyzed were medium trucks, heavy trucks, school buses, urban transit, freight rail and marine vehicles. If not, please list the vehicle types analyzed.

Response:

Confirmed.

24.2.1 Please include the forecast natural gas consumption for each vehicle type listed in the response to the question above for each of the years from 2013 through to 2033.

Response:

The table below shows the numerical data for the NGT Reference Case as presented in the Application.

Table 1: Reference Case Data for Figure 3-13, page 58 of Application

Total Load (GJ/yr)	2010-2011	2012	2013F	2014F	2015F	2016F	2017F		
Vocational trucks	21,000	73,000	109,000	142,000	245,000	329,000	397,000		
Buses	11,000	11,000	13,000	13,000	60,400	70,400	74,400		
Class 8 tractors	162,500	162,500	302,000	356,000	653,000	977,000	1,247,000		
Marine	-	-	-	-	150,000	300,000	450,000		
Total NGT Fleet	194,500	246,500	424,000	511,000	1,108,400	1,676,400	2,168,400		
	2018F	2019F	2020F	2021F	2022F	2023F	2024F		
Vocational trucks	470,211	556,922	659,624	781,266	925,339	1,095,981	1,298,090		
Buses	88,120	104,370	123,617	146,414	173,414	205,393	243,269		
Class 8 tractors	1,476,959	1,749,325	2,071,918	2,454,001	2,906,543	3,442,539	4,077,377		
Marine	532,985	631,272	747,685	885,566	1,048,873	1,242,295	1,471,387		
Total NGT Fleet	2,568,275	3,041,890	3,602,845	4,267,246	5,054,169	5,986,208	7,090,124		
	2025F	2026F	2027F	2028F	2029F	2030F	2031F	2032F	2033F
Vocational trucks	1,537,471	1,820,996	2,156,806	2,554,543	3,025,626	3,583,582	4,244,430	5,027,146	5,954,202
Buses	288,131	341,265	404,197	478,736	567,019	671,583	795,430	942,115	1,115,850
Class 8 tractors	4,829,287	5,719,855	6,774,654	8,023,968	9,503,668	11,256,239	13,332,002	15,790,556	18,702,493
Marine	1,742,726	2,064,102	2,444,743	2,895,578	3,429,551	4,061,995	4,811,067	5,698,276	6,749,095
Total NGT Fleet	8,397,614	9,946,218	11,780,400	13,952,824	16,525,864	19,573,399	23,182,930	27,458,094	32,521,641

24.3 Please explain how the typical fuel consumption for each vehicle type was determined.

Response:

The typical fuel consumption was estimated based on the historical experience that FEI has gained from existing operators of applicable fleets. For example, FEI used average consumption per vehicle from its existing LNG customers operating Class 8 tractors, and so forth for school buses, transit buses, and trucks for CNG.

For marine vessels, FEI used data provided by the two marine vessel operators in BC that are exploring switching to LNG for their marine vessels.

Freight rail was included in the total scenario market share percentage calculation as natural gas transportation for rail may gain traction over the 20 year planning horizon, however none of the scenarios included any forecasts for natural gas transportation rail as at the time of filing the 2014 LTRP the FEU had no NGT rail demand on the system. As such, a typical fuel consumption figure for rail has not yet been derived.

24.4 Please discuss the factors considered when deriving the relationship between NGT market share and total vehicle market size.

Response:

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 assume is going to grow at a rate of 2% per year.

The 2033 natural gas vehicle market shares for the three NGT scenarios were calculated by projecting the 2010 NRCan data for the transportation market to the end of the forecast period. The 2010 NRCan data was increased by a 2% annual growth rate to reach an applicable 2033 total vehicle market size. FEI believes that a 2% annual growth rate in the transportation market is a reasonable assumption for economic growth and thus a reasonable predictor of growth in these commercial vehicle markets over the planning horizon.

The factors considered in deriving the NGT share of total vehicle market size for these vehicle categories in the three different NGT annual demand forecast scenarios were:

- The 2010 NRCan market shares for the individual vehicle classes, as grown out to 2033 as described above and used in the forecast, were examined to ensure the various scenarios were feasible;
- The initial share of this total vehicle market captured by natural gas vehicles was less than 0.2% in 2011;
- A range of market share scenarios was developed to provide a range of demand based on the total market size for these vehicle categories and feedback received from stakeholders via the Resource Planning Advisory Group was examined;
- The possibility was considered (in the low demand scenario) that without incentive funding beyond the end of the GGRR period firms may not purchase additional natural gas fuelled vehicles regardless of the fuel cost savings that can be achieved; and
- The availability of fuelling stations was also a key consideration in determining NGT market share. As funding limits to construct CNG and LNG fuelling stations expire after March 31, 2017 (i.e. the end of the GGRR period), there was the assumption made that fuelling stations would only be constructed for dedicated return-to-base fleets that could economically support a fuelling station for the long term.

On page 57 of the Application, FEU states:

> "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." (Exhibit B-1)

24.5 Please explain the rationale behind the choice of 1 percent, 15 percent and 30 percent market share, respectively, as a basis for the low, reference and high NGT forecasts.

Response:

The NGT Low Case Annual Demand scenario reaches a 1% market share of the total applicable vehicle market in 2033. The low case represents a zero relative growth rate post GGRR period (2013-2017) and this reflects the lower bound of what the FEU believe could reasonably be expected to occur over time. This scenario examines the possible outcome that if

no further incentive funding is available beyond 2017 to continue driving growth in market share of NGT, fleet owners may decide not to continue converting their fleets and instead simply maintain the fleets that exist at the end of 2017.

The NGT High Case Annual Demand 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 30% NGT market share of the total applicable vehicle market in 2033 was chosen as it equates to exactly double the volume of NGT that the FEU are expecting at the end of the 20 year forecast. Given the relatively new growth in NGT market share in B.C. and limited market data on which to estimate market share growth rates, the FEU believe this approach is reasonable for a high demand forecast. The FEU also took into consideration feedback received from the Resource Planning Advisory Group in deciding to examine a forecast that was double the reference case.

The NGT Reference Case Annual Demand scenario is based on a continuation of the demand growth anticipated as an outcome of the NGT Incentive Program, and includes anticipated vehicle market expansion and a subsequent increase in natural gas demand volumes as a result of the amount of market capture by NGT in this scenario. The 15% NGT market share of the total applicable vehicle market in 2033 was chosen as it represented a reasonable estimate of the penetration of natural gas vehicles into the marketplace over the next two decades given the very small market share for NGT at the outset of the planning period.

25.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.3.7, pp. 57–59; Section 5.1.3.2, p. 121;

Exhibit B-1, Application, Appendix A-8, pp. 2, 5

LNG Component of NGT Demand

On page 57 of the Application, FEU states:

> "The first part covers the period for which the Companies are currently permitted to provide incentives under the GGRR (2013 to 2017)." … "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 on market share capture assumptions." (Exhibit B-1)

On page 5 of Appendix A-8, FEU states: "the Utilities can assist the B.C. Government in further advancing its goals of promoting LNG as a transportation fuel and reducing GHG emissions by converting vehicles of more carbon intensive fuels (diesel and gasoline) to relatively cleaner burning natural gas."

25.1 Please describe FEU's assumptions regarding the quantities of LNG or market share of the LNG portion of the NGT market that are forecast to be supplied by parties other than FEU for NGT demand within British Columbia over the period of the forecast.

Response:

The FEU assume that the question is referring to the supply source of the liquefied natural gas and not the provider of fuelling services to the NGT customer. Over the forecast period in the LTRP, the FEU have assumed that no other source of LNG production would be present to penetrate and serve the LNG demand in BC.

Although NGT customers can have their fuelling station (CNG or LNG) constructed by any party other than the FEU, the natural gas either in gaseous or liquid form would originate from the FEU.

25.2 Does FEU anticipate over the forecast period that some LNG for domestic consumption may be produced within British Columbia at facilities that are not supplied by natural gas that flows through the FEU system? Please explain the response.

Response:

FEI is not aware of any firm plans at this time about any LNG facility being built for domestic consumption that is not on the FEU system. It is however possible over the forecast period that LNG facilities could be built by companies such as by Pacific Northern Gas Ltd. to serve local markets that are not on the FEU system. Under the FEU's GGRR programs, customers taking advantage of the vehicle incentives are required to buy natural gas delivered throught the FEU system.

25.3 Please provide, where available, a forecast of LNG demand that will be supplied by FEU, broken out to the end-use category including, but not limited to, the categories indicated in the following table. Also include this data in a functional Microsoft Excel spreadsheet.

LNG - Annual Demand Forecast (TJ)									
Case	Actual 2011	Actual 2012	Actual 2013	2014	2015	2016	2017	.....	2033
Low (Total)									
NGT									
Power Generation									
Propane Grids switched to Natural Gas									
Winter Peaking for core Natural Gas									
(List other End Uses)									
Reference/Actual (Total)									
(List End Uses)									
High (Total)									
(List End Uses)									

Response:

Please refer to Attachment 25.3 for a live Excel spreadsheet that details the low, reference and high case forecasts broken down by the categories listed above. This is the same forecast for NGT demand that was presented in the LTRP.

Forecasts for power generation and propane grids are not included, as there have been no firm commitments to date from customers for these two categories and as such FEI has not forecasted LNG demand for these two market segments. However market development efforts are ongoing for these two market segments and FEI will make this information available once more certainty is gained.

25.4 Please provide a forecast of the quantity of LNG that will be exported from BC during the planning period. Add this quantity to the total reference case LNG forecast from the question above.

LNG Demand Forecast (TJ/yr)	Actual 2011	Actual 2012	Actual 2013	2014	2015	2016	2017	.....	2033
(A) RS46 LNG exported from BC									
Reference/Actual Total + (A)									

Response:

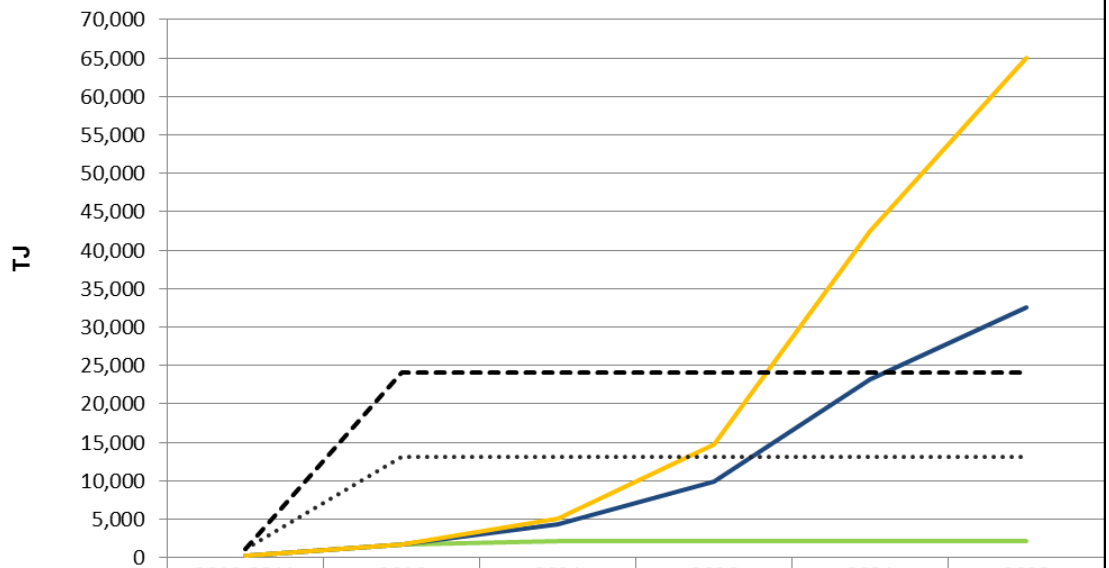
FEI has been in discussions with interested parties to export LNG. To date, FEI has not received a firm commitment from any of these customers. In the absence of an executed agreement, FEI is unable to provide a forecast with any level of certainty.

25.5 Please use charts to show the estimated annual and peak LNG capacity over time and indicate the extent to which LNG supply capacity exceeds demand or vice versa.

Response:

Please see the chart below whish shows the estimated demand and liquefaction capacity.

Figure 3-13 Annual NGT Demand with Tilbury Expansion Supply Capabilities



	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
Tilbury (30 TJ)	1,168	13,140	13,140	13,140	13,140	13,140
Tilbury (60 TJ)	1,168	24,090	24,090	24,090	24,090	24,090

25.5.1 Please discuss how the results could influence the projected infrastructure needs (both LNG facilities and the need for other system reinforcement projects) for FEU.

Response:

The proposed Tilbury LNG expansion project by itself does not require any significant system expansion needs in order to complete the expansion as permitted under the Special Direction. However, if further LNG plant or infrastructure expansions are required to serve higher LNG demand and if additional industrial load locates in the lower mainland, there would be a need to upgrade existing pipeline and compression systems in order to accommodate these development activities.

25.6 On page 121 of the Application, FEU states "FEI is planning to further examine the integration of this potential LNG opportunity with an overall LNG market assessment" [Emphasis added] (Exhibit B-1).

Please describe the overall LNG market assessment FEU has completed to-date.

Response:

The reference made in the 2014 LTRP to "an overall LNG market assessment" was mischaracterized by the FEU. On page 121 of the LTRP, the FEU are referring to how this potential LNG market opportunity (i.e. Revelstoke) will fit with the FEU's overall LNG market *strategy*.

In other words, the quoted text in the preamble of BCUC IR 1.25.6 was made in reference to making sure that the potential conversion of the Revelstoke propane system fits into the FEU's overall LNG development plans, in which there will be competing demands for LNG from other customers. In addition, factors such as logistics planning, supply availability, peaking requirements, scheduling, and others will also be considered in the potential conversion of Revelstoke from propane to natural gas.

25.6.1 Describe the extent to which this LNG market assessment will include an assessment of each of the following factors: benefits to existing FEU customers, BC greenhouse gas emissions reductions and availability of LNG supply from third parties.

Response:

Please refer to the response to BCUC IR 1.25.6.

25.6.2 Please describe the extent of discussions and marketing activities FEU has undertaken to date to develop existing and new markets for LNG to be supplied by FEU.

Response:

The FEU have been in discussions with a number of potential customers on using LNG as a preferred fuel choice. For instance, the FEU are currently working 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.

In terms of marketing activities, the FEU engage prospective customers through traditional sales channels and develop contacts gained through exposure at industry trade events. The FEU website is also used to guide discussions with prospective customers, and site visits are made to potential customer sites.

Due to the commercial sensitivity of these discussions and developments, the FEU cannot divulge specific information with respect to individual projects.

26.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3, pp. 56–58; Section 5.1.2.3, p. 119; Appendix A-10

LNG Component of NGT Demand

26.1 Please provide the liquefaction capacities of the existing Tilbury and Mt. Hayes LNG facilities in gigajoules per day and gigajoules per year.

Response:

The net liquefaction capacities of the existing Tilbury and Mt. Hayes LNG facilities are 5110 GJ/day and 8200 GJ/day, respectively. The annual liquefaction capacities would vary from year to year and would depend on the uptime of the equipment and demand of LNG.

26.2 Please provide the anticipated incremental liquefaction capacity of the expanded Tilbury LNG facility provided for under Special Direction No. 5 in gigajoules per day and gigajoules per year and the date the facility is expected to commence operations.

Response:

The FEU are currently working with the potential vendor to determine the optimal liquefaction capacity, in addition to the cost for the 1 billion cubic feet (BCF) storage tank. The FEU expect that the facility will be able to produce approximately 30-40,000 GJ/Day. Annual liquefaction will depend upon customer commitments and various storage arrangements, and will range between 300 and 350 days per year of liquefaction. The facility is expected to be in service in 2016.

26.3 Please describe the additional LNG facilities beyond the Tilbury and Mt Hayes LNG facilities described above that FEU anticipates it will require in order to meet the LNG component of NGT demand over the forecast period including the facility in the Okanagan described in paragraph 2 on page 119 of the Application. Include the anticipated timing, cost, location, liquefaction capacity and impact to the FEU system of such additional LNG facilities.

Response:

The FEU do not have any planned additional LNG liquefaction facilities beyond the Tilbury and Mt Hayes LNG facilities to meet the LNG component of NGT demand over the forecast period.

26.4 Please describe how additional FEU LNG production facilities such as the potential LNG production facility in the Okanagan will impact the FEU NGT demand forecast.

Response:

The potential LNG production facilities in the Interior would only be constructed if the demand for LNG from either NGT, remote communities or other sources of demand justifies the construction of such facilities. At present, the LNG forecasts presented in the LTRP and the Evidentiary Update, filed on February 21, 2014, contemplate that all LNG sales will be serviced from the Tilbury and Mt. Hayes LNG facilities.

27.0 Reference: ENERGY DEMAND FORECASTING

Exhibit A2-3, Rate Schedule 16 Pilot Program 2013 Annual Report, Table 1, p. 2

LNG Component of NGT Demand

27.1 The Rate Schedule 16 Pilot Program 2013 Annual Report filed by FEI on January 22, 2014, has been filed in this proceeding as Exhibit A2-3. For each of the ten Rate Schedule 16 customers shown in Table 1 on page 2 of Exhibit A2-3, please describe the nature of the customer's end-use for the LNG supply contracted for (e.g. NGT, power generation, etc.)

Response:

Rate Schedule 16 Customer	Nature of End-Use
ATCO Gas	Power generation
Vedder Transport	Class 8 truck
Encana Corporation*	Locomotive trials and Class 8 trucks
Puget Sound Energy*	System backup
Westport Power	Engine testing – R&D
Denwill Enterprises	Class 8 truck
NWT Energy Corporation	Power Generation
Ledcor Resources and Transportation LP	Class 8 truck
ENN Canada Corp.	Class 8 truck
Wheeler Transport	Class 8 truck

**Encana and Puget Sound have not purchased LNG supply under Rate Schedule 16 from FEI since 2012*

28.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3, Figure 3-13, p. 58; Appendix A-10;

Joint Transportation Committee Final Report "Evaluating the Use of Liquefied Natural Gas in Washington State Ferries"[7], pp. 33–34;

Exhibit A2-3, Rate Schedule 16 Pilot Program 2013 Annual Report, p. 2

LNG Component of NGT Demand

A January 2012 Final Report titled "Evaluating the Use of Liquefied Natural Gas in Washington State Ferries" was prepared for Washington State's Joint Transportation Committee. Page 33 of this report includes a list of the liquefaction and/or storage facilities in the Pacific Northwest and includes the following reference to British Columbia:

> "FortisBC owns and operates two LNG production and storage facilities, one at Tilbury on Vancouver Island (sic) and one at Mt. Hayes. This is the supplier that BC Ferries is working with. FortisBC is in the process of expanding production capacity. In consultant interviews, FortisBC have indicated that they anticipate having sufficient supply to meet WSF's initial LNG requirements."

Further in this same report on page 34, the report identifies the following as one of the three options for supplying LNG for Washington State Ferries (WSF) needs: "*Truck LNG from within the Pacific Northwest*. Discussions with FortisBC indicate that they could be a potential supplier for WSF. There are also other entities considering expanding capacity in the Pacific Northwest."

28.1 Please confirm, as listed in Table 1 on page 2 of the Rate Schedule 16 Pilot Program 2013 Annual Report, that FEI has or had a Rate Schedule 16 contract in place to supply LNG on a spot basis to Puget Sound Energy, a natural gas distribution utility based in the United States (US).

Response:

Confirmed. However, although Puget Sound executed a Rate Schedule 16 with FEI, they have not purchased LNG from FEI to date.

[7] http://www.leg.wa.gov/JTC/Documents/Studies/LNG/LNG_FINALReport_Jan2012.pdf

28.2 Please confirm that Rate Schedule 46 has no terms or conditions that would either prevent FEU from supplying LNG to US parties such as WSF or that would allow FEU to decline to supply US parties such as WSF under Rate Schedule 46 in the event WSF requested service under Rate Schedule 46. If not confirmed, please explain with an appropriate reference in Rate Schedule 46.

Response:

Confirmed.

28.3 Has FEU made any commitments to supply LNG to WSF?

Response:

No. The FEU have held exploratory discussions with WSF and has provided information regarding tariff terms and pricing, but the FEU have made no commitments to date.

28.3.1 Is any WSF demand forecast included in the NGT demand forecast shown in Figure 3-13 on page 58 of the Application? If not, please explain.

Response:

The demand forecasts shown in Figure 3-13 illustrate three different demand forecast scenarios. In the Reference Case scenario, FEI did not include WSF demand due to the preliminary nature of discussions with WSF with respect to LNG supply arrangements. Further, FEI believes that the High Forecast Demand scenario is sufficient to capture any potential WSF demand should it materialize.

29.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3, Figure 3-13, p. 58;

Northwest Territories Energy Action Plan[8], p. 43;

Yukon Utilities Board proceeding in the matter of the Yukon Energy Corporation Application for an Energy Project Certificate and An Energy Operation Certificate Regarding the Proposed Whitehorse Diesel-Natural Gas Conversion Project, Yukon Energy Corporation Information Responses YUB-YEC-1-4, February 27, 2014[9], p. 3;

Exhibit A2-3, Rate Schedule 16 Pilot Program 2013 Annual Report, p. 2

LNG for Power Generation Demand

The Northwest Territories "Energy Action Plan: A Three-Year Action Plan and Long-Term Vision" dated December 2013 outlines on page 43 the Northwest Territories policy and action regarding the use of LNG as follows:

> 7.7.1. INTRODUCE AN LNG SUPPLY CHAIN INTO THE BEAUFORT DELTA
>
> NTPC has already investigated the possibility of using LNG in Inuvik and will commission a pilot project there in the autumn of 2013. By mid-2014, it is hoped that nearly 75% of the power needs of Inuvik will be met with LNG. The GNWT will further explore the potential costs, supply chain details, and benefits of using LNG in other communities, most notably Fort Simpson, Fort Liard and Fort McPherson, in order to foster a strong LNG supply chain in the NWT.
>
> ACTION
>
> Invest $100,000 in 2013-14 to develop a supply chain of LNG in Inuvik.

The following is excerpted from page 3 of the Yukon Energy Corporation Information Responses YUB-YEC-1-4 dated February 27, 2014 in the proceeding currently underway before the Yukon Utilities Board in the matter of the Yukon Energy Corporation Application for an Energy Project Certificate and An Energy Operation Certificate Regarding the Proposed Whitehorse Diesel-Natural Gas Conversion Project (Yukon Energy Project), a project for the replacement of two diesel generating units replacement of two diesel generating units (9.1 MW total capacity) scheduled for retirement by 2015 with up to three new modular natural gas-fired generating units (13.1 MW total capacity) supplied by LNG.

"As background, NT Energy is currently sourcing LNG from FortisBC's Tilbury facility, and hauling this LNG, using Tridem units with a net payload of approximately 64.5 m3

[8] http://www.iti.gov.nt.ca/sites/default/files/energy_action_plan_web_feb_20.pdf
[9] http://yukonutilitiesboard.yk.ca/pdf/YEC_LNG_Application/YEC_Consolidated_IR_Responses.pdf

per unit, from Delta BC to Inuvik via Yukon and the Dempster Highway. NT Energy target LNG load for power generation at Inuvik on average approximates 250,000 GJ/year or 28 m3/day, with load requirements reasonably steady through the year but with the Dempster access closed for about two months each year due to river access seasonal closures for the month of May and for a month during the November to December period. By the fall of 2014, NT Energy expects to have four Tridem units engaged in this activity (there are currently two Tridem units in operation during the initial start up phase)."

29.1 Is the NWT Energy Corporation Rate Schedule 16 contract that is listed in Table 1 on page 2 of Exhibit A2-3 used to supply the Inuvik power generation pilot project?

Response:

Yes. However, Rate Schedule 16 expires on December 31, 2014 and FEI and NWT Energy Corporation are in discussions presently to execute a Rate Schedule 46 LNG supply agreement that will ensure reliable and cost effective LNG supply for NWT Energy Corporation over the long term.

29.1.1 If not, please explain what FEU understands the end-use requirement for the LNG contracted for by NWT Energy Corporation to be.

Response:

Please refer to the response to BCUC IR 1.29.1. The NWT Energy Corporation Rate Schedule 16 contract that is listed in Table 1 on page 2 of Exhibit A-2-3 is used to supply the Inuvik power generation pilot project.

29.2 Has FEU made any commitments to NWT Energy Corporation or other parties to supply LNG for the Northwest Territories' proposed "LNG Supply Chain"?

Response:

FEI currently supplies LNG to NWT Energy Corporation for power generation activities at the utility. FEI has not made commitments to NWT Energy Corporation, or to any other parties to supply LNG for the Northwest Territories proposed "LNG Supply Chain".

Currently NWT Energy Corporation takes LNG under Rate Schedule 16 on a spot (or, as-needed) basis. As Rate Schedule 16 expires on December 31, 2014, NWT Energy Corporation will need to execute a Rate Schedule 46 LNG sales agreement to continue to receive LNG supply from FEI.

29.2.1 If so please describe the terms, timing, amount and whether the sale is firm or spot.

Response:

Please refer to the response to BCUC IR 1.29.2.

29.2.2 Please describe in detail where this demand is included in the overall demand forecast described in the Application.

Response:

FEI did not explicitly include the demand as indicated by NWT Energy Corporation for the following key reasons:

1. Uncertainty regarding future commitments considering that NWT Energy Corporation is taking LNG supply from FEI on a spot basis; and

2. NWT Energy Corporation has purchased approximately 16,000 GJs over a four month period from January to April 2014. Extrapolating this over a 12 month period equates to about 48,000 GJ for a 12 month period, which is materially lower than the forecast indicated by NWT Energy Corporation of 250,000 GJ per year.

FEI will have greater certainty regarding NWT Energy Corporation's plan to purchase LNG from FEI upon executing a Rate Schedule 46 LNG sales agreement. Until such time, FEI is reluctant to include demand from NWT Energy Corporation equal to 250,000 GJ per year.

30.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3, Figure 3-13, p. 58;

Yukon Utilities Board proceeding in the matter of the Yukon Energy Corporation Application for an Energy Project Certificate and An Energy Operation Certificate Regarding the Proposed Whitehorse Diesel-Natural Gas Conversion Project, Yukon Energy Opening Comments dated March 31, 2014[10], pp. 6–7

LNG for Power Generation Demand

The following is excerpted from pages 6 and 7 of the Yukon Energy Corporation's Opening Comments in the proceeding currently underway before the Yukon Utilities Board in the matter of the Yukon Energy Project:

> "The March 27, 2014 update explained Shell's decision not to proceed with its Jumping Pound LNG plant, and set out the following revised plans by Yukon Energy to secure LNG supply for the Project:
>
> - LNG supply from FortisBC: Yukon Energy will now secure LNG supply from the FortisBC LNG facility at Tilbury (Delta BC) until such time as a lower cost source of LNG is available.
>
> - Yukon Energy has met with FortisBC and has confirmed that ample LNG supply is available to meet Project requirements from the operating FortisBC facility at Tilbury, including supply from existing facilities during 2015 and supply from the next major expansion that has BC Government regulatory approval and is planned to start operation in 2016.
>
> - The rate for supply from Fortis will be based on the regulatory cost-based price under BCUC approved Rate Schedule 46 (approved in accordance with a direction to the BCUC from the BC Government as set out in OIC 557-13).
>
> - LNG supply chain development & optimization with NT Energy: Yukon Energy is coordinating plans with NT Energy (who is currently securing LNG from FortisBC at Tilbury for use at Inuvik) to utilize NT Energy's Tridem units until such time as A-Train units are permitted. Yukon Energy and NT Energy are also exploring how joint cost savings with A-Train units can be secured once they are permitted.

10 http://yukonutilitiesboard.yk.ca/pdf/YEC_LNG_Application/YEC_Opening_Comments__March_31__2014.pdf

- Other potential near-term LNG supply options: YEC is working with NT Energy on other potential near term lower cost LNG supply options that could be located closer to Yukon, including potential options with AltaGas and Ferus as noted in the March 27, 2014 update. Overall, the interest in near term LNG domestic supply development has grown considerably in the last 12 months in both Alberta and B.C., including potential facilities in Edmonton, Grande Prairie, Dawson Creek and Fort Nelson."

30.1 Has FEU made any commitments to supply LNG to the Yukon Energy Corporation for the Yukon Energy Project? If so please describe the terms, timing, contracted quantities and whether the sale is firm or spot.

Response:

The FEU currently provide LNG supply to Yukon Energy Corporation on a spot basis under Rate Schedule 16. The FEU and YEC are currently engaged in negotiating a firm supply contract under Rate Schedule 46. To date, there is no executed agreement for firm supply, therefore the FEU have not included this demand in the forecast.

30.2 Please elaborate whether this Yukon demand for LNG for power generation is included in the NGT Demand forecast in Figure 3-13 (p. 58) or in the overall demand forecast described in the Application.

Response:

The YEC's demand for LNG is not included in Figure 3-13 on page 58 of the Application. Figure 3-13 provides a demand forecast for Natural Gas for Transportation applications. The YEC demand is for power generation and not transportation.

YEC plans to execute an Rate Schedule 46 agreement for spot supply but this agreement has not been executed. Demand is not certain at this point and can be terminated at any time. Similar to other industrial demand, the FEU do not forecast industrial demand until it has a firm commitment from the customer. As such, FEI did not include demand from YEC in the forecasts presented in the Application.

30.3 If this power generation demand is not included in either the NGT or the overall demand forecast, please explain why FEU has not included demand for LNG for this power generation.

Response:

Please refer to the response to BCUC IR 1.30.2.

31.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Appendix A-10;

FEI 2012 Biomethane Application, Section 4.3.1, p. 54, para. 3

LNG Component of Demand Forecast

31.1 Please confirm that Rate Schedule 46 provides for the supply of biomethane as LNG. If not confirmed, please explain.

Response:

Confirmed. Rate Schedule 46 provides customers with the option to purchase a percentage of biomethane as a portion of their gas. Biomethane will be charged at the Biomethane Energy Recovery Charge (BERC) rate as approved by the BCUC.

31.2 Does the demand forecast in section 3 of the Application include any forecast demand from the Haida Gwaii power generation project, mentioned on page 54 of the FEI 2012 Biomethane Application, or similar renewable LNG projects or customers? If so, please provide details of the demand.

Response:

The demand forecast in section 3 of the Application does not include any forecast demand from the Haida Gwaii power generation project mentioned on page 54 of the FEI 2012 Biomethane Application, nor does it include any similar renewable LNG projects or customers.

To date, there have not been discussions with such customers who have requested LNG supply from FEI. As there are currently no agreements or ongoing discussions with these customers, FEI has not forecast any demand from these projects due to the uncertainty regarding implementation and quantity of supply required to serve this demand.

32.0 Reference: ENERGY DEMAND FORCASTING

Exhibit B-1, Application, Section 3.3.9 Potential New Industrial Annual Demand, p. 62, Figure 3-16

Total Annual Demand including NGT and Woodfibre Example

On page 62 of the Application, FEU states:

> "Figure 3-16 provides the full range of potential annual demand using the lowest case annual demand and NGT scenarios (Scenario B and NGT Low); the Reference Case annual demand and NGT scenarios; and the highest case annual demand combined with the highest NGT demand scenario (Scenario C and NGT High). The broken lines represent the effect of adding new industrial load such as that of the Woodfibre LNG Project onto the FEU's system."

32.1 Recognizing that infrastructure is often designed to meet peak demand, please elaborate on how the demand scenarios directly or indirectly impact projected infrastructure needs.

Response:

The demand scenarios in Section 3 are based on annual demand forecasts and do not directly impact infrastructure needs. Infrastructure needs are based on regional peak demand forecasts as discussed in Section 5 of the LTRP. However, large increases in base load (such as the Woodfibre example) would tend to increase overall peak demand on a given system. Should these large base load increases occur, then it may be necessary to advance planned reinforcements, supplement planned reinforcements or install new infrastructure.

3.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.4, pp. 62–68; Section 5.1.2.1, pp. 100–106

Peak Day Demand

On page 63 of the Application, FEU states: "The relationship between consumption and weather is determined through regression analysis of historical daily consumption and historical daily temperature experienced over the past three years" (Exhibit B-1).

33.1 What is the reasoning behind choosing a three-year period as the basis for the regression analysis to determine the relationship between consumption and weather? Is three years a long enough period to avoid unusual swings in the design day estimate for a 20 year forecast?

Response:

The methodology captures the daily consumption response relative to weather. Three years' worth of data gives us over 1000 data points which allows us to estimate customer response to changes in temperature. A three year period was chosen because it gives us enough data points while at the same time ensures we are considering the most current customer behavior data. Once the weather response is estimated, the design temperature is used to derive the expected design day estimate for a given year. This analysis is updated on an annual basis to make sure we use the latest information. The long term forecast is then updated accordingly, incorporating these results.

33.2 Please state if Figure 5-2 on page 103 of the Application includes forecasts for the Peak Day Demand from the proposed Woodfibre LNG plant.

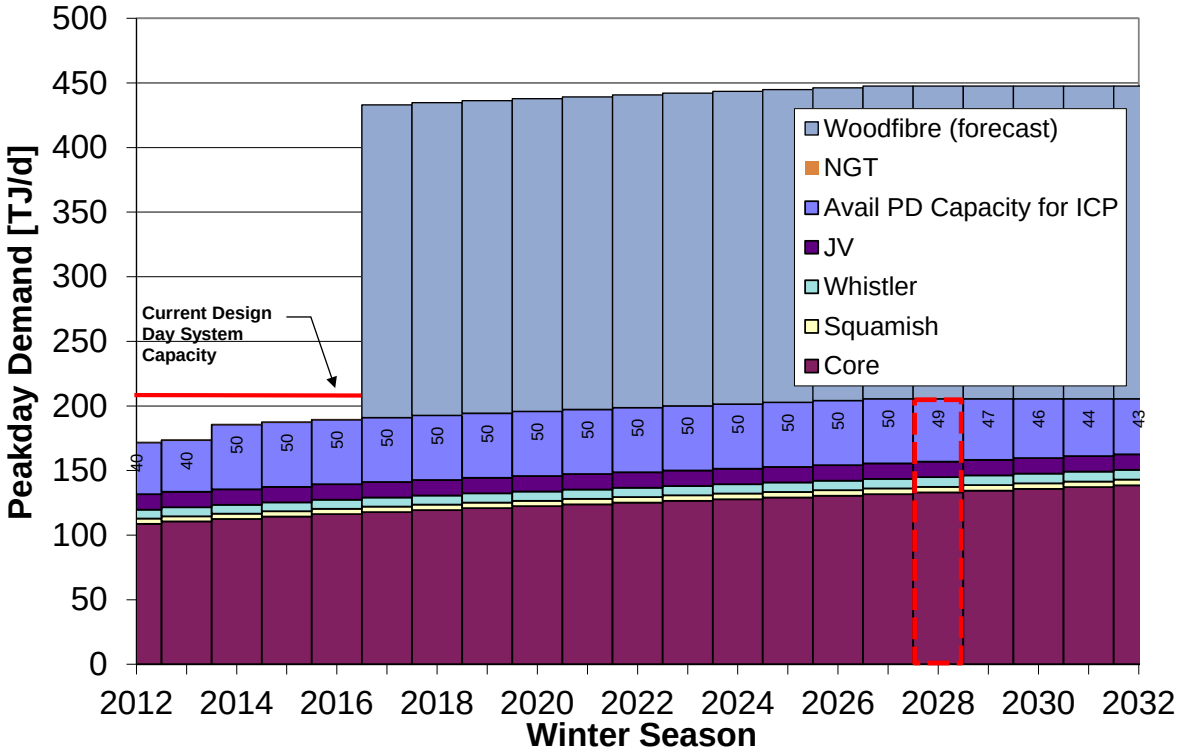
Response:

No, Figure 5-2 does not include forecast demand from the proposed Woodfibre LNG plant.

33.2.1 If not, please provide an updated version of this chart including a reasonable forecast for the Peak Day Demand from the proposed Woodfibre LNG.

Response:

Figure 5-2 is updated below with a reasonable forecast of the proposed Woodfibre LNG load (base load increase of approximately 242 TJ/d). This demand forecast for Woodfibre is additive to the existing FEVI forecast customer peak demand.



34.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 5.1.2, pp. 99, 103, 106

Regional Peak Day Demand Sensitivities

34.1 Please describe the basis for the low and high daily demand sensitivities for the FEVI transmission system and the FEI coastal transmission system discussed on pages 103 and 109 respectively. Are they driven by anticipated changes to customer additions in each service area? If not, how are the factors used to create the sensitivities derived?

Response:

No, the high and low regional peak demand sensitivities were not driven by anticipated changes to customer additions in each service area. Please refer to the response to BCUC IR 1.15.2 for an explanation of why high and low customer additions forecasts were not prepared for the 2014 LTRP. The high and low regional peak demand sensitivities from Section 5 of the 2014 LTRP were used to test the sensitivity of the timing of infrastructure requirements to higher or lower than expected growth in peak demand. The percentages applied to the peak demand for this purpose were chosen to be consistent with those used in the previous LTRP (the 2010 LTRP) for the same purpose.

34.2 Please discuss the factors used to derive the Low and High daily demand forecast sensitivities for the ITS system discussed on page 116 of the Application.

Response:

The same methodology that was used for the FEVI and FEI Coastal Transmission System was also used for the ITS. Please refer to the response to BCUC IR 1.34.1.

35.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.4, pp. 62–68;

Exhibit A2-1, 2014 Gas Outlook, Appendix A5, p. 28

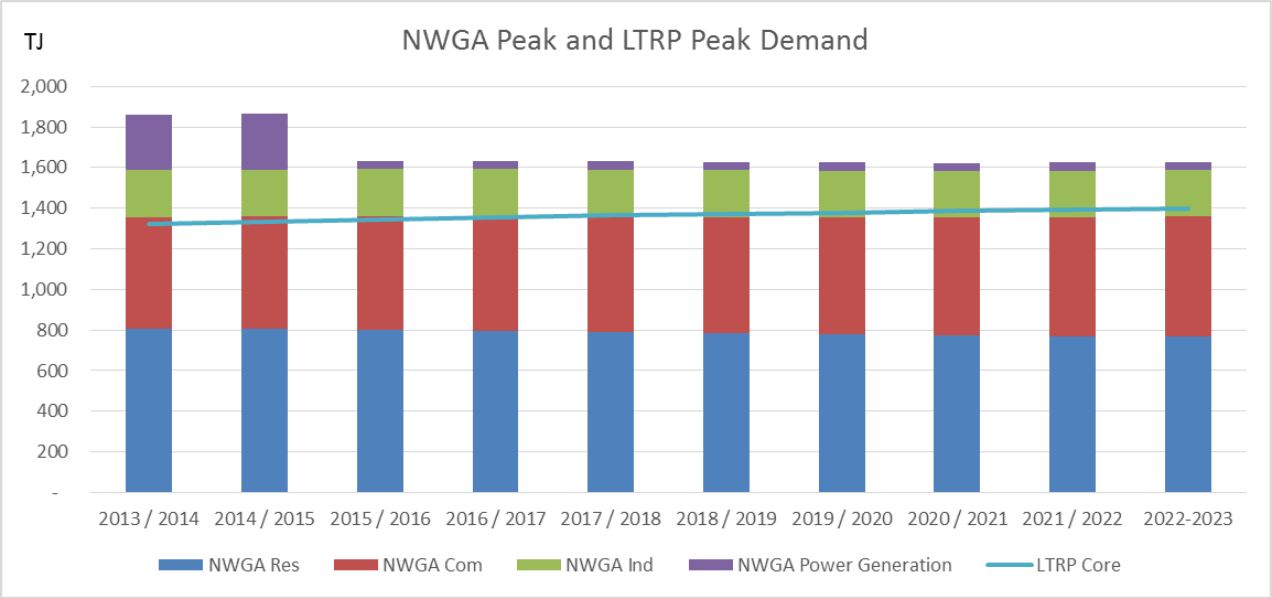
Peak Day Demand Forecast Comparison

FortisBC Energy Inc. has provided yearly Peak Day Demand/Supply Balance Expected Case forecasts for BC Lower Mainland and Vancouver Island from 2013 through to 2023 in the 2014 Gas Outlook, compiled by the Northwest Gas Association (NWGA) and its members (Exhibit A2-1, p. 28).

35.1 Please provide a chart comparing the yearly Peak Demand Forecasts for the BC regions and sectors in the NWGA's 2014 Gas Outlook with the same regions and sectors using year Peak Demand forecast data from the 2014 FEU LTRP. Please use terajoules (TJ) per day as the units for peak demand forecast in the chart.

Response:

A chart comparing the yearly peak demand forecasts for the BC regions and sectors from the NWGA's 2014 Gas Outlook with the same regions from the LTRP is provided below (in TJ per day). The NWGA 2014 Gas Outlook forecast includes sectors that are not included in the LTRP forecast. The peak demand forecast data for the LTRP was prepared for the core rate classes as a whole for gas supply planning purposes and so does not include transportation demand or power generation demand. Core rate classes include non-interruptible customers from Rate Schedules 1 to 7. Transportation demand refers to the demand of the customers who bring in their own supply and use the FEU pipelines to transport their gas. Therefore, the difference seen in this chart is reflective of the transportation demand and power generation, which are excluded from the LTRP but included in NWGA's figures.



35.1.1 Please explain in detail the reason(s) for any significant differences between the values or the trends of the forecasts being compared.

Response:

Please refer to the response to BCUC IR 1.35.1.

36.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.3.2, p. 46; Section 4.2, Figure 4-1, p. 76;

Exhibit B-1, Application, Appendix B-3, p. 19

End-Use Annual Demand Methodology and Energy Efficiency and Conservation

On page 46, the Resource Plan states that:

> "The reference case is based on end-use patterns observed in the base year and keeps these patterns constant throughout the planning period. The impact of EEC programs up to and including 2011 were thus implicitly included in the end-use characteristics identified for the base year, but were not assumed to continue through the planning period for the purpose of demand forecasting. The impact of future EEC activities is considered in Section 4."

On page 19 of Appendix B-3, the description of Scenario B states: "Condensing boilers are assumed to be adopted at a rate 5% higher than the current rate, when boilers are replaced at the end of their normal life" (Exhibit B-1).

36.1 Is it correct to conclude, from the statement on page 46, that such changes in the end-use model scenarios, which reflect changes in energy–efficiency measures, are independent of any EEC measures taken by the utility after 2011? Please explain.

Response:

Yes. Because the demand forecasting process began in 2012, 2011 was the most recent complete year of actual demand data available to use as a base year (refer also to the responses to BCUC IRs 1.19.5 and 1.19.5.1). By necessity, therefore, 2011 was also the base year for the long term EEC analysis even though much of the work for the EEC analysis was undertaken in 2013. Therefore actual energy savings that occur as a result of EEC programming after 2011 are not incorporated into the long term EEC analysis.

EEC programming through 2012 and 2013 was based on the same CPR that was used to develop the long term EEC analysis for the 2014 LTRP, with the exception that the CPR model was updated with 2011 actual consumption data (refer also to the response to BCUC IR 1.19.3) for the 2014 LTRP analysis. Therefore, the FEU do not believe that any differences between actual EEC savings achieved in the short term (i.e. in 2012 and 2013) and estimated savings included in the 2014 LTRP for this period will materially impact the long range estimate of potential EEC energy savings across the range of scenarios examined.

With respect to the reference made in the preamble to page 19 of the LTRP, the change in the rate of condensing boiler adoption described in Exhibit B-1 is an assumed change in "natural conservation" activity incorporated into Scenario B as a result of the economic assumptions that are part of that scenario. In the modeling sequence this change comes before the application of EEC savings. This increase in natural conservation within Scenario B has the effect of reducing the overall scope for EEC savings that remains to be captured, compared to the original Reference Case scenario. Savings for some measures would be slightly reduced in Scenario B, because they are more likely to be applied in a building with a more efficient boiler. Other than those interactive effects, however, natural conservation is independent of the EEC programs undertaken by the FEU.

36.2 Please show how the savings in Figure 4-1 were developed with reference to the savings estimates in Appendix C.

Response:

The savings estimates shown in Figure 4-1 on page 76 of Exhibit B are the total energy savings estimate outputs from the EEC analysis across all the FEU customer groups and service regions for each of the milestone years and future scenarios examined. Thus, adding up the savings estimates from residential customers (provided in Tables 4-2 and 4-3, pp 87 and 88 of the 2014 LTRP), commercial customers (provided in Tables 1A and 1B of Appendix C-3), and the industrial customers (provided in Tables 2A and 2B of Appendix C-3) will provide the total results depicted the milestone years 2016 and 2033 respectively in Figure 4-1.

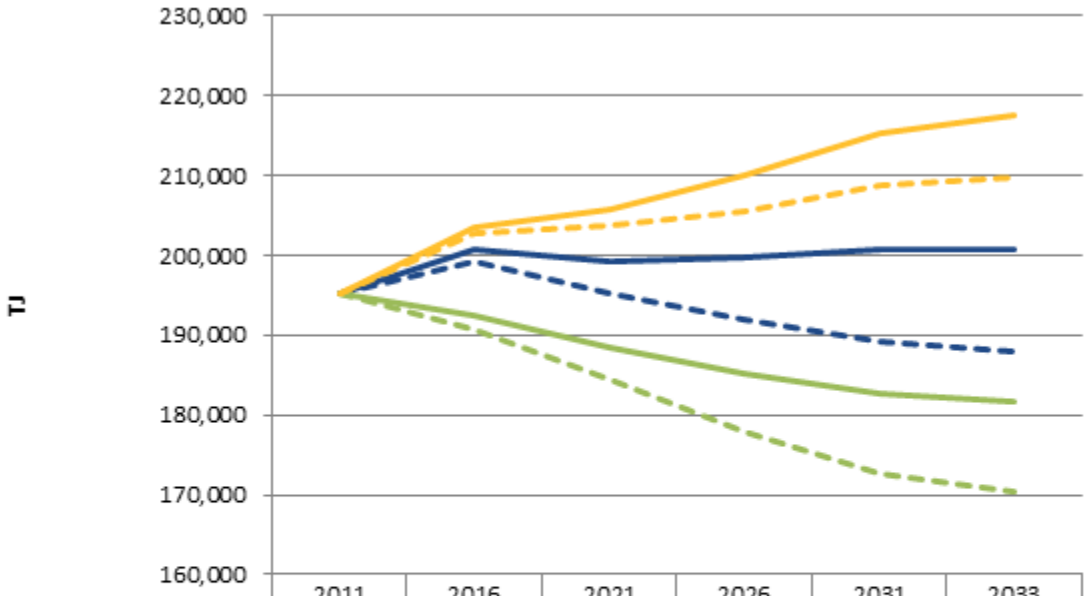
For ease of reading, the FEU did not include the tabular EEC savings for each of the milestone years, but rather provided only the next (2016) and last (2033) milestone years of results. However, the results for each scenario and all milestone years were used to create Figures 4-1, 4-3, 4-4, 4-5 and 4-6 in Section 4 of the LTRP as well as Figures 1 and 2 in Appendix C-3 of the LTRP.

The methodology used to develop all of these savings estimates is explained in Section 4.2.2 of the LTRP (exhibit B-1).

36.3 Please show figures comparable to Figure 3-12 on page 56 that shows the EEC savings for each scenario and the load forecast inclusive of the EEC savings for each scenario.

Response:

The Figure below contains the requested graphs. Because the FEU's intent is to show the potential range of total demand before and after EEC, and the annual demand Scenarios A and D, which resulted in annual demand outcomes between the highest and lowest demand results identified during the demand forecasting process, were not carried forward into the EEC analysis. Therefore the figure below contains the results of three annual demand scenarios (those being the Reference Case and Scenarios B and C) before and after EEC rather than the five scenarios shown in Figure 3-12.



	2011	2016	2021	2026	2031	2033
Reference Case	195,122	200,735	199,304	199,777	200,679	200,817
Reference Case after EEC	195,122	199,148	195,212	191,834	189,235	187,891
Scenario B	195,122	192,333	188,399	185,148	182,773	181,608
Scenario B after EEC	195,122	190,767	184,493	177,827	172,644	170,352
Scenario C	195,122	203,393	205,630	210,022	215,388	217,430
Scenario C after EEC	195,122	202,778	203,688	205,480	208,682	209,778

36.4 In the opinion of the FEU, is the range of forecast EEC savings sufficient to test the sensitivity of system resources needs and alternatives fully? Please explain your answer.

Response:

The range of forecast annual demand after estimated EEC savings identified in Section 4.2 of the LTRP and as shown in the response to BCUC IR 1.36.3 is not assumed to have any impact on system resource needs. System resource needs are driven by the peak demand requirements or system sustainment needs, not by the annual throughput on the system. Please see the discussion on pages 98 and 99 of Exhibit B-1 and the response to BCUC IR 1.48.1 for an explanation of why EEC is not assumed to impact peak demand.

In the opinion of the FEU, the range of forecast annual demand is sufficient to examine the risks and opportunities for the FEU over the planning horizon as a result of the full range of potential annual demand outcomes forecast, including estimated EEC savings.

37.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Appendix A-10; UCA, section 39

LNG Component of Demand Forecast

37.1 Please discuss FEU's obligation to serve Rate Schedule 46 customers under section 39 of the UCA for customers located outside the province of BC.

Response:

Under section 39, the public utility is required to provide service to

***… all** persons who*

(a) Apply for service,
(b) Are reasonably entitled to it, and
(c) *Pay or agree to pay the rates established for that service under this Act.* [Emphasis added]

In the case of RS 46, the asset providing the service under the Rate Schedule is located in BC and the title to the LNG dispensed is transferred in BC. With respect to potential customers, in the context of RS 46, section 39 of the UCA does not contain any wording that limits the service or the obligation to serve based on the geographic location of the potential customers.

37.2 Please confirm that Rate Schedule 46 is available on a first come, first serve basis regardless of the end-use requirement the customer has for the LNG purchased under this rate schedule. In particular, please confirm that parties who receive vehicle incentives from FEU do not have a higher priority of service relative to other LNG customers.

Response:

Confirmed.

Although the FEU provide service under Rate Schedule 46 regardless of the customer's end-use agreement and without giving a higher priority to any group of customers, as detailed in Section 3.3 of Rate Schedule 46, in the case of competing requests for LNG service, the FEU will give priority to a customer with a longer term agreement. In the case where the agreement term is the same, priority will be given to the customer with higher demand volume.

There is no discrimination or preference given to a customer based on the customer's end use requirement, nor are parties who receive vehicle incentives given higher priority than any other segment of customers. If there are competing requests for service, the provision of service is decided solely on the terms of the contract; specifically the length and demand volume as defined and approved under Rate Schedule 46.

37.2.1 If not confirmed, please explain and provide the reference to the applicable clause in Rate Schedule 46.

Response:

Please refer to response to BCUC IR 1.37.2.

38.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Appendix B-3

End-Use Annual Demand Forecasting Scenario Descriptions

Appendix B-3 lists the assumptions and interpretation and change in variable value relative to the reference case.

38.1 Please provide a table showing for each variable the value in the reference case and the value in the scenario analysis. An example table is shown below for the residential sector. Please correct any incorrect values since some examples require some speculation as to what was meant in the original table. Please also provide similar tables for the commercial and industrial sectors.

Residential					
Variable	**Scenario**	**Assumption**	**Value**	**Action Taken**	**Cumulative Result**
Commodity Price plus Carbon Price	Reference			???	2031 UPC increase/decrease of...
	A	Low gas price, high carbon price	Gas: $8.17/GJ	1% decrease in growth of gas heat dwellings	
			Carbon: $6.00 (rounded from $5.92?)	1% of existing gas furnaces switch to alt fuel	
			Combined: $14.17/GJ	1% of existing gas DHW switch to alt fuel.	UPC decrease of...
	B	Moderate to high gas price, moderate carbon price	Gas: $12.03/GJ	2% reduction in new gas ht	
			Carbon: $3.00 (rounded from $2.96?)	2% of replacement ducted gas heat switch to gas	
			Combined: $15.03/GJ	2% of replacement non-gas DHW switch to gas	EUI decrease of ...
	C	Low gas price, low carbon price	Gas: $7.64/GJ	9% increase in gas hear	Increase in UPC of ...
			Carbon: $1.48/GJ	9% of existing non-gas heat replace with gas	
			Combined: not specified ($9.12/GJ?)	9% of eligible non-gas DHW replace	
	D	Moderate gas price, moderate carbon price	Gas: $10.04/GJ	2% increase in growth of new gas heat dwellings	
			Carbon: $2.22/GJ ($2.25?)	2% of replacement ducted gas heat switch to gas	UPC decrease of ...
			Combined: 12.29/GJ	gas DHW switch to gas	
Economic growth	Reference	???	???	???	???
	A	Strong –	no change to housing starts relative to reference case	???	???
	B				
	C				
	D				
Government Policy					
Renewable, thermal and energy efficiency					
Regional energy strategies					

Response:

Please refer to Attachment 38.1, which contains a live spreadsheet in the above format for each of the three sectors.

38.1.1 For each of the categories in the tables provided in response to the above question, please identify the key variables and whether they are endogenous or exogenous variables.

Response:

All of the variables in the tables in response to BCUC IR 1.38.1 are adjusted exogenously to the model and manually input into the workbooks that feed the model.

39.0 Reference: ENERGY DEMAND FORECASTING

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

End-Use Annual Demand Forecasting Scenario Descriptions

Scenario A on page 3, in the last paragraph in the 'Actions Taken' column, states:

> "These three fuel choice adjustments, with 1% changes in each case, are introduced gradually, as the commodity and carbon prices gradually change. They produce a total change somewhat smaller than the result suggested by price elasticity, so there may be some additional reduction from the price change. In reality the carbon price may produce a mixture of fuel choice changes and efficiency improvements. For reasons of clarity, we have kept the efficiency changes separate, as a response to carbon reduction policy, below." (Exhibit B-1, Appendix B-3)

In other instances as well, the Utilities suggest that the results produced by the model are low relative to elasticity estimates (e.g. Scenario B. p. 15; Scenario C, p. 26; Scenario D, p. 37).

39.1 Are the fuel choice adjustments exogenous changes made to the model? If so, what was the reason for assuming that these changes were more reasonable than the elasticity estimates? Please explain.

Response:

Confirmed. The fuel choice adjustments are made exogenously to the model. The adjustments were made manually, by changing the assumptions such as what percentage of customers change fuels for a specific type of appliance as those appliances wear out and get replaced. There are practical and behavioral limitations on these decisions. The FEU and external consultants made adjustments that were realistic and then examined the consumption change that resulted. If the change overshot the fuel price elasticity described in the literature, the FEU and consultants reduced the adjustment. However, if the consumption change was less than the elasticity would predict, the FEU and consultants did not attempt to reach that level of change if it would require assumptions on people's fuel choices that were unrealistic based on our knowledge of the marketplace.

40.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Appendix B-3, p. 4

End-Use Annual Demand Forecasting Scenario Descriptions

Scenario A, on page 4, under the 'Strong Economic Growth' Assumption states: "Decision was to make no change in housing starts or housing types" (Exhibit B-1, Appendix B-3, p. 4).

40.1 Why was the decision made to make no change to the assumption of housing starts or housing types in spite of the strong economic growth assumption? Please explain.

Response:

According to our review of the literature, housing starts are more likely to be a leading indicator of economic growth than the reverse. Population growth is the main driver for home construction, and the changes in floor space in schools, retail, health care and other sectors also tend to follow, resulting in economic growth. Clearly, some specific examples of economic growth, such as rapid expansion of an industry (e.g., a new mine), will drive localized population growth in an area and hence expand housing construction, but these effects are difficult to see in economy-wide data.

41.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Appendix B-3, pp. 4–5

End-Use Annual Demand Forecasting Scenario Descriptions, District Energy

In the Interpretation column of Scenario A (pages 4–5) FEU states that:

> "There would also be an increased switch from natural gas towards renewable supply and district energy. Renewable energy is assumed to displace both natural gas and other fuels such as electricity. It is assumed to displace them in approximately the ratio of their initial shares of the end use."

In the Actions Taken column on pages 4 and 5, FEU states:

> "The share reached by district energy was based on an internal study of market potential done by FortisBC. The study assumed negligible penetration of the residential market before 2021. By 2030 a penetration of up to 0.37% (displacing natural gas) was estimated to be technically possible. Scenario A includes a somewhat less aggressive adoption curve for district energy, so we assumed penetration in 2031 would reach just over 0.25%."

41.1 Is it correct to conclude that this means a less aggressive adoption curve for district energy than the Reference Case? If not, please explain, what 'less aggressive' is relative too.

Response:

No, it is not correct that the adoption curve is less aggressive than the adoption curve for renewable thermal supply and district energy in the Reference Case. The FEU agree in hind sight that this reference may be confusing and will address it in future annual demand forecasting exercises. The stated reference to "less aggressive adoption curve" is made in relation to the most aggressive adoption curve considered for the four alternative future scenarios. That most aggressive adoption curve was included in Scenario B, so the phrase "less aggressive" is therefore relative to Scenario B.

41.1.1 If the statement is intended to mean less aggressive than the Reference Case, please identify the level of displacement of natural gas adopted by 2031 for the Reference Case.

Response:

Please refer to the response to BCUC IR 1.41.1. The level of displacement for natural gas by renewable thermal supply and district energy adopted by 2031 for the Reference Case is zero.

41.2 Why, for a scenario that suggests there would be an increased switch from natural gas towards renewable supply and district energy, does the model adopt a less aggressive adoption curve for district energy? Please explain.

Response:

Please refer to the responses to BCUC IRs 1.41.1 and 1.41.2. Scenario A has an increased switch from natural gas towards renewable supply and district energy compared to the Reference Case. It has a less aggressive adoption curve for district energy compared to the most aggressive adoption curve assumed within the four scenarios (i.e. compared to Scenario B).

41.3 How does the expansion of on-site thermal systems and district energy systems affect the load factor of the distribution system and peak day design forecasts? Please elaborate.

Response:

The referenced caption from Exhibit B-1 refers only to the end use annual demand forecast methodology. The impact of an on-site thermal and/or district energy system (referred to in the remainder of this response as a "renewable thermal system") on peak demand and load factor depends on the design and circumstance of the specific project. The following are some general examples:

- A renewable thermal system installed for new customers that in no way relies on natural gas will have no impact on peak demand or load factor.
- A renewable thermal system installed in a retrofit situation that in no way relies on natural gas will reduce peak demand and increase load factor.
- A renewable thermal system installed for new customers that relies on natural gas as back up or for peaking needs may increase demand and may decrease load factor. The

amount of the increase in peak demand could be less than if a conventional natural gas system served the entire load.

- A renewable thermal system installed in a retrofit situation that relies on natural gas for back up or peaking needs could reduce peak demand and may decrease load factor.
- A renewable thermal system installed for new customers that switches entirely to natural gas to serve all thermal needs during a peak event would increase the peak and decrease the load factor. The amount of the increase in peak would not be expected to be more than if a conventional natural gas system were installed instead of the renewable thermal system.

The specific design of each individual renewable thermal system will determine these and other implications for natural gas peak demand. The FEU have not yet been able to identify a discernable overall trend among these potential results within their service territory, but are continuing efforts to better understand the impact of renewable thermal systems.

42.0 Reference: DEMAND SIDE RESOURCES — IDENTIFICATION AND MEASUREMENT

Exhibit B-1, Application, Section 4, pp. 75, 82; Decision for Commission Order G-14-11 regarding TGI 2010 LTRP, p. 18; DSM Best Practices Update, IndEco 2010[11], p. 76

EEC Cost Effectiveness Tests

FEU states: "These [EEC] estimates are grounded in the results of the most recent Conservation Potential Review (CPR) study completed by FEU and the assumption that current funding levels … persist over the planning horizon. … The Companies believe it best to provide [an EEC] range that bounds the estimated achievable measures savings over the long term" (Exhibit B-1, pp. 75, 82).

The Commission states on page 18 of the TGI 2010 LTRP Decision (G-14-11) "The Terasen 2010 LTRP provides little detail to assist in the assessment of whether the EEC measures it will undertake in the future are adequate and cost effective."

IndEco 2010 report titled "DSM best practices update" states on page 76: "Conducting an independent audit of DSM activities is best practice as it provides an unbiased and independent review of DSM activities and results. … As required by their regulator, external third parties conduct audits of Enbridge and Union's DSM activities."

42.1 Does FEU consider that, to meet the requirements of the Resource Planning Guidelines, it should identify all cost effective EEC? If not, please explain why not.

Response:

Yes, although neither the BCUC's Resource Planning Guidelines nor the *Utilities Commission Act* stipulate that all cost-effective demand-side measures be implemented, the FEU do believe that the identification of all cost-effective EEC measures is an important step in the planning process to ensure that the Companies are addressing the Guidelines and meeting the requirements of the Act to pursue adequate, cost-effective demand-side measures. The Companies identify (in Appendix C-1 of Exhibit B-1) and include all cost-effective EEC measures (as defined by the TRC or MTRC where applicable) in the LTRP analysis and energy savings estimates. Analysis in the LTRP involves applying the CPR methodology to find all cost-effective measures under different future scenarios.

[11] http://www.cga.ca/wp-content/uploads/2011/02/CGA-DSM-Best-Practices-Report-2010-Update.pdf

42.1.1 Does FEU consider that a 20-year LTRP should examine a broader range of EEC funding options compared to that included in a five year performance based ratemaking (PBR) application (for example, as DSM Regulations may change significantly over a 20-year time period)? Please explain.

Response:

In the case of the FEU's 2014 LTRP, no, the FEU do not believe examining a broader range of funding options would provide additional, meaningful information for the LTRP. Both the 2014 LTRP and the 2014-2018 EEC Plan (submitted as part of the FEI 2014-2018 PBR Application) were prepared using the best available information and carefully considered all cost-effective demand side measures available to the FEU over their respective planning periods. The FEU have no basis against which to speculate regarding possible significant changes in regulations affecting DSM such that meaningful estimates of energy savings could be prepared. The FEU believe that $35 million in EEC funding represents what the market can reasonably expect to bear given market conditions and the regulatory framework and considering all cost effective EEC measures available. Less spending on EEC will, in all likelihood, result in less energy savings. The FEU believe that examining higher funding levels within the 2014 LTRP would not be a meaningful exercise.

It should be pointed out that the LTRP is submitted on a regular and relatively frequent basis (every 2 to 4 years) and changes in policy that impact demand forecasts or EEC savings will be picked up in subsequent iterations of the plan. The FEU believe a far better approach will be to conduct the next CPR as described on page 164 of Exhibit B-1, item 4 of the Action Plan, and incorporate any new information on achievable potential from that exercise in further examining appropriate funding levels beyond 2018 in a future iteration of the LTRP.

42.2 Please explain how the FEU CPR ties into the $35 million/year EEC budget included in FEU's LTRP.

Response:

The CPR identified achievable levels of EEC available to the FEU and made recommendations about the types of EEC programs that can be developed. The market information made available to the FEU via the CPR has informed successive EEC funding applications as well as program design and portfolio planning up to and including the 2014-2018 EEC Plan, filed as part of FEI's 2014-2018 PBR Application. The CPR information, combined with the experience of the FEU in delivering EEC programs has helped to establish the annual level of funding at $35

million as the approximate funding level that the FEU believe the market can absorb. The FEU believe this is a reasonable assumption to carry forward through the planning period for the purposes of estimating the amount of energy savings from EEC activity over the planning period, such that the FEU can provide a reasonable range of pre and post-EEC energy demand forecasts.

42.3 Does FEU consider that the Utility Cost Test (UCT) identifies the cost to the utility of meeting a customer's need for space and water heating through demand side rather than supply side resources? If not, please explain why not.

Response:

The UCT does not identify the costs to the utility for delivering a demand side measure or program; rather it compares the costs of delivering that measure or program to the cost of supplying the energy that is displaced by the program. The costs are an input to the UCT, not an output.

The FEU consider that the purpose of the UCT, as it is applied to EEC programs that target space heating and hot water demand, can be described as identifying whether it would be cost effective from the Companies' perspective for the utility to meet that portion of a customer's need for energy for heating and hot water that is targeted by the DSM program, through demand side activities rather than natural gas supply.

42.4 Does FEU consider that, in order to properly compare supply and demand side options, the UCT should include an estimate of the cost of emissions as a supply side cost? If not, please explain why not.

Response:

Please refer to the responses to BCUC IRs 1.1.4 and 1.2.1 regarding the appropriateness of comparing supply and demand side options in the FEU's 2014 LTRP. The FEU do believe that the cost of GHG emissions should be included appropriately in the cost effectiveness of EEC programs for the purpose of long term planning. It is the view of the FEU, however, that the TRC/MTRC is the appropriate vehicle to determine the cost-effectiveness of EEC measures.

42.4.1 What emissions value does FEU include in the UCT, and what range of cost of carbon estimates does FEU consider could reasonably be included in the UCT? Please explain.

Response:

The 2014 LTRP did not present UCT values for the planning period. UCT values for the 2014-2018 EEC Plan were presented at the program level in the 2014-2018 PBR application and included carbon cost at the rate of the current BC carbon tax ($1.50/GJ) in determining the avoided cost of gas. The FEU do not expect the carbon cost to change over the 2014-2018 period.

Beyond 2018, the FEU incorporated a range of carbon costs in determining which measures are cost effective according to the TRC or the mTRC as appropriate. The FEU believe that the Commission's current practice of determining cost effectiveness using the TRC/mTRC is appropriate.

The following range of carbon prices (from highest to lowest) were incorporated into the overall cost of gas included in the demand and EEC savings forecasts according to the future scenario descriptions developed for the LTRP, as presented in Appendix B-3 of Exhibit B-1:

- Scenario A incorporates the highest carbon price examined, which increases to $120/tonne by the end of the planning period resulting in a total price of gas of $14.17/GJ.
- Scenario B incorporates a moderate increase to the carbon price of $60/tonne by 2033 resulting in a total gas price of $15.03/GJ.
- Scenario D incorporates a modest increase in the carbon price to $45/tonne by 2033, resulting in a total gas price of $12.29/GJ.
- Scenario C incorporates the lowest carbon price, by maintaining it at the current level throughout the planning period.

Since Scenarios B and C resulted in the highest and lowest demand respectively, these were the alternative future scenarios within which EEC savings were estimated to determine post-EEC high and low total demand estimates. As such, a range of $30/tonne to $60/tonne were included in the examination of cost-effective measures, however, the overall gas cost including carbon costs in this analysis ranged from increasing to $9.75/GJ in scenario C to $15.03/GJ in scenario B by 2033.

The end use demand forecasting methodology was a key development in being able to analyze the potential impact of varying gas and carbon costs. In future LTRPs, this methodology will allow for the analysis of changing estimates of future gas and carbon costs as well as other potential cost implications that can be examined via alternative future scenarios.

42.5 Does FEU consider that a deliverable of the LTRP should be the cost to the utility, in $/GJ, of all EEC programs that provide a net societal benefit to BC, and that this could be shown in the form of (i) a levelized cost curve for EEC and (ii) different portfolio options at different average $/GJ price? If not, please explain why not.

Response:

The FEU include analysis of all EEC programs that are cost-effective as defined by the BC *Demand Side Measures Regulation*. The DSM Regulation does not include direction on what constitutes a "net societal benefit." The closest evaluation of EEC/DSM from a societal perspective is the MTRC. Cost effective DSM as defined by the MTRC portion of the DSM Regulation is included in the FEU's analysis of demand in the LTRP.

The FEU do not consider levelized cost curves to be a useful deliverable of its LTRP as the FEU do not directly compare demand and supply side resources as would a vertically integrated electric utility. Please refer to the response to BCUC IR 1.2.1.

The FEU do include consideration of different EEC portfolio options in the LTRP. Please refer to the response to BCUC IR 1.2.3.

42.6 In undertaking its EEC analysis, does FEU adjust the cost of gas estimate for (i) load shape (for example, heating vs. hot water load), (ii) the location of the measure or end-use and (iii) the persistence of savings? If yes, please explain how the adjustment is made. If no, please explain why not and estimate how the LRMC of gas could differ if these adjustments were made.

Response:

(i) The FEU did not adjust the cost of gas estimate for load shape. Adjusting for load shape implies that certain measures would have a greater or lesser impact on reducing peak demand and therefore would have a greater or lesser impact on avoiding capacity related infrastructure needs. Please refer to the response to BCUC IR 1.48.1 and Section 5.1.1.2 of Exhibit B-1, pp 98 and 99 for an explanation of why EEC is not assumed to have a significant impact on peak demand.

(ii) The FEU did not use a receipt point allocation in determining the calculation of the Commodity Cost component of the avoided cost of gas calculation, and so did not adjust the cost of gas estimate for the location of the measure or end-used. Doing so would result in a different cost effectiveness result for each installed measure and would be contrary to the FEU's principles of universal accessibility to EEC programs and consistent rates for customers throughout the province. As the avoided cost of gas calculation is meant to represent the marginal or most expensive, rather than the average cost in the gas portfolio, FEI instead derived a Sumas price for the commodity component. The FEU believe that their method of calculating the avoided cost of gas is an appropriate methodology which considers elements common to many utilities.

(iii) Consideration of the persistence of savings was included in the EEC savings estimates for various measures stemming from the original CPR.

42.7 Does FEU consider that there is inherently a level of uncertainty in estimating energy reductions from EEC, but that this can be addressed by (i) use of best practices in estimating energy reductions and (ii) independent review of these estimates? Please explain why or why not.

Response:

The FEU believe that there is inherently a greater level of uncertainty in estimating energy reductions from EEC activity over the long term than there is at the program planning and design stages. For this reason, the LTRP has not embarked on detailed program or portfolio planning over the 20 year planning period, but instead has estimated the energy savings that can be achieved over that period by examining all cost-effective demand side measures given known market conditions and the known regulatory framework. The FEU further believe that the best practices referred to in the above preamble are aimed at program and portfolio planning and design such as that which has been reviewed at great length as part of FEI's 2014-2018

PBR Application, and that a discussion of the merits of such best practices is more appropriately undertaken at that stage.

The FEU do not believe that further review of the FEU's EEC analysis from an independent third party, beyond that which is already being undertaken as part of this regulatory proceeding by current participants, will shed any further light on the uncertainties inherent in estimating energy savings over the long term. Nor do the FEU believe that there is any value to its customers for an additional third party review of the long term EEC analysis given the costs for such an activity and that the analysis in the CPR and the LTRP has already been conducted by a group of third-party consulting firms who are experts in demand side management.

The FEU would also like to note that the best practices discussed in the IndEco 2010 report titled "DSM best practices update" cited above are intended, in a broad sense, to apply to DSM program planning, design, evaluation and measurement, rather than to the analysis of energy savings estimates over the long term. The complete citation reads as follows:

> *"Conducting an independent audit of DSM activities is best practice as it provides an unbiased and independent review of DSM activities and results.*
>
> *Five of the Seven Participating LCDs (Enbridge, Gaz Metro, Manitoba Hydro, SaskEnergy, and Union) have an independent audit of their DSM activities. These independent audits are either conducted in-house, by a department external to those responsible for DSM activities, or by an external third party.*
>
> *Gaz Metro, Manitoba Hydro, and SaskEnergy all conduct internal, yet independent, audits of their DSM activities. Gaz Metro's accounting department conducts an annual audit of all departments, including the marketing department responsible for DSM activities. This audit examines the processes employed in administering DSM, including databanks used and how information is extracted and calculated (e.g. data quality, how calculations are done, source of data). The regulator and intervenors are also involved in the internal audit. This involvement takes the form of consultation meetings held four times a year. At these meeting Gaz Metro provides the intervenors and regulatory staff with information about its DSM activities and invites the regulator and intervenors to ask questions about the past year's data and about activities for the upcoming year.*
>
> *As required by their regulator, external third parties conduct audits of Enbridge and Union's DSM activities. The third party auditor conducts a review of the Evaluation Report produced by each of the LCDs."* (emphasis added)

From this report it is clear that the majority of LCUs (3 of the 5) conduct in-house independent reviews. This is also the practice of the FEU. Therefore, according to this IndEco best practice update, the FEU are an exemplar of independent DSM review best practice.

42.7.1 Does the estimation of energy savings from EEC follow best practices, and are the results reviewed by an independent third party? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 1.42.7.

42.8 Please provide the EEC budget allocated to (i) codes and standards and (ii) rate design, and provide a high level justification of the budgeted amounts.

Response:

The FEU's 2014 LTRP did not examine detailed program and portfolio level planning and did not assign budgets to specific program areas. The allocation of budgets to specific program areas such as codes and standards or rate design is a matter assessed as part of detailed program and portfolio level planning in a revenue requirement or PBR application; as was done in preparing the FEU's 2014- 2018 EEC Plan, filed as part of FEI's 2014-2018 PBR Application.

The FEU interpret "rate design" for the purposes of this question to indicate using rate design as a demand side management tool to motivate customers to lower their natural gas demand or shift their demand (peak shaping). Demand side pricing is typically used as a tool for peak shaping, usually in the form of price increases or Time of Use pricing. Please refer to the discussion on pages 98 and 99 of the Application (Exhibit B-1) and the response to BCUC IR 1.48.1 for an explanation of why EEC is not considered to have an impact on peak demand. As such, rate design has not been considered in the long term EEC analysis included in the 2014 LTRP.

43.0 Reference: DEMAND SIDE RESOURCES — IDENTIFICATION AND MEASUREMENT

Exhibit B-1, Application, Section 4, p. 75; FEI 2014–2018 PBR Application, Exhibit B-1-1, Appendix A, p. 3, Appendix I, Attachment I-1, p. 105, Exhibit B-11, BCUC IR 1.207.2.1

'Bottom-up' EEC Portfolio Options

FEU states "These [EEC] estimates are grounded in the results of the most recent [CPR] study completed by FEU…" (Exhibit B-1, p. 75).

FEU states in the FEI 2014–2018 PBR Application, Exhibit B-1-1, Appendix I, Attachment I-1, p. 105 that it has budgeted $500,000 for an update of the Conservation Potential Review (CPR) in 2015 and that the update is planned in collaboration with FortisBC (electric) and BC Hydro.

FEI states on page 3 of Appendix A to Exhibit B-1-1 of the FEI 2014 to 2018 PBR Application: "From FEI's perspective, the primary objectives of DSM are the increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources."

FEU states in BCUC IR 1.207.2.1 to the 2014 to 2018 FEI PBR Application: "The FEU are also mindful of rate impacts to its customers with EEC expenditures and in that regard have sought to undertake an appropriate level of cost-effective DSM." FEU states in BCUC IR 1.226.1 of the same application: "An increase in available funding may allow the inclusion of more measures ... while at the same time being mindful of customer rate impact." (Exhibit B-11)

43.1 Does FEU consider it would be appropriate, for the purpose of developing a 20 year plan, to model EEC budgets which reflect alternative approaches to defining 'cost effective' EEC? Please explain why or why not.

Response:

The FEU are unclear as to what is meant by "alternative approaches to defining 'cost-effective' EEC." Currently, the cost-effectiveness of EEC is defined by BC's *Demand Side Measures Regulation*. The FEU model cost-effective EEC as defined by the *Demand Side Measures Regulation* and according to industry standards, and have no other reliable basis with which to model "alternative approaches". Please also refer to the response to BCUC IR 1.42.1.1 regarding the consideration for modelling significant changes to DSM regulations.

43.2 Please estimate, in table and graph form, the 'bottom up' EEC funding proposal budget over the next 20 years, if all 'cost effective' EEC was included.

Response:

The FEU have included the "bottom up" EEC funding proposal of all cost-effective EEC in the 2014 LTRP. EEC measures included in the 2014 LTRP analysis were based on all cost effective measures, as determined in an update to the results of the most recent CPR. The analysis in the 2014 LTRP involves applying the CPR methodology to find all cost effective measures under different future scenarios over the planning horizon. EEC expenditures of approximately $35 million annually for all service regions over the planning horizon has been assumed based on a bottom up costing approach to the 2014-2018 EEC Plan as well as previous EEC funding applications and the FEU's expectation on the amount of EEC that the market will be able to uptake based on experience and third party DSM expertise.

The FEU plan to undertake a new CPR during the 2014-2018 period that will examine any new technologies and trends that have come to market since the last CPR was done, and will consider the level of market transformation that has occurred as a result of EEC programs to date. As a result, updated economic and achievable energy savings levels will be identified. This new level of savings potential will inform the updating of appropriate expenditure levels to be examined in future LTRPs and future EEC funding applications.

43.2.1 Please state how FEU has defined 'cost effective' and describe all assumptions made. Please also demonstrate how this portfolio ties into the CPR.

Response:

Currently, the cost-effectiveness of EEC is defined by BC's *Demand-side Measures Regulation*. The FEU apply cost effectiveness to EEC based on industry standards for calculating cost effectiveness and on the *Demand-side Measures Regulation*.

For the purposes of the 2014 LTRP, all cost effective EEC/DSM measures were identified by the Conservation Potential Review (CPR) as defined by the Demand Side Measures Regulation. The demand forecast in the 2014 LTRP allowed for some additional measures that were not considered cost effective under the TRC stipulations outlined in the Regulation at the time the CPR was developed in order to account for the modified Total Resource Cost (mTRC) stipulations in the current Regulation. To account for this, the LTRP consultant, ICF Marbek,

allowed some residential measures that were close to but below the TRC threshold to be included in the energy savings forecast.

Whereas the 2014-2018 EEC Plan addresses DSM Regulation adequacy requirements in detail, the 2014 LTRP considers the overall contribution of the individual measures that contribute to energy savings and GHG emissions reductions over the LTRP planning period. Future EEC plans developed beyond 2018 will address any requirements of adequacy that are in place at that time.

The CPR Summary Report is contained in Appendix C-2 of the 2014 LTRP and describes the study approach and methodology used to determine the potential for energy savings, along with the study results.

43.2.2 Please compare the cost, in $/GJ, of this EEC portfolio, and compare it to the cost in $/GJ of FEU's $35m/year proposal. Please also estimate the effect of this proposal on average customer bills (not rates) and emissions reductions compared to FEU's $35m/year proposal.

Response:

The approximately $35 million assumed for each of the EEC portfolios examined in the 2014 LTRP does include all cost effective measures as identified by the 2010 CPR (as updated to include 2011 year-end consumption data). There are no additional cost effective measures available to the FEU with which to create additional portfolios for the purpose of comparing costs, bill or rate impacts, or GHG reductions. Please also refer to the responses to BCUC IRs 1.43.1 and 1.2.3.

If, in the preamble, the BCUC is referring to some potential alternative budget based on the sentence "An increase in available funding may allow the inclusion of more measures" from the response to BCUC IR 1.226.1 cited in the preamble, the complete context of the question and this response should be reviewed.

The cited question refers to a hypothetical situation:

"Please describe the results FEU considers would be obtained *if there was an increase in available EEC funding for each residential EEC program with a positive UCT*."

The complete response states:

"An increase in available funding *may* allow the inclusion of more measures in a program, the provision of greater incentives, or increased marketing investments which may in turn increase

program participation and result in greater realized savings. *However,* FEU believes that the requested funding envelope provides a good balance of opportunities for customers to achieve energy savings while at the same time being mindful of customer rate impact. This is outlined further in the response to BCUC IR 1.224.1 and 1.224.1.1." [emphasis added]

The responses to BCUC IRs 1.224.1 and 224.1.1 in FEI's 2014-2018 PBR Plan Application lay out how the budget was arrived at. These responses indicate that the $35m/year budget is the one that the FEU believes is realistic and one that the FEU is comfortable with for the 2014-2018 EEC Plan.

Estimated emissions reductions from the FEU EEC Portfolios are included in the 2014 LTRP in Figure 4.7 on pg. 89.

43.3 Does FEU consider that an independent third party could undertake the next province wide CPR and provide BC utilities with portfolio options to include in their resource planning? If no, please explain why not.

Response:

The FEU, FortisBC Inc. (electric) and BC Hydro intend to work collaboratively on the next CPR, the actual preparation of which will be contracted to an independent third party. DSM options identified in the CPR will be used by the respective utilities in their resource planning.

44.0 Reference: DEMAND SIDE RESOURCES — IDENTIFICATION AND MEASUREMENT

Exhibit B-1, Application, Section 4, p. 75; RP Guidelines, p. 3; FEI 2014–2018 PBR Application, Exhibit B-24, BCUC IR 2.364.6.1; TGI 2010 LTRP, Exhibit B-1, p. E-9

'Top-down' EEC Portfolio Options

FEU states "These [EEC] estimates are grounded in … assumption that current funding levels of approximately $35 million annually ... persist over the planning horizon" (Exhibit B-1, p. 75).

The Resource Planning Guidelines state on page 3 "[Resource plan] Objectives include, but are not limited to: … equal consideration of DSM and supply resources."

The TGI 2010 LTRP Application (p. E-9) states:

> "… cost / benefit criteria for approval of EEC funding do not adequately consider the implications of carbon reduction targets. The Terasen Utilities examined both energy savings and GHG emissions reductions for different potential EEC funding scenarios, ranging from current approved funding only, to an ongoing increase in funding set at 5% of gross annual revenues (~$80 million annually) for the next 10 years."

FEI included the following table in response to BCUC IR 2.364.6.1 of the 2014–2018 FEI PBR Application (Exhibit B-24):

Year	2012 (actual)	2013 (forecast)	2014	2015	2016	2017	2018
Annual EEC Savings (TJ)	452.563	502.537	703.948	898.76	802.37	681.29	626.051
Annual Retail Sales Volumes (TJ)	168,793	169,949	170,567	172,102	173,473	174,797	175,656
Annual Energy Savings as % of retail sales	0.27%	0.30%	0.41%	0.52%	0.46%	0.39%	0.36%

44.1 Does FEU consider it would be appropriate, for the purpose of developing a 20-year plan, to model EEC budgets which reflect alternative 'top-down' approaches to developing an EEC budget? Please explain why or why not.

Response:

For the purposes of this response the FEU interpret "top-down" approaches to mean basing an EEC budget on a fixed amount, for example, as a fixed percentage of revenues as suggested in the response to BCUC IR 1.44.2.

The FEU do not believe it is appropriate to model EEC budgets which reflect alternative "top-down" approaches. Budgets set by top down approaches may or may not accurately reflect the potential level of cost-effective EEC activity. EEC potential is impacted by many variables

independent of retail sales volumes or utility revenues. Such variables include the impacts of market transformation from past EEC activity, new regulatory measures, evolved codes and standards, the price of natural gas, and the economic environment, among others. Therefore, the FEU consider that potential, future EEC activity should be identified in a comprehensive CPR, assessed for cost effectiveness according to the *Demand Side Measures Regulation*. Budgets would then be developed based on the result of the CPR and in consideration of past budget levels and program activity that provide some indication of the level of EEC that the market is comfortable with.

44.2 Does FEU consider that alternative EEC 'top-down' portfolio approaches could include setting the EEC budget at a fixed percentage of gross revenues and at a level required to generate a fixed percentage of TJ conservation? Please explain.

Response:

No. Please refer to the response to BCUC IR 1. 44.1

45.0 Reference: DEMAND SIDE RESOURCES — IDENTIFICATION AND MEASUREMENT

DSM Best Practices Update, IndEco 2010, p. 20

Benchmarking

The IndEco 2010 report titled "DSM best practices update" includes on page 20 a table titled "2009 DSM expenditures, by company, as a proportion of revenue."

45.1 Please reproduce Table 5 of the IndEco 2010 report titled "DSM best practices update" and include 2014 data for FEU. Please also provide updated data for the other Canadian utilities to the extent reasonably available.

Response:

The values provided for 2014 are the 2014 EEC budget requested in the FEI 2014-2018 PBR Application and forecast revenue and forecast gross margin at approved 2013 rates as reported in the FEI 2014-2018 PBR Application, and the 2014 FEVI and FEW revenue requirement applications.

2014 Requested EEC Expenditure ($millions)	Forecast Total Utility Revenue 2014 ($millions)	% of Total Utility Revenue	Forecast Utility Revenue Less Cost of Gas 2014 ($millions)	% of Utility Revenue Less Cost of Gas
34.4	1,327.7	2.6%	741.9	4.6%

The FEU cannot provide updated data for the other Canadian utilities as 2014 data is not publicly available from these utilities. A CGA DSM Working Group was set up to undertake an analysis of EEC spend as a percent of revenue for CGA utilities. This analysis had to be abandoned as the working group could not arrive at a common methodology for determining distribution plus gas commodity revenue. Further, the Information Request above asks about forward-looking information, and the available Canadian Gas Association data is backward-looking. This issue was covered extensively in the IR responses to BCUC IRs from the FortisBC Energy Inc. Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018.

Again, the FEU do not believe that this is a relevant question for the 2014 LTRP, as the LTRP does not attempt to design the EEC budget. Rather, the 2014 LTRP has estimated future savings on annual demand for natural gas based on all cost effective demand side measures as identified by the most recent Conservation Potential Review. A discussion of the EEC budget is more appropriate for FEU EEC Plans.

46.0 Reference: DEMAND SIDE RESOURCES — IDENTIFICATION AND MEASUREMENT

Exhibit B-1, Application, Section 4, pp. 74, 77; DSM Regulations, Section 3

Effect on Social Objectives

FEU describes on page 74 of the Application the objectives of EEC, and on page 77 of the Application states that the FEU 2014–2018 EEC Plan is 'adequate' for the purposes of Section 44.1(8)(c) of the UCA.

Section 3 of the DSM Regulations require that the DSM portfolio includes a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption and a demand-side measure intended specifically to improve the energy efficiency of rental accommodations.

46.1 Does FEU have any EEC programs (i) intended specifically at rental accommodations and (ii) targeted at rental accommodations in detached dwelling? If yes, please describe.

Response:

Yes. Within the 2014-2018 EEC Plan contained in the FEI PBR application, residential programs support demand side measures which are available to rental accommodations. Note also that a number of the Commercial and Low Income programs support demand side measures which are available to rental accommodations. Additionally the Companies provide support for demand side measures intended specifically to improve the energy efficiency of rental accommodations. Some of these include:

- **Energy Specialists**, through the Energy Specialist Program, are placed at BC Housing and the BC Non-Profit Housing Association. An Energy Specialist was also placed with the BC Apartment Owners and Managers Association (now a part of the BC Rental Housing Council), until that organization decided to terminate the position. These Energy Specialists are specifically tasked with finding and implementing energy efficiency initiatives within their organization's membership. Each of these three organizations is focused on rental accommodations and each serve the entire Province.
- In 2012 under the **Multi Unit Residential Building** (MURB) Program the Companies, in partnership with the City of Vancouver, participated in a pilot program to directly install low flow showerheads in multifamily rental accommodations. In 2013 the FEU are participating in a similar initiative, known as "Tap by Tap" in the Capital Regional District. In addition to low flow showerheads, Tap by Tap will also provide participants with low flow kitchen and bathroom faucet aerators. This program's primary target is multifamily rental accommodations, though stratas have not been explicitly excluded. The

Companies intend to continue support for these measures throughout the plan period, though at this early stage the proportion of support dedicated specifically to rental accommodations has not yet been established.

- The **Energy Savings Kit** (ESK) program streams participants living in an apartment (generally renters in this low income program) through to an ESK that includes only the measures specifically suited to apartment units.
- The **Energy Conservation Assistance Program** (ECAP) accommodates applicants that are renters by requiring a landlord consent form to accompany the application so that FEU can improve the energy efficiency in the rental accommodation (where the renter is low income).

Given the above, the FEU are of the belief that they have met all the requirements for rental accommodation adequacy, and will continue to do so throughout the 2014-18 plan period.

46.2 Does FEU consider it should, in its delivery of EEC to low-income customers, focus on programs that provide gas savings rather than those primarily driven by non-energy benefits? Please explain why or why not and describe the approach used by FEU for its low income EEC programs.

Response:

The FEU aim to design and offer low income programs that provide gas savings, while recognizing that there are significant non-energy benefits also provided by these programs. Low-income programs offer many non-energy benefits, such as improved air quality which can lead to improved health of the occupants and therefore reduce the burden on health care systems which all FEU ratepayers help support through their tax dollars. Additionally, low income programs must be considered in the context of equity and accessibility; low-income customers ultimately pay for EEC through rates, but are typically not in a financial situation to benefit from most EEC programs and measures. It is for these reasons that low income EEC programs should be designed by taking into consideration the non-energy benefits, while making the best efforts to provide energy savings that keep these programs cost effective as part of a portfolio deemed cost effective at the portfolio level.

Examples of FEUs' efforts to expand the energy savings potential of low income programs and keep these programs cost-effective under the current *Demand Side Measures Regulation* include: partnering with BC Hydro on low-income programs to reduce non-incentive costs; and, partnering with the Ministry of Social Development and Social Innovation on a mail-out to expand the Energy Savings Kit program awareness and reach.

46.3 In the LTRP, has FEU considered the inclusion of funding to support broader social objectives? Please explain why or why not, and how FEU determines the appropriate level of funding.

Response:

For the purposes of responding to this question, the FEU assume that the question refers to the EEC portfolio modeled in the demand scenario forecasts of the 2014 LTRP. As such, the FEU have inherently considered broad social objectives within the context of current provincial policy and regulation. The FEU have no other basis on which to assess 'broader social objectives'. The 2014 LTRP considers all cost-effective measures identified by the CPR and defined by the DSM Regulation. Please refer to the responses to BCUC IRs 1.42.1.1 and 1.42.2 for an explanation of how the FEU established the EEC funding level for the purposes of resources planning.

Whereas the 2014-2018 EEC Plan addresses DSM Regulation adequacy requirements in detail, the 2014 LTRP considers the overall contribution of the individual measures that contribute to energy savings and GHG emissions reductions over the LTRP planning period. The 2014 LTRP includes all cost-effective measures identified by the CPR and defined by the DSM Regulation. Additionally, the demand forecast in the 2014 LTRP allowed for some additional measures that were not considered cost effective under the TRC stipulations outlined in the Regulation at the time the CPR was developed in order to account for the modified Total Resource Cost (mTRC) stipulations in the current Regulation. To account for this, the LTRP consultant, ICF Marbek, allowed some residential measures that were close to but below the TRC threshold to be included in the energy savings forecast.

46.4 Please provide a graph and a table showing FEU EEC projected spending, as a percentage of total revenues, for each customer class for the last five years and forecast for the next 20 years. Please state all assumptions used, and explain any significant variations (by class or over time).

Response:

Please refer to Table 1.46.4 below. Percentages for 2014-18 are forecasts.

Revenue forecasts for the FEU do not exist beyond 2018[12]. Therefore, the FEU have limited the analysis period to the five year forecasting period from which the revenue forecasts that were embedded in the most recent revenue requirement application for FEI, FEVI and FEW were drawn. Any twenty year forecast would not provide meaningful information since it would involve very simple assumptions, such as a simple trend of nominal growth and inflation.

Further, given the simplifying assumptions that would be required (such as inflating the EEC expenditures and revenues both by the same inflation rate and holding EEC expenditures constant between the rate classes), the percentages shown during the remaining fifteen years are not expected to vary significantly from what is shown in 2018.

Notable variations from 2009-2013 are due to the fact that EEC activity was ramping up year to year over the initial EEC test period. In particular, there were no industrial EEC programs offered in 2009-2010. In the 2014-2018 PBR period, expenditures on commercial and industrial programs are proposed to increase over 2013 levels.

Table 1.46.4: FEU EEC spending, as percentage of total revenues, by customer class

	Residential[1]	Commecial[2]	Industrial[3]
	% of Total Utility Revenue	% of Total Utility Revenue	% of Total Utility Revenue
2009	0.6%	0.3%	0
2010	1.0%	1.0%	0
2011	1.2%	1.3%	0.2%
2012	2.2%	1.4%	0.4%
2013	2.2%	2.3%	0.9%
2014	2.4%	3.3%	2.0%
2015	2.8%	4.2%	2.6%
2016	2.7%	3.9%	3.2%
2017	2.7%	3.8%	3.3%
2018	2.9%	3.3%	3.9%

Notes:

Please note that reported revenues are revenues from FEU residential, commercial and industrial customers only (representing the rate schedules indicated below) and do not represent the total FEU revenues.

1. Rate Schedule 1
2. Rate Schedules 2, 3, 16, 23
3. Rate Schedules 4, 5, 6, 7, 22, 25, 27

[12] Section 8.9 of Exhibit B-1 provided a directional, 20-year view of FEI's **delivery rates** only.

In populating the table, the following assumptions were made in order to allocate EEC spending by customer class:

- All Low Income program costs were allocated to Residential.
- For 2009-2013, Portfolio level activities were allocated across customer classes based on a ratio of EEC Customer class spending to total EEC spending.
- For 2009-2013, Enabling Activities are included in Residential and are not double counted at the portfolio level.
- For 2009-2013, Conservation Education and Outreach ("CEO") activities were allocated to their respective customer classes. All non-program specific expenditures were allocated across customer classes based on a ratio of CEO Customer class spending to total CEO spending for the given year. For 2014 to 2018, CEO expenditures classed "School Education Program", were allocated to the Residential customer class.
- For 2011-2013, Innovative Technologies activities were allocated to their respective customer classes. All non-program specific expenditures were allocated across customer classes based on a ratio of Innovative Technologies Customer class spending to total Innovative Technologies spending for the given year.
- For 2014 and 2018, non-program specific Enabling Activities expenditures were allocated across customer classes based on a ratio of EEC Customer class spending to total EEC spending for the given year.

46.4.1 Are there any regional variations in access to EEC programs? Please explain.

Response:

The 2014 LTRP has been prepared assuming universal access (i.e. no regional variations to access) to EEC measures. Consideration of regional variations in customer needs for EEC programs and resulting program design is dealt with at the program design stage which is not part of the LTRP process.

47.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Application, Section 5, p. 95

System Resource Needs and Alternatives

On page 95 of the Application, FEU states:

> "… the FEU's system sustainment planning process has identified important near-term and longer term system renewal requirements, particularly in the Lower Mainland area of FEI's system. The FEU take a broad outlook that considers long term system capacity and sustainment plans, potential new, large increases in industrial load and growing NGT demand, which enables an integrated approach to determining the most effective system improvements."

47.1 Please identify, for each utility and region, which of the pipeline projects are to meet increasing demand and which are reliability-driven to meet existing demand.

Response:

Pipeline projects discussed in the 2014 LTRP on pages 95 to 131 are listed in the following table showing which ones are driven by reliability and/or increasing demand. In some cases, multiple alternatives exist to meet these drivers; this is shown by numbering and grouping the pipeline projects in a solid box. In general, when a pipeline is looped to address capacity concerns there is also an improvement in system reliability resulting from having two pipelines available to serve load.

47.1.1 Are there alternative system reliability measures currently in place to ensure existing demand is met safely and reliably? If so, please identify these measures.

Response:

Yes, FEI does have alternative system reliability measures currently in place to ensure existing demand is met safely and reliably. These measures are within the Integrity Management Plan (IMP).

The IMP is the primary management system the FEU use to ensure the integrity of gas system assets. It includes activities to monitor for hazards that may lead to failures, to mitigate such

hazards, and to manage integrity data. Activities monitored within the IMP include third party damage, natural hazards, pipe condition, material defects & equipment failures, construction and operations, class location management, odorization management, leak survey, and also core activities such as asset assessment and design, corrective work management, planning, and standards management. Together, these activities are fundamental to the FEU's commitment to the safe, efficient and reliable delivery of natural gas and propane to homes and businesses throughout British Columbia.

48.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Application, Section 5.1.1.2, pp. 98–99

System Capacity Planning Considerations

On page 98 of the Application, FEU states: "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" (Exhibit B-1).

48.1 Please discuss the factors that determine the extent to which EEC activities are expected to influence Peak Hour demand.

Response:

The effect of EEC activities on Peak demand is difficult to determine since different activities could lead to either a reduction or an increase in peak demand. This is dependent upon the specific mix of different EEC activities and daily or hourly coincidence of these activities.

Consider the following examples:

- Smart thermostats can be programmed to reduce space heating when it is not required while residents are at work or during the night when buildings are unoccupied or the occupants are sleeping. The furnace is then turned on at a specific time in the morning to heat the building. If there are several buildings requiring gas for heating at the same time, coincident demand, then the peak demand could increase.
- On demand water heaters only use gas when required to heat the water. If several different residences used on demand water heating simultaneously (e.g. 7am in preparation for work), that could lead to an increase in peak demand.
- Conversely, installation of high efficiency windows or insulation can lead to both a net reduction in average gas usage and a reduction in peak gas usage.

The FEU believe that the effect of EEC and changing end-use trends on peak demand cannot be predicted without knowing the details of specific equipment installations and that it is a reasonable approach to assume that these effects offset one another. To date, the FEU have not been able to identify any trends that indicate EEC activities are either increasing or decreasing peak demand.

48.1.1 If Peak Hour demand is influenced by EEC activities, how does this effect system capacity planning and in turn the growth infrastructure discussed, particularly for the Lower mainland?

Response:

Please refer to the response to BCUC IR 1.48.1.

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 will have a negligible effect on peak demand. Should any significant changes in peak demand actually occur, these changes would be captured as part of the annual load review process.

48.1.1.1 Where system design is based on peak hour demand to what extent could an increasing emphasis on EEC activities offset the requirements for system capacity increase?

Response:

Please refer to the response to BCUC IR 1.48.1.1.

49.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 5.1.1.2, p. 98; Figure 5-5, p. 108

Peak Hour Demand Forecast

On page 108, Figure 5-5: CTS Peak Demand and Capacity Curve to Serve the Coquitlam Area via the Nichol to Coquitlam Pipeline suggests that capacity reinforcements for the Nichol to Coquitlam area are designed to meet a peak hour forecast.

49.1 Is the peak hour forecast for reinforcement, such as the Nichol to Coquitlam pipeline, developed for the entire Coastal Transmission System or for a localized system in or around Coquitlam?

Response:

The peak hour forecast for reinforcement was developed for the entire Coastal Transmission System (CTS). Current capacity constraints on the CTS can be attributed to the Nichol to Coquitlam pipeline as shown in Figure 5-5 of Exhibit B-1.

49.2 How is the peak hour forecast developed?

Response:

The peak demand forecast is developed by multiplying the peak Use Per Customer (UPC) by the forecast number of customers on the gas system and adding other firm and committed loads.

The UPC is based on a regression of billed consumption data for *all* heat sensitive customers (e.g. those customers exhibiting an increase in usage with lower temperatures) against ambient temperature. This regression is then used to extrapolate to peak demand on the Design Degree Day (DDD). The DDD is the coldest mean daily temperature expected to occur once during a specified return period. The FEU use a return period of 20 years. This results in the Peak UPC. UPC values are reviewed annually and averaged over a three year period to smooth out variations in data. UPC values are generated for each different customer rate class and for customers within the same municipalities.

Account forecasts are generated for the different customer rate classes and multiplied by their respective Peak UPC's. This provides the core demand. For demands that vary on an hourly basis, the peak day demand forecast is converted to peak hour using a Peak Hour Factor. This factor is based upon empirical information which is representative of the relationship between

peak day demand and peak hourly demand. Due to the lower pressure and lack of usable line pack on the CTS, it has been historically modeled using a peak hour load.

Non-heat sensitive loads and firm load commitments are added to the core demand to arrive at the peak demand forecast.

50.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Application, Section 5.1.2.2, pp. 106–113

BC Hydro 2013 Integrated Resource Plan, Chapter 3 — Resource Options[13], pp. 54–55

Burrard Thermal Generating Station

On page 3-55 of their 2013 Integrated Resource Plan, BC Hydro states: "No energy is assumed from Burrard for planning purposes as a result of subsections 3(5) and 6(2)(b) of the CEA. Burrard cannot be relied on for dependable capacity after Mica Unit 6 goes into service in about 2016 as a result of the Burrard Thermal Electricity Regulation."

50.1 Please indicate the firm demand, in TJ/d, required to service all six thermal power units at Burrard Thermal Generating Station.

Response:

BC Hydro contracts for 275 TJ/d of capacity under the Bypass Transportation Agreement with FEI, of which 225-235 TJ/d is reserved for Burrard Thermal.

50.2 Please indicate if the firm demand for Burrard Thermal is included in the either the traditional annual demand forecasts or the end-use annual demand forecasts (reference case/scenarios).

Response:

For the end-use annual demand forecasts, actual billed consumption data was included. For the traditional forecast, annual demand was assumed to be approximately 470 TJ which was based on the 2011 consumption.

50.3 Please indicate if contractual obligations to reserve pipeline capacity to supply all six thermal power units at Burrard Thermal have changed since the compilation of this Application.

[13] http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0003-nov-2013-irp-chap-3.pdf

Response:

FEI has not received a notice of change to these contractual obligations since the time of compilation of the Long Term Resource Plan and response to this IR.

50.3.1 If yes, please present an updated version of Figure 5-5 on page 108 and Figure 5-6 on page 109 and please elaborate on any other amendments to the application.

Response:

Please refer to the response to BCUC IR 1.50.3.

50.3.2 If no, does FEU consider it reasonable to believe that contractual obligations will change when Mica Unit 6 goes into service?

Response:

The FEU consider it reasonable that the contractual obligations may change in the future. The FEU consider it reasonable not based necessarily upon Mica 6 coming into service but based upon the announcement made by the provincial government that directed BC Hydro to stop using Burrard Thermal for generation purposes and to only use it in a Transmission support role by 2016.

51.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Application, Section 5.1.2.3, p. 116

Interior Transmission System (ITS) Demand Forecast Sensitivity (Reference Case, High and Low Scenarios)

Figure 5-11 on page 116 shows the forecasted demand for the ITS.

51.1 Please explain what the specific limiting factors are that define the current capacity? What are the +/- (TJ/Day) margins on this capacity? For example what limits or what would be the impacts of operating the system at 5 percent or 10 percent above the current capacity?

Response:

Specific limiting factors that define the current capacity on the ITS include the requirement for ensuring:

- transmission mainline pressures are above a minimum threshold; and,
- inlet pressures to gate stations do not fall below a minimum threshold.

There is insufficient information available to comment on the statistical error bounds for the margins on this capacity.

With regards to operating the system above the current capacity: the system is limited by available compression power, the pipeline size and the maximum operating pressure. Because of these limits, the FEU can only operate the system at levels that provide supply up to the current capacity. Should the customer demand exceed the current capacity, then during a peak event there would be a drop in pressures resulting in customer outages.

51.1.1 How does this affect the accuracy of time frame (years) of the graph in figure 5-11?

Response:

Low, reference and high demand cases are used to determine general sensitivity to time frame. With major system reinforcements there can be several years required for planning, permitting and construction which necessitate early action to ensure reliable gas service.

51.1.1.1 The apparent rate of forecasted demand significantly increases in 2013; what factors causes this significant increase in forecasted demand?

Response:

Actual account numbers were used to compute the daily demand in 2012 whereas forecasted account numbers were used to compute future demand (e.g. beyond 2013). In this case the actual account numbers exceeded forecasted accounts for 2012 leading to a slightly elevated daily demand. Subsequently, the forecasted increase in demand from 2012 to 2013 was lower than that forecasted for the remainder of the planning window which leads to an apparent increase in forecasted demand at the start of the forecast period.

Also, it is not unreasonable to expect that there will be instances of higher and lower demand growth year-over-year due to changes in forecasts of local account additions.

52.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Application, Section 3.4.3, p. 63; Section 5.1.3.2, p. 121–122

Revelstoke Propane System

On page 121 of the Application FEU states:

> "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."

52.1 Please provide the current annual load requirement for Revelstoke.

Response:

The current annual load requirement for Revelstoke for the 2014/15 contracting year is approximately 228 TJ (8,925 M^3).

52.2 Please indicate the estimated timeline for completion of the conversion of Revelstoke's propane system to a natural gas system.

Response:

The FEU continue to examine the potential to convert Revelstoke's propane system to a natural gas system. At this time the FEU have not fully completed the pre-feasibility process and therefore do not yet have enough information to determine if the Companies should convert Revelstoke to natural gas. Should the FEU decide to proceed towards implementation of the conversion project, the earliest estimated timeline for completion of the conversion is Q3 2017.

52.3 Please provide a potential annual demand forecast for the Revelstoke area for each of the relevant years in the planning period. Be sure to include discussions of methods used and assumptions made when determining the forecast.

Response:

Revelstoke is included as part of the Interior region in the end use forecast and cannot be separated from the Interior demand.

The end use forecast base case for the Interior region is provided below.

Interior Reference Case
Annual Demand by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	17,305,707	17,219,413	16,809,769	16,805,131	16,830,168	16,761,241
Rate 2	6,083,324	6,262,017	6,375,016	6,451,259	6,504,747	6,520,757
Rate 3	2,926,922	2,787,120	2,744,157	2,701,249	2,663,697	2,644,111

The latest annual demand forecast for the Revelstoke area for the short term up to 2018 can be found in Appendix E2-5, FEI 2014-2018 PBR and is included here for completeness. Note that the units below are PJ.

Revelstoke Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Residential	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Total	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3

Based on 2016 data from both forecasts shown above, Revelstoke accounts for approximately 1.1% of the forecast 2016 energy demand.

52.4 Please update Figure 3-16, on page 62, to include the following plots:

i. Reference + NGT
ii. Reference + NGT + Woodfibre
iii. Reference + NGT + Woodfibre + Revelstoke
iv. Scen B + NGT
v. Scen C + NGT + Woodfibre + Revelstoke

Response:

Figure 3-16 shows annual demand forecasts. The long range annual demand forecast for Revelstoke has already been included in the reference portion as part of the Interior region demand, as described in the response to BCUC IR 1.52.3. Accordingly, no updates to Figure 3-16 are required.

53.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Application, Section 5.2.2.3, pp. 129–130

FEI Interior Transmission Systems

On page 129 of the Application FEU states:

> "Initial reviews have identified areas where there are integrity issues such as corrosion and security of supply vulnerabilities. While the FEU's Asset Management team is focusing on the more immediate concerns identified on the Coastal System, examination of the Interior Transmission System is an ongoing process that will result in a long term asset replacement plan for the Interior system. These identified conditions will provide a starting point for in-depth analysis that will be conducted in the future when FEI focuses more closely on sustainment issues in the Interior." (Exhibit B-1)

53.1 Please describe the areas and related integrity issues that FEU has identified in initial reviews.

Response:

The initial review of the Interior Transmission System led to the identification of integrity issues on certain segments of a number of pipelines, including the Castlegar-Nelson NPS6, Trail-Castlegar NPS8, Vernon-Penticton NPS12, and Penticton-Oliver NPS10 pipelines. The integrity issues identified on the segments of these pipelines include a history of minor and generally random leaks (primarily related to coating damage), difficulties in providing adequate cathodic protection (due to soil conditions or poor coating condition), the presence of hydrotechnical and/or geotechnical hazards, indication of anomalies in In-Line Inspection (ILI) data, and also security of supply issues (with respect to a number of the pipelines being the only source of supply into an area). As stated on Page 129 of the Application, these identified conditions provide a starting point for in-depth analysis to be conducted in the future, which will ultimately lead to the determination of any mitigating action that may be required.

53.1.1 To what extent can FEU say if the resolution of these integrity issues may provide opportunities to expand system capacity, or alternatively to reduce the need for expansion?

Response:

As integrity issues are identified, subsequent analysis typically leads to the determination of any mitigating action required. Depending on the mitigating action, opportunities to expand system capacity, or alternatively reduce the need for expansion may be identified. However, with regard to the FEI Interior Transmission System, integrity issues tend to be very localized relative to the length of the pipelines. As such, there is low probability that integrity issues alone will warrant a mitigating action significant enough to provide opportunities to expand system capacity, or reduce the need for expansion.

53.1.2 When does FEU expect that it will be able to focus on the ITS system integrity issues and complete its more detailed analysis?

Response:

The FEU would like to clarify that it is not ignoring the ITS system integrity and security of supply issues while significant focus is being devoted to the Coastal System. The FEU are conducting investigations, assessments and analysis to develop a long term plan for the Interior Transmission System. The FEU expect to produce the plan in 2015.

54.0 Reference: ENERGY DEMAND FORECASTING

BC Ferries — Transition to LNG Presentation[14], pp. 8–15

Potential Commercial Loads — BC Ferries

In a presentation titled "BC Ferries — Transition to LNG," prepared for Transportation Conference 2014: Facing the Future[15], BC Ferries outlined plans to replace 11 vessels over the next 10 years. On page 8 of the presentation BC Ferries restated their intent to proceed with ensuring new Intermediate Class Ferries have Dual Fuel capabilities, which would allow for operation using either LNG or Marine Diesel Oil. BC Ferries further discussed that they haven't ruled out future classes of vessels fueled only by LNG. On page 10 of the presentation BC Ferries indicated that the first LNG fueled vessel will likely be ready for service in spring 2016.

54.1 Please discuss to what extent, if any, this information was considered when preparing the NGT forecasts and peak day demand capacity planning.

Response:

The information presented by BC Ferries (BCF) was considered in formulating the initial years of the annual NGT forecasts and peak demand implications as presented in the 2014 LTRP. To date, BCF has committed to converting at least 3 marine vessels and will take incentive dollars under FEI's NGT Incentive Program towards this initiative. BCF has applied for incentive funding toward the purchase of 3 dual fuel marine vessels, with the first to be in operation by late 2016, and the remaining two vessels to be in operation in six month increments thereafter.

FEI felt that including LNG demand forecasts for 11 vessels over the next 10 years to be too uncertain and thus included only the plans by BCF to convert the immediate 3 vessels in the short term. It is reasonable to estimate that over the remaining portion of the planning period beyond 2017, some of the continued growth in NGT volumes in the reference and high NGT annual demand forecasts would be the result of additional marine vessels. The later portions of the NGT annual demand forecast were developed by assigning growth rates to the full category. As such the overall growth rate provides for a degree of increase within each subcategory including the marine category.

Pages 111 through 113 of the 2014 LTRP explain how the impact of this demand on peak capacity requirements was examined.

[14] http://www.acec-bc.ca/media/29434/B3%20BC%20Ferries%20Transition%20to%20LNG.pdf
[15] http://www.acec-bc.ca/events/transportation-conference.aspx

54.2 Is it reasonably possible that BC Ferries will approach FEU to provide supply and/or transportation service for LNG to fuel their vessels? If not, please discuss why.

Response:

To clarify, under the GGRR program, should BCF execute a contract for incentives, BCF would be required to take the supply of LNG from the FEU or repay the incentive. The FEU expect that an incentive agreement will be executed with BCF regarding the purchase of three dual fuel vessels. The FEU also expect that BCF will execute a Rate Schedule 46 agreement for supply of LNG to these ferries.

Transportation service is an optional element under Rate Schedule 46. At this point it is not clear whether BCF will elect to have the FEU provide the transportation or if they will explore other alternatives.

BCF have indicated that they may go through a public fuel procurement process to determine the successful service provider and the FEU may be competing with other potential suppliers.

54.3 If the forecasts were not previously included in the annual NGT demand and the peak day demand please prepare estimates based on the scenarios outlined in the presentation and discuss the impact that these would have on the current demand forecasts and thus, FEU's system capacity.

Response:

Please refer to response to BCUC IR 1.54.1.

54.4 If BC Ferries were to take LNG service for ferries from FEU, would FEU likely supply the LNG from Tilbury or Mt. Hayes? If Tilbury, has FEU included the addition of that load in its estimates of the potential total demand on Tilbury in combination with other potential demand including LNG for transportation, Revelstoke LNG conversion, and assisting in meeting the Lower Mainland winter peak? Please discuss.

Response:

BCF's fueling requirements are still being developed. At present it is understood that one vessel will fuel at Comox, one at Tsawwassen and the third is a relief vessel that may have more than one fueling location (Tsawwassen and Swartz Bay).

Under Rate Schedule 46 the FEU have flexibility to supply from either Mt Hayes or from Tilbury. It is likely that supply to Comox and Swartz Bay will be from Mt Hayes while supply to Tsawwassen will be from Tilbury.

To the extent that supply will come from Tilbury, the FEU have included these volumes in its estimates of the potential demand on Tilbury, in addition to the demand resulting from the NGT program, Revelstoke LNG conversion, and peak day demand from core customers.

55.0 Reference: GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Exhibit B-1, Application, Section 3.4.1. Figure 3-18, p. 65; Section 5, p. 132;

FEI 2014–2018 PBR Application, Exhibit B-11, BCUC IR 1.52.1

Supply Portfolio Planning

In the FEI 2014–2018 Multi-year Performance Based Ratemaking Application, in BCUC IR 1.52.1 FEI was asked to confirm that the following table was compiled from the forecast design peak day demand and annual normal demand used by FEI in determining the Annual Contracting Plan (ACP) for the each of the noted contract years and asked to confirm that the forecast design peak day demand for sales gas customers that is used to determine the load requirements for the FEI Annual Contracting Plan for corresponding upcoming contract year has consistently declined over the past five contract years.

ACP Filing	2009–10	2010–11	2011–12	2012–13	2013–14
Forecast Design Peak Day (TJ/d)	1281	1268	1240	1224	1218
Forecast Annual Normal Load (PJ/yr)	110	114.5	114.4	113.8	117.3

55.1 Please reconcile the consistent decline in peak day load requirements for FEI sales customers with the forecast increase in peak day requirements for the FEI core customers as shown in Figure 3-18 on page 65 of the Application.

Response:

The underlying assumption in the forecasting methodology is that the base year peak day requirement increases by future customer additions. This means that as the FEI customer base grows over time, the peak day forecast provided in each Annual Contracting Plan (ACP) also increases in the future. However, base year consumption changes over time as the result of many variables, such as Energy Efficiency and Conservation, updates to building codes and mix of household appliances.

FEI updates the base year peak day forecast annually with the most recent daily sent out data. The decline in peak day load requirements reflects the fact that actual customer consumption decreased in the past five years. However, the degree to which this decline occurs is difficult to predict with accuracy so that it is primarily seen each year after the next forecast is prepared. The effect this forecasting approach has is that the forecast peak day generally increases over a five year period while the base year is reset each year after consumption changes are factored in, which moves the overall forecast lower over time.

Given this forecasting uncertainty and the need to manage a portfolio of gas supply resources in a very constrained region, the FEU require a peak day forecast that is relatively accurate in the first year and then slightly conservative for the period thereafter. This conservatism is important to help prevent a potential shortfall in the availability of gas supply resources. FEI takes a cautious approach to planning the supply portfolio by assuming that the consumption of existing customers will remain unchanged in the future and that total forecast demand will increase in the future as the number of total customers grows. The fact that actual consumption has been generally declining somewhat is always embedded in the next design peak day forecast when the base year consumption is updated each year.

This approach helps to assure that any current ACP is based on a relatively accurate forecast for planning the requirements of the next gas year. The forecast design peak day forecast for the period after the initial year is only used for medium term planning scenarios in order to identify potential portfolio changes that should be considered more closely in future ACPs.

56.0 Reference: GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Exhibit B-1, Application, Appendix A-2, Figure 5, p. 12; Appendix E, p. E-3

Supply Portfolio Planning

On page 12 of Appendix A-2 of the Application FEU states:

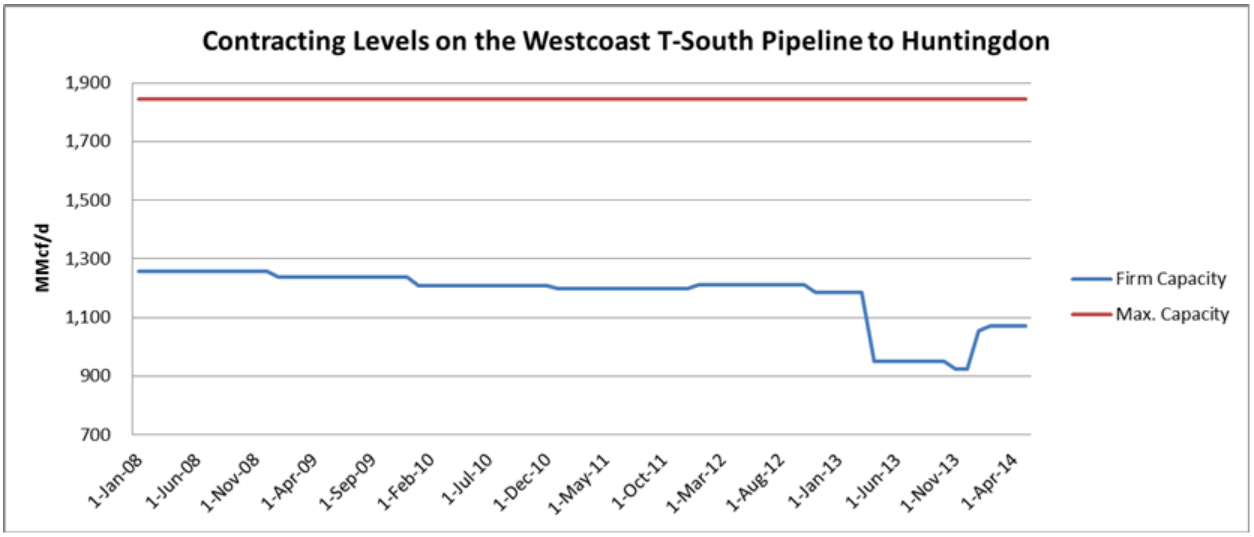
> "The Westcoast T-South system flows at maximum levels during cold or peak weather events. The lack of firm transportation contracting means that more supply to the Huntingdon market hub will flow via interruptible transportation during key demand periods in the winter. As interruptible transportation is subject to cuts when pipeline use reaches maximum capacity (which it does during peak load in the winter), this will reduce supply reliability at the Huntingdon market hub and increase the potential for price disconnections. An additional issue this contracting trend creates is higher tolling costs for firm shippers which, in turn, increases costs for natural gas customers. In response to these issues, FEI has reviewed, and will continue to assess, the level of Huntingdon supply that should be included in its gas supply portfolio." (Exhibit B-1)

On page E-3 of Appendix E, the FEI/FEVI 2013/2014 Annual Contracting Plan, the key elements of FEI's Commodity Portfolio regarding receipt point allocations for 2013/2014 are described.

56.1 Please provide an updated version of "Figure 5: Contracting Levels on the Westcoast T-South Pipeline to Huntingdon" on page 12 of Appendix A-2.

Response:

Figure 5 provided on page 12 of Appendix A-2 has been updated to include the most recent contracting information made public by Spectra as of May 2014. The overall level of firm contracting has increased slightly.



56.2 Please describe how FEI's strategy to reallocate the Commodity Portfolio reduced FEI's exposure to supply unreliability and price disconnects at Huntingdon over the past winter.

Response:

FEI has traditionally contracted for seasonal gas supply at the Huntingdon market hub to help meet winter loads. Contracting for this seasonal supply was discontinued starting the 2013/14 winter season because of risks associated with the decontracting of firm transportation capacity on Spectra's T-South transmission system that has the potential to adversely impact the reliability of the Huntingdon market hub. This is occurring because producers and marketers selling gas supply at the Huntingdon market hub are increasingly relying on interruptible transportation service to meet firm supply requirements. The availability of this supply is at risk during the winter when Spectra's T-South system flows at capacity and interruptible transportation service faces cuts. The impact of such cuts has increased price volatility that occurs as a result of counterparties attempting to overcome such transportation cuts in order to meet gas firm supply obligations.

This problem occurred during the past 2013/14 winter when demand exceeded Spectra's T-South system capacity and interruptible transportation was cut during two significant cold spells. This caused significant price spikes at the Huntingdon market hub. The first occurred during December 6-9, 2013 period, when prices reached a high of $10.50 US/MMBtu. The second occurred on February 6, 2014, when prices reached a high of $41.00 US/MMBtu. In contrast, prices at Station 2 were $3.72 US/MMBtu for December 6-9 and $19.18 US/MMBtu on February

6. By shifting away from the Huntingdon market hub this past winter, FEI was able to mitigate the impact of these price spikes and ensure the continued reliable supply of natural gas.

Customers may continue to benefit from the change in receipt point allocation because price volatility at Huntingdon may continue during periods of peak regional demand given the current capacity constraints on Spectra's T-South system and expectations of growing regional demand.

57.0 Reference: GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Exhibit B-1, Application, Appendix A-2, pp.12–13;

Exhibit A2-1, NWGA 2014 Gas Outlook, pp. 19–22;

Supply Portfolio Planning

On pages 12 to 13 of Appendix A-2 of the Application FEU discusses the impact of recent low contracting levels on the Westcoast T-South system and reliance on interruptible capacity.

The Northwest Gas Association's 2014 Gas Outlook (NWGA Report) which is filed as Exhibit A2-1 in this proceeding, discusses regional system capacity for the Pacific Northwest region, including the British Columbia, Washington, Oregon and Idaho. One of the key conclusions of the NWGA Report is: "Additional capacity is likely to be required within the forecast horizon to serve new demand for natural gas, particularly on a peak (design) day. Industrial and generation demand above the expected case will amplify and accelerate the need for incremental capacity" (NWGA 2014 Gas Outlook, p. 19).

Figure C2 on page 20 of the NWGA Report shows the region-wide peak day resource/demand balance for three demand scenarios.

The NWGA Report goes on to describe on page 22, three active regional infrastructure proposals: the Washington Expansion Project, the Northwest Market Access Expansion (N-MAX)/Cross Cascades Expansion and the Spectra/FortisBC System Enhancement Project.

57.1 Please discuss the extent to which each of these regional infrastructure projects would be expected to impact throughput on the Westcoast T-South system and the anticipated impact on T-South tolls and demand at Station 2.

Response:

If the Washington Expansion Project were to proceed, an expansion on systems upstream of Sumas/Huntingdon would likely be required, which could support an expansion on Spectra's T-South/T-North systems or a combination of Spectra FortisBC System Enhancement Project/T-South expansion.

- The T-South toll impact will be dependent on the amount of the T-South expansion and the use of existing uncontracted T-South capacity on the system. Spectra's T-North system is fully contracted at this time. In order to meet the possible expansion on the T-South system, Spectra will also likely require expanding its T-North system. A T-North expansion would increase the supply transported through to Station 2.

- A Spectra FortisBC System Enhancement Project would bring more supply to the Spectra system via FEI's interior system and would likely not increase T-South tolls and if anything at times this project would reduce the demand at Station 2.

The Northwest Market Access Expansion (N-MAX)/Cross Cascades Expansion would bring more supply to the Pacific NorthWest I-5 region from the south. If the project were to proceed to meet incremental baseload requirements in the region then the impact to the Spectra system would likely be minimal.

57.2 Please discuss the likelihood that increased regional demand and the three active infrastructure proposals described in the NWGA Report would tend to increase the cost-effectiveness of transporting gas from northeastern BC and Alberta to the FEU load centres over the forecast period.

Response:

Assuming adequate firm transportation commitments support the development of these infrastructure proposals, then the addition of new incremental base load demand in the region and subsequent infrastructure development should increase the cost effectiveness of transporting supply from northeastern BC and Alberta.

Additional demand is important because it will encourage new commitments from producers to increase production and flow gas to the region. This will increase utilization of existing infrastructure by absorbing spare transportation capacity and is an important driver for triggering future expansion requirements that will need to be implemented sooner than otherwise contemplated.

58.0 Reference: GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Exhibit B-1, Application, Section 6, p. 143; Appendix E, p. E-8

Supply Portfolio Planning

On page 143 of the Application, FEU states:

> "The FEU will continue to examine these regional developments and participate in regional project approval processes wherever they see a need to act to protect their customers' interests in maintaining secure, cost-effective supply sources and infrastructure over the long term. This includes continuing to examine potential opportunities on the FEU's own transmission and storage systems, such as expanding the FEI transmission system between Kingsvale and Oliver, in order to improve supply security and diversity for the region." [Emphasis Added] (Exhibit B-1)

On page E-8 of Appendix E, the FEI/FEVI 2013/2014 Annual Contracting Plans Executive Summary, FEU discusses the alternatives that FEI has in regard to the Midstream Portfolio for replacing expiring resources and/or meeting future growth requirements and states that "Additionally, FEI also has on-system gas supply from resources such as the Tilbury and Mt. Hayes LNG storage facilities that can provide high volume supply on short demand during periods of cold and extreme winter weather or emergency situations" (FEI/FEVI 2013/2014 ACP, Appendix E, p. E-8).

58.1 To the extent regional resources such as peaking gas at Huntingdon and/or market area storage at Jackson Prairie and Mist become more costly or unavailable, is the option of increasing either the number of days duration and/or peak day quantities sourced from the existing Tilbury and Mt. Hayes LNG storage facilities for the purpose of meeting the peak design day portfolio load requirements an alternative that is routinely evaluated as part of the annual contracting plan process? Please explain.

Response:

As part of the resource options the FEU consider in the annual contracting plan process, the FEU already take into account the full capability of the existing Tilbury and Mt Hayes facilities when optimizing the portfolio. Thus, the facilities are already fully utilized within the existing Annual Contracting Plans.

The key objectives of the ACP are for FEI to contract for resources that provide supply security, diversity and flexibility within the portfolio while minimizing overall portfolio costs over the short and long term. Market area storage and on-system resources are critical for FEI because they provide important balancing capabilities to manage intraday load fluctuations. On-system

resources, such as Mt Hayes and Tilbury LNG, offer greater security of supply as supply can be brought directly onto the FEI system on short notice at any time of the day.

The FEU also evaluate opportunities on an on-going basis within its own operating region to improve infrastructure leading to better diversity and reliability within the portfolio over the long term. For example, FEI is currently planning to expand the liquefaction and storage capacity at the Tilbury site, primarily to meet the growing market for LNG applications. This may provide an opportunity for the FEU to source additional on-system storage resources, in particular if additional vaporization facilities can be incorporated into the expanded facility. The addition of vaporization to the facility and ability to liquefy at a greater rate than the original peak shaving Tilbury facility could allow FEI to utilize this resource as a market area storage resource during cold weather events. FEI could potentially replace expiring Mist and NWP transportation contracts in the future or replace incremental resources that may be required to meet growing load requirements. The FEU will continue to assess this potential opportunity as part of the annual contracting process.

58.1.1 Does FEU envision it might potentially include additional peak day resources for the core market peak design day portfolio sourced from the expanded Tilbury LNG facility? Please elaborate.

Response:

Please refer to the response to BCUC IR 1.58.1.

59.0 Reference: GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Exhibit B-1, Application, Section 6, p. 140; Appendix A-2, pp. 1, 8-9

Price Risk Management

On page 140 of the Application, FEU states:

> "While the focus of price risk management in the past has been primarily on short term planning, the FEU believe the current market price 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." [Emphasis added] (Exhibit B-1)

On page 1 of Appendix A-2 of the Application, FEU states "British Columbia's reserve estimates have grown significantly to reach approximately 3,000 trillion cubic feet. B.C.'s natural gas potential is now considered to be second only to the Marcellus shale gas play…" (Exhibit B-1).

On pages 8 and 9 of Appendix A-2 of the Application, FEU discusses the potential impact of developments in BC by TransCanada with its NGTL system and states "these issues create the potential to increase regional transportation costs, affect future access to gas supplies at fair market prices, and reduce the liquidity of gas commodity markets at Station 2 and Huntingdon" (Exhibit B-1).

59.1 When FEU notes it is considering longer term instruments or tools such as fixed price purchases or investment in natural gas reserves in part to ensure security of supply for customers, is FEU suggesting that, in spite of BC's considerable gas reserves, gas supply may be unavailable to FEU on the competitive market in some circumstances in the future irrespective of the market price FEU may be willing to pay? Please elaborate further.

Response:

No. The FEU do believe that there will continue to be access to BC supply in the future. However, depending on how future infrastructure is developed, the FEU may not be able to access the supply, or may have reduced access to supply, at fair market prices and/or face price disconnects during periods of high demand. For example, the FEU currently source approximately 75% of its gas supply at the Station 2 market hub which is connected to Spectra's Westcoast T-North System. NGTL is continuing to propose expansions of its system into BC to give BC producers direct access to AECO/NIT market, which has the potential to entice volumes away from the Spectra system. .This may mean that the FEU have to pay higher

pipeline transportation costs than it has in the past to move supply to Station 2 or bid supply away from the NGTL system. This may be because of having to pay pipeline tolls on both NGTL and Spectra systems, as opposed to just the Spectra system, to access BC supply and/or pay a higher toll for Spectra pipeline transportation capacity due to lower Spectra system throughput.

The FEU are exploring the use of tools such as long term purchases (i.e. up to 10 years) or investment in natural gas reserves in part to ensure there are long term commitments to move natural gas to Station 2 or other access points where FEU holds firm transportation capacity to move the gas to its service areas. Please also refer to the response to BCUC IR 1.59.2.

59.2 On pages 8 and 9 of Appendix A-2, FEU suggests the infrastructure development in northeastern BC may result in the Spectra system not being cost-effectively connected to gas reserves. Please discuss how the acquisition of reserves by FEU would address the underlying issue of a potential lack of connection of the Spectra's Westcoast system to reserves.

Response:

By 'the acquisition of reserves' the FEU are referring to the potential to acquire part ownership of a specific gas production play which would give it control on how production from that play would be connected to market. Obviously, if the FEU were to consider acquiring reserves in Northeast BC, it would ensure it could contract for either existing or expansion capacity to move the production to Station 2 or some other point where the FEU can move the gas into its service areas. This could support higher usage (i.e. lower tolls) and potential expansion (i.e. greater liquidity) of the Spectra system.

60.0 Reference: GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Exhibit B-1, Application, Section 6, p. 140; Decision accompanying Order G-120-11 regarding FEI-FEVI 2011–2014 Price Risk Management Plan, p. 20

Price Risk Management

On page 140 of the FEU 2014 Long Term Resource Plan, FEU states "The FEU's price risk management activities are aimed at protecting customers from market price volatility and helping to ensure the competitiveness of natural gas."

On page 20 of the Reasons for Decision that accompanied Commission Order G-120-11, the Commission found that "the need for an objective related to the competitiveness of natural gas with other energy sources has not been established."

60.1 Does FEU intend to present further evidence to support the objective of ensuring competitiveness of natural gas as an appropriate objective for FEU's price risk management activities when FEU files its price risk management plan application?

Response:

The FEU are currently undergoing a review of its price risk management tools and strategy and is planning to submit a Price Risk Management Review Report to the Commission in mid-2014. FEU is conducting this review in light of the Commission directives in the Reasons for Decision that accompanied Commission Order G-120-11 regarding the FEI 2011-2014 Price Risk Management Plan, customer research and the recent increase in market gas prices and price volatility, particularly during winter 2013/14.

This review report will include a discussion of the FEU's price risk management objectives and make recommendations that take into account the Commission's conclusions in its decision. The review report will also review and report on the range of tools and instruments available to FEU to meet these objectives, the recently conducted research regarding customers' preferences in terms of rate stability and the recommended strategy going forward. The report will also include a discussion of the consideration of alternative rate offerings for customers. The review includes an assessment of both shorter-term as well as longer-term tools and instruments, which includes investment in natural gas reserves.

The FEU intend the proposed filing to be a review report that will form the basis for further consultation with BCUC staff and other stakeholders before making application for any specific action. As the review report is still under development, the FEU believe that process will be the proper forum to explore the further questions related to price risk management activities raised

by BCUC IRs 1.60.1.1, 1.60.2, 1.60.3, 1.60.4, 1.61.1, 1.61.1.1, 1.61.2, 1.61.3 and 1.61.4 if necessary.

60.1.1 If so, please describe the rationale and/or nature of the new evidence FEU intends to present in the application for a price risk management plan.

Response:

Please refer to the response to BCUC IR 1.60.1.

60.2 Does FEU agree that customers who wish protection from market price volatility have other alternatives such as the Customer Choice Program and/or transportation service? Please discuss.

Response:

Please refer to the response to BCUC IR 1.60.1.

60.3 Has FEU conducted surveys of its customers to determine the extent to which customers wish to be protected from market price volatility and how much they are willing to pay for such protection? If so, please describe these customer surveys and the results.

Response:

Please refer to the response to BCUC IR 1.60.1.

60.4 Is FEU considering developing rate alternatives that would provide the opportunity for those customers who wish to be protected from rate volatility to enroll in a rate that provided a higher level of rate stability? Please elaborate.

Response:

Please refer to the response to BCUC IR 1.60.1.

61.0 Reference: GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Exhibit B-1, Application, Section 6, p. 140; Commission's Generic Cost of Capital Proceeding (Stage 1) Decision, dated May 10, 2013, p. 114

Price Risk Management

On page 140 of the FEU 2014 LTRP, FEU discusses the prospect of FEU investing in natural gas reserves in order to provide long term cost certainty and help provide stability in rates, and also ensure security of supply for customers.

61.1 In FEU's view, is investing in gas reserves an activity that gas distribution utilities typically engage in? Please discuss.

Response:

Please refer to the response to BCUC IR 1.60.1.

61.1.1 Please provide examples of natural gas distribution utilities that have invested in natural gas reserves and describe the circumstances that led to such utilities investing in gas reserves.

Response:

Please refer to the response to BCUC IR 1.60.1.

61.2 Please describe the nature and extent of incremental resources, skill sets, tools or staffing that FEU would need to acquire in order to assess, purchase and manage investments in gas reserves.

Response:

Please refer to the response to BCUC IR 1.60.1.

61.3 Please describe how an investment in gas reserves by FEU would be treated for rate making purposes.

Response:

Please refer to the response to BCUC IR 1.60.1.

61.4 If FEU makes an investment in natural gas reserves would it impact FEU's risk profile? Please elaborate.

Response:

Please refer to the response to BCUC IR 1.60.1.

Attachment 18.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 19.11

Residence (Site) Address

& ID Code

November 5, 2012

Dear Customer,

At FortisBC, we're committed to providing a range of energy services to meet your needs today and tomorrow. Planning for your future needs means understanding how residential customers like you currently use energy and if you plan to change how you use energy in the future.

This survey is an important tool for understanding how energy is used in homes, the types of space and water heating appliances installed, how those appliances are used, the energy efficiency of homes and attitudes about energy issues.

This information is used to:

- forecast future demand for natural gas
- design energy efficiency programs to help you save money on your energy bills
- protect the environment by lowering greenhouse gas emissions

How to complete the survey

This survey should be completed by the person most responsible for the maintenance and repair of your home. Also please ensure that the survey responses refer to the residence located at the address shown above.

1. You can complete the enclosed survey and return it in the postage paid envelope provided; or

2. You can complete the survey online at, www.websurveys.ca/fbcreus by entering the survey id included at the top of this page.

You could win a $1,000 home improvement gift certificate

Return your completed survey by **December 24, 2012** and you'll be entered into a draw to **win one of four $1,000 gift certificates to a home improvement store near you.**

Complete the survey online and double your chances of winning. Full contest rules are at the back of the survey.

Privacy

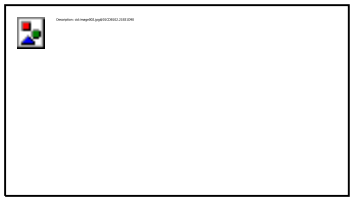
The survey will tell us how you use energy in your home. To meet the goals of this survey, FortisBC will also analyze how much natural gas your home has used over the past two years.*

To protect your privacy, Ipsos, the national market research company that is conducting this survey on behalf of FortisBC, will not have access to your account information. As well, FortisBC will not see your

individual responses. The information collected will be treated confidentially and in accordance with the provisions of the *Personal Information Protection* Act (British Columbia). The information collected will not be used for any marketing or sales purpose.

If you have any questions, please contact Walter Wright, Market Research, at 604-592-7653 or walter.wright@fortisbc.com.

Yours truly,



Tom Loski
Vice-President, Customer Service
FortisBC

**FortisBC Energy Inc. is administering this survey on behalf of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. By participating in this survey, I agree that the aforementioned FortisBC utilities may use and disclose between the FortisBC utilities, the consumption information for my home for the past two years.*

Instructions for Completing the Mail Survey
Some questions require you to place an "X" in the appropriate box, for example:

Do you rent or own this residence? Rent ☒ Own ☐

Some questions require you to fill in a number, for example: "23" years

Some questions allow you to check several answers. These questions will have the instruction "check all that apply."

When you have completed the survey, please put the questionnaire in the enclosed envelope. No postage is needed. Surveys are due by December 24, 2012.

If you have mislaid the return envelope, please mail the questionnaire to:

Ipsos
200 - 1285 West Pender
Vancouver, BC V6E 4B1

Dear Participant:

Throughout this questionnaire, when we ask about your home or residence, we are referring to area covered by your FortisBC bill. If you live in an apartment or townhouse complex, please do not include building hallways or outside lighting which are not covered by your own bill.

A. About This Residence

A1. Do you own or rent this residence?

☐ 1 Own/co-op → **CONTINUE**
☐ 2 Rent → **GO TO QUESTION A3**

A2. Do you pay maintenance fees?

☐ 1 Yes ☐ 2 No → **GO TO QUESTION A4**

A3. Which of the following are included in your rent or maintenance fees?

☐ 1 Heat
☐ 2 Hot water
☐ 3 Fuel for gas fireplace
☐ 0 None of the above
☐ 9 Don't know
☐ 4 Fuel for gas cooking
☐ 5 Fuel for gas clothes drying
☐ 6 Electricity

A4. Is this residence a…

☐ 1 Single family dwelling (detached)
☐ 2 Duplex
☐ 3 Row/townhouse (3 or more units attached each with separate entrance)
☐ 4 Apartment / Condominium
☐ 5 Mobile home
☐ 6 Other (please specify): _____

A5. When was this residence built?

☐ 1 Before 1950
☐ 2 1950-1975
☐ 3 1976-1985
☐ 4 1986-1995
☐ 5 1996-2005
☐ 6 2006 or later
☐ 9 Don't know

A6. Is this your principal residence?

☐ 1 Yes ☐ 2 No

A7. How many weeks per year is this residence occupied?

_____ weeks ☐ 1 Always occupied

A8. How many years have you lived in this residence?

_____ years

A9. What are the heights of the ceilings in this residence, excluding the basement? Please indicate the percentage of the residence with each ceiling height. Choose the closest height. Your answers should sum to 100%.

8 feet	_____
9 feet	_____
10 feet	_____
More than 10 feet	_____
TOTAL	**100%**

A10. What type of basement does your residence have?

☐ 1 No basement → **GO TO QUESTION A14**
☐ 2 Full basement
☐ 3 Crawl space → **GO TO QUESTION A13**
☐ 4 Partial basement

A11. Is the basement area of this residence…

☐ 1 Completely below ground ☐ 2 Completely above ground ☐ 3 Partially above ground

A12. Is the basement area of this residence unfinished, partly finished, or completely finished?

☐ 1 Unfinished ☐ 2 Partly finished ☐ 3 Completely finished

A13. During the heating season, is your basement or crawl space usually heated?

☐ 1 Yes ☐ 2 No

A14. What is the total floor area of this residence, including the basement and unfinished areas but excluding the garage or carport?

_____ Square feet OR _____ Square meters

A15. How many floors of heated living space does this residence have? (include basement if heated)

☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5+

A16. Does the electric bill for this residence cover any of the following, and if so, how many:

	Yes	No	Don't Know	Number
Secondary suite(s)	☐ 1	☐ 2	☐ 9	☐ 1 ☐ 2 ☐ 3 ☐ 4+
Detached garage / workshop	☐ 1	☐ 2	☐ 9	☐ 1 ☐ 2 ☐ 3 ☐ 4+
Other buildings (e.g., sheds, farm buildings)	☐ 1	☐ 2	☐ 9	☐ 1 ☐ 2 ☐ 3 ☐ 4+
1. Pumps (e.g., wells, irrigation, etc.)	☐ 1	☐ 2	☐ 9	☐ 1 ☐ 2 ☐ 3 ☐ 4+

A17. Please indicate which areas of this residence have insulation and if you know whether the insulation is below average, average or above average.

Location	Have insulation? Yes	No	Don't Know	Below Average (R6 or 1.75" fiberglass or less)	Average (R12 or 3.5" fiberglass or less)	Above Average (R20 or 6" fiberglass or more)	Don't know
In the attic	☐ 1	☐ 2	☐ 9	☐ 1	☐ 2	☐ 3	☐ 9
In your walls	☐ 1	☐ 2	☐ 9	☐ 1	☐ 2	☐ 3	☐ 9
In your basement / crawl space	☐ 1	☐ 2	☐ 9	☐ 1	☐ 2	☐ 3	☐ 9

A18. How effective is the draft proofing in this residence?

☐ 1 Not at all drafty ☐ 2 Sometimes drafty ☐ 3 Always drafty

A19. Please estimate what percentage of your windows are:

	% of Total Windows	Argon Gas Filled?
Single pane regular (clear) glass	_____%	
Double pane regular (clear) glass	_____%	☐ 1 Yes ☐ 2 No ☐ 9 Don't know
Double pane low-E*	_____%	☐ 1 Yes ☐ 2 No ☐ 9 Don't know
Triple pane regular (clear) glass	_____%	☐ 1 Yes ☐ 2 No ☐ 9 Don't know
Triple pane low-E*	_____%	☐ 1 Yes ☐ 2 No ☐ 9 Don't know
Other – Specify: _____	_____%	☐ 1 Yes ☐ 2 No ☐ 9 Don't know
	Total 100%	

** Low-E coated glass has a slight shading or tint when compared to standard windows.*

A20. Please estimate the percentage of your windows that have the following frames:

	% of Total Windows
Aluminum frames	_____%
Wood frames	_____%
Vinyl frames	_____%
Fiberglass frames	_____%
Other (please specify): _____	_____%
Total	100%

A21. Please indicate the number of outside doors in this residence. If this residence is an apartment or condominium, please count only doors in your unit that open directly to the outdoors.

	Number		Number
Wood doors	____ 1	Glass doors with wooden frames	____ 4
Wood doors with aluminum storm doors	____ 2	Glass doors with aluminum frames	____ 5
Insulated steel or fibreglass doors	____ 3	Glass doors with vinyl frames	____ 6

A22. Do you or anyone in your household use part of this residence as a full-time or part-time office from which they conduct a business?

☐ 1 Yes, full-time business ☐ 2 Yes, part-time business ☐ 3 No

B. Space Heating

B1. What is the main fuel used to heat this residence? The main fuel is the one that provides most of the heat in the home during a typical year. (Check one fuel only.)

Electricity ☐ 1	Bottled propane ☐ 4	Other ☐ 7
Natural gas ☐ 2	Oil ☐ 5	Don't know ☐ 9
Piped propane ☐ 3	Wood ☐ 6	

Do I have piped natural gas or piped propane service?

If you are a gas customer of FortisBC and live anywhere in British Columbia *other than Revelstoke*, your residence uses *natural gas*. Customers in Revelstoke receive their gas service in the form of piped propane. Propane from a refillable tank is considered "bottled" propane.

B2. Have you changed from one main fuel to another to heat this residence over the past five years?

Yes ☐ 1 → **CONTINUE**
No ☐ 2 → **GO TO QUESTION B4**

B3. What was the previous main space heating fuel? (check one fuel only)

Electricity ☐ 1	Bottled propane ☐ 4	Other ☐ 7
Natural gas ☐ 2	Oil ☐ 5	Don't know ☐ 9
Piped propane ☐ 3	Wood ☐ 6	

B4. Please indicate any OTHER fuel(s) used to heat this residence (check all that apply) and which OTHER fuel is used the most (check one only). Note: both air source and ground source (geothermal) heat pumps require electricity to operate.

	All OTHER Fuels *(check all that apply)*	**Most commonly used OTHER Fuel** *(check one only)*
Electricity	☐ 1	☐ 1
Natural gas	☐ 2	☐ 2
Piped propane	☐ 3	☐ 3
Bottled propane	☐ 4	☐ 4
Oil	☐ 5	☐ 5
Wood	☐ 6	☐ 6
Other	☐ 7	☐ 7
Don't know	☐ 9	☐ 9

UNLESS OTHERWISE STATED, ANY REFERENCES TO "GAS" FROM THIS POINT FORWARD IN THE SURVEY MEAN EITHER NATURAL GAS OR PROPANE GAS.

B5. There are several methods that can be used to heat a home. Please check the main method used to heat this residence, then the second most used method, and then all other methods used to heat this residence.

	Main method *(check one only)*	Second most used method *(check one only)*	All other methods *(check all that apply)*
Central forced air furnace	☐ 1	☐ 1	☐ 1
Multi-fuel forced air furnace	☐ 2	☐ 2	☐ 2
Wired-in electric heater (baseboards)	☐ 3	☐ 3	☐ 3
Wired-in electric wall heater (fan forced)	☐ 4	☐ 4	☐ 4
Heat pump–air source	☐ 5	☐ 5	☐ 5
Heat pump – ground source (geothermal)	☐ 6	☐ 6	☐ 6
Hot water baseboards	☐ 7	☐ 7	☐ 7
Hot water radiant in-floor / underfloor heat	☐ 8	☐ 8	☐ 8
Electric radiant heat (floors, walls, and/or ceilings)	☐ 9	☐ 9	☐ 9
Gas wall heater	☐ 10	☐ 10	☐ 10
Portable electric heaters	☐ 11	☐ 11	☐ 11
Gas fireplace	☐ 12	☐ 12	☐ 12
Gas heater stove	☐ 13	☐ 13	☐ 13
Wood stove	☐ 14	☐ 14	☐ 14
Wood burning fireplace	☐ 15	☐ 15	☐ 15
Electric fireplace	☐ 16	☐ 16	☐ 16
Other (Specify) _____	☐ 17	☐ 17	☐ 17

IF THIS RESIDENCE DOES NOT HAVE A GAS FURNACE, ELECTRIC FURNACE, OR GAS BOILER, GO TO QUESTION B18

B6. Which of the following does this residence have?

☐ 1 Gas boiler → **GO TO QUESTION B7**
☐ 2 Gas furnace → **GO TO QUESTION B8**
☐ 3 Electric furnace → **GO TO QUESTION B12**
☐ 0 None of the above → **GO TO QUESTION B18**

B7. Boiler efficiency refers to how much useful heat your boiler extracts from the gas. The higher the efficiency of the boiler, the less fuel is required to heat your house. Boilers are categorized as low efficiency, mid-efficiency, or high efficiency.

What is the efficiency of your boiler?

☐ 1 Low efficiency – 60% efficient
☐ 2 Mid-efficiency – 80% to 85% efficient
☐ 3 High efficiency – 90% efficient or higher
☐ 9 Don't know

→ **GO TO QUESTION B9**

B8. Furnace efficiency refers to how much useful heat your furnace extracts from the gas. The higher the efficiency of the furnace, the less fuel is required is to heat your house. Furnaces are categorized as low (standard) efficiency, mid-efficiency, or high efficiency.

What is the efficiency of your gas furnace?

☐ 1 Low (standard) efficiency – less than 78% efficient
☐ 2 Mid-efficiency – 78% to 85% efficient
☐ 3 High efficiency – 90% efficient or higher
☐ 9 Don't know

Gas Boiler Types

Low Efficiency Gas Boilers:
- 13 years old or older
- 60% efficient
- uses a standing pilot light

Mid-Efficiency Gas Boilers:
- 80% to 85% efficient
- no pilot light, uses igniter instead
- uses induced draft fan or damper

High Efficiency Gas Boilers:
- 90% efficient or higher
- no pilot light, uses igniter instead
- uses plastic exhaust pipe that exits the roof or side of house

Gas Furnace Types

Low (Standard) Efficiency Gas Furnaces:
- 18 years old or older
- less than 78% efficient
- typically uses a pilot light
- uses metal flue that exits the roof

Mid-Efficiency Gas Furnaces:
- 78% to 85% efficient
- no pilot light, uses igniter instead
- uses a metal flue that exits the roof

High Efficiency Gas Furnaces:
- 90% efficient or higher
- no pilot light, uses igniter instead
- uses plastic exhaust pipe that exits the side of the house.
- ENERGY STAR qualified

B9. Is your gas furnace or boiler an ENERGY STAR® qualified model?

☐ 1 Yes ☐ 2 No ☐ 9 Don't Know

ENERGY STAR® qualified products are some of the most energy efficient products that you can buy today. ENERGY STAR products will display the ENERGY STAR logo on the product or its packaging when new.

B10. Has a gas furnace or gas boiler been installed in this residence in the past five years?

Yes ☐ 1 → **CONTINUE**
No ☐ 2 } → **GO TO QUESTION B12**
Don't know ☐ 9 }

B11. What was the main reason for installing a natural gas furnace or natural gas boiler? (Check one reason only)

☐ 1 New home
☐ 2 Wanted to change to gas
☐ 3 Wanted more efficient furnace or boiler
☐ 4 Existing furnace or boiler had failed
☐ 5 Anticipated furnace or boiler failure
☐ 6 Wanted an environmentally friendly fuel
☐ 7 Wanted a lower cost fuel
☐ 8 Other (please specify): _____

B12. How old is your furnace or boiler? _____ years ☐ 9 Don't know

RESIDENCES WITH GAS OR ELECTRIC FURNACES

B13. How often does your furnace fan blower operate? Choose the best answer.

☐ 1 Only when furnace is operating
☐ 2 Only when furnace or air conditioning is operating
☐ 3 Continuously during the heating season
☐ 4 Continuously during the heating and cooling season
☐ 5 Continuously year round → **GO TO QUESTION B15**
☐ 9 Don't know

B14. In addition to the above, do you also turn on the furnace fan to provide ventilation for part of the year?

☐ 1 Yes → **How many weeks per year does the furnace fan operate in this mode?** _____ weeks
☐ 2 No

B15. Does your furnace have a high efficiency blower motor (often called a variable speed motor or electronically controlled motor (ECM))?

☐ 1 Yes ☐ 2 No ☐ 9 Don't know

B16. Have you undertaken any repairs to your furnace or boiler during the past three years?

Yes ☐ 1
No ☐ 2 } → **GO TO QUESTION B18**
Don't know ☐ 9 }

B17. In total, how much did you spend on repairs to your furnace or boiler over the past three years?

$ _____ ☐ 999 Don't know

B18. Please indicate whether you always, usually, occasionally or never do the following (check one box per row).

	Always	Usually	Occasion-ally	Never	Don't know	Not Applicable
Change the furnace filter regularly	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
Have the heating system serviced annually by a contractor	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
Service the heating system annually myself	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

B19. How many rooms in this residence are heated? (Exclude bathrooms, closets and hallways)

Number of rooms that are always heated _____
Number of rooms that are sometimes heated _____
Number of rooms that are rarely or never heated _____

B20. Do you use programmable thermostat(s) in this residence? ☐ 1 Yes ☐ 2 No ☐ 9 Don't Know

C. Fireplaces and Heater Stoves

Many homes are equipped with fireplaces or heater stoves. Some provide ambiance but little or no heat, while others can be used to heat one or more rooms.

C1. Do you have a fireplace or heating stove in this residence?

Yes ☐ 1 → **CONTINUE**
No ☐ 2 → **GO TO SECTION D**

Gas Fireplace and Stove Types

Decorative fireplaces – Provide ambiance but have little or no heating ability. The firebox is typically steel or masonry, and the hearth is often open to the room or equipped with opening glass doors.

Heater type fireplaces (built-ins and inserts) – These fireplaces are efficient heaters with fixed glass fronts and may have features such as fans and thermostatic control. They may be built-in at the time of construction, or inserted into an existing masonry or other fireplace as an upgrade.

Free standing fireplaces and heater stoves – These are stand alone units that that can be used for both ambiance and heating. Gas heater stoves resemble wood stoves in appearance but use gas instead of wood.

C2. How many of the following types of fireplaces and heater stoves do you have? For each type, please indicate whether they are used primarily for heating, ambiance or both.

	Number (Check one) type that you have)				Used primarily for:		
	1	2	3	4+	Heating	Ambiance	Both
Gas (decorative)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Gas (heater type)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Gas (free standing)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Electric	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Wood burning fireplace	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Wood burning stove	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Other: _____	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3

C3. How many hours are the fireplaces and heater stoves in use during a typical week in each of the following seasons? Please sum the total hours for ALL fireplaces and heater stoves used in a typical week in each season.

Summer (July – September) _____ hours per week
Fall (October – December) _____ hours per week
Winter (January – March) _____ hours per week
Spring (April – June) _____ hours per week

C4. Approximately, what share of this residence's space heating requirements are provided by your fireplace or heater stove? Please include all fireplaces and heater stoves at this residence in your answer.

0% (none) ☐ 0
Up to 10% ☐ 1
Up to 25% ☐ 2
Up to 50% ☐ 3
Up to 75% ☐ 4
Up to 100% ☐ 5
Don't know ☐ 9

IF THIS RESIDENCE DOES NOT HAVE A GAS FIREPLACE, GO TO SECTION D

C5. How old is (are) your gas fireplace(s)?

Gas fireplace 1 _____ years Don't know ☐ 99
Gas fireplace 2 _____ years Don't know ☐ 99
Gas fireplace 3 _____ years Don't know ☐ 99

C6. For each gas fireplace you have, please indicate whether it has a fixed glass front, glass doors that open, or an open hearth design (no glass) by checking the appropriate box.

	Gas Fireplace 1	Gas Fireplace 2	Gas Fireplace 3
Fixed glass front	☐ 1	☐ 1	☐ 1
Glass doors that open	☐ 2	☐ 2	☐ 2
No glass (open hearth)	☐ 3	☐ 3	☐ 3

C7. For each gas fireplace you have, please indicate whether it has a pilot light? The pilot light is a small flame that is used to ignite the fireplace.

	Gas Fireplace 1	Gas Fireplace 2	Gas Fireplace 3
Yes	☐ 1	☐ 1	☐ 1
No	☐ 2	☐ 2	☐ 2
Don't know	☐ 3	☐ 3	☐ 3

C8. GAS FIREPLACES WITH PILOT LIGHTS ONLY: Do you typically turn off your fireplace pilot light? If yes, how many months is the pilot light typically turned off?

Yes ☐ 1 → **Number of months per year pilot light off: _____**
No ☐ 2 } → **GO TO SECTION D**
Don't know ☐ 9 }

C9. Who typically re-lights the pilot light for your gas fireplace?

☐ 1 Myself
☐ 2 Contractor
☐ 3 Some other member of my household
☐ 4 Other: _____
☐ 9 Don't' Know

D. Domestic Water Heating

D1. How many water heaters are there in this residence? If you live in an apartment, townhouse, or row house where hot water is centrally provided to all units (from outside your unit), please check "none".

1 ☐
2 ☐
3 ☐
None ☐ → **GO TO QUESTION D15**

D2. What type of fuel does your water heater(s) use? Homes with more than one water heater usually have one water heater that provides more hot water than the others. For classification purposes, consider this unit your main water heater.

	Heater 1 (Main Unit)	Heater 2	Heater 3
Electricity	☐ 1	☐ 1	☐ 1
Natural gas	☐ 2	☐ 2	☐ 2
Piped propane	☐ 3	☐ 3	☐ 3
Bottled propane	☐ 4	☐ 4	☐ 4
Solar	☐ 5	☐ 5	☐ 5
Oil	☐ 6	☐ 6	☐ 6
Geothermal	☐ 7	☐ 7	☐ 7
Other	☐ 8	☐ 8	☐ 8

Water Heater Fuels: Hint

Most hot water heaters use gas, oil or electricity. If your hot water heater has a flue/vent then it uses gas or oil. If there is no vent then it uses electricity. Please consider the fuels used in your house when completing this question.

D3. Please indicate whether the water heater(s) uses solar energy to pre-warm or supplement the water heating process.

	Heater 1 (Main Unit)	Heater 2	Heater 3
Yes	☐ 1	☐ 1	☐ 1
No	☐ 2	☐ 2	☐ 2

D4. Have you changed the water heating fuel at this residence within the past five years?

Yes ☐ 1 → **CONTINUE** No ☐ 2 → **GO TO QUESTION D6**

D5. What was the previous water heater fuel?

	Heater 1 (Main Unit)	Heater 2	Heater 3
Electricity	☐ 1	☐ 1	☐ 1
Natural gas	☐ 2	☐ 2	☐ 2
Piped propane	☐ 3	☐ 3	☐ 3
Bottled propane	☐ 4	☐ 4	☐ 4
Solar	☐ 5	☐ 5	☐ 5
Oil	☐ 6	☐ 6	☐ 6
Geothermal	☐ 7	☐ 7	☐ 7
Other	☐ 8	☐ 8	☐ 8

D6. What types of water heater(s) are there in this residence?

	Heater 1 (Main Unit)	Heater 2	Heater 3
Conventional storage (tank)	☐ 1	☐ 1	☐ 1
On-demand (tankless)	☐ 2	☐ 2	☐ 2
Hybrid on-demand (uses small storage tank)	☐ 3	☐ 3	☐ 3
Combined space and water heater	☐ 4	☐ 4	☐ 4
Hybrid heat pump water heater (tank)	☐ 5	☐ 5	☐ 5
Don't know	☐ 9	☐ 9	☐ 9

Tankless & Hybrid On-Demand Water Heaters

On-demand (tankless) water heaters, also known as instantaneous water heaters, are compact units that provide hot water on demand. Hybrid on-demand models use a small storage tank to reduce temperature fluctuations during use.

Hybrid heat pump water heaters combine a heat pump with an electric hot water tank to improve energy efficiency.

D7. If this residence has a conventional storage (tank) water heater, does it have a:

	Heater 1 (Main Unit)	Heater 2	Heater 3
Vent through the side wall	☐ 1	☐ 1	☐ 1
Vent through the roof	☐ 2	☐ 2	☐ 2
No vent (electric tank)	☐ 3	☐ 3	☐ 3
Don't know	☐ 9	☐ 9	☐ 9

D8. If this residence has an on-demand (tankless or hybrid) water heater, does it have a:

	Heater 1 (Main Unit)	Heater 2	Heater 3
Metal vent	☐ 1	☐ 1	☐ 1
Plastic vent	☐ 2	☐ 2	☐ 2
No vent (electric tankless)	☐ 3	☐ 3	☐ 3
Don't know	☐ 9	☐ 9	☐ 9

D9. How old is (are) your water heater(s)?

Heater 1 (Main Unit)	_____ years	Don't know ☐ 99
Heater 2	_____ years	Don't know ☐ 99
Heater 3	_____ years	Don't know ☐ 99

D10. What is the size (volume) of the largest hot water tank in your home? The size is printed on the label attached to your tank.

☐ 1 On-demand (tankless or hybrid)
☐ 2 10 imperial gallons (46 litres)
☐ 3 33 imperial gallons (150 litres)
☐ 4 40 imperial gallons (182 litres)
☐ 5 60 imperial gallons (273 litres)
☐ 6 Other (please specify): _____
☐ 9 Don't know

D11. Have you installed a water heater within the past five years?

Yes ☐ 1 → **CONTINUE**
No ☐ 2 → **GO TO QUESTION D13**

D12. What was the main reason you installed the water heater? (Check one only)

New home	☐ 1
Wanted to change to gas	☐ 2
Wanted more efficient water heater	☐ 3
Water heater had failed	☐ 4
Anticipated water heater failure	☐ 5
Needed more hot water	☐ 6
Wanted faster hot water recovery	☐ 7
Wanted an environmentally friendly fuel	☐ 8
Wanted a cheaper fuel	☐ 9
Other	☐ 10

D13. Some energy efficient gas water heaters require access to an electrical outlet. Is there an electrical outlet within 5 feet (1.5 metres) of your current water heater?

☐ 1 Yes ☐ 2 No ☐ 9 Don't know

D14. Drain water heat recovery systems capture heat from drain pipes in the home and use this heat to reduce the amount of energy used by the water heater. Does this home use a drain water heat recovery system?

☐ 1 Yes ☐ 2 No ☐ 9 Don't know

Drain Heat Recovery System

D15. Please indicate the total number of the following for your residence:

	Number
Showerheads (all kinds)	_____
Low flow showerheads	_____
Water heater blankets	_____
Instant hot water dispensers	_____
Bathroom and kitchen faucet aerators	_____

D16. Please indicate the total number of the following for all members of your household:

	Number
Number of dishwasher loads per week	_____
Number of baths per week	_____
Number of showers per week	_____

D17. Please estimate the total amount of time that shower(s) are used on a typical weekday (total for all members of this residence).

_____ minutes per day ☐ 1 No showers – take baths only

A FRIENDLY REMINDER

Please ensure your survey responses refer to the residence at the address identified on the front page of this survey. Your responses will be kept strictly confidential.

To ensure you are eligible to win one of the four $1,000 gift certificates, make sure you return your survey by December 24, 2012 using the self-addressed postage-paid return envelope included with your survey package. Easier still, complete your survey online by December 24, 2012 and double your chance at winning a $1,000 gift certificate. Only one survey (paper or online) will be accepted per household.

Thank you for completing this important survey.

E. Swimming Pools & Hot Tubs

E1. Do you have a swimming pool at this residence?

Yes, indoor ☐ 1
Yes, outdoor ☐ 2
→ **CONTINUE**

No ☐ 3 → **GO TO QUESTION E7**

E2. Is this pool for the exclusive use of this residence (example: backyard pools in single family dwellings) or shared with other residences (example: pools in apartments / condominiums / townhouse complexes)?

Exclusive use only ☐ 1 → **CONTINUE**
Share with others ☐ 2 → **GO TO QUESTION E7**

E3. Which fuel do you use to heat the water in your pool and do you use solar energy to help heat the water?

	Main pool heater fuel	Supplemented with solar heating
Solar	☐ 1	
Natural gas	☐ 2	☐ 2
Electricity	☐ 3	☐ 3
Propane	☐ 4	☐ 4
Other	☐ 5	☐ 5

Pool not heated ☐ 6 → **GO TO QUESTION E6**

Solar Heating

There are two main types of solar heating. Photovoltaic panels which use light to power an electric appliance and thermal solar which uses the sun's heat to warm tubes filled with water or diluted antifreeze.

E4. How many months per year is your pool heated? _____ months per-year

E5. During the months when you heat your pool, do you cover it when not in use? Yes ☐ 1 No ☐ 2

E6. Does your pool pump use a high efficiency motor (often called a variable speed motor or electronically controlled motor (ECM))?

☐ 1 Yes ☐ 2 No ☐ 9 Don't know ☐ 3 Not applicable

E7. Do you have a hot tub at this residence?

Yes, indoor ☐ 1
Yes, outdoor ☐ 2
→ **CONTINUE**

No ☐ 3 → **GO TO QUESTION E12**

E8. Is this hot tub for the exclusive use of this residence (example: hot tubs in single family dwellings) or shared with other residences (example: hot tubs in apartments / condominiums / townhouse complexes)?

Exclusive use only ☐ 1 → **CONTINUE**
Share with others ☐ 2 → **GO TO QUESTION E12**

E9. What fuel is used to heat the hot tub?

Natural gas ☐ 1 Solar ☐ 3 Other ☐ 5
Propane ☐ 2 Electricity ☐ 4

E10. How many months per year is your hot tub heated? _____ months

E11. During the months when you heat your hot tub, do you cover it when not in use? Yes ☐ 1 No ☐ 2

E12. Does this residence have a sauna that is for your exclusive use?

Yes ☐ 1 → **CONTINUE**
No ☐ 2 → **GO TO SECTION F**

E13. What fuel is used to heat the sauna?

Electricity ☐ 1 Propane ☐ 3 Don't know ☐ 9
Natural gas ☐ 2 Other ☐ 4

F. Appliances

F1. Please indicate the number of each of the following appliances in use in this residence. For each appliance please indicate the approximate age (your best guess is fine). If you do not have the appliance, please check the "0" box.

	Number in Use				Age of Appliance (in years)		
	0	1	2	3+	#1	#2	#3
COOKING							
Electric range (cook top and oven)	☐ 0	☐ 1	☐ 2	☐ 3			
Gas range (cook top and oven)	☐ 0	☐ 1	☐ 2	☐ 3			
Dual fuel range (gas cook top, electric oven)	☐ 0	☐ 1	☐ 2	☐ 3			
Electric cook top	☐ 0	☐ 1	☐ 2	☐ 3			
Gas cook top	☐ 0	☐ 1	☐ 2	☐ 3			
Electric wall oven	☐ 0	☐ 1	☐ 2	☐ 3			
Gas wall oven	☐ 0	☐ 1	☐ 2	☐ 3			
Microwave oven	☐ 0	☐ 1	☐ 2	☐ 3			
Gas barbeque (piped gas)	☐ 0	☐ 1	☐ 2	☐ 3			
Gas barbeque (bottled gas)	☐ 0	☐ 1	☐ 2	☐ 3			
Commercial grade range hood	☐ 0	☐ 1	☐ 2	☐ 3			
REFRIGERATION							
Refrigerator – manual defrost	☐ 0	☐ 1	☐ 2	☐ 3			
Refrigerator – automatic defrost	☐ 0	☐ 1	☐ 2	☐ 3			
Stand alone freezer – upright	☐ 0	☐ 1	☐ 2	☐ 3			
Stand alone freezer – chest style	☐ 0	☐ 1	☐ 2	☐ 3			
CLEANING							
Dishwasher	☐ 0	☐ 1	☐ 2	☐ 3			
Clothes washer - top load	☐ 0	☐ 1	☐ 2	☐ 3			
Clothes washer - front load	☐ 0	☐ 1	☐ 2	☐ 3			
Electric clothes dryer	☐ 0	☐ 1	☐ 2	☐ 3			
Gas clothes dryer	☐ 0	☐ 1	☐ 2	☐ 3			
HEATING							
Air source heat pump	☐ 0	☐ 1	☐ 2	☐ 3			
Ground source heat pump	☐ 0	☐ 1	☐ 2	☐ 3			
Heat recovery ventilator/ make up air unit	☐ 0	☐ 1	☐ 2	☐ 3			
Gas outdoor heater (piped gas)	☐ 0	☐ 1	☐ 2	☐ 3			
Gas outdoor heater (bottled gas)	☐ 0	☐ 1	☐ 2	☐ 3			
Gas outdoor fire pit or fireplace	☐ 0	☐ 1	☐ 2	☐ 3			

F2. Please indicate below the number of each appliance in this residence, the months of the year the appliance is regularly used, and the average number of hours per day when in use. If an appliance is in use year-round, write in Jan – Dec for the months in use.

	Number in Use				Used in a typical year		Average # hours per day when used
	0	1	2	3+	From (month)	To (month)	
Central air conditioner	☐ 0	☐ 1	☐ 2	☐ 3			
Portable air conditioner	☐ 0	☐ 1	☐ 2	☐ 3			
Room window air conditioner	☐ 0	☐ 1	☐ 2	☐ 3			
Portable fan	☐ 0	☐ 1	☐ 2	☐ 3			
Humidifier	☐ 0	☐ 1	☐ 2	☐ 3			
Dehumidifier	☐ 0	☐ 1	☐ 2	☐ 3			
Portable electric heater	☐ 0	☐ 1	☐ 2	☐ 3			
Rotating ceiling fans without light fixtures	☐ 0	☐ 1	☐ 2	☐ 3			
Rotating ceiling fans with light fixtures	☐ 0	☐ 1	☐ 2	☐ 3			

F3. How likely are you to buy a portable, room, or central air conditioner in the next 12 months?

	Definitely will	Most likely will	Might or might not	Most likely will not	Definitely will not
Portable air conditioner	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
Room or window air conditioner	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
Central air conditioner	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5

SECTIONS G AND H APPLY TO FORTISBC ELECTRICITY CUSTOMERS ONLY. THESE SECTIONS HAVE BEEN OMITTED FROM YOUR SURVEY.

I. Renovations & Energy Use

I1. Please indicate renovations or actions you have undertaken at this residence during the past five years, whether you received a government or utility rebate to complete them, and the renovations you plan to undertake within the next two years.

	Did this – past 5 years		Plan to do this – next 2 years
	With rebate	Without rebate	
Improve insulation in walls, attic, basement, or crawlspace	☐ 1	☐ 1	☐ 1
Install energy efficient window(s)	☐ 2	☐ 2	☐ 2
Install insulated outside door(s) or storm doors	☐ 3	☐ 3	☐ 3
Install low flow showerhead(s)	☐ 4	☐ 4	☐ 4
Install programmable thermostat(s)	☐ 5	☐ 5	☐ 5
Install pipe wrap	☐ 6	☐ 6	☐ 6
Install weather stripping or caulking	☐ 7	☐ 7	☐ 7
Install hot water heater blanket	☐ 8	☐ 8	☐ 8
Install drain pipe waste heat recovery system	☐ 9	☐ 9	☐ 9
Install on-demand (tankless or hybrid) water heater	☐ 10	☐ 10	☐ 10
Install high efficiency hot water tank	☐ 11	☐ 11	☐ 11
EcoENERGY or LiveSmart BC certified energy audit completed	☐ 12	☐ 12	☐ 12
Install a sauna		☐ 13	☐ 13
Install heated swimming pool		☐ 14	☐ 14
Install hot tub		☐ 15	☐ 15
None of the above	☐ 0		☐ 0

I2. Did you undertake any renovations that involve fireplaces or heating stoves at this residence in the past five years, or plan to do so in the next two years?

☐ 1 Yes → **CONTINUE**
☐ 2 No → **GO TO QUESTION I5**

I3. Please indicate the renovations that involve fireplaces or heating stoves that you did at this residence during the past five years, whether you received a government or utility rebate to complete them, and those you plan to undertake within the next two years.

Note: there several types of fireplaces available in the market today. Please read carefully and select the category that best describes your renovation plan involving fireplaces.

	Did this – past 5 years		Plan to do this – next 2 years
	With rebate	Without rebate	
Install free standing gas fireplace or heating stove	☐ 1	☐ 1	☐ 1
Install wood stove	☐ 2	☐ 2	☐ 2
Install gas heater type fireplace insert in an existing wood fireplace	☐ 3	☐ 3	☐ 3
Replace decorative gas fireplace with gas heater type insert	☐ 4	☐ 4	☐ 4
Remove or disconnect gas fireplace		☐ 5	☐ 5
Remove wood fireplace or wood stove		☐ 6	☐ 6
Install decorative gas fireplace		☐ 7	☐ 7
Install electric fireplace		☐ 8	☐ 8
None of the above	☐ 0		☐ 0

I4. IF YOU INSTALLED A GAS FIREPLACE IN THE PAST FIVE YEARS: Was this gas fireplace an ENERCHOICE model?

☐ 1 Yes ☐ 2 No ☐ 9 Don't know

I5. Which of the following home renovations would you typically do yourself, use a contractor, or both do it yourself and use a contractor?

	Do it myself	Use a contractor	Both
Install new appliances (dishwashers, laundry machines, other)	☐ 1	☐ 2	☐ 3
Install / replace windows	☐ 1	☐ 2	☐ 3
Install low flow showerheads	☐ 1	☐ 2	☐ 3
Improve weather stripping / draft proofing	☐ 1	☐ 2	☐ 3
Improve insulation in walls, ceilings or attics	☐ 1	☐ 2	☐ 3

EnerChoice Gas Fireplaces

All new fireplaces and heater stoves are required to be CSA approved and display an EnerGuide label which shows how much energy they consume.

Fireplaces and heater stoves that also display an ENERCHOICE label are the most energy efficient models on the market today.

ENERCHOICE ENERCHOICE.ORG

I6. How influential are the following sources of information when purchasing a major appliance.

		Not at all Influen-tial 1	2	3	4	Very Influen-tial 5
a.	Contractors / tradespeople	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
b.	Customer ratings	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
c.	Expert reviews (e.g., magazines, websites, TV)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
d.	Electric or gas utilities	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
e.	Government	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
f.	Appliance salespeople	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
g.	Knowledgeable family member, friend, or neighbour	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5

Thank you for participating in this important survey. You have completed about 70% of the survey.

J. Managing Energy Use

This section is intended to help FortisBC understand how you use / manage energy at this residence.

J1. At what temperature do you usually keep this residence during the winter (heating) season? If this residence has air conditioning (central, window, portable, or heat pump), also tell us what temperature you usually keep this residence during the summer (cooling) season.

	Winter (Heating)		Summer (Cooling)	
	Degrees C or	Degrees F	Degrees C or	Degrees F
When someone is at home	___	___	___	___
When no one is home	___	___	___	___
During the night	___	___	___	___

☐ Do not use air conditioning

Next, we would also like to understand the types of actions that you take to manage energy usage at this residence. Please check the answer that best describes what you normally do.

J2. Space Heating

		Always	Usually	Occasionally	Never	Don't Know	Not Applicable
a.	Close window coverings to keep in heat	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
b.	Turn down the heat at night either manually or using a programmable thermostat	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
c.	Turn down the heat either manually or using a programmable thermostat when no one is at home	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
d.	Reduce temperature in unused rooms by closing vents or turning down room thermostats	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
e.	Check and re-seal air leaks in the house at least once a year (weather stripping and caulking)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
f.	If single pane windows, install storm windows each fall	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
g.	Install plastic window coverings on drafty windows during winter months	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

J3. Are you able to reduce the temperature in unoccupied rooms at this residence? This could be done by turning down individual room thermostats, closing doors, and closing vents?

☐ Yes ☐ No ☐ Don't Know

J4. Air Conditioning / Cooling

		Always	Usually	Occasionally	Never	Don't Know	Not Applicable
a.	Set the thermostat at 26 degrees C (78°F) or higher during the summer to save energy	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
b.	Close the window coverings (drapes, blinds, etc.) during hot weather to reduce heat in the dwelling	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
c.	Clean the air conditioner filter and coils at least once per season	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
d.	Turn on air conditioning only when very hot and natural ventilation is insufficient	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

J5. Have you done either of the following to keep this residence cool:

	Yes	No	Don't know
Planted trees or other vegetation	☐ 1	☐ 2	☐ 9
Installed shading devices (i.e., awnings, pergolas)	☐ 1	☐ 2	☐ 9

J6. Water Usage

		Always	Usually	Occasionally	Never	Don't Know	Not Applicable
a.	Turn off the water heater or use its "vacation setting" when no one is home for more than 2 or 3 days	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
b.	Only do laundry with full loads	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
c.	Clean the dryer lint filter before drying clothes	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
d.	Use the dryer's temperature / moisture sensor to turn off the dryer rather than using timed dry	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
e.	Hang clothes to dry rather than machine dry	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
f.	Only run dishwasher when full	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
g.	Air dry the dishes in the dishwasher rather than use the dry cycle	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

J7. How many loads of laundry does your household do per week?

Number of loads done in cold, warm or hot water _____ per week
Number of loads using cold water wash and rinse only _____ per week
Number of dryer loads _____ per week
Number of loads dried using a clothes line or drying rack during SUMMER _____ per week
Number of loads dried using a clothes line or drying rack during WINTER _____ per week

J8. How much extra cold water wash and rinse could you do?

Number of loads more _____ per week ☐ 0 None, already doing all I can

J9. Lighting

		Always	Usually	Occasionally	Never	Don't Know	Not Applicable
a.	Only have the minimum number of lights on in a room for what I am doing	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
b.	Turn off the lights when on one is in the room	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
c.	Leave outdoor lights on at night (exclude those you do not control)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
d.	Check timers to reflect daylight savings time	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

J10. Refrigeration

		Always	Usually	Occasionally	Never	Don't Know	Not Applicable
a.	Clean the refrigerator coils at least once a year	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
b.	Check the temperature of the refrigerator to ensure food is not too cold or warm	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
c.	Check the temperature of your freezer to ensure food remains frozen, but that the freezer is not too cold	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

J11. Other

		Always	Usually	Occasion-ally	Never	Don't Know	Not Applicable
a.	Turn off TV / entertainment systems when no one is in the room and actively using them	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
b.	Turn off the computer and printers when not in use	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
c.	Unplug or use a power bar to turn off TVs, entertainment systems, and computers when not in use?	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
d.	Leave one or more windows open during winter	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

J12. What, if anything, would encourage you to use less energy at this residence?

J13. What prevents you from using less energy at this residence?

J14. Who makes the most effort to conserve electricity / gas in your household? Choose the most appropriate answer.

- ☐ 1 Myself
- ☐ 2 Someone else in the household
- ☐ 3 Most members of the household
- ☐ 4 All members of the household
- ☐ 0 None of us

K. Products & Services

K1. How familiar are you with the following brand names?

	Not at all familiar 1	2	3	4	Very familiar 5
PowerSense (FortisBC)	☐	☐	☐	☐	☐
PowerSmart (BC Hydro)	☐	☐	☐	☐	☐
ENERGY STAR	☐	☐	☐	☐	☐
LiveSmart BC	☐	☐	☐	☐	☐

K2. During the last five years, did your household participate in any of the following programs that offered rebates to reduce energy use in your home?

Check all that apply

- ecoENERGY / LiveSmart BC ☐ 1
- PowerSense (FortisBC Electric) ☐ 2
- FortisBC Energy (formerly Terasen Gas) ☐ 3
- PowerSmart (BC Hydro) ☐ 4
- None of the above ☐ 0

K3. On a scale of one to four, where one is not at all interested and four is very interested, how interested would you be in the following products and services?

		Not at all Interested 1	2	3	Very Interested 4
a.	Home energy audit to determine main energy uses in the home and identify opportunities to save energy	☐ 1	☐ 2	☐ 3	☐ 4
b.	Do-it-yourself online energy audit	☐ 1	☐ 2	☐ 3	☐ 4
c.	Furnace or heat pump tune-up to ensure they are working safely and efficiently	☐ 1	☐ 2	☐ 3	☐ 4
d.	Program to replace a low efficiency furnace with a high efficiency furnace	☐ 1	☐ 2	☐ 3	☐ 4
e.	Program to install high efficiency gas fireplace	☐ 1	☐ 2	☐ 3	☐ 4
f.	Program to replace standard efficiency clothes washer with high efficiency clothes washer	☐ 1	☐ 2	☐ 3	☐ 4
g.	Program to replace standard efficiency water heater with high efficiency water heater	☐ 1	☐ 2	☐ 3	☐ 4
h.	Program to upgrade attic and wall insulation	☐ 1	☐ 2	☐ 3	☐ 4
i.	Program to improve draft proofing	☐ 1	☐ 2	☐ 3	☐ 4
j.	Program to install programmable thermostats	☐ 1	☐ 2	☐ 3	☐ 4
k.	Program to install an in-home display that allows you to monitor your home's energy usage	☐ 1	☐ 2	☐ 3	☐ 4
l.	Program to purchase an electric automobile	☐ 1	☐ 2	☐ 3	☐ 4
m.	Program to compare your home's energy use with homes of comparable size and type	☐ 1	☐ 2	☐ 3	☐ 4
n.	Program that allows you to pay for energy efficient improvements to your home via instalments on your utility bill	☐ 1	☐ 2	☐ 3	☐ 4

K4. Thinking about major appliance purchase decisions for this residence, please indicate your role in the decision making process.

☐ 1 I am the sole decision maker
☐ 2 Someone else in the house makes the decision
☐ 3 Decisions are made jointly between myself and another person

K5. Does this residence have access to the Internet?

☐ 1 Yes, high speed (ADSL, cable, smart phone, other)
☐ 2 Yes, dial up modem
☐ 3 No Internet access

K6. How comfortable are you with navigating the Internet?

☐ 1 Very comfortable
☐ 2 Somewhat comfortable
☐ 3 Not very comfortable
☐ 4 Not at all comfortable

L. Attitudes Towards Energy Use

L1. In order to serve you better, we would like to understand your views on a number of energy related issues. For the following set of statements, please check the answer that most accurately reflects your agreement or disagreement with the statement.

On a scale of one to five, where one means that you strongly disagree and five means that you strongly agree, please indicate how much you agree or disagree with the following statements on energy and natural gas usage.

		Strongly Disagree 1	2	Neither Agree or Disagree 3	4	Strongly Agree 5
a.	There are many ways that a person can save energy when you add them up, they result in substantial savings	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
b.	By making my home more energy efficient, I am helping to do my part for the environment	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
c.	I think natural gas is a clean and efficient energy source	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
d.	Members of my household regularly limit the length of their showers to save energy	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
e.	I don't want to think about natural gas or electricity, I simply want it to work	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
f.	I consider natural gas to be a safe energy source	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
g.	When something needs to be done around home, I usually hire someone	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
h.	I almost always have a home renovation on the go	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
i.	It is cheaper to heat a home with natural gas than it is with electricity	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
j.	Our household has reduced its energy use by as much as reasonably possible	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
k.	I am a busy person with little or no time to research ways to save energy	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
l.	I conserve energy because it saves money not because it helps the environment	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5

L2. On a scale of one to five, where one means that you strongly disagree and five means that you strongly agree, please indicate how much you agree or disagree with the following statements.

		Strongly Disagree 1	2	Neither Agree or Disagree 3	4	Strongly Agree 5
a.	I am usually the first one to try new products	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
b.	I am usually willing to pay more for brand name items	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
c.	I prefer dealing with British Columbia based companies	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
d.	I always look for the best price when buying products or services	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
e.	I usually take time to research issues thoroughly before making a decision	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
f.	I am the type of person to have good insurance coverage	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5

M. About your Household

The final questions are for classification purposes only and are completely confidential, as are all your answers.

QUESTIONS M1 & M2 APPLY TO FORTISBC ELECTRICITY CUSTOMERS ONLY. THESE QUESTIONS HAVE BEEN OMITTED FROM YOUR SURVEY.

M3. Into which of the following age categories do you fit?

- 18 years or under ☐ 1
- 19-24 years ☐ 2
- 25-34 years ☐ 3
- 35-44 years ☐ 4
- 45-54 years ☐ 5
- 55-64 years ☐ 6
- 65 years and older ☐ 7

M4. You are: Female ☐ 1 Male ☐ 2

M5. What is your marital status?

- Single ☐ 1
- Married/common law ☐ 2
- Divorced/separated ☐ 3
- Widowed ☐ 4

M6. How many people, including yourself, are currently living at this residence (please include any boarders or renters covered under your FortisBC account)

_____ number

M7. Please indicate the number of occupants by age categories

	0	**1**	**2**	**3**	**4**	**5**	**6+**
0 – 5 years	☐	☐	☐	☐	☐	☐	☐
6 - 12 years	☐	☐	☐	☐	☐	☐	☐
13 - 18 years	☐	☐	☐	☐	☐	☐	☐
19 - 24 years	☐	☐	☐	☐	☐	☐	☐
25 - 44 years	☐	☐	☐	☐	☐	☐	☐
45 - 64 years	☐	☐	☐	☐	☐	☐	☐
65 years and older	☐	☐	☐	☐	☐	☐	☐

M8. Has the number of people in this residence changed in the last two years?

Yes ☐ 1 No ☐ 2 → **GO TO QUESTION M10**

M9. How has the number of people in this residence changed over the past two years (please check the best answer)?

- In the past there were more people in this residence ☐ 1
- In the past there were fewer people in this residence ☐ 2
- In the past there were sometimes more people and sometimes fewer people in this residence ☐ 3

M10. What is the highest level of education you have completed?

- Some high school ☐ 1
- Completed high school ☐ 2
- Some trade/technical school ☐ 3
- Completed trade/technical school ☐ 4
- Some university/college ☐ 5
- Completed university/college ☐ 6
- Post graduate ☐ 7

M11. What was your total household income before taxes in 2011?

Less than $20,000	☐ 1	$60,000 to $79,999	☐ 6
$20,000 to $29,999	☐ 2	$80,000 to $99,999	☐ 7
$30,000 to $39,999	☐ 3	$100,000 to $124,999	☐ 8
$40,000 to $49,999	☐ 4	$125,000 or more	☐ 9
$50,000 to $59,999	☐ 5	Prefer not to answer	☐ 10

M12. What are the languages spoken at this residence?

	Main language *(check one only)*	**Other languages** *(check all that apply)*	
English	☐ 1	☐ 1	
Mandarin	☐ 2	☐ 2	
Cantonese	☐ 3		☐ 3
Hindi	☐ 4	☐ 4	
Punjabi	☐ 5	☐ 5	
Tagalog	☐ 6	☐ 6	
Farsi (Persian)	☐ 7	☐ 7	
French	☐ 8	☐ 8	
German	☐ 9	☐ 9	
Other (please specify):	☐ 10 _____	☐ 10 _____	

M13. From time to time, FortisBC hires market research contractors to conduct research. This is done to better understand our customers' needs and gather information to design programs to help you save money on your energy bill.

Do we have your permission to contact you in the future for the purpose of additional market research? If yes, please provide your name and telephone number below. This is only permission to contact you. You are not obligated to participate if contacted by us or a market research company we hire.

☐ 1 YES - it is OK to contact me for follow-up research

First name: _____

Last name: _____

Telephone: ____ - ____ - _____

Email: _____ (optional)

FortisBC and Ipsos would like to thank you for your help and assistance.
If you have any questions please contact Walter Wright, Market Research, FortisBC, at 604-592-7653 or walter.wright@fortisbc.com.

Win a $ 1000 Gift Certificate

Contest Rules

1. All entries must be received by Ipsos by December 24, 2012. Limit of one entry per eligible entrant. A contestant's name will be determined by a random draw on January 21, 2013 from all entries received. To win, the selected contestant must answer a time limited mathematical skill-testing question, without mechanical or other assistance.
2. The selected contestant will be notified by telephone by Ipsos. Ipsos will attempt to reach the selected contestant no more than 3 times. If Ipsos is unable to contact him or her within 5 days of the draw date, Ipsos may draw the name of another contestant to be eligible for the prize.
3. Contestants who complete and return the survey form by mail will have their name entered once in the draw. Contestants who complete the survey form online will have their name entered into the draw twice.
4. Contestants must be residents of British Columbia.
5. FortisBC customers who have completed and returned the FortisBC 2012 Residential End-Use Survey by December 24, 2012 are automatically entered and no further action is required on the part of the customer. To enter without completing the survey, mail a letter with your name, telephone number and address to Ipsos, 1285 West Pender Street, 2nd Floor, Vancouver, BC, V6E 4B1. Mark the envelope "Residential Survey Contest".
6. Chances of winning are based on the number of eligible entries received via mail and online.
7. Employees or agents of FortisBC and their immediate families are not eligible to win.
8. There are four $1,000 prizes to be awarded, each prize is a $1,000 gift certificate from a home improvement store located near the prize winner.
9. FortisBC and Ipsos assume no responsibility for lost or misdirected entry forms.
10. By entering, contestants agree to abide by the contest rules and that the decision of the judge shall be final.

Attachment 21.9

This tab "2010 LTRP - TGI Coastal" (TGI (Terasen Gas Inc.) contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for 2010-2030

Annual use rate per Customer by Rate Class(GJ) RESIDENTIAL Core

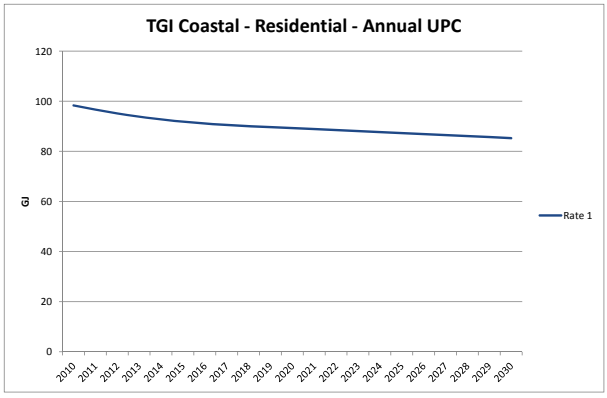
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate 1	98	97	95	94	93	92	91	90	90	90	89	89	88	88	88	87	87	86	86	86	85

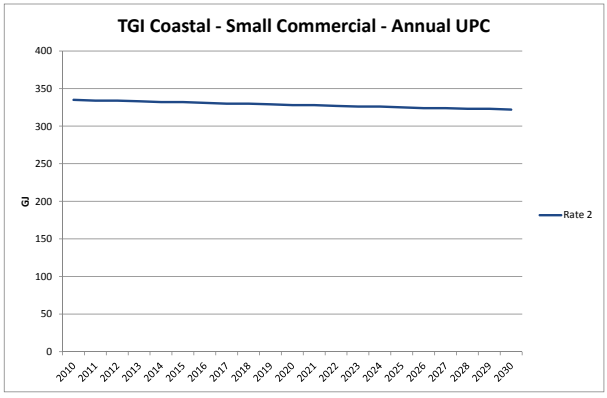
Annual use rate per Customer by Rate Class(GJ) SMALL COMMERCIAL Core

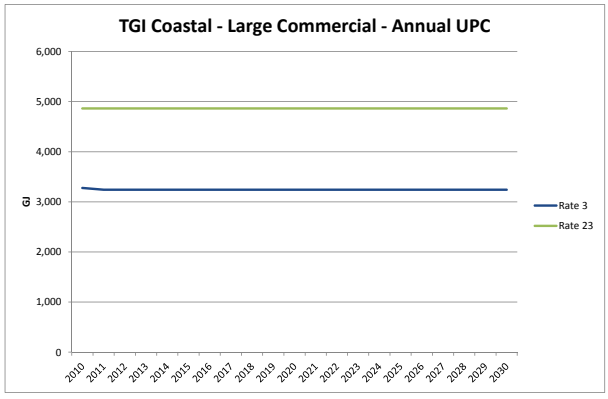
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate 2	335	334	334	333	332	332	331	330	330	329	328	328	327	326	326	325	324	324	323	323	322

Annual use rate per Customer by Rate Class(GJ) LARGE COMMERCIAL Core

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate 3	3,276	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243
Rate 23	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865







This tab "2010 LTRP - TGI Interior" (TGI (Terasen Gas Inc.) contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for 2010-2030

Annual use rate per Customer by Rate Class(GJ) RESIDENTIAL Core

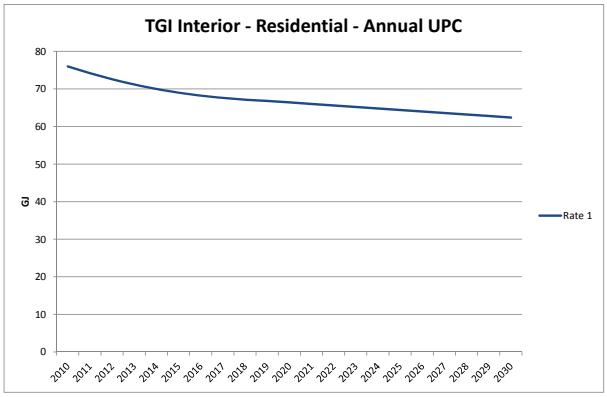
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate 1	76	74	73	71	70	69	68	68	67	67	66	66	66	65	65	64	64	64	63	63	62

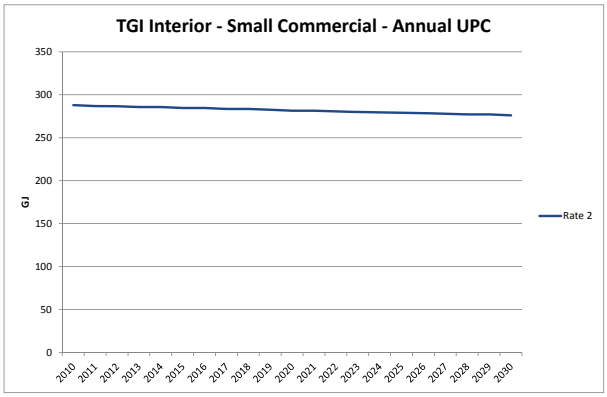
Annual use rate per Customer by Rate Class(GJ) SMALL COMMERCIAL Core

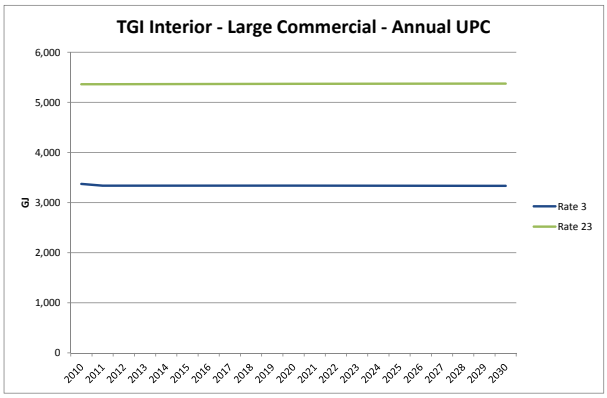
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate 2	288	287	287	286	286	285	285	283	283	282	281	281	280	280	279	279	278	278	277	277	276

Annual use rate per Customer by Rate Class(GJ) LARGE COMMERCIAL Core

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate 3	3,372	3,338	3,338	3,338	3,338	3,338	3,338	3,338	3,338	3,338	3,338	3,337	3,337	3,337	3,337	3,337	3,337	3,337	3,336	3,336	3,335
Rate 23	5,362	5,363	5,364	5,365	5,366	5,367	5,368	5,368	5,369	5,370	5,370	5,371	5,371	5,372	5,372	5,373	5,374	5,374	5,374	5,375	5,375







This tab "2010 LTRP - TGVI" (TGVI (Terasen Gas Vancouver Island) contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and

Annual use rate per Customer by Rate Class(GJ) RESIDENTIAL

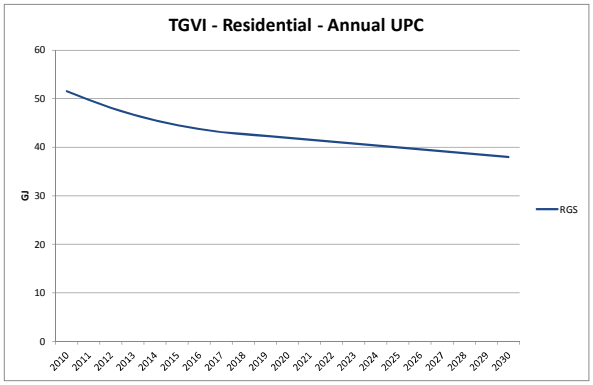
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RGS	52	50	48	47	46	45	44	43	43	42	42	42	41	41	40	40	40	39	39	38	38

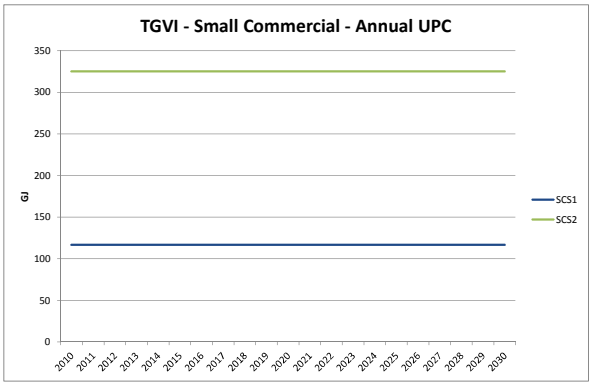
Annual use rate per Customer by Rate Class(GJ) SMALL COMMERCIAL

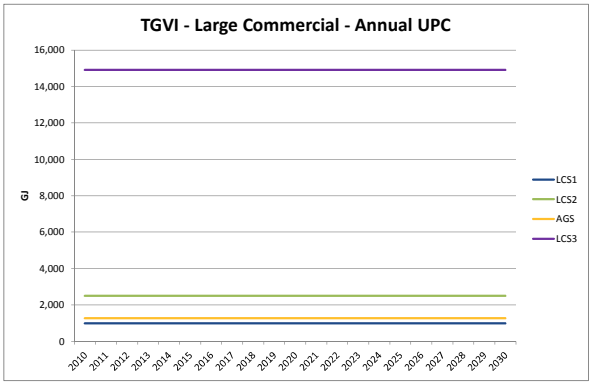
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SCS1	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116
SCS2	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325

Annual use rate per Customer by Rate Class(GJ) LARGE COMMERCIAL

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
LCS1	980	980	980	980	980	980	980	980	980	980	980	980	980	980	980	980	980	980	980	980	980
LCS2	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481
AGS	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259
LCS3	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911	14,911







This tab "2010 LTRP - TGW" (TGW (Terasen Gas Whistler) contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for 2010-2030

Annual use rate per Customer by Rate Class(GJ) RESIDENTIAL

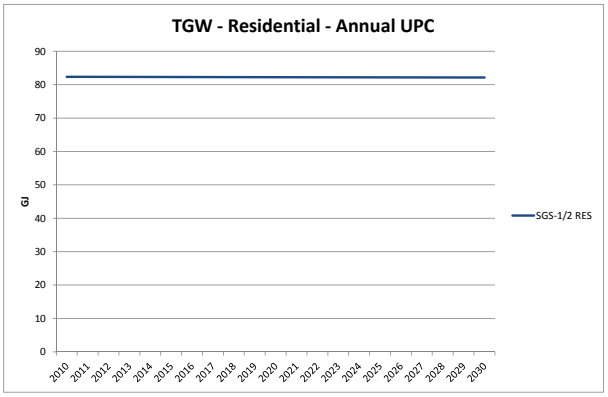
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SGS-1/2 RES	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82

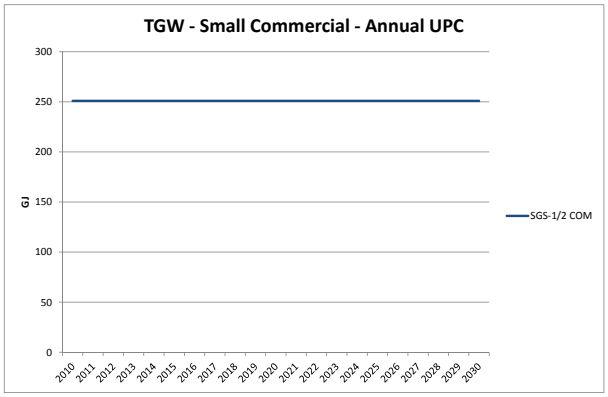
Annual use rate per Customer by Rate Class(GJ) SMALL COMMERCIAL

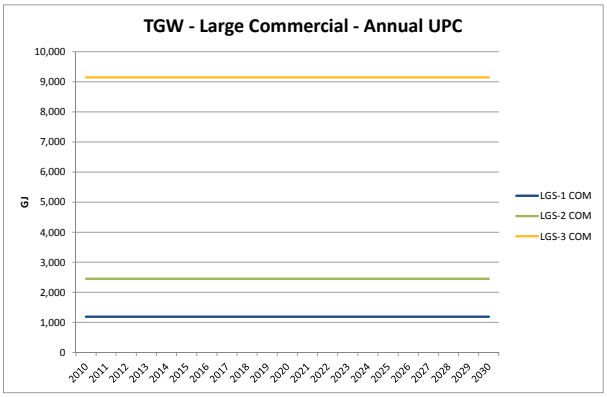
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SGS-1/2 COM	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251

Annual use rate per Customer by Rate Class(GJ) LARGE COMMERCIAL

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
LGS-1 COM	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185	1,185
LGS-2 COM	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447
LGS-3 COM	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150	9,150





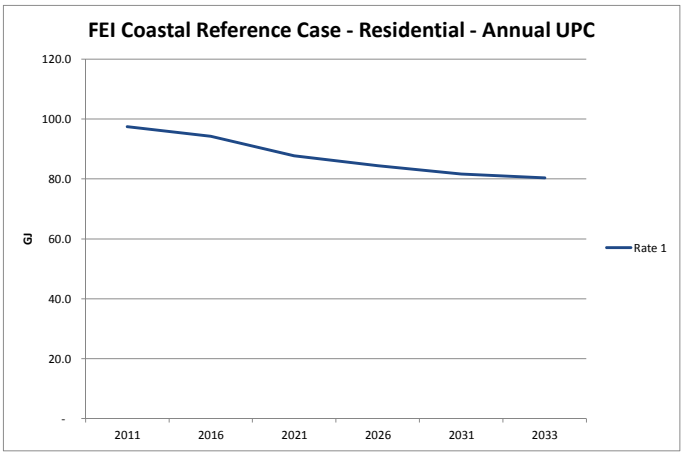


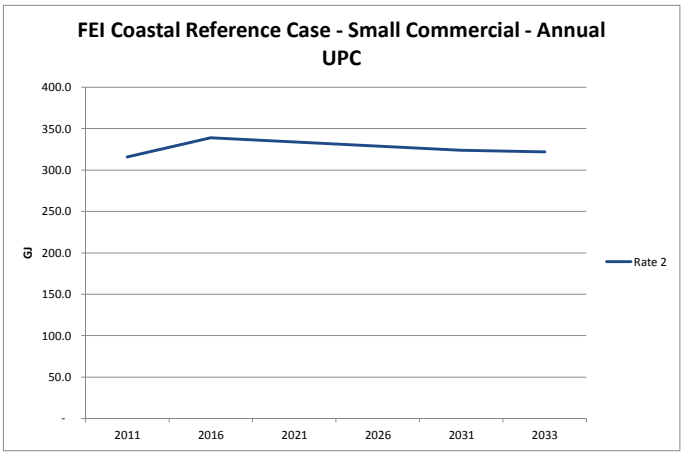
This tab "2014 LTRP - FEI Coastal Ref" contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for the Reference Case milestone years

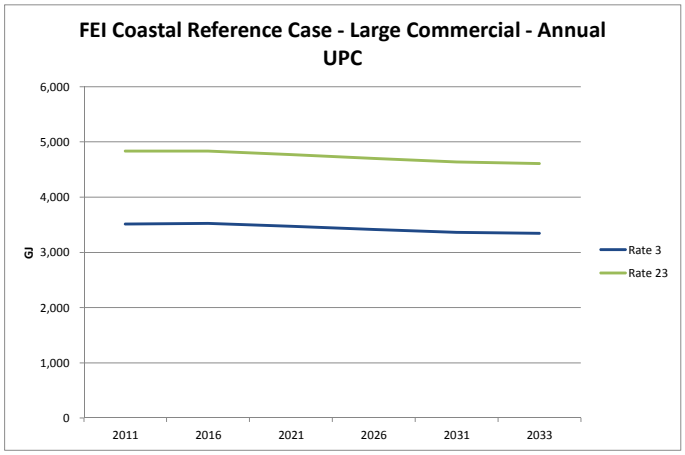
Annual Use Rate per Customer by Rate Class (GJ) RESIDENTIAL	2011	2016	2021	2026	2031	2033
Rate 1	97.5	94.3	87.7	84.5	81.7	80.4

Annual Use Rate per Customer by Rate Class (GJ) SMALL COMMERCIAL	2011	2016	2021	2026	2031	2033
Rate 2	315.7	338.7	333.8	328.7	323.8	321.7

Annual Use Rate per Customer by Rate Class (GJ) LARGE COMMERCIAL	2011	2016	2021	2026	2031	2033
Rate 3	3,510	3,524	3,471	3,416	3,365	3,343
Rate 23	4,835	4,835	4,769	4,701	4,637	4,610





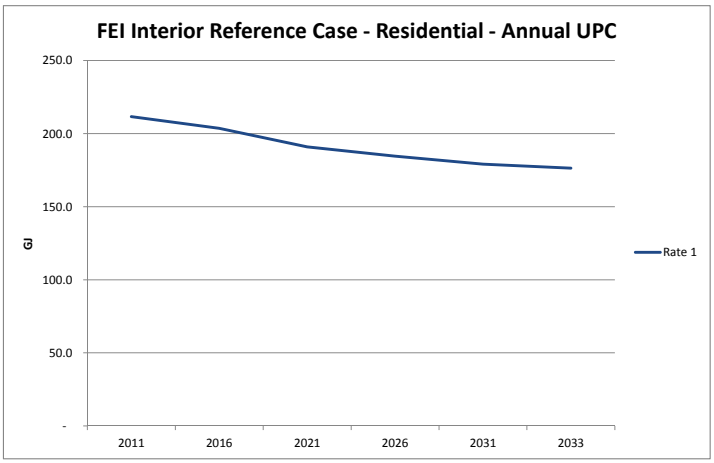


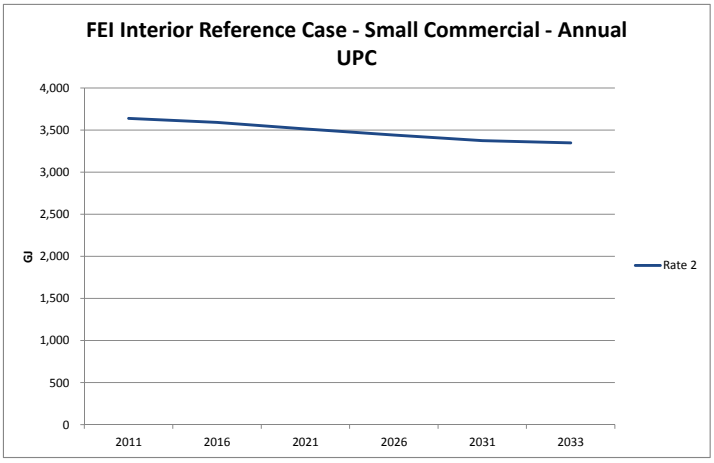
This tab "2014 LTRP - FEI Interior Ref" contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for the Reference Case milestone years

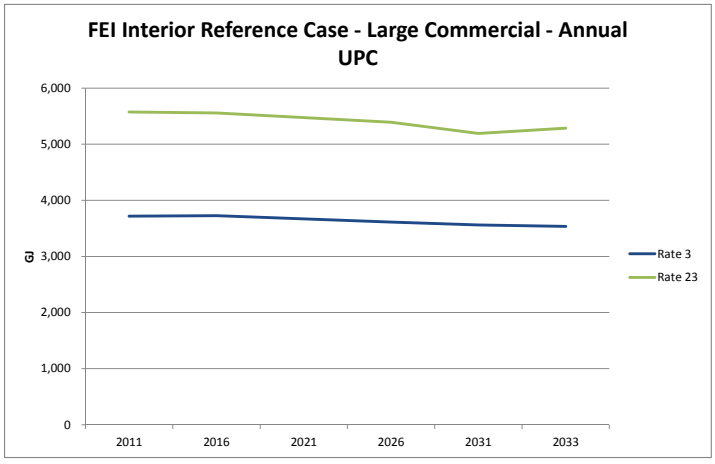
Annual Use Rate per Customer by Rate Class (GJ) RESIDENTIAL	2011	2016	2021	2026	2031	2033
Rate 1	211.6	203.6	190.9	184.5	179.1	176.4

Annual Use Rate per Customer by Rate Class (GJ) SMALL COMMERCIAL	2011	2016	2021	2026	2031	2033
Rate 2	3,639	3,591	3,512	3,441	3,375	3,347

Annual Use Rate per Customer by Rate Class (GJ) LARGE COMMERCIAL	2011	2016	2021	2026	2031	2033
Rate 3	3,719	3,726	3,669	3,611	3,561	3,535
Rate 23	5,574	5,556	5,474	5,392	5,192	5,286





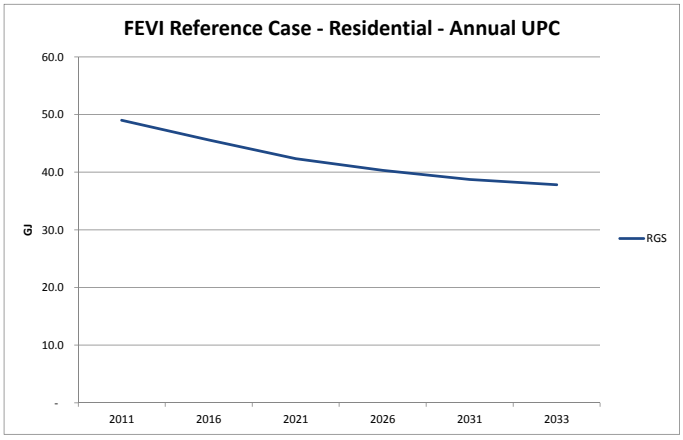


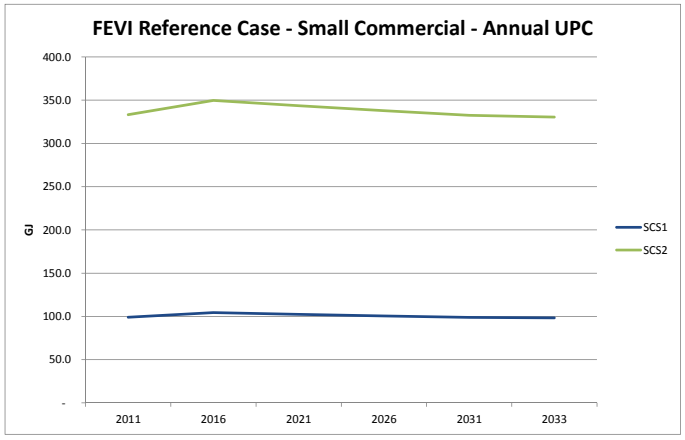
This tab "2014 LTRP - FEVI Ref" contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for

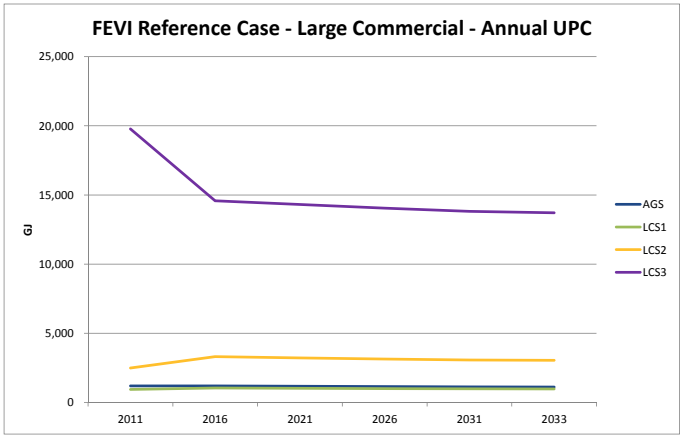
Annual Use Rate per Customer by Rate Class (GJ) RESIDENTIAL	2011	2016	2021	2026	2031	2033
RGS	49.0	45.6	42.4	40.3	38.7	37.8

Annual Use Rate per Customer by Rate Class (GJ) SMALL COMMERCIAL	2011	2016	2021	2026	2031	2033
SCS1	99.0	104.4	102.4	100.6	98.9	98.3
SCS2	333.3	349.7	343.5	337.8	332.5	330.4

Annual Use Rate per Customer by Rate Class (GJ) LARGE COMMERCIAL	2011	2016	2021	2026	2031	2033
AGS	1,202	1,197	1,172	1,149	1,128	1,120
LCS1	947.3	1,052	1,028	1,006	986.8	979.1
LCS2	2,495	3,318	3,226	3,147	3,078	3,052
LCS3	19,766	14,581	14,311	14,051	13,812	13,711





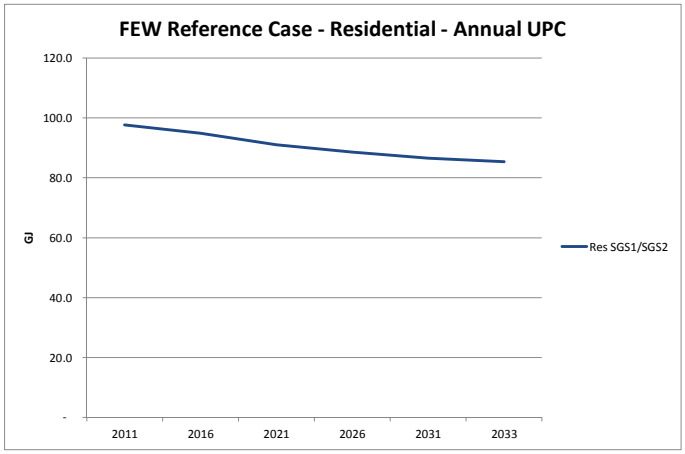


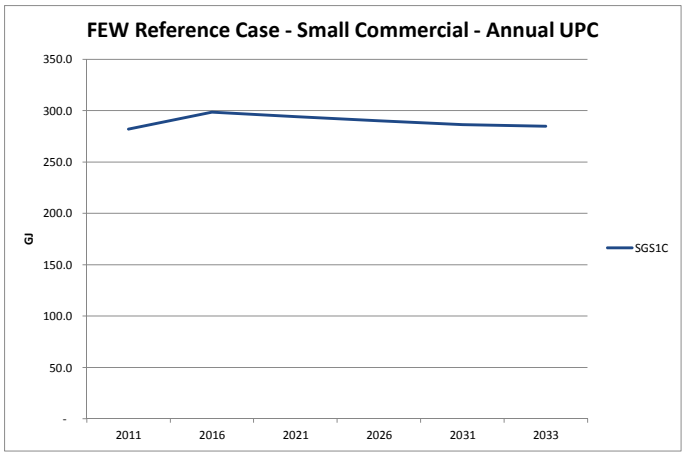
This tab "2014 LTRP - FEW Ref" contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for the Reference Case milestone years

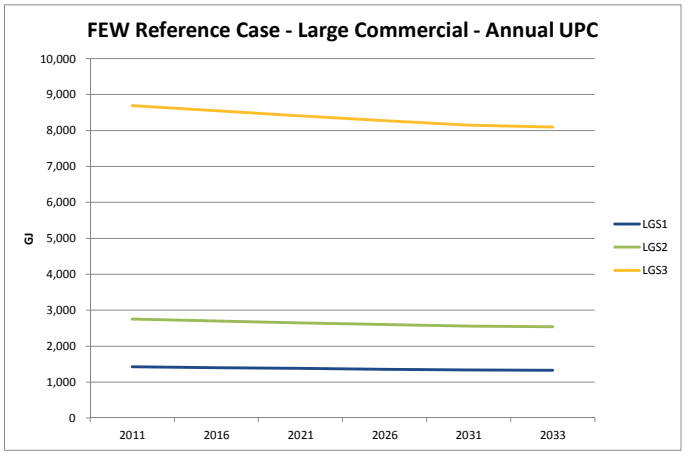
Annual Use Rate per Customer by Rate Class (GJ) RESIDENTIAL	2011	2016	2021	2026	2031	2033
Res SGS1/SGS2	97.7	94.9	91.0	88.6	86.6	85.4

Annual Use Rate per Customer by Rate Class (GJ) SMALL COMMERCIAL	2011	2016	2021	2026	2031	2033
SGS1C	281.9	298.6	294.2	290.1	286.3	284.8

Annual Use Rate per Customer by Rate Class (GJ) LARGE COMMERCIAL	2011	2016	2021	2026	2031	2033
LGS1	1,429	1,403	1,379	1,356	1,334	1,326
LGS2	2,750	2,701	2,649	2,600	2,554	2,535
LGS3	8,693	8,550	8,408	8,274	8,143	8,091





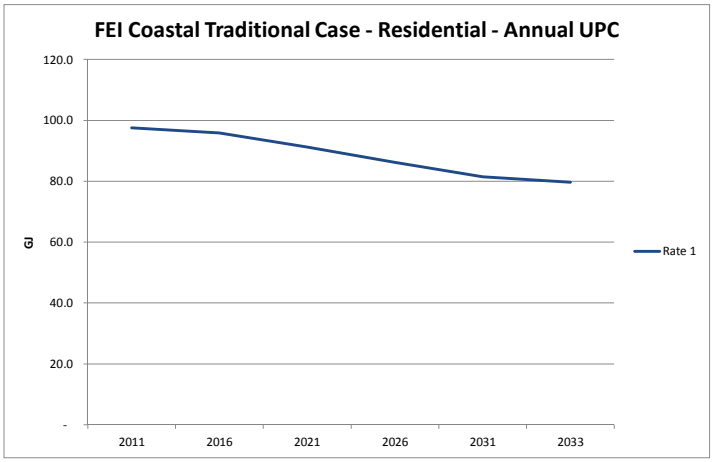


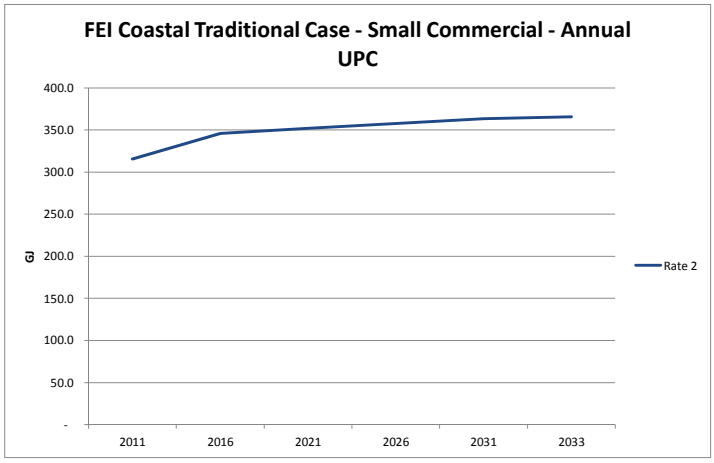
This tab "2014 LTRP - FEI Coastal Trad" contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for the Traditional Case milestone years

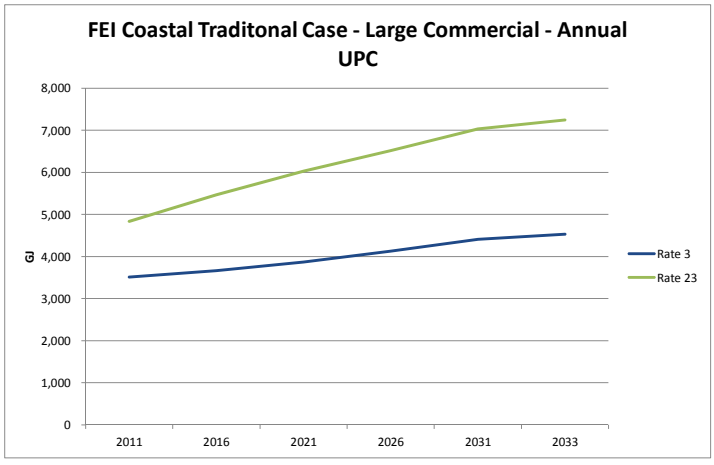
Annual Use Rate per Customer by Rate Class (GJ) RESIDENTIAL	2011	2016	2021	2026	2031	2033
Rate 1	97.5	95.9	91.2	86.2	81.5	79.7

Annual Use Rate per Customer by Rate Class (GJ) SMALL COMMERCIAL	2011	2016	2021	2026	2031	2033
Rate 2	315.7	346.1	352.0	357.7	363.5	365.8

Annual Use Rate per Customer by Rate Class (GJ) LARGE COMMERCIAL	2011	2016	2021	2026	2031	2033
Rate 3	3,510	3,662	3,869	4,131	4,411	4,529
Rate 23	4,835	5,470	6,029	6,513	7,030	7,247





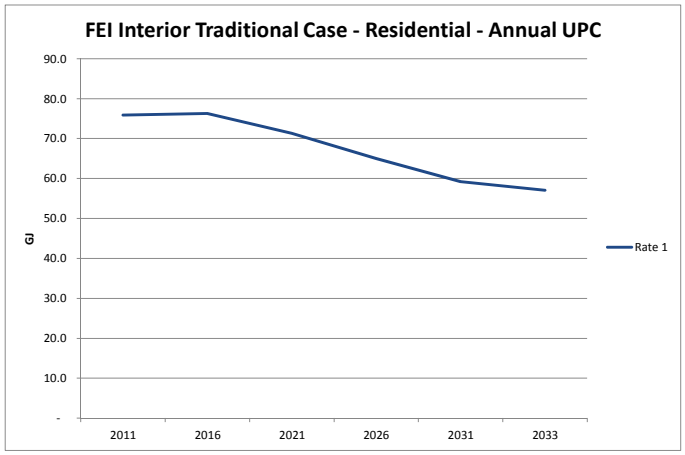


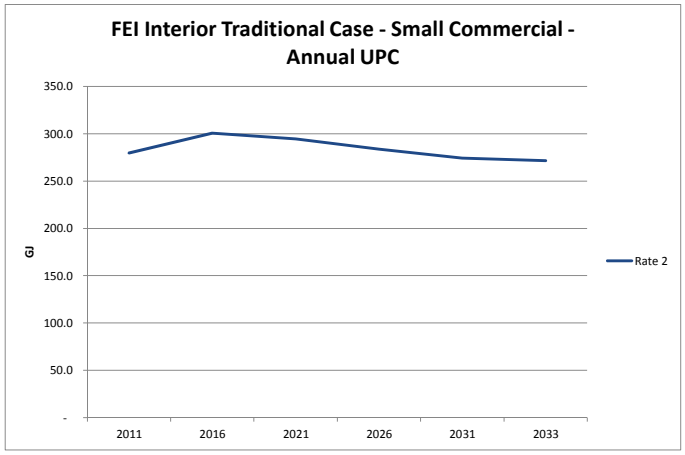
This tab "2014 LTRP - FEI Interior Trad" contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for the Traditional Case milestone years

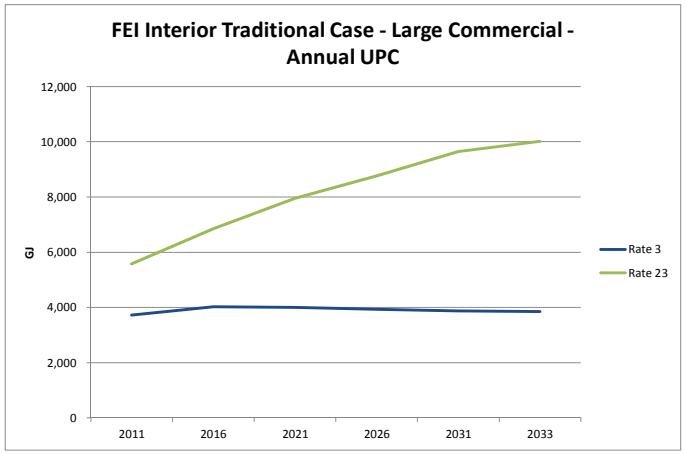
Annual Use Rate per Customer by Rate Class (GJ) RESIDENTIAL	2011	2016	2021	2026	2031	2033
Rate 1	75.8	76.3	71.3	65.0	59.2	57.1

Annual Use Rate per Customer by Rate Class (GJ) SMALL COMMERCIAL	2011	2016	2021	2026	2031	2033
Rate 2	279.6	300.6	294.5	283.5	274.3	271.4

Annual Use Rate per Customer by Rate Class (GJ) LARGE COMMERCIAL	2011	2016	2021	2026	2031	2033
Rate 3	3,719	4,028	3,998	3,933	3,872	3,848
Rate 23	5,574	6,850	7,957	8,769	9,649	10,019





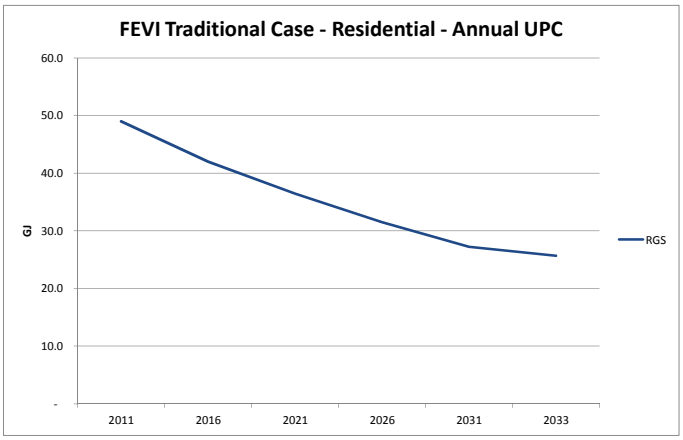


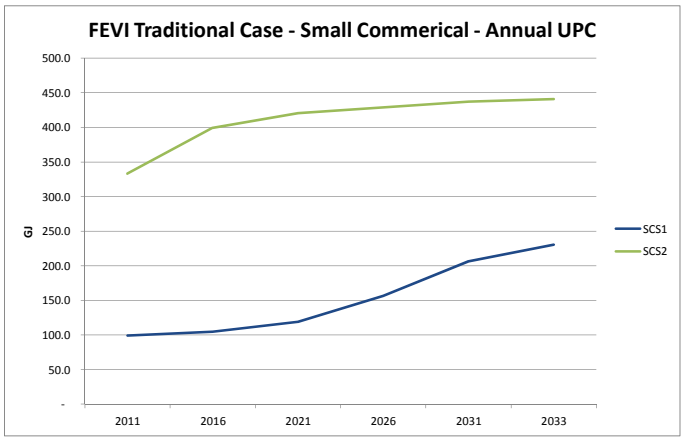
This tab "2014 LTRP - FEVI Trad" contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for

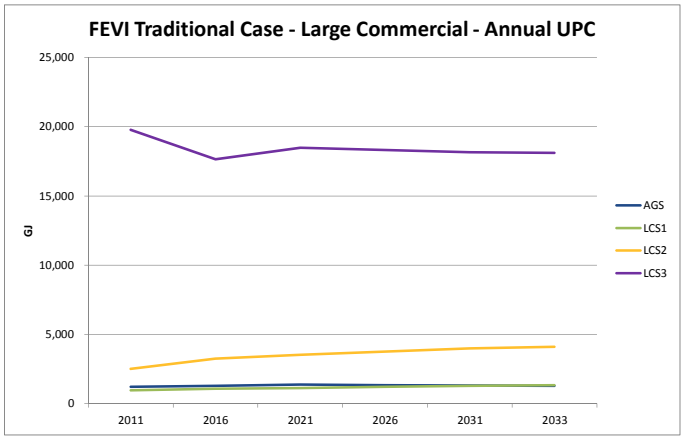
Annual Use Rate per Customer by Rate Class (GJ) RESIDENTIAL	2011	2016	2021	2026	2031	2033
RGS	49.0	42.0	36.5	31.5	27.2	25.7

Annual Use Rate per Customer by Rate Class (GJ) SMALL COMMERCIAL	2011	2016	2021	2026	2031	2033
SCS1	99.0	104.5	119.1	156.6	206.3	230.4
SCS2	333.3	399.1	420.5	428.8	437.4	440.9

Annual Use Rate per Customer by Rate Class (GJ) LARGE COMMERCIAL	2011	2016	2021	2026	2031	2033
AGS	1,202	1,285	1,363	1,331	1,299	1,287
LCS1	947.3	1,063	1,119	1,199	1,284	1,320
LCS2	2,495	3,239	3,517	3,743	3,985	4,086
LCS3	19,766	17,640	18,476	18,320	18,165	18,103





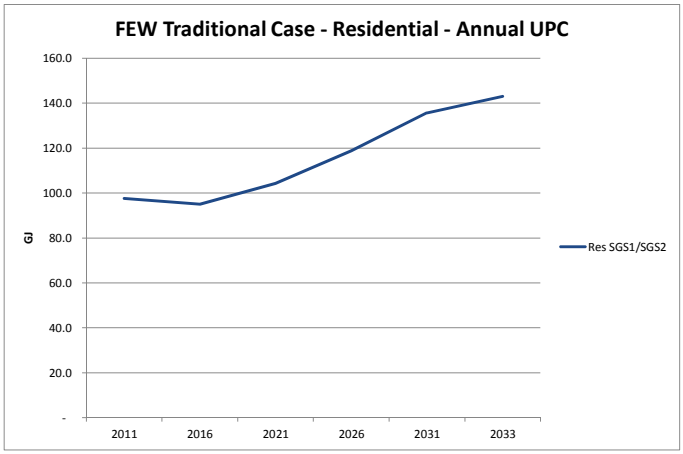


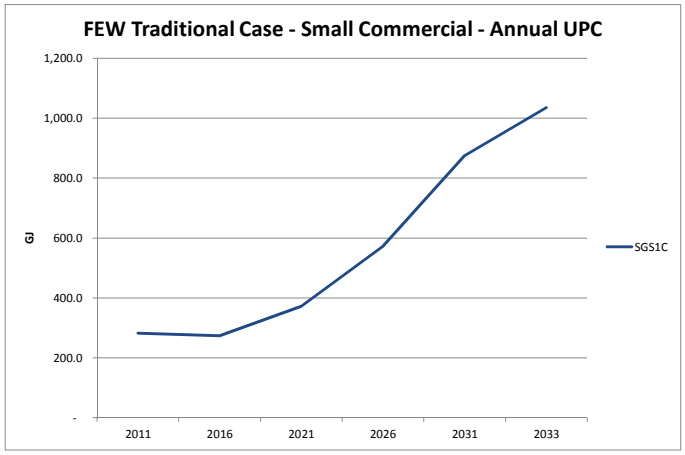
This tab "2014 LTRP - FEW Trad" contains three tables and three corresponding graphs showcasing Annual UPC (Usage per Customer) data for Residential, Small Commercial, and Large Commercial rate classes for the Traditional Case milestone years

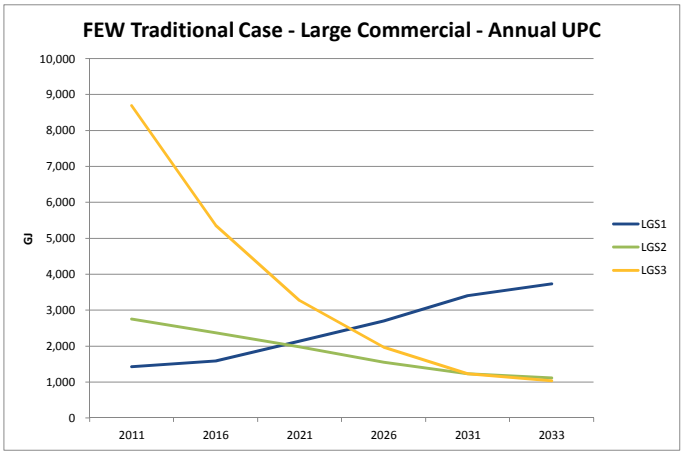
Annual Use Rate per Customer by Rate Class (GJ) RESIDENTIAL	2011	2016	2021	2026	2031	2033
Res SGS1/SGS2	97.7	95.1	104.3	118.9	135.6	143.0

Annual Use Rate per Customer by Rate Class (GJ) SMALL COMMERCIAL	2011	2016	2021	2026	2031	2033
SGS1C	281.9	273.7	372.5	573.0	875.0	1,035

Annual Use Rate per Customer by Rate Class (GJ) LARGE COMMERCIAL	2011	2016	2021	2026	2031	2033
LGS1	1,429	1,585	2,139	2,698	3,400	3,728
LGS2	2,750	2,373	1,978	1,555	1,227	1,116
LGS3	8,693	5,365	3,267	1,971	1,235	1,039







Attachment 24.1

NGT Actual Demand for 2011-2013

This tab includes actual rate class data for NGT (Rate 6, CNG, & LNG) by region for 2011, 2012, and 2013. Please note there was no NGT on FEVI or FEW for 2011, 2012, or 2013. Also note that Rate 16 will cease to exist as of January 1st, 2015 at which point all Rate 16 customers will be moved over to Rate 46.

FEI - Lower Mainland

Lower MainLand (GJ)	2011	2012	2013
CNG (Rate 6)	65,138.26	57,313.49	47,531.90
CNG (Rate 23, 25, & 25S)	25,764.80	52,012.30	120,346.50
LNG (Rate 16 & 46)		163,219.00	193,129.20
FEI LML	**90,903.06**	**272,544.79**	**361,007.60**

FEI - Interior

Interior (GJ)	2011	2012	2013
CNG (Rate 6)	4,336.62	5,163.44	3,443.24
CNG (Rate 23, 25, 25S)	-	-	-
LNG (Rate 16 & 46)	-	-	-
FEI Interior	**4,336.62**	**5,163.44**	**3,443.24**

FEVI

Interior (GJ)	2011	2012	2013
CNG (Rate 6)	-	-	-
CNG (Rate LCS-13, HLF)	-	-	-
LNG (Rate 16 & 46)	-	-	-
FEI Interior	**-**	**-**	**-**

FEW

Interior (GJ)	2011	2012	2013
CNG (Rate 6)	-	-	-
CNG (Rate LCS-2)	-	-	-
LNG (Rate 16 & 46)	-	-	-
FEI Interior	**-**	**-**	**-**

NGT Demand Forecast by CNG/LNG

This tab includes a CNG and LNG breakdown for the NGT Cases (Low, Reference, & High). Please note that Rate 16 will cease to exist as of January 1st, 2015 at which point all Rate 16 customers will be moved over to Rate 46.

Low Case (1% Market Share in 2033)

Total Load (GJ/yr)	2010-2011	2012	2013F	2014F	2015F	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2026F	2027F	2028F	2029F	2030F	2031F	2032F	2033F
CNG (Rate 23, 25, 25S, LCS-2, LCS-13, HLF)	32,000	84,000	122,000	155,000	305,400	399,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400	471,400
LNG (Rate 16 & 46)	162,500	162,500	302,000	356,000	803,000	1,277,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000	1,697,000

Reference Case (15% Market Share in 2033)

Total Load (GJ/yr)	2010-2011	2012	2013F	2014F	2015F	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2026F	2027F	2028F	2029F	2030F	2031F	2032F	2033F
CNG (Rate 23, 25, 25S, LCS-2, LCS-13, HLF)	32,000	84,000	125,668	169,672	320,072	414,072	486,072	573,003	675,965	797,914	942,351	1,113,425	1,316,046	1,556,032	1,840,274	2,176,933	2,575,676	3,047,951	3,607,317	4,269,837	5,054,532	5,983,933	7,084,724
LNG (Rate 16 & 46)	162,500	162,500	302,000	356,000	803,000	1,277,000	1,697,000	2,009,944	2,380,598	2,819,603	3,339,567	3,955,416	4,684,834	5,548,765	6,572,012	7,783,957	9,219,397	10,919,546	12,933,219	15,318,234	18,143,069	21,488,833	25,451,588

High Case (30% Market Share in 2033)

Total Load (GJ/yr)	2010-2011	2012	2013F	2014F	2015F	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2026F	2027F	2028F	2029F	2030F	2031F	2032F	2033F
CNG (Rate 23, 25, 25S, LCS-2, LCS-13, HLF)	32,000	84,000	125,668	184,344	334,744	428,744	500,744	612,395	750,491	921,294	1,132,553	1,393,848	1,717,031	2,116,759	2,611,163	3,222,667	3,979,006	4,914,483	6,071,528	7,502,620	9,272,665	11,461,946	14,169,758
LNG (Rate 16 & 46)	162,500	162,500	302,000	356,000	803,000	1,277,000	1,697,000	2,098,934	2,596,067	3,210,946	3,971,458	4,912,098	6,075,528	7,514,517	9,294,330	11,495,693	14,218,447	17,586,087	21,751,351	26,903,159	33,275,172	41,156,397	50,904,289

NGT Demand Forecast by Region and Vehicle Type

This tab includes vehicle breakdown by NGT Case (Low, Reference, & High) and Region (Interior, Lower Mainland, FEVI, FEW). Please note that Rate 16 will cease to exist as of January 1st, 2015 at which point all Rate 16 customers will be moved over to Rate 46.

Low Case

Total Load (GJ/yr)

Category	2010-2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Interior (Rate 23, 25, 25S)	4,811	16,724	24,972	32,532	56,130	75,374	90,953	90,953	90,953	90,953	90,953	90,953	90,953	90,953	90,953	90,953	90,953	90,953	90,953	90,953	90,953	90,953	90,953
Lower Mainland (Rate 23, 25, 25S)	16,000	55,619	83,047	108,190	186,666	250,665	302,474	302,474	302,474	302,474	302,474	302,474	302,474	302,474	302,474	302,474	302,474	302,474	302,474	302,474	302,474	302,474	302,474
FEVI (LCS-13, HLF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEW (LCS-2)	191	664	992	1,292	2,230	2,994	3,613	3,613	3,613	3,613	3,613	3,613	3,613	3,613	3,613	3,613	3,613	3,613	3,613	3,613	3,613	3,613	3,613
Vocational trucks	**21,000**	**73,000**	**109,000**	**142,000**	**245,000**	**329,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**	**397,000**
Interior (Rate 23, 25, 25S)	2,836	2,836	3,351	3,351	15,571	18,149	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180
Lower Mainland (Rate 23, 25, 25S)	8,135	8,135	9,614	9,614	44,666	52,061	55,019	55,019	55,019	55,019	55,019	55,019	55,019	55,019	55,019	55,019	55,019	55,019	55,019	55,019	55,019	55,019	55,019
FEVI (LCS-13, HLF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEW (LCS-2)	32	32	38	38	175	204	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216
Buses	**11,000**	**11,000**	**13,000**	**13,000**	**60,400**	**70,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**	**74,400**
Interior	80,226	80,226	149,097	175,757	322,386	482,345	615,644	615,644	615,644	615,644	615,644	615,644	615,644	615,644	615,644	615,644	615,644	615,644	615,644	615,644	615,644	615,644	615,644
Lower Mainland	82,258	82,258	152,872	180,207	330,549	494,557	631,231	631,231	631,231	631,231	631,231	631,231	631,231	631,231	631,231	631,231	631,231	631,231	631,231	631,231	631,231	631,231	631,231
FEVI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Class 8 tractors (Rate 16 & 46)	**162,500**	**162,500**	**302,000**	**356,000**	**653,000**	**977,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**	**1,247,000**
Marine - Ferries (Rate 46)	**0**	**0**	**0**	**0**	**150,000**	**300,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**
Total NGT Fleet	**194,500**	**246,500**	**424,000**	**511,000**	**1,108,400**	**1,676,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**	**2,168,400**

Reference Case

Total Load (GJ/yr)

Category	2010-2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Interior (Rate 23, 25, 25S)	4,811	16,724	24,972	32,532	56,130	75,374	90,953	107,725	127,591	151,120	178,988	211,995	251,089	297,393	352,235	417,190	494,124	585,246	693,171	820,999	972,399	1,151,719	1,364,108
Lower Mainland (Rate 23, 25, 25S)	16,000	55,619	83,047	108,190	186,666	250,665	302,474	358,254	424,319	502,568	595,246	705,016	835,028	989,015	1,171,399	1,387,417	1,643,271	1,946,306	2,305,225	2,730,331	3,233,832	3,830,182	4,536,506
FEVI (LCS-13, HLF)	0	0	3,668	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672	14,672
FEW (LCS-2)	191	664	992	1,292	2,230	2,994	3,613	4,279	5,068	6,003	7,110	8,421	9,973	11,813	13,991	16,571	19,627	23,246	27,533	32,611	38,624	45,747	54,183
Vocational trucks	**21,000**	**73,000**	**112,668**	**156,672**	**259,672**	**343,672**	**411,672**	**484,883**	**571,594**	**674,296**	**795,938**	**940,011**	**1,110,653**	**1,312,762**	**1,552,143**	**1,835,668**	**2,171,478**	**2,569,215**	**3,040,298**	**3,598,254**	**4,259,102**	**5,041,818**	**5,968,874**
Interior (Rate 23, 25, 25S)	2,836	2,836	3,351	3,351	15,571	18,149	19,180	22,717	26,907	31,869	37,745	44,706	52,950	62,715	74,280	87,978	104,202	123,418	146,178	173,134	205,062	242,877	287,666
Lower Mainland (Rate 23, 25, 25S)	8,135	8,135	9,614	9,614	44,666	52,061	55,019	65,165	77,182	91,415	108,273	128,239	151,888	179,898	213,073	252,365	298,904	354,025	419,311	496,636	588,220	696,694	825,171
FEVI (LCS-13, HLF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEW (LCS-2)	32	32	38	38	175	204	216	256	303	358	425	503	596	705	836	990	1,172	1,388	1,644	1,948	2,307	2,732	3,236
Buses	**11,000**	**11,000**	**13,000**	**13,000**	**60,400**	**70,400**	**74,400**	**88,120**	**104,370**	**123,617**	**146,414**	**173,414**	**205,393**	**243,269**	**288,131**	**341,265**	**404,197**	**478,736**	**567,019**	**671,583**	**795,430**	**942,115**	**1,115,850**
Interior	80,226	80,226	149,097	175,757	322,386	482,345	615,644	729,175	863,642	1,022,906	1,211,540	1,434,960	1,699,581	2,013,001	2,384,219	2,823,893	3,344,647	3,961,433	4,691,961	5,557,205	6,582,009	7,795,798	9,233,421
Lower Mainland	82,258	82,258	152,872	180,207	330,549	494,557	631,231	747,637	885,508	1,048,805	1,242,215	1,471,292	1,742,613	2,063,968	2,444,585	2,895,391	3,429,330	4,061,732	4,810,757	5,697,908	6,748,659	7,993,180	9,467,202
FEVI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Class 8 tractors (Rate 16 & 46)	**162,500**	**162,500**	**302,000**	**356,000**	**653,000**	**977,000**	**1,247,000**	**1,476,959**	**1,749,325**	**2,071,918**	**2,454,001**	**2,906,543**	**3,442,539**	**4,077,377**	**4,829,287**	**5,719,855**	**6,774,654**	**8,023,968**	**9,503,668**	**11,256,239**	**13,332,002**	**15,790,556**	**18,702,493**
Marine - Ferries (Rate 46)	**0**	**0**	**0**	**0**	**150,000**	**300,000**	**450,000**	**532,985**	**631,272**	**747,685**	**885,566**	**1,048,873**	**1,242,295**	**1,471,387**	**1,742,726**	**2,064,102**	**2,444,743**	**2,895,578**	**3,429,551**	**4,061,995**	**4,811,067**	**5,698,276**	**6,749,095**
Total NGT Fleet	**194,500**	**246,500**	**427,668**	**525,672**	**1,123,072**	**1,691,072**	**2,183,072**	**2,582,947**	**3,056,562**	**3,617,517**	**4,281,918**	**5,068,841**	**6,000,880**	**7,104,796**	**8,412,286**	**9,960,890**	**11,795,072**	**13,967,496**	**16,540,536**	**19,588,071**	**23,197,602**	**27,472,766**	**32,536,313**

High Case

Total Load (GJ/yr)

Category	2010-2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Interior (Rate 23, 25, 25S)	4,811	16,724	24,972	32,532	56,130	75,374	90,953	112,495	139,139	172,094	212,855	263,270	325,625	402,749	498,141	616,125	762,054	942,547	1,165,789	1,441,906	1,783,422	2,205,825	2,728,275
Lower Mainland (Rate 23, 25, 25S)	16,000	55,619	83,047	108,190	186,666	250,665	302,474	374,115	462,725	572,321	707,875	875,535	1,082,906	1,339,392	1,656,627	2,048,999	2,534,305	3,134,555	3,876,974	4,795,235	5,930,987	7,335,741	9,073,211
FEVI (LCS-13, HLF)	0	0	3,668	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344	29,344
FEW (LCS-2)	191	664	992	1,292	2,230	2,994	3,613	4,468	5,527	6,836	8,455	10,457	12,934	15,997	19,786	24,473	30,269	37,439	46,306	57,273	70,839	87,617	108,369
Vocational trucks	**21,000**	**73,000**	**112,668**	**171,344**	**274,344**	**358,344**	**426,344**	**520,373**	**636,674**	**780,520**	**958,436**	**1,178,491**	**1,450,667**	**1,787,307**	**2,203,681**	**2,718,672**	**3,355,640**	**4,143,473**	**5,117,904**	**6,323,130**	**7,813,813**	**9,657,564**	**11,938,008**
Interior (Rate 23, 25, 25S)	2,836	2,836	3,351	3,351	15,571	18,149	19,180	23,723	29,342	36,292	44,887	55,519	68,669	84,933	105,049	129,930	160,704	198,767	245,844	304,073	376,092	465,170	575,345
Lower Mainland (Rate 23, 25, 25S)	8,135	8,135	9,614	9,614	44,666	52,061	55,019	68,050	84,168	104,103	128,759	159,256	196,976	243,630	301,333	372,704	460,979	570,162	705,205	872,233	1,078,821	1,334,340	1,650,379
FEVI (LCS-13, HLF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEW (LCS-2)	32	32	38	38	175	204	216	267	330	408	505	625	772	955	1,182	1,462	1,808	2,236	2,766	3,421	4,231	5,233	6,472
Buses	**11,000**	**11,000**	**13,000**	**13,000**	**60,400**	**70,400**	**74,400**	**92,022**	**113,817**	**140,775**	**174,117**	**215,357**	**266,364**	**329,452**	**407,483**	**503,995**	**623,366**	**771,011**	**953,624**	**1,179,490**	**1,458,853**	**1,804,382**	**2,231,750**
Interior	80,226	80,226	149,097	175,757	322,386	482,345	615,644	761,459	941,811	1,164,879	1,440,780	1,782,029	2,204,102	2,726,144	3,371,831	4,170,450	5,158,221	6,379,945	7,891,035	9,760,027	12,071,689	14,930,869	18,467,245
Lower Mainland	82,258	82,258	152,872	180,207	330,549	494,557	631,231	780,739	965,656	1,194,372	1,477,259	1,827,148	2,259,908	2,795,167	3,457,203	4,276,041	5,288,822	6,541,479	8,090,828	10,007,141	12,377,333	15,308,904	18,934,818
FEVI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Class 8 tractors (Rate 16 & 46)	**162,500**	**162,500**	**302,000**	**356,000**	**653,000**	**977,000**	**1,247,000**	**1,542,352**	**1,907,658**	**2,359,487**	**2,918,331**	**3,609,538**	**4,464,457**	**5,521,864**	**6,829,717**	**8,447,336**	**10,448,087**	**12,922,717**	**15,983,462**	**19,769,145**	**24,451,467**	**30,242,797**	**37,405,803**
Marine - Ferries (Rate 46)	**0**	**0**	**0**	**0**	**150,000**	**300,000**	**450,000**	**556,583**	**688,409**	**851,459**	**1,053,127**	**1,302,560**	**1,611,071**	**1,992,653**	**2,464,613**	**3,048,357**	**3,770,360**	**4,663,370**	**5,767,889**	**7,134,014**	**8,823,705**	**10,913,600**	**13,498,486**
Total NGT Fleet	**194,500**	**246,500**	**427,668**	**540,344**	**1,137,744**	**1,705,744**	**2,197,744**	**2,711,330**	**3,346,558**	**4,132,240**	**5,104,011**	**6,305,946**	**7,792,559**	**9,631,276**	**11,905,494**	**14,718,360**	**18,197,453**	**22,500,570**	**27,822,880**	**34,405,779**	**42,547,837**	**52,618,342**	**65,074,047**

Attachment 25.3

REFER TO LIVE SPREADSHEET MODEL

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Attachment 38.1

REFER TO LIVE SPREADSHEET MODEL

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