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May 3, 2023

BC Solar & Storage Industries Association
PO Box 33019
West Vancouver, BC
V7V 4W7

Attention: Steve Davis

Dear Steve Davis:

Re: FortisBC Energy Inc. (FEI)

2022 Long Term Gas Resource Plan (LTGRP) – Project No. 1599324

Response to the BC Solar and Storage Industries Association (BCSSIA) Information Request (IR) No. 2

On May 9, 2022, FEI filed the LTGRP referenced above. In accordance with the amended regulatory timetable established in British Columbia Utilities Commission Order G-99-23 for the review of the LTGRP, FEI respectfully submits the attached response to BCSSIA IR No. 2.

In its responses, FEI has identified responses which were provided by, contributed to, or developed with its consultants, the Posterity Group and Guidehouse.

For convenience and efficiency, if FEI has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FEI intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Parties

11.0 Topic: GHG Reduction Targets

Reference: Exhibit B-1, Section 2.2.2, Provincial Energy and Climate Policies

In Section 2.2.2.1, FEI describes the Province of B.C.'s GHG reduction targets [underlining added for emphasis]:

> ***"2.2.2.1 Climate Change Accountability Act***
>
> *In 2017, the provincial government enacted the Climate Change Accountability Act (CCAA) which included targets for reducing GHG emissions in BC. The CCAA identified GHG reduction targets below 2007 levels as follows:*
>
> *16 percent by 2025;*
>
> *40 percent by 2030;*
>
> *60 percent by 2040; and*
>
> *80 percent by 2050.*
>
> *... In March 2021, sectoral targets for 2030 were established as follows, expressed as a percentage reduction from 2007 sector emissions:*
>
> *Transportation - 27 to 32 percent;*
>
> *Industry- 38 to 43 percent;*
>
> *Oil and Gas - 33 to 38 percent; and*
>
> *Buildings and Communities - 59 to 64 percent*
>
> *... FEI delivers the majority of its energy to the industry and buildings and communities sectors, which are the sectors with the most ambitious targets. This places significant pressure on FEI to source a[fordable, reliable and low- carbon energy. "*

Then, in Section 2.2.2.2, FEI described the further requirements laid out in the CleanBC Roadmap to 2030 and the GHG Reduction Standards that will apply to FEI's future GHG emissions [underlining added for emphasis]:

> ***"2.2.2.2 CleanBC Roadmap to 2030 (Roadmap)***
>
> *On October 25, 2021, the provincial government released the CleanBC Roadmap to 2030 (Roadmap) as an update to the 2018 CleanBC plan and part of its commitment to achieve BC 's legislated GHG reduction target of 40 per cent below 2007 levels by 2030. The Roadmap articulates a plan to fully achieve this target*

and sets the course to reach net-zero by 2050. The Roadmap, includes ambitious measures that place FEI at the forefront of the global energy transition. It is also anticipated to have a significant impact on FEJ's customer rates, competitiveness and throughput.

... Key measures in the Roadmap that directly impact FE/ include:

- *An increased carbon tax which will rise to $170 per tonne by 2030;*
- *A GHG cap for natural gas utilities;*
- *A zero-carbon requirement for new buildings and highest efficiency standards for space and water heating equipment by 2030;*
- *Amendments to the Greenhouse Gas Reduction (Renewable & Low-carbon Fuel Requirements) Act and the Renewable & Low-carbon Fuel Requirements Regulation, known collectively as British Columbia 's Low-carbon Fuel Standard (BC-LCFS), to decrease the carbon intensity*

benchmark while including marine and aviation fuels in the amendment; and

- *A 75 percent reduction in oil and gas methane emissions by 2030.*

... 2.2.2.2.2 GREENHOUSE GAS REDUCTION STANDARD (GHGRS): EMISSIONS CAP FOR NATURAL GAS UTILITIES

... The Province's approach was updated in the Roadmap with a cap on GHG emissions for natural gas utilities called the GHGRS. The GHGRS will establish an obligation fQr. natural gas utilities to reduce GHG emissions from energy use in the buildings and industrial sectors. FEI expects compliance with the cap to be overseen by the BCUC and that enabling legislation will be developed that will further define how this policy will be implemented for gas utilities.

... The GHGRS is the first of its kind in Canada, and will mandate FEI to invest in carbon saving technologies and solutions to displace natural gas consumption by 2030. As described in the report, "the cap will be set at approximately Q Mt of CO2e per year for_ 2030, which is approximately 47 percent lower than 2007 levels." [Representing the average sectoral reduction required for the buildings and communities and industry sectors.] The GHGRS would require a GHG reduction of approximately 5.5 Mt of CO2e, which is equivalent to displacing approximately half of the natural gas delivered by FEI.

Additionally, the GHGRS imposes a target of a 61 percent emissions reduction in the buildings sector by 2030. This is an aggressive goal that disproportionately impacts FEL and is more representative of a 2040 target, thereby requiring a more rapid transition in the buildings sector at greater cost and risk."

11.1 Why does FEI use the word "Additionally", in referring to the GHGRS target of a 61 percent emissions reduction in the buildings sector by 2030? Is that in addition to the 5.5 Mt reduction referred to in the previous paragraph? Has the GHGRS been specified as to each individual sector or only with respect to FEI overall?

Response:

FEI used the word "Additionally" in the cited paragraph as an adverb to the next point being made. FEI was not suggesting that there is any addition to the 5.5 Mt reduction referred to in the previous paragraph. The GHGRS is specific to natural gas utilities, in which the Province will require gas utilities to undertake activities and invest in technologies that will lower GHG emissions from natural gas used in to the buildings and industrial sectors.

11.2 In saying that the GHGRS will cap FEI's emissions at 6 Mt/year in 2030 and that will be a 47% reduction from its 2007 emissions, is that to imply that FEI's emissions in 2007 were 11.3 Mt? What were FEI's emissions in 2007 with respect to the buildings and communities and the industry sectors? What are they today?

Response:

FEI's 2007 baseline customer end-use emissions for the residential, commercial and industrial customer types was 10.9 $MtCO_2e$. The analysis is based on end-use emission factors, as these factors are what BC provincial targets are being measured against. Please refer to the response to CEC IR1 6.3 (Exhibit B-12) and Tables 1 and 2 in CEC IR2 56.1 which provide further discussion including a breakdown of GHG emissions by customer type.

FEI's 2022 customer-related emissions are not yet publicly available. In 2021, FEI's customer-related emissions were 11.7 $MtCO_2e$ as published in the FortisBC Corporate Annual Sustainability Report[1]. Of this total, 10.5 $MtCO_2e$ represents the customer end-use emissions for the residential, commercial and industrial customer types based on the methodology used in the LTGRP.

11.2.1 How were these emissions measured in 2007 and what do they include? How are they measured in 2022 and what do they include? For instance, do they only include emissions that FEI has direct control over, or do they also include FEI's customers' emissions from the combustion or other use of the gas? Do they also include the upstream emissions of FEI's gas suppliers and the upstream pipeline emissions? Exactly which emissions is FEI being held accountable for under the GHGRS caps?

[1] https://www.fortisbc.com/sustainabilityreport

Response:

The customer related GHG (end use) emissions provided in response to BCSSIA IR2 11.2 include the combustion of natural gas by customers. These end-use emission values are not life cycle values, in that they do not include upstream emissions of FEI suppliers or upstream pipeline emissions. This is standard practice for GHG emissions accounting and how the BC GHG inventory is compiled. Please refer to Table 1-2 in the Application for a description of the emission factors associated with fuel types in the LTGRP, including end use and life cycle emission factors.

As described in Section 9.2 of the Application, GHG emissions from FEI's residential, commercial and industrial customers will be subject to the proposed GHGRS cap on emissions for the buildings and industrial sectors based on the end-use emission factors. FEI does not have details from the Province on the scope of GHG emissions covered under the proposed policy nor does it have details on the methodology used to derive the cap.

11.2.2 If FEI is not deemed responsible for the upstream emissions of its suppliers, then why does it seek low-emitting supplies, such as renewable and low-carbon gas or Hydrogen?

Response:

FEI is seeking low-carbon gases like RNG and hydrogen primarily because the GHG emissions related to their combustion and use are much lower than conventional natural gas, as illustrated in Table 1-2 in the Application, thereby reducing FEI's customers' emissions. FEI is expected to reduce its customers' emissions under the GHGRS, subject to its pending design.

11.2.3 Does "low-carbon gas" include gas that comes from electrified shallow cut processing plants that are use renewable electricity such as from the BC Hydro grid (i.e., for compression and cooling, which reduce GHG emissions 60-70 percent as compared to gas fired shallow cut plants)? Does FEI prefer to source its gas supply from electrified processing plants? Would such a lower emission supply of gas be credited to FEI's emission reductions? If not, then why not, and why does FEI receive such a credit for purchasing renewable gas or hydrogen?

Response:

While there is no standard definition of “low-carbon gas,” FEI currently considers “renewable and low carbon gas” to be any gas with a lifecycle carbon intensity below the federally recommended carbon intensity threshold for blue hydrogen of 36 gCO2e/MJ. This is approximately 40 percent lower than the lifecycle carbon intensity of natural gas in BC.

FEI does not prefer to source its gas supply from electrified processing plants because gas that comes from electrified shallow cut processing plants that use renewable electricity will likely not be considered “low-carbon gas.” Since the combustion emissions of natural gas are approximately 50 gCO_2e/MJ, this gas supply would not meet the 36 gCO_2e/MJ threshold to be considered as low-carbon gas.

However, several options to lower the carbon intensity of the energy supplied by FEI are being considered, which could include acquiring natural gas that has a demonstrated lower-than-average carbon intensity. FEI is currently examining options of procuring natural gas with lower lifecycle carbon intensity than 60 gCO2e/MJ. FEI outlines its preferred gas acquisition strategy in its Annual Contracting Plan.

At present, the BC government has not developed a mechanism by which lower carbon conventional natural gas, renewable gas or hydrogen can be credited to FEI’s emission reductions.

11.2.4 If FEI disagrees with the 60-70 percent range, please explain in detail? For example, please see page 15 of:

https://projects.eao.gov.bc.ca/api/public/document/5886b08de036fb01057695ce/download/Project%20Description%20and%20Supporting%20Materials %20-%20March%2031%2C%202015.pdf

where it says: "An estimated 76% reduction in CO2 emissions would be realized due to electrification, compared to if the proposed Project used natural-gas driven compressors."

Response:

FEI is not in a position to agree or disagree with the 60-70 percent range cited, as FEI has not investigated the degree to which a gas plant can reduce its emissions by using electrification technologies, However, FEI notes that the cited CO_2 reductions relate to the processing facility only – not to the lifecycle emissions of the natural gas. Therefore, the 76 percent emissions reduction in the referenced report does not apply to the lifecycle emissions of the natural gas, but rather to the emission from the natural gas processing plant alone.

11.2.5 Does any FEI sourced gas, from Alberta, B.C. or elsewhere pass, through deep cut or straddle processing plants that are gas fired (i.e., for compression and cooling)? Through electrified deep cut or straddle processing plants that use renewable electricity such as from the BC Hydro grid?

Response:

Yes. FEI's sourced gas from Alberta and BC is required to go through deep cut or straddle processing plants to ensure they meet the pipeline specifications, and can be either gas fired or powered by electricity. FEI is aware that the BC Government is working with the producers to find ways to reduce emissions from its upstream infrastructure, but generally, the older plants are likely using gas-fired plants while the new plants are using more renewable electricity such as from the BC Hydro grid. FEI anticipates that this activity will expand, as the Energy Action Framework announced by the Provincial government will focus on achieving additional GHG reductions from upstream gas extraction where electricity will be an important abatement option.

11.2.6 What would the reduction in GHGs be if gas is passed through an electrified deep cut or straddle processing plants that use renewable electricity such as from the BC Hydro grid vs. gas fired deep cut or straddle processing plants?

Response:

In order to determine the GHG reduction potential associated with electrification of these processing plants, FEI would require equipment-based information and their attributed GHG emissions. Given that FEI does not own and is not privy to additional data related to these facilities, FEI is unable to provide an estimate.

11.2.7 What would the reduction in GHGs be if gas is transported in pipelines that use renewable electricity such as from the BC Hydro grid to provide compression, rather than gas-fueled compressors?

Response:

Please refer to the response to BCSSIA IR1 6.3.

In its response to BCUC IR 1.74.1, FEI states a different value for the GHGRS cap:

> *"... Additional actions will be taken by 2030 to further reduce emissions by 0.9 Mt CO2e to meet the proposed GHGRS cap of 5.7 Mt CO2e. There are no additional actions required to meet the BC legislated GHG emissions target of 4.3 Mt CO2e (60 percent reduction of FEI's 2007 emissions) by 2040."*

11.3 Has FEI's GHGRS cap been specified more clearly since the date when the Application was filed? Has it now been set to 5.7 Mt/year, rather than 6 Mt/year, as stated in Section 2.2.2.2.2? How has the 5.7 Mt/year cap been determined? Has the cap for 2040 been set definitely to 4.3 Mt?

Response:

Please refer to the responses to BCSEA IR1 1.1 and 1.2 and BCSEA IR2 46.1 for confirmation that FEI has not received updated information, timing or further details about compliance pathways for the GHGRS. As explained in Section 9.2.1.5 of the Application, the referenced cap of 6 MtCO2e refers to the cap on GHG emissions required from *all* gas utilities in BC. The portion of the cap that applies to FEI is estimated to be 5.7 Mt CO2e.

11.4 If these caps have been finally specified, how have they been determined? If they are yet to be specified, then how are they expected to be determined?

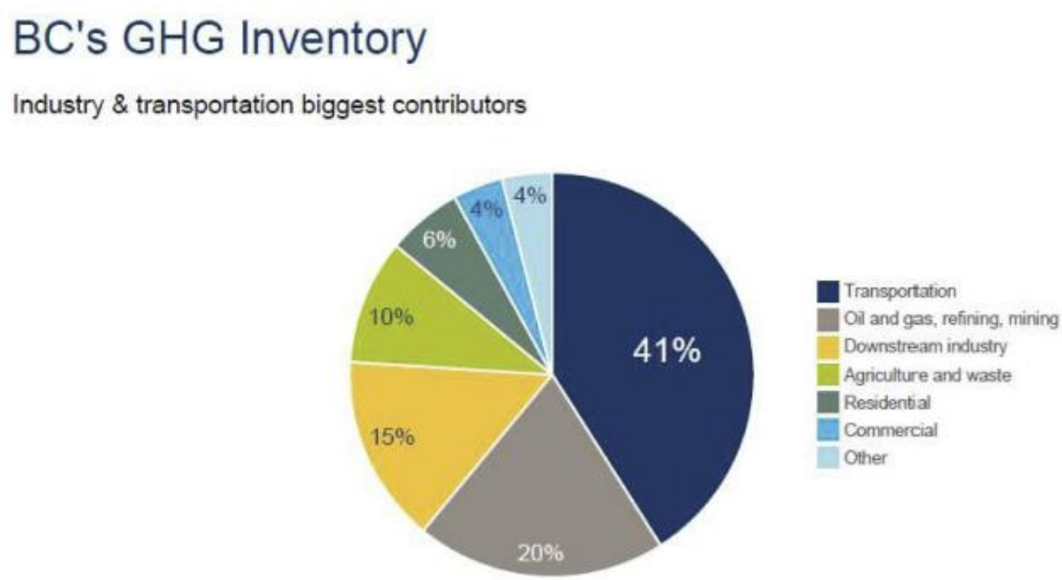
Response:

Please refer to the response to BCSSIA IR2 11.3. The details of the GHGRS, including how the cap is calculated, has not yet been determined.

12.0 Topic: B.C.'s Greenhouse Gas Inventory Sectoral Classification

Reference: Exhibit B-11, Attachment 1.1, pdf page 114 of 453, and 427 of 453, and Provincial GHG Inventory at Provincial greenhouse gas emissions inventory - Province of British Columbia (gov.be.ca)

FEI described the sectoral distribution of GHGs in the following pie chart, taken from its February 12, 2021 RPAG presentation (page 114 of 453):



This sectoral distribution was supported by the following table, taken from its February 10, 2022 RPAG presentation (page 427 of 453):

BC GHG Inventory, 2019

Transport	41%
Oil and Gas, Refining, Mining	20%
Downstream Industry	15%
Agriculture and Waste	10%
Residential	6%
Commercial	4%
Other	4%

The table makes clear that distribution is dated 2019.

However, the following data is extracted from the Provincial GHG Emissions Inventory, online at Provincial greenhouse gas emissions inventory - Province of British Columbia (gov.bc.ca)

Greenhouse Gas Emissions in British Columbia				percent	percent	percent
Unit: $MtCO_2e$	2007	2019	2020	2007	2019	2020
TOTAL[1]	65.5	67.9	64.6	100%	100%	100%
ENERGY	51.4	55.4	52.3	78%	79%	78%
STATIONARY COMBUSTION	20.7	21.1	20.4	32%	31%	32%
TRANSPORT[2]	24.2	29.4	27.3	37%	37%	36%
FUGITIVE SOURCES	6.5	4.9	4.7	10%	11%	10%
IPPU, AGRICULTURE, AND WASTE	11.3	9.6	9.4	17%	17%	17%
INDUSTRIAL PROCESSES AND PRODUCT USE (IPPU)	4.3	3.9	3.7	7%	7%	7%
AGRICULTURE	2.2	2.2	2.2	3%	3%	3%
WASTE	4.8	3.6	3.5	7%	7%	7%
LAND-USE CHANGE	2.8	2.9	2.8	4%	4%	4%
LAND-USE CHANGE	2.8	2.9	2.8	4%	4%	4%

This official GHG Inventory data appears to use a completely different breakdown of the emissions by sectors, and appears to show that the Transport sector is responsible for 37% of emissions in 2019 (also 2007) and 36% in 2020 (rather than 41% as shown in the previous pie chart and table). It also shows Industrial Processes at 7% rather than 15%.

A third classification system is also used. When FEI discusses its emissions reductions, it classifies them as being in Industry, Transportation, or the Built Environment.

12.1 Can FEI please provide some reconciliation of these three quite different sectoral classification schemes being applied to the provincial data? This should explain how the online provincial data are reclassified in such a way that they can agree with the breakdown shown in the table and chart taken from the RPAG presentations, and shed some light on what is classified as the Built Environment.

<u>Response:</u>

FEI confirms that the three presentations illustrating the provincial breakdown of sectoral emissions referred to in the preamble are sourced from the provincial GHG emissions inventory data.[2] The figures represented in the RPAG presentations were developed by the Province, and FEI sourced these figures from the provincial website at the time of the respective presentations. They are simply two different graphical representations of the same sourced figure. FEI confirms that it did not "reclassify" the provincial data in developing the figures in the RPAG presentations.

The third data extract is also from the same provincial government website but taken at a more current date. FEI notes that the framework regarding the attribution of emissions to sectoral targets is the provincial government's responsibility, not FEI's. FEI recognizes the difficulty associated with categorizing sectoral emissions extracted from the provincial website; however, FEI developed Table 1 below illustrating FEI's most reasonable interpretation of the third data extract in the preamble to the provincial sectoral classification presented in RPAG. FEI recognizes

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[2] 2019 sectoral GHG emissions sourced from the provincial website during the application preparation process. The latest GHG emissions are updated online at https://www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/progress-targets#emissions.

that these datasets are based on different extract dates and FEI cannot provide a complete analysis due to limitations in its understanding of how the Province attributes sectoral emissions.

FEI confirms that there is a mechanism in place for its reporting of gas distribution and its customers' emissions to the provincial government registries. FEI submits annual reports to the Community Energy and Emissions Inventories managed through the Climate Action Secretariat.

As discussed in the response to BCSSIA IR2 11.2.1, details pertaining to FEI's compliance pathways to the proposed GHGRS have yet to be announced.

Table 1: Current Provincial GHG Sectoral Emissions Data Extract in Comparison to 2019 Provincial Sectoral Presentation Used in RPAG Presentation

Category	Source	Activities	Calculation (Mt)	Percentage
Transportation	GHG Inventory 2019 – Activity Categories	Transport (minus Pipeline Transport)	(29.4-1.4)/67.9	41.2%
Oil and Gas, Refining, Mining	GHG Inventory 2019 – Activity Categories	Oil and Gas Extraction, Mining, Pipeline Transport, Fugitive Emissions	(6.7+0.7+1.4+4.9)/67.9	20.1%
Downstream Industry	GHG Inventory 2019 – Activity Categories	Petroleum Refining Industries, Electricity and Heat, Manufacturing Industries, Construction, Industrial Processes and Product Use	(0.5+0.9+4.5+0.1+3.9)/67.9	14.6 %
Agriculture and Waste	GHG Inventory 2019 – Activity Categories	Agriculture and Forestry, Agriculture, Waste	(0.6+2.2+3.6)/67.9	9.4%
Residential	GHG Inventory 2019 – Activity Categories	Residential	4.2/67.9	6.1%
Commercial	GHG Inventory 2019 – Activity Categories	Commercial and Institutional	2.9/67.9	4.3%
Other	GHG Inventory 2019 – Activity Categories	Land-Use Change	2.9/67.9	4.3%

12.2 Please explain how FEI's share of the emissions, and emission reductions, is determined, and how it fits within the overall provincial emissions.

Response:

Please refer to the response to BCSSIA IR2 11.2.1. In addition, please refer to Sections 9.1 and 9.2 of the Application and the responses to the BCUC IR1 72 and 74 series for a discussion on FEI's emission reductions initiatives in achieving the proposed GHGRS emissions cap and how FEI's customer emissions fit into overall provincial emissions.

12.3 Please explain how any parties can be held accountable for some share of the emission reductions, if there is no clear and consistent accounting system in place throughout the process of reducing those emissions.

Response:

Please refer to the response to BCSSIA IR2 12.1.

13.0 Topic: FEI Annual Energy Delivery and Peak Day Demand

Reference: Exhibit B-1, Table ES-1 (page ES-2), and Figure 4-9 (page 4-27), and Exhibit B-11, RPAG, February 10, 2022 (pdf page 423 of 453)

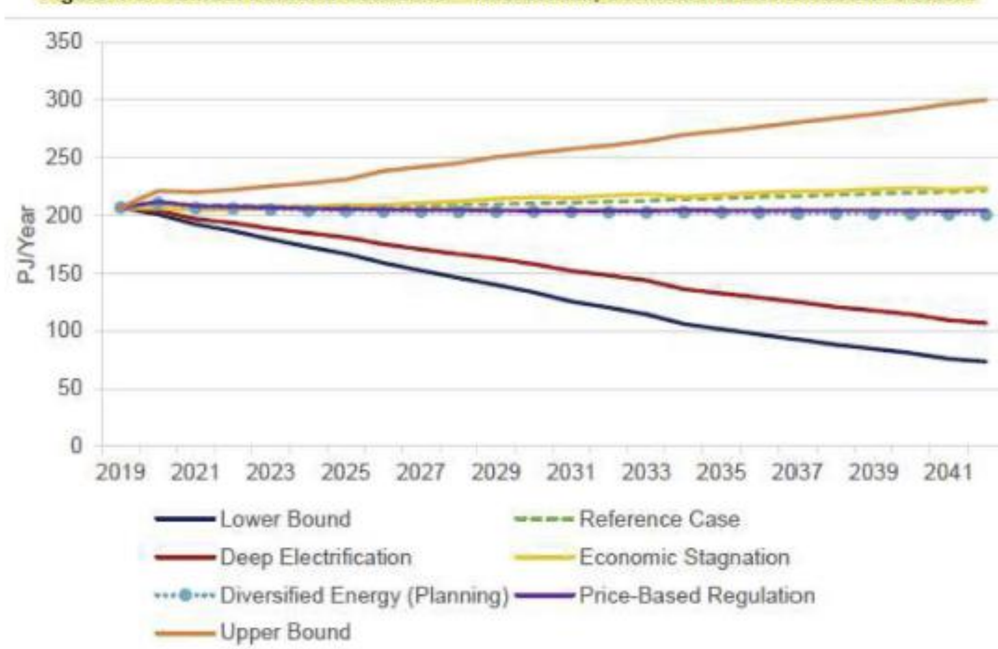
Table ES-1 lists FEI's Annual Demand as 228 PJ and Peak Day Demand as 1,399 TJ/day in 2021:

Table ES-1: FEI Service Statistics

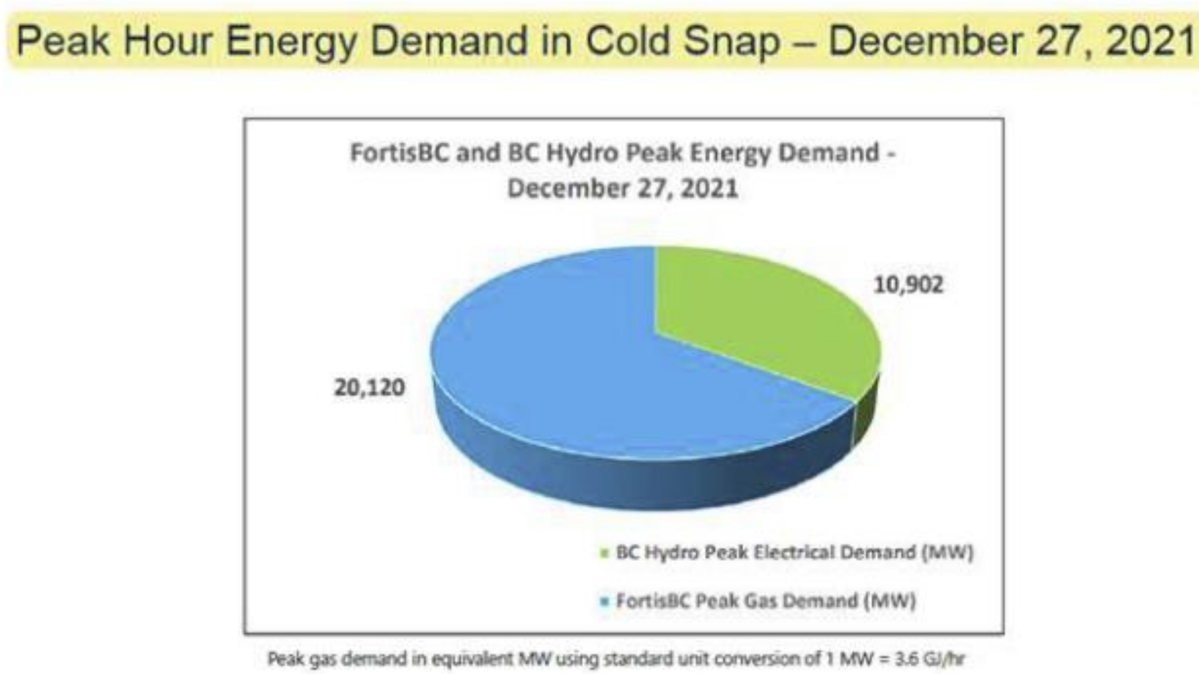
	2016	2021	Percentage Increase Since 2017 LTGRP
Number of Customers	994,004	1,064,800	7.1%
Annual Demand (PJ)[1]	197	228	15.7%
Peak Day Demand (TJ/day)[2]	1,334	1,399	4.9%
Length of Transmission Pipeline (km)	2,959	2,970	0.4%
Length of Distribution Pipeline* (km)	45,741	47,523	3.9%

Figure 4-9 shows Annual Demand of approximately 205 PJ in 2021:

Figure 4-9: Annual Demand Scenarios – Residential, Commercial and Industrial Sectors



The following pie chart from the February 10, 2022, RPAG presentation, shows Peak Hour Demand of 20,120 MW



Peak gas demand in equivalent MW using standard unit conversion of 1 MW = 3.6 GJ/hr

13.1 What is the reason for the difference between Annual Demand of 228 PJ, (shown in Table ES-1), vs. 205 PJ (shown in Figure 4-9)? Which one is the correct quantity for FEI's current annual energy deliveries?

Response:

There is a difference between the Annual Demand of 228 PJ (shown in Table ES-1) and 205 PJ (shown in Figure 4-9) because the two summaries represent different demand profiles and cannot be directly compared. Table ES-1 provides the total volume of gas FEI distributed in 2021 and includes all rate classes.[3] Its volume is therefore higher than that in Figure 4-9, which illustrates the Reference Case forecast annual demand in 2021 and includes only the residential, commercial and industrial sectors as noted on the title of the chart.

The correct quantity for FEI's 2021 annual energy deliveries is the actual 228 PJ provided in Table ES-1.

13.2 If FEI's Annual Demand is 228 PJ/year, what does that convert to in terms of MMcf/day?

[3] Including the co-generation plant on Vancouver Island.

Response:

An annual demand of 228 PJ per year would translate to an average daily delivery of approximately 566 MMcf of natural gas with an assumed heating value of 39 MJ per m^3. FEI notes that the gas requirement in the FEI service territory is highly variable and increases with colder weather; thus, on any given day, the volume delivered can vary substantially from the average.

13.3 How does the Peak Day Demand of 1,399 TJ/day (shown in Table ES-1), compare to the Peak Hour Demand of 20,120 MW (shown in the pie chart from the RPAG presentation)?

Response:

In preparing this response, FEI determined that the peak day demand of 1,399 TJ per day (shown in Table ES-1) was recorded on December 26, 2021, a day earlier than the peak hour demand represented in the RPAG presentation. The daily delivery for December 27, 2021, was approximately 1,529 TJ per day and the peak hour delivery that day reached a high of 1,738 TJ per day. The conversion of this peak hourly delivery rate of 1,738 TJ per day equates to the 20,120 MW value shown in the figure included in the February 10, 2022 RPAG presentation.

13.4 Please discuss the relative importance of the Peak Day vs. Peak Hour Demand for the purposes of planning FEI's gas delivery infrastructure.

Response:

Peak day and peak hour demand are both essential elements in FEI's gas delivery infrastructure planning processes, though they are used for different applications.

Peak hour demand is primarily used in assessing capacity on FEI's distribution systems. Given the relatively lower operating pressure of the distribution systems, there is less available linepack[4] to absorb the regular swings in demand that occur throughout each day. The distribution system infrastructure must be designed to be able to transport the peak hour flow to ensure that demand is met at all times of each day.

Peak day demand can be used in assessing capacity and infrastructure requirements for transmission systems because transmission infrastructure generally operates at higher

[4] "Linepack" describes the total volume of gas contained within the system.

pressures, has larger diameter pipes and, therefore, has higher linepack than distribution systems. The linepack can be used to absorb hourly peaks in demand throughout the day and, therefore, planning infrastructure considering a peak day demand verses a Peak Hour Demand can help attenuate the need for additional facilities.

14.0 Topic: FEI Annual Energy Delivery and RNG Supply

Reference: Canadian Energy Regulator (CER) website at CER - Provincial and Territorial Energy Profiles - British Columbia (cer-rec.gc.ca)

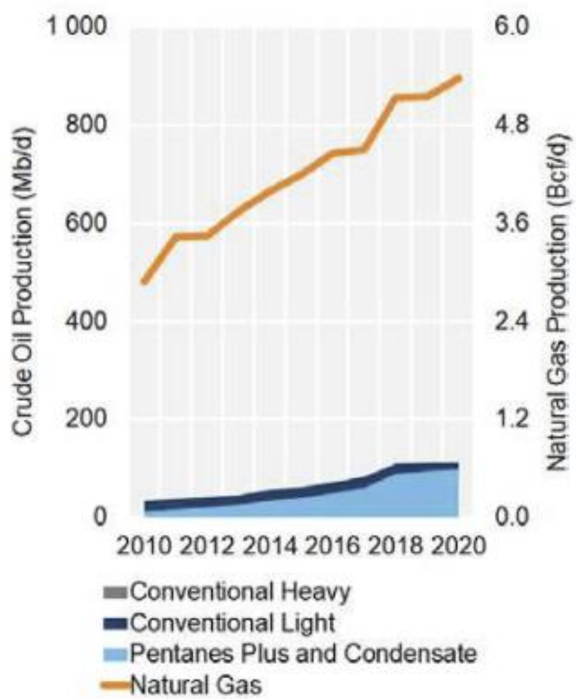
The CER website states the annual natural gas production in B.C. in 2020 was 5.4 Bcf/day, as follows:

"Natural Gas/Natural Gas Liquids (NGLs)

In 2020, natural gas production in B.C. averaged 5.38 billion cubic feet per day (Bcf/d) (Figure 1), accounting for 35% of total Canadian natural gas production.

Natural gas is produced in the northeastern part of B.C., predominantly from the Montney Formation. Development of tight gas in the Montney Formation is the primary factor behind B.C.'s gas production almost doubling from 2010, when production averaged 2.88 Bcf/d."

And the CER's Figure 1 shows the B.C. oil and gas production since 2010:



14.1 What does 5.4 Bcf/day convert to in terms of PJ per year? Please confirm that FEI's total Annual Demand of 205 PJ is only about 10% of the total B.C. Natural Gas production. Where does the balance go?

Response:

5.4 Bcf per day converts to approximately 2,110 PJ per year based on a heat rate of 37.8 MJ/m^3[5]; however, the exact value depends on the actual heat rate.

FEI confirms that its total annual demand approximates to roughly 10 percent of the total BC natural gas production. For further discussion on the disposition of BC natural gas production, please refer to the response to BCSSIA IR2 14.3.

14.2 Who else, besides FEI, delivers gas in B.C. and how much do they deliver? Does the GHGRS cap on natural gas utilities apply to these other deliveries? If so, how much of the cap will apply to them and how much to FEI?

Response:

There are two utilities that deliver natural gas in BC, FEI and Pacific Northern Gas (PNG). Together, in 2020, FEI and PNG delivered an average of 0.5 Bcf per day that was consumed in BC, as shown in the response to BCSSIA IR2 14.3. The data from the Government of BC in this response indicates that, of this 0.5 Bcf per day, FEI delivers approximately 97 percent.

FEI's understanding is that the GHGRS cap would apply to deliveries by both utilities. To achieve the cap, a reduction from 2007 GHG emissions levels of 47 percent or approximately 5.5 Mt is required. FEI's portion of that reduction would be approximately 5.3 Mt of CO2e per year. PNG would be responsible for the remaining 0.2 Mt.

14.3 How much of the B.C. gas production goes to Alberta and to the U.S.? How much is used to power the pipeline compressor stations in B.C.?

Response:

Gas production in BC can be exported to the US at Huntingdon/Sumas, where the Westcoast T-South pipeline connects with Williams' Northwest Pipeline, and can also be transported either to Alberta or the US Midwest via the Alliance pipeline or the Nova Gas Transmission Ltd. (NGTL) system. FEI is not aware of information that illustrates perfectly whether gas production in BC goes to Alberta or beyond to Eastern Canada or the US.

5 TransCanada, Customer Express Conversion Tool, online at: http://www.tccustomerexpress.com/conversiontool/.

However, FEI can provide where wellhead gas production in BC is disposed or distributed and provides the following data sourced from the Government of BC's website for 2020.[6] FEI assumes that the gas used to power the pipeline compressor stations is accounted for in the table below under the "Other" category:

	Bcf/day
BC Wellhead Production	6.0
Other[7]	-0.6
Total Available Marketable Gas	5.4
BC Consumption	0.5
Alliance pipeline	0.3
NGTL System	4.0
US Exports through Huntingdon	0.9

The CER website also states the following about Renewable Natural Gas produced in B.C.:

"Renewable Natural Gas

Renewable natural gas (RNG) is produced by five facilities and is transported on FortisBC's system. Together, these facilities can provide up to 316,000 gigajoules of RNG per year, enough to heat 3,470 homes."

14.4 Is the CER's statement of 316,000 GJ an accurate value for FEI's RNG supply from B.C. sources? If not, what is the accurate figure, and what proportion does it represent of FEI's total Annual Demand?

Response:

The CER statement approximates the expected volume that can be produced from currently-operating BC-based projects that supply RNG to FEI. However, expected volume from FEI's BC-based RNG supply is approximately 2.5 PJ annually, once all BCUC-approved projects are fully operational. This represents approximately 1.2 percent of FEI's total annual demand.

[6] Government of BC, Natural Gas & Oil Statistics (2008-Current) online at: https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/statistics.

[7] Total Field and Plant Disposition, Unaccounted Receipts and Backhaul in Pipelines.

14.5 How much of FEI's RNG supply is currently sourced from outside B.C.? Please explain how RNG supplies external to B.C. can receive a credit for GHG reductions in B.C. Aren't those external jurisdictions going to claim those reductions for their own GHG inventory accounts?

<u>Response:</u>

FEI's current RNG supply portfolio includes 19 approved contracts for projects located outside BC, or 58 percent of all approved RNG supply contracts. FEI's RNG supply contracts legally claim all environmental benefits or attributes, including GHG emissions reductions associated with FEI's RNG purchases, so that the supplier cannot claim them. In this way, the environmental attributes are transferred to FEI along with the title to the energy. FEI is not aware of any jurisdiction in North America that has attempted to inventory GHG benefits associated with the production of RNG within its jurisdiction that is subsequently sold outside its jurisdiction. There is general acceptance that the environmental benefits such as GHG inventory reduction can be transferred to the buyer subject to contractual terms. Nevertheless, as additional assurance of FEI's contractual requirements with RNG suppliers, FEI actively monitors the RNG marketplace and engages a third-party review to ensure there is no double-counting of the environmental attributes of FEI's RNG supply.

14.6 Please describe how the internal and external sources of RNG are forecast to increase over the planning period.

<u>Response:</u>

By "internal" and "external" sources of RNG, FEI assumes the question refers to "in-BC" and "out-of-BC" sources of RNG. Please refer to the responses to BCUC IR1 52.4, 52.5 and 52.6.

15.0 Topic: Greenhouse Gas Emission Rates

Reference: Exhibit B-1, Executive Summary Table ES-2, and Exhibit B-6, FEI's response to BCUC IR 1.3.1, Exhibit B-11, response to BCSSIA IR 1.6.1

Table ES-2 lists the Life Cycle and End Use Emission Factors for various fuels:

Table ES-2 Fuel Types and Decarbonization Technologies Used in the 2022 LTGRP

Fuel Type	Description[3]	Life cycle Emission Factor ($tCO_{2}e/GJ$)	End use cycle Emission Factor ($tCO_{2}e/GJ$)
Natural gas	Natural gas is a naturally occurring hydrocarbon. Hydrocarbons are a class of organic compounds consisting of carbon and hydrogen. Raw natural gas (before processing) is composed primarily of methane.[4]	0.0598	0.04987[5]
Renewable natural gas (RNG)	Upgraded biogas produced from farm or municipal organic biomass. Upgraded synthesis gas (syngas) produced from wood biomass at pulp mills and some municipal organic biomass.	0.0100	0.0003
Syngas	Produced from wood to displace natural gas used in lime kilns at pulp mills. Can also be upgraded to green hydrogen.	0.0100	0.0000
Lignin	Produced from black liquor to displace natural gas used in lime kilns at pulp mills.	0.0100	0.0000
Green Hydrogen	Produced via water electrolysis using renewable electricity feedstock.	0.0000	0.0000
Blue Hydrogen	Reformed from hydrocarbon feedstock with up to 90 percent carbon sequestered.	0.0200	0.0000[6]
Natural Gas with Associated Carbon Capture, Utilization and Storage (CCUS)	Applying the carbon reduction benefits of CCUS to the delivery of natural gas on FEI's gas network.[7]	0.0148	0.0148

FEI's response to BCUC IR 1.3.1 explains how FEI seeks to reduce the life-cycle carbon intensity of the gas it distributes [underlining added for emphasis]:

"Reducing emissions from upstream gas production would reduce the lifecycle carbon intensity associated with the natural gas distributed by FEI.

FEI is evaluating all options to reduce GHG emissions associated with the energy it distributes to its customers, including emissions associated with the upstream extraction, processing and transmission of natural gas to its system. The emissions associated with direct combustion of natural gas are approximately 0.04987 tCO2e per GJ (Table 1-2 of the Application), whereas the indirect upstream emissions are much smaller at approximately 0.00993 tCO2e per GJ, resulting in an approximate lifecycle GHG carbon intensity of 0.0598 tCO2e per GJ for natural gas in BC.

The GHG-reducing opportunities to reduce the carbon intensity associated with upstream natural gas activities being examined by FE! and the industry in general *include using carbon capture, utilization and sequestration, electrification of upstream compression, and methane reduction technologies.*

Employing these technologies on the natural gas supply that FEI acquires would reduce the lifecycle carbon intensity associated with the indirect upstream emissions of natural gas that FEI distributes. "

15.1 Please confirm that the GHG emissions due to FEI's customers burning the natural gas can be restated as approximately 50 kg/GJ (i.e., 0.04987 t/GJ) and the upstream emissions as about 10 kg/GJ (i.e., 0.00993 t/GJ).

Response:

Confirmed.

15.1.1 What if a customer does not burn the gas but instead uses it to produce chemical products, or if he burns it but sequesters the CO2, does FEI make an adjustment for those reduced emissions? Is FEI always aware of the end uses of its customers?

Response:

FEI is not aware of any of its customers using natural gas for chemical production or customers that sequester CO_2 at volumes that would materially affect its long-term planning. FEI believes it would be aware of any customers conducting these activities because they would likely approach FEI to seek associated carbon tax relief.

15.1.2 If the upstream emissions intensity of 10 kg/GJ is applied to the total B.C. gas production of 5.4 Bcf/day what are the resulting total GHG emissions in mega-tonnes per year?

Response:

FEI does not estimate upstream GHG emissions and instead uses lifecycle emissions tools like the Province of BC's GHGenius to evaluate the upstream emissions component of the fuel it provides. For reference, BC's GHG inventory depicts 6.9 Mt of GHG emissions from upstream oil and gas extraction, 1.3 Mt from pipeline transport and 3.7 Mt from natural gas fugitives, venting and flaring.

15.1.3 If the upstream emissions intensity of 10 kg/GJ is applied to FEI's total Annual Demand of 205 PJ, what are FEI's resulting total upstream GHG emissions in mega-tonnes per year? How does this quantity compare to the GHGRS cap being assigned to FEI?

Response:

FEI interprets the question to be asking for the upstream emissions associated with FEI's total annual customer demand of 205 PJ, assuming an upstream emission factor of 10 kgCO2e per GJ. The answer depends on how much annual demand is displaced by renewable gas supply. However, if the entire annual customer demand of 205 PJ is assumed to be comprised of conventional gas supply, upstream emissions would be approximately 2.05 Mt. Based on the information FEI has at this time, FEI does not expect upstream emissions will be within the scope of the GHGRS cap on natural gas distribution utilities, but would be addressed by the oil and gas emissions cap announced in the Energy Action Framework.

15.2 Please confirm that the GHG emissions due to FEI's customers burning Renewable natural gas (RNG) can be restated as only 0.3 kg/GJ (i.e., 0.0003 t/GJ) and the upstream emissions at about 9.7 kg/GJ (i.e., 0.0097 t/GJ), making a total of 1O kg/GJ for the life-cycle emissions.

Response:

Not confirmed. The lifecycle GHG emissions for RNG as presented in Table ES-2 (i.e., 10 kgCO2e per GJ) represents a conservative high-end estimate for the purposes of future supply forecasting as part of the LTGRP and does not reflect current RNG supply carbon intensity.

15.2.1 Please explain the reasoning as to why burning this RNG is only counted as producing 0.3 kg/GJ of GHG emissions. Why doesn't it produce the standard 50 kg/GJ just like any regular natural gas?

Response:

Please see the BC Best Practices Methodology for Quantifying Greenhouse Gas Emissions,[8] which states:

> The CO2 released to the atmosphere during combustion of biomass [which includes RNG] is assumed to be the same quantity that had been absorbed from the atmosphere during plant growth. Since CO2 absorption from plant growth and the emissions from combustion occur within a relatively short timeframe of one another (typically 100-200 years), there is no long-term change in atmospheric CO2 levels. For this reason, biomass is often considered "carbon-neutral", and the Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories specifies the separate reporting of CO2 emissions from biomass combustion. See: IPCC (2006), 2006 IPCC Guidelines for National Greenhouse Gas Inventories, p. 5.5; and the Climate Registry (2019), General Reporting Protocol Version 3.0, p. B-4.

15.2.2 It appears that the upstream emissions from RNG are almost the same as those from regular natural gas (9.7 kg/GJ compared to 10 kg/GJ). Please explain what causes the upstream emissions of RNG to be 9.7 kg/GJ. How much is due to methane or other leaks and venting?

Response:

In developing the 2022 LTGRP, FEI conservatively estimated upstream emissions of future RNG production facilities as 9.7 kgCO2e per GJ. The upstream carbon intensity of RNG production comes from the carbon intensity of electricity inputs at RNG production facilities, trace fugitive methane emissions, any refined petroleum products consumed with materials delivery, handling and disposal, etc. FEI follows lifecycle GHG accounting best practices and uses BC provincial government approved lifecycle assessment models such as GHGenius or other officially recognized methodological approaches like Open LCA framework software. There are negligible GHG emissions due to leaks and venting of RNG.

15.3 FEI states that it seeks to take advantage of the various listed technologies to "reduce the lifecycle carbon intensity associated with the indirect upstream

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8 BC Ministry of Environment and Climate Change Strategy, 2021 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions (May 2022) online at: https://www2.gov.bc.ca/assets/gov/environment/climate-change/cng/guidance-documents/2021-best-practices-methodology_for_archive.pdf.

emissions of natural gas that FE/ distributes." How much GHG reduction is FEI able to achieve through this preferred supply?

Response:

At this time, FEI is not able to quantify the GHG reductions from sourcing lower carbon supply from upstream providers as relevant policies such as the oil and gas cap announced in the Energy Action Framework and the GHGRS (specifically, compliance pathways) have yet to be defined by the Province. Consequently, FEI has not included this supply towards GHG emission reductions modelled in the Application.

15.3.1 How is FEI able to influence the Enbridge T-South pipeline to use electrification for its pipeline compressor stations to use renewable electricity such as from the BC Hydro grid? What success has it achieved, and will this help FEI to reach its GHG reduction goals?

Response:

As owner and operator of the T-South system, Enbridge is responsible for determining under which circumstances it is appropriate to consider the use of electric compressor stations on its system. FEI's ability to influence Enbridge in this regard is therefore limited.

A decision to replace gas fired compressor stations will presumably be driven primarily by any need to meet GHG emissions reduction targets (either voluntary or regulated) and to minimize the impact of the cost of carbon emissions that is planned to rise over time. At this time, FEI is not aware of specific plans by Enbridge to electrify compressor stations used by its T-South system. FEI expects such plans would consider the reliability of electrified compression and the need for adequate backup so that the reliability of the T-South system is maintained.

Enbridge recently completed a program to replace older, less efficient gas fired compressor stations with new units which reduced the carbon intensity of the T-South system. FEI notes that while a reduction in the carbon intensity of the T-South system is important, this reduction will not have significant impact on helping FEI to reach its GHG reduction goals and obligations.

15.3.2 Does FEI also seek to acquire gas supply preferentially from producers that use electrified processing plants that use renewable electricity such as from the BC Hydro grid? If so, how much GHG reduction is FEI able to achieve through this preferred supply? If not, why not?

Response:

FEI has not yet sought to acquire gas supply sourced from processing plants that are powered by renewable electricity. FEI's gas supply portfolio has historically not focused on the carbon content of conventional gas supply it purchases from producers. However, as the natural gas market evolves to reflect public policy imperatives such as the pending oil and gas cap or GHGRS, so may FEI's procurement strategies within the gas supply portfolio as opportunities are identified and explored.

FEI is in the early stages of exploring opportunities to procure lower carbon natural gas, which over time could include supply purchases from producers that use renewable electricity from BC Hydro. At this time, any such supply purchases would likely require paying a premium and receiving necessary regulatory approvals. FEI currently has insufficient information to determine the level of any GHG reduction that could be achieved through this type of supply option.

15.3.3 In its response to BCSSIA IR 1.6.1, FEI stated that it currently has 11 gas-powered compressor stations on its gas transmission system, with total horsepower of approximately 80,000 hp. How much of FEI's GHG emissions are contributed by these gas- powered compressor stations?

Response:

In 2021, the total GHG emissions from combustion at compressor stations were approximately 47,000 tCO_2e, whereas FEI's total operational GHG emissions were 140,000 tCO_2e.

15.3.3.1 How many of these existing pipeline compressor stations does FEI plan to convert to electrification and that will use renewable electricity such as from the BC Hydro grid, and when are these expected during the planning period?

Response:

FEI interprets electrification as the addition of electric compressor units for the purposes of gas compression. FEI is planning to add two new electric compressor units at FEI's Eagle Mountain Compressor Station. Completion of this work is anticipated in 2026.

15.3.3.2 Will all new compressor stations or expansions of existing stations such as any for the Tilbury expansion project or Woodfibre LNG be electrified and use renewable electricity such as from the BC Hydro grid?

Response:

All new compressors and liquefaction units at Tilbury will run on electricity provided by BC Hydro. With respect to the Woodfibre LNG project, two new electric units will be added to the Eagle Mountain Compressor Station. The proposed V2 compressor station servicing the Woodfibre LNG plant will be gas fired.

16.0 Topic: Kelowna Electrification Case Study: Generation to meet Peak Demand

Reference: Exhibit B-11, FEI Response to BCSSIA IR.1.9.1 and 9.2; Exhibit B-8, FEI response to BC Hydro IR 1.4.1 and 4.2; Exhibit B-6, FEI response to BCUC IR.1.30.3; Exhibit B-11, pages 105 and 106, lines 37-12,. Exhibit B- 20, FEI Evidentiary Update, Kelowna Electrification Case Study

The purpose of the following series of questions is to better understand why FEI stated that the results of the Study show that substantial electrification levels are implausible in the required timeframe - with regard to new generation needed to meet peak winter demand.

FEI's Response to BCUC IR 1.30.3, and to BCSSIA IR1.9.1 and BC Hydro IR 1.4.1 states that it considers that the Deep Electrification Scenario is not plausible due to the extreme challenges of converting the peak heating load to electricity. Specifically, FEI states [underlining added for emphasis]:

> *"FEI concludes that the Lower Bound and <u>the Deep Electrification Scenarios</u>, modelled as part of its 2022 LTGRP and which involve rapid and extensive declines in annual gas demand, <u>are not plausible</u> by drawing on its examination of alternative pathways to decarbonize as well as the extensive experience of FortisBC 's gas and electric utilities in acquiring, transmitting and distributing gas and electricity to customers in BC Additionally, there is a lack of clear evidence that these scenarios are plausible when fully considering all of the challenges of completely electrifying buildings and industry in BC ... Due to <u>the extreme challenges of converting the peak heating load for more than 1 million gas customers to an alternative energy source and system, namely electricity</u>, within the time required, these two scenarios would involve high costs and implementation delays that would stall efforts to decarbonize, cause high gas and electric rate increases and potentially place existing energy delivery networks at greater risk.*

> *"To further support this conclusion, FortisBC is analyzing the impacts of electrification on its electric and gas utilities, examining the challenges for the planning and installation of electricity infrastructure in BC, and <u>finalizing its Kelowna Electrification Case Study for one city in its shared service territory to illustrate the extreme scale of impacts on peak electricity demand and the subsequent transmission and distribution infrastructure requirements</u>. "*

Study Appendix A: Challenges in British Columbia for a Deep Electrification Pathway, page 1, states [underlining added for emphasis]:

> *"The purpose of this Appendix is to:*

> *"Show that these* ***challenges*** *make the Deep Electrification Scenario1 in Kelowna (and, by extension, throughout the FortisBC electric service territory) implausible within the time frame required to meet the Province's carbon reduction targets, and even moderate levels of electrification challenging.*
>
> *FortisBC, in delivering both natural gas (through FortisBC Energy Inc. or FEI) and electricity (through FortisBC Inc. or FBC), has extensive experience in transmitting and distributing energy to customers throughout British Columbia. FortisBC leverages its experience and industry expertise to provide local (and regional when not available) examples of technical and logistical challenges in building the supporting infrastructure required in the timeframe for a deep electrification energy pathway in BC.*[2] *These challenges can be categorized as follows:*
>
> - Execution and feasibility for shifting demand and ensuring adequate supply (Section 2)
> - Acquiring land for new infrastructure (Section 3);
> - Obtaining necessary project permits, approvals, and consent (Section 4);
> - Constructing transmission and distribution projects (Section 5); and
> - Transitioning customers to electricity (Section 6). "

FEI and FBC state on page 14:

> *"FBC preferred portfolio C3 (clean resource portfolio with renewable natural gas (RNG)-fueled generation) from the 2021 LTERP contains some capacity generation resources that are assumed to be located in the Kelowna region, namely two RNG-SCGT (simple-cycle gas turbine) units and a 25 MW utility-scale battery. These resources would provide a combined 173 MW of dependable winter capacity at an estimated cost of approximately $350 million. which is exclusive of land acquisition costs. Locating generation in the Kelowna area would reduce a portion of the peak demand on the transmission system, thereby potentially deferring some transmission requirements and providing locational value.*[30]

16.1 Did FEI and FBC seriously consider other capacity generation resources located in the Kelowna region, other than "two RNG-SCGT units and a 25 MW battery"? If so, which were the next best resources and why were they not selected?

Response:

FEI and FBC have not explored or proposed any specific new generation resources within the Kelowna Electrification Case Study. The Study focuses on transmission and distribution impacts and assumes that all incremental power supply required to meet the peak hour demand originates from outside the Kelowna area. FEI and FBC consider this to be a reasonable assumption given that FBC has no existing generation resources in the Okanagan region. Furthermore, the Study did not consider energy requirements over the winter heating season, or even on an annual basis;

rather, it assessed the potential firm capacity requirements of an extreme winter peak hour. Please also refer to the response to BCUC IR2 120.1.

In Section 4.3 of the Study, FEI and FBC provided a high-level discussion of the power supply requirements from BC Hydro's system based on existing tariffs in order to support the assumptions made in Section 4.1 to estimate the system upgrade costs. FEI and FBC also included a discussion on the dispatchable capacity resources identified as components of FBC's preferred portfolio as presented in the 2021 LTERP. The purpose of this discussion is to illustrate the magnitude of the Kelowna capacity requirements (up to 1,429 MW) relative to the capacity resources currently being considered (173 MW), based on FBC's existing Reference Case load forecast and recently accepted 2021 Long-Term Electric Resource Plan.

FEI and FBC recognize it may be possible to defer some of the transmission projects if local generation were connected in a favorable location on the system. FEI and FBC did not conduct any analysis regarding the two RNG-SCGT units and the 25 MW battery from FBC's preferred portfolio compared to any other potential supply-side resources.

16.2 When FEI referred to "ensuring adequate supply" as one of the "challenges" was the supply resource solution it was referring to the "two RNG-SCGT units and a 25 MW utility-scale battery"?

Response:

When FEI referred to "ensuring adequate supply" as one of the "challenges" of deep electrification, FEI was not referring specifically to the "two RNG-SCGT units and a 25 MW utility-scale battery". The purpose of Appendix A titled "Challenges in British Columbia for a Deep Electrification Pathway" is to broadly discuss the generalized challenges associated with developing any new utility generation resources within the Province to ensure adequate supply and is not specifically related to a single supply-side resource as provided in the Study, or otherwise.

16.3 Please describe the "two RNG-SCGT units and 25 MW battery" resource. For example; the SCGT unit sizes (MW) and annual generation (GWh/yr), Unit Energy Cost, Unit Capacity Cost, Generation profile (annual/monthly and hourly over the course of a several day cold snap). And for example; the type of battery (i.e., Lithium ion?) and that battery's discharge capability (i.e., X GWh over 4 hours).

Response:

The "two RNG-SCGT (Simple-Cycle Gas Turbine) units and a 25 MW utility-scale battery" reflect the dependable capacity resources RNG_SCGT2, RNG_SCGT1, and DistBattery6 contained in FBC's Preferred Portfolio C3 as presented in the 2021 LTERP.[9] Portfolio C3 was accepted as FBC's preferred portfolio by the BCUC.[10]

The following table shows the unit sizes and range of unit capacity costs (UCC) as stated in FBC's 2021 LTERP.[11] The unit energy cost (UEC) is not considered applicable for capacity-oriented (dispatchable) resources, as these resources are primarily used for providing capacity and not energy,[12] and therefore was not included in the table.

Resource ID	Dependable Winter Capacity (MW)	UCC ($/kW-Year)
DistBattery6	25.0	$226 - $267
RNG_SCGT2	100.4	$131 - $148
RNG_SCGT1	47.6	$131 - $148
Total	**173.0**	

The battery resource options considered in the 2021 LTERP were lithium-ion with a 4-hour duration. A 4-hour dispatch from a 25 MW battery provides approximately 100 MWh (0.1 GWh) of energy storage. In the response to CEC IR1 44.2 in FBC's 2021 LTERP proceeding,[13] FBC discussed the challenges associated with battery resources becoming an increasingly larger portion of the capacity used to meet the daily load curve.

FEI is unable to provide a generation profile for the three resources in the context of the Kelowna Electrification Case Study. The Study analyzed the potential capacity requirements of cold weather on peak demand under various levels of electrification. The scope of the Study did not include an assessment of winter energy requirements, nor any other resource portfolio analysis that selects, builds, and dispatches resources.

16.4 What is the location of the "two RNG-SCGT units and 25 MW battery" resource?

9 Exhibit B-1, FBC 2021 LTERP, Section 11.3.8: Portfolios Considered for Preferred Portfolios, PDF p. 219.
10 BCUC Decision and Order G-380-22 (December 21, 2022), PDF p. 46.
11 Exhibit B-1, FBC 2021 LTERP Section 10: Supply-Side Resources Options, Table 10-2: Supply-Side Resource Options Unit Cost Summary, PDF p. 196.
12 A capacity-oriented resource would have little incremental energy produced (or negative net energy in the case of battery storage), and thereby would reflect a high UEC.
13 Exhibit B-9, FBC 2021 LTERP, responses to CEC IR1 44 Series, PDF p. 81.

Response:

The Study did not explicitly include any new generation in the Kelowna area and focused specifically on a transmission and distribution analysis.

The specific site locations associated with resources contained in FBC's preferred portfolio are uncertain at this time. Any proposed location would be subject to consultation and engagement with Indigenous groups and stakeholders, and would consider public impacts, environmental requirements, and community feedback.

Page 14 of the Study states:

> *"The challenge of ensuring that sufficient capacity is available is compounded <u>through the nature of cold snaps, which generally last multiple days and shift the entire daily load curve upward</u>, thereby creating a much higher energy requirement. The need for large volumes of energy in several consecutive hours, or even days, is a challenge for capacity resources such as batteries that store energy rather than generate energy, as the storage capabilities (duration) becomes the limiting factor of operation given the need to recharge.*

16.5 Please describe how the "two RNG-SCGTs and 25 MW battery" would meet the demand during a cold snap that lasts "several consecutive hours, or even days." Please show this graphically (i.e., hourly generation/charge/discharge over a week). Please summarize how "the two RNG-SCGT units and 25 MW battery" would meet the peak demand of the City of Kelowna.

Response:

The Study focuses on plausible extreme peak capacity requirements at a single point in time (peak hour conditions). The "two RNG-SCGTs and 25 MW battery", with a collective installed capacity of 173 MW, are not sufficient on their own to meet identified peak demand, but would be a component of a portfolio of resources, which is not defined at this time. Therefore, FEI is unable to provide a table or graphic that shows how the two RNG-SCGT units and a 25 MW battery would operate within a larger portfolio of resources over a series of peak winter days.

However, FEI offers the following commentary to describe the key differences between energy <u>storage</u> and energy <u>generating</u> resources during a cold snap. Batteries do not create energy and so, during a cold snap that lasts several consecutive hours, or even days, a 25 MW battery with 4 hours duration will only be able to provide 100 MWh of energy before needing to recharge and this may not be long enough such that either alternate supply or load reductions are required.

While FBC would attempt to recharge the battery, ensuring it is available for the next discharge cycle,[14] there is no certainty this would be successful as there may be no surplus power available. This could be since either the intermittent energy resource the battery is paired with may not be generating or no market power is available for purchase. Even if market power is available, it is highly likely that the power needed to recharge the battery would be coming from an SCGT unit somewhere on the grid.[15] Finally, even if the intermittent energy resource is generating, the utility may not be able to direct the power to battery recharge as it may be needed immediately to meet load.

Conversely, a SCGT unit can generate energy and provide firm capacity in every consecutive hour of each day of the cold snap as needed, assuming unlimited fuel and no forced outages. The ability to control the fuel source of the SCGT generator provides assurances the installed capacity will create sufficient electrical energy during the period the capacity is required.

16.6 What is the UEC and UCC of the "two RNG-SCGT units and 25 MW battery" supply resource?

Response:

Please refer to the response to BCSSIA IR2 16.3.

16.7 Was the UEC and UCC of the "two RNG-SCGT and 25 MW battery" supply resource lower than all other supply resources? If not what other supply resources have lower UEC and UCC? Why did FEI not propose those other resources to supply the City of Kelowna with electricity?

Response:

Please refer to the response to BCSSIA IR2 16.3.

14 The next discharge cycle could be as little as only 9 hours away if the battery is required to meet both the morning and the evening peak.

15 During the coldest weather periods, it is extremely unlikely that any significant volume of renewable power will be available for purchase.

16.8 In response to BCSSIA IR 1.3.1 in the FortisBC 2021 Long Term Electricity Resource Plan proceeding, FortisBC provided the following table of 11 Selected Solar Projects:

Resource	Installed Capacity (MW)	Average Annual Dependable Capacity (MW)	Annual Reliable Energy (GWh)	Average Annual Capacity Factor (%)
Solar1	17	4	27.5	18.8
Solar2	39	9	65.0	19.1
Solar3	47	11	78.7	19.2
Solar4	93	24	170.2	20.9
Solar5	99	23	166.1	19.2
Solar6	106	24	177.4	19.1
Solar7	110	26	183.9	19.0
Solar8	177	45	316.2	20.3
Solar9	216	48	341.2	18.0
Solar10	268	59	417.4	17.8
Solar11	490	107	754.4	17.6
Total	1,662	380	2698.0	18.5

16.9 Did FEI consider a solar plus battery project to supply more electricity for the City of Kelowna's electrification? If yes, which of the above 11 solar projects did it consider, and what size was the accompanying battery?

<u>Response:</u>

FEI assumes that BCSSIA IR2 16.8 is a statement for the preamble to BCSSIA IR2 16.9.

FEI did not consider a solar plus battery project to supply more electricity for the City of Kelowna's electrification. Please refer to the responses to BCSSIA IR2 16.1 and 16.3.

17.0 Topic: Kelowna Electrification Case Study: Transmission to meet Peak Demand

Reference: Exhibit B-11, FEI Response to BCSSIA IR.1.9.1 and 1.9.2; Exhibit B-8, FEI response to BC Hydro IR 1.4.1 and 4.2; Exhibit B-6, FEI response to BCUC IR.1.30.3; Exhibit B-11, pages 105 and 106, lines 37-12; Exhibit B-20, FEI Evidentiary Update, Kelowna Electrification Case Study; BC Hydro Transmission System Drawing No. G-T06-00010.

The purpose of the following series of questions is to better understand why FEI stated that the results of the Study show that substantial electrification levels are implausible in the required timeframe - with regard to transmission expansion needed to meet peak winter demand.

FEI's Response to BCUC IR 1.30.3, and to BCSSIA IR1.9.1 and BC Hydro IR 1.4.1 states that it considers that the Deep Electrification Scenario is not plausible. Specifically, FEI states [underlining added for emphasis]:

> *"FEI concludes that the Lower Bound and <u>the Deep Electrification Scenarios</u>, modelled as part of its 2022 LTGRP and which involve rapid and extensive declines in annual gas demand, <u>are not plausible</u> by drawing on its examination of alternative pathways to decarbonize as well as the extensive experience of FortisBC 's gas and electric utilities in acquiring, transmitting and distributing gas and electricity to customers in BC ...*

> *... To further support this conclusion, FortisBC is analyzing the impacts of electrification on its electric and gas utilities, examining the challenges for the planning and installation of electricity infrastructure in BC, and <u>finalizing its Kelowna Electrification Case Study for one city in its shared service territory to illustrate the extreme scale of impacts on peak electricity demand and the subsequent transmission and distribution infrastructure requirements.</u> "*

The Introduction on Page 4 of the Study states:

> *"The results from the Kelowna Electrification Case Study (Study) show that at 100% electrification of gas load and a mean daily temperature of -26 Celsius (C)[1], peak demand in 2040 would more than triple, from 472 megawatts (MW) to 1,429 MW2, resulting in a high-level estimate of between approximately; <u>$2.6 and $3.4 billion in capital expenditures on the electric distribution and transmission system which would be needed in less than 20 years</u>." Even at 25% electrification of gas load, peak demand would increase to 711 MW and result in an estimated range of <u>$1.3 to $1.7 billion in capital expenditures over this same timeframe</u>. "*

> *"... While the Study examines the <u>extensive electricity infrastructure requirements</u> and cost estimates associated with electrification in the City of Kelowna, Appendix A describes other challenges faced with respect to building new energy infrastructure in BC The discussion in Appendix A supports the <u>conclusions that a deep electrification scenario is not plausible within the rapid timeframe required</u> to meet Provincial carbon emission reduction targets and that utilizing both the*

existing electricity and gas infrastructure in BC will be needed to meet these targets."

Table 4-2 describes the additional transmission projects required to meet various Peak Demand Electrification Cases by 2040:

Table 4-2: Additional Projects[22] Required to Meet a Peak Demand of 25%, 50% and 100% Electrification Cases by 2040

Peak Demand and Electrification Cases	Project Costs ($ Millions)		
	711 MW (25%)	950 MW (50%)	1,429 MW (100%)
New Distribution Stations	120	180	300
New Distribution Feeders	80	120	200
Meshing Kelowna 138 kV Transmission System	20	20	20
138 kV Transmission Line Re-conductor	80	120	200
138 kV Transmission Line Addition	60	90	150
Ashton Creek to Vaseux Lake (ACK-VAS) 500 kV Transmission Line	500	500	500
DG Bell Second 230/138 kV Transformer Addition	20	20	20
Kelowna 230 kV Source (Line & Terminal Station)	50	50	50
Additional Ashton Creek to Vaseux Lake (ACK-VAS) 500 kV Transmission Line (Station not Required)[23]	n/a	450	450
Total	**930**	**1,550**	**1,890**

Page 11 of the Study states:

"Table 4-2 illustrates the escalation of electric system upgrade costs through cases of increasing amounts of incremental electrification of gas demand within the City of Kelowna_ If peak demand in the Kelowna area surpasses 550 MW, the complexity of the system upgrades quickly moves beyond primarily modifications and transformer additions. <u>The load level of550 MW triggers the requirement for the Ashton Creek to Vaseux Lake 500 kV transmission line, and upon surpassing 950 MW, an additional 500 kV line is required, with an expected lead time of at least ten years. The approximately $1.9 billion of required additional proiects under the 100% electrification case implies many operational, environmental and other permitting and system planning challenges</u>, a major one of which is siting and acquisition of land rights and construction, which are further discussed in Appendix A. "

Study Appendix A: Challenges in British Columbia for a Deep Electrification Pathway, page 1, states [underlining added for emphasis]:

"The purpose of this Appendix is to:

"Show that these <u>challenges</u> make the Deep Electrification Scenario1 in Kelowna (and, by extension, throughout the FortisBC electric service territory) implausible within the time frame required to meet the Province's carbon reduction targets, and even moderate levels of electrification <u>challenging</u>.

FortisBC, in delivering both natural gas (through FortisBC Energy Inc. or FE/) and electricity (through FortisBC Inc. or FBC), has extensive experience in transmitting and distributing energy to customers throughout British Columbia. FortisBC leverages its experience and industry expertise to provide local (and regional when *not available) <u>examples of technical and logistical challenges in building the supporting infrastructure required in the timeframe</u> for a deep electrification energy pathway in BC. These challenges can be categorized as follows:*

- Execution and feasibility for shifting demand and ensuring adequate supply (Section 2);
- Acquiring land for new infrastructure (Section 3);
- Obtaining necessary project permits, approvals, and consent (Section 4);
- <u>Constructing transmission and distribution projects</u> (Section 5); and
- Transitioning customers to electricity (Section 6)."

17.1 When FEI referred to "construction transmission and distribution projects" as one of the "challenges (that) makes the Deep Electrification in Kelowna implausible within the timeframe required" was the transmission project it was referring to the Ashton Creek to Vaseux 500 kV transmission line?

<u>Response:</u>

Not confirmed. Appendix A: Challenges in British Columbia for a Deep Electrification Pathway discusses general challenges to planning, designing, and building transmission and distribution projects in the province and is not referring to a specific system upgrade project as provided in the Study or otherwise.

As shown in Table 4-2 cited above, a significant amount of new electric transmission and distribution infrastructure would be required to meet the additional electric peak demand resulting from even nominal amounts (25 percent) of gas to electric load switching. However, of the projects shown in Table 4-2 of the Study, the Ashton Creek to Vaseux Lake 500 kV transmission line would likely require the longest lead time and have the most challenges to being built within the required timeframe.

17.2 Please provide a map showing the "Ashton Creek to Vaseux Lake 500 kV transmission lines" route and the City of Kelowna. Please show the distance from Ashton Creek to Kelowna and distance from Kelowna to Vaseux Lake.

<u>Response:</u>

The Study did not determine or specify the precise location of a 500 kV substation required for the Ashton Creek to Vaseux Lake transmission line interconnection. For the purposes of the Study, the approximate length of the interconnecting transmission lines and need for the substation were sufficient to define the high-level costs. As such, FBC is unable to provide a map showing the transmission line route at this time.

17.3 Please confirm that the "10-year lead time" for the Ashton Creek to Vaseux 500 kV transmission lines project is the main "challenge (that) makes the Deep Electrification in Kelowna implausible within the timeframe required". And specify what the "timeframe required" is referring to. i.e., 2030, 2040, or 2050?

Response:

Not confirmed. There are numerous infrastructure construction challenges that make the Deep Electrification scenario implausible, and it is not specifically as a result of a single project. Section 1 of Appendix A: Challenges in British Columbia for a Deep Electrification Pathway states:

> This Appendix provides an initial examination of the challenges to building out the electric system to handle the increase in load that would be caused by entirely or substantially shifting current and future gas use in BC to electricity. It is not intended to be exhaustive, nor is it meant to suggest that any one or even a number of these challenges cannot be overcome. Considered as a whole across numerous and diverse projects, however, these issues can be expected to delay or confound efforts to decarbonize through electrification, and potentially put the electricity generation, transmission and delivery system at risk if electrification proceeds while infrastructure development is delayed. Together, these issues and the high infrastructure costs presented in the Study, result in an implausible scenario for shifting demand and supporting infrastructure development in the envisioned time frame.

17.4 Did FEI consider alternative transmission line expansions? If yes, which alternatives did it consider?

Response:

FEI considered the following two alternative transmission line expansions:

1. 500 kV line from Nicola to Kelowna to Ashton Creek
2. 500 kV line from Selkirk to Kelowna to Ashton Creek

Both of these options and additional alternatives would require a longer line length than the proposed Ashton Creek to Vaseux Lake 500 kV line. A longer line length would be more challenging to complete, as it would also require more land acquisition, permitting, approvals, and consent, and, therefore, likely have a higher cost upon completion and longer schedule for completion.

The following map is excerpted from BC Hydro Transmission System Drawing No. G-T06-00010 (2021/22) found at

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/suppliers/transmission-system/maps/transplt-Default-001.pdf. It shows the transmission lines in Kelowna area. It includes a 138 kV line, 1L244, to the Westbank substation (WBK) which is located 20 km from Kelowna. WBK is connected to BC Hydro's Nicola substation (NIC) via 1L244.

17.5 Please confirm that the length of the Ashton Creek to Vaseux Lake transmission line is 160 km (per footnote 24 on page 12 of the Study).

Response:

FEI confirms that, as stated in the Study, the length of the line is approximately 160 km.

17.6 What would be the length of the transmission line from the City of Kelowna to the Westbank substation (WBK)?

Response:

A transmission line interconnecting the City of Kelowna to the BC Hydro Westbank substation would be approximately 15 km long.

17.7 How much electricity capacity could be delivered to the City of Kelowna if it was connected to the WBK substation at the existing 138 kV level?

How much electricity capacity could be delivered to the City of Kelowna if it was connected to the WBK substation if that line was at a 230 kV or 500 kV level?

Response:

There is no meaningful capacity that could be delivered to Kelowna from an interconnection at the Westbank substation given the current capacity constraints of the line connecting the Nicola substation with the Westbank substation (1L244), and the supply and resiliency needs for West Kelowna.

The current capacity of the line connecting the Westbank substation to the Nicola substation is 169.7 MVA. There is approximately 100 MW of load currently served on this line, which leaves approximately 70 MVA of capacity, which is far below the peak demand of Kelowna. In contrast, the additional 500 kV line from Ashton Creek would provide approximately 2,300 MVA of available capacity.

If the BC Hydro and FBC systems were connected at the Westbank substation (as is currently being explored by BC Hydro), the purpose would be to serve West Kelowna's energy supply and reliability needs, not Kelowna's. BC Hydro has proposed an interconnection; however, this would offer supply to West Kelowna in the event of an outage on the Nicola-Westbank line,[16] not supplemental supply to FBC's system.

[16] BC Hydro, West Kelowna Transmission Project, online at: https://www.bchydro.com/energy-in-bc/projects/wktp.html.

The existing 1L244 transmission line could be rebuilt to operate at a higher voltage, or an entirely new transmission line could be constructed. Based on thermal ratings, a 230 kV or 500 kV line could provide approximately 400 MVA or 2,200 MVA of capacity, respectively, to Kelowna. As such, a hypothetical 500-kV interconnection could provide the necessary transmission capacity. However, constructing a 500-kV line passing through West Kelowna and across Okanagan Lake would make this solution extremely technically challenging and costly with significant public and Indigenous impacts.

17.8 What are the high level pros/cons of connecting the City of Kelowna with the Westbank Substation compared to expanding the Ashton Creek to Vaseux Lake transmission lines.

Response:

Such a comparison cannot be made as an interconnection with the Westbank substation would not provide any meaningful transmission capacity to Kelowna. Please refer to the response to BCSSIA IR2 17.7.

18.0 Topic: Kelowna Electrification Case Study: Further analysis for other BC cities.

Reference: Exhibit B-11, FEI Response to BCSSIA IR.1.9.1 and 1.9.2; Exhibit B-8, FEI response to BC Hydro IR 1.4.1 and 4.2; Exhibit B-6, FEI response to BCUC IR 1.30.1 and 1.55.1; Exhibit B-11, pages 105 and 106, lines 37-12; Exhibit B-20, FEI Evidentiary Update, Kelowna Electrification Case Study.

BCSSIA asks the following questions to understand where a subsequent electrification study could best be done in B.C.

FEI's Response to BCSSIA IR1.9.1, BCUC IR 1.30 and BC Hydro IR 1.4.1 describes its extensive utility experience in BC that pertains to the Study. Specifically, FEI states:

> *"FEI concludes that the Lower Bound and the Deep Electrification Scenarios, modelled as part of its 2022 LTGRP and which involve rapid and extensive declines in annual gas demand, are not plausible by drawing on its examination of alternative pathways to decarbonize as well as <u>the extensive experience Q[FortisBC's gas and electric utilities in acquiring, transmitting and distributing gas and electricity to customers in BC.</u>*

In the Introduction to Study Appendix A FEI describes the challenges facing building energy infrastructure in BC on Page 4:

> *"While the Study examines the extensive electricity infrastructure requirements and cost estimates associated with electrification in the City of Kelowna, Appendix A describes other challenges faced with respect to building new energy infrastructure in BC.*

FEI’s title of the Appendix A; Challenges in British Columbia for a Deep Electrification Pathway, reflects it believes that the Study could be applied beyond the City of Kelowna.

FEI says this kind of Study could be repeated elsewhere in B.C., stating on page 2, [underlining added for emphasis]:

> *"The results of this Study are preliminary, should be considered as directional or indicative, and are subject to on-going refinement and more in-depth analysis. <u>This Study is a precursor to further studies</u> of load shifting and optimization technologies, such as hybrid heating systems, peak load shifting pilots, interruptible rates, and generation back-up systems, to understand the impacts of electrification on the combined service territory for FortisBC The results of these studies could be used as a model elsewhere for optimizing and achieving the lowest cost per greenhouse gas (GHG) emissions reduction."*

FEI states that in BC the gas and electric systems experience winter peak demand at substantially the same time. Specifically, page 2 of the Appendix states [underlining added for emphasis]:

> *"Deep electrification entails conversion of gas demand into load (or load and plausible energy savings) on the electric system, and conversion of peak building heating load from gas to electricity. Transitioning peak building heating load creates especially challenging capacity requirements, as the gas and electric systems experience winter peak demand during the same, or very similar, times in BC."*

The last paragraph of the Study's Summary and Conclusion states that further analysis of electrification to lower GHG emissions is required throughout the Province [underlining added for emphasis]:

> *"Further bottom-up analysis on electrification could include specificity regarding energy and capacity resources to meet higher demand, energy conservation, additional localized generation, analysis of various-end use conversions, and analysis of the benefits of load shifting or rate mitigation. Therefore, further work is required in the future to more closely consider the shifting of substantial energy use throughout the province, the combined gas and electric rate and bill impact to BC energy consumers, the total costs and implementation risks of electrification, as well as the benefits that may be achieved through other pathways to decarbonization. The Kelowna Electrification Case Study illustrates the need to further examine the tools to moderate peak energy demand and leverage the gas and electric systems to work together to support g, practical, resilient, and more affordable pathway to lower GHG emissions in the province."*

FEI suggests further analysis be done in "other regions that include a high number of customers as well as a lower load factor." On pages 17 and 18 of the Study, FEI and FBC state [underlining added for emphasis]:

> *"This Study provides a starting point for further analysis to understand the holistic impacts of electrification, including the current state of the electric system's ability to accommodate electrified load, as well as in other regions that include a higher number of customers as well as a lower load factor (i.e. higher weighting to winter heating demand), highlighting the importance of collaboration and coordination between the gas and electric systems in the province.*

18.1 For further electrification Studies does a "region that includes a higher number of customers" essentially mean a City (like Victoria) or a region (like Vancouver Island)?

Response:

In the Study, the statement “this Study is a precursor to further studies” was intended to mean further studies within the shared service territory of FEI and FBC, including the City of Kelowna and other communities. For further explanation, please refer to the response to BCUC IR2 121.1.

In the future, dependent on data collaboration and coordination between gas and electric utilities, additional regions, that include a higher number of customers than Kelowna where two different gas and electric utilities service the same region, could be studied.

18.2 Does a "region that includes ... a lower load factor (i.e., higher weighting to winter heating demand)" typically mean an area with a high proportion of residential customers vs industrial and commercial customers?

Response:

Not confirmed. To clarify, the statement in the Study “[…] as well as in other regions that include a higher number of customers as well as a lower load factor […]” was intended to suggest two potential opportunities for further analysis:

- Regions that have a greater population than the City of Kelowna and, therefore, a higher number of customers (and hence potential higher peak demands relative to available electric system capacity); and
- Regions that experience even colder average temperatures during the winter (and accordingly, a lower load factor for space heating) and therefore could be more challenging to electrify from the perspective of requiring higher performing heat pumps.

18.3 What is the load factor of the City of Kelowna? What is the load factor of the cities of Victoria and Vancouver? What is the load factor for Vancouver Island or the Lower Mainland?

Response:

Please refer to the response to BCUC IR2 121.2 for the calculation of the load factor, in that case for the City of Kelowna. This calculation is similar for other locations as well, although inputs will vary from location to location.

FEI interprets this request to be asking about the load factor of the FEI gas system in the cited municipalities; however, FEI’s service area boundaries within its system and corresponding hydraulic models do not necessarily align with the requested municipal boundaries. FEI has based its response on hydraulic modelling boundaries that most closely approximate the municipal boundaries cited in the request, and as such there are some differences in the service areas as noted below.

FEI provides the requested system load factors in the following table:

Region Requested	Load Factor	Service Area Description
City of Kelowna	0.23	Area fed by the Kelowna DP[17], Cary Rd and Quail Ridge Gate Stations: approximately 80 percent of demand of City of Kelowna.
Greater Victoria	0.32	Greater Victoria Area – all demand downstream of the Langford Gate Station.
Greater Vancouver	0.31	FEI cannot provide the load factor for the City of Vancouver due to lack of measurement data specific for the City proper. This area includes what is fed by the Fraser, Coquitlam, and Pattullo Gate Stations: Vancouver, Burnaby, Coquitlam, North Vancouver, New Westminster, Port Coquitlam, West Vancouver, Port Moody, Anmore, Belcarra.
Vancouver Island	0.37	Vancouver Island Transmission System (VITS) - all demand downstream of the Eagle Mountain Compressor Station.
Lower Mainland	0.34	Coastal Transmission System (CTS) and Zone 3 Laterals off the Westcoast System (Chilliwack, Hope etc.).

Page 1 lines 12-17 in the Appendix states:

"The results from the Kelowna Electrification Case Study show that at 100% electrification of gas load and a mean daily temperature of-26 C, peak demand in 2040 would more than triple, from 472 MW to 1,429 MW, ... Even at 25% electrification of gas load, peak demand would increase to 711 MW ... "

The first paragraph of section 4.4 state:

"... However, the Study demonstrates that for an area such as Kelowna that does not have substantial remaining system capacity, greater amounts of electrification can rapidly translate into infrastructure investments and higher capital costs. "

18.4 Given the significant increase in peak demand expected from extensive electrification, and the higher capital cost of expanding infrastructure for areas that do not have substantial remaining system capacity, does FEI suggest that future electrification studies focus first on areas with little remaining system capacity?

[17] Distribution Pressure system, the Kelowna IP (Intermediate Pressure) gate station serves West Kelowna and was excluded from this analysis to match the Study (and BC Hydro provides electricity service to West Kelowna).

Response:

FEI does not necessarily suggest that future electrification studies, whether by FortisBC or others, be conducted first on sub-regions or areas that do not have substantial remaining system capacity. FortisBC plans to conduct its next analysis for its entire shared service territory, as explained in the response to BCSSIA IR2 18.1.

The sub-title of the Kelowna Electrification Case Study is "*Electrification and the Impacts of Cold Temperature on Peak Demand and System Upgrade Costs.*"

FEI's response to BCUC IR 1.55.1 contained the following table that showed the Mean Daily Temperature (MDT) that was used to determine the peak energy demand in several regions:

Transmission System	Regions served	Index Weather Station (Airport Code)	DDD	Mean Daily Temperature (C)
VITS	Squamish	Squamish (WSK)	32.9	-14.9
	Whistler	Whistler (WAE)	39.5	-21.5
	Powell River, Sechelt, Gibsons	Powell River (YPW)	29.0	-11
	Campbell River	Campbell River (YBL)	31.9	-13.9
	Comox, Courtenay	Comox (YQQ)	27.8	-9.8
	Nanaimo Region, Port Alberni	Nanaimo (YCD)	29.9	-11.9
	Victoria Region	Victoria (YYJ)	28.8	-10.8
CTS	Metro Vancouver	Vancouver (YVR)	30.2	-12.2
	Fraser Valley	Abbotsford (YXX)	32.5	-14.5
ITS	Kamloops	Kamloops (YKA)	46.7	-28.7
	North and Central Okanagan	Kelowna (YLW)	43.9	-25.9
	South Okanagan	Penticton (YYF)	39.1	-21.1
	West Kootenay	Castlegar (YCG)	39.7	-21.7

BCSSIA calculates that the average Mean Daily Temperature of the regions served by each Transmission System are: Vancouver Island Transmission (VIT) = -13.4'C, Coastal Transmission System (CTS) = -13.4'C, and Interior Transmission System (ITS) = -23.4'C

18.5 Given that Kelowna's MDT is within 4.3' C of each of the other regions served by ITS, does FEI expect that the scale of increase in winter peak demand in the other regions served by the ITS would be generally similar to that found in the Study?

Response:

In regard to the locations listed in the preamble for the ITS, FEI is unable to draw any conclusions regarding the winter peak demand in Kamloops, as FBC does not provide the electricity service to that subregion and, therefore, FEI and FBC do not have the equivalent data necessary to compare to the City of Kelowna. For the South Okanagan and West Kootenay regions as shown in the preamble, please refer to the responses to BCSSIA IR2 18.1 and BCUC IR2 121.1.

18.6 Given that the MDTs of the regions served by VIT and CTS (from -9.8'C to - 14.9'C) are much warmer than the ITS (-21.1'C - 28.7'C), does FEI expect that the scale of increase in winter peak demand in the regions served by the VIT and CTS would be materially different that that found in the Study?

Response:

FEI is unable to draw any conclusions on the VITS and CTS regions, as FBC does not provide the electricity service to any cities or communities within those areas; therefore, FEI and FBC do not have the equivalent data necessary to compare to the City of Kelowna.

18.7 Given that BC Hydro delivers electricity to the customers receiving gas in FEI's VIT and CTS regions, and that FEI/FBC collaborated on Energy Scenarios does FEI see any barriers to collaborating with BC Hydro to do an analysis of peak demand electrification in those regions?

Response:

Please refer to the response to BCUC IR2 121.4.

18.8 Given that Victoria's MDT of -10.8' C is much warmer than Kelowna at - 25.9'C, and it is within 4.1'C of all the regions served by the VITS and CTS, other than Whistler, does FEI consider that Victoria would be a good location to do another electrification study?

Response:

Please refer to the response to BCUC IR2 121.4.

19.0 Topic: Kelowna Electrification Case Study: Daily Gas Demand Profiles on cold days and during cold snaps

Reference: Exhibit B-11, FEI Response to BCSSIA IR 1.4.5; Exhibit B-20, FEI Evidentiary Update, Kelowna Electrification Case Study; Exhibit B-4, FEI's response to BCUC IR 1.55.1

BCSSIA asks the following questions to see the daily gas demand profile for a cold day in each of Kelowna, the ITS, Victoria, the VITS, Metro Vancouver and the CTS. And also to see the daily gas demand profiles during a "cold snap" (i.e. 14 days around the coldest day) for these six locations.

A.) Daily Gas Demand Profiles on cold winter days

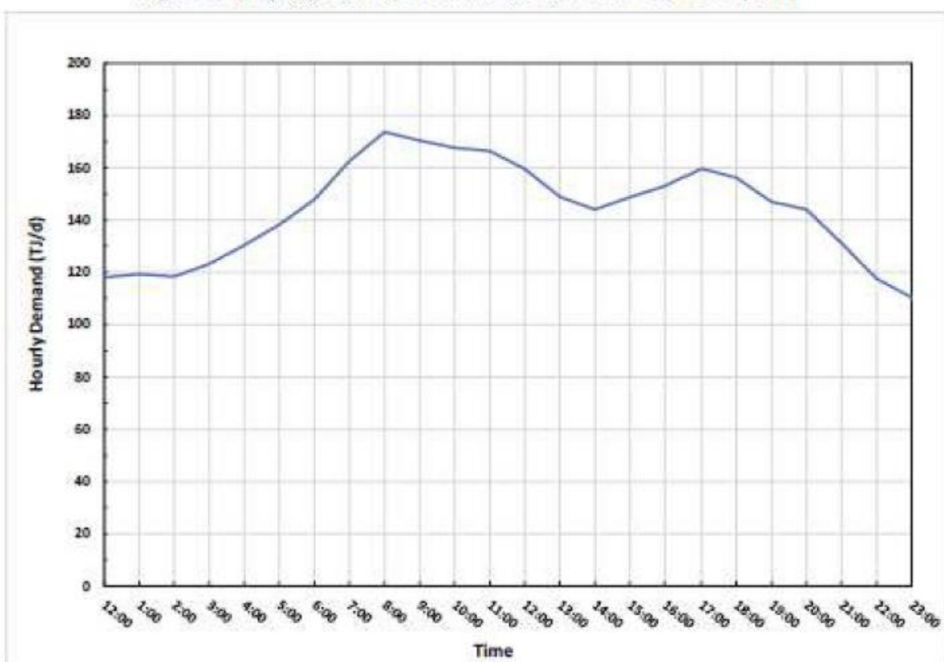
BCSSIA IR 1.4.5 asked:

"Please provide the daily aggregate gas demand profile for FEI customers on Vancouver Island- for a typical peak demand day. (i.e., a cold winter day)

FEI Response to BCSSIA IR. 4.5 stated:

"The requested daily aggregate gas demand profile for FEI customers on Vancouver Island for the coldest day in the winter of 2021-2022, December 27, 2021, is provided in the figure below. The region experienced a daily average temperature of minus 7.3°C (25.3 degree day) recorded at the Victoria Airport weather station."

Figure 1: Daily aggregate gas demand profile of VITS on Dec 27, 2021



19.1 For cold winter days, is this profile, that shows a higher demand peak in the morning than in the evening, typical for VITS? Or is it more typical to see a peak in the evening?

Response:

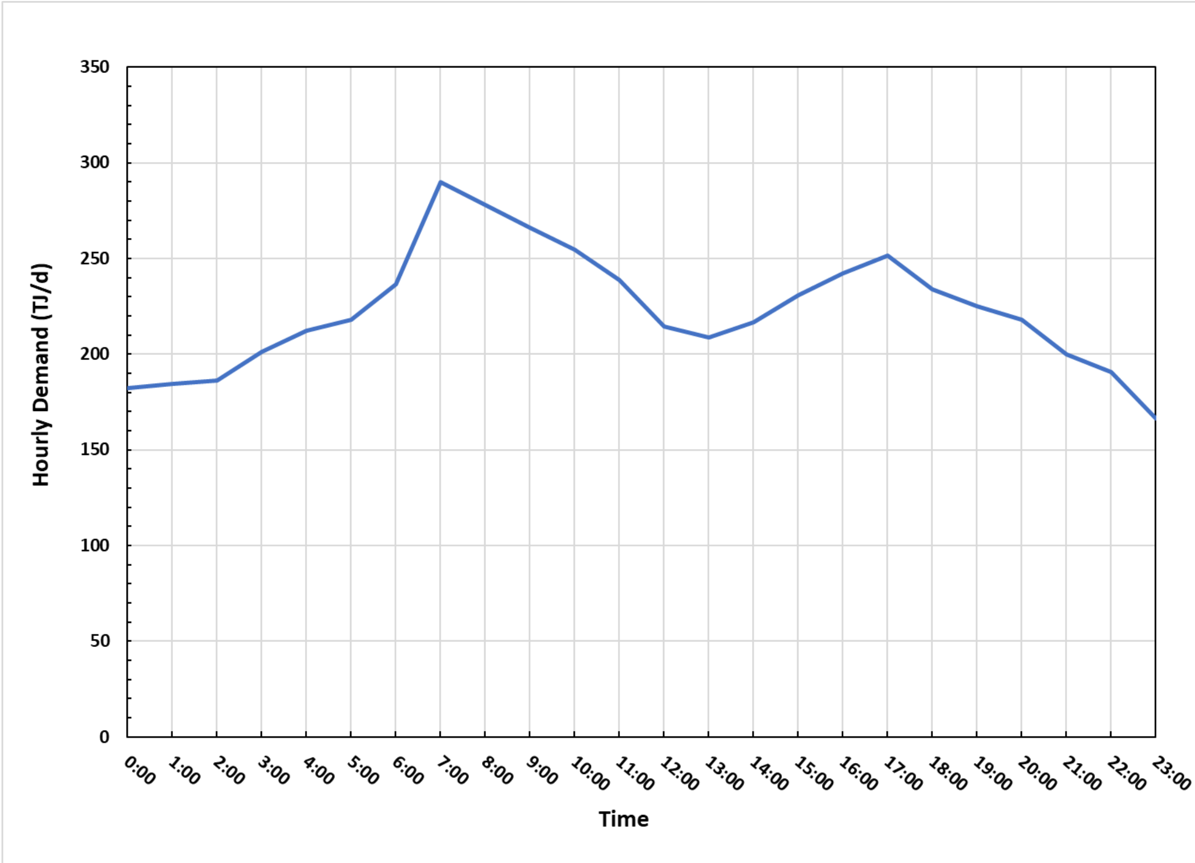
On cold winter days, peak hourly demand occurring in the morning is generally, but not exclusively, observed. Some factors that could result in a higher evening flow include the occurrence of cold weather on weekends versus weekdays, or a downward trend in day-over-day temperatures.

19.2 Please provide the daily aggregate gas demand profile for FEI customers on the Interior Transmission System (ITS) for a typical peak demand day. (i.e., a cold winter day).

Response:

The requested daily aggregate gas demand profile for FEI customers on the ITS for the coldest day in the winter of 2022/23 on December 22, 2022, is provided in the figure below. The region experienced a daily average temperature of -24.4 °C (42.4 degree day) recorded at the Kelowna Airport weather station.

Figure 1: Daily Aggregate Gas Demand Profile of ITS on December 22, 2022



The Study states, on page 1, lines 12-16, [underlining added for emphasis]:

> *"The results from the Kelowna Electrification Case Study (Study) show that at 100% electrification of gas load and a mean daily temperature of-26 C[1], peak demand in 2040 would more than triple, from 472 MW to 1,429 MW, resulting in a high-level estimate of between approximately $2.6 and $3.4 billion in capital expenditures on the electric distribution and transmission system which would be needed in less than 20 years. "*
>
> *Footnote 1: "-25.9 C is a calculated mean daily temperature (average of the daily high and the daily low) using the extreme value analysis method described in response to BCUC IR 1 55.1 and 55.1.1 in the FE/ 2022 LTGRP Proceeding (Exhibit B-6). An actual mean daily temperature of-26.2 C was observed at the Kelowna Airport on December 22, 2022, as recorded by Environment Canada. "*

FEI's response to BCUC IR 1.55.1 contained the following table that showed the Mean Daily Temperature (MDT) that was used to determine the peak energy demand in several regions:

Transmission System	Regions served	Index Weather Station (Airport Code)	DDD	Mean Daily Temperature (C)
VITS	Squamish	Squamish (WSK)	32.9	-14.9
	Whistler	Whistler (WAE)	39.5	-21.5
	Powell River, Sechelt, Gibsons	Powell River (YPW)	29.0	-11
	Campbell River	Campbell River (YBL)	31.9	-13.9
	Comox, Courtenay	Comox (YQQ)	27.8	-9.8
	Nanaimo Region, Port Alberni	Nanaimo (YCD)	29.9	-11.9
	Victoria Region	Victoria (YYJ)	28.8	-10.8
CTS	Metro Vancouver	Vancouver (YVR)	30.2	-12.2
	Fraser Valley	Abbotsford (YXX)	32.5	-14.5
ITS	Kamloops	Kamloops (YKA)	46.7	-28.7
	North and Central Okanagan	Kelowna (YLW)	43.9	-25.9
	South Okanagan	Penticton (YYF)	39.1	-21.1
	West Kootenay	Castlegar (YCG)	39.7	-21.7

19.3 Please provide the daily aggregate gas demand profile for FEI customers in the North and Central Okanagan Region (Kelowna weather station) for December 27, 2021 and for December 22, 2022.

Response:

BCSSIA IR2 19.3 and 19.14 refer to the information in the table provided in the preamble. This table shows the mean daily temperatures that correspond to the design degree day (DDD) for each of the regions shown. The DDD is the temperature value FEI assumes in its simulations when assessing peak day demand requirements on the system. In the past 20 years, temperature values that low have not been observed in the referenced areas. Accordingly, to respond to BCSSIA IR2 19.3 and 19.14, FEI has provided, as proxies, combinations of data corresponding to the above-mentioned December 27, 2021 (coldest day for CTS and VITS) and December 22, 2022 (coldest day for ITS) dates. The aggregate demand profiles shown in these responses express both hourly and daily flow rates in terajoules per day (TJ/d) equivalents. To determine an hourly energy equivalent, the values can be divided by 24.

For the transmission systems (ITS, CTS, VITS), a key input required to provide the requested profiles is the system linepack data on the day(s) in question. This information is only held by FEI's systems for 1 year. As such, while December 27, 2021 was approximately 1 degree C colder than December 22, 2022 for CTS and VITS, December 22, 2022 system linepack data was used as the proxy for a number of the responses as it allows for a comparison of the broad areas (e.g., ITS, CTS, VITS) to subsets of those areas (e.g., North and Central Okanagan, Metro Vancouver, Victoria).

The requested daily aggregate gas demand profiles for FEI customers in the North and Central Okanagan regions for December 27, 2021, and December 22, 2022, are provided in the figures below.

Figure 1: North and Central Okanagan Region: Daily Aggregate Gas Demand Profile on December 27, 2021

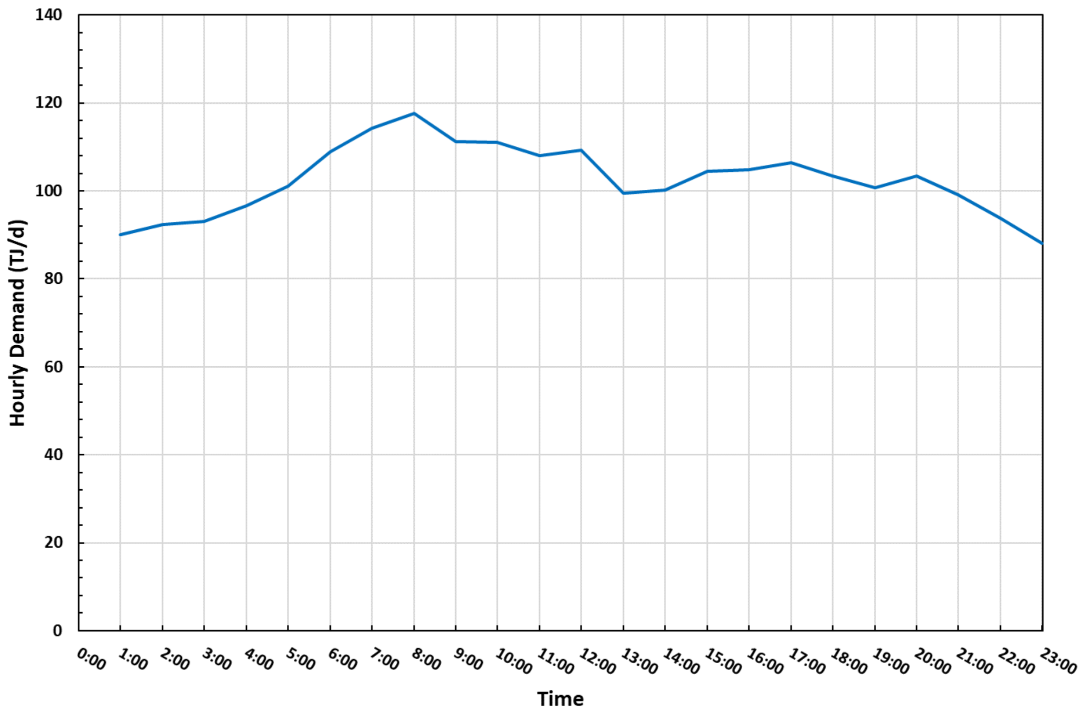
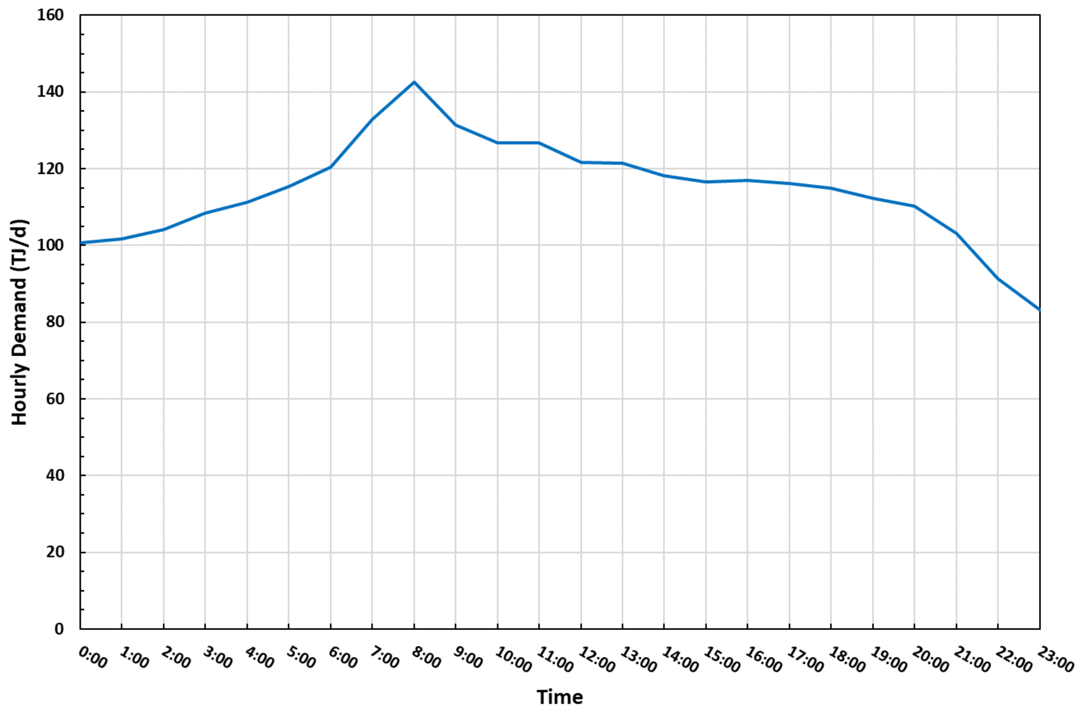


Figure 2: North and Central Okanagan Region: Daily Aggregate Gas Demand Profile on December 22, 2022



19.4 Please provide the daily aggregate gas demand profile for FEI customers on the Interior Transmission System (ITS) for December 27, 2021 and for December 22, 2022.

Response:

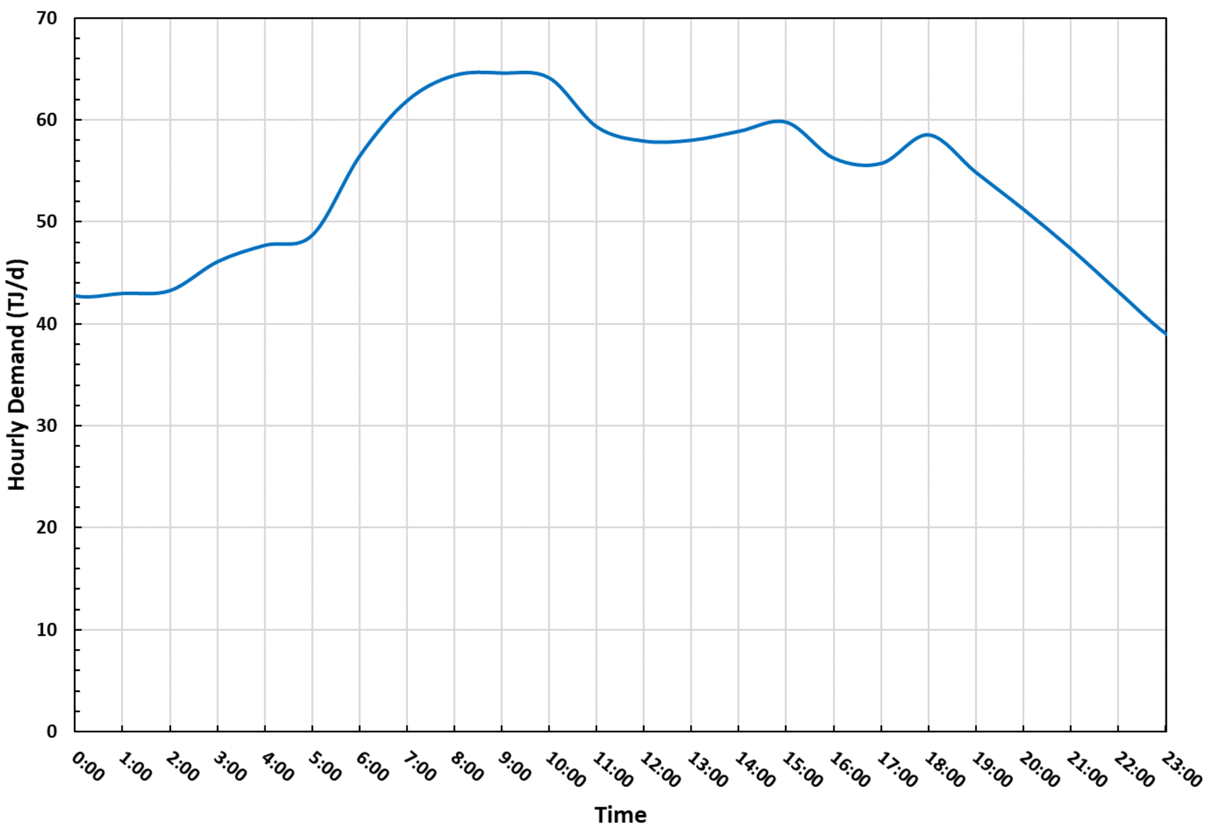
The daily aggregate gas demand profile for the ITS on December 22, 2022 is provided in the response to BCSSIA IR2 19.2. As previously described, absent system linepack information, FEI is not able to provide the ITS demand profile for December 27, 2021.

19.5 Please provide the daily aggregate gas demand profile for FEI customers in the Victoria Region for a peak demand day when the daily average temperature at the Victoria Airport was at or about -10.8 degrees C. If that occurred more than once in the last 20 years, please provide the profile for each of those days.

Response:

The region experienced a daily average temperature of -6 degrees C (24 degree day) recorded at the Victoria Airport weather station on December 22, 2022. The daily aggregate gas demand profile is presented in the figure below.

Figure 1: Daily Aggregate Gas Demand Profile of Victoria Region on December 22, 2022

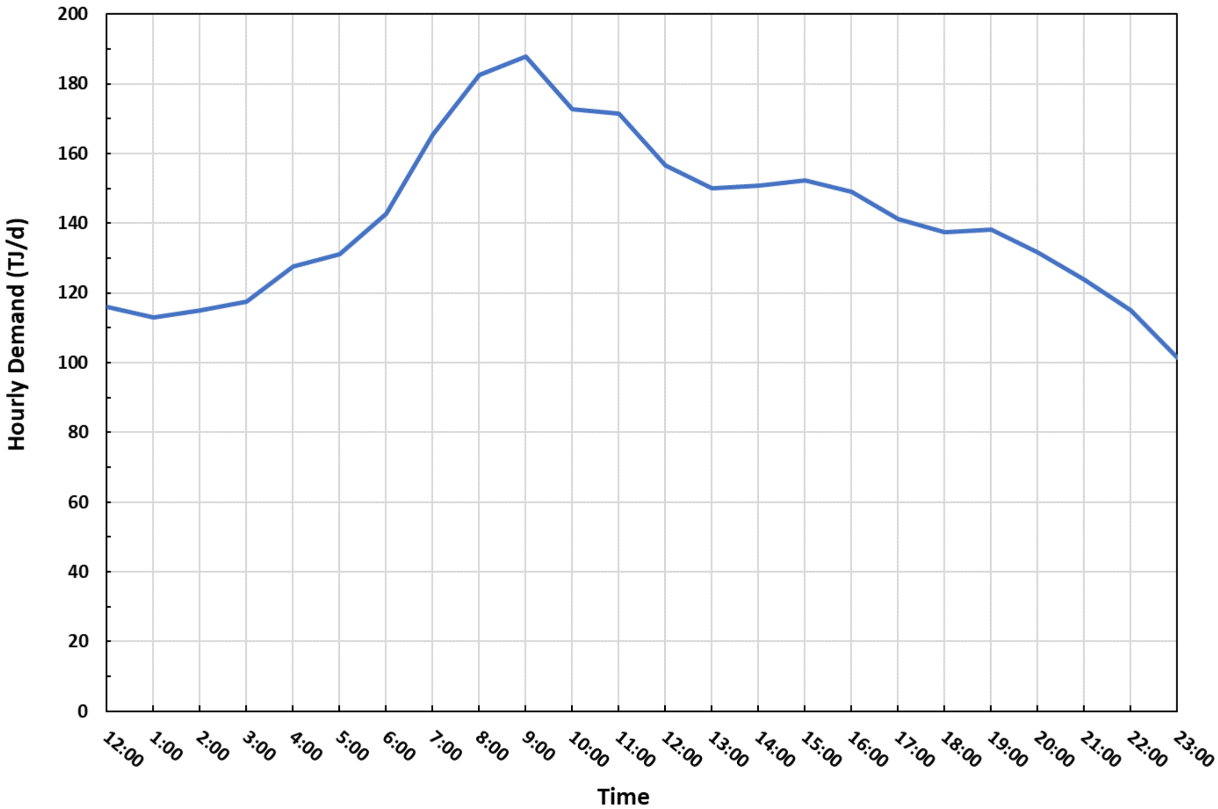


19.6 Please provide the daily aggregate gas demand profile for FEI customers in the Vancouver Island Transmission System (VITS) for a peak demand day when the daily average temperature at the Victoria Airport was at or about -10.8 degrees C. If that occurred more than once in the last 20 years please provide the profile for each of those days.

Response:

The region experienced a daily average temperature of -6 degrees C (24 degree day) recorded at the Victoria Airport weather station on December 22, 2022. The daily aggregate gas demand profile is presented in the figure below.

Figure 1: Daily Aggregate Gas Demand Profile of VITS on December 22, 2022



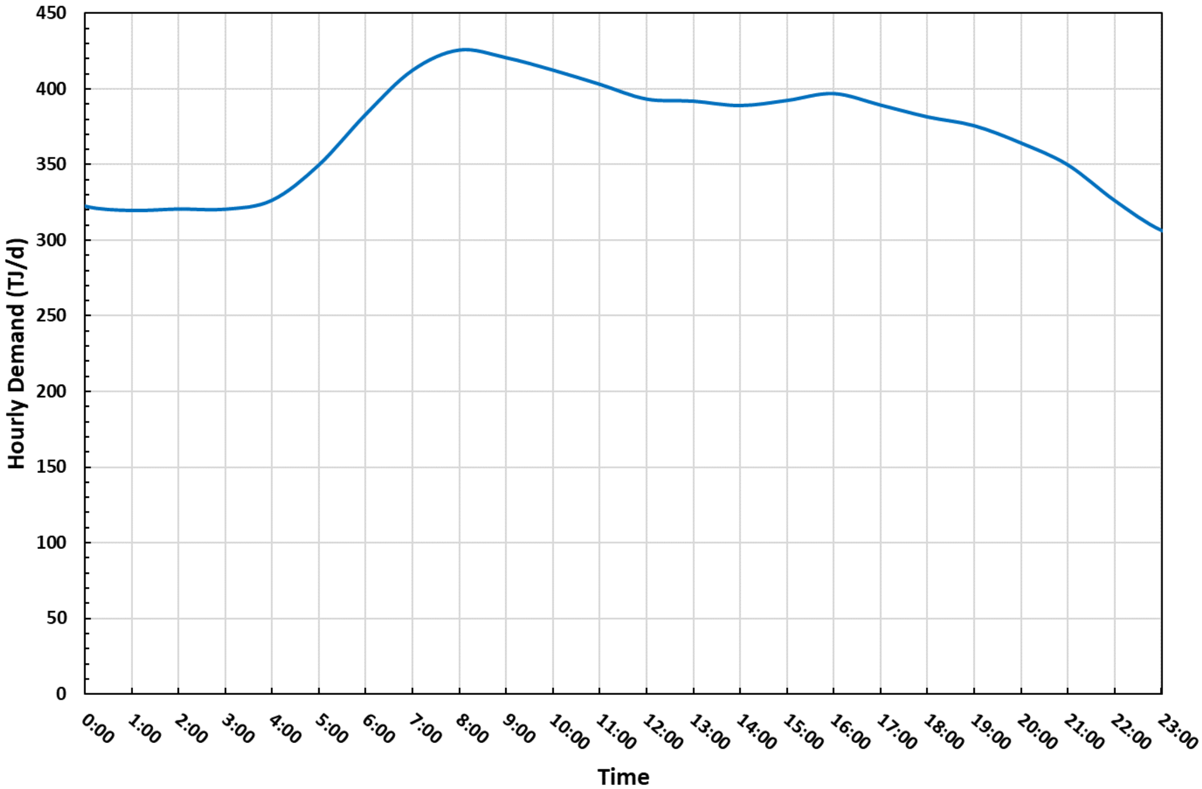
19.7 Please provide the daily aggregate gas demand profile for FEI customers in the Metro Vancouver Region for a peak demand day when the daily average temperature at YVR was at or about -12.2 degrees C. If that occurred more than once in the last 20 years please provide the profile for each of those days.

Response:

The Metro Vancouver Region is within a highly interconnected subset of the CTS without discrete measurement points. To respond to this IR, FEI has provided station flow data from the three major gate stations (Fraser, Coquitlam, and Pattullo gates) that feed a larger area which includes Vancouver, Burnaby, Coquitlam, North Vancouver, New Westminster, Port Coquitlam, West Vancouver, Port Moody, Anmore, and Belcarra.

The region experienced a daily average temperature of -10.2 degrees C (28.2 degree day) recorded at the Vancouver Airport weather station on December 22, 2022. The daily aggregate gas demand profile for the above-mentioned area is presented in the figure below.

Figure 1: Daily Aggregate Gas Demand Profile on December 22, 2022

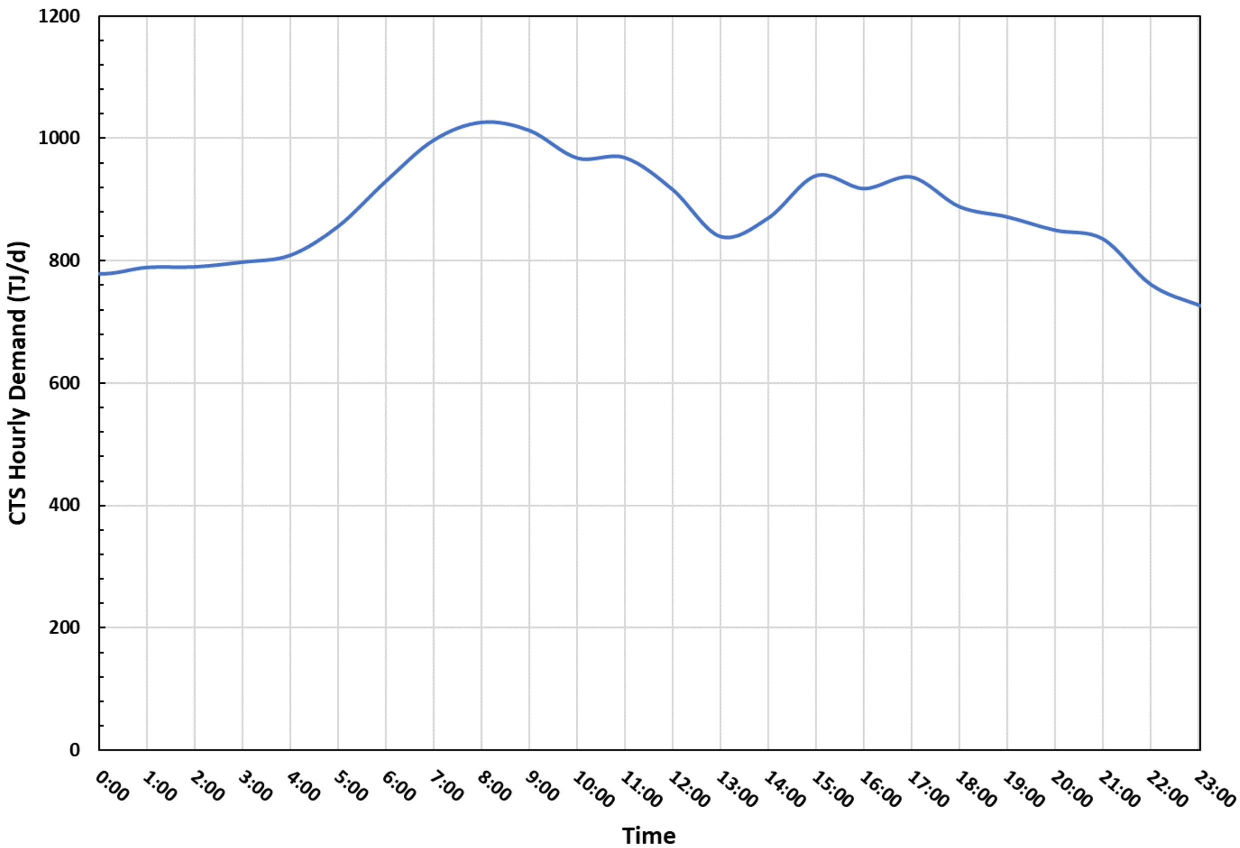


19.8 Please provide the daily aggregate gas demand profile for FEI customers in the Coastal Transmission System (CTS) for a peak demand day when the daily average temperature at YVR was at or about -12.2 degrees C. If that occurred more than once in the last 20 years please provide the profile for each of those days.

Response:

The CTS region experienced -10.2 degrees C (28.2 degree day) on December 22, 2022, recorded at the Vancouver Airport weather station. The requested profile is provided in the figure below.

Figure 1: Daily Aggregate Gas Demand Profile of CTS on December 22, 2022



B. Daily Gas Demand Profiles during winter "cold snaps"

The Study, page 14, lines 13-19, states [underlining added for emphasis]:

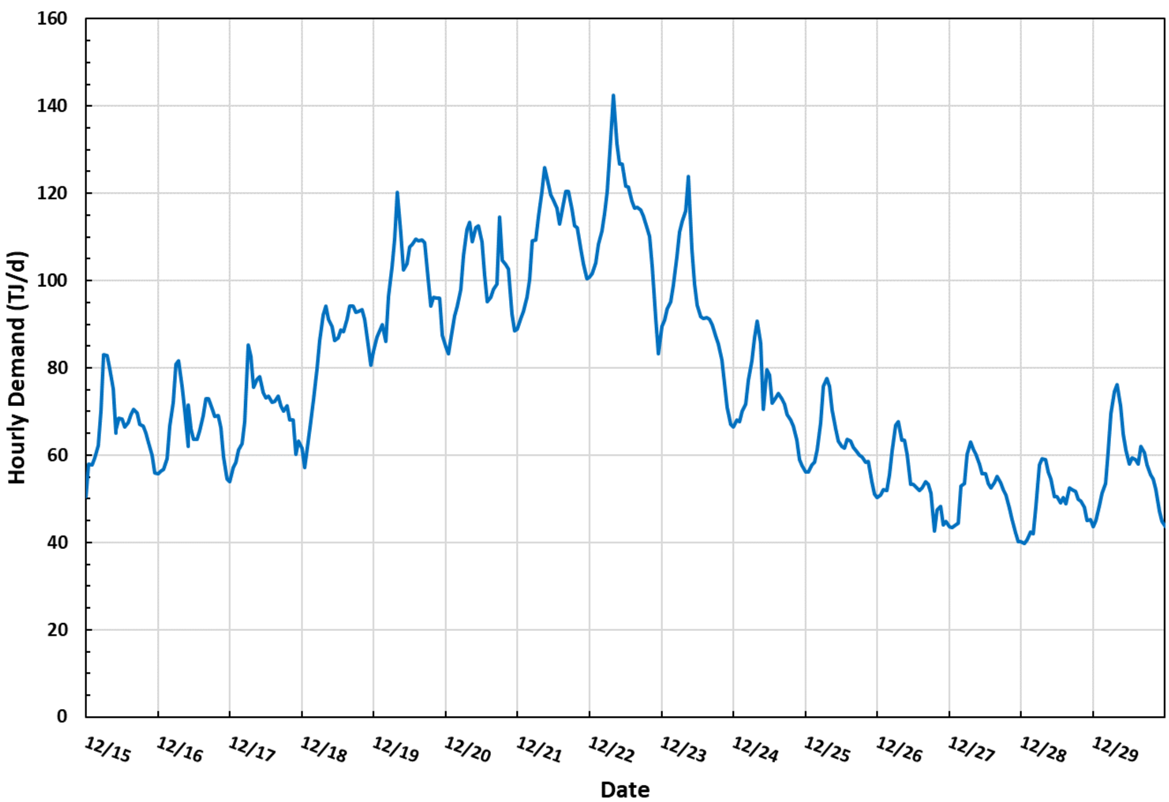
> *" The challenge of ensuring that sufficient capacity is available is compounded through the nature of cold snaps, which generally last multiple days and shift the entire daily load curve upward, thereby creating a much higher energy requirement. The need for large volumes of energy in several consecutive hours, or even days, is a challenge for capacity resources such as batteries that store energy rather than generate energy, as the storage capabilities (duration) becomes the limiting factor of operation given the need to recharge. "*

19.9 Please provide the daily aggregate gas demand profile for FEI customers in the North and Central Okanagan Region (Kelowna weather station) for the 14 days around the date when the daily average temperature was at or about -26 degrees C. (i.e., 7 days before and also after that day). If that occurred more than once, please provide the 14-day profile for each of those occasions over the last 20 years.

Response:

The region experienced a -24.4 degrees C (42.4 degree day) average daily temperature recorded at the Kelowna Airport weather station on December 22, 2022. The daily aggregate gas demand profile for the 14 days around this date is provided in Figure 1 below.

Figure 1: North and Central Okanagan Region 14-day Daily Aggregate Gas Demand Profile from December 15, 2022 to December 29, 2022

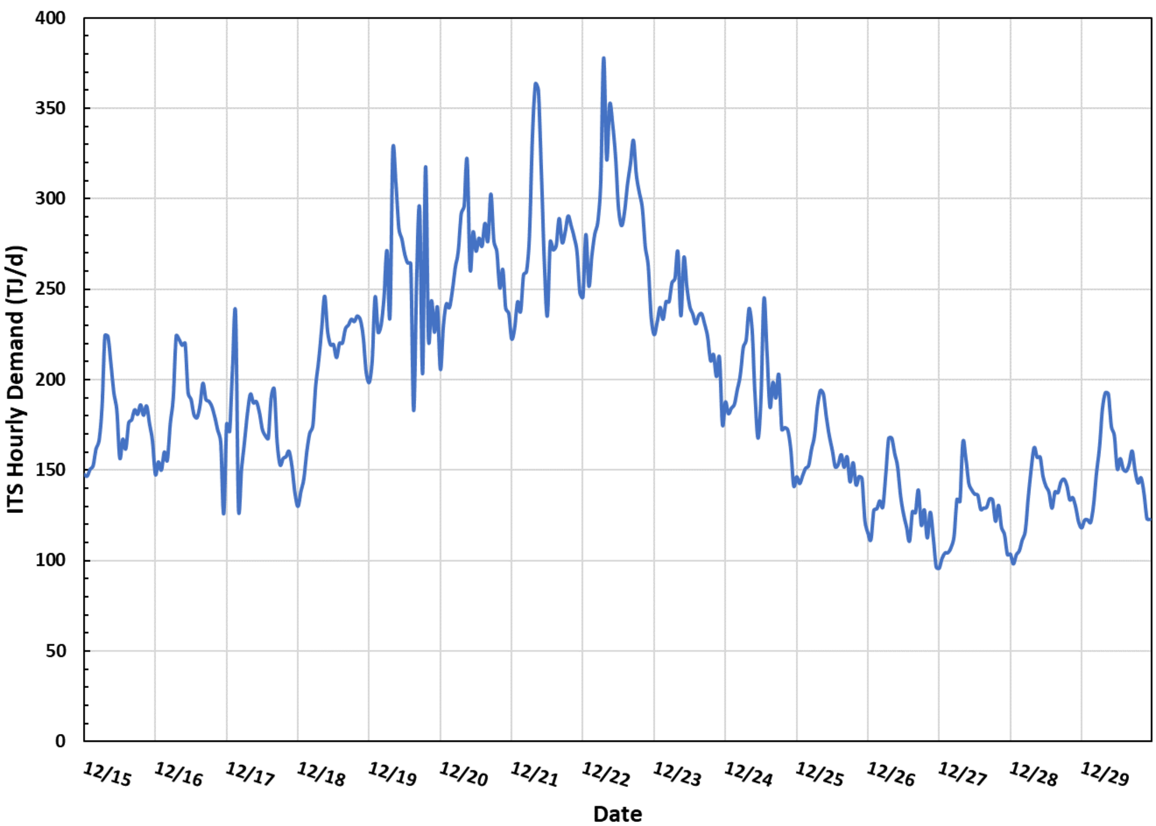


19.10 Please provide the daily aggregate gas demand profile for FEI customers in the Interior Transmission System {ITS) for the 14 days around the date when the daily average temperature was at or about -26 degrees C. If that occurred more than once, please provide the 14-day profile for each of those occasions over the last 20 years.

<u>Response:</u>

The region experienced a -24.4 degrees C (42.4 degree day) average daily temperature recorded at the Kelowna Airport weather station on December 22, 2022. The daily aggregate gas demand profile for the 14 days around this date is provided in Figure 1 below.

Figure 1: ITS 14-day Daily Aggregate Gas Demand Profile from December 15, 2022 to December 29, 2022

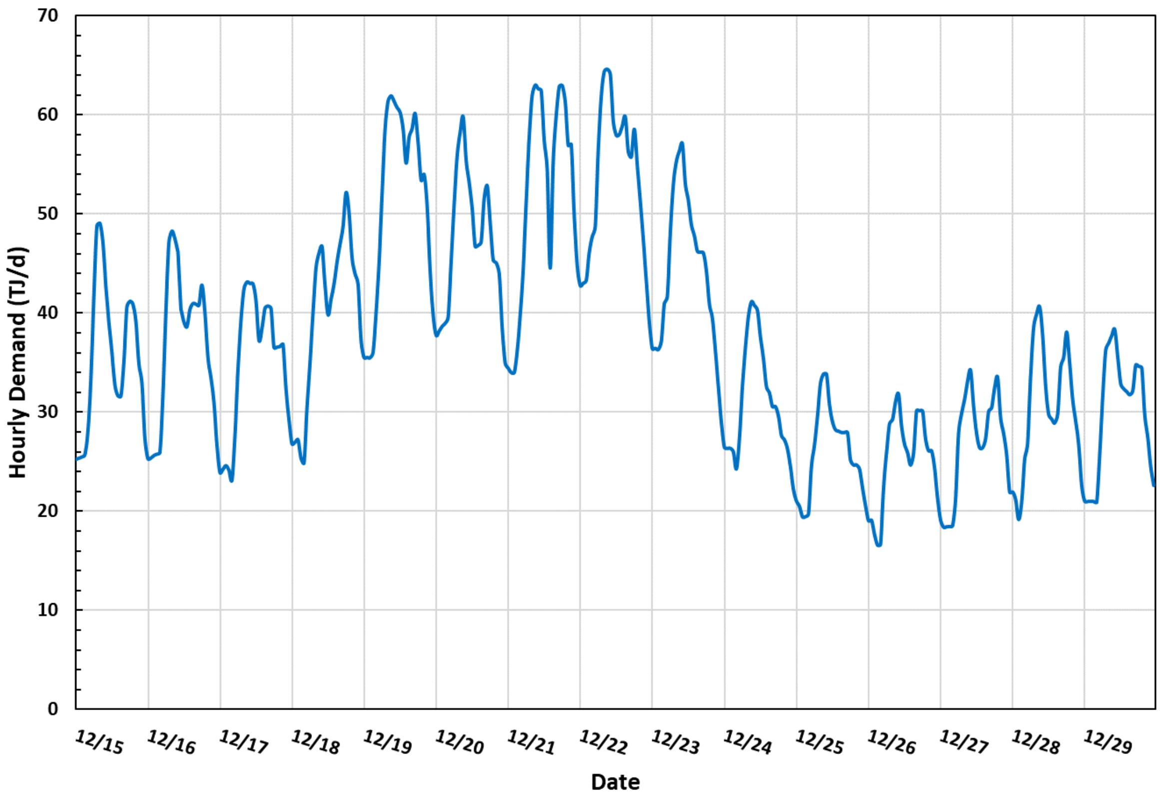


19.11 Please provide the daily aggregate gas demand profile for FEI customers in Victoria Region - for the 14 days around the date when the daily average temperature was at or about -10.8 degrees C. If that occurred more than once, please provide the 14-day profile for each of those occasions over the last 20 years.

<u>Response:</u>

The Victoria Region experienced a daily average temperature of -6 degrees C (24 degree day) on December 22, 2022 recorded at the Victoria Airport weather station. The daily aggregate demand profile for the 14 days around this date is provided in Figure 1 below.

Figure 1: Victoria Region 14-day Daily Aggregate Gas Demand Profile from December 15, 2022 to December 29, 2022

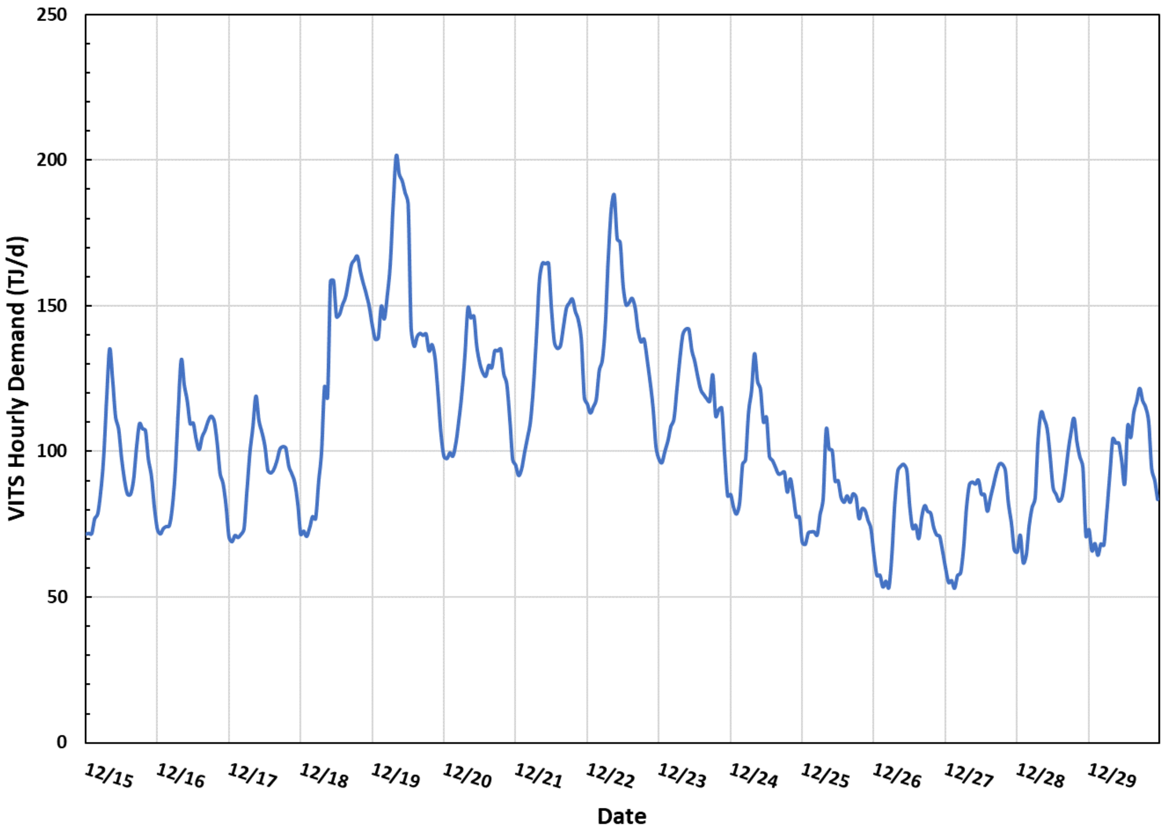


19.12 Please provide the daily aggregate gas demand profile for FEI customers served by the VITS - for the 14 days around the date when the daily average temperature was at or about -10.8 degrees C. If that occurred more than once, please provide the 14-day profile for each of those occasions over the last 20 years.

Response:

The VITS region experienced a daily average temperature of -6 degrees C (24 degree day) on December 22, 2022 recorded at the Victoria Airport weather station. The daily aggregate demand profile for the 14 days around this date is provided in Figure 1 below.

Figure 1: VITS 14-day Daily Aggregate Gas Demand Profile from December 15, 2022, to December 29, 2022



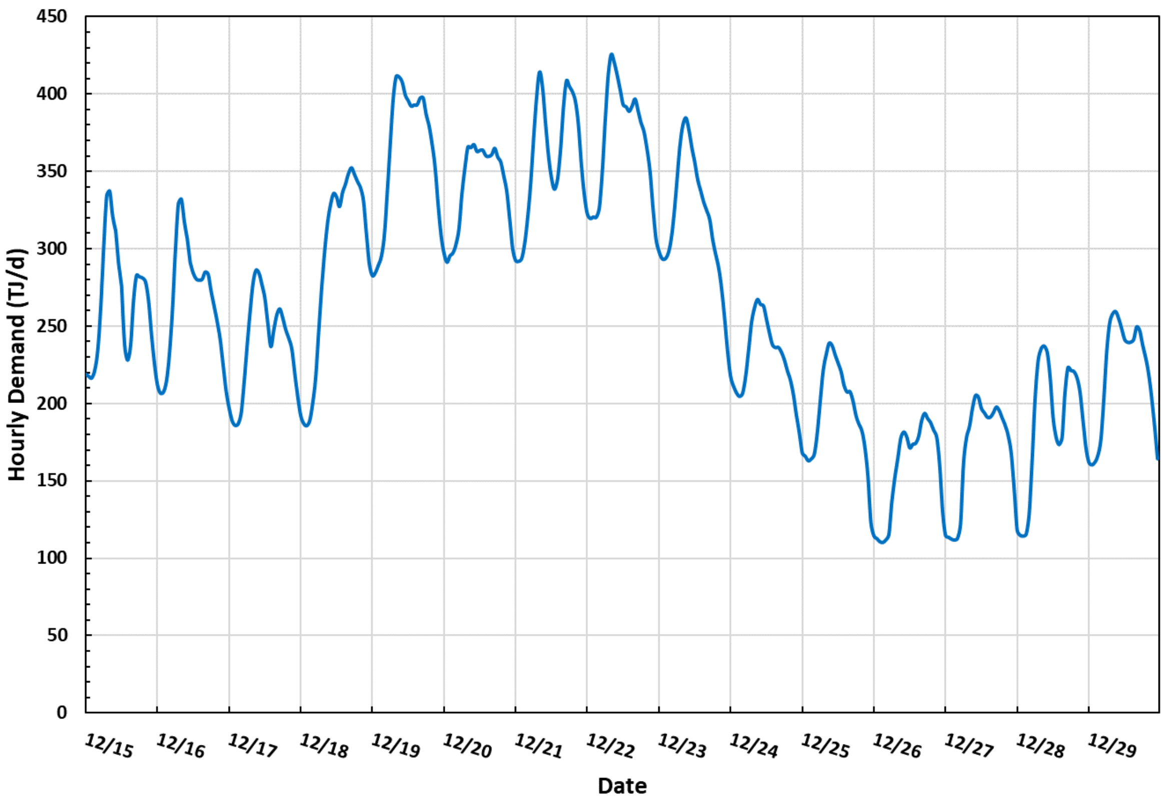
19.13 Please provide the daily aggregate gas demand profile for FEI customers in the Metro Vancouver Region -for the 14 days around the date when the daily average temperature was at or about -12.2 degrees C. If that occurred more than once, please provide the 14-day profile for each of those occasions over the last 20 years.

Response:

The region experienced a daily average temperature of -10.2 degrees C (28.2 degree day) recorded at the Vancouver Airport weather station on December 22, 2022. The figure below shows the aggregate demand for the 14 days around that date.

Please refer to the response to BCSSIA IR2 19.7 which defines the area for which the below data describes.

Figure 1: Daily Aggregate Gas Demand Profile from December 15 to 29, 2022

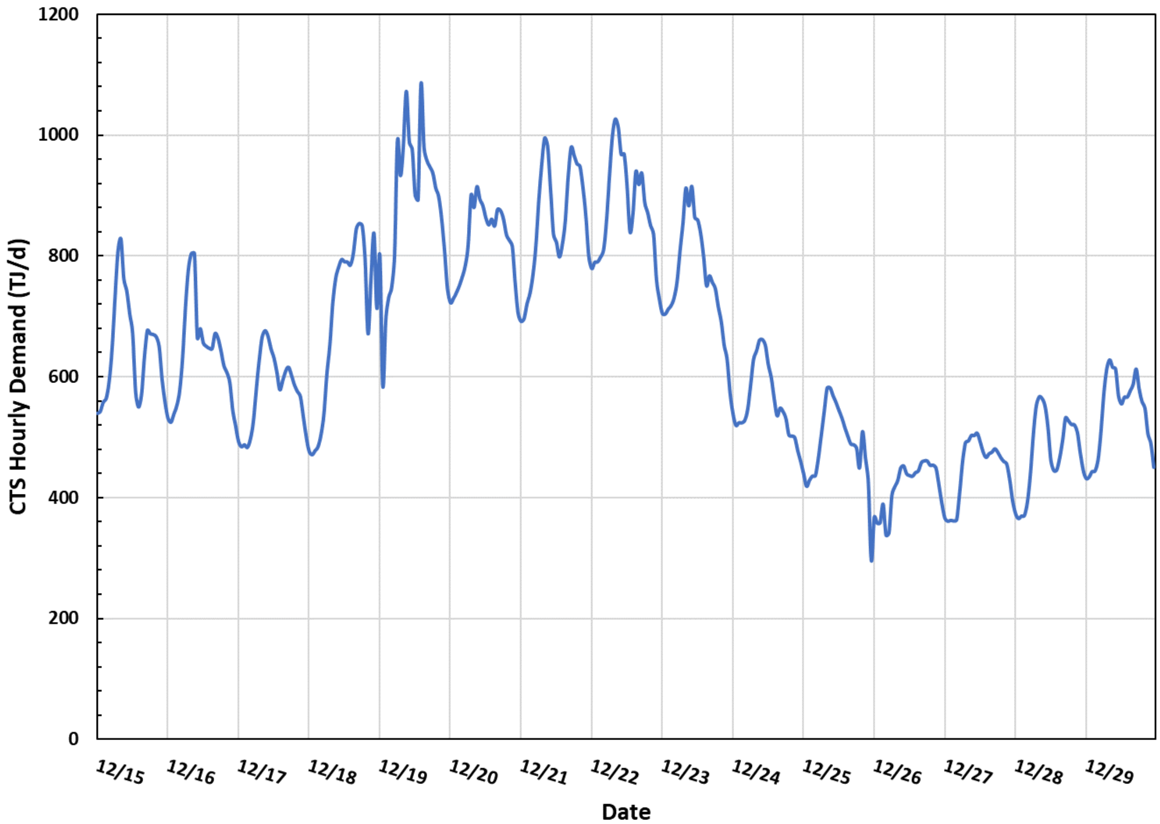


19.14 Please provide the daily aggregate gas demand profile for FEI customers served by the CTS - for the 14 days around the date when the daily average temperature was at or about -10.8 degrees C. If that occurred more than once, please provide the 14-day profile for each of those occasions over the last 20 years.

Response:

The region experienced a daily average temperature of -10.2 degrees C (28.2 degree day) recorded at the Vancouver Airport weather station on December 22, 2022. The figure below shows the aggregate demand of the CTS for the 14 days around that date.

1 **Figure 1: CTS 14-day Daily Aggregate Gas Demand Profile from**
2 **December 15, 2022 to December 29, 2022**



3

20.0 Topic: Kelowna Electrification Case Study

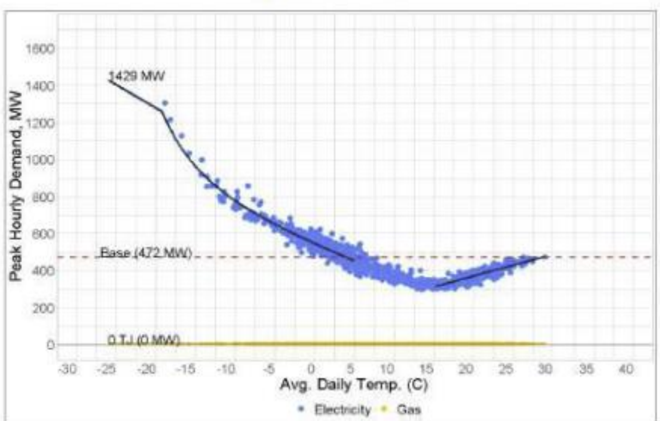
Reference: Exhibit B-20, FEI Kelowna Electrification Case Study, Sections 3.2 to 3.5

FEI's modelling shows that peak load in 2040 would increase from 472 MW (with zero electrification) to 1,429 MW for the 100% electrification scenario, as shown in Table 3-2 and Figure 3-5, below:

Table 3-2: City of Kelowna - Electricity Peak Winter Load in 2040 at Cold Temperatures Based on 25 Percent Increments of Electrification

	Electrification Case				
	0%	25%	50%	75%	100%
Mean Daily Temperature (C)	Peak (MW)				
0	354	415	477	539	555
-5	377	463	548	634	660
-10	400	516	632	748	790
-15	423	581	739	897	984
-20	446	657	867	1,078	1,289
-26	472	711	950	1,190	1,429

Figure 3-5: City of Kelowna - Electricity and Gas Demand by Temperature in 2040 with 100 Percent Electrification[17]



On page 12 of the Study, FEI outlines the need for an expensive transmission upgrade being required to serve peak loads exceeding 550 MW and a further new line triggered by surpassing 950 MW. Its modelling shows that 50% electrification reaches the 950 MW threshold, and 100% electrification reaches 1,429 MW, hence either level would require almost $1 billion of new transmission, as indicated in Table 4-2 below:

> *"The load level of 550 MW triggers the requirement for the Ashton Creek to Vaseux Lake 500 kV transmission line24, and upon surpassing 950 MW, an additional 500 kV line is required, with an expected lead time of at least ten* years."

Table 4-2: Additional Projects[22] Required to Meet a Peak Demand of 25%, 50% and 100% Electrification Cases by 2040

Peak Demand and Electrification Cases	Project Costs ($ Millions)		
	711 MW (25%)	950 MW (50%)	1,429 MW (100%)
New Distribution Stations	120	180	300
New Distribution Feeders	80	120	200
Meshing Kelowna 138 kV Transmission System	20	20	20
138 kV Transmission Line Re-conductor	80	120	200
138 kV Transmission Line Addition	60	90	150
Ashton Creek to Vaseux Lake (ACK-VAS) 500 kV Transmission Line	500	500	500
DG Bell Second 230/138 kV Transformer Addition	20	20	20
Kelowna 230 kV Source (Line & Terminal Station)	50	50	50
Additional Ashton Creek to Vaseux Lake (ACK-VAS) 500 kV Transmission Line (Station not Required)[23]	n/a	450	450
Total	**930**	**1,550**	**1,890**

20.1 What has been the population growth rate for Kelowna over the past 10 years, and what has been the growth rates for gas and electric energy and peak demand over the past 10 years?

Response:

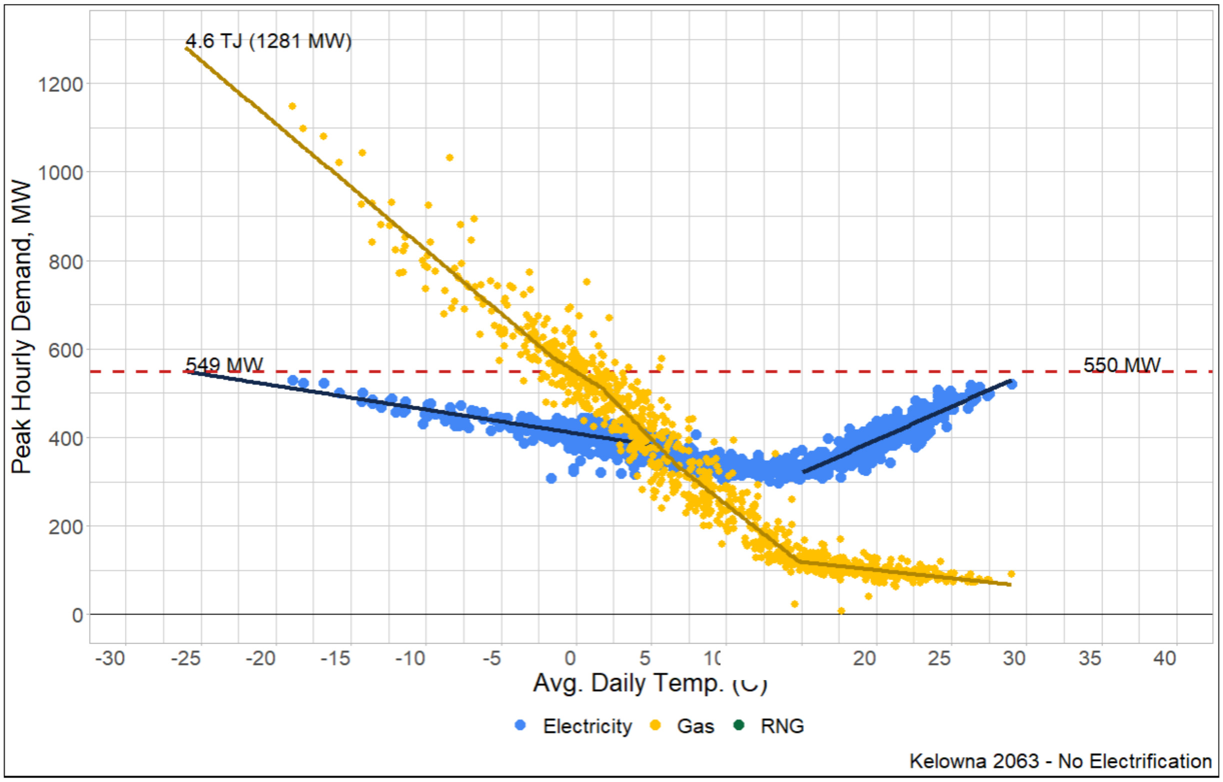
The table below provides the requested growth rates. FEI notes that the electric energy growth rate of 0.7 percent as used in the Study is a conservative assumption compared to other growth rates.

	Growth Rate
Population	2.2%
Gas energy	2.3%
Gas peak	2.3%
Electric energy	0.7%
Electric peak	1.8%

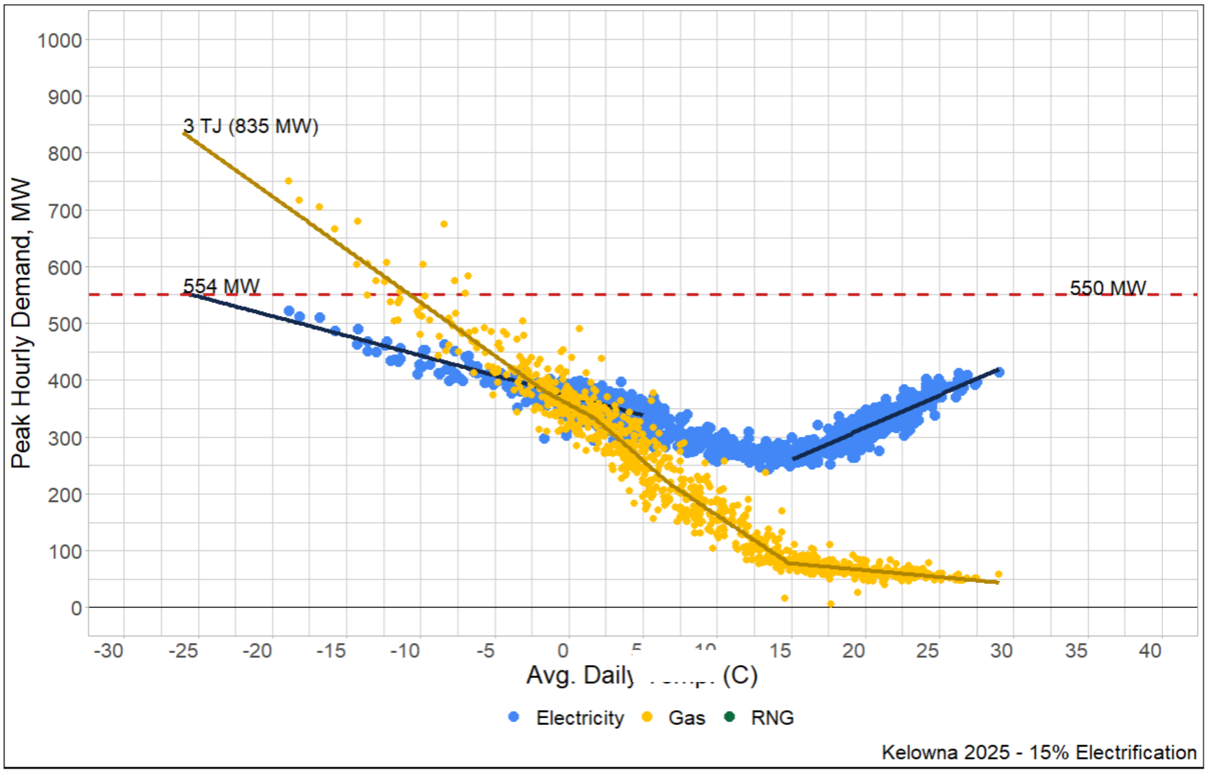
20.1.1 If that same growth rate of peak electric demand were continued in the future, how many years would it take for the current peak electric demand to reach 550 MW?

Response:

In the model used for the Kelowna Electrification Case Study, if all other settings are unchanged in the base case (i.e., no fuel switching from gas to electricity), the forecast duration can be extended 43 years (to 2063) before the 550 MW threshold is reached, as shown below.



If all other settings are unchanged in the base case (meaning the same growth rate is continued, and all else equal) and 15 percent of the gas demand is electrified, the forecast duration can only be extended 5 years (to 2025) before the 550 MW threshold is exceeded, as shown below.



20.2 Why is it necessary to build the new transmission line all the way between Ashton Creek and Vaseux Lake, when Kelowna is only midway between them?

Response:

The new 500 kV line was proposed from Ashton Creek to Vaseux Lake as the only transmission solution capable of meeting the significant increase in load as illustrated in the Study for the Kelowna area. The portion of the line from Kelowna to Vaseux Lake will provide the required redundancy in the event of an outage between Ashton Creek to Kelowna. This redundancy is mandatory to satisfy the TPL-001-4 single contingency MRS requirements.

21.0 Topic: Heat Pump Efficiencies

Reference: Exhibit B-20, page 4 and RDH BC Cold Climate Heat Pump Field Study found at

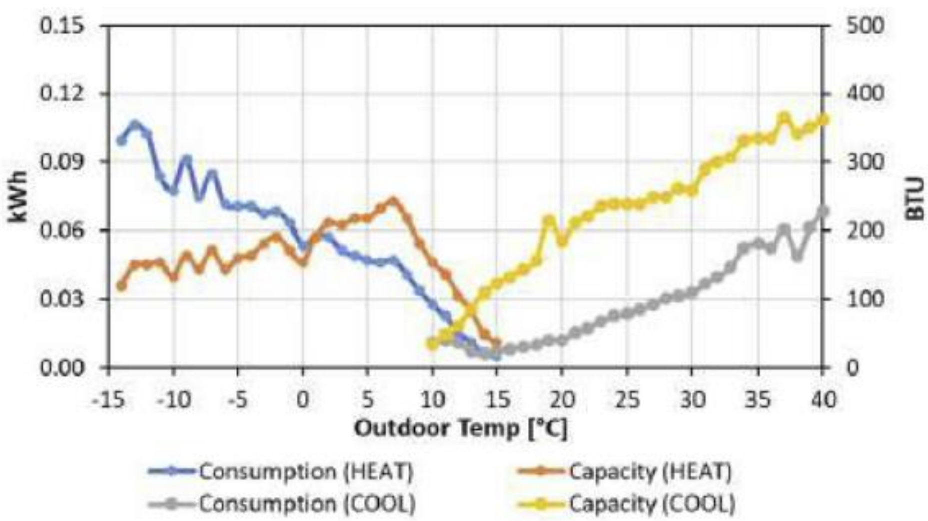
https://www.rdh.com/wp-content/uploads/2021/01/BC-Cold-Climate-Heat-Pump-Study-Final-Report.pdf

Footnote 12 on page 4 of the Study states that: "The data utilized for modelling heat pumps is taken from Figure 3.16 of this BC Cold Climate Field Study"

Figure 3.16 shows the average Coefficient of Performance ("COP", a measure of efficiency, being the ratio of output to input energy) of the heat pumps monitored in the field study, over a full range of outdoor temperatures, for both heating and cooling:

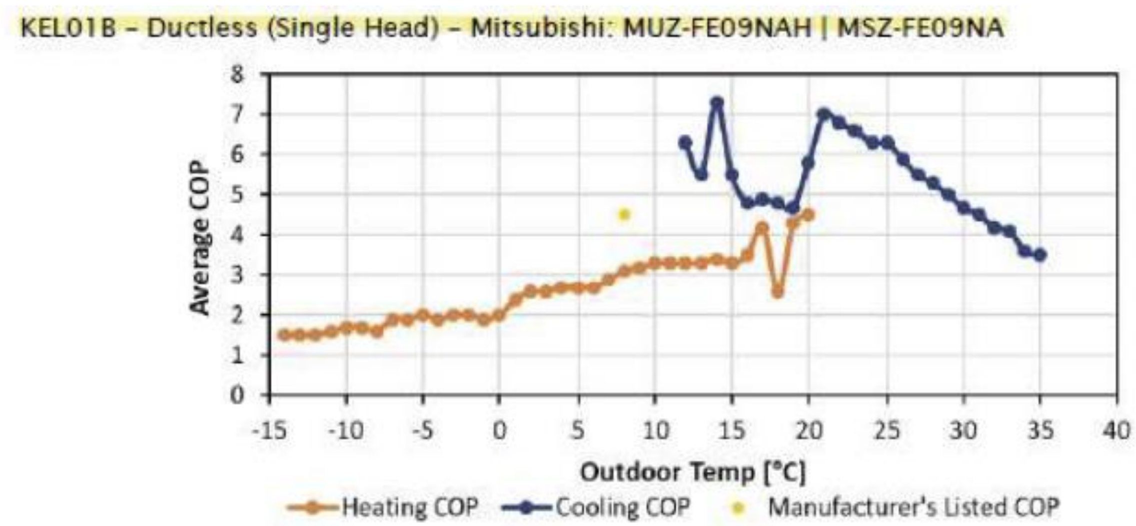
Figure 3.16 – average heating COP range of all heat pumps vs. outdoor temperature.

Further analysis shows that the poorest performing unit was a ductless mini-split system. For a better understanding why the unit may not be performing as expected, *Figure 3.17* is a plot of the average heat pump consumption and capacity in heating and cooling for the unit.

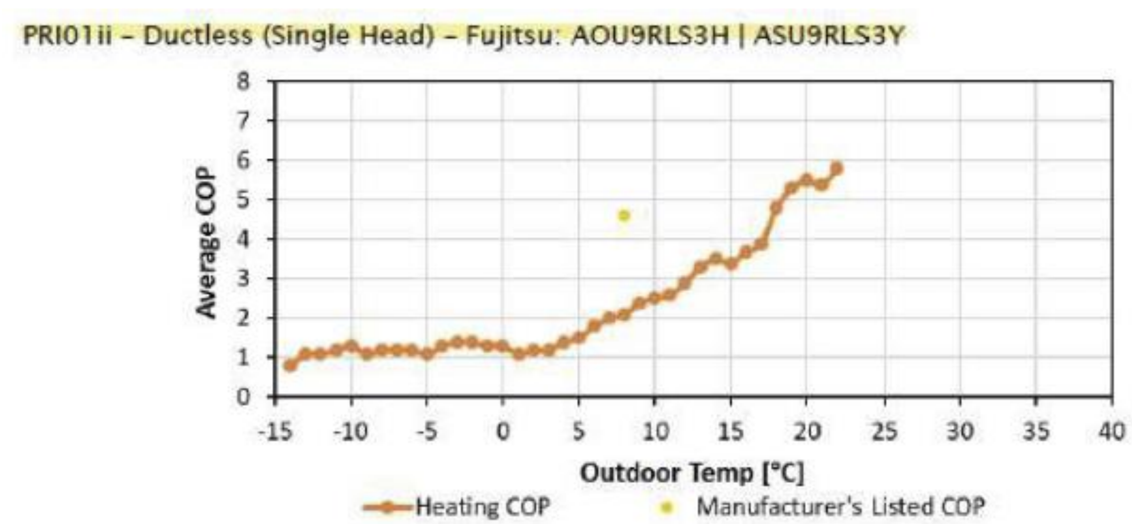


From this chart it is apparent that the average heat pump's heating efficiency drops dramatically below about 7C, even dropping below a COP of 1 at around 0C. By contrast, cooling efficiencies seem to be maintained well up to maximum summer temperatures.

However, there seems to be a great range of performance among the various heat pumps that were monitored. For instance, this is a chart of the COP for a typical unit in Kelowna, that maintains a COP over 2 (i.e., 200% efficiency) down to an outside temperature of -5C:



Whereas this unit installed at Princeton shows a heating COP dropping below 2 for all temperatures below about +7C:



Clearly, at lower temperatures, the second unit is not as efficient as the first. It seems that many of the heat pumps monitored in Kelowna were designed to operate efficiently at the colder temperatures in the interior, whereas those monitored in Victoria were less efficient at cold temperatures.

21.1 We presume the cold weather units must be more costly. Please provide a synopsis of the cost of a variety of electric heat pump units that are (a) designed to operate at colder temperatures, and (b) designed to operate at more moderate temperatures. Please give a breakdown of the equipment costs and the installation costs of the various units.

Response:

As explained in the Application[18] FEI retained the service of an external consultant to estimate the capital and installation costs of a standard efficiency central heat pump (not a cold climate heat pump) for a medium-sized house in the Lower Mainland.[19] The results are provided in Table 2-1 of the Application, and are broken down below:

Component	Cost Estimate	Notes
Standard efficiency central heat pump	$6,500	Costs vary based on brand, efficiency, warranty, etc.
Ductwork	$8,000	Costs include labour which is often outsourced to sheet metal contractors
Installation	$6,500	
Total	**$21,000**	

FEI does not have cost estimates for cold climate heat pumps as the consultant's cost survey was only focused on the Lower Mainland. However, FEI assumes that cold climate electric heat pumps are typically more costly.

21.2 There did not appear to be any gas-powered heat pumps in the field study, but FEI has mentioned the possibility of using gas-powered heat pumps in achieving its GHG reduction objectives. Please provide a full description of gas-powered heat pumps, including how do they work? How costly are they relative to the electric heat pumps? What is their COP over the full range of temperatures? What GHG emissions do they produce as compared to high efficiency gas furnaces?

Response:

Gas heat pumps are very similar to electric heat pumps, with the main difference being that gas heat pumps are fueled by gas or renewable natural gas as opposed to electricity. Heat pumps work by using energy to capture heat from the outdoor ambient air as an additional energy source to their fuel source and then transferring the heat indoors for space or hot water heating. By transferring heat, the energy output is greater than the energy input allowing heat pumps to achieve efficiencies of more than 100 percent.

Commercial gas absorption heat pump unit costs can range from $15 to 20 thousand which FEI understands is on par with unit costs for similar scale electric heat pumps. However, total project costs for installation will depend on manufacturer type, installation, piping and insulation costs. Please refer to the response to BCUC IR1 10.9.1 for more information. FEI does not have total

[18] Exhibit B-1, p. 2-32.
[19] FEI notes these estimates were prepared in 2021 and, therefore, may not reflect the current prices.

project cost estimates for electric heat pumps as FEI’s pilots and studies focus on conventional natural gas equipment comparisons. FEI does not have residential gas heat pump costs comparisons to electric heat pumps as this technology is not commercially available across North America.

To date, gas heat pumps have system efficiencies with a COP of 1.2 to 1.6, depending on the type and end use application. Today, most gas heat pumps are rated to perform in temperatures as low as -25 to -40 degrees Celsius, and their COP does not degrade dramatically as outdoor ambient temperatures drop since they utilize a gas burner rather than an electric air compressor and therefore do not rely solely on ambient air temperature for heat extraction. This may offer an advantage in comparison to electric vapor compression heat pumps in winter months. Gas heat pump products are relatively early in their development and market adoption and developers continue to focus on improving COP performance as well as reducing costs.

Compared to conventional natural gas furnaces, gas heat pumps offer customers the ability to significantly reduce greenhouse gas emissions. Residential customers who install a gas heat pump (compared to their standard efficiency furnace) could save about 33 gigajoules of natural gas a year, which is roughly about four months of annual use by a typical household. This also means it can help lower energy bills by up to almost $400 annually compared to a standard natural gas furnace and hot water heater. Customers can further reduce emissions by opting into FEI’s Renewable Natural Gas (RNG) program and designate a portion of their gas use, up to 100 percent, to be low carbon RNG.

22.0 Topic: Heat Pump Cost Effectiveness to the Customer Reference: General

BCSSIA seeks to better understand the circumstance in which electric or gas heat pumps will be more cost effective for the customer than heating with a high efficiency gas furnace, and when they will be less cost effective.

22.1 Given the current cost of natural gas, delivered to a typical Kelowna customer (with the Carbon Tax set at $65/tonne of CO2e), what is the cost to the customer, per GJ of heat energy delivered from a 96% efficient gas furnace?

Response:

FEI interprets the question to be referring to the cost to the customer on a fuel-cost basis as indicated in BCSSIA IR2 22.2.1 for calculating the break-even point. The burner tip rate for a customer with a 96 percent efficient gas furnace is $16.85 per GJ as calculated below:

Cost Item	FEI's Burner tip rate as of April 1, 2023 ($/GJ)
Cost of gas	$ 4.16
Storage and Transport	$ 1.13
Fixed Basic charge[20]	$ 1.71
Delivery charge	$ 5.93
Carbon tax	$ 3.24
Burner tip rate	$ 16.18
Burner tip rate adjusted for 96% efficiency[21]	$ 16.85

22.2 And, given the current cost of electricity (BC Hydro residential tier 2 price), please provide a table and graph showing the cost per GJ of delivered heat energy from a hypothetical electric heat pump over a range of COPs from 1.0 to 4.0.

22.2.1 What is the minimum heating COP of the electric heat pump required to break even (on a fuel-cost basis) with the 96% efficient gas furnace?

Response:

As of April 1, 2023, BC Hydro's Tier 2 rate is $0.1417 per kWh or the equivalent of $39.36 per GJ[22]. The efficiency adjusted rates in dollars per GJ equivalents for various assumed heat pump efficiencies is provided below:

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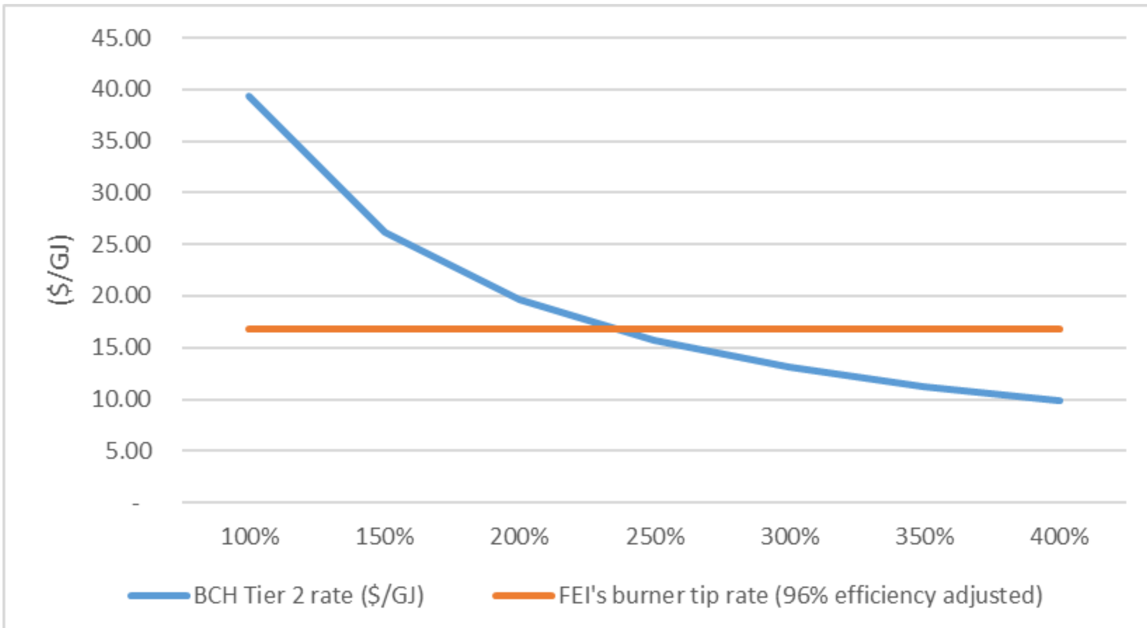
[20] Assuming 90 GJ annual consumption.
[21] Calculated by dividing the burner tip rate by 96 percent.
[22] To convert $/kWh to $/GJ, BC Hydro rate is multiplied by 277.78.

Heat pump efficiency	100%	150%	200%	250%	300%	350%	400%
Efficiency adjusted BCH Tier 2 rate[23] ($/GJ)	39.36	26.24	19.68	15.74	13.12	11.25	9.84

The following figure graphically provides this information compared to FEI's burner tip rate adjusted for 96 percent efficiency:



As shown in the graph above, on a fuel-cost basis, the efficiency for a heat pump needs to be a minimum of 234 percent[24] to break even with a 96 percent efficiency gas furnace at current gas and electricity prices.

22.3 Please provide a similar analysis assuming FEI's projected delivered gas price in 2030 (including the Carbon Tax of $170/tonne) and an electricity price escalated at 2% per year.

<u>Response:</u>

In providing the analysis described in the question, FEI notes that the assumption of electricity prices (i.e., BC Hydro electricity rates) to escalate at 2 percent per year would be extremely conservative given the expected capacity upgrades required in all aspect of BC Hydro's electric system (for example, Site C). For example, as shown in the Kelowna Electrification Case Study,[25] 50 percent to 100 percent electrification would require FBC to upgrade its infrastructure with

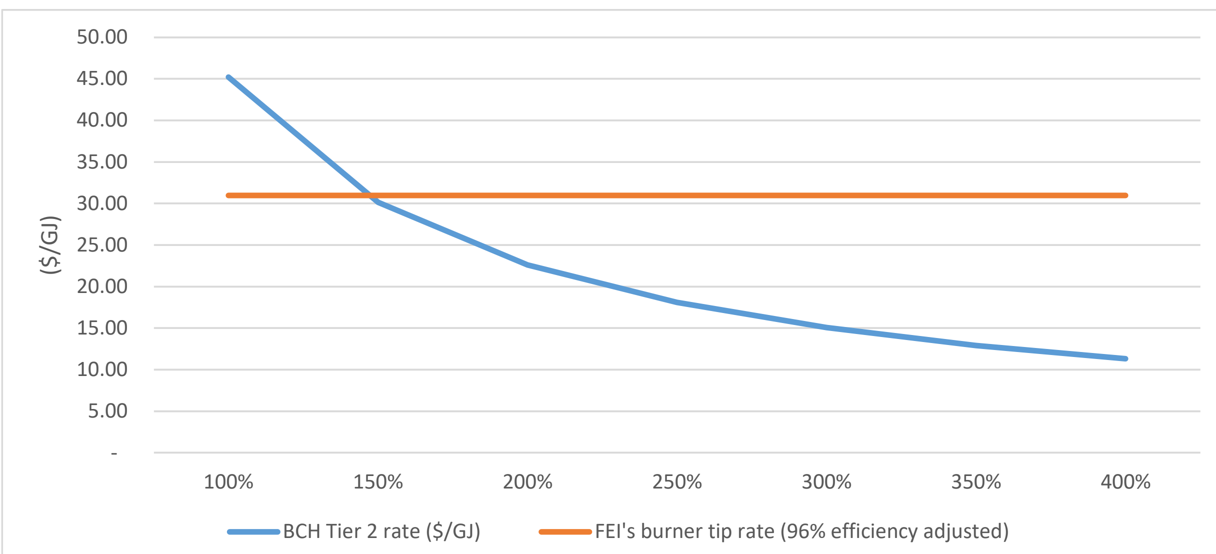
[23] Calculated by dividing BC Hydro's Tier 2 rate by the assumed efficiency rate.
[24] Calculated by dividing BC Hydro's Tier 2 rate by FEI's burner tip rate adjusted for 96% efficiency.
[25] Exhibit B-20, filed by FEI on February 24, 2023 as Evidentiary Update to this Application.

capital costs in the range of $2.2 billion to $3.4 billion for a city with a population of about 143,000 residents.[26] FEI expects BC Hydro would also require significant capital upgrades to support electrification and, therefore, expects the impact to electricity prices would be much higher than 2 percent.

However, to be responsive to the question, FEI provides the same analysis as provided in the response to BCSSIA IR2 22.2, but based on the estimated gas rates in 2030 under FEI's DEP Scenario as shown in Section 9.4 of the Application as a comparison against BC Hydro's Tier 2 rate in 2030, assuming an annual 2 percent electricity price escalation.

Heat pump efficiency	100%	150%	200%	250%	300%	350%	400%
Efficiency adjusted BCH Tier 2 rate[27] ($/GJ)	45.21	30.14	22.61	18.09	15.07	12.92	11.30

The following figure graphically provides this information compared to FEI's burner-tip rate under the DEP Scenario in 2030, adjusted for 96 percent efficiency. The minimum efficiency for a heat pump would be approximately 146 percent to break even with a 96 percent efficiency gas furnace, based on the assumed gas and electricity price in 2030 as discussed above. However, as also discussed above, it is anticipated that electricity rates would be much higher, and thus heat pump efficiency would need to be much higher, to break even with a high efficiency furnace.



[26] Online at: www.Kelowna.ca.

[27] Calculated based on BC Hydro's Tier 2 rate effective April 1, 2023, with 2 percent annual escalation to 2030 and divided by the assumed efficiency rate.