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May 3, 2023

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

Attention: Christopher P. Weafer

Dear Christopher P. Weafer:

Re: FortisBC Energy Inc. (FEI)

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

Response to the Commercial Energy Consumers Association of British Columbia (CEC) 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 CEC 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

49. Reference: FEI Responses to CEC IR 1.1.2[1] and BCUC IR 1.52.4[2]

> 1.2 Please confirm the present supply of low-carbon gas in FEI's system, as percentage of average daily total system supply; the type(s) of low-carbon gas that are offered; and to which customer groups.
>
> **Response:**
>
> Currently, FEI is only purchasing RNG, or gas derived from the decomposition of organic waste. In 2021 FEI purchased approximately 0.7 PJ of RNG, which is less than one percent of FEI's 2021 total gas throughput of 227.5 PJ. Currently, RNG is available to all FEI customers except for those in Revelstoke and Fort Nelson.

> ***1. Identification of Risks to Increasing Renewable and Low-Carbon Gas Supply***
>
> The BC Renewable and Low-Carbon Gas Supply Potential Study[57] (Study) quantitively compares various renewable and low-carbon gas pathways from a portfolio and cost perspective. The Study presents strategies and actions relating to feedstock, financial considerations, infrastructure, regulatory, climate and carbon intensity that FEI will take into consideration in scaling supply. Supply risks identified in the Study, aside from competition, include:
>
> - The future cost allowed by the GGRR for anaerobically produced RNG;
> - The availability and cost of electricity for green hydrogen;
> - The availability of suitable geological features to sequester CO2; and
> - The supply and distribution of woody biomass and wood residues within BC.
>
> FEI provides an additional review of the renewable and low-carbon supply risks in Section 8.3 of Appendix A to FEI's Generic Cost of Capital Evidence in which the key risks identified include lower than expected supply volume, competition from other purchasers and gas system readiness.

49.1 Please provide a comparison of the contents of the RNG, which FEI presently acquires from third parties and physically injects into its gas pipeline system, with the natural gas pipeline content.

Response:

RNG injected into the existing FEI system must contain a minimum of 96.5 percent methane in order to meet the minimum required heating value for pipeline specifications. The remainder is made up primarily of nitrogen and carbon dioxide. This meets the same conventional natural gas specifications which also has a minimum heating value. The primary difference is the presence of other hydrocarbons in conventional natural gas which are not present in RNG. Similarly, RNG injected into gas systems outside of BC will be required to meet the pipeline specifications of those local utilities or pipeline carriers.

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1 Exhibit B-12.
2 Exhibit B-6.

49.2 Please explain whether FEI has a 'target methane content' for the RNG that it plans to acquire and physically absorb in its system over the course of its LTGRP, and if so, what is the target?

Response:

Please refer to the response to CEC IR2 49.1.

49.3 Please clarify as to whether FEI presently ascertains or assesses any 'gas system readiness' risks as it concerns physically absorbing the planned (as per the LTGRP) volumes of RNG purchases into its gas pipeline system.

49.3.1 If yes, please explain the nature of such risks.

Response:

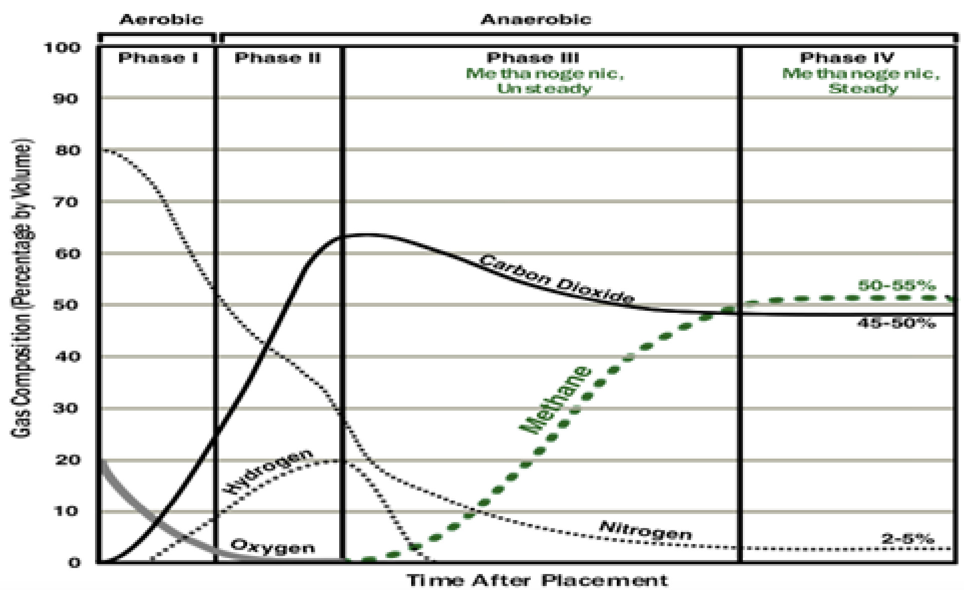
This is not required for RNG because biomethane and conventional gas molecules are interchangeable. Hence, the existing piping system can accept biomethane into the grid as if it was conventional natural gas.

FEI has provided its overview of considerations for integrating renewable and low-carbon gas supplies, including the technical requirements, for the system to be able to incorporate physical delivery of these energy supplies to customers in Section 7.4.1 and Table 7-2 of the Application. FEI discusses the strategy and actions it is taking to mitigate the risks and expand upon the opportunities of acquiring renewable and low-carbon gas in the response to BCUC IR1 52.4, and FEI's support for BC production initiatives in the response to BCUC IR1 52.5. Similarly, specifically with regard to hydrogen, FEI provides a comprehensive review in the responses to BCUC IR1 61.3 and 61.9. A summary of considerations by fuel type is illustrated in the response to CEC IR1 9.3.

50. Reference: FEI Responses to CEC IR 1.1.1[3] and BCUC IR 1.52.5[4]

> In December 2021, FEI filed its Comprehensive Review and Application for a Revised Renewable Gas Program (RG Program Application), which, along with other revisions, seeks to blend RNG volumes with natural gas to be sold to all sales customers as part of their gas service. As RNG supply increases to meet government emission reduction targets, FEI intends to distribute that supply to all sales customers. As shown in the Figure 1[58] below, the program has changed over the years with respect to the maximum volumes, supply projects, service offerings and pricing.

50.1 As biogas derived from the decomposition of organic waste[5] has a high carbon content prior to it being processed into RNG (see the graphical representation below[6]), please describe the generic upgrading process by which it is converted into RNG (a low-carbon fuel).



Response:

Upgrading landfill gas has three basic steps:

- Removal of trace contaminants such as hydrogen sulfide, siloxanes, and volatile organic compounds;
- Gas compression; and
- Separation of methane from other gas components (i.e., carbon dioxide and nitrogen).

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3 Exhibit B-12.
4 Exhibit B-6.
5 https://www.epa.gov/lmop/basic-information-about-landfill-gas.
6 https://www.epa.gov/lmop/basic-information-about-landfill-gas.

The methane is retained while the other gases are removed. At the end of the process, RNG that meets the biomethane specification is injected into the gas grid.

50.2 Please confirm or otherwise explain whether FEI contracts directly with RNG producers or third parties to acquire the present supply of RNG it incorporates into its offering. Does FEI have plans for any other processes, other than directly contracting with RNG producers?

Response:

FEI is currently acquiring RNG directly from RNG producers and also from third parties. FEI also purchases raw biogas and upgrades it to RNG.

An example of a direct contract would be the Seabreeze biomethane purchase agreement (BPA) in BC.

With regard to third-party sellers, these sellers acquire RNG from upstream sellers, i.e., RNG producers, and then sell the gas to FEI through a BPA. An example of a third-party seller contract is the Tidal-London BPA from out-of-province. In this case, FEI buys RNG from Tidal who has a contract with the supplier (in London, Ontario) for RNG.

FEI also contracts raw biogas to feed its own RNG upgrading facilities. In these cases, FEI produces the RNG.

In all cases, the BPAs include provisions to access and audit supplier facilities to confirm compliance with RNG production standards and that the gas is physically being delivered.

50.3 Please confirm the carbon content of the RNG which FEI presently contracts for and physically absorbs into its gas pipeline system.

Response:

RNG and conventional natural gas have comparable chemical compositions, which is primarily methane. However, the benefit of RNG is that it is derived from organic sources; therefore, its carbon composition comes from carbon that already exists within the ecosystem. Hence, combustion of RNG does not contribute a net addition of greenhouse gas into the atmosphere, in comparison to conventional natural gas which is derived from a fossil source. This convention for carbon accounting for biomass-derived fuels is broadly accepted by provincial and federal governments.

RNG lifecycle carbon intensity (CI) varies depending on whether the gas is generated from a landfill or an anaerobic digestion process (AD), which uses food waste, dairy farm waste or manure as feedstock. Landfill projects' CIs are typically in the range of 10 to 16 $kgCO_2e/GJ$. AD projects have generally sub-zero CIs, from around -10 and as low as -180 $kgCO_2e/GJ$. The lifecycle carbon intensity of FEI's RNG portfolio ranges approximatively from 20 to -90 $kgCO_2e/GJ$.

In comparison, the lifecycle carbon intensity of conventional natural gas is estimated at 60 $kgCO_2e/GJ$.

50.4 While FEI retains the environmental attributes of the low-carbon RNG it contractually acquires, please describe, which parties bear the contractual risk associated with the carbon content in the pre-processed biomethane gas?

Response:

The supplier bears the contractual risk that the RNG meets the carbon intensity it has been contracted to provide. This includes the carbon content in the pre-processed biomethane which is part of the carbon intensity of the biomethane acquired by FEI. The current version of BPAs specifies an agreed-upon maximum carbon intensity threshold, specific to each supplier's facility. These contracts include a financial penalty including potential contract termination for biomethane suppliers that exceed this maximum carbon intensity on an annual basis.

In addition, FEI has a contractual right to perform audits to track individual facility inputs and outputs to verify carbon intensity if required. FEI undertakes audits on all of its supplier facilities to verify that the facility is injecting RNG into the system, and to confirm its inputs and emissions, so that the RNG's carbon intensity can be calculated and verified.

50.5 To the extent there are CO2 emissions from the biogas upgrading process, how are these emissions handled and what is the quantity for each end point of the handling process?

Response:

FEI calculates the lifecycle emissions of biomethane production and use by hiring independent consultants to calculate the carbon intensity of biomethane facilities using the GHGenius model. For the biogas upgrading process, this model accounts for emissions from sources including, but not limited to:

- emissions from fuels and electricity used in the upgrading process, and
- fugitive and vented methane emissions.

FEI considers the full life-cycle emissions when calculating the carbon intensity of biomethane, not just the emissions from biogas upgrading. The carbon intensity calculation also includes GHG emissions from producing and transporting feedstock, distribution of biomethane to customers, non-CO_2 emissions produced in combustion of biomethane, and reductions in emissions from organic waste diversion and the use of digestate rather than conventional fertilizer.

51. Reference: FEI Responses to CEC IR 1.1.1[7] and BCUC IR 1.52.5[8]

51.1 Over 20 years ago, siloxanes[9] were identified on gas engines running on landfill and sewage gas. These organic compounds (VMS) are known to have a negative impact on machinery causing wear on internal parts and increasing operating costs as a result.[10] Please comment on whether such compounds (i.e. VMS) are present in the RNG supply that FEI acquires and physically injects into its gas pipeline system.

Response:

Upgrader systems are used at biogas facilities to refine raw biogas to RNG and are designed to remove contaminants such as volatile organic compounds (VOC). To ensure quality, all biomethane purchase agreements include language that suppliers need to comply with FEI biomethane specification. Also, before injecting into FEI's system, RNG produced at a facility is continuously tested with a chromatograph to ensure the gas meets the pipeline quality gas.

51.1.1 Please elaborate on any risks to the FEI gas pipeline system from volatile organic components (i.e. VMS) that could find their way into biomethane-derived RNG.

Response:

The risk is mitigated by controlling the quality of the RNG before it gets injected into the gas network. For projects located in BC, FEI's interconnection stations include a chromatograph system that tests the biomethane on an ongoing basis before it is injected into the pipeline. If the produced biomethane does not meet pipeline quality gas, the gas is automatically rejected.

For off-system projects, there is no risk to FEI because it is the responsibility of suppliers to ensure they meet pipeline quality gas of the local distribution system or pipeline.

51.1.2 Please describe by what means FEI assures the quality of the RNG gas supply that it acquires on behalf of its customer base.

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[7] Exhibit B-12.

[8] Exhibit B-6.

[9] Volatile Methyl Siloxanes (VMS) - https://www.alsglobal.com/en/air-quality/ambient-air-analysis/siloxanes-inbiogas-and-landfill-gas.

[10] Volatile Methyl Siloxanes (VMS) - https://www.alsglobal.com/en/air-quality/ambient-air-analysis/siloxanes-inbiogas-and-landfill-gas.

<u>Response:</u>

Please refer to the responses to CEC IR2 51.1.1 and BCUC IR1 52.5 for details on monitoring the quality of RNG before it gets injected into the gas network system.

52. Reference: FEI Responses to CEC IR 1.1.1[11] and BCUC IR 1.52.5[12]

52.1 Please provide in a table format the volumes of RNG purchases as forecast annually for the period 2022 to 2042, along with total gas throughput projections, and RNG purchases as percentage of total gas throughput.

Response:

Please see Table 1 below that illustrates the annual volumes of renewable and low-carbon gas purchases, total gas supply[13], percentage of RNG, and the percentage of renewable and low-carbon gas, for the period of 2022 to 2042 for the DEP Scenario. Table 1 confirms that FEI expects its proportion of renewable and low-carbon gas supply to exceed 15 percent by 2030.

Table 1: FEI Annual Forecast of Natural Gas, Renewable and Low-Carbon Gas Supply for the DEP Scenario (2022-2042) in PJ per Year

Year	Natural Gas	Renewable and Low-Carbon Gas Supply							
		RNG	Hydrogen	Syngas and Lignin	CCUS	Renewable and Low-Carbon	Total Gas Supply	RNG Portion	Renewable and LC Gas Portion
	(PJ)							(%)	(%)
2022	201.1	5.8	0.0	0.0	0.0	5.8	207.0	2.8%	2.8%
2023	193.2	10.7	0.0	0.0	0.2	11.0	204.2	5.3%	5.4%
2024	185.2	12.9	2.7	0.4	0.3	16.3	201.6	6.4%	8.1%
2025	177.1	16.1	5.4	0.8	0.4	22.7	199.8	8.1%	11.4%
2026	168.6	19.3	8.1	1.6	0.6	29.5	198.1	9.7%	14.9%
2027	159.3	22.5	10.7	3.2	0.7	37.0	196.3	11.4%	18.9%
2028	150.2	25.6	13.4	4.7	0.8	44.6	194.8	13.2%	22.9%
2029	141.3	28.8	16.1	6.3	0.9	52.2	193.5	14.9%	27.0%
2030	132.3	32.2	20.0	6.7	1.3	60.2	192.5	16.7%	31.3%
2031	126.9	32.8	22.8	6.9	1.7	64.1	191.0	17.1%	33.6%
2032	121.6	33.3	25.5	7.0	2.1	68.0	189.5	17.6%	35.9%
2033	116.5	33.9	28.3	7.2	2.5	71.8	188.3	18.0%	38.1%
2034	112.0	34.5	31.0	7.4	2.9	75.7	187.7	18.4%	40.3%
2035	107.0	35.1	33.8	7.5	3.2	79.6	186.5	18.8%	42.7%
2036	102.1	35.6	36.5	7.7	3.6	83.5	185.5	19.2%	45.0%
2037	97.2	36.2	39.3	7.9	4.0	87.3	184.6	19.6%	47.3%
2038	92.6	36.8	42.0	8.0	4.4	91.2	183.8	20.0%	49.6%
2039	88.1	37.4	44.8	8.2	4.8	95.1	183.2	20.4%	51.9%
2040	83.6	37.9	47.5	8.4	5.2	99.0	182.6	20.8%	54.2%
2041	79.4	38.5	50.3	8.5	5.5	102.8	182.2	21.1%	56.4%
2042	75.4	39.1	53.0	8.7	5.9	106.7	182.1	21.5%	58.6%

In Table 2 below, FEI provides the following information regarding commodity cost estimates[14] used in the DEP Scenario market costs for the years 2022 to 2042:

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[11] Exhibit B-12.
[12] Exhibit B-6.
[13] Includes Vancouver Island co-generation plant.
[14] All prices are in real dollars Canadian.

A. Estimated natural gas price ($/GJ)

B. Estimated cost of RNG, syngas, lignin, CCUS ($/GJ)

C. Estimated cost of hydrogen ($/GJ)

D. Weighted average cost of RNG, syngas, lignin, CCUS, hydrogen ($/GJ)

E. FEI effective rate ($/GJ)

F. Carbon tax on natural gas

G. Comparison of renewable and low-carbon gas cost to natural gas

H. Comparison of renewable and low-carbon gas cost to natural gas with carbon tax

I. Natural gas cost – FEI's Commodity Cost Recovery Charge (CCRC) lower bound

J. Comparison of renewable and low-carbon gas cost to natural gas (CCRC lower bound)

K. Natural gas cost – CCRC upper bound

L. Comparison of renewable and low-carbon gas cost to natural gas (CCRC upper bound)

M. Natural gas cost – AECO/NIT[15]

N. Comparison of renewable and low-carbon gas cost to natural gas (AECO/NIT)

Table 2 provides commodity cost estimate comparisons to illustrate the range of cost increases that will be experienced as FEI displaces natural gas with low-carbon energy. A number of comparisons can be made based on the analysis that compares the commodity costs.

- Renewable and low-carbon gas is estimated to range from 4.6 to 6.6 times more than natural gas based on DEP Scenario estimates;
- Renewable and low-carbon gas is estimated to range from 14.6 to 17.2 times more than CCRC lower bound estimates;
- Renewable and low-carbon gas is estimated to range from 3.8 to 4.5 times more than CCRC upper bound estimates; and
- Renewable and low-carbon gas is estimated to range from 6.4 to 9.2 times more than AECO/NIT estimates.

However, when also considering the cost of carbon, the preliminary forecast of renewable and low-carbon gas cost is approximately 4 times greater than the natural gas and carbon price in 2020, or 2 times greater than the forecast natural gas and carbon price in 2030 and onwards.

15 AECO/NIT prices from Figure 2-4 in the Application.

Table 2: Commodity Cost Comparisons for Natural Gas, Renewable and Low-Carbon Gases Based on DEP Scenario Cost Estimates and Natural Gas Market Prices (2022-2042)

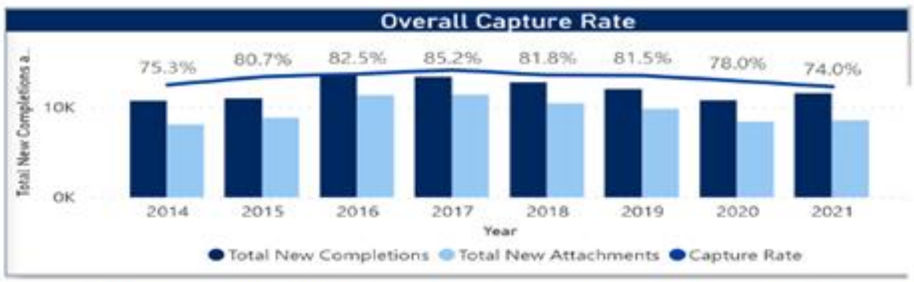
Year	DEP Scenario								Natural Gas Market					
	Natural Gas	RNG / Syngas and Lignin / CCUS	Hydrogen	RGand LC (Weighted Average)	FEI Effective Rate	Carbon Tax on Natural Gas	RG and LC in Comparison to Natural Gas (DEP)	RG and LC in Comparison to Natural Gas (DEP) + Carbon Tax	CCRC Lower Bound	RG and LC in Comparison to Natural Gas (Lower)	CCRC Upper Bound	RG and LC in Comparison to Natural Gas (Upper)	AECO/NIT	RG and LC in Comparison to Natural Gas (AECO/NIT)
	($/GJ)	($/GJ)	($/GJ)	(B+C)/Volume	($/GJ)	($/GJ)	(D/A)	(D/(A+F))	($/GJ)	(D/I)	($/GJ)	(D/K)	($/GJ)	(D/M)
	A	B	C	D	E	F	G	H	I	J	K	L	M	N
2022	$ 3.7	$ 22.6	$ 30.5	$ 22.6	$ 4.2	$ 2.6	6.1	**3.6**	$ 1.6	14.6	$ 5.9	3.8	$ 3.1	7.2
2023	$ 3.7	$ 23.1	$ 30.5	$ 23.1	$ 4.6	$ 3.3	6.3	**3.3**	$ 1.6	14.9	$ 5.9	3.9	$ 2.5	9.2
2024	$ 3.9	$ 23.6	$ 30.5	$ 24.7	$ 5.4	$ 4.0	6.4	**3.1**	$ 1.6	15.9	$ 5.9	4.2	$ 2.7	9.2
2025	$ 3.9	$ 24.0	$ 30.5	$ 25.6	$ 6.0	$ 4.7	6.6	**3.0**	$ 1.6	16.5	$ 5.9	4.3	$ 2.8	9.2
2026	$ 3.9	$ 24.6	$ 30.5	$ 26.2	$ 6.6	$ 5.5	6.6	**2.8**	$ 1.6	16.9	$ 5.9	4.4	$ 3.0	8.9
2027	$ 4.1	$ 25.1	$ 30.5	$ 26.6	$ 7.4	$ 6.2	6.5	**2.6**	$ 1.6	17.2	$ 5.9	4.5	$ 2.9	9.1
2028	$ 4.1	$ 25.6	$ 15.0	$ 22.4	$ 7.0	$ 6.9	5.5	**2.0**	$ 1.6	14.5	$ 5.9	3.8	$ 3.0	7.4
2029	$ 4.3	$ 26.1	$ 15.0	$ 22.7	$ 7.7	$ 7.7	5.3	**1.9**	$ 1.6	14.6	$ 5.9	3.8	$ 3.1	7.3
2030	$ 4.4	$ 26.7	$ 15.0	$ 22.8	$ 8.4	$ 8.4	5.1	**1.8**	$ 1.6	14.7	$ 5.9	3.9	$ 3.1	7.4
2031	$ 4.4	$ 27.2	$ 15.0	$ 22.9	$ 8.6	$ 8.4	5.2	**1.8**	$ 1.6	14.8	$ 5.9	3.9	$ 3.1	7.3
2032	$ 4.5	$ 27.8	$ 15.0	$ 23.0	$ 9.0	$ 8.4	5.1	**1.8**	$ 1.6	14.8	$ 5.9	3.9	$ 3.2	7.3
2033	$ 4.7	$ 28.4	$ 15.0	$ 23.1	$ 9.4	$ 8.4	5.0	**1.8**	$ 1.6	14.9	$ 5.9	3.9	$ 3.3	7.0
2034	$ 4.6	$ 29.0	$ 15.0	$ 23.3	$ 9.7	$ 8.4	5.1	**1.8**	$ 1.6	15.0	$ 5.9	3.9	$ 3.2	7.2
2035	$ 4.6	$ 29.6	$ 15.0	$ 23.4	$ 10.0	$ 8.4	5.1	**1.8**	$ 1.6	15.1	$ 5.9	4.0	$ 3.2	7.3
2036	$ 4.7	$ 30.2	$ 15.0	$ 23.6	$ 10.4	$ 8.4	5.0	**1.8**	$ 1.6	15.2	$ 5.9	4.0	$ 3.2	7.3
2037	$ 4.6	$ 30.9	$ 15.0	$ 23.7	$ 10.7	$ 8.4	5.1	**1.8**	$ 1.6	15.3	$ 5.9	4.0	$ 3.2	7.3
2038	$ 4.7	$ 31.0	$ 15.0	$ 23.6	$ 11.0	$ 8.4	5.0	**1.8**	$ 1.6	15.2	$ 5.9	4.0	$ 3.3	7.3
2039	$ 4.9	$ 31.0	$ 15.0	$ 23.5	$ 11.4	$ 8.4	4.8	**1.8**	$ 1.6	15.1	$ 5.9	4.0	$ 3.3	7.1
2040	$ 4.8	$ 31.0	$ 15.0	$ 23.3	$ 11.6	$ 8.4	4.8	**1.8**	$ 1.6	15.0	$ 5.9	3.9	$ 3.5	6.7
2041	$ 4.9	$ 31.0	$ 15.0	$ 23.2	$ 11.8	$ 8.4	4.7	**1.7**	$ 1.6	15.0	$ 5.9	3.9	$ 3.6	6.5
2042	$ 5.0	$ 31.0	$ 15.0	$ 23.1	$ 12.1	$ 8.4	4.6	**1.7**	$ 1.6	14.9	$ 5.9	3.9	$ 3.6	6.4

52.2 Please provide in a table format the projected weighted average cost of RNG purchases ($/GJ) annually for the period 2022 to 2042, along with FEI's total effective rate ($/GJ).

<u>Response:</u>

Please refer to the response to CEC IR2 52.1.

53. Reference: FEI Response[16] to CEC IR 1.2.1



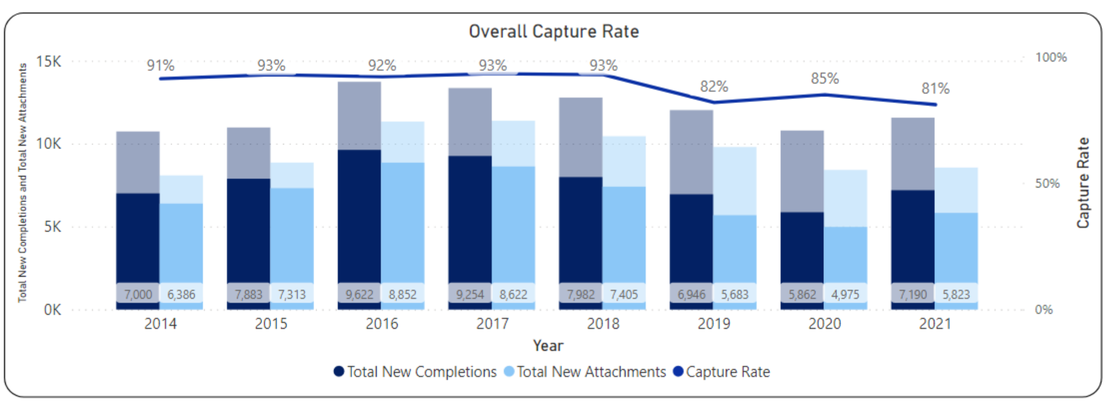
Housing construction has remained strong, but due to climate related policy actions by governments, FEI's share of the new residential construction market is declining and expected to decline further in the near term. Further, these policy actions will also impact existing customers potentially resulting in a further slowing of net customer growth.

53.1 In response to CEC IR 1.2.1, FEI advises of an overall decline in the market share (capture rate) of new residential construction since 2017, as illustrated in the graph provided. Please explain whether there were any differing trends as between detached, semidetached and/or multiple unit construction over this same period.

Response:

Yes, there are differing trends for the various types of construction as shown below. FEI's market capture rate is lower for multi-family building construction and condominiums. For example, in 2021, FEI's market capture rate was 48 percent for condominiums, 60 percent for townhomes and 81 percent for single-family homes.

Figure 1: FEI Historical Capture Rate Data for Single family Homes (2014- 2021)



[16] Exhibit B-12.

Figure 2: FEI Historical Capture Rate Data for Semi-Detached Homes (2014- 2021)

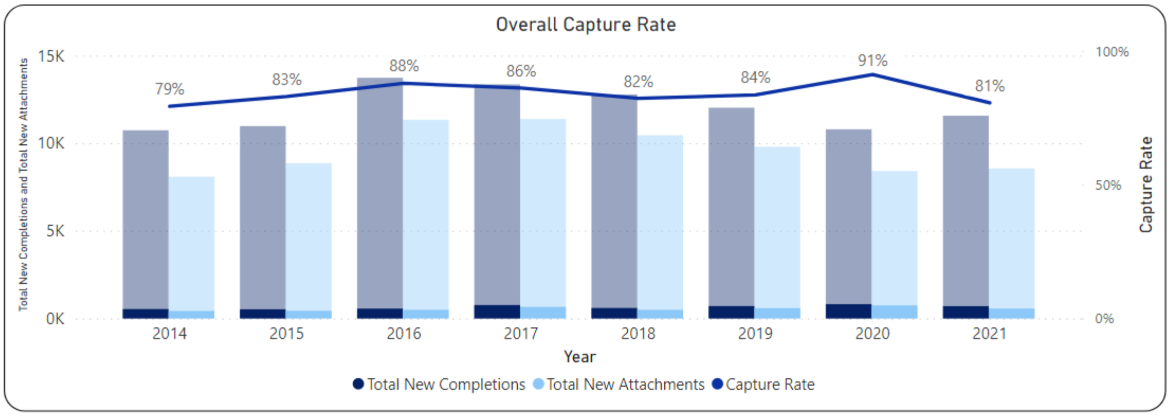
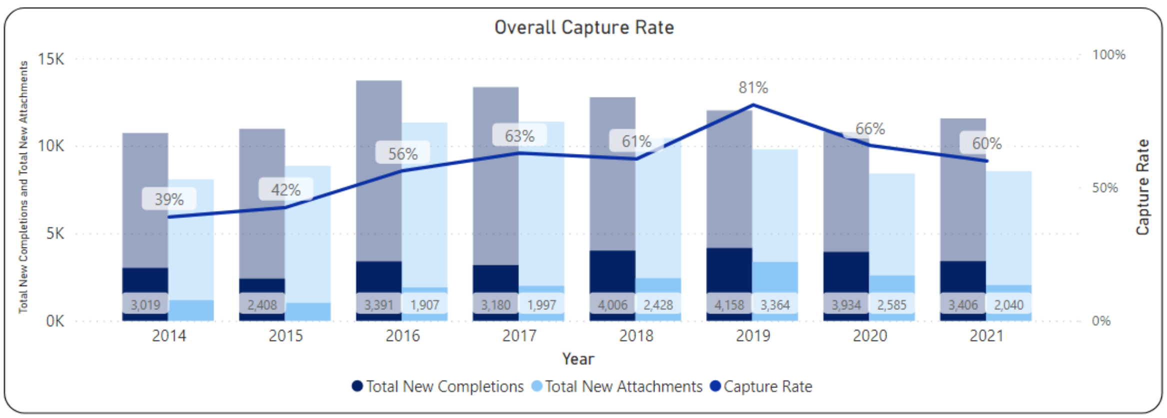


Figure 3: FEI Historical Capture Rate Data for Townhomes (2014- 2021)



For the condominium buildings market capture rate chart, please refer to the response to CEC IR2 53.2.

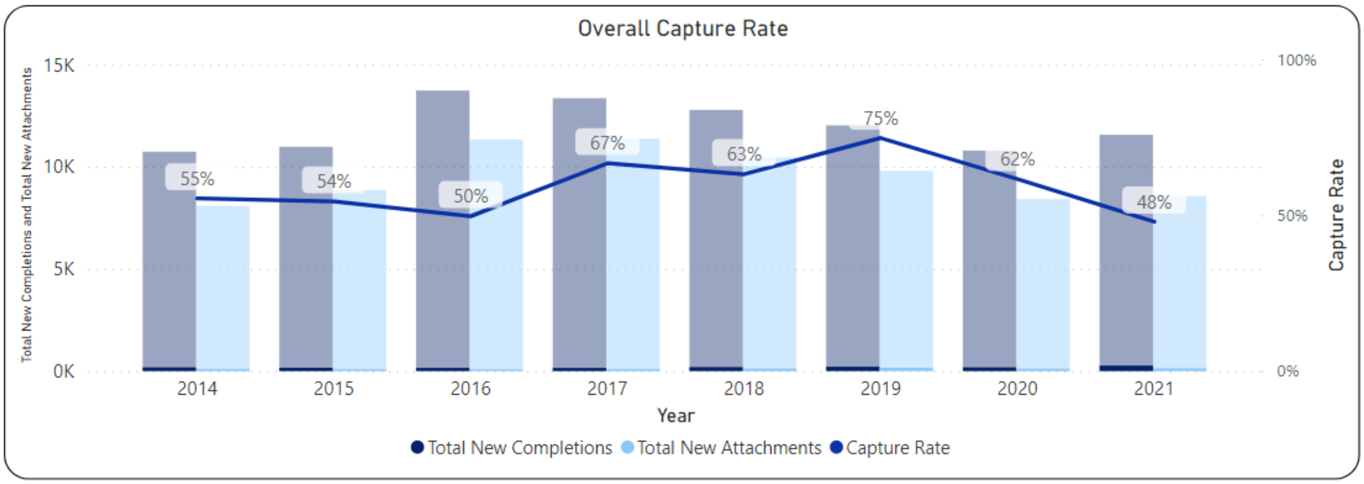
53.2 Please advise on whether FEI has analysis of similar trends (i.e. capture rate) occurring for the commercial sector, on account of local governments applying increasingly stringent regulations on buildings.

Response:

The diversity of industries within the commercial sector compounded by the diversity of gas appliance end uses creates limitations on FEI's ability to accurately analyze commercial market share or capture rates. That being said, FEI does have insight into the market share of new construction of condominium buildings, a subset of commercial customers. In these buildings, there is some crossover of nomenclature between residential building usage and commercial rate class. Technically, these are residential buildings; however, since the account is under the name of a strata corporation or property management firm, these buildings are typically cast under a commercial rate class.

Figure 1 below illustrates that FEI's market share of the new construction condominium market is declining in response to climate-related policy actions by governments, similar to the overall trends in the residential new construction market. However, the actual capture rate of commercial condominium market is much lower than residential new construction. In 2021, the commercial new construction capture rate was 48 percent while the capture rate of residential new construction was 74 percent.

Figure 1: FEI Historical Capture Rate Data for Condominium Buildings (2014- 2021)



53.3 Please elaborate on any trends observed with respect to the capture rate for new commercial construction.

Response:

Please refer to the response to CEC IR2 53.2

53.4 Please provide in a table format the carbon tax versus FEI's total effective rate ($/GJ) annually for the period 2022 (actual) to 2042 (projected). In providing the carbon tax, please provide both $ per Tonne of CO2e assumption and the equivalent $/GJ. Please provide FEI's total effective rate in $/GJ. Please provide the carbon tax as percentage of FEI's total effective rate (%).

Response:

Please see Table 1 below for the requested information using a carbon tax that grows to $140 per tonne CO2e by 2030. For this response, FEI used the forecasted carbon tax and effective rate information from the DEP Scenario for residential (RS 1) customers as an example. FEI notes that carbon tax is one of the contributors to FEI's cumulative projected rate increases of approximately 9 percent for the residential customer group by 2042, as shown in the response to BCUC IR1 75.5. Please also refer to BCUC IR2 117.1 which shows that the carbon tax contributed approximately 11 percent and 12 percent of the cumulative projected increases for small and large commercial customers, respectively. FEI also notes that carbon tax is not the only component of FEI's projected rate increase that is related to climate change policies. Please refer to the response to BCOAPO IR2 18.1 which shows that almost 60 percent of FEI's projected cumulative rate increase by 2042 can be attributed to climate change policies.

Table 1: Breakdown of FEI's 2022-2042 Total Effective Rates and Carbon Tax under the DEP Scenario for Residential Customers

Year	Carbon Tax ($/Tonne)	Effective Carbon Tax ($/GJ)	FEI Effective Rate ($/GJ)	Total Effective Rate ($/GJ)	% (Carbon Tax/Total Effective)
2022	$ 50	$ 2.488	$ 14.662	$ 17.150	15%
2023	$ 61	$ 2.965	$ 16.025	$ 18.990	16%
2024	$ 74	$ 3.519	$ 17.535	$ 21.054	17%
2025	$ 86	$ 3.983	$ 19.184	$ 23.166	17%
2026	$ 98	$ 4.416	$ 21.675	$ 26.090	17%
2027	$ 109	$ 4.777	$ 23.346	$ 28.123	17%
2028	$ 120	$ 5.124	$ 23.897	$ 29.021	18%
2029	$ 130	$ 5.382	$ 25.229	$ 30.611	18%
2030	$ 140	$ 5.581	$ 26.500	$ 32.081	17%
2031	$ 140	$ 5.460	$ 27.172	$ 32.632	17%
2032	$ 140	$ 5.345	$ 28.063	$ 33.408	16%
2033	$ 140	$ 5.223	$ 28.858	$ 34.081	15%
2034	$ 140	$ 5.108	$ 29.411	$ 34.519	15%
2035	$ 140	$ 4.985	$ 30.098	$ 35.083	14%
2036	$ 140	$ 4.867	$ 30.729	$ 35.596	14%
2037	$ 140	$ 4.741	$ 31.338	$ 36.079	13%
2038	$ 140	$ 4.620	$ 31.827	$ 36.448	13%
2039	$ 140	$ 4.495	$ 32.248	$ 36.743	12%
2040	$ 140	$ 4.376	$ 32.544	$ 36.920	12%
2041	$ 140	$ 4.256	$ 32.894	$ 37.149	11%
2042	$ 140	$ 4.140	$ 33.181	$ 37.321	11%

For clarity, the effective carbon tax rates in dollars per GJ shown in Table 1 above are calculated based on the carbon tax in dollars per tonne and the annual estimated percentage mix between conventional natural gas and renewable gas under the DEP Scenario as shown in the response to BCUC IR1 71.8.1. For example, if the gas in FEI's system consists of 70 percent conventional natural gas, then the effective carbon tax rate in dollars per GJ will be calculated based on the portion of conventional natural gas only – i.e., the carbon tax value multiplied by 70 percent. FEI also notes that the percentage of carbon tax rate over the total effective rate begins to decline in 2031 and this is because the carbon tax in dollars per tonne is assumed to be held at the same level beyond 2030 while FEI's effective rates (i.e., delivery, cost of gas, storage and transport charge) will continue to increase beyond 2030.

Table 2 below provides the effective carbon tax rate based on the committed carbon tax plan that reaches $170 per tonne CO2e by 2030. The percentage of carbon tax to the total effective rate has increased from 17 percent in 2030 in Table 1 above to 20 percent in 2030 in Table 2 below.

Table 2: Breakdown of FEI's 2022-2042 Total Effective Rates and Carbon Tax under the DEP Scenario for Residential Customers and Carbon Tax Reaching $170 per tonne by 2030

Year	Carbon Tax ($/Tonne)	Effective Carbon Tax ($/GJ)	FEI Effective Rate ($/GJ)	Total Effective Rate ($/GJ)	% (Carbon Tax/Total Effective)
2022	$ 50	$ 2.488	$ 14.662	$ 17.150	15%
2023	$ 65	$ 3.159	$ 16.025	$ 19.185	16%
2024	$ 80	$ 3.804	$ 17.535	$ 21.339	18%
2025	$ 95	$ 4.400	$ 19.184	$ 23.583	19%
2026	$ 110	$ 4.956	$ 21.675	$ 26.631	19%
2027	$ 125	$ 5.478	$ 23.346	$ 28.824	19%
2028	$ 140	$ 5.978	$ 23.897	$ 29.875	20%
2029	$ 155	$ 6.417	$ 25.229	$ 31.646	20%
2030	$ 170	$ 6.776	$ 26.500	$ 33.277	20%
2031	$ 170	$ 6.630	$ 27.172	$ 33.802	20%
2032	$ 170	$ 6.491	$ 28.063	$ 34.554	19%
2033	$ 170	$ 6.343	$ 28.858	$ 35.200	18%
2034	$ 170	$ 6.203	$ 29.411	$ 35.613	17%
2035	$ 170	$ 6.054	$ 30.098	$ 36.152	17%
2036	$ 170	$ 5.909	$ 30.729	$ 36.639	16%
2037	$ 170	$ 5.756	$ 31.338	$ 37.095	16%
2038	$ 170	$ 5.610	$ 31.827	$ 37.438	15%
2039	$ 170	$ 5.458	$ 32.248	$ 37.706	14%
2040	$ 170	$ 5.314	$ 32.544	$ 37.857	14%
2041	$ 170	$ 5.168	$ 32.894	$ 38.061	14%
2042	$ 170	$ 5.028	$ 33.181	$ 38.209	13%

54. Reference: FEI Response[17] to CEC IR 1.3.4

> 3.4 Where it concerns customer service, particularly for commercial, industrial and remote customers, would a closer integration of electricity and gas systems typically lead to increased (or decreased) resiliency of systems and/or solutions? Please explain why with quantification where possible.
>
> **Response:**
>
> FEI considers that customer service for commercial, industrial and remote customers could benefit from a closer integration of electricity and gas systems leading to increased resiliency of systems and/or solutions. The increasing volume of extreme weather events witnessed in recent years leads FEI to conclude that the use of the gas system, combined with increasing integration of energy systems closer to and at the end-use location, will be critical for decarbonizing BC's economy. Decarbonization initiatives must ensure continued access to reliable, resilient, and cost-effective energy service to FEI customers, and to the benefit of non-customers who rely on the services and products delivered by FEI customers. Therefore, the integration of electricity and gas systems, resulting in increased resiliency for BC's energy system as a whole, will benefit all British Columbians.

54.1 How do the needs of remote BC communities inform FEI's LTGRP?

Response:

FortisBC is an integrated energy provider in BC and as such, FortisBC will continue to look at opportunities to support remote BC communities through both its gas and electric service offerings. FEI believes that LNG presents a good opportunity to support remote communities' transition away from diesel, and FEI has been actively pursuing this market. In the LTGRP, FEI has included a forecast for the Remote Power and Mining Industry Growth demand category for LNG. Please refer to the table included in the response to BCUC IR1 33.7.

54.2 What plans if any, are embedded in the LTGRP in support of increased resiliency of solutions for those BC communities that are presently under-served or isolated (i.e., from electricity and/or the gas systems)?

Response:

The Action Plan included in Section 10 of the Application includes actions that will support increased resiliency of solutions for those BC communities that are presently under-served or isolated (i.e., from electricity and/or the gas systems). Though not identified in detail, such actions can be categorized under Action Plan Item 8 (continue monitoring, analyzing and contributing to the energy planning environment while working with government on policy framework for deep decarbonization) and Action Plan Item 9 (protect and promote the interests of FEI's customers by

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[17] Exhibit B-12.

securing reliable, cost-effective, long-term gas supplies that include increasing proportions of renewable and low-carbon gas).

FEI considers that the action of providing service to these communities will inherently improve energy resiliency for these communities. The amount of demand from these isolated communities is small enough to be captured in FEI's long range supply and system outlooks without being separately forecasted. Further details of actions to address resiliency for such communities are a matter for shorter-term planning on a project-by-project basis for FEI and partners once such opportunities are sufficiently advanced, and so are not laid out in detail in the LTGRP.

54.3 Please explain whether, in developing the LTGRP, FEI considered scenarios for LNG solutions as part of electrification opportunities for remote BC communities and/or remote commercial or industrial business? If so, please provide the 20-year outlook for this type of service.

Response:

Yes, FEI has included a forecast of LNG for remote power and mining. Please refer to the responses to BCUC IR1 33.7 and BCUC IR1 33.8. The 20-year forecast for remote power and mining is shown in the following table for the Planning Setting. The forecast does not have a breakdown between remote power and mining, as they are assumed to be a single market sector.

Remote Power and Mining Load	
Year	**Planning Setting (GJs)**
2023	-
2024	425,000
2025	850,000
2026	1,275,000
2027	1,700,000
2028	2,125,000
2029	2,550,000
2030	2,975,000
2031	3,012,500
2032	3,118,750
2033	3,225,000
2034	3,331,250
2035	3,437,500
2036	3,543,750
2037	3,650,000
2038	3,756,250
2039	3,862,500
2040	3,968,750
2041	4,075,000
2042	4,181,250

54.4 As FEI plans to increasingly cater to displacing higher carbon fuels (such as coal and oil) in international markets, what does it make of the role of natural gas and/or LNG in displacing diesel fuel presently used for power generation in certain remote BC communities?

Response:

FEI believes that LNG can play an important role in displacing diesel fuel presently used for power generation in certain remote communities; however, there still exists significant barriers to making the transition, including the delivered cost of LNG to these remote communities due to long transportation distances, and low economies of scale, as these remote communities may not use a lot of energy. FEI will need to remain flexible and adaptable for this market as the industry is constantly evolving with new technology. FEI will continue to engage with stakeholders in support of displacing diesel fuel in remote communities and will actively pursue this opportunity to reduce emissions in remote BC communities.

55. Reference: FEI Responses[18] to CEC IR 1.4.1 and CEC IR 1.4.2

Planned Supply Portfolio Compared to Peak Day Demand (2012/13 to 2022/23)

Peak Day Portfolio	2012/13 (TJ/day)	2014/15 (TJ/day)	2016/17 (TJ/day)	2018/19 (TJ/day)	2020/21 (TJ/day)	2022/23 (TJ/day)
Fort Nelson Supply	5	5	5	5	5	5
Baseload Supply	331	345	331	374	416	417
Seasonal Supply	132	115	175	151	134	127
Seasonal Storage	195	197	195	197	201	201
Spot Supply	105	91	46	49	109	128
Market Area Storage	213	215	211	211	211	211
Peaking LNG (Mt.Hayes & Tilbury)	326	326	326	326	326	326
Industrial Curtailment	26	28	28	28	29	26
Total Resources (TJ/day)	**1,333**	**1,322**	**1,317**	**1,341**	**1,431**	**1,441**
Peak Day Demand (TJ/day)	**1,333**	**1,322**	**1,317**	**1,341**	**1,431**	**1,441**
% of Peak Day Demand (Market Area Storage/ Industrial Curtailment/Peaking LNG)	**42%**	**43%**	**43%**	**42%**	**40%**	**39%**

*FEI has the right to curtail Rate Schedule 22A customers and use their gas during each gas year (5-days maximum). The supply fluctuation is a result of industrial customers swiching rate schedules or closing their facilities.

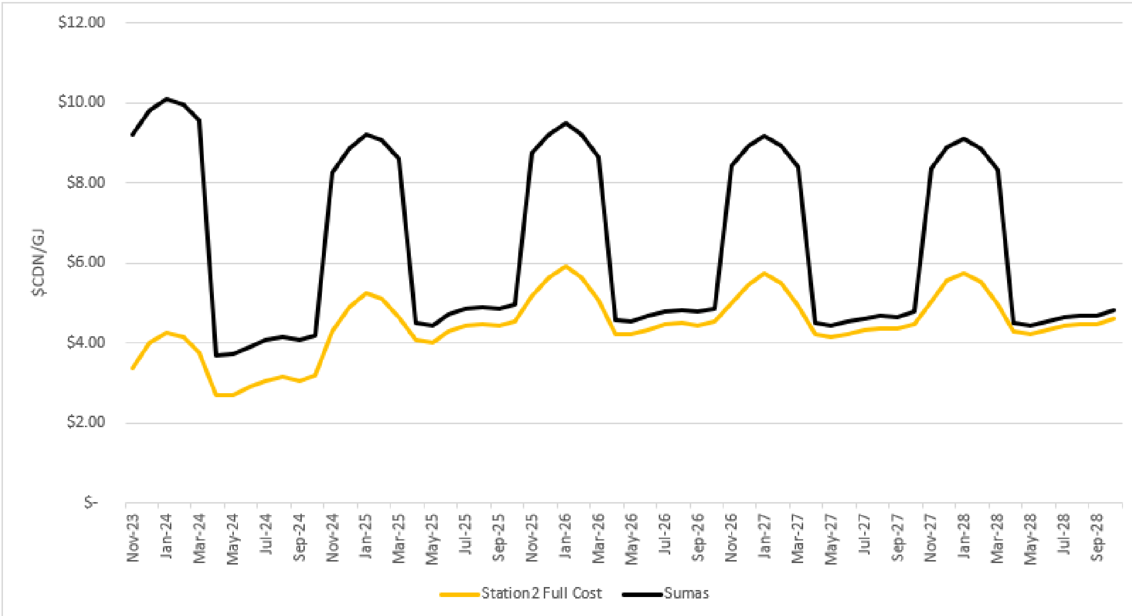
55.1 In response to CEC IR 1.4.1, FEI advises that it generally delivers its baseload supply through its contracted capacity on the Westcoast, NGTL and Foothills systems. The CEC calculates that FEI's baseload supply increased by approximately 26% between 2012/13 and 2022/23. Are there any physical limitations to FEI's ability to increase contracted capacity on these systems in the future?

<u>Response:</u>

At this time, there are physical limitations to FEI's ability to increase contracted capacity on these systems because the resources in the region are fully contracted and constrained during the winter season. FEI has mitigated some of this future risk by securing firm resources above the current load forecast for Core customers, as discussed in Section 6.2.4 of the Application. However, absent new infrastructure in the region, FEI will likely pay a significantly higher cost in the future if additional resources are required. FEI would have to try to secure pipeline capacity from counterparties that currently hold capacity on Westcoast's T-South system in the secondary market. FEI believes the costs for obtaining that resource will be closely tied to the forward price at the Sumas/Huntingdon market, which is significantly higher than Station 2 full costs, as illustrated below:

[18] Exhibit B-12.

Figure 1: Station 2 Full Cost and Sumas Forward Price Comparison[19]



For example, if FEI hypothetically required an additional 20,000 GJ/day of pipeline capacity for the 2023/24 gas year due to forecasted load growth, the costs could be as high as $27.2 million (based on the forward settlement prices as of April 3, 2023).

Table 1: Estimated Annual Cost for Securing Additional T-South Capacity (Market Price)				
November 2023 to October 2024	$3.73/GJ (T-South Value)	20,000 (GJ/day)	365 (Days)	$ 27.2 million

FEI believes these premiums will likely remain high until new infrastructure is built. It is also important to consider the costs illustrated in Table 1 are well higher than the existing toll on Westcoast as well as the estimated costs for a future Westcoast T-South expansion, as shown below.

Table 2: Estimated Annual Cost for Securing Additional Capacity (Based on Existing Tolls and Future Expansion Tolls)			
$0.60/GJ (Westcoast 2023 Interim Toll)	20,000 GJ/day	365 (Days)	$ 4.4 million
$1.00/GJ (Estimated Westcoast Expansion)	20,000 GJ/day	365 (Days)	$ 7.3 million

[19] Graph is based off indicative forward pricing provided by Amerex on April 3, 2023. Station 2 Full Cost includes Station 2 forward monthly price, T-South fuel, Westcoast 2023 Interim Tolls, Motor Fuel Tax and Carbon Tax.

55.2 Please confirm that FEI uses seasonal supply and spot supply as complementary resources in planning to meet peak day demand.

Response:

Confirmed.

55.3 Please comment on the trade-offs between the use of seasonal supply versus spot supply, including liquidity (supply) and market pricing considerations.

Response:

FEI's management of its seasonal (winter) and spot supply requirements must first consider how much supply is required at the AECO/NIT and Station 2 market to fill its contracted capacity on the Westcoast and TC Energy pipeline systems, of which along with FEI's baseload supply (provided in the table in the preamble) would meet the peak day demand. FEI does also have some excess seasonal and spot supply in its portfolio for resiliency purposes (i.e., contingency resources[20]) which FEI would consider as complementary (i.e., additional) resources to the peak day portfolio. Given the significant amount of T-South capacity that FEI contracts to manage winter load requirements, FEI does consider the liquidity at the Station 2 market when determining how much supply should be termed up (seasonal supply) and how much supply can be left on the day to purchase (spot).

For example, the Station 2 market is illiquid compared to AECO/NIT, due to its smaller market size, and has a lower number of participants (suppliers and end users). Station 2 physically delivers 2 billion cubic feet per day (Bcf/day) compared to 12 Bcf/day at AECO/NIT. Therefore, purchasing a significant amount of spot supply in a relatively small market can adversely affect the pricing and security of supply at Station 2, under certain market conditions.

This can also apply to the producers in the region, as they would prefer having a portion of their supply locked in a seasonal term to avoid having too much exposure on the day. Given these developments, FEI typically terms up more of its winter load requirements compared to its spot purchases at Station 2. However, FEI would be reluctant to completely avoid spot supply purchases at Station 2 as it would remove the daily interactions and relationship that FEI currently maintains and fosters with its counterparties.

[20] See Section 6.2.4.1 of the Application. Contingency resources are not illustrated in the table in the preamble.

The trade-offs between FEI utilizing spot or seasonal supply at the AECO/NIT hub are relatively minor compared to Station 2. This is because the AECO/NIT market is one of the most liquid natural gas trading hubs in North America, and FEI's winter supply requirements at AECO/NIT are significantly lower compared to Station 2.

The significant increase in spot supply from 2018/19 to 2020/21, as illustrated in the preamble above, is on account of FEI's return to the East Kootenay marketplace due to the incremental capacity that FEI secured on SCP.[21] This supply requirement is above FEI's contracted capacity on the TC Energy pipeline system, so FEI has negotiated a mix of call option arrangements and purchases on the spot market, only when required. Based on market pricing considerations and internal analysis showing a minimal number of days that this supply was required, this was a more cost-effective approach than terming up the supply.

55.4 Please advise whether the planned Tilbury LNG Storage Expansion (TLSE) project will augment FEI's peaking LNG capabilities, and if so, by how much.

Response:

The proposed 3 Bcf storage tank and 800 MMcf per day (approximately 880 TJ per day) of regasification capacity was sized and designed for resiliency purposes while also providing ancillary gas supply benefits. One of the gas supply benefits includes enhancing FEI's peaking LNG capabilities to meet its forecast peak day demand requirements. When incorporating the TLSE project with FEI's other gas supply resources, Tilbury's peaking LNG capabilities could increase above 163 TJ per day[22] to something higher (up to 880 TJ per day), depending on the load forecast, which results in a more efficient portfolio that offers value to customers.

55.5 Please provide the average cost of each of the portfolio supply options for each of the years in the Table provided in response to CEC 1.4.1.

Response:

The table provided in the response to CEC IR1 4.1 (and replicated in the preamble above) provided a summary of the natural gas supply portfolio resources as filed in the Annual Contracting Plan (ACP) for each of the indicated years. The table provided data for every second gas year from the 2012/13 gas contracting year through to the 2022/23 gas contracting year. FEI

[21] As discussed in Section 6.2.4, a portion of pipeline capacity on SCP was historically contracted out to regional parties. However, FEI took back this capacity effective November 1, 2020, as it was the only opportunity in the marketplace for FEI to diversify its supply portfolio.

[22] The existing Tilbury Base Plant has 163 TJ per day of regasification capacity.

does not specifically track or report costs by each line shown in the table that is provided in the preamble above.

After BCUC acceptance of the relevant ACP, FEI contracts its natural gas supply resources. The costs related to the natural gas supply resources contracted are then captured in various accounts and are recovered via various gas cost recovery rates. Further, FEI utilizes calendar-based quarterly and annual periods, rather than gas contracting year periods; directly correlating with how gas costs and recoveries are reported to the BCUC and, under normal circumstances, how gas cost recovery rates are reviewed.

FEI has prepared the information for each of the eight consecutive calendar years from 2015 to 2022. Commencing in 2015, the annual data provides greater year to year comparability as it corresponds with the December 31, 2014, amalgamation of FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) with FEI and the implementation of common gas cost recovery rates effective January 1, 2015.

The following table provides the recorded costs, quantities, and a calculated average cost for the Fort Nelson natural gas supply portfolio for the years 2015 to 2022.

Fort Nelson Service Area Natural Gas Supply Portfolio Annual Costs

		2015	2016	2017	2018	2019	2020	2021	2022
Fort Nelson GCRA (Gas Cost Reconciliation Account)									
Costs Incurred	($000)	$ 1,132.5	$ 1,021.6	$ 906.7	$ 779.2	$ 683.7	$ 1,141.1	$ 1,751.3	$ 2,449.5
Quantity [(a)]	(TJ)	510.9	499.8	489.8	500.4	479.4	511.8	532.3	541.9
Average Cost	($/GJ)	$ 2.22	$ 2.04	$ 1.85	$ 1.56	$ 1.43	$ 2.23	$ 3.29	$ 4.52

Notes: (a) Quantity based on the recorded annual gas cost recovered quantities.

Slight differences in totals due to rounding

The following table provides the recorded costs, quantities, and a calculated average cost for the FEI – Mainland and Vancouver Island service area natural gas supply portfolio for the years 2015 to 2022.

FEI - Mainland and Vancouver Island Service Area Natural Gas Supply Portfolio Annual Costs

		2015	2016	2017	2018	2019	2020	2021	2022
FEI Baseload Commodity - CCRA (Commodity Cost Reconciliation Account)									
Costs Incurred	($000)	$ 275,742.0	$ 205,519.1	$ 235,573.9	$ 223,103.8	$ 204,294.1	$ 318,858.4	$ 506,701.1	$ 771,728.4
Quantity [(a)]	(TJ)	116,740.8	117,231.0	119,909.7	131,282.5	133,048.2	146,207.7	144,427.8	146,060.3
Average Cost	($/GJ)	$ 2.36	$ 1.75	$ 1.96	$ 1.70	$ 1.54	$ 2.18	$ 3.51	$ 5.28
Customer Choice Marketers Baseload Commodity									
Costs Incurred	($000)	$ 29,752.2	$ 24,920.4	$ 21,810.2	$ 20,301.9	$ 20,325.7	$ 21,280.7	$ 24,247.6	$ 32,013.4
Quantity [(a)]	(TJ)	5133.0	4338.0	3816.1	3721.4	3908.9	4676.1	4857.1	5,776.8
Average Cost	($/GJ)	$ 5.80	$ 5.74	$ 5.72	$ 5.46	$ 5.20	$ 4.55	$ 4.99	$ 5.54
FEI Midstream - MCRA (Midstream Cost Reconciliation Account)									
Costs Incurred [(b)]	($000)	$ 97,960.0	$ 113,056.7	$ 87,724.4	$ 177,997.3	$ 188,029.2	$ 186,092.0	$ 175,499.0	$ 87,624.0
Quantity [(c)]	(TJ)	111,004.1	117,034.8	136,825.7	129,489.4	140,297.1	149,996.3	155,366.5	163,536.0
Average Cost	($/GJ)	$ 0.88	$ 0.97	$ 0.64	$ 1.37	$ 1.34	$ 1.24	$ 1.13	$ 0.54

Notes: (a) Quantity based on the baseload quantities available for load.

(b) Costs incurred include the costs related to the commodity, storage, and transportation resources, net of the mitigation revenues.
The 2021 and 2022 Costs Incurred amounts have been adjusted to exclude the Revelstoke propane supply costs.

(c) Quantity based on the recorded annual gas cost recovered quantities, excluding any RNG related sales.
The 2021 and 2022 Quantity amounts have been adjusted to exclude the Revelstoke propane related sales.

Slight differences in totals due to rounding

The data provided within the tables is consistent with how the forecast and recorded costs, quantities, and recoveries are tracked and reported to the BCUC within FEI's quarterly / annual gas cost reports.

56. Reference: FEI Response[23] to CEC IR 1.6.3

Table 1: Percentage GHG Emission Reductions (End Use) Over the 2007 Emissions Baseline for FEI's Residential, Commercial and Industrial Customer Types for Milestone Years in the DEP Scenario

		Diversified Energy (Planning) - GHG Emissions (Mt CO2e) Residential, Commercial and Industrial Customer Types			
	2007	2019	2030	2040	2042
FEI Total GHG Emissions (Mt CO2e)	10.9	10.7	5.7	4.3	3.9
Percent Reduction over 2007 Base Level		1.3%	47.6%	60.8%	64.4%

The DEP Scenario for residential, commercial and industrial customer types meets the BC-legislated GHG emissions reduction target of 60 percent reduction over the 2007 baseline by 2040, as illustrated in Table 1.

56.1 Please provide in a table format (similar to Table 1 provided in response to CEC IR 1 6.3) a breakdown of GHG emissions by customer type (residential, commercial and industrial) for each of the milestone years in the DEP scenario, along with a breakdown by customer type of the contribution to the 'GHG emissions percent reductions over 2007 base level'.

Response:

Please refer to the response to BCUC IR1 72.2 which illustrates a breakdown of GHG emissions by customer type for each of the milestone years in the DEP Scenario as illustrated in Table 1 below. The breakdown by customer type as a percentage of reductions over the 2007 base level as described in the preamble is illustrated in Table 2 below.

Table 1: GHG Emissions (End Use Emissions) (Mt CO_2e) for Residential, Commercial and Industrial Customers for the DEP Scenario

Customer Type		Diversified Energy (Planning) (Mt CO_2e)			
	2007	2019	2030	2040	2042
Residential		3.8	1.9	1.4	1.3
Commercial		3.1	1.9	1.5	1.4
Industrial		3.7	1.9	1.4	1.2
FEI Total GHG's	10.9	10.7	5.7	4.3	3.9

Table 2: GHG Emissions (End Use Emissions) as a Percentage of Reductions Over 2007 Base Levels for Residential, Commercial and Industrial Customers for the DEP Scenario

Customer Type	Diversified Energy (Planning) 2007 Baseline Emissions (Percentage)			
	2019	2030	2040	2042
Residential	0.5%	16.0%	19.7%	21.0%
Commercial	0.4%	16.0%	21.7%	23.3%
Industrial	0.4%	15.6%	19.3%	20.2%
Percent Reduction over 2007 Base Level	1.3%	47.6%	60.7%	64.4%

[23] Exhibit B-12.

56.2 Please describe how the GHG reductions will be achieved, and for each category of emission reduction approach, please provide the quantity projected and the price for achieving the reductions for each timeframe in the Table above.

Response:

This response also addresses MS2S IR2 11.2 which asks for similar information, but in an expanded format including a breakdown of DSM initiatives by customer type and renewable and low-carbon gas by type (RNG versus hydrogen).

Consistent with the preamble, FEI provides the categories of emission reduction initiatives, the associated annual emission reductions, and the annual investments that are required to achieve these investments. In Table 1 below, FEI summarizes this information and has broken down the information into sub-categories to address the response to MS2S IR2 11.2. This information is also available in previous IR responses as follows:

- BCUC IR1 72.2 and 74.2 describes the categories of GHG reduction initiatives FEI is undertaking and the forecast of associated emission reductions;
- BCUC IR1 72.2.1 provides emissions by customer type;
- Table 5-4 in the Application illustrates the annual investments in the DEP Scenario High DSM Setting; and
- BCUC IR1 71.8.1 illustrates the annual costs of acquiring renewable and low-carbon gas supply.

FEI notes that it is not making investments related to pre-DSM demand reductions (natural efficiency and fuel switching) as incentive programs that might influence such reductions are offered through provincial and federal programs, BC Hydro, and local governments.

Table 1: Overview of FEI's Total Emissions[24] (End-Use) and Emission Reduction Activities and Their Associated Annual Expenditures

Clean Growth Pathway Categories Annual Emission Reduction	Annual Emission Reductions ($Mt\ CO_2e/Yr$)			Annual Expenditures (Millions)		
	2030	2040	2042	2030	2040	2042
Pre-DSM Reduction (Electrification and Natural Efficiency)	0.4	0.9	1.0	N/A	N/A	N/A
Residential DSM Program Area	0.3	0.4	0.4	$ 75	$ 48	$ 25
Commercial DSM Program Area	0.3	0.5	0.6	$ 103	$ 53	$ 43
Industrial DSM Program Area	0.2	0.3	0.3	$ 5	$ 3	$ 2
DSM Demand Reduction (High DSM Setting) - Total	0.9	1.3	1.3	$ 183	$ 104	$ 70
RNG, Syngas and Lignin	1.9	2.3	2.4	$ 1,037	$ 1,435	$ 1,481
Hydrogen, CCUS	1.1	2.6	3.0	$ 335	$ 872	$ 979
Renewable and Low-Carbon Gas Supply - Total	3.0	4.9	5.3	$ 1,373	$ 2,308	$ 2,460
FEI Additional Actions (Under development)	0.9			N/A	$ -	$ -
Total Reductions	**5.2**	**7.1**	**7.6**	**$ 1,556**	**$ 2,412**	**$ 2,530**
FEI Total Remaining GHG Emissions	5.7	4.3	3.9			

[24] FEI's Total Demand GHG's include emission reductions from non-DSM reductions (natural efficiency and fuel switching), DSM, renewable and low-carbon gas supply.

57. Reference: FEI Response[25] to CEC IR 1.7.1

57.1 Please provide FEI's projections for the total number of customers in the LTGRP time horizon, broken down by customer type (residential, commercial and industrial) annually (or for each of the milestone years) in the DEP scenario.

Response:

Please see Table 1 below illustrating the total number of forecast customers, broken down by customer type (residential, commercial and industrial) annually in the DEP Scenario.

Table 1: DEP Scenario Forecast for Residential, Commercial and Industrial Customers[26]

Year	Residential	Commercial	Industrial	Total
2019	942,769	96,880	1,325	1,040,974
2020	952,204	97,997	1,328	1,051,529
2021	959,904	99,157	1,331	1,060,392
2022	968,373	100,310	1,333	1,070,016
2023	975,522	101,471	1,335	1,078,328
2024	982,245	102,631	1,338	1,086,214
2025	988,426	103,785	1,338	1,093,549
2026	994,357	104,966	1,338	1,100,661
2027	1,000,045	106,147	1,338	1,107,530
2028	1,005,513	107,337	1,338	1,114,188
2029	1,010,764	108,541	1,338	1,120,643
2030	1,015,826	109,728	1,338	1,126,892
2031	1,020,705	110,934	1,337	1,132,976
2032	1,025,417	112,152	1,337	1,138,906
2033	1,029,967	113,372	1,337	1,144,676
2034	1,034,365	114,583	1,337	1,150,285
2035	1,038,609	115,796	1,337	1,155,742
2036	1,042,710	116,997	1,337	1,161,044
2037	1,046,668	118,179	1,337	1,166,184
2038	1,050,486	119,356	1,337	1,171,179
2039	1,054,180	120,515	1,337	1,176,032
2040	1,057,756	121,663	1,337	1,180,756
2041	1,061,334	122,814	1,337	1,185,485
2042	1,064,902	123,978	1,337	1,190,217

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25 Exhibit B-12.

26 Rate Schedule 46 (LNG - natural gas for transportation accounts) is not included.

58. Reference: FEI Responses[27] to CEC IR 1.7.2 and CEC IR 1.2.1

> 7.2 To what extent, if any, would 'sharing costs, between electric and gas systems, across a diverse set of customer segments' be a departure from past practices or present planning anticipated?
>
> **Response:**
>
> FEI clarifies that "sharing costs across a diverse set of customer segments" as referenced in the preamble is referring to FEI's DEP Scenario which would allow British Columbians to benefit from an overall reduced level of costs by maintaining both BC's gas and electric infrastructure while sharing the costs of ongoing innovation and acceleration of decarbonization to both systems. The costs and the resulting rate impact of decarbonization of the gas system will be borne by FEI's customers while the costs and the resulting rate impact for the electric system will be borne by the electric customers.

> ***Summary***
>
> In summary, the competitive environment for FEI's products has grown more complex as a multitude of pricing and non-price considerations are influencing customer energy choices. Decarbonizing FEI's gas supply in response to climate policy will result in higher rates for FEI customers, reducing FEI's price competitiveness when compared to other energy alternatives. Unfortunately, if municipal and provincial policy does not change it may be difficult to attach new customers and keep existing customers despite a low-carbon offering. However, action is necessary to meet the GHG emission targets set out in the CleanBC Roadmap and to respond with urgency to address climate change, just as electrification will also result in increased costs for ratepayers and taxpayers.

58.1 Please confirm that 'sharing the costs of ongoing innovation and acceleration of decarbonization to both systems' will result in, all else equal, higher costs to be borne by FEI's (i.e. gas) customers and higher costs to be borne by the electric customers.

<u>Response:</u>

Not confirmed. FEI agrees that the energy transition will increase costs to be borne by both gas and electric customers; however, the evidence in Appendix A-2 and A-9 of the Application, which addresses the energy needs from a system-wide perspective through a diversified energy future, where the costs of ongoing innovation and acceleration of decarbonization is shared, will lessen the impact of rate increases for all customers on both the gas and electric systems. Please also refer to the responses to MoveUP IR1 1.2 and 1.3.

58.2 Please confirm that most commercial and industrial customers of FEI are both gas and electric customers, in that they consume both gas and electricity in the normal course of their ongoing business.

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[27] Exhibit B-12.

Response:

Confirmed.

58.3 Please confirm that, as per FEI's 'Summary' paragraph in response to CEC IR 1.2.1 included above, all else equal, if FEI encounters a future scenario where it may become more difficult to attach new customers and keep existing customers despite a low carbon offering, then the costs of decarbonizing FEI's gas supply to be borne by its remaining customer base will be even higher on a per individual customer basis.

Response:

Confirmed.

58.4 Does FEI anticipate, if it has a reduced load in the future, that its efforts to reduce emissions may provide its customers lower costs than they might otherwise have, based carbon tax reductions?

Response:

Please refer to the response to CEC IR2 58.1 which discusses that the DEP Scenario leads to overall lower costs than other scenarios. As shown in the responses to BCUC IR1 75.5 and BCUC IR2 117.1, the carbon tax is only one of the many contributors to the overall rate increases. In fact, the majority of the rate increase is due to the reduction in demand. For example, almost 40 percent of the cumulative rate increase by 2042 for residential customers under the Deep Electrification Scenario is due to the reduction in demand, while carbon tax contributed to about 10 percent, as shown in the response to BCUC IR2 117.1. Any reduction in carbon tax due to reduced load would be unlikely to offset the increase in rates due to the loss of demand in the gas system, which will be worse under the Deep Electrification Scenario than the DEP Scenario.

59. Reference: FEI Response[28] to CEC IR 1.8.1.2

> In addition, FEI invites regional districts and Indigenous communities located within proximity to the FEI service territory to participate in community and Indigenous engagement workshops. In some instances, regional districts or Indigenous communities may only be partially served by FEI given the proximity of FEI's system infrastructure to community lands. These communities were invited to the engagement process and had the opportunity to identify their energy priorities to FEI. Some communities with partial or no FEI energy service participated in community engagement sessions, and provided input to FEI on their energy priorities, such as but not limited to, extending FEI service to their communities.
>
> A common sentiment from these attendees that is different from attendees from locations within FEI's service area, and one which FEI takes into consideration, is the desire to connect their communities to FEI's gas system. This includes communities that are just outside of the current FEI service area and communities where large transmission pipes pass close to or through the respective communities, but where demand from the community is insufficient under current system extension policy to undertake the investment in the needed infrastructure to provide service.
>
> Further, through other business activities (besides LTGRP-specific engagement), FEI does receive feedback from representatives of more remote communities and industrial operations concerning the potential for providing service through deliveries of LNG via truck, rail or ship in order to, for example, reduce reliance on diesel as a fuel for heavy transportation or electricity generation. Such feedback is taken into account in the Application where these potential services are discussed. Finally, a growing consideration for Indigenous and other communities near or beyond the current limits of FEI's service territory is the potential opportunity to develop production facilities for renewable and low-carbon gas that could be acquired by FEI.

59.1 Please identify the market share (in PJ) which FEI plans to capture, in the 20-year horizon of the LTGRP, arising from extending service to BC communities which it presently does not serve, in terms of both gas service as well as potential for LNG to reduce reliance on diesel as fuel for heavy transportation or electricity generation.

<u>Response:</u>

FEI has not completed a detailed market assessment for the entire market potential of serving BC communities which they presently do not serve, although they may be located within close proximity of FEI's service territory, or for potential for LNG in remote communities to reduce reliance on diesel as fuel for heavy transportation or electricity generation.

In terms of extending gas connection to communities within close proximity, community consultation suggests a high degree of interest in accessing gas service as described in the response to CEC IR1 8.1.2. Further, in the response to CEC IR1 13.3, FEI notes that in addition to performing a mains extension (MX) test on a case-by-case basis, FEI works with the community to determine ways, such as reviewing economic development opportunities, to arrive at an economically feasible business case to provide access to gas service.

In terms of LNG service, FEI has completed forecasting scenarios for remote power and mining load that is intended to capture potential load growth scenarios for the sector. Please refer to the responses to BCUC IR2 94.4 and CEC IR2 54.3.

[28] Exhibit B-12.

FEI will continue to conduct market research and community consultation with regards to these growth opportunities and will provide further updates to their market potential in the next LTGRP.

59.2 If available, please provide a breakdown of the new (i.e., new service to those communities who are presently remote or underserved) market share by type of service (i.e., gas service; LNG for transportation; LNG for electricity generation), annually and/or for each of the milestone years in the DEP scenario.

Response:

Please refer to the response to CEC IR2 59.1.

60. Reference: FEI Responses[29] to CEC IR 1 9.2 and CEC IR 1 9.3 Series

60.1 In response to CEC IR 1.9.3.1, FEI provides Table 1: Overview of Considerations for Integrating Renewable and Low-Carbon Gas. Please specify where in its LTGRP planning cycle does FEI account for and incorporate these considerations? Do these considerations inform FEI's LTGRP, and if so, how? If not, please explain why not.

<u>Response:</u>

FEI's considerations for integrating renewable and low-carbon gas is the primary focus of the 2022 LTGRP, and the impact of this transition is incorporated into all aspects of the resource planning process, as outlined in the opening paragraphs of Executive Summary page ES-1 and Introduction page 1-1.

> This 2022 LTGRP is profoundly shaped by the developments in climate change policy in recent years and, in particular, the Province's 2018 CleanBC plan and CleanBC Roadmap to 2030 (Roadmap) which set out ambitious targets for reducing greenhouse gas (GHG) emissions. In response to these policies and the need to reduce GHG emissions, this 2022 LTGRP provides FEI's plan to transition to a low-carbon energy future and transition toward distributing renewable and low-carbon gas. Future resource plans will build on this plan as innovation in low-carbon gas production, supply and use advances.
>
> The foundation for the 2022 LTGRP and this transformational reduction in GHG emissions is FEI's existing infrastructure, service offerings, workforce and logistics, as well as the regional gas supply infrastructure that is vital to serving the energy needs of British Columbians. Table ES-1 provides a summary of FEI customer, demand and pipeline characteristics. Table ES-2 presents the renewable and low-carbon gas resources included in the 2022 LTGRP that, over the planning horizon, along with increased DSM and growth in fuel service for the low-carbon transportation (LCT) sector, are pivotal in reaching BC's GHG emission reduction goals.

More specifically, Table 1 below provides a high-level discussion of the key resource planning activities illustrated in Figure 1-2 in the Application, and how these activities support the integration of renewable and low-carbon gases in long-term planning.

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[29] Exhibit B-12.

1 **Table 1: How FEI's Incorporation of Renewable and Low-Carbon Gas Informs the 2022 LTGRP**

Steps in Resource Planning Process	Incorporation of Renewable and Low-Carbon Gas Considerations
1. Examining the Planning Environment	Climate change is dramatically impacting the physical, political, social and economic environment in which FEI operates. Governments at all levels are enacting environmental policies and regulations aimed at reducing GHG emissions. These evolving energy and environmental policies are key factors in the LTGRP planning environment and help inform FEI regarding potential impacts on future customer demand and supply over the planning horizon. The policy and regulatory environment are key considerations in FEI's transition to renewable and low-carbon gas. The competitive environment for FEI's products has grown more complex as a multitude of pricing and non-price considerations are influencing customer energy choices. Gas markets continue to be volatile and decarbonizing FEI's gas supply in response to climate policy puts upward pressure on gas costs.
2. Forecasting Energy Needs	Annual demand provides the basis for calculating GHG emissions and emission reductions. These calculations support FEI's renewable and low-carbon gas supply targets and the potential for DSM savings.
3. Determine DSM Potential	DSM activities over the planning horizon further reduce GHG emissions and promote energy conservation to all customer types. The future role of renewable and low-carbon gas in DSM programming and modelling is under discussion and will be included in the next LTGRP.
4. Gas Supply Portfolio	FEI's energy supply portfolio planning ensures that the forecast normal and peak day demand of core market (Core)[30] customers can be met. The considerations required for the transition to renewable and low-carbon gas was integrated within the traditional planning process that includes gas supply purchases, physical gas storage, pipeline resources, price risk management, pipeline and storage resources, and potential changes in demand or market conditions.
5. Examine Options for Growth and Sustainment	The system resource needs reflect the transition to delivering renewable and low-carbon gases in increasingly larger volumes over the planning horizon and the infrastructure changes required to accommodate this transition. These impacts were considered within system sustainment and renewal, integrity upgrades, and system expansion contributing to overall system resiliency. The physical properties of these gases, such as density and energy content per standard volume, can have an impact on capacity. Gases with physical properties within the range of conventional gas, such as RNG, will have no net impact on delivery capacity. Delivering hydrogen or a blend of hydrogen and natural gas or hydrogen and RNG, where the gas density and energy content are different from traditional natural gas supply, will change the energy delivery capacity. These are important considerations in capacity planning moving forward.
6. Establish Action Plan to meet Long-Term Resource Needs	The Action Plan describes the activities that FEI intends to pursue over the next four years based on the discussion and conclusions provided in this LTGRP. Action Item 1 is to "Accelerate the development and acquisition of renewable and low-carbon gas supplies to meet customer energy needs and contribute to provincial emission reduction targets". This illustrates the importance of this action item in FEI's long-term vision.

[30] Core customers refer to customers on Rate Schedules 1, 2, 3, 5, 6, 46 and excludes customers on Rate Schedule 4 (seasonal). FEI's gas supply portfolio includes the forecast normal, design, and peak day demand of these customers. Transportation Service customers arrange for their own supply that is then transported by FEI to their premises. System capacity planning (Section 7) needs to consider total system throughput to ensure that sufficient capacity exists on FEI's system to reliably deliver gas supply to meet the demand for both Core and Transportation service customers.

CEC seeks further information from discussions in the response to CEC IR1 9.3.1 pertaining to renewable and low-carbon gas considerations. These questions are listed in the responses to CEC IR2 60.2 to 60.5. For expediency, and comparative purposes, these considerations are summarized in Table 2 below. The materiality of the impact that these considerations had on the 2022 LTGRP planning process is noted in column 4 of the table.

Table 2: Additional Considerations Outlined in Response to CEC IR2 60.2 to 60.5

CEC IR2 IR #	Subject	Considerations in LTGRP	Material Impact
60.2	Emission Factors	Emission reduction is the key driver in FEI's transition to low-carbon energy. Therefore, all steps in the resource planning process are informed by Table 1-2 of the Application.	Yes
60.3	RNG Local Storage Solutions	Although this is not explicitly completed for the purposes of the LTGRP, FEI routinely evaluates requests for the connection of RNG production facilities using forecasts and simulations that are updated annually through the system planning process. This ensures customer demands are met while RNG production is not constrained. Given the generally small scale of these projects, in relation to the large number of distribution system upgrades, this consideration does not explicitly inform FEI's LTGRP. Table 1 in response to CEC IR1 9.2.1 and Section 1.4 of the Application outlines the LTGRP planning objectives which inform FEI's approach to connecting low carbon supply sources, including RNG. When considered as a whole, these are of material consequence as they describe the benefits and challenges of the various renewable and low-carbon fuel types that must be considered in FEI's long-term plans.	Not explicitly for LTGRP, as this function is completed within routine distribution system upgrade procedures.
60.4	Integration of Green Hydrogen	The physical properties of hydrogen are such that its inclusion in pipeline blends will have a measurable effect on capacity and, therefore, have implications in terms of the need for system upgrades. Further, where hydrogen is introduced into and transported throughout FEI's natural gas systems, material compatibility will need to be assessed. This may also impact system upgrade requirements to facilitate. FEI plans to evaluate the gas system readiness related considerations including material compatibility, allowable blend percentages with existing and future facilities and operating conditions via the BC Hydrogen Blending Study and Technical Assessment. The findings and recommendations from this study and other research will inform FEI's next LTGRP. Please refer to Section 7.4.1 and Table 7-2 of the Application and the responses to BCUC IR1 61.3 and 61.9 for a comprehensive review of FEI's hydrogen development initiatives.	Yes, to the extent FEI had available information.
60.5	Integration of Blue/Turquoise Hydrogen	As above in Row 60.4.	Yes, to the extent FEI had available information.

60.2 In response to CEC IR 1.9.3.1, FEI provides Table 1: Overview of Considerations for Integrating Renewable and Low-Carbon Gas. Are these considerations reflected upon alongside the emission factors presented in Table 1-2 of the Application,[31] and if so, how? If not, please explain why not.

Response:

Yes. Please refer to the response to CEC IR2 60.1.

60.3 In response to CEC IR 1.9.3.1, FEI provides in Table 1 considerations regarding integration of RNG, as per the excerpt below:

> - Steady production of RNG requires access to consistent consumer demand so that RNG production is not constrained. If located in distribution systems, this may require local system upgrades (pipeline or local storage) to enable access to sufficient consumer demand.

60.3.1 Please specify where in its LTGRP planning cycle does FEI account for and incorporate the consideration for local storage solutions for those RNG production facilities located in distribution systems?

60.3.2 Does this consideration inform FEI's LTGRP, and if so, how? If not, please explain why not.

60.3.3 Please explain whether FEI deems this consideration to be of material consequence in the context of its long-term planning efforts.

Response:

Please refer to the response to CEC IR2 60.1.

60.4 In response to CEC IR 1.9.3.1, FEI provides in Table 1 considerations regarding integration of Green Hydrogen, as per the excerpts below:

> - Has different physical properties, including energy content, from conventional natural gas and, therefore, exhibits flow characteristics that reduce pipeline capacity compared to conventional natural gas.

> - Need to consider material compatibility, allowable blend percentages with existing and future facilities and operating conditions.

[31] Exhibit B-1, Table 1-2, Page 1-6 and Page 1-7.

60.4.1 Please specify where in its LTGRP planning cycle FEI accounts for these considerations.

60.4.2 Do these considerations inform FEI's LTGRP, and if so, how? If not, please explain why not.

60.4.3 Please explain whether FEI deems these considerations to be of material consequence in the context of its long-term planning efforts.

<u>Response:</u>

Please refer to the response to CEC IR2 60.1.

60.5 In response to CEC IR 1.9.3.1, FEI provides in Table 1 considerations regarding integration of Blue/Turquoise Hydrogen, as per the excerpts below:

> - Has different physical properties, including energy content, from conventional natural gas and, therefore, exhibits flow characteristics that reduce pipeline capacity downstream of injection locations compared to conventional natural gas.
> - Need to consider material compatibility, allowable blend percentages with existing and future facilities and operating conditions.

60.5.1 Please specify where in its LTGRP planning cycle FEI accounts for these considerations.

60.5.2 Do these considerations inform FEI's LTGRP, and if so, how? If not, please explain why not.

60.5.3 Please explain whether FEI deems these considerations to be of material consequence in the context of its long-term planning efforts.

<u>Response:</u>

Please refer to the response to CEC IR2 60.1.

61. Reference: FEI Response[32] to CEC IR 1.10.3

> 10.3 Is FEI's body of work in developing the Diversified Energy Planning Scenario and the other five scenarios presented in Table 4-1 (on Page 4-21 of the Application: Alternate Future Scenario Summary), a leading or a lagging body of work as compared to FEI's peers in Canada and the PNW?
>
> **Response:**
>
> FEI believes that it is at the forefront of climate action among its utility peers in Canada and the PNW. FEI first introduced a climate compliance scenario in Appendix E of the 2017 LTGRP and since developed its Clean Growth Pathway, its 30BY30 target, the Pathways Report and now the DEP Scenario in the Application. FEI is not aware of any utility resource planning effort in Canada or the PNW with as ambitious a scenario as the DEP Scenario. This is because the policy framework outlined in the CleanBC Roadmap is the most ambitious and stringent climate policy impacting gas utilities anywhere in Canada or the PNW.

61.1 As FEI confirms that it is at the forefront of climate action among its utility peers in Canada and the PNW, please comment on the prudency of its LTGRP in charting a future path, and how its Diversified Energy Planning (DEP) scenario reflects FEI's conservative approach to long-term rate making principles.

Response:

FEI's statement that it is "at the forefront of climate action among its utility peers in Canada" was referring to the influence of BC's policy regime on FEI relative to its industry peers. BC is a jurisdiction that is at the forefront of climate action in Canada, which means that FEI is also at the forefront of climate action in responding to policy direction.

With respect to the prudency of FEI's LTGRP in charting a future energy pathway, please refer to the response to BCSEA IR1 32.1 which provides a discussion on why the choice of FEI's DEP Scenario is the most prudent choice for BC's energy transition. Additionally, please refer to the response to CEC IR2 58.1, which discusses prioritizing the use of existing infrastructure in a system-wide approach to energy planning as the most prudent approach, and the response to BCUC IR1 74.2, in which FEI discusses its initiatives exhibiting prudency in emissions reduction, including a focus on decarbonizing the gas supply, promoting DSM programs, and activities in low-carbon transportation and global LNG initiatives.

FEI's DEP Scenario also reflects the most conservative approach in terms of long-term rate impacts while still meeting the GHG reduction targets. As discussed in the response to CEC IR2 58.1, increasing energy rates for both gas and electric customers will be unavoidable in order to fund the capital investments needed due to decarbonization and climate change. For a similar level of GHG reduction by 2042 as shown in Figure 9-2 of the Application, the alternative Deep Electrification Scenario will result in significantly higher rate impacts to both gas and electric customers than FEI's preferred DEP Scenario as illustrated by the rate impact analysis included in Section 9.4 of the Application and further supported by the Kelowna Electrification Case Study.

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[32] Exhibit B-12.

61.2 In FEI's assessment, please discuss whether FEI believes its LTGRP path renders the DEP scenario susceptible to macroeconomic or policy shifts, as it concerns the path, technological means and/or pace of decarbonization.

Response:

Any long-term integrated resource planning scenario is susceptible to macroeconomic or policy shifts to some extent, whether it is a Reference Case, planning, or contingency scenario. For example, as explained in the preamble, a shift in the climate policy framework such as the CleanBC Roadmap would influence any scenario under FEI's LTGRP. Similarly, a macroeconomic shift or event (such as the COVID-19 pandemic) would influence FEI regardless of which path or scenario was presented. FEI's LTGRP path (its DEP Scenario) does not in itself cause it to be any more or less susceptible to a shift during the path to decarbonization. As utility resource plans are susceptible to macroeconomic policy shifts, this is one reason why they are prepared and submitted on relatively regular and frequent intervals.

62. Reference: FEI Response[33] to CEC IR 1.11.1

> The GGRR enables FEI to be more flexible, stimulates investment in renewable energy and accelerates growth of renewable and low-carbon gas supply in the gas system and acquire renewable and low-carbon gases from $30 to $31 per GJ for contracts. The changes to the GGRR enable FEI to help to achieve the CleanBC Plan objectives, which call for a 15 percent renewable and low-carbon gas content in the natural gas system by 2030. Further, with the recent introduction of the Roadmap in October 2021, FEI expects supply volumes to exceed 15 percent.
>
> 11.1 Please provide the equivalent price or price ranges (in $/GJ) that FEI would have typically paid to acquire natural gas for the needs of its customers in recent years.
>
> **<u>Response:</u>**
>
> The "equivalent price" that FEI would have typically paid to acquire natural gas, excluding any carbon tax impacts,[3] is on average reflected in FEI's Commodity Cost Recovery Charge (CCRC).[4]
>
> The figure below illustrates that in recent years, the CCRC for Lower Mainland, Vancouver Island, North and South Interior customers, has ranged from $1.55 per GJ to $5.91 per GJ.

62.1 Please confirm that in the DEP scenario FEI plans to substitute, by 2030, at least 15% of its system's entire gas supply with low-carbon gas. Also, please confirm that this substitute product (i.e. low-carbon gas) will cost on average 5-20 times more on a per GJ basis than FEI's current gas supply (as indicated by the lower and upper ranges of FEI's CCRC provided in response to CEC IR 1.11.1).

<u>Response:</u>

Please refer to the response to CEC IR2 52.1.

62.2 Please confirm that in the DEP scenario FEI plans to substitute, by 2030, at least 15% of its system's entire gas supply with low-carbon gas. Also, please confirm that this substitute product (i.e. low-carbon gas) will cost on average at least 5 times more on a per GJ basis (in real dollar value terms) than the upper bound of Station 2 and/or AECO/NIT forward price range (as per forecast provided in response to CEC IR 1.11.1).

<u>Response:</u>

Please refer to the response to CEC IR2 52.1.

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33 Exhibit B-12.

63. Reference: FEI Responses[34] to CEC IR 1.12.1 and CEC IR 1.12.3

> FEI notes that decarbonizing the BC energy system will require increased costs to energy consumers in order to meet the decarbonization goals as set out by the Province, regardless of whether a diversified pathway or electrification pathway is pursued. If FEI is unable to mitigate the risk of increased cost to its customers, and customers switch away from the gas system due to increased rates during the coming decades, a larger share of the cost would need to be absorbed by customers who remain on the system and there would be an increased risk of systemic failure risks that go along with that scenario.

> In addition, as discussed in the response to CEC IR1 12.2, there will be increased costs due to decarbonization whether it is through the diversified pathway or the electrification pathway. FEI's view is that the diversified pathway will be less expensive than the electrification pathway, i.e., by about $100 billion less according to the Pathways Report.[7] This is consistent with the rate impact analysis described in Section 9.4 of the Application, where the Deep Electrification Scenario results in higher rate impacts for gas customers than the DEP Scenario.

63.1 Please confirm that the DEP scenario (i.e. diversified pathway) also carries with it an increased risk of systemic failure risks, in the event that FEI is unable to mitigate the risk of increased costs to its customers prompting customers to switch away from the gas system.

<u>Response:</u>

There are risks associated with the DEP Scenario as there are risks with any resource plan scenarios. However, FEI considers that the risks of a decarbonization pathway like the DEP Scenario needs to be compared against other pathways and not against the current state. In FEI's assessment conducted initially as part of the Pathways to 2050 Report and now, in this LTGRP proceeding, FEI considers that risks of the DEP Scenario are lower than a pathway focused on electrification, that overall investment costs of decarbonization and the subsequent rate impacts will be lower in the DEP Scenario, the provincial energy system will be more resilient and reliable, and that it is inherently less risky to spread abatement needs across both major energy delivery systems rather than focusing on one. FEI's Clean Growth Pathway involves maintaining both the gas and electric infrastructure as part of BC's future energy system and leveraging FEI's existing infrastructure to reduce risks associated with the low-carbon transition.

63.2 Does FEI anticipate that it could have a mandate, such as the DSM mandate, enabling FEI to invest in incentives for its customers to reduce or abate their carbon emissions and manage their costs effectively?

[34] Exhibit B-12.

Response:

FEI currently can invest in its customers' efforts to reduce or abate their carbon emissions and manage their costs through applications under either the DSM Regulation or GGRR. Additionally, the GHGRS announced in the CleanBC Roadmap represents an emissions cap mandate for GHG reductions in the buildings and industrial sectors.

64. Reference: FEI Response[35] to CEC IR 1.13.2

> Although the Application did not designate specific locations or regions to bring forward some of these specific solutions (hydrogen production locations, for example), the information acquired through the engagement sessions supported the scenario analysis and the selection of the DEP Scenario as FEI's planning scenario and has helped to inform ongoing LTGRP analysis and other planning considerations. As resource planning is an ongoing process, FEI plans to continuously improve opportunities for community outreach to further understand the unique needs of geographical variations in customer perceptions and energy needs in resource planning and other aspects of FEI's energy distribution business.

64.1 Please confirm and/or otherwise explain whether FEI is not of the opinion that a long-term resource plan is the typical strategic and planning setting for a utility to signal its path forward, including analysis of regional opportunities and specific locations for future resource development.

Response:

Not confirmed. FEI agrees that the long-term resource plan is the typical strategic and planning setting for a utility to signal its path forward, but does not agree that analysis of all regional opportunities and specific locations for future resource development is always necessary in order to be able to signal its path forward.

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[35] Exhibit B-12.

65. Reference: FEI Responses[36] to CEC IR 1.16.5 and CEC IR 1.16.6

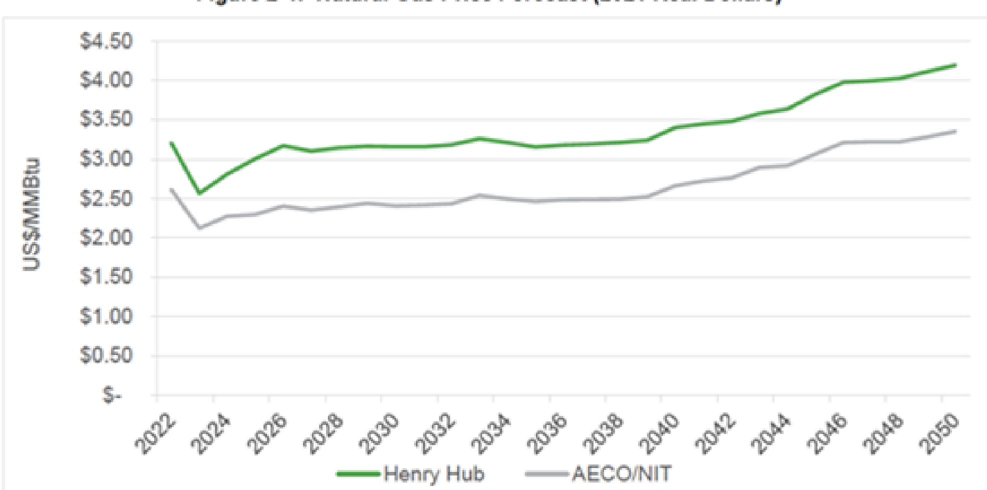
> 16.5 What assumptions, if any, do AECO/NIT and Station 2 prices incorporate with regard to LNG production in BC over the forecasted period?
>
> **Response:**
>
> The AECO/NIT price forecast from IHS Markit, released in February 2022, assumes that LNG export demand begins in late 2025, starting with Phase 1 of LNG Canada and then followed by Woodfibre LNG in 2027. Additional LNG exports are not expected to begin operating in Canada until 2035. Increasing demand from LNG helps to provide some upside pressure on forecast prices, helping to offset the assumption of declining residential and commercial demand for natural gas after 2033. IHS Markit assumes that there is a minimal price increase from LNG exports due to the assumption of increasing natural gas production; however, prices may have further upside pressure if actual natural gas production does not increase to meet the marginal LNG demand.

65.1 Please provide FEI's expectations of the upper bound of 'further upside pressure on gas prices', if actual natural gas production does not increase to meet the marginal LNG demand forecasted by IHS Markit.

Response:

FEI uses price forecasts that are provided by S&P Global (formerly known as IHS Markit). S&P Global does not have a price scenario for AECO/NIT and Station 2 that shows the impact on prices if actual natural gas production does not increase to meet marginal LNG demand. However, in general, S&P Global assumes that prices would rise and be at or near Henry Hub prices, which is the benchmark price for North America, as shown in the Figure 2-4 from the Application. Also, S&P Global assumes that prices would eventually reach a level that would incentivize western Canadian producers to increase natural gas production which would alleviate the pressure on regional prices.

Figure 2-4: Natural Gas Price Forecast (2021 Real Dollars) [87]



[36] Exhibit B-12.

66. Reference: FEI Responses[37] to CEC IR 1.17.1 and CEC IR 1.17.2

> 17.1 Please provide the equivalent to Figure 2-5 to show the Commercial Annual Bill Amount Trend in BC.
>
> **Response:**
>
> FEI does not have a source for the historical annual bill amounts of BC Hydro's commercial and industrial customers and therefore is not able to respond to this question. Further, unlike the residential rate class where the need for space and hot water heating allows for an apples-to-apples comparison, the end-uses for commercial and industrial customers are significantly more diverse with efficiency information that is less certain. Gas and electricity applications as well as the consumption pattern for commercial and industrial customers are different and their respective rate schedules have different eligibility criteria, which makes an apples-to-apples comparison not possible and less meaningful.

66.1 In the absence of historical (2015 to 2022) data from BC Hydro on commercial annual bill amounts, can FEI advise on whether it has discerned any notable trends from the observation of its own commercial customers, which it collectively serves with FBC? If yes, how would such trends compare with those observed in the residential sector?

Response:

FEI notes that the purpose of Figure 2-5 of the Application, which was the subject of the discussion in the response to CEC IR1 17.1, was to demonstrate the decreasing trend of an energy cost differential for residential customers between natural gas and electricity. Section 2.4.2.1 of the Application explained that the decrease is primarily attributed to the higher natural gas commodity costs, the recent increase in FEI's delivery rates, as well as the carbon tax rates. All three of these factors are not unique to residential customers, as FEI's commercial and industrial customers faced the same increase in delivery rates, commodity costs, and carbon tax over the same period. As such, the general trend of decreasing energy cost differentials between natural gas and electricity would also be expected for commercial and industrial customers.

The reason that FEI provides the bill comparison between gas and electric for residential customers is because an apples-to-apples comparison is possible. In most cases, the majority of the energy use of residential homes in BC is for space heating, which will likely be from gas or electricity. Since the primary use of energy is typically the same between a gas-heated and electric-heated home, it is possible to compare the annual bill between the two.

In contrast, although the trend of decreasing energy cost differentials exists for commercial and industrial customers as discussed above, FEI is unable to illustrate this trend graphically in the same format as Figure 2-5, regardless of whether FEI uses BC Hydro's rates or FBC's electric rates. This is because, as discussed in the response to CEC IR1 17.1, the end-uses for commercial and industrial customers are significantly diverse and the efficiency information between gas and electric equipment in large commercial or industrial settings is less certain. Further, FEI (and FBC) do not collect the individual end-use or equipment type of its

[37] Exhibit B-12.

commercial/industrial customers to be able to isolate certain customer groups for an apples-to-apples comparison. As such, any general trend shown using the same graphical format for the average commercial and industrial customer would not be useful. FEI would be unable to discern whether the trend, if any, shown graphically would be due to energy costs, the diversity of end-uses or for some other reason. Similarly, comparing such a graphical trend for commercial/industrial customers against the trend for residential customers would not be useful.

66.2 In the absence of historical (2015 to 2022) data from BC Hydro on industrial annual bill amounts, can FEI advise on whether it has discerned any notable trends from the observation of its own industrial customers, which it collectively serves with FBC? If yes, how would such trends compare with those observed in the residential sector?

Response:

Please refer to the response to CEC IR2 66.1.

67. Reference: FEI Responses[38] to CEC IR 1.19.2 and CEC IR 1.19.3

> 19.2 Does FEI believe that summer A/C demand related to warmer weather events in BC, is best served by the electric systems or by the gas systems, in the long run? Please explain.
>
> **Response:**
>
> FEI anticipates that there will be increased customer demand to retrofit homes and buildings without cooling with air conditioning solutions. Although FEI believes that summer cooling is appropriately served by the electric system (as opposed to a gas system), there will likely be circumstances where it is impractical or cost-prohibitive for the customer to upgrade their electrical service in order to support it. In those cases, providing customers with gas-powered options that can also provide cooling (such as gas heat pumps) could be a viable solution. Also, FEI considers that both the gas and electric system must complement each other throughout the year. To this end, FEI has been evaluating hybrid heating systems which use both an electric heat pump and a gas heating appliance, with an integrated controller to engage either system in an optimal manner. FEI sees potential with hybrid systems and gas heat pumps to meet summer cooling and winter peak heating demand while reducing customer costs and GHG emissions.

67.1 If available, please provide estimates of market capture rate for summer cooling load associated with the future use of gas heat pumps, for each of the milestone years in the DEP scenario.

Response:

The following response has been provided by Posterity Group in consultation with FEI.

In developing the forecast model, an estimate of the future market size for summer cooling load was not developed and, therefore, market capture rate cannot be calculated for each of the milestone years.

However, in the DEP Scenario, the percentage of residential dwelling units that are affected by gas heat pump measures can be provided – which is 0.3 percent by 2030 and 2.1 percent by 2042. The percentage of commercial floor area estimated to be affected by gas heat pump measures in the DEP Scenario can also be provided – 3.6 percent by 2030 and 10.5 percent by 2042.

67.2 Please provide estimates of the market share (in PJ) for each of the milestone years in the DEP scenario, which FEI expects would be owing to the use of gas heat pumps to serve incremental summer cooling load (as compared to 2021).

[38] Exhibit B-12.

Response:

The following response has been provided by Posterity Group in consultation with FEI.

In the DEP scenario with the High DSM setting, gas heat pumps would supply an estimated 0.003 PJ of residential cooling in 2030 and an estimated 0.018 PJ of residential cooling in 2042. Assuming a cooling COP of approximately 1.35, the gas heat pumps would consume an estimated 0.002 PJ of energy to provide this cooling in 2030 and approximately 0.013 PJ in 2042.

A similar estimate cannot be produced for the commercial sector based on the modeling performed for the LTGRP, because the commercial model did not include a space cooling end use.

67.3 If available, please provide estimates of market capture rate for summer cooling load associated with the future use of hybrid heating systems, for each of the milestone years in the DEP scenario.

Response:

The following response has been provided by Posterity Group in consultation with FEI.

In the DEP Scenario, the only hybrid heating systems considered are air-source electric heat pumps with a gas furnace primarily used for peak heating purposes. The gas furnace in such a system would not contribute to the summer cooling load, as this would be met entirely by the air-source electric heat pumps. Therefore, there is a 0 percent market capture rate and 0 PJ provided for summer cooling load associated with the future use of hybrid systems in the scenario.

67.4 Please provide estimates of the market share (in PJ) for each of the milestone years in the DEP scenario, which FEI expects would be owing to the use of hybrid heating systems to serve incremental summer load (as compared to 2021).

Response:

Please refer to the response to CEC IR2 67.3.

68. Reference: FEI Response[39] to CEC IR 1.19.4

> Under the DEP Scenario, more customers retain their gas heating equipment.[11] During winter peak demand events and some service disruptions to electric utility customers, heating needs could still be met with gas equipment. Utility Distributed Energy Resource Managements Systems (DERMS) may increasingly provide load switching services in the near future to participating customers that connect with smart thermostats or Building Management Systems (BMS), further improving system resilience.

68.1 As part of its 2021 LTGRP, did FEI explore and/or consider a scenario whereby more customers retain their gas heating equipment, as compared to the DEP scenario? If yes, please elaborate.

68.1.1 If not, please explain the reasons for not doing so.

<u>Response:</u>

The DEP Scenario includes moderate fuel switching driven by policy and higher carbon price than the reference setting. In a given sector, building segment, and end use, the model implements fuel switching based on whichever of these settings has the greater effect.

There are several scenarios in which there is either less electrification than in the DEP Scenario or where there is fuel switching away from electricity towards gas. They are as follows:

Reference Case:

- The reference setting includes no fuel switching driven by policy.
- The reference setting for gas commodity price does not cause any fuel switching in the model.
- The reference setting for carbon price does not cause any fuel switching in the model.

Economic Stagnation:

- This scenario uses the reference setting for fuel switching driven by policy, so there is none.
- This scenario uses a gas commodity price setting lower than the reference setting, driving fuel switching away from electricity towards gas.
- This scenario uses a carbon price setting lower than the reference setting, driving fuel switching away from electricity towards gas.

Upper Bound:

- This scenario uses the reference setting for fuel switching driven by policy, so there is none.

[39] Exhibit B-12.

- This scenario uses a gas commodity price setting lower than the reference setting, driving fuel switching away from electricity towards gas.
- This scenario uses a carbon price setting lower than the reference setting, driving fuel switching away from electricity towards gas.

69. Reference: FEI Responses[40] to CEC IR 1.21.1; CEC IR 1.21.2; CEC IR 1.21.3

- The Hydrogen Strategy for Canada: Figure 17 - Carbon Intensities of Hydrogen from Different Production Pathways for the range of CI of hydrogen from different production methods.[12]
- The BC Hydrogen Study: Figure 26 – Carbon Intensity of Hydrogen Production Pathways in BC.[13]
- The BC Renewable and Low-Carbon Gas Supply Potential Study: Section 3.4, Hydrogen Production from Solid Biomass, and Section 4, Hydrogen From Non-Biomass Resources.[14]

[12] Exhibit B-1, Appendix A-2.
[13] Exhibit B-1, Appendix A-6.
[14] Exhibit B-1, Appendix D-2.

69.1 Please confirm that the reference provided as Footnote 12 in FEI's response to CEC IR 1.21.1, ought to read Appendix A-3 (Appendix A-2 of the Application is titled 'Pathways for British Columbia to achieve its GHG Reduction Goals').

Response:

Confirmed. Footnote 12 in the response to CEC IR1 21.1 should read "Appendix A-3".

69.2 The CEC notes that Figure 17 in Appendix A-3 of the Application provides carbon intensities of hydrogen from different production pathways: on the left axis carbon intensity is expressed in g-CO2e/MJ; while on the right axis carbon intensity is expressed in kg-CO2e/kg-H2. Due to the scale of the graph, it is difficult to ascertain the exact carbon intensity numbers. Please provide carbon intensity information in a table format expressed in kg-CO2e/GJ consistent with FEI's measurement of choice in response to CEC 1.21.1.

Response:

The carbon intensity information from Figure 17 in Appendix A-3 of the Application is presented in Table 1 below expressed in kgCO2e/GJ. FEI also compares the carbon intensity measures of hydrogen from different production pathways based on two sources of information and summarizes comparable production pathways in Table 1 below. There is general alignment in the

[40] Exhibit B-12.

carbon intensities, but there is some variation in the carbon intensity values because of differences in the studies' assumptions. FEI notes that this is a general observation as it did not conduct the studies.

The sources are described as follows:

- Figure 17 in Appendix A-3 of the Application is from the Hydrogen Strategy for Canada. The study provides Carbon Intensity ranges from different sources, such as IEA, Transition Accelerator and BCBN. When multiple data are not available, single numbers are provided. Units used in this Figure are gCO2e/MJ (on the left side of the figure) and kgCO2e/kg H2 (on the right side of the Figure). As described in the preamble "Due to the scale of the graph, it is difficult to ascertain the exact carbon intensity numbers" and therefore the data extract is approximated.
- Figure 26 in Appendix A-6 of the Application is from the BC Hydrogen Study. The study provides findings in the carbon intensity of hydrogen production pathways tailored for BC cases. The unit used in this Figure is gCO2e/MJ.

Most of the production pathways from the two figures are comparable, while some production pathways are only covered in one of the figures. Only comparable production pathways are provided for comparative purposes. FEI considers that there is general alignment in the two sources of data, although assumptions and site variations may explain differences in results.

Table 1: Comparison of Carbon Intensity Values for Comparable Hydrogen Production Pathways from Two Studies

BC Hydrogen Study (Figure 26)		The Hydrogen Strategy for Canada (Figure 17)	
Description	CI Value (kgCO2e/GJ)	CI Value (kgCO2e/GJ)	Description
SMR	89.1	60-90	SMR W/O CCUS
SMR+CCS	22.4	25-45	SMR w/50% CCUS
SMR+CCS	22.4	4-20	SMR w/90% CCUS
Thermal Pyrolysis	14.7	11	Pyrolysis
Plasma Pyrolysis	12.5	11	Pyrolysis
Biomass Gasification	6.7	4-15	Biomass Gasification
Electrolysis BC Grid	27.4	20	Actual Grid BC
Electrolysis Wind Grid Connected	16.4	14	Electrolysis Wind Grid Connection
Electrolysis Wind Off-Grid	0	0-5	Electrolysis Wind Off-Grid

Note: 1 gCO2e/MJ equals 1 kgCO2e/GJ.

69.3 As both Figure 17 in Appendix A-3 of the Application and Figure 26 in Appendix A-6 of the Application contain carbon intensity measures of hydrogen from different production pathways, please advise whether there are any notable differences between the two sets of figures (i.e. the two different studies).

Response:

Please refer to the response to CEC IR2 69.2.

69.4 If possible, please reconcile the carbon intensity measures from the two studies (i.e. Figure 17, Appendix A-3 and Figure 26, Appendix A-6) in a table format expressed in kg-CO2e/GJ consistent with FEI's measurement of choice in response to CEC 1.21.1.

Response:

Please refer to the response to CEC IR2 69.2.

69.5 Please provide the assumed average hydrogen carbon intensity which FEI used in the LTGRP to determine the expected volume of hydrogen required as part of its low-carbon gas portfolio.

Response:

The average hydrogen carbon intensity adopted for the purposes of this assessment was 20 kgCO2e/GJ. Please refer to the response to BCUC IR1 71.7 that discusses the supporting assumptions and calculations used to arrive at the forecast 60 PJ and 99 PJ of renewable and low-carbon gas supply by 2030 and 2040, respectively. FEI's top-down approach included the six following steps:

1. Identifying the amount of carbon emission reductions needed to meet the proposed GHGRS 2030 Emissions Cap (the Cap);
2. Determining the amount of emission reductions that other actions such as DSM activities could contribute to meeting the Cap;
3. Calculating the remaining emission reductions required by FEI to meet the Cap after the actions from the preceding step were assumed to have been taken;
4. Assessing the availability of renewable and low-carbon gas over the planning horizon;

5. Assessing the ability of FEI to acquire the available quantities of renewable and low-carbon gas over the planning horizon; and
6. Finalizing the forecasted contribution of each of the emission reduction initiatives, including the acquisition and delivery of renewable and low-carbon gas to customers, in meeting the proposed GHGRS emissions cap.

As discussed above, Steps 4 and 5 were achieved through FEI's research and internal discussions to come up with the 60 PJ and 99 PJ of renewable and low-carbon gas supply that it considers is feasible to acquire over the planning horizon. The hydrogen component within this portfolio was developed as a part of these discussions in terms of what internal experts thought is feasible in this timeframe.

The assumed hydrogen carbon intensities used to develop FEI's emission reductions initiatives are based on FEI's research as illustrated in Table ES-2 in the Application. The sources of these factors are described in the response to BCUC IR1 71.4.

69.6 Figure 17 in Appendix A-3 of the Application contains carbon intensity measures of hydrogen produced from steam reforming of methane (SRM), without carbon capture utilization storage (CCUS) and with two different levels of CCUS (respectively 50% and 90%). In the case where FEI envisions future procurement of hydrogen produced from SRM, would FEI contractually assume the cost pertaining to CCUS technology? What does the LTGRP signal in this regard, and how does it position FEI on behalf of its customer base?

Response:

Hydrogen production from steam methane reforming (SMR) without carbon capture and sequestration is not considered low carbon intensity hydrogen; FEI would not consider acquiring hydrogen with a carbon intensity above the federally recommended 36.4 gCO2e/MC threshold. If FEI procures hydrogen produced from SMR, it would include the cost pertaining to CCUS in order to meet or exceed this threshold. FEI would acquire all environmental attributes (including greenhouse gas reduction benefits) associated with the low-carbon intensity hydrogen and the price that FEI would pay for the hydrogen would include the cost associated with CCUS.

As outlined in Appendix A-3, Hydrogen Strategy for Canada,[41] Canada has vast natural gas resources which, when combined with CCUS, can be converted into low CI hydrogen. This pathway has the advantages of potentially being the lowest cost production method of large-scale, clean hydrogen, based on current technologies, commodity costs and including the cost pertaining to CCUS. Procuring this form of low carbon hydrogen signals that FEI is ready to

[41] Exhibit B-1, Appendix A-3, Hydrogen Strategy for Canada, Section 3, Canada's Production & Distribution Opportunities.

support its customers with low carbon energy resources that will help its customer base reduce its GHG emissions.

70. Reference: FEI Responses[42] to CEC IR 1.22 Series

> 22.3 Are similar test programs being undertaken elsewhere in the PNW region? Please explain.
>
> **Response:**
>
> FEI is not aware of similar trials being undertaken elsewhere in the PNW. However, FEI is actively engaged with other utility companies, industry associations and other forums, such that if FEI becomes aware of similar trials, then FEI will endeavor to engage to support the most efficient approach to avoid duplication of effort.

70.1 Is FEI surprised or concerned by the lack of initiative elsewhere in the PNW with respect to pilot testing for industrial hydrogen blending applications, such as at pulp mills and cement kilns? Please explain.

Response:

No, FEI is not surprised or concerned by the perceived lack of announced initiatives elsewhere in the PNW. FEI understands that each jurisdiction has different policy drivers and different pathways to decarbonization. As such, industrials, such as pulp mills and cement plants, may pursue alternative decarbonization pathways dependent on available resources.

[42] Exhibit B-12.

71. Reference: FEI Response[43] to CEC IR 1.23.4

> CHP systems using low-carbon gas could be used to allow the gas and electric systems to work together to provide customers with affordable energy while reducing emissions. For example, greenhouses, which have a requirement for heat, electricity, and CO_2, could potentially make use of CHP systems to reduce the demand placed on the electrical grid and/or avoid investments in electrical infrastructure, which may result in reduced costs for greenhouse operators, and help further enable the electric grid to displace other sources of emissions such as those related to transportation.

71.1 Please advise whether CHP systems, which operate with combustion engines (piston or turbine), would be at risk from potential Volatile Methane Siloxanes (VMS) when supplied by a gas stream containing renewable natural gas (please see also CEC 2.1.9).

Response:

FEI's biomethane specification requires that the concentration of siloxanes in biogas be sufficiently reduced prior to the biomethane being injected into the gas system. To ensure compliance with the specification, FEI tests biomethane to be injected into the gas system on a regular basis. The specification allows for no more than 1 mg of siloxanes per cubic metre of RNG. FEI believes that at this level there is no risk to CHP systems supplied with a gas stream containing RNG.

71.2 Has FEI identified CHP systems that can operate with various fuel products, including with H2 and CH4 mixes, which could potentially be more cost effective?

Response:

FEI is not aware of any CHP products that are currently commercially available and that have been certified for use with a blend of hydrogen and natural gas.

FEI is aware of Capstone Green Energy which has successfully tested its CHP microturbines with 30 percent hydrogen blended with natural gas; however, FEI understands this was the result observed during testing, and their products are not yet certified for commercial use on a blend of hydrogen and methane.

FEI is also aware of 2G, a European manufacturer of CHP systems that can operate on hydrogen, methane, or a mix of both with up to 40 percent hydrogen, and whose products are currently commercially available in Europe. It appears however that 2G's products are not commercially available in Canada at present.

[43] Exhibit B-12.

72. Reference: FEI Response[44] to CEC IR 1.24.1

> alternatives to diesel. FEI is also currently providing LNG service to customers who deliver LNG for remote power generation customers, and FEI is supporting their attempts to increase demand.

72.1 Please provide a brief commentary on the magnitude of the current efforts by FEI customers who deliver LNG for remote power generation applications. How widespread are these efforts in BC? What LNG volumes are involved?

<u>Response:</u>

Please refer to the responses to CEC IR2 54.1 to 54.4.

[44] Exhibit B-12.

73. Reference: FEI Responses[45] to CEC IR 1.19.1 and CEC IR 1.25.2

> For example, the U.S. Energy Information Administration (EIA) reports in the Annual Energy Outlook 2022 that as of January 1, 2020, there are 2,926 trillion cubic feet (Tcf) of technically recoverable resources, 464 of that which are proved resources (or commercially recoverable reserves).[16] Assuming the same annual rate of US dry natural gas production in 2020 of 30 Tcf, the US has enough dry natural gas to last around 100 years, or 15 years based on proved resources.
>
> Similarly, according to the 2018 Oil and Gas Reserves and Production Report from the BC Oil and Gas Commission as referenced in the preamble, BC has marketable resources of 15.058 trillion cubic metres, and remaining raw reserves of 1.165 trillion cubic metres.[17] Assuming the same annual rate of BC natural gas production in 2018 of 60 billion cubic metres, BC has enough natural gas to last around 250 years, or 19 years based on raw reserves.

73.1 In response to CEC IR 1.19.1, FEI states that 'it is widely recognized that the PNW region is facing a period of resource adequacy concerns… in terms of the electric grid'. In FEI's opinion, do (proven/raw) natural gas reserve life estimates (15 years/19 years respectively for the US/BC as outlined above in response to CEC IR 1.25.2), generally exacerbate or help alleviate resource adequacy concerns for the PNW region?

Response:

The drivers of resource adequacy concerns within the western electric grid include significant changes in climate, weather, energy consumption patterns, a rapidly transforming resource mix including coal and natural gas retirements, and a push for electrification.[46] While substantial (proven/raw) natural gas reserves would help to fuel natural gas electricity generation, which has been increasingly relied upon for power generation in recent years, the emerging energy policies within the West are pushing for decarbonization over the long term.

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[45] Exhibit B-12.

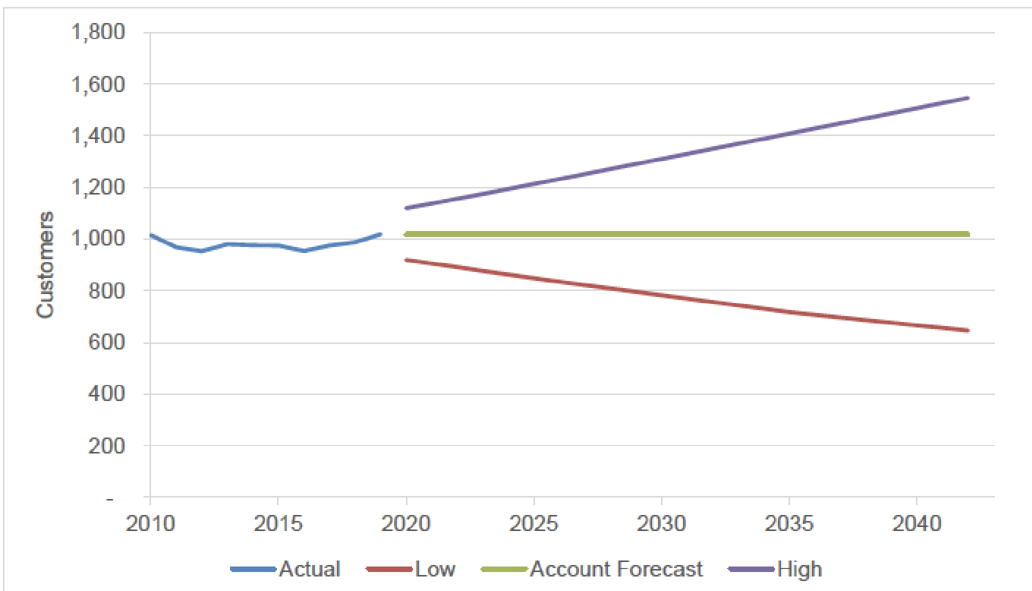
[46] 2022 Western Assessment of Resource Adequacy, WECC, Pg 2, URL: 2022 Western Assessment of Resource Adequacy.pdf (wecc.org).

74. Reference: FEI Responses[47] to CEC IR 1.28 Series

Response:

The mathematical formula used for the uncertainty calculation is based on the standard deviation of 10 years of historical actual customer totals. The standard deviation itself is based on how far each annual customer total is from the average customer total. Half of the annual customer totals are less than the average while the other half are greater. As a result, the mathematical formula provides a single uncertainty value that is both subtracted from and added to the forecast value to provide the upper and lower uncertainty bands. The use of a single value that is added to and subtracted from the forecast results in symmetrical uncertainty bands and recognizes that deviations from the forecast have an equal chance of being greater than or less than the forecast values. This is the common way to calculate uncertainty intervals whether from a textbook, analytics software package, or Microsoft Excel "wizard".

Figure B3-6: Customer Forecast Parameters – Industrial Rate Schedules



74.1 In response to CEC IR 1.28.2 inquiring as to the uncertainty interval associated with the long-term industrial customer forecast as provided in Figure 4-4, in Chapter 4 of the Application, FEI offers that '… the mathematical formula provides a single uncertainty value that is both subtracted from and added to the forecast value to provide the upper and lower uncertainty bands. The use of a single value that is added to or subtracted from the forecast results in symmetrical uncertainty bands… '. Upon further scrutiny of Figure B3-6, on Page 6 of Appendix B-3 to the Application (copied herein above), the CEC concludes that the uncertainty band around the industrial customer forecast is not quite symmetrical. Please reconcile

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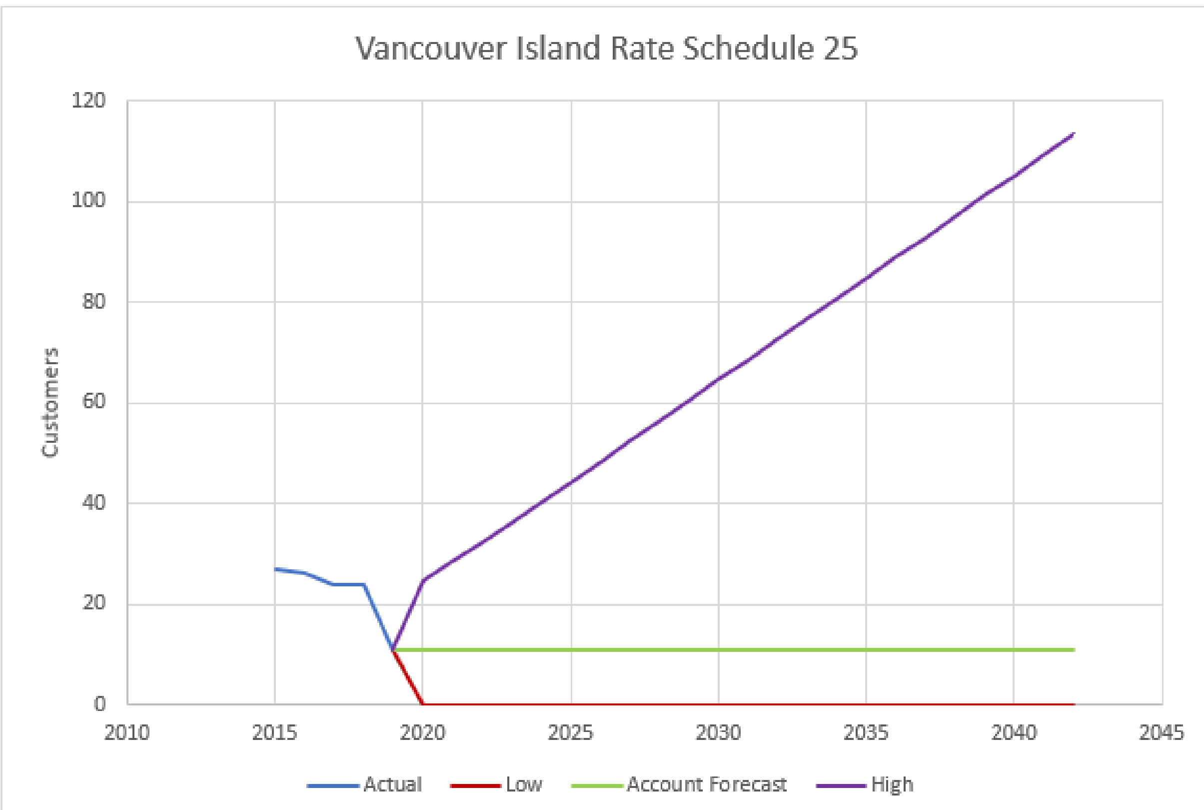
[47] Exhibit B-12.

the statement included in response to CEC IR 1.28.2 with the graph provided as Figure B3-6 in Appendix B-3 to the Application.

Response:

FEI confirms that, in general, the mathematical formula provides a single uncertainty value that is both subtracted from and added to the forecast value to provide the upper and lower uncertainty bands. However, in cases where the subtraction of the uncertainty value from the forecast value would result in a negative customer number, the customer value was held at 0. As a result, when all the regions are summed up, the cases where the customer total for the lower uncertainty band are 0 result in a slightly smaller aggregate lower uncertainty band.

As an example, the Vancouver Island Rate Schedule 25 customer forecast parameters are shown in the figure below.



74.2 Does FEI anticipate that, in the future, it will be more difficult to add customers than the risk that FEI will lose customers; or will loss of customers compound the difficulty of getting new customers and the future customer acquisition risks may become significantly correlated with the customer retention risks?

Response:

Considering the preamble to this information request, FEI interprets the question to be referring specifically to industrial customers. FEI's long-term industrial customer forecast in the 2022 LTGRP did not anticipate that it will be more difficult or less difficult to add customers than it is today and further considers that future conditions could be more favourable or less favourable for customer additions at different times throughout the planning period. For this reason, FEI has examined a range of future scenarios and a range of customer forecasts in its 2022 LTGRP. FEI's DEP Scenario contemplates that adding industrial customers will involve the same level of difficulty that has occurred in the recent past.

75. Reference: FEI Response[48] to CEC IR 1.29.1

29.1 Please detail some of the broad changes in consumption patterns for the residential demand that were observed for the 10-year period ending with the base forecast year (2019), based on 10 years of weather normalized actual use rate data.

Response:

The following table shows the weather normalized residential use rates for the ten-year period ending in 2019. The CAGR over the period was -0.7 percent per year. The 2019 UPC was 6 GJ lower than 2010.

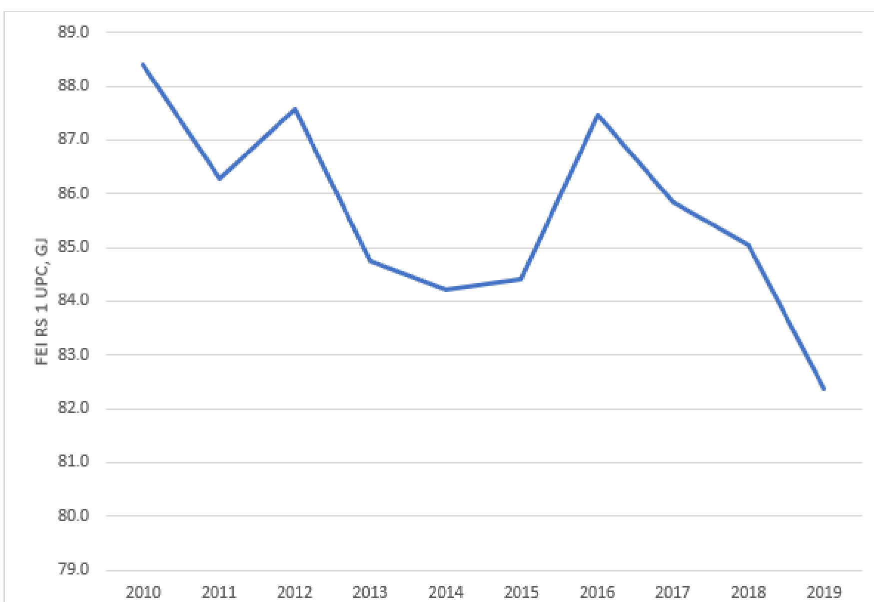
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
FEI RS 1 UPC, GJ	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	-0.70%

75.1 In FEI's opinion, is the -0.7 percent per year CAGR for the residential use rates statistically significant?

Response:

Since 2010, the residential use rate has been generally declining, as shown in the following figure. FEI expects that this downward trajectory will continue, however, FEI is not aware of a statistical significance test for the compound annual growth rate (CAGR) calculation itself. A regression analysis is typically used to evaluate the relationship between two variables. The CAGR value is simply the rate of change between a starting point and an end point and does not examine the relationship between two variables.

Figure 1: History of Annual Residential Use Rates



[48] Exhibit B-12.

76. Reference: FEI Response[49] to CEC IR 1.29.2

Response:

The table and figure below show the annual residential customer totals for FEI's overall system, as well as for the Mainland, Vancouver Island and Whistler regions. FEI notes the following:

- The CAGR for the Mainland region is significantly lower than other regions;
- The low Mainland CAGR results in a low blended CAGR for FEI; and
- Between 2010 and 2019, FEI added 87,259 residential customers.

Table 1: Residential Customer Count

Residential Customers											
Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
FEI	853,492	860,403	854,050	863,189	873,661	886,169	897,528	910,865	930,142	940,751	0.98%
Mainland	760,559	765,553	759,712	766,668	774,083	782,914	790,562	798,917	811,696	817,817	0.73%
Vancouver Island	90,671	92,554	92,067	94,173	97,162	100,747	104,358	109,259	115,618	119,998	2.84%
Whistler	2,262	2,296	2,271	2,348	2,416	2,508	2,608	2,769	2,828	2,936	2.64%

- The CAGR for the Mainland region is similar to the FEI regional CAGR;
- The residential UPC in all regions declined by more than 0.5 percent per year;
- Vancouver Island UPCs are significantly lower than use rates in other regions; and
- The FEI blended use rate is heavily influenced by the Mainland use rate.

Table 2: Residential UPC

Residential UPC, GJ											
Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
FEI	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	-0.70%
Mainland	92.6	90.4	92.2	89.3	88.8	88.7	92.0	90.4	89.7	87.1	-0.62%
Vancouver Island	52.5	51.8	49.5	47.3	47.1	50.5	52.6	51.5	51.6	49.7	-0.55%
Whistler	99.5	94.7	89.4	87.3	87.6	91.3	97.7	93.5	96.3	94.2	-0.54%

76.1 As evident in FEI's response to CEC IR 1.29.2, over the past decade FEI's Vancouver Island region has experienced higher than average customer growth. Does FEI expect the dynamics that are contributing to this growth to continue into the next decade?

Response:

In 2014, rates for FEI's customers were amalgamated. As a result, the residential rates in Vancouver Island decreased by over 20 percent. This widened the cost differential between gas and other forms of energy in favor of natural gas. As affordability is and remains a strong motivator for homeowners when choosing their energy source, FEI saw a significant upswing in existing homes moving away from other sources of energy, such as oil or propane, in favor of natural gas connections. Approximately 50 percent of historical new customer additions on Vancouver Island have come from existing homes and businesses switching to natural gas.

[49] Exhibit B-12.

At the same time, over the last decade, all major population centers on Vancouver Island have experienced unprecedented growth in the number of new homes constructed, as the demand for new homes of all configurations continues to outstrip supply.

Both of these factors are the major drivers related to the "higher than average" historical growth rates on Vancouver Island over the last decade.

FEI does not expect the same growth rates to continue on Vancouver Island due to policy favouring electricity as well as incentives for electric heating equipment. In 2022 and YTD in 2023, FEI has seen reduced demand from customers switching from oil or propane to gas in favour of electric heat pumps due to the significant incentives provided by the Province, BC Hydro and some municipalities. Further, municipalities are now adopting the Zero Carbon Step Code as a mechanism to lower emissions, but without a renewable gas alternative, this is expected to result in fewer new construction additions.

76.2 Please explain the Vancouver Island customer count growth dynamics and the persistence assumptions embedded into the residential customer count for the LTGRP horizon.

Response:

Please refer to the response to CEC IR2 76.1. FEI does not have and does not apply any specific "persistence assumptions" to the customer count forecast. Please see the attachment to the response to BCUC IR1 11.1 "FEI 20 Year Customer Forecast Method" for more details.

76.3 Please explain to what factors FEI attributes the significantly lower use rates (UPC) for Vancouver Island, as compared to other regions.

Response:

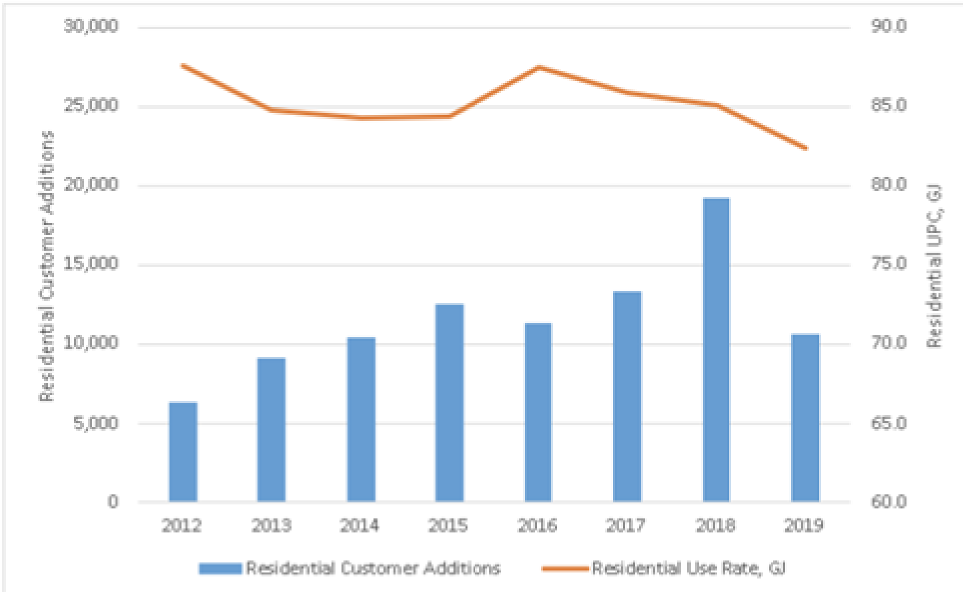
There are two major factors that contribute to lower usage rates (UPC) on Vancouver Island, as compared to other regions.

- The climate in the region. Vancouver Island has one of the most temperate climates in Canada. As a result, the seasonal heating needs on Vancouver Island are much less than in other regions of BC.
- The maturity of the gas market on Vancouver Island. Natural gas has only been available on Vancouver Island since 1991, and in the beginning, only in main urban areas such as

Victoria, Nanaimo, the Comox Valley, Campbell River and Port Alberni. Over the decades, the system has grown to include more and more towns and neighbourhoods. As many of the homes attached to the gas grid on Vancouver Island were built before gas was available, not all of the homes use natural gas for the full suite of appliances, and many homes are heated with a combination of energy sources. For example, on Vancouver Island, it is not uncommon to find a home using both baseboard electric and a heating style gas fireplace or space heater to heat the home. Homes may use a gas appliance for space heating but have an electric water heater due to the original design of the home, where the water heater is located in an area of the home where venting a gas appliance would be impractical or impossible. With many homes not using natural gas for both space and water heating, Vancouver Island gas UPC is lower than other regions.

77. Reference: FEI Response[50] to CEC IR 1.29.3

> As a result of newer homes being more energy efficient, requiring less energy to heat, along with ongoing efforts through FEI's DSM initiatives to update existing homes with more efficient equipment, FEI expects to see the residential UPC to continue to decline over time.



77.1 What lower bounds does FEI forecast in the LTGRP horizon for the residential UPC, in light of expected energy efficiency advancements for homes and appliances?

Response:

Please see the Lower Bound scenario residential UPC forecast below. FEI has modelled this Lower Bound scenario, but has not defined or modelled an "expected lower bound". FEI's expectation is to pursue its Clean Growth Pathway as modelled in the DEP Scenario.

[50] Exhibit B-12.

Table 1: Lower Bound Residential Average Annual UPC (GJ) Forecast

Year	UPC (GJ)
2019	82
2020	80
2021	78
2022	75
2023	73
2024	71
2025	68
2026	66
2027	64
2028	61
2029	59
2030	56
2031	54
2032	52
2033	49
2034	46
2035	44
2036	41
2037	39
2038	36
2039	34
2040	32
2041	31
2042	29

As stated in the Application, this scenario is designed to represent the most extreme, low-gas-demand scenario from an annual demand perspective. In addition to electrification policies, all other critical uncertainties that could act to reduce gas demand do so. However, in this scenario, like the Deep Electrification Scenario, the requirement for corresponding increases in electricity energy and peak demand requirements that are not fully modelled in FEI's annual gas demand analysis are anticipated to make the Lower Bound annual demand scenario not plausible, as described in Section 4.6.1.1.

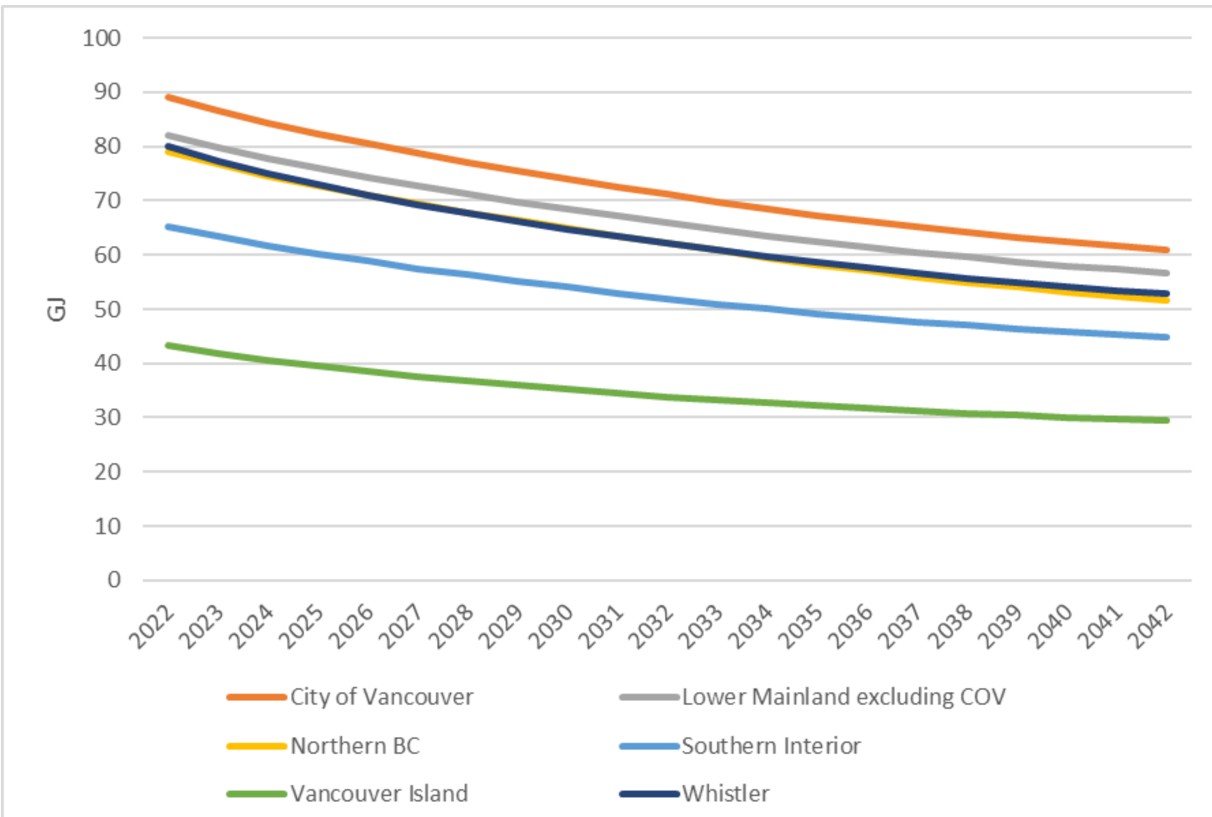
While the Lower Bound and Deep Electrification Scenarios are useful for examining a full range of possible future actions and testing the boundaries of the critical uncertainties that can change the way energy is used in the future, there are significant implications for electricity demand, particularly with respect to peak capacity requirements, system resiliency and economic implications, that cannot be reconciled for these scenarios. Both of these scenarios assume that 100 percent of residential and commercial demand for gas is switched to electricity by 2050, and that 30 percent of industrial demand is switched to electricity in the Lower Bound Scenario and 20 percent in the Deep Electrification Scenario over that time period.

77.2 Please advise if FEI anticipates regional diversity with regard to residential UPC trends.

Response:

FEI anticipates similar UPC trends for all regions. The long-term residential UPC trend is declining for all regions as shown in the following figure.

Figure 1: Residential UPC by Region for the DEP Scenario



78. Reference: FEI Response[51] to CEC IR 1.29.4

> **<u>Response:</u>**
>
> The following table shows the FEI weather-normalized commercial use rates for the ten-year period ending in 2019 by rate schedule. The CAGRs over the period for Rate Schedules 2 and 3 were almost flat at 0.06 percent and 0.09 percent, respectively, indicating very little year-over-year change to the use rates for these classes. The CAGR for the large commercial class (Rate Schedule 23) was 0.41 percent per year.

Commercial Use Rates											
Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
Rate Schedule 2	316.2	317.7	341.2	331.6	330.6	332.6	339.1	336.8	332.5	318.1	0.06%
Rate Schedule 3	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,550	3,517	0.09%
Rate Schedule 23	4,050	5,130	5,230	5,149	5,260	5,174	5,279	5,361	5,345	5,051	0.41%

78.1 To the extent that FEI may have actual data, did the CAGR trend for the large commercial class (Rate Schedule 23) continue over the period 2020-2022? Please provide commentary as to what FEI may have observed in this regard, from the most recent years of actuals.

<u>Response:</u>

The CAGR trend for the large commercial class (Rate Schedule 23) increased to 2.26 percent for the period from 2020 to 2022, as shown in the following table.

Table 1: Rate Schedule 23 UPC and CAGR

Use Rates (GJ)	2020	2021	2022	CAGR
Rate Schedule 23	5,440.7	5,724.3	5,818.1	2.26%

As explained in the response to CEC IR1 29.4, FEI cannot definitively explain changes in UPC or consumption patterns.

78.2 To what factors does FEI attribute the declining commercial UPC for the Vancouver Island region?

<u>Response:</u>

FEI notes that the response to CEC IR1 29.4 and reproduced in the preamble of this question is for the entire FEI region, and not specifically for Vancouver Island as asked in this question.

The following table for Vancouver Island commercial use rates shows that Rate Schedule 2 use rates have declined very slightly since 2013. Rate Schedule 3 use rates have been declining more

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51 Exhibit B-12.

steadily and the CAGR for rate schedule 3 is -1.8 percent. Rate Schedule 23 use rates have increased slightly since 2015.

Commercial Use Rates											
VI UPC, GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	CAGR
Rate Schedule 2	344	328	346	343	345	351	333	322	331	338	-0.2%
Rate Schedule 3	4,431	3,901	3,894	4,060	4,181	4,074	3,827	3,404	3,604	3,708	-1.8%
Rate Schedule 23			5,636	5,052	5,158	5,260	4,369	4,727	6,023	5,751	0.3%

Commercial customers on Vancouver Island operate in 141 industrial sectors. These sectors are each subject to different factors that may both increase and decrease use rates for customers. FEI cannot definitively explain any change in UPC in a given year, as it is a result of many factors that may be both compounding and offsetting.

FEI expects that its demand will continue to be influenced by many factors that may have affected demand variances in the past, including customer behavior, economic activity, DSM, government policies (such as environmental policy), new technology, etc.

79. Reference: FEI Response[52] to CEC IR 1.30.1

Response:

The tables below provide FEI's Commercial and Industrial Program Area expenditures and associated energy savings for the 2016 to 2021 program years.

	2016	2017	2018	2019	2020	2021	Total
Commercial							
Utility Expenditures ($000s)	$10,637	$10,834	$10,098	$11,709	$13,571	$21,309	$78,159
Incremental Annual Gas Savings, Net (GJ)	255,408	238,688	234,228	281,205	334,485	413,589	1,757,603
Industrial							
Utility Expenditures ($000s)	$1,003	$2,099	$3,195	$6,481	$6,124	$5,438	$24,340
Incremental Annual Gas Savings, Net (GJ)	18,349	105,516	123,356	301,668	269,354	297,760	1,116,003

79.1 The CEC calculates that, for the period 2016 to 2021, FEI's DSM expenditures for the Commercial Program Area were in the range of $40.57 - $51.52 per GJ of net gas saved annually, for an average over the entire period of $44.47 per GJ. Please confirm the calculations.

Response:

Confirmed.

79.2 The CEC calculates that, for the period 2016 to 2021, FEI's DSM expenditures for the Industrial Program Area, were in the range of $18.26 - $54.66 per GJ of net gas saved annually, for an average over the entire period of $21.81 per GJ. Please confirm the calculations.

Response:

In preparing this response, FEI noted that its 2021 industrial DSM expenditures illustrated in the table were incorrect as they represented the planned industrial DSM expenditures rather than actual. Therefore, $5.438 million in the table above was replaced with $6.095 million for the purposes of this calculation. As a result, DSM expenditures for the Industrial Program Area for the period of 2016 to 2021 were in the range of $19.89 - $54.66 per GJ of net gas saved annually, for an average over the period of $22.40 per GJ.

[52] Exhibit B-12.

79.3 For the table above, please provide the annual savings for the next 15 years, year by year, that are associated with each year's DSM expenditures.

Response:

Please note that the table in the preamble represents FEI's actual commercial and industrial DSM expenditures from 2016 to 2021. FEI interprets the question to be seeking the forecasted net incremental annual gas savings from the DEP High DSM Scenario, year by year, from 2022-2036.

Please refer to the response to BCUC IR1 43.5 for further discussion and to review Table 2 in which this information was provided for the combined program areas. For the purpose of this response, FEI used this information to breakdown the annual energy savings by individual program areas as illustrated in Table 1 below.

Table 1: FEI's Estimated Annual Energy Savings by Program Area and Cumulative Energy Savings[53] from 2022 to 2036 in the DEP Scenario - High DSM Setting

Year	Residential	Commercial	Industrial	Annual Savings 1 (GJ/yr)	Cumulative Savings (GJ/yr)
	GJ/Yr	GJ/Yr	GJ/Yr		
2022	998,289	307,480	633,614	2,007,896	6,396,572
2023	755,702	422,528	479,152	1,657,431	8,054,003
2024	604,094	552,806	387,540	1,544,504	9,598,506
2025	444,048	658,578	340,251	1,442,769	11,041,275
2026	407,480	733,898	293,615	1,435,010	12,476,285
2027	383,163	789,521	226,672	1,399,364	13,875,649
2028	373,914	819,384	228,342	1,421,698	15,297,347
2029	312,060	805,693	179,431	1,297,125	16,594,472
2030	258,354	762,863	117,348	1,138,702	17,733,174
2031	323,267	710,230	187,826	1,221,184	18,954,358
2032	303,285	640,751	176,823	1,120,850	20,075,208
2033	261,083	585,974	134,902	981,998	21,057,206
2034	246,137	547,683	123,724	917,499	21,974,705
2035	238,078	486,940	122,602	847,711	22,822,417
2036	161,268	438,848	97,021	697,069	23,519,486

[53] Savings from measures implemented in a specific year are not an output of the model. The model does output the difference between pre-DSM and post-DSM consumption, which is the savings in the current year from all measures still in place from previous years and also the new measures for the current year. To calculate *new* savings from measures installed in a given year, which is what is provided in this table, the previous year's savings (pre-DSM minus post-DSM) were subtracted from the current year's (pre-DSM minus post-DSM consumption). The results are an approximation because the value does not account for changes in reference case adoption or demolition of older buildings.

80. Reference: FEI Response[54] to CEC IR 1.31.2

> 31.2 Do higher avoided costs for natural gas and carbon price increases cause any reconsideration as to FEI's processes for the economic screening of DSM measure potential?
>
> **Response:**
>
> The following response has been provided by Posterity Group in consultation with FEI.
>
> Yes, higher avoided natural gas and carbon price increases impact the economic screening of DSM measures in the following ways:
>
> - Measures that were previously not cost-effective may become cost-effective, and therefore would be proposed for inclusion for future DSM activities.
> - Measures that were previously cost-effective will have their payback period decreased, thereby increasing their forecasted rate of market adoption in the DSM model.

80.1 As FEI states in its response to CEC IR 1.31.2, with higher avoided costs for natural gas and carbon price increases, more measures would be deemed cost-effective resulting in increased or improved DSM propositions. Would this outcome, in turn, prompt FEI to revise its economic screening tests for DSM measures? Please explain.

Response:

FEI does not have jurisdiction to choose or revise its economic screening tests for DSM measures as these tests are set by the Province through the Demand-Side Measures Regulation.

80.2 As the backdrop (in the form of natural gas and carbon pricing) to FEI's economic screening for DSM measures becomes more dynamic, does a need arise for a feedback loop to prompt frequent revisiting of FEI's DSM screening tests? Please explain.

Response:

Please refer to the response to CEC IR2 80.1.

80.3 Does FEI, in its economics screening test, use the anticipated Present Value (PV) of future carbon prices as part of the economic savings test? Please explain.

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[54] Exhibit B-12.

Response:

Yes. FEI includes the known future carbon prices and commodity price forecast in the Total Resource Cost calculations.

81. Reference: FEI Response[55] to CEC IR 1.47.2

> 44.2 Would potential carbon credits associated with such niche applications (in theory) be captured in Figure 9-3?
>
> **Response:**
>
> Figure 9-3 represents the potential GHG emissions reduction associated with fuel switching in the transportation and Global LNG markets. If further niche applications for LNG in BC represented an opportunity to fuel switch from a higher carbon fuel to LNG in these markets, then the related carbon reductions could potentially be represented in a future version of this figure. However, as indicated in Section 9.2.2, FEI is not inferring ownership associated with any carbon credits but instead presenting the overall societal benefit associated with fuel switching. The ability to monetize this GHG emissions reduction in the form of carbon credits would not change this overall societal benefit of fuel switching.

81.1 In FEI's assessment, which party would obtain ownership of carbon credits associated with the purchase of LNG from FEI for use in BC applications, whereby there would be opportunities to fuel switch from a higher carbon fuel to LNG (for example displacement of diesel-generated electricity for remote locations with LNG-fired applications).

Response:

FEI is currently reviewing the federal Clean Fuel Regulations (CFR) to determine how to register and receive CFR compliance credits as a voluntary credit creator. Additionally, FEI is in the process of reviewing which counterparties would obtain ownership of the carbon credits across the different fuels, including RNG, LNG and CNG. FEI can confirm there are opportunities to garner credits from LNG by replacing higher intensity fuels, such as diesel, specifically in transportation applications. As written in the CFR,[56] the ownership of CFR compliance credits is a function of the owner/operator of the LNG fueling station. FEI's understanding of the CFR is that diesel consumption for remote communities is exempted and that LNG for remote communities would not generate credits, although FEI has not confirmed this with Environment and Climate Change Canada.

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[55] Exhibit B-12.

[56] Clean Fuel Regulations. (June 2022). https://www.canadagazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html.

82. Reference: FEI Response[57] to CEC IR 1.45.1

> To be clear, the UPCs listed on page 9-12 of the Application are simply the averages of forecast annual demand divided by the forecast annual customer count from 2022 to 2024 under the DEP scenario. These UPCs listed on page 9-12 of the Application are not used to forecast the demand or the delivery margin for any of the scenarios over the 20-year period of the 2022 LTGRP. Please refer to Section 4 of the Application for an explanation of the demand forecasting methodology used in the 2022 LTGRP.

Table 1: Comparison of Average UPCs between 2022 LTGRP and 2017 LTGRP

Rate Schedule	2022 LTGRP Average 2042 UPC (GJ/Year)	2017 LTGRP Average 2036 UPC (GJ/Year)
Residential (RS 1)	60 GJ per year	72 GJ per year
Small Commercial (RS 2)	293 GJ per year	300 GJ per year
Large Commercial (RS 3)	3,253 GJ per year	3,307 GJ per year
Industrial General Firm Service (RS 5)	18,542 GJ per year	8,153 GJ per year

82.1 The CEC calculates that the average residential UPC in the 2022 LTGRP is approximately 17% lower than that of the 2017 LTGRP. In FEI's assessment, is this entirely a result of expected energy efficiency improvements, or does it also anticipate trends concerning type of housing mix and size of new dwellings?

82.1.1 If the latter, what is the percentage split, as between the average residential UPC decline associated with changes in the type of housing mix versus the decline associated with energy efficiency improvements?

Response:

There are a number of drivers that could lead to lower future use rates in the 2022 LTGRP and the 2017 LTGRP. All drivers are intrinsic in the data used to prepare Table 1 in the preamble. It is possible that this is due to changes in the type of housing mix, or the decline associated with energy efficiency improvements, or other potential drivers. For example, as shown in Table 4-1 of the Application, FEI's DEP Scenario (which Table 1 of the preamble was based on) includes a higher level of electrification than the Reference Scenario, which will lead to a reduced UPC forecast over the 20-year planning period. Furthermore, as discussed in Section 5 of the Application and also illustrated in Figure 5-2 of the Application, FEI's DEP Scenario assumed the high DSM setting as opposed to the Reference Case, which will also lead to an additional reduction in the UPC forecast when compared to the 2017 LTGRP.

FEI is unable to provide the percentage breakdown or split of the average residential UPC decline based on the different drivers, as FEI does not have the detailed data that would be needed to complete this analysis.

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57 Exhibit B-12.

83. Reference: FEI Responses[58] to CEC IR 1.47 Series

> 47.2 How does FEI apply the resiliency criteria to identify and select a preferred project alternative?
>
> **Response:**
>
> FEI applies specific resiliency criteria to each of its service regions based on their own unique system requirements. For instance, the resiliency considerations for the Lower Mainland do not necessarily apply to the Vancouver Island and the Interior Service areas. The Lower Mainland

> 47.3 Does the resiliency criteria contribute (a score) to the ranking of project alternatives; or does the resiliency criteria 'check' result in additional project scope where a resiliency deficiency is identified?
>
> **Response:**
>
> Each of FEI's major capital projects are necessary and have their own unique drivers which contribute to the need and timing for these projects. Although resiliency may not be the primary driver for some projects, many of the capital projects that FEI is currently developing or assessing will improve and strengthen system resiliency. In the ranking of alternatives, FEI considers resiliency, but the score or contribution to alternative project ranking may vary depending on the underlying need for the project. The TLSE Project, for example, has resiliency

83.1 Has FEI finalized and laid out the resilience criteria for each of its service regions, in a formal planning document?

83.1.1 If yes, does FEI plan to share this document in this proceeding, or make it available to stakeholders?

Response:

FEI has not developed resilience criteria for each of its service regions. Instead, system-specific resiliency is addressed on a case-by-case and area-by-area basis, as discussed in the responses to CEC IR1 47.1 and 47.3.

On March 23, 2023, pursuant to the BCUC's Decision and Order G-62-23 relating to the FEI CPCN Application for the TLSE Project, the BCUC invited FEI to provide a detailed resiliency plan and file it as additional evidence in that proceeding. FEI is currently reviewing the BCUC's decision in detail and is assessing the next steps with regard to preparing the additional evidence outlined in the decision, including the requested resiliency plan. Any additional evidence filed publicly in the TLSE Project proceeding would be available for review by interveners and other stakeholders.

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[58] Exhibit B-12.

83.1.2 If not, does FEI envision that its service region-specific resiliency considerations or criteria will form part of the next iteration of its Main Extension (MX) test?

Response:

FEI would not expect to include resiliency considerations or criteria in the next iteration of its MX test. The MX test assesses whether it is reasonable to proceed with system extension activities to connect new customers to the gas system. The MX test considers what is required to connect the customers to the gas system, including, for example, the costs to install pipes, valves, and meters, and compares these requirements to the potential revenues from these new customers.

In contrast, system resiliency affects all customers, both existing and new, either regionally or on the gas system as a whole. Applying system resiliency criteria to customers requesting a new connection to the gas system would therefore result in a differential treatment between existing customers and new customers, even though both would benefit equally from system resiliency activities. FEI submits that this differential treatment would be inappropriate and likely discriminatory to new customers.

84. Reference: Evidentiary Update - Kelowna Electrification Case Study[59]

> • The gas residential use per customer (UPC) was held constant[9] to the 2021 UPC of 71 GJ to isolate the impacts of electrifying from increased demand-side management (DSM) measures and gas heating efficiency gains over the forecast period;

84.1 In response to CEC IR 1.45.1,[60] FEI advises that the average residential gas UPC for purposes of the 2022 LTGRP is estimated at 60 GJ. The CEC understands that the Kelowna Electrification Case Study horizon largely matches that of the 2022 LTGRP, and that both the electrification envisioned in the Kelowna Electrification Case Study and the 2022 LTGRP targets are not presumed to be achieved overnight rather in annual increments over the 20-year horizon. Please further explain, as to why for purposes of the Kelowna Electrification Case Study, FEI and FBC held the average residential gas UPC constant at 71 GJ, thereby removing from any consideration in the study the entirety of the impacts from DSM and gas heating efficiency gains.

Response:

The average residential gas UPC could decline from 71 GJ in 2021 to 60 GJ in 2040 as a result of two reasons:

- Increased DSM and technology measures resulting in a lower usage of gas for the same equivalent end-use requirement; and/or
- Fuel-switching (electrification) of gas load to electric load, meaning customers either reduce or remove their gas usage in favor of electricity.

To understand the impacts of electrification separately as for the purpose of the Study, FEI held the gas UPC constant so that it could instead "toggle" the electrification setting to determine the latter of the above two points. The UPC was set at the 2021 value and held constant to isolate the impacts of the remaining changes in variable settings, to result in the electrification of gas demand cases. Additionally, in an electrification-centric future, FEI assumes that a significantly reduced UPC due to fuel-switching would not result in the same level of DSM measures being pursued and presented as it would be in the response to CEC IR1 45.1 to reduce the UPC to 60 GJ.

84.2 Wouldn't some of the impacts from DSM and gas heating efficiency gains, be incrementally achieved along the way, even while achieving electrification targets incrementally? Please explain.

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59 Exhibit B-20, Page 4.
60 Exhibit B-12.

Response:

Confirmed. In practice, some of the impacts from DSM and gas heating efficiency gains would be expected to occur concurrently with fuel switching initially. However, this would not necessarily be the case out to 2040 for the reasons described in the response to CEC IR2 84.1.

Additionally, as stated in the response to BCUC IR1 30.3, the Kelowna Electrification Case Study was completed to confirm that the Lower Bound and the Deep Electrification Scenarios are not plausible within the timeframe presented in the 2022 LTGRP. This means that the decline in gas usage in the Study meets or exceeds the timeline for electrification of gas demand[61] in the 100 percent electrification case and was not modelled to demonstrate the incremental achievement of both DSM and fuel switching at the same time. These incremental efficiency savings would not alter the conclusions of the Study.

84.3 Please discuss as to why FEI and FBC did not set the average residential gas UPC for the Kelowna Electrification Case Study to reflect the middle of the 60-71 GJ range.

Response:

Please refer to the response to CEC IR2 84.1.

[61] As discussed in Section 3.5 of the Study.

85. Reference: Evidentiary Update - Kelowna Electrification Case Study[62]

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

The settings and assumptions in FEI's forecasting model determined the design peak demand forecasts at a mean daily temperature of -26 C of 711 MW, 950 MW, and 1,429 MW by 2040 for each of the electrification cases, as shown above. The assumptions used in the model to create

[13] The "Renewable Gas" setting in the forecasting model removes conventional gas load from being converted to electricity under the "Electrification %" setting as the gas demand is instead met through low-carbon and renewable gas.

85.1 Please describe what assumptions are embedded in the Kelowna Electrification Case Study, with respect to the level of volumes of RNG gas supply (and/or hydrogen) for each of the electrification scenarios (i.e. 25%, 50%, 75%, and 100%).

Response:

As illustrated in Table 3-1 of the Study, the Renewable Gas setting (any RNG, hydrogen, and other low-carbon gas supply) was held constant at 0 percent to isolate the impacts that electrification would have on reducing gas demand, and subsequently, increasing electric demand. In other words, if the Renewable Gas setting was set at 75 percent, then the model used in the analysis for the Study would effectively remove 75 percent of the gas load first before converting any remaining gas load to electric load through the Electrification setting, meaning electrification on the 75 percent would not be required.

85.2 What priorities are observed in the Kelowna Electrification Case Study with respect to displacement of natural gas vs. RNG (and/or hydrogen) along the path of electrification scenarios (i.e. 25%, 50%, 75%, and 100%)? For example, while on the path to electrifying the City of Kelowna's gas load, does FEI continue to increase RNG (and/or hydrogen) acquisition volumes, or are these assumed to be the first to be displaced on account higher costs (as compared to natural gas), resulting in higher sunk costs along an electrification path?

[62] Exhibit B-20, Page 5, Footnote 13.

Response:

The Kelowna Electrification Case Study was not intended to identify priorities with respect to the acquisition and use of renewable and low carbon gases, but rather was focused on studying the impacts to the electric system of various increments of electrification.

One priority that can be observed in the Study, however, is that the gas and electric systems need to work together and are both integral to achieving climate reduction targets. Therefore, FEI disagrees that increased RNG and other low-carbon gas volumes would result in higher sunk costs since integrating renewable and low-carbon gas supply can effectively be used both as a means to further decarbonize hybrid systems as well as to avoid the expansion of costly electric capacity expansions associated with the electrification of gas demand. The Study demonstrates that a scenario under which electrification is the sole mechanism to meet carbon reduction goals is not plausible, nor the best solution, as it would forego opportunities for the gas system to help decarbonize the provincial energy delivery system in the best interests of all gas and electricity customers.

85.3 How does the Kelowna Electrification Case Study deal with the displacement of natural gas / RNG / Hydrogen for industrial (and certain commercial) applications in the higher electrification scenarios (i.e. 75% and 100%)?

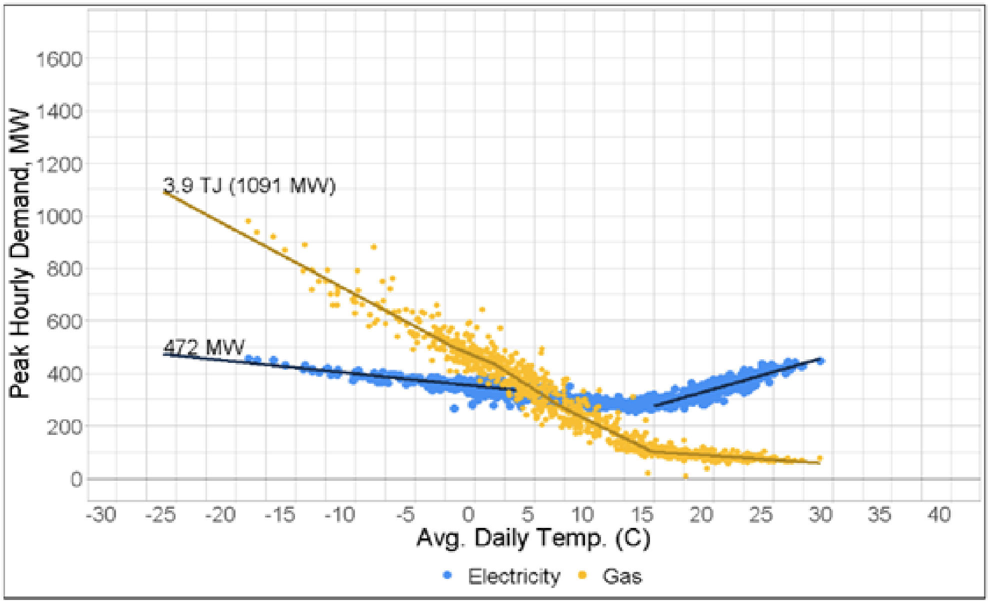
Response:

In the Study, each of the electrification scenarios assumed that there would be a 0 percent renewable gas blend, in order to isolate the impacts of electrification from removing the need to electrify conventional gas load.

In general, industrial customers within the City of Kelowna primarily take gas service under the Transportation model, as discussed in the response to BCUC IR2 119.1.1, and could either electrify or consume a lower carbon fuel than conventional gas.

86. Reference: Evidentiary Update - Kelowna Electrification Case Study[63]

Figure 3-3: City of Kelowna - Electricity and Gas Demand by Temperature in 2040 with Zero Percent Electrification



86.1 Please provide in a table format the actual observed ranges of ‘average daily temperature’ for the City of Kelowna, for each month in year 2020.

<u>Response:</u>

The following table provides the minimum and maximum observed mean daily temperatures (MDT) for the City of Kelowna for each month in 2020.

2020	Minimum MDT	Maximum MDT
January	(18.9)	4.7
February	(6.5)	6.0
March	(4.2)	10.4
April	(0.5)	13.7
May	10.1	19.1
June	9.7	21.2
July	13.7	26.9
August	15.3	29.0
September	11.9	22.7
October	(2.9)	16.4
November	(3.7)	9.3
December	(6.4)	7.5

[63] Exhibit B-20, Page 7, Figure 3-3.