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July 20, 2026

Commercial Energy Consumers Association of BC (CEC)
David Craig, Executive Director

Council of Senior Citizens' Organizations of BC (COSCO)
Leigha Worth, Executive Director General Counsel

Residential Consumer Intervenor Association (RCIA)
Michael Vaney, Executive Director

Dear CEC-COSCO-RCIA:

Re: FortisBC Energy Inc. (FEI)
2026 Long Term Gas Resource Plan (LTGRP)
Response to CEC-COSCO-RCIA Joint Information Request (IR) No. 1

On March 27, 2026, FEI filed the 2026 LTGRP referenced above. In accordance with the regulatory timetable established in British Columbia Utilities Commission (BCUC) Order G-84-26 for the review of the 2026 LTGRP, FEI respectfully submits the attached response to CEC-COSCO-RCIA IR No. 1.[1]

FEI notes that CEC-COSCO-RCIA have submitted IRs that, while presented as a single numbered IR, contain multiple distinct requests for information. For example, CEC-COSCO-RCIA IRs 10.1, 11.1, 12.1, 13.1 and 14.1 are examples of IRs that contain multiple IRs in one.

FEI considers that this approach is inconsistent with the wording and purpose of Order G-111-26. In that Order, the Panel consolidated parties into intervener groups, directed them to file information requests jointly, and limited intervener groups to "a maximum of 30 questions each, inclusive of sub-questions, for Intervener Information Request (IR) No. 1." The intent of these directions was to promote a focused and efficient review process. Submitting compound IRs, or requests including sub-questions that exceed the 30-question limit undermines the efficiency objectives underlying Order G-111-26, increasing the scope of IRs contemplated by the Panel. Further, incorporating multiple IRs into a single IR has decreased the understandability of the questions, which has increased the amount of time and effort required by FEI to respond to the questions and thus has undermined the intended regulatory efficiencies from limiting the number of IRs.

Notwithstanding its concerns regarding compliance with the Panel's direction, FEI has provided responses to these IRs by addressing the central inquiry raised by each request, with

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[1] 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.

a view to assisting the Panel's review of the Application and ensuring that interveners receive responsive information on the key issues they seek to examine. FEI advises that, in future processes, it may object to multiple discrete requests for information being combined into a single question.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registrar
Registered Interveners

1.0 Reference: Exhibit B-1, page ES-17

Preamble: FEI provides the following table:

Table ES-2: Key Elements and Initiatives to Advance Affordability, Reliability and Sustainability

Key Elements and Initiatives	
Coordinated Utility Planning	Strengthen joint collaboration amongst utilities to improve comparability, alignment, and planning for long-term demand scenarios.
Support and Invest in Innovation	Use innovation funding to advance new technologies for demand-side or supply-side resources. Key initiatives include supporting climate adaption and safety in the field leveraging artificial intelligence (AI).
Exploring Opportunities in Transportation, Marine and ISO Shipments	Continue to pursue opportunities to serve demand in these sectors and lower emissions. Key initiatives include hydrogen deployment in heavy-duty transportation and continued development of lower-carbon marine gas.
Pursue Adequate and Cost-Effective DSM	Continue to bring forward portfolios of efficiency and conservation programs and activities that reduce customer consumption and emissions. Key initiatives include dual-fuel systems, deep energy retrofits, and gas-fired heat pumps.
Advance Renewable and Lower-Carbon Gas Supply	Increase renewable and lower-carbon gas supply over the long term, including taking a measured approach to hydrogen development as a strategic priority. Key initiatives include hydrogen pilot and demonstration projects.
Planning Supply Resources	Continue to develop a portfolio of resources that provides customers secure and reliable access to low-cost natural gas supply, and manage supply and pricing risks to mitigate cost pressures. Key initiatives include advancing the North Mist Expansion and TLSE projects to further optimize supply portfolio planning and increase resiliency.
Planning System Resource Needs	Continue to assess peak demand requirements and resolve capacity constraints through pipelines, compression, storage, and non-pipe solutions. Key initiatives include preparing system capacity to support growth in the transportation, marine and ISO shipments sectors.

1.1 For each of the seven key elements and initiatives listed in the table, please provide a qualitative description or explanation of how the initiative promotes, hinders or has no impact on each of the three fundamental priorities of affordability, reliability and sustainability.

Response:

FEI considers affordability, reliability, and sustainability to be fundamental interconnected energy priorities that must be balanced and managed collectively. As discussed in Section 9 of the 2026 LTGRP, balancing these priorities requires managing trade-offs, as actions that advance one priority may create pressures for another, and solutions have advantages and drawbacks in different areas.

FEI provides illustrative examples of how the key elements and initiatives listed in Table ES-2 (also Table 9-12) of the 2026 LTGRP support these interconnected priorities in different ways.

Coordinated Utility Planning:

- Collaboration among utilities, through long-term demand scenario and other planning processes, improves coordination of energy infrastructure investments, supports the

development of energy systems in a complementary manner, and ensures resources are aligned with system needs to support reliability and affordability.

- Coordinated planning, including joint dual-fuel heating system incentive programs or shared development of electric supply-side resources, may enhance economies of scale, improve deliverability and system reliability, and support affordability.

Support and Invest in Innovation:

- Investments in climate adaptation and field safety, including the use of AI-enabled tools, support system performance and enhance long-term reliability.
- In the shorter-term, increased investment in innovation and the adoption of new technologies may increase costs; however, over the longer-term, depending on the efficiencies gained from new technologies, affordability may be enhanced.

Exploring Opportunities in Transportation, Marine and ISO shipments:

- Expanding the use of CNG, R-CNG and hydrogen in heavy-duty transportation supports the transition to lower-carbon energy sources and advances sustainability.
- Supporting the development of LNG infrastructure and the use of R-LNG in the marine sector provides lower-carbon fuel options relative to other marine fuels (e.g., bunker oil) and supports emission reductions in that sector.

Pursue Adequate and Cost-Effective DSM:

- DSM initiatives support reductions in customer energy consumption, contributing to affordability while advancing sustainability through lower energy use and emission reductions.
- DSM programs can also support peak demand reduction and load management, which may defer or optimize the timing of infrastructure investments, thus supporting system reliability and affordability.

Advance Renewable and Lower-Carbon Gas Supply:

- Increasing the availability of renewable and lower-carbon gas supports sustainability by reducing GHG emissions associated with customer energy consumption. Innovation in lower-carbon energy solutions, such as hydrogen, can contribute to achieving sustainability while providing customers with additional lower-carbon supply options.
- FEI's planning approach evaluates a range of renewable gas blending levels and associated bill impacts, recognizing the trade-offs between GHG emissions reductions and affordability.

Planning Supply Resources:

- In FEI's recently accepted 2026/2027 Annual Contracting Plan (ACP), FEI demonstrates how the three interconnected energy priorities are integrated within its contracting strategies for storage, supply, and pipeline resources.[1]
- Long-term supply planning supports the availability of sufficient energy resources to meet customer demand under a range of future conditions, contributing to system reliability. Evaluating multiple supply options also enables considerations of relative cost and emissions impacts.

Planning System Resource Needs:

- Planning and investing in system capacity and infrastructure expansions supports the safe and reliable delivery of energy to customers. By assessing alternative demand forecasts and resource development pathways, FEI can make investment decisions that balance system reliability requirements with customer bill impacts, supporting affordability.

[1] Order G-147-26 dated July 7, 2026, Appendix A, Non-Confidential Executive Summary of the 2026/27 ACP, online at: https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/523231/index.do.

2.0 Reference: Exhibit B-1, page 3-12

Preamble: FEI states:

> *"The results of the referenced third-party studies indicate that although natural gas demand is negatively impacted by an increase in natural gas price (hence negative elasticity estimates), it largely remains inelastic, reflecting the necessity-based nature of natural gas end-uses such as space and water heating."* [footnote omitted]

2.1 Presumably the data used to estimate the long-run price elasticity for residential, commercial and industrial users relied on historical price (and quantity) data. Please provide the range of natural gas prices that formed the data set used to estimate the long-run price elasticity

Response:

Similar to its previous long-term gas resource plans, FEI relies on price elasticity studies conducted by reputable independent research entities for its elasticity estimates. While these studies provide their research methodology for estimating price elasticity, they do not provide a specific range of historical natural gas prices used to estimate elasticity.

The residential and commercial elasticity values are from a 2021 US Energy Information Administration (EIA) report titled "Price Elasticity for Energy Use in Buildings in the United States" (EIA Report). These elasticity estimates are based on simulations that double natural gas prices starting in 2020 and model the associated consumption changes by 2050 under the Annual Energy Outlook (AEO) 2020 Reference Case, which is developed by the EIA's National Energy Modeling System (NEMS). As discussed in the EIA Report, the AEO reference case and NEMS demand modules reflect simulated responses grounded in historical data and expert judgement, rather than an observed historical price-quantity relationship:[2]

> To estimate responses to energy price changes, this analysis considers a series of simulations performed by adjusting the energy price paths from the AEO2020 Reference case. Only the buildings modules are used in these simulations; integrated effects with the rest of NEMS are not included. The elasticities computed from the NEMS projections reflect the results of statistical analyses of historical energy price and consumption data, along with expert judgment. The three main energy sources for the commercial and residential sectors are electricity, natural gas, and distillate. To compute the price elasticities, for each simulation, the price of one of these energy sources is doubled.

The Washington State Department of Commerce was the source used for the industrial sector price elasticity value since the EIA Report did not provide values from the industrial sector. The Washington State Department of Commerce Carbon Tax Assessment Model (CTAM) publishes

[2] U.S Energy Information Administration, "Price Elasticity for Energy Use in Buildings in the United States" (January 2021), p. 1, online at: https://www.eia.gov/analysis/studies/buildings/energyuse/pdf/price_elasticities.pdf.

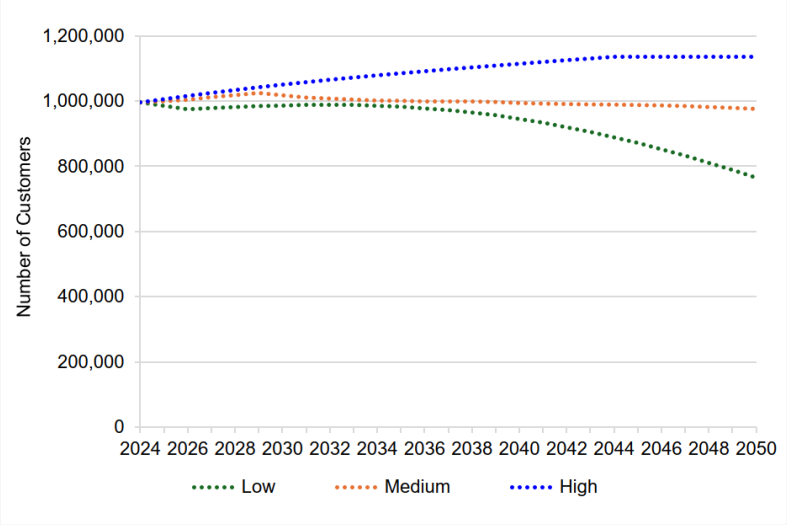
the long-run price elasticity values by sector and fuel used in their analysis[3] that were obtained by conducting a literature review. For the industrial sector specifically, several primary studies contributed to the determination of the price elasticity value. The "default" value from the CTAM's elasticities dataset for the industrial sector for natural gas was used for the 2026 LTGRP.

[3] Pacific Northwest Economic Region, *Carbon Tax Modeling for Washington State* (2015), p. 8, online at: https://pnrec.org/wp-content/uploads/2024/01/2015_Carbon-Tax-Modeling-Washington.pdf.

3.0 Reference: Exhibit B-1, page 3-26

Preamble: FEI provides the following figure:

Figure 3-10: Residential Customer Accounts Sensitivity from Crowd Opinion Forecast and BAU Forecast



3.1 Please explain how the "Low" customer account setting has been incorporated into the 2026 LTGRP analysis and specify the cumulative delivery rate impact for the remaining residential customers if this sensitivity materializes while FEI proceeds with the capital expenditure plan associated with the Diversified Approach.

Response:

The “Low” residential customer account sensitivity has been incorporated into the 2026 LTGRP in response to the BCUC’s recommendation to consider potential demand reduction impacts. This sensitivity is included as an analytical consideration in response to the BCUC’s recommendation rather than a key resource planning assumption.

With respect to rate impacts, the 2026 LTGRP does not quantify cumulative delivery rate effects under this sensitivity within the Diversified Approach. Should a future scenario emerge in which residential customer accounts decline toward the “Low” setting (as illustrated in Figure 3-10), a comprehensive rate impact assessment could assist in considering the interaction between reduced customer volumes and the associated capital expenditure program to fully understand potential implications for remaining residential customers.

While FEI has not yet observed customer attrition in its historical and current data, its resource planning framework is designed to be adaptive to evolving demand conditions. Infrastructure investment decisions are actively managed rather than fixed, enabling FEI to reassess the timing, scale, and scope of planned investments in response to sustained changes in demand to ensure alignment with system needs.

4.0 Reference: Exhibit B-1, page 5-7

Preamble: FEI provides the following table:

Table 5-1: Renewable and Lower-Carbon Gas Supply Outlook (PJ/Year)

	Low Setting				Medium Setting				High Setting			
Milestone Year	RNG	H_2	Other Fuels	Total	RNG	H_2	Other Fuels	Total	RNG	H_2	Other Fuels	Total
2030	16.8	0.0	0.0	**16.8**	29.0	1.0	0.0	**30.0**	39.5	4.5	0.0	**44.0**
2040	16.8	0.0	0.0	**16.8**	48.5	13.2	0.0	**61.7**	71.1	21.3	1.3	**93.6**
2050	16.8	0.0	0.0	**16.8**	60.0	60.0	0.0	**120.0**	90.1	70.0	5.0	**165.1**

4.1 Please explain what technology drivers or policy drivers lead to increases in both RNG and Hydrogen (H_2) under the Medium and High Settings.

Response:

The increases in RNG and hydrogen supply under the Medium and High settings reflect assumed advancements in both technology and policy over the planning horizon.

From a technology perspective, increases in RNG supply are supported by expected improvements in project development and upgrading technologies, including the emergence of smaller-scale production, modular production, gas production enhancements, and output management providing additional revenues (e.g., improved fertilizers). These types of technologies can lower capital costs and/or improve supplier revenues to enable the development of projects using distributed or lower-volume feedstock sources that may not have been economically viable previously.

From a policy perspective, the Medium and High settings assume continued support for lower-carbon fuels through regulatory and market mechanisms. Demand-side measures, such as the Output-Based Pricing System (OBPS) which encourages industries to reduce GHG emissions through measures such as fuel switching to RNG, can provide greater certainty for project developers by ensuring a stable market for produced volumes. This type of demand certainty can strengthen investment signals and support the development of additional supply.

In addition, policy clarity and stability, including defined program duration under frameworks such as the Clean Fuel Regulations (CFR), can improve confidence by reducing long-term uncertainty. This can support investment in RNG and hydrogen production by providing more predictable revenue expectations over the life of a project.

Together, these technology and policy drivers underpin the higher levels of RNG and hydrogen supply under the Medium and High settings, while remaining subject to the broader uncertainties identified in the 2026 LTGRP.

5.0 Reference: Exhibit B-1, pages 5-8 and 5-9

Preamble: On page 4-8, FEI provides the following table:

Table 5-3: Potential RNG – Breakdown by Within Province and Out-of-Province Sources (PJ/Year)

	Low			Medium			High		
Milestone Years	Within BC	Outside BC	Total	Within BC	Outside BC	Total	Within BC	Outside BC	Total
2030	2.5	14.4	**16.8**	4.3	24.7	**29.0**	5.8	33.7	**39.5**
2040	2.5	14.4	**16.8**	7.1	41.4	**48.5**	10.5	60.6	**71.1**
2050	2.5	14.4	**16.8**	8.8	51.2	**60.0**	13.2	76.8	**90.1**

On page 5-9, FEI states:

"More recently, the Inner City Fund (ICF) published a report estimating about 275 PJ of expected RNG supply by 2030 within North America based on existing projects." [footnote omitted]

5.1 Please provide a comparison of BC's current (most recent available data) consumption of RNG relative to North American (Canada and US) use of RNG.

Response:

FEI estimates that:

- Based on data from third-party sources[4], RNG represents approximately 0.5 percent of total natural gas consumption in North America;
- BC's RNG consumption represents approximately 2 percent of total North American RNG use; and
- RNG consumption in BC is approximately 2.5 percent of total natural gas consumption in the province.

While subject to data limitations, these estimates are consistent with the early-stage development of the RNG market.

5.1.1 Please provide an overview of usage and trends of RNG across jurisdictions in Canada and the United States.

[4] Wood Mackenzie, News Release: "Robust growth drives North America RNG market to 604 mmcfd capacity in 2025" (June 26, 2025), online at: https://www.woodmac.com/press-releases/robust-growth-drives-north-america-rng-market-to-604-mmcfd-capacity-in-2025/.

Response:

RNG use in Canada and the US remains at an early stage but has been increasing, largely driven by supportive policy and regulatory frameworks.

In Canada, RNG use is concentrated in provinces with established policies and utility programs. In BC, RNG is supported by provincial climate policy and utility programs that enable both voluntary participation and system-wide blending into the natural gas system. Québec has adopted a regulatory approach with mandatory RNG blending requirements, including a target of 10 percent. More recently, Québec has proposed extending the timeline for achieving this target from 2030 to 2032. Other provinces, such as Ontario, rely primarily on voluntary utility programs, while provinces such as Alberta are at an earlier stage of RNG adoption with more limited policy support.

In the United States, RNG use has increased significantly, particularly in the transportation sector, supported by federal and state policy incentives. The federal Renewable Fuel Standard[5] requires increasing volumes of renewable fuels in transportation and generates Renewable Identification Number (RIN) credits, which provide financial value and encourage RNG production and consumption.[6] State level programs, particularly California's Low Carbon Fuel Standard,[7] provide additional incentives for low carbon fuels, further supporting RNG demand. As a result, RNG consumption has grown over time. For example, RNG volumes used under the California Low Carbon Fuel Standard increased from approximately 15.5 million MMBtu in 2018 to 29.2 million MMBtu in 2024.[8] In addition, RNG accounted for approximately 79 percent of on-road natural gas vehicle fuel use in 2023,[9] indicating strong uptake within the transportation sector.

Overall, trends across jurisdictions indicate increasing adoption over time, with differences in usage patterns largely driven by the structure and strength of policy and regulatory frameworks.

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5 United States Environmental Protection Agency, Renewable Fuel Standard (June 8, 2026), online at: https://www.epa.gov/renewable-fuel-standard.

6 United States Environmental Protection Agency, Renewable Identification Numbers (RINs) under the Renewable Fuel Standard Program (December 31, 2025), online at: https://www.epa.gov/renewable-fuel-standard/renewable-identification-numbers-rins-under-renewable-fuel-standard-program.

7 California Air Resources Board, Low Carbon Fuel Standard (2026), online at: https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard.

8 cCarbon, Scaling North American Renewable Natural Gas: Outlook to 2035 Highlights Policy Momentum and Feedstock Evolution (September 11, 2025), online at: https://www.ccarbon.info/article/scaling-north-american-renewable-natural-gas-outlook-to-2035-highlights-policy-momentum-and-feedstock-evolution/.

9 The Transportation Project, Press Release: Renewable Natural Gas Breaking Motor Fuel Usage Records (April 24, 2024), online at: https://transportproject.org/2024/04/24/renewable-natural-gas-breaking-motor-fuel-usage-records-2/.

6.0 Reference: Exhibit B-1, pages 5-14 and 5-15

Preamble: FEI states:

"A more detailed breakdown of the signposts is provided below:

- *Economics*

  …

- *Market Adoption*

  …

- *Policy and Regulatory*

  …

- *Technology and Infrastructure*

  ….

These signposts collectively determine whether hydrogen can progress beyond pilots to commercial-scale deployment. FEI's strategy is to advance readiness while monitoring these indicators, ensuring that when conditions align, the organization is positioned to enable a scalable hydrogen economy in a manner that is prudent, cost-effective, and aligned with provincial emissions reduction goals."

6.1 For each of the listed Signposts, please provide the assumptions FEI has made regarding the year (or range of years) when the signpost will be reached.

Response:

FEI has not assigned a specific year or range of years for when each of the listed signposts will be reached. The signposts are not intended to operate as fixed forecast milestones; rather, they are indicators that FEI will monitor to assess whether conditions are supportive of progressing hydrogen from early-stage activity toward broader commercial-scale deployment.

The timing of the Economics, Market Adoption, Policy and Regulatory, and Technology and Infrastructure signposts will depend on the evolution of external conditions, including market demand aggregation, technology maturity, cost competitiveness, and policy and regulatory support.

7.0 Reference: Exhibit B-1, pages 5-17 and 5-18

Preamble: On page 5-17, FEI states:

"The cost to produce renewable and lower-carbon gas may go down over time and will be influenced by technological improvements that will positively impact production volumes and associated benefits resulting from economies of scale."

On page 5-18, FEI provides the following:

Table 5-4: Outlook of Energy Prices for Fuel Types[143]

	Price Forecast (Real $2023)								
	Low ($/GJ)			Medium ($/GJ)			High ($/GJ)		
Milestone Years	NG[144]	RNG	H_2	NG	RNG	H_2	NG	RNG	H_2
2025	2.24	24.88	24.79	2.84	25.01	25.20	4.07	25.34	26.01
2030	2.29	24.88	21.89	3.08	25.69	23.22	4.81	27.79	29.25
2035	2.70	20.92	20.81	3.80	26.39	23.96	5.47	30.48	35.41
2040	2.71	17.49	19,79	4.25	27.11	24.26	5.70	33.42	42.88
2045	3.10	14.52	18.82	4.47	27.85	24.81	6.13	36.65	51.92
2050	3.48	11.95	17.90	4.60	28.61	25.09	6.46	40.20	62.86

7.1 For the Medium price assumption and the High price assumption, please explain why prices of both RNG and Hydrogen (H2) increase when development of both of these relatively nascent industries should see reduced costs arising from scale economies, learning by doing, etc.

Response:

The Medium and High price assumptions reflect trajectories in which the factors increasing the real cost of RNG and hydrogen supply are greater than the cost reductions associated with technological improvements and economies of scale.

While technological learning and scale efficiencies are expected to reduce production costs over time, FEI also expects that additional supply will increasingly come from higher cost feedstocks, projects, or production pathways as lower cost opportunities are developed first. In addition, growing demand for renewable and lower carbon gases across jurisdictions and sectors may increase competition for available supply.

Accordingly, the Medium and High assumptions reflect trajectories in which increasing marginal supply costs and market demand outweigh the expected benefits of technological improvement and economies of scale, resulting in increasing real prices over the planning horizon.

8.0 Reference: Exhibit B-1, page 6-8

Preamble: FEI states:

"Therefore, until new infrastructure is developed, the most practical approach to maintain the 15 percent planning margin for resiliency purposes is to utilize Huntingdon/Sumas supply options through shippers that hold firm pipeline capacity in the region."

8.1 Please provide a table covering the period 2010 through 2025 that lists each date when FEI has drawn on the contingency resources, the duration of the event, the amount of energy purchased, and the average price paid (2023 $CAD/GJ).

Response:

Between the 2010/2011 and the 2017/2018 gas years, FEI did not maintain contingency resources within its gas supply portfolio. Rather, the October 9, 2018 rupture on the Westcoast T-South pipeline system and the subsequent capacity restrictions imposed on that system (T-South Incident) highlighted a material risk to FEI's ability to reliably meet customer demand, necessitating the establishment of contingency resources. The development and evolution of these contingency arrangements are described in further detail below.

Contingency resources, including excess pipeline capacity on the T-South system and Huntingdon/Sumas supply arrangements (including Sumas call options), are integrated components of FEI's overall gas supply portfolio. These resources are not dispatched as discrete supply sources but are instead managed and utilized on a system-wide basis to meet aggregate load requirements. As such, FEI does not maintain records identifying specific dates when contingency resources are drawn, the duration of such events, the volumes attributable solely to contingency resources, or the corresponding average prices. Therefore, FEI is unable to provide the requested table of individual contingency draw events. Instead, FEI provides a summary of the fixed costs associated with maintaining these contingency resources (table below), together with a description of how they have been utilized since the T-South Incident.

Table 1: Annual Cost of Maintaining Contingency Capacity and Supply Arrangements

Gas Year	Fixed Cost ($CAD millions)
2018/2019	209.1
2019/2020	57.7
2020/2021	17.2
2021/2022	18.0
2022/2023	10.8
2023/2024	11.8
2024/2025	8.2

To mitigate the risks associated with the T-South Incident for the 2018/2019 gas year, FEI filed an Amendment to the 2018/2019 ACP to secure incremental supply (approximately 125 TJ/day) at the Huntingdon/Sumas market. This supply was acquired in lieu of stranded Station 2 volumes that could no longer reliably flow on the restricted T-South system. At that time, Huntingdon/Sumas supply represented the only feasible option to ensure continuity of supply for FEI's Core customers. As illustrated in Table 1 above, the fixed costs associated with securing these arrangements were high, totaling $209 million in 2018/2019, reflecting both the constrained market conditions and the absence of lower-cost alternatives.

Capacity constraints on the T-South system persisted into the 2019/2020 gas year. In addition, a significant volume of transportation service customers returned to bundled service after the T-South Incident, increasing FEI's supply requirement for that gas year. As a result, FEI continued to rely on Huntingdon/Sumas supply arrangements at approximately 95 TJ/day, resulting in continued elevated fixed costs.

Following these two gas years, FEI secured additional transportation capacity through a combination of secondary market transactions on the T-South system and taking back capacity on FEI's Southern Crossing Pipeline (SCP).[10] These actions resulted in approximately 90 TJ/day of incremental pipeline capacity, which has since been used to support a 15 percent planning margin as discussed in Section 6.4.1 of the 2026 LTGRP. While fixed costs associated with this capacity are reflected in the 2020/2021 and 2021/2022 gas years (see the table above), these costs were primarily offset through ongoing portfolio optimization activities (i.e., selling the Station 2 supply if it is not required on a daily basis at the Huntingdon/Sumas market).

From the 2022/2023 gas year through the 2024/2025 gas year, the composition of contingency resources has changed, with a reduced level of excess pipeline capacity available to support the 15 percent planning margin, declining to approximately 45 TJ/day. In previous years, excess pipeline capacity was sufficient to substantively meet the full planning margin requirement. However, growth in Core customer market demand, specifically from the ongoing movement of transportation service customers returning to bundled service, has reduced the amount of surplus pipeline capacity available for contingency purposes.

To maintain the 15 percent planning margin, FEI has supplemented its portfolio with Sumas call options. As a result, contingency resources are now comprised of a combination of excess pipeline capacity and Sumas options. As shown in the table above, the incremental fixed costs associated with contingency resources have declined materially beginning in the 2022/2023 gas year, coinciding with FEI's increased reliance on Sumas call options to maintain the 15 percent planning margin. While this shift has reduced near-term fixed costs relative to earlier years when contingency requirements were largely met through higher cost pipeline-based arrangements, it introduces greater exposure to potential commodity price volatility. Specifically, because Sumas call options have not been called upon/executed in these years, the recorded costs remain low; however, if system conditions were to require their use, FEI could incur significantly higher incremental gas costs. As such, the lower fixed costs reflected in the table for recent years should

[10] A portion of pipeline capacity on the SCP was historically contracted out to regional parties. However, FEI took back this capacity effective November 1, 2020, as it was the only opportunity for FEI to diversity its supply portfolio.

be considered alongside the increased reliance on contingent resources that may result in higher costs under disruption scenarios.

Finally, since implementing this approach, including maintaining contingency resources and securing additional pipeline capacity, overall gas supply costs have remained low while continuing to support system reliability and the 15 percent planning margin.

9.0 Reference: Exhibit B-1, page 6-13 and 6-14

Preamble: FEI states:

"During this interim period, FEI's portfolio would experience increased exposure to the Huntingdon/Sumas market. Although this exposure is expected to be limited in duration, the longer-term planning risk arises if the in-service date of the project is further delayed, which would extend FEI's reliance on higher-risk market-based supply alternatives."

9.1 Please explain whether there are technical or contractual constraints that would prevent FEI from relying on gas storage in Alberta (at Rockpoint or a different storage location) during the aforementioned interim period.

Response:

FEI's Rockpoint supply contributes to overall supply diversity within its portfolio, but does not directly address the primary constraint facing the region, which relates to storage and pipeline limitations serving the Lower Mainland and the Pacific Northwest (PNW) region.

While FEI could potentially secure additional supply at Rockpoint, the ability to deliver incremental volumes into the Lower Mainland is constrained by the operating capacity on FEI's SCP. As a result, additional Rockpoint supply would not materially enhance FEI's ability to meet peak or contingency demand requirements, as upstream supply availability does not translate into incremental deliverability without corresponding pipeline capacity.

Accordingly, Rockpoint is not a solution to address the regional delivery constraints that underpin FEI's contingency planning needs.

10.0 Reference: AFFORDABILITY: RATE IMPACT IMPLICATIONS OF SCENARIOS

Exhibit B-1, Section 9.4, Figure 9-7 & Table 9-8

Topic: Drivers of Bill Impacts

Preamble: FEI's LTGRP includes forecasts of cumulative delivery-rate impacts and residential bill impacts under each long-term scenario. While the LTGRP discusses factors that influence affordability, it does not clearly identify the relative contribution of individual drivers to the differences in customer impacts observed across scenarios. From a ratepayer standpoint, understanding the principal drivers of residential customer costs is important in assessing the affordability implications of alternative planning pathways.

10.1 Please explain, in general terms, the primary drivers of differences in residential delivery-rate impacts and the average residential bill impacts relative to FEI's currently approved rates between the LTGRP scenarios, including both the overall trends and outcomes along with the way in which those are forecast to affect those rates and bill impacts in 2040 and 2050. In this response, please quantify the contributions of the key drivers including but not limited to the forecast changes in annual demand, DSM expenditures, renewable and lower-carbon gas procurement, capital expenditures, new large load and LNG demand, dual-fuel adoption and any other material contributors. Where FEI has not quantified or is not able to quantify those contributors, please explain why not and identify the information available to FEI regarding the relative significance of the factor.

Response:

Please refer to Tables 1 and 2 below for a comparison of the estimated cumulative delivery rate impact and total bill impact for residential customers from 2024 to 2040 and from 2024 to 2050, respectively, between all 2026 LTGRP scenarios, broken down by various drivers. FEI's description of each driver is provided below.

Delivery Rate-Related Drivers:

- **Reference Driver:** the actual delivery rate increase from 2024 to 2026 as well as increases from 2027 to 2050 due to factors that are not influenced by any LTGRP scenarios and are applied equally across all scenarios. These factors include:
    - Inflationary increases in O&M and property tax;
    - Cost of service (i.e., depreciation, income tax, and earned return) on assets already in FEI's rate base up to 2026 as well as capitalized overhead from 2027 to 2050; and
    - Retirement of existing assets (based on approved depreciation rates) and salvage provision from 2027 to 2050 for FEI's existing assets.

- **Demand Forecast Driver:** captures changes in the demand under each scenario over the 27-year analysis period (from 2024 to 2050) as illustrated in Section 3.6 of the 2026 LTGRP. The impact on demand due to adoption of dual-fuel systems or fuel switching driven by policies or incentives are reflected in the demand forecast of each scenario. For example, when developing the demand forecast for the Diversified Approach and the Lower-Carbon Transportation and LNG Future scenarios, the adoption of dual-fuel systems would be prioritized, whereas the Electrification Focus scenario would prioritize fuel switching.
- **DSM Expenditures Driver:** provides the associated savings in demand for each scenario in accordance with Table 4-1 in Section 4.3.2 of the 2026 LTGRP.
- **Regular Capital (Growth and Sustainment) Driver:** based on the approved[11] levels from the FortisBC 2025-2027 Rate-Setting Framework (RSF) Application.
- **Major Projects Driver:** captures recently filed or approved major capital projects (includes both BCUC-approved major projects and projects approved through Order in Council (OIC)):
    - Inland Gas Upgrades (IGU) Project;
    - Pattullo Gas Line Replacement Project;
    - Tilbury LNG Storage Expansion (TLSE) Project, including gas supply benefits;
    - Advanced Metering Infrastructure (AMI) Project;
    - CTS and ITS Transmission Integrity Management Capabilities (TIMC) Projects;
    - Okanagan Capacity Mitigation Plan (OCMP) Project;
    - Gibsons Capacity Upgrade (GCU) Project; and
    - Enterprise Resource Planning (ERP) Modernization Project.
- **New Large Load and LNG Demand Driver:** includes both costs (i.e., cost of service related to Tilbury Phases 1A and 1B, and Eagle Mountain-Woodfibre Gas Pipeline) and offsetting revenue (i.e., RS 46 and RS 50).

Commodity Cost-Related Drivers:

- **Cost of Gas and S&T Charge Driver:** reflects the cost of gas and storage and transport (S&T) charges, including approved actual increases from 2024 to 2026 and the long-term price forecast from 2027 to 2050 shown in Table 5-4 of Section 5.4 of the 2026 LTGRP, dependent on each LTGRP scenario.
- **Renewable and Lower-Carbon Gas Blending Driver:** includes the blending percentage of renewable and lower-carbon gas under each LTGRP scenario in accordance with Table 5-2 of Section 5.3.1 of the 2026 LTGRP.

[11] 2025-2027 RSF Decision and Order G-69-25.

Other Drivers:

- **Elimination of Carbon Tax (From 2025) Driver:** reflects the impact to customer bills due to the elimination of the carbon tax on April 1, 2025, given the 27-year analysis period for the 2026 LTGRP begins in 2024.

Table 1: Cumulative and Compound Annual Delivery Rate and Total Bill Impact for Average Residential Customer by 2040 (2024 to 2040) by Driver

	2024 to 2040		2024 to 2040		2024 to 2040		2024 to 2040		2024 to 2040	
	Diversified Approach		Electrification Focus		Prolonged Transition		Lower-Carbon Transportation and LNG Future		Baseline Trends	
Drivers	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual
Delivery Rate Related:										
Reference	26%	1.4%	26%	1.4%	26%	1.4%	26%	1.4%	26%	1.4%
Demand Forecast	14%	0.8%	36%	1.8%	6%	0.3%	31%	1.6%	28%	1.5%
DSM Expenditures	26%	1.4%	12%	0.7%	16%	0.9%	11%	0.6%	11%	0.6%
Regular Capital (Growth and Sustainment)	17%	0.9%	19%	1.1%	16%	0.9%	20%	1.1%	18%	1.0%
Major Capital (CPCNs)	12%	0.7%	5%	0.3%	5%	0.3%	27%	1.4%	13%	0.7%
New Large Load and LNG Demand	-6%	-0.3%	-6%	-0.3%	-5%	-0.3%	-26%	-1.8%	-6%	-0.4%
Commodity Cost Related:										
Cost fo Gas and S&T Charge	-2%	-0.9%	32%	0.9%	-3%	-0.6%	18%	-0.5%	-3%	-0.7%
RG and Lower-Carbon Gas Blending	32%	2.2%	12%	1.4%	3%	0.6%	79%	4.3%	5%	0.7%
Other:										
Elimination of Carbon Tax (From 2025)	-19%	-1.2%	-19%	-1.2%	-19%	-1.2%	-19%	-1.2%	-19%	-1.2%
Total Cumulative Bill Impact - Residential (%)	**100%**	**4.2%**	**117%**	**4.7%**	**46%**	**2.2%**	**166%**	**5.9%**	**73%**	**3.3%**

Table 2: Cumulative and Compound Annual Delivery Rate and Total Bill Impact for Average Residential Customer by 2050 (2024 to 2050) by Driver

	2024 to 2050		2024 to 2050		2024 to 2050		2024 to 2050		2024 to 2050	
	Diversified Approach		Electrification Focus		Prolonged Transition		Lower-Carbon Transportation and LNG Future		Baseline Trends	
Drivers	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual
Delivery Rate Related:										
Reference	37%	1.2%	37%	1.2%	37%	1.2%	37%	1.2%	37%	1.2%
Demand Forecast	25%	0.8%	70%	2.0%	10%	0.3%	59%	1.7%	50%	1.5%
DSM Expenditures	48%	1.5%	26%	0.9%	33%	1.1%	11%	0.4%	22%	0.7%
Regular Capital (Growth and Sustainment)	32%	1.0%	42%	1.3%	30%	1.0%	38%	1.2%	36%	1.1%
Major Capital (CPCNs)	8%	0.3%	1%	0.1%	2%	0.1%	20%	0.7%	8%	0.3%
New Large Load and LNG Demand	-14%	-0.6%	-12%	-0.5%	-9%	-0.3%	-53%	-2.8%	-14%	-0.5%
Commodity Related:										
Cost fo Gas and S&T Charge	3%	-0.8%	42%	0.8%	2%	-0.1%	19%	-0.6%	2%	-0.2%
RG and Lower-Carbon Gas Blending	60%	2.3%	22%	1.3%	2%	0.3%	134%	3.7%	4%	0.4%
Other:										
Elimination of Carbon Tax (From 2025)	-19%	-0.8%	-19%	-0.8%	-19%	-0.8%	-19%	-0.8%	-19%	-0.8%
Total Cumulative Bill Impact - Residential (%)	**181%**	**3.9%**	**208%**	**4.3%**	**88%**	**2.4%**	**245%**	**4.7%**	**126%**	**3.1%**

As shown in the above tables, the primary drivers for the delivery rate increase and total bill impact for an average residential customer are different depending on the LTGRP scenarios, as further discussed below.

<u>Diversified Approach:</u>

- The largest driver of the increases by 2040 and by 2050 under the Diversified Approach scenario is the level of renewable and lower-carbon gas blending into FEI's system (i.e.,

up to 84 percent by 2050), followed by DSM expenditures. These two drivers play an important role in achieving the climate targets in terms of GHG emissions reductions towards the end of the 27-year analysis period, as shown in Figure 9-4 of the 2026 LTGRP.

- The growth in LNG demand under the Diversified Approach scenario helps to offset some of the delivery rate and total bill impacts over the 27-year period.

Electrification Focus:

- The largest driver of the increases by 2040 and by 2050 under the Electrification Focus scenario is the significant reduction in demand due to the prioritization of fuel switching through polices and incentives. However, as shown in Figure 9-4 of the 2026 LTGRP, the Electrification Focus scenario would not achieve the climate targets in terms of GHG emissions reductions over the 27-year analysis period. The second largest driver of the increases is the high price of commodity due to the minimal support and lack of market demand for renewable and lower-carbon gas, despite FEI only assuming approximately 15 percent blending by 2050.
- Although the demand under the Electrification Focus scenario is assumed to decline significantly, sustainment capital is still needed to provide safe and reliable service for the remaining customers and load. The substantially reduced demand increases the per unit cost, resulting in the ongoing sustainment capital becoming the third largest driver of the delivery rate and total bill impacts.

Prolonged Transition:

- The three largest drivers under the Prolonged Transition scenario are the cost of service of FEI's existing assets (included as reference in Tables 1 and 2 above), the continuation of DSM programs, and the need for regular capital (growth and sustainment) over the 27-year analysis period.
- The impacts due to renewable and lower-carbon gas and the decline in demand are minimal under the Prolonged Transition scenario, contributing only 2 percent and 10 percent, respectively, toward the overall total bill impact of 88 percent by 2050.

Lower-Carbon Transportation and LNG Future:

- Given the increased blending of renewable and lower-carbon gas to approximately 93 percent as shown in Table 9-10 of the 2026 LTGRP, renewable and lower-carbon gas is the largest driver of the total bill impact by 2050, contributing 134 percent out of the total bill impact of 245 percent. This elevated level of renewable and lower-carbon gas blending leads to the highest GHG emissions reductions out of all the 2026 LTGRP scenarios, as shown in Figure 9-4 of the 2026 LTGRP.
- The significant increase in LNG demand and new large demand (i.e., rate benefit of 53 percent) helps to almost entirely offset the negative impact due to the decline of Core customer load (i.e., rate impact of 59 percent).

Baseline Trends:

- The largest driver for the delivery rate and total bill impacts is the continuation of demand reduction based on current government policies, contributing to approximately 50 percent out of the total bill impact of 126 percent by 2050. This is followed by the cost of service of FEI's existing assets (included as reference in Tables 1 and 2 above) and regular growth and sustainment capital.

11.0 Reference: AFFORDABILITY: RATE IMPACT IMPLICATIONS OF SCENARIOS
Exhibit B-1, Section 9.4

Topic: Affordability Benchmark

Preamble: FEI identifies affordability as one of the primary objectives of its long-term planning framework and presents analysis of delivery-rate and customer bill impacts under the LTGRP scenarios. While the LTGRP discusses the affordability implications of alternative pathways, it is not clear what metric, benchmark, threshold, or customer affordability framework FEI uses to determine whether a particular pathway remains affordable for residential customers. Because there is a fundamental difference between cost-effective, lowest cost, and affordable, it is important to understand specifically how FEI evaluates the affordability of its delivery rates when assessing the relative merits of alternative planning pathways and the significance of forecast customer bill impacts.

11.1 Please explain whether, as a natural gas utility, FEI considers a comparison to electric rates its affordability metric, threshold or its residential customer bill impact benchmark for long-term planning purposes and, if so, why FEI considers this comparison to be appropriate. In doing so, please also discuss whether FEI has considered any customer-oriented affordability measures, including household energy burden, bill-to-income impacts, or impacts on low-and fixed-income customers; whether FEI has established any maximum acceptable residential customer bill impact, delivery-rate impact, or energy burden threshold while specifying whether FEI has assessed any of its LTGRP against such thresholds, putting on the record in this process the results of any such assessment. However, if FEI does not use electric rates to be an appropriate affordability measure or if it has not used any specific affordability metrics, benchmarks or thresholds to assess affordability in this LTGRP, please explain how it performed that assessment as well as how interveners and the Commission are to evaluate the evidence of or representations regarding the affordability of FEI's delivery service to residential customers in each of its long-term planning scenarios.

Response:

While a comparison to electric rates provides important information influencing the energy choices of customers, FEI does not consider electric rates (or the gap between gas and electric rates) to be an affordability metric, threshold, or bill impact benchmark for long-term planning purposes.

FEI considers affordability to be a relative measure that is defined differently by different customer segments, and even by customers within each segment. As such, there is no specific threshold of increase or bill impact, or other metric such as household energy burden, income level, or impact on low- and fixed-income customers that can be used to measure affordability or affordable

rates. This was acknowledged by the BCUC in its decision on FortisBC's 2025-2027 RSF Application:[12]

> The Panel acknowledges BCOAPO's concerns regarding affordability for both FEI and FBC but agrees with FortisBC's position that affordability is subjective and largely depends on the economic position of the individual customer or a household. The Panel acknowledges that rate increases impact all customers and specifically and more disproportionately, low-income customers. However, there is no specific level that can be used to meaningfully measure affordability across FortisBC's customer base at this time.

As discussed in Section 9 of the 2026 LTGRP, FEI considers affordability, reliability, and sustainability to be fundamentally interconnected energy priorities that must be balanced and managed collectively. FEI expects that pursuing policy-driven sustainability initiatives will put pressure on its rates. As such, FEI's view on affordability and affordable rates should be through the lens of FEI's ability to transition to lower-carbon gas at the lowest reasonable cost while also maintaining safe and reliable service to its customers, rather than on specific thresholds of rates or rate increases. In other words, the evaluation regarding affordability should be on which scenario can progress towards the policy-driven climate targets with a lower delivery rate and total bill impact to customers over the long-term planning horizon to 2050.

For instance, as shown in Section 9.4 of the 2026 LTGRP and further discussed in the response to CEC-COSCO-RCIA IR1 10.1, both the Diversified Approach and the Electrification Focus scenarios are pursuing policy-driven climate targets through different approaches (i.e., the Diversified Approach scenario prioritizes dual-fuel systems, blending of renewable and lower-carbon gas, and DSM expenditures, while the Electrification Focus scenario prioritizes fuel switching).[13] However, the Diversified Approach scenario is expected to achieve the provincial GHG emissions reduction target with a lower cumulative delivery rate and total bill impact by 2050 than the Electrification Focus scenario. As such, FEI considers the Diversified Approach scenario, with rate impacts primarily driven by increasing levels of renewable and lower-carbon gas blending and increasing DSM expenditures, to be more cost-effective and affordable for its customers than the Electrification Focus scenario, with rate impacts primarily driven by a substantial decline in demand and an increase in commodity costs due to lack of support and market demand.

[12] Decision and Order G-69-25, p. 69.

[13] As illustrated in Figure 9-4 of the 2026 LTGRP, the Electrification Focus scenario is not projected to achieve the GHG emission reduction targets, whereas the Diversified Approach scenario is projected to exceed the targets toward the end of the 27-year planning horizon of the 2026 LTGRP.

12.0 Reference: AFFORDABILITY: RATE IMPACT IMPLICATIONS OF SCENARIOS
Exhibit B-1, Sections 9.4 & 9.4.3

Topic: Lowest Cost Pathway

Preamble: The LTGRP evaluates alternative long-term pathways and discusses trade-offs between affordability, reliability and sustainability. The LTGRP also presents differing customer bill and delivery-rate impacts across scenarios. However, it is not clear whether FEI has specifically evaluated which pathway represents the lowest-cost option for customers under conditions of declining gas demand, or the extent to which alternative approaches such as continued use of existing gas infrastructure, dual-fuel systems, DSM, renewable and lower-carbon gas, and electrification were assessed from a customer cost perspective. Understanding whether such an assessment has been undertaken is important in evaluating affordability implications of the LTGRP and the relative merits of alternative pathways.

12.1 Has FEI evaluated the lowest-cost pathway for customers in a declining gas demand scenario. If yes, please summarize the analysis; identify and discuss the pathway FEI considers to be the lowest-cost option for customers and why; explain how continued gas service, dual-fuel systems, DSM, renewable and lower carbon gas, and electrification were considered in that assessment; and identify any material assumptions upon which the assessment depends. If FEI has not performed this evaluation, please explain why not.

Response:

As discussed in Section 9 of the 2026 LTGRP, the preferred pathway for customers should be one that balances affordability, reliability, and sustainability collectively rather than considering only the pathway with the lowest rate or rate impacts to customers. If the consideration only focuses on having the lowest-cost pathway, then as shown in Figure 9-12 of the 2026 LTGRP, the Prolonged Transition scenario would have the least delivery rate and total bill impacts to customers over the long-term planning horizon to 2050. However, this pathway is associated with a future in which climate targets and pledges are delayed or not implemented, reflecting significant changes in government policies.

When considering how to achieve the best balance between affordability, reliability, and sustainability, the Diversified Approach scenario is FEI's preferred pathway for the following reasons.

- Compared to the Electrification Focus scenario, the Diversified Approach scenario has directionally lower delivery rate and total bill impacts over the 27-year planning horizon to 2050 (as shown in Figure 9-12 of the 2026 LTGRP), while also achieving more GHG emissions reductions (and meeting the climate target by 2050) by prioritizing dual-fuel systems, DSM expenditures, and a substantial increase in renewable and lower-carbon gas blending. Further, with increased adoption of dual-fuel systems, the Diversified

Approach scenario helps to maintain reliability by leveraging the operational flexibility of the gas system to meet peak demand, manage system constraints, and support overall energy resilience instead of relying heavily on the electric system under the Electrification Focus scenario.

- Compared to the Lower-Carbon Transportation and LNG Future scenario, the Diversified Approach scenario achieves relatively lower GHG emissions reductions (as shown in Figure 9-4 of the 2026 LTGRP). However, the Diversified Approach scenario results in much lower delivery rate and total bill impacts to customers over the planning horizon (i.e., 245 percent by 2050 for the Lower-Carbon Transportation and LNG Future scenario versus 181 percent by 2050 for the Diversified Approach scenario) as shown in Figure 9-12 of the 2026 LTGRP.
- Compared to the Baseline Trends scenario, the Diversified Approach scenario has relatively higher delivery rate and total bill impacts (as shown in Figure 9-12 of the 2026 LTGRP). However, the Diversified Approach scenario achieves much greater GHG emissions reductions than the Baseline Trends scenario (as shown in Figure 9-4 of the 2026 LTGRP). FEI notes that the Baseline Trends scenario only assumes currently known government policies that are in force and announced as of April 2025, thus it would not achieve any of the climate targets under the *Climate Change Accountability Act* (CCAA).

Based on the discussion above, FEI considers the Diversified Approach scenario to be the lowest-cost pathway when considering the trade-offs between affordability, reliability, and sustainability. For a detailed discussion on the different drivers of the delivery rate and total bill impacts for each scenario, please refer to the response to CEC-COSCO-RCIA IR1 10.1. For the rate impact assumptions included in each scenario, please refer to Section 9.4.1 of the 2026 LTGRP.

13.0 Reference: AFFORDABILITY & SYSTEM PLANNING

Exhibit B-1, Sections 7.1, 7.3 & 9.4

Topic: Changes in the Utilization of Major Facilities

Preamble: The LTGRP relies on continued use of major transmission systems to meet forecast peak demand and support long-term affordability. Understanding expected utilization under each LTGRP scenario is important to assess whether existing infrastructure continues to provide value to customers and whether future infrastructure decisions are aligned with customer affordability.

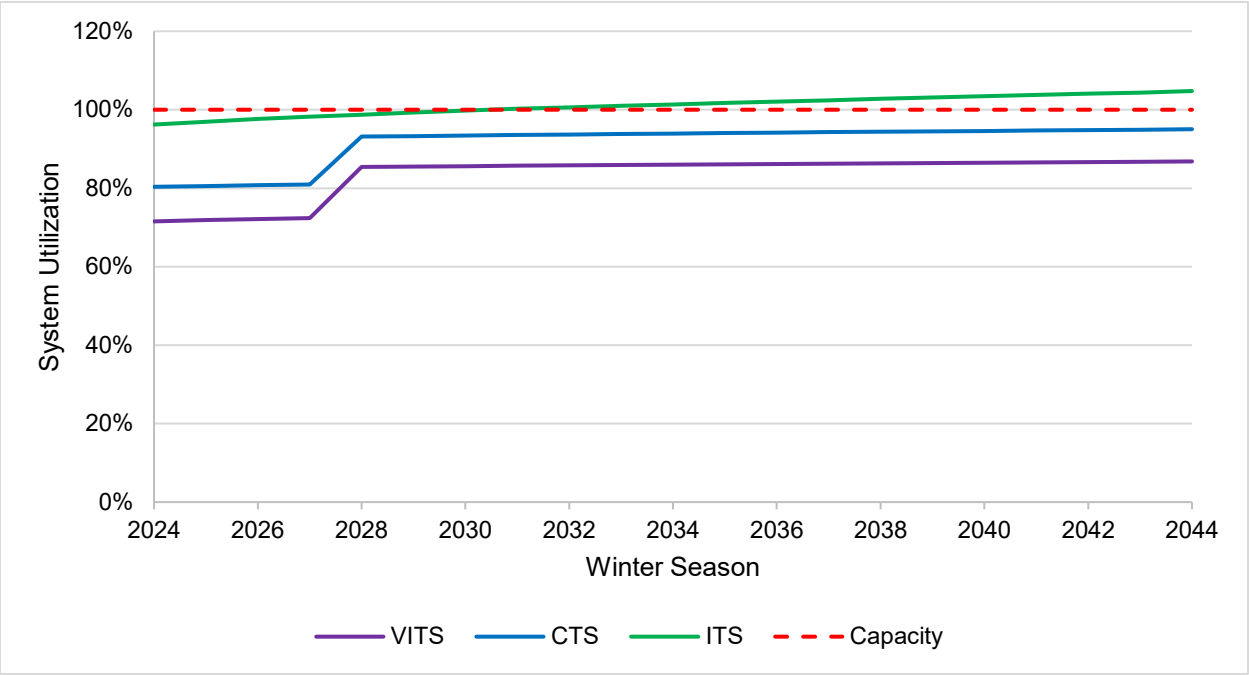
13.1 Please provide FEI's forecast utilization of its major transmission facilities, including VITS, CTS, and ITS under each LTGRP scenario at 2030, 2040 and 2050. As part of the response, please define the utilization metric used, including whether it is based on annual throughput, peak demand, design capacity, contracted capacity or another measure and the principal drivers of changes in utilization in addition to listing any facility FEI expects will or may become materially underutilized during the planning horizon as well as the expected affordability implications to its customers, particularly as it relates to residential customers.

Response:

FEI expects its facilities to remain highly utilized during periods of peak demand throughout the planning horizon.

FEI's forecast utilization shown in Figure 1 below is calculated as the ratio of the given transmission system's System Peak Forecast value in a given year divided by its associated capacity. Over the planning horizon, FEI expects utilization across its transmission systems to increase steadily in response to forecast peak demand growth. The ITS will experience a capacity shortfall necessitating expansion to meet the demand growth and maintain system reliability.

Figure 1: Forecast Utilization Based on the System Peak Forecast[14]



The peak demand forecasts above include all customer types; however, peak demand growth is forecast only in the residential and commercial customer rate classes with industrial demand being held constant. As part of the 2026 LTGRP, FEI considered prospective new large loads across all three transmission systems, including potential demand growth from power generation and within the transportation, marine and ISO shipments sectors. Such loads would materially increase the respective system utilizations, necessitating the system expansions described throughout Section 7 of the 2026 LTGRP. These loads would increase both peak and annual demand, as reflected in Sections 3.5.3, 3.5.4, 3.5.5, 7.3.2.2, 7.3.2.3, and 7.3.3.3.

[14] Consistent with the approach presented in Section 7 of the 2026 LTGRP, the System Peak Forecast produces a 20-year forecast spanning the period from 2024 to 2044. Utilization of both the VITS and CTS increases in 2028 due to additional load from the Woodfibre LNG Project, which drives demand on Vancouver Island and throughput on the CTS. While the Eagle Mountain – Woodfibre Gas Pipeline (EGP) project increases the capacity of the VITS by a similar volumetric amount, the ratio of load to capacity still increases.

14.0 Reference: AFFORDABILITY & DUAL-FUEL HEATING

Exhibit B-1, Sections 4.6, 4.7 & 9.4

Exhibit A-4, BCUC IRs 8.1-8.3 & 11.1-11.9

Topic: Adoption of Dual-Fuel Heating Systems

Preamble: FEI's LTGRP identifies dual-fuel heating systems as an important tool to support affordability, reduce emissions, and avoid or defer electric system infrastructure costs. Dual-fuel adoption appears to be a material assumption underlying FEI's Diversified Approach, it is important to understand the extent to which long-term planning outcomes depend on customers actually adopting dual-fuel systems, and what the implications would be if adoption is lower than forecast.

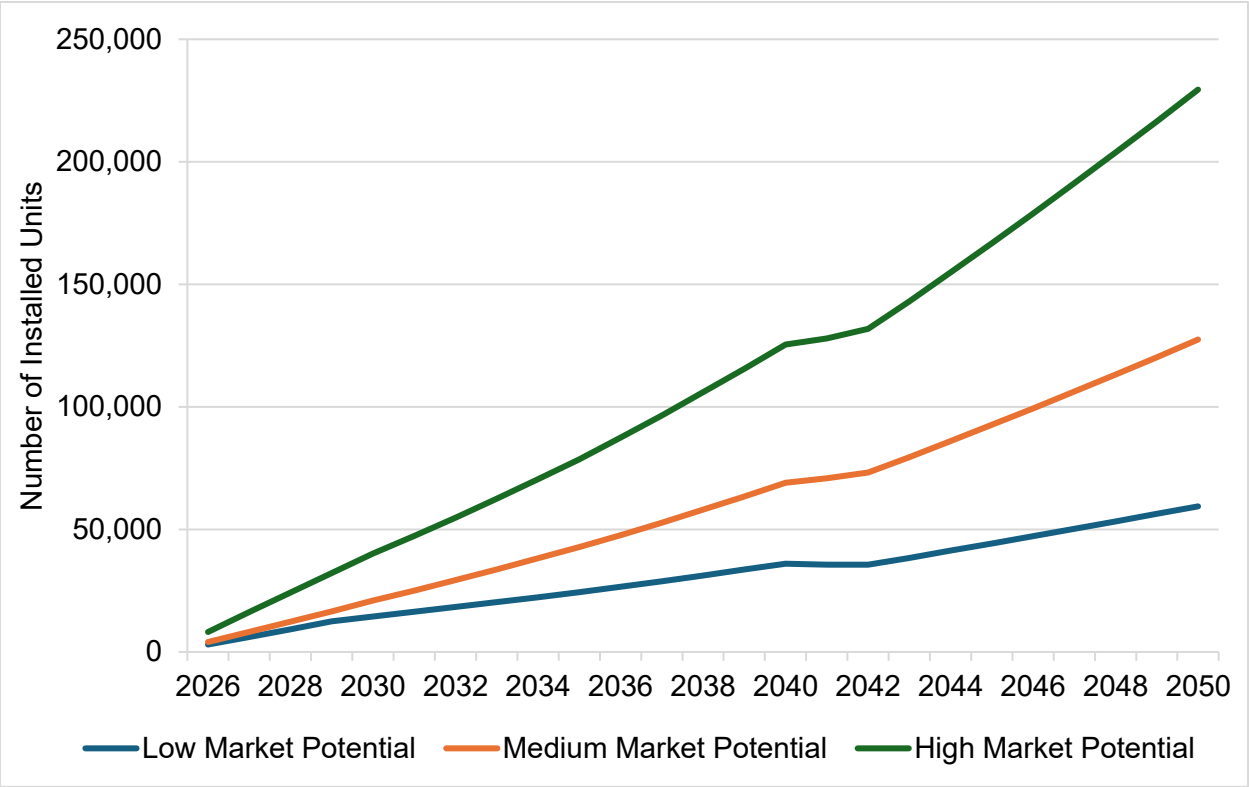
14.1 Further to the BCUC IRs identified above, please identify the extent to which FEI's long-term affordability, demand, infrastructure planning and GHG reduction outcomes rely upon forecast adoption of residential dual-fuel systems. As part of the response please identify the residential adoption assumptions built into each LTGRP scenario as well as how those adoption levels are reflected in FEI's demand peak demand forecast, infrastructure planning, GHG reduction analysis and affordability analysis; the key risks to achieving those adoption levels as well as the potential implications of materially lower adoption levels; any mitigation measures available to FEI if the forecast adoption levels are not achieved; and a quantification of the effect of materially lower dual-fuel adoption on residential delivery rates, customer bills, infrastructure requirements and GHG outcomes.

Response:

The 2024 Conservation Potential Review (CPR) determined market potential trajectories for energy efficiency and fuel switching measures, including residential dual-fuel heating systems, for a forecast period of 2026-2050. As discussed in Section 4.3 of the 2026 LTGRP, the 2024 CPR was used to inform the Low, Medium, and High DSM settings. Figure 1 below was generated from the analysis that was used to inform the CPR, which was then used to inform the DSM Measure Groups for the 2026 LTGRP DSM settings. Therefore, the three market potential trajectories below provide a high-level projection of dual-fuel market potential.

This market potential below is only for retrofit installations for the residential sector and does not include forecast dual-fuel installations in new construction. Dual-fuel potential in new construction is captured within the New Construction DSM Measure Group using a whole-building approach, not representing forecast adoption of individual measures. As discussed in Section 4.4.2 of Appendix C to the 2026 LTGRP, dual fuel was modelled so that a requirement of the measure is that it replaces existing equipment. The switchover temperatures per region are explained in the response to BCUC IR1 10.2.

Figure 1: Residential Dual Fuel Heating Systems – Market Potential Trajectories



As shown in Table 4-1 of the 2026 LTGRP, the Low, Medium, and High market potential informed the Low, Medium, and High DSM settings. The Low DSM setting was utilized for the Baseline Trends, Electrification Focus[15], Prolonged Transition, and Lower-Carbon Transportation and LNG Future scenarios, while the Medium DSM setting was utilized for the Diversified Approach scenario. The demand scenarios shown in Section 3 of the 2026 LTGRP reflect underlying energy demand prior to the application of DSM impacts. Annual demand forecasts incorporating DSM impacts are presented in Section 4.4.3 of the 2026 LTGRP. In summary, these various residential dual-fuel adoption assumptions are incorporated into the respective scenarios' GHG emissions reductions and rate impact analysis as quantified and presented in Section 9 of the 2026 LTGRP.

For infrastructure planning, Section 7 of the 2026 LTGRP presented the System Peak Demand forecast that incorporates DSM assumptions, as described in Section 7.5.1.2 of the 2026 LTGRP. Accordingly, the residential dual-fuel adoption assumptions are reflected within the Low and High DSM settings illustrated in each figure. FEI cannot disaggregate the impacts of dual-fuel systems to these DSM forecast settings.

For the residential, commercial, and industrial annual demand volumes, please refer to the tables in Appendix B of the 2026 LTGRP.

[15] It is not possible to disaggregate dual-fuel adoption in any scenario to FEI's billing regions. FEI also did not have a DSM measure for full electric heating in the 2024 CPR. There was no assumption regarding reverse switching from electric back to gas.

Some key risks to achieving the forecast market potential adoption levels are customer perception and behavior, economic and financial assessments, regulatory and policy uncertainty, and broader market and economic conditions. Mitigation measures available to FEI could include program design and level of incentive offer, among others.

15.0 Reference: AFFORDABILITY & ELECTRIFICATION

Exhibit B-1, Section 9.4, Figure 9-7 & Table 9-8

Exhibit A-4, BCUC IRs 8.1-8.3 & 9.2

Topic: Electrification Scenario

Preamble: FEI states that the Electrification Focus scenario is expected to result in the highest cumulative delivery-rate impact by 2050, and that electrification would likely create significant electric-system infrastructure requirements and upward pressure on electric rates. Because those electric-system costs are not fully reflected in FEI's gas rate-impact analysis, it is important to understand FEI's assessment of the broader customer affordability implications of the Electrification Focus scenario.

15.1 Please provide an assessment of the effect on customer affordability of the Electrification Focus scenario, separately identifying and discussing the incremental customer equipment costs as well as any electric generation, transmission and distribution infrastructure costs; any avoided, deferred or reduced gas infrastructure costs; and overall customer affordability impacts.

Response:

Please refer to the response to BCUC IR1 9.2.

16.0 Reference: AFFORDABILTY & RENEWABLE/LOWER CARBON GAS SUPPLY
Exhibit B-1, Section 5.3, Section 9.4.3, Table 9-10, Section 9.4.4, Figure 9-13

Exhibit A-4, BCUC IRs 5.1, 20.1 - 22.1

Topic: Bill Impacts of Renewable Natural Gas

Preamble: FEI indicates that renewable and lower-carbon gas procurement is a significant contributor to future customer bill impacts, particularly under scenarios with higher renewable and lower-carbon gas penetration. Understanding the incremental bill impact attributable solely to renewable and lower-carbon gas is important to distinguish between the cost of maintaining and using the gas system and the cost of decarbonizing the gas supply.

16.1 Please provide the estimated incremental average residential bill impacts attributable solely to renewable and lower-carbon gas procurement under each LTGRP scenario at 2030, 2040, and 2050. As part of this response please provide a dollars per month and percentage impacts relative to the currently approved average residential bill and identify the assumed renewable and lower carbon gas percentage and commodity cost assumed for each scenario and year.

Response:

Please refer to Tables 1 to 5 below for the estimated incremental average residential bill impacts in dollars (line 12) and in percentage (line 13) attributable solely to renewable and lower-carbon gas under each 2026 LTGRP scenario at 2030, 2040, and 2050 when compared to the currently approved average residential bill based on 2026 Approved rates.

Table 1: Incremental Average Residential Bill Impact Attributed Solely to Renewable and Lower-Carbon Gas (Diversified Approach)

Line	Diversified Approach	Reference	2026 Approved	2030	2040	2050
1	Average RS 1 UPC (GJ)	Section 9.4.4 of 2026 LTGRP	55	55	55	55
2	Cost of Gas ($/GJ)	Table 5-4 of 2026 LTGRP	$ 1.660	$ 2.290	$ 2.710	$ 3.480
3	RNG Rider ($/GJ)	Table 5-4 x Line 4	$ 0.909	$ 4.046	$ 7.196	$ 13.282
4	RNG Blend Percentage (%)	Table 5-1 and Table 5-2	3.5%	15.4%	37.7%	83.7%
5						
6	RNG Cost ($)	Line 3 x Line 1	$ 50.0	$ 222.5	$ 395.8	$ 730.5
7	Cost of Gas Offset ($)	-Line 1 x Line 2 x Line 4	(3.2)	(19.3)	(56.1)	(160.2)
8	Net Commodity Cost ($)	Line 7 + Line 6	$ 46.8	$ 203.2	$ 339.7	$ 570.3
9	Net Commodity Cost per Month ($)	Line 8 / 12	3.9	16.9	28.3	47.5
10						
11	Total RS 1 Bill @ 2026 Approved Rates ($)	G-285-25, G-287-25, and G-131-26	$ 847.0	$ 847.0	$ 847.0	$ 847.0
12	Incremental Net Commodity Cost ($)	Line 8, Compared to 2026	$ -	$ 156.4	$ 292.9	$ 523.5
13	Total Bill Impact - Compared to 2026 Approved (%)	Line 11 / Line 12	0.0%	18.5%	34.6%	61.8%

Table 2: Incremental Average Residential Bill Impact Attributed Solely to Renewable and Lower-Carbon Gas (Electrification Focus)

Line	Electrification Focus	Reference	2026 Approved	2030	2040	2050
1	Average RS 1 UPC (GJ)	Section 9.4.4 of 2026 LTGRP	55	55	55	55
2	Cost of Gas ($/GJ)	Table 5-4 of 2026 LTGRP	$ 1.660	$ 4.810	$ 5.700	$ 6.460
3	RNG Rider ($/GJ)	Table 5-4 x Line 4	$ 0.909	$ 2.641	$ 4.255	$ 6.496
4	RNG Blend Percentage (%)	Table 5-1 and Table 5-2	3.5%	8.9%	12.0%	15.2%
5						
6	RNG Cost ($)	Line 3 x Line 1	$ 50.0	$ 145.2	$ 234.1	$ 357.3
7	Cost of Gas Offset ($)	Line 2 x (1 - Line 4) x Line 1	(3.2)	(23.7)	(37.5)	(54.0)
8	Net Commodity Cost ($)	Line 7 + Line 6	$ 46.8	$ 121.6	$ 196.5	$ 303.2
9	Net Commodity Cost per Month ($)	Line 8 / 12	3.9	10.1	16.4	25.3
10						
11	Total RS 1 Bill @ 2026 Approved Rates ($)	G-285-25, G-287-25, and G-131-26	$ 847.0	$ 847.0	$ 847.0	$ 847.0
12	Incremental Net Commodity Cost ($)	Line 8, Compared to 2026	$ -	$ 74.8	$ 149.7	$ 256.4
13	Total Bill Impact - Compared to 2026 Approved (%)	Line 11 / Line 12	0.0%	8.8%	17.7%	30.3%

Table 3: Incremental Average Residential Bill Impact Attributed Solely to Renewable and Lower-Carbon Gas (Prolonged Transition)

Line	Prolonged Transition	Reference	2026 Approved	2030	2040	2050
1	Average RS 1 UPC (GJ)	Section 9.4.4 of 2026 LTGRP	55	55	55	55
2	Cost of Gas ($/GJ)	Table 5-4 of 2026 LTGRP	$ 1.660	$ 2.290	$ 2.710	$ 3.480
3	RNG Rider ($/GJ)	Table 5-4 x Line 4	$ 0.909	$ 2.207	$ 1.689	$ 1.263
4	RNG Blend Percentage (%)	Table 5-1 and Table 5-2	3.5%	8.3%	9.1%	9.9%
5						
6	RNG Cost ($)	Line 3 x Line 1	$ 50.0	$ 121.4	$ 92.9	$ 69.4
7	Cost of Gas Offset ($)	Line 2 x (1 - Line 4) x Line 1	(3.2)	(10.5)	(13.5)	(19.0)
8	Net Commodity Cost ($)	Line 7 + Line 6	$ 46.8	$ 110.9	$ 79.4	$ 50.4
9	Net Commodity Cost per Month ($)	Line 8 / 12	3.9	9.2	6.6	4.2
10						
11	Total RS 1 Bill @ 2026 Approved Rates ($)	G-285-25, G-287-25, and G-131-26	$ 847.0	$ 847.0	$ 847.0	$ 847.0
12	Incremental Net Commodity Cost ($)	Line 8, Compared to 2026	$ -	$ 64.1	$ 32.6	$ 3.6
13	Total Bill Impact - Compared to 2026 Approved (%)	Line 11 / Line 12	0.0%	7.6%	3.8%	0.4%

Table 4: Incremental Average Residential Bill Impact Attributed Solely to Renewable and Lower-Carbon Gas (Lower-Carbon Transportation & LNG Future)

Line	Lower-Carbon Transportation and LNG Future	Reference	2026 Approved	2030	2040	2050
1	Average RS 1 UPC (GJ)	Section 9.4.4 of 2026 LTGRP	55	55	55	55
2	Cost of Gas ($/GJ)	Table 5-4 of 2026 LTGRP	$ 1.660	$ 3.080	$ 4.250	$ 4.600
3	RNG Rider ($/GJ)	Table 5-4 x Line 4	$ 0.909	$ 6.066	$ 16.887	$ 27.104
4	RNG Blend Percentage (%)	Table 5-1 and Table 5-2	3.5%	22.4%	60.0%	92.8%
5						
6	RNG Cost ($)	Line 3 x Line 1	$ 50.0	$ 333.6	$ 928.8	$ 1,490.7
7	Cost of Gas Offset ($)	Line 2 x (1 - Line 4) x Line 1	(3.2)	(38.0)	(140.3)	(234.9)
8	Net Commodity Cost ($)	Line 7 + Line 6	$ 46.8	$ 295.6	$ 788.5	$ 1,255.8
9	Net Commodity Cost per Month ($)	Line 8 / 12	3.9	24.6	65.7	104.7
10						
11	Total RS 1 Bill @ 2026 Approved Rates ($)	G-285-25, G-287-25, and G-131-26	$ 847.0	$ 847.0	$ 847.0	$ 847.0
12	Incremental Net Commodity Cost ($)	Line 8, Compared to 2026	$ -	$ 248.8	$ 741.7	$ 1,209.0
13	Total Bill Impact - Compared to 2026 Approved (%)	Line 11 / Line 12	0.0%	29.4%	87.6%	142.7%

Table 5: Incremental Average Residential Bill Impact Attributed Solely to Renewable and Lower-Carbon Gas (Baseline Trends)

Line	Baseline Trends	Reference	2026 Approved	2030	2040	2050
1	Average RS 1 UPC (GJ)	Section 9.4.4 of 2026 LTGRP	55	55	55	55
2	Cost of Gas ($/GJ)	Table 5-4 of 2026 LTGRP	$ 1.660	$ 2.290	$ 2.710	$ 3.480
3	RNG Rider ($/GJ)	Table 5-4 x Line 4	$ 0.909	$ 2.286	$ 2.077	$ 1.666
4	RNG Blend Percentage (%)	Table 5-1 and Table 5-2	3.5%	8.6%	11.2%	13.1%
5						
6	RNG Cost ($)	Line 3 x Line 1	$ 50.0	$ 125.7	$ 114.2	$ 91.6
7	Cost of Gas Offset ($)	Line 2 x (1 - Line 4) x Line 1	(3.2)	(10.9)	(16.7)	(25.1)
8	Net Commodity Cost ($)	Line 7 + Line 6	$ 46.8	$ 114.9	$ 97.6	$ 66.5
9	Net Commodity Cost per Month ($)	Line 8 / 12	3.9	9.6	8.1	5.5
10						
11	Total RS 1 Bill @ 2026 Approved Rates ($)	G-285-25, G-287-25, and G-131-26	$ 847.0	$ 847.0	$ 847.0	$ 847.0
12	Incremental Net Commodity Cost ($)	Line 8, Compared to 2026	$ -	$ 68.1	$ 50.8	$ 19.7
13	Total Bill Impact - Compared to 2026 Approved (%)	Line 11 / Line 12	0.0%	8.0%	6.0%	2.3%

17.0 Reference: FUTURE INFRASTRUCTURE INVESTMENTS

Exhibit B-1, Sections 6.5, 7.3 & 9.4

Exhibit A-4, BCUC IRs 4.3 & 9.2

Topic: Major Infrastructure Expansion Drivers

Preamble: FEI's LTGRP identifies future transmission and supply requirements to maintain reliability, meet peak demand, support resiliency, and respond to future load growth. For residential customers, it is important to understand what major infrastructure projects are contemplated, what is driving the need for those projects, and the extent to which residential customers may bear costs associated with projects driven by other customer classes, LNG/marine demand, or broader reliability requirements.

17.1 Please provide a table identifying each major transmission or supply infrastructure project relied upon or identified in the LTGRP, along with each's principal need driver; estimated capital cost (or range if final estimate is not available); expected in-service date or planning timeframe; expected average residential delivery rate and bill impact as well as the extent to which the project is driven by

a. Residential demand;
b. Commercial demand;
c. Industrial demand;
d. LNG demand;
e. Marine demand;
f. Reliability or resiliency requirements; or
g. Other factors.

If the residential rate or bill impact has not been estimated for a project, please identify and explain how FEI evaluated customer affordability in its assessments of the project.

Response:

Please refer to Table 1 below for the list of major projects that were approved either by the BCUC or through OIC, including the directional rate increase and total bill impact projections over the planning horizon from 2024 to 2050 in the 2026 LTGRP.

Table 1: List of Major Projects Included in the Rate Impact Analysis of the 2026 LTGRP

Project	Approval	Principle Drivers	Estimated / Actual Capital Cost ($ million)	Expected / Actual In-service Date	Estimated / Actual Delivery Rate and Total Residential Bill Impact, Compared to 2026 Approved (%)
Inland Gas Upgrade (IGU)	G-12-20	Integrity	$361.1 million (Actual)	2025	Delivery: 2.2% Total Bill: 1.57%
Tilbury LNG Storage Expansion (TLSE)	C-6-25	Resiliency and Gas Supply	$1,100 million	2030	Delivery: 11.0% Total Bill: 7.5%
Advanced Metering Infrastructure (AMI)	C-2-23	Metering	$808.5 million	2028	Delivery: 7.6% Total Bill: 5.4%
CTS TIMC Project	C-3-22	Integrity	$109.2 million (Actual)	2025	Delivery: 0.7% Total Bill: 0.5%
ITS TIMC Project	C-1-24	Integrity	$84.6 million	2027	Delivery: 0.5% Total Bill: 0.4%
Okanagan Capacity Mitigation Plan (OCMP)	C-2-25	Capacity (Residential, Commercial, and Industrial Demand in Okanagan area)	$50.4 million	2027	Delivery: 0.4% Total Bill: 0.3%
Gibsons Capacity Upgrade	G-352-22	Capacity (Residential, Commercial, and Industrial Demand in Gibsons area)	$13.517 million (Actual)	2025	Delivery: 0.1% Total Bill: 0.07%
ERP Modernization Project	G-125-26	SAP Replacement	$92.2 million (FEI Allocation)	2028	Delivery: 1.2% Total Bill: 0.9%
Tilbury Phase 1A and 1B	OIC 557/2013	LNG Demand, including marine	$425 million (Phase 1A) and up to $400 million (Phase 1B)[16]	2030	N/A: Offsetting revenue under RS 46
Eagle Mountain-Woodfibre Gas Pipeline (EGP)	OIC 749/2014	LNG Demand (Woodfibre LNG)	$750 million (net of contribution in aid of construction)	2027	N/A: Offsetting revenue under RS 50

As shown in the table above, the majority of the major projects were required for integrity or resiliency reasons and would thus be required regardless of the pathways over the planning horizon. Further, for major projects such as Tilbury Phase 1A/1B and EGP that are supporting the increase in LNG demand, there will be offsetting revenue from the LNG customers over the planning horizon which is ultimately a benefit to all customers.

Beyond the list of major projects provided in the table above, FEI has not completed detailed assessments on further major projects that might be required over the planning period to 2050. As such, FEI is unable to provide detailed cost information and estimated in-service dates or the resulting delivery and bill impacts of each potential major project through to 2050. However, for the purposes of the directional rate increase and total bill impact to 2050 presented in Section 9.4

[16] FEI included incremental capital expenditures of approximately $1.4 billion as a proxy for a future expansion of the Tilbury LNG facility in accordance with the potential LNG demand contemplated in the Medium setting in Figure 3-1 of the 2026 LTGRP.

of the 2026 LTGRP, in addition to the approved major projects identified above, FEI also included approximately $2 billion of capital expenditures over the period from 2030 to 2050 as a proxy for future major projects that will likely occur for various reasons, including integrity, reliability, resiliency, and capacity needs. As shown in the response to CEC-COSCO-RCIA IR1 10.1, the incremental cost of service (including all offsetting revenue,[17] O&M and capital savings[18]) related to all approved major projects listed in the table above, as well as the proxy of future major capital to 2050 as discussed above, contributed approximately 8 percent to the overall cumulative bill impact of 181 percent from 2024 to 2050 under the Diversified Approach scenario.

[17] Offsetting revenues from RS 46 and RS 50.

[18] O&M and capital savings resulting from the implementation of the AMI and ERP Modernization Projects, as well as gas supply mitigation available from the TLSE Project.

18.0 Reference: EXISTING INFRASTRUCTURE LONGEVITY

Exhibit B-1, Sections 7.1, 7.3 & 9.4

Topic: Long Term Value of Existing Infrastructure

Preamble: FEI's LTGRP considers long-term needs to 2050, while many transmission and distribution assets may remain in service beyond the planning horizon. Understanding which major assets are expected to remain in service beyond 2050, their expected utilization, and any potential underutilization risk is relevant to assessing whether residential customers will continue receiving value from existing infrastructure under FEI's long-term planning scenarios.

18.1 Please provide a table identifying each piece of FEI's major transmission or distribution infrastructure expected to remain in service beyond 2050 along with each of those assets' expected remaining service life (after 2050), the expected utilization under each LTGRP scenario based on the utilization metric FEI considers most appropriate; a brief explanation of the utilization metric used; and whether FEI expects any material underutilization of those assets (and which) under any of the presented LTGRP scenarios.

If FEI has not assessed expected utilization beyond 2050 for any of its major assets or asset groups, please explain why not and discuss how FEI considers long-term customer affordability and asset utilization risk in its resource planning.

Response:

Please refer to the response to CEC-COSCO-RCIA IR1 13.1 for the expected peak-day utilization of FEI's three major transmission systems. Based on the System Peak Forecast, FEI expects its major transmission systems to remain highly utilized in meeting peak day demand on the system. Generally speaking, these facilities are designed, maintained, and expected to remain in service through 2050 and beyond.

The transmission systems are designed to meet peak-day delivery requirements, which ensures that deliveries can be made to all customers that require gas on any day of the year. Peak-day utilization is therefore considered a better metric for this purpose.

Further, the System Peak Forecast accounts for policies which have been implemented or have defined timeframes and will influence gas peak demand. As any policy changes are implemented, future iterations of the System Peak Forecast may suggest different trajectories of forecast peak demand and therefore change FEI's expected utilization by 2050. FEI evaluates the capacity needs of each system based on the most recent System Peak Forecast.

19.0 Reference: AFFORDABILITY BENEFITS OF LARGE LOAD GROWTH

Exhibit B-1, Section 3.5, pages 3-13 to 3-18, Sections 7.3.2, 9.4 & 9.4.2.1

Exhibit A-4, BCUC IRs 4.1-4.3

Topic: Rate Impacts & Large Load Growth Assumptions

Preamble: FEI's LTGRP indicates that growth in LNG demand, marine demand, ISO shipments and new large loads may mitigate delivery-rate impacts by increasing system utilization and spreading fixed costs over a larger volume base. For residential customers, it is important to understand the extent to which FEI's affordability conclusions depend on these loads materializing, and the risks to residential customers if such growth does not occur as forecast.

19.1 Please quantify the extent to which forecast growth in LNG demand, marine demand, ISO shipments and other new large loads contributes to mitigation of residential delivery-rate impacts under each LTGRP scenario. As part of the response, please quantify the estimated impact of this growth on residential delivery rates; the extent to which FEI's existing infrastructure utilization is expected to be improved; the extent to which major capital expenditures are forecast to avoided, deferred or accelerated; and ny material risks associated with relying on such growth to mitigate residential delivery rate and bill impacts.

Response:

Please refer to the response to CEC-COSCO-RCIA IR1 10.1 for quantification of the benefits of LNG demand and new large loads to residential customer rates for each LTGRP scenario.

Improvements to the utilization of FEI's existing infrastructure were demonstrated in Figures 7-8 and 7-9 of the 2026 LTGRP:

- Figure 7-8 of the 2026 LTGRP shows that the incremental demand from the Woodfibre LNG Project, which is served by the VITS via the CTS, makes use of the capacity available on the CTS; and
- Figure 7-9 shows that the Medium setting for LNG demand (dark blue line), which is the LNG demand applied in the Diversified Approach scenario, would push the forecast system peak closer to the CTS capacity (red dash line), thus enabling the near full utilization of the CTS.

The growth in LNG demand and potential for new large loads would not avoid or defer the need for major capital expenditures for future expansion. As shown in Figure 7-9 of the 2026 LTGRP, an expansion would potentially be needed if the LNG demand grows beyond the Medium setting used in the Diversified Approach scenario (brown line). However, such an expansion would enable further growth in LNG demand and would result in new incremental revenue under RS 46

(or in the case of a new large load, incremental revenue under RS 50), which would help to offset the cost of the expansion. Additionally, the continued growth of incremental revenue would further help to mitigate rate increases for all of FEI's customers.

While there is uncertainty associated with growth in LNG demand and the potential of another new large load beyond the Medium setting materializing, as discussed in the response to BCUC IR1 4.1, there are strong indications of growth in LNG demand. For example, FEI has experienced significant growth in the Marine and ISO Shipments segment, primarily through increased marine bunkering deliveries in 2025 and in the first five months of 2026. This development suggests strong potential for continued growth in marine LNG demand, which will ultimately help to mitigate the delivery rates and bill impacts for FEI's customers.

Finally, as shown in the response to CEC-COSCO-RCIA IR1 10.1, the risk of LNG demand and new large loads not materializing exists for both the Diversified Approach and the Electrification Focus scenarios. Therefore, even without consideration of LNG demand growth and new large loads, the Diversified Approach would continue to be more affordable than the Electrification Focus scenario.

20.0 Reference: Exhibit B-1 - Page 2-27 & 2-28

Preamble: Global, federal and provincial policy shifts are also reshaping the transportation sector, marked by a pause on ZEV mandates, strengthened low-carbon fuel incentives, and evolving carbon-pricing frameworks. Globally, in April 2025, the International Maritime Organization's (IMO) Net-Zero Framework was approved by the Marine Environment Protection Committee during its 83rd session.52

The framework is a set of international regulations designed to reduce GHG emissions from international shipping in alignment with the 2023 IMO GHG Strategy, which targets net-zero GHG emissions from shipping by or around 2050. The framework is intended to incentivize ship owners to transition to zero- and lower-carbon energy, including LNG, with increased relevance for bunkering. If adopted, the framework would shift demand toward fuels that help minimize compliance costs. On September 9, 2025, the federal government committed to amending the Clean Fuel Regulations (CFR) to support the development and resilience of Canada's lower-carbon energy supply for the transportation sector to reduce GHG emissions. Subsequent federal Budget 2025 measures further reinforced this direction by directing an annual $500 million from CFR compliance revenues to support biofuels, including RNG, strengthening the policy's capacity to stimulate demand for lower-carbon fuels.

Provincially, the BC Low Carbon Fuels Act and regulations came into effect in January 2024, now known as the BC Low Carbon Fuel Standard55 (BC LCFS). The new framework replaces the previous Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act56 and raises the 2030 carbon intensity reduction target from percent below 2010 levels to 30 percent. The 2023 Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) amendments expanded prescribed undertakings for utilities like FEI to reduce GHG emissions and recover costs through customer rates. These changes enable utilities to offer grants or zero-interest loans for the purchase of eligible ZEVs and machines, including on-road medium- and heavy-duty vehicles, certain off-road vehicles, and equipment.

These federal and provincial transportation policies directly shape FEI's planning and programs. Shifts within the transportation sector have the potential to significantly increase demand for gaseous fuels as fleets move towards lower-carbon options. This is especially true for medium- and heavy-duty vehicles, where operational needs such as range and refuelling speed make full electrification challenging. In response, FEI must design and deliver lower-carbon energy programs, deploy supporting infrastructure such as CNG and LNG fuelling facilities, and provide incentives to help customers transition to renewable and lower-carbon

technologies. While these policies create opportunities for the transportation sector to support provincial climate action goals, the pace and scale of adoption remain uncertain.

20.1 With regard to future energy needs, where FEI may be looking to supply the trucking market with CNG or LNG, has FEI considered the pending and relatively immediate electrification of this trucking market as a risk to this aspect of its business and forecasts and if so what is the FEI projection for electrification taking up this market?

Response:

FEI considered electrification of the trucking market as part of its assessment of transportation-sector uncertainty and on-road vehicle fuel switching. The assessment included battery-electric vehicle adoption as well as other lower-carbon and zero-emission transportation pathways.

Rather than forecasting a single electrification outcome, the 2026 LTGRP addresses uncertainty through a range of transportation fuel-switching scenarios that reflect differing rates of adoption for battery-electric, hydrogen, and lower-carbon gas technologies.

FEI does not assume that medium- and heavy-duty long-haul trucking will be fully or immediately electrified. As discussed in the 2026 LTGRP, range, refueling speed, payload, infrastructure availability and operating requirements can make full electrification challenging for some medium- and heavy-duty applications.

Under the 2026 LTGRP settings, FEI forecasts CNG demand in 2050 ranging from approximately 1.7 PJ per year in the Low setting to approximately 6.6 PJ per year in the High setting. These forecast outcomes reflect FEI's assessment that medium- and heavy-duty trucking may transition to lower-carbon pathways through a mix of technologies rather than a single pathway.

Accordingly, FEI's planning reflects a range of potential outcomes in which electrification plays an increasing role, while gaseous fuels may continue to serve certain medium- and heavy-duty applications.

20.2 With regard to the marine bunkering there are solutions where these ships are able to have their energy supply supported with methanol burning engines, has FEI looked into this technology and whether or not it could produce methanol via hydrogenation of concentrated CO2 emissions processes in the province of BC and or elsewhere if the GHG reductions would be allowable for FEI to claim.

Response:

FEI tracks the development of all alternative fuels, including methanol, and continues to focus on developing LNG supply for use in the Port of Vancouver and surrounding region.

In 2025, LNG vessels continued to dominate alternatively fueled shipping orders[19] and DNV[20], a global maritime data-driven assurance and classification organization, shows LNG's strong leadership as an alternative marine fuel, with 892 LNG vessels in operation and 671 on order, for a total of 1,563 vessels in Q2 2026, almost three times the combined total of all other alternative fuels (methanol, hydrogen, and ammonia at 539 vessels).

LNG remains the most viable alternative in the shipping industry to higher carbon intensity fuels as it has advantages in energy density, cost, availability, safety and other technical considerations. For example, the World Shipping Council estimated that e-methanol would cost 4.25 times the cost of LNG and 2.5 times the cost of liquefied bio-methane.[21] As a result, LNG continues to grow and is available in over 200 ports worldwide. Further, the carbon intensity of LNG can be further reduced with the inclusion of RNG, providing the shipping industry with a pathway to continue to reduce their carbon emissions. As a result, FEI has not evaluated the potential production and use of methanol at this time.

[19] Sea-LNG, The Journey: A Decade Moving Towards a Cleaner Future, p. 2, online at: https://sea-lng.org/wp-content/uploads/2026/01/A_View_From_The_Bridge_2026-1.pdf.

[20] DNV, online at: https://dnv.com/ca

[21] World Shipping Council, ESC EU Shipping Decarbonization Report (2025), p. 21, online at: https://static1.squarespace.com/static/5ff6c5336c885a268148bdcc/t/67da76ba69fe472a4accc763/1742370494878/WSC+EU+Shipping+Decarbonisation+Report+-+2025.pdf.

21.0 Reference: Exhibit B-1, Page 4-27

Preamble: Figure 4-21 below illustrates how dual-fuel heating systems (with or without using RNG) have low GHG abatement costs, illustrating cost-effective emissions reductions for a customer when compared against both all-electric options (either average efficiency or ccASHP) and an increased RNG blend percentage up to 45 percent in an existing gas furnace. A uniform $10,000 incentive is applied to all equipment options, excluding a stand-alone gas furnace, to ensure a consistent comparison.

Figure 4-21: Household Abatement Values (PCT Perspective) from Heating Options[126] and RNG Blend Percentages

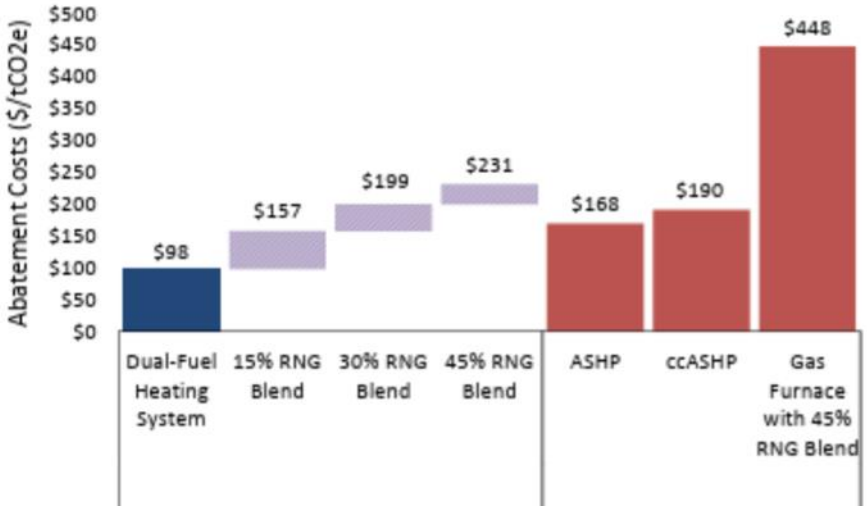


Figure 4-21: Household Abatement Values (PCT Perspective) from Heating Options and RNG Blend Percentages 4.7.4.3 Dual-Fuel Heating Systems Can Lower Customers Energy Bills Dual-fuel heating systems can lower household energy bills compared to either an electric heat pump or a gas furnace. This conclusion is supported through FEI's residential dual-fuel heating system pilot results, which demonstrate consistent energy and emissions benefits across participating homes. The pilot results indicates that the majority of participants achieved net energy savings and emissions reductions. Heating cost outcomes were more variable; however, more than half of participating households experienced bill savings relative to a gas furnace baseline.

21.1 Given the expense involved with RNG would FEI get credit if it focused on the largest greenhouse gas emitters in the Province and for that matter elsewhere in the world to deliver far more cost-effective GHG emissions reductions and if so what if any technologies has FEI considered for substantially more cost-effective GHG emissions reductions and where has FEI identified opportunities for such reductions and if not would FEI be open to examining all of these potential technologies and the locations where they could cost effectively be supplied and achieve highly cost-effective GHG emissions reductions?

Response:

FEI has a well-developed DSM portfolio of energy efficiency and conservation programs that provide solutions for residential, commercial and industrial customers to reduce energy use and lower GHG emissions. Investment in DSM measures tend to achieve a lower cost per tonne of GHG emissions reduced than RNG; however, RNG is a competitive drop-in fuel that makes use of the existing gas delivery system and enables GHG emissions reductions for industries with high energy intensity requirements without a capital outlay requirement for the business owner.

FEI continually assesses new technologies and innovation through its Clean Growth Innovation Fund (CGIF), as discussed in Section 2.7 of the 2026 LTGRP. The CGIF is an important mechanism to advance innovative technologies that will help reduce GHG emissions and support the transition to a lower-carbon economy while optimizing the use of its gaseous energy delivery system for the benefit of FEI's customers. The CGIF contributes to the acceleration of energy innovation by helping to achieve performance breakthroughs and cost reductions on emerging technologies.

21.2 Given the substantial peak winter heating requirements and the natural gas requirements driven by this, has FEI examined any long-term energy storage technologies that can be used to cost-effectively store thermal energy and release this energy seasonally other than its LNG storage for the natural gas system and if so which ones has FEI examined and are there any potentially viable options FEI has found to be interesting and if not would FEI be open to examining such alternative during its long term planning.

Response:

FEI does not consider long-term thermal energy storage technologies to be a feasible solution to peak gas capacity mitigation and has therefore not examined any long-term energy storage technologies that can be used to store thermal energy and release this energy seasonally.

Central, large-scale thermal energy solutions require energy input, a medium (such as water) to store the heat, and a (non-gas) distribution system to convey the heat to homes and businesses. In particular, the lack of a thermal energy network to distribute the stored energy to homes and businesses remains a key impediment to the development of centralized thermal energy solutions at scale.

Alternatively, thermal energy storage can be on site (at home or businesses) and could be used to store heat energy for peak use. However, this would require changes to a customer's equipment at the premises, including a means to exchange and distribute this form of energy inside their premises.

While there may be market alternatives for thermal storage (to eliminate/reduce peak use) that larger commercial or industrial customers could deploy, these systems are typically located downstream of FEI's meter and FEI is typically prohibited from entering markets downstream of its gas meters.

Finally, while FEI's CGIF provides funding for pre-commercial activities to potentially reduce gas usage and peak gas usage, FEI would have to wait for commercially viable solutions to be developed before considering their use.

22.0 Reference: Exhibit B-1, pages 8-10, 8-11

8.6 COLLABORATION WITH BC HYDRO TO FACILITATE A COMPARISON IN 5 LONG-TERM RESOURCE PLANS

Preamble: As discussed in Section 2.2.5, coordinated long-term planning between utilities enhances planning and helps to achieve provincial goals. To coordinate planning, both FortisBC and BC Hydro participated in each other's technical advisory committees. In addition, FEI and BC Hydro's resource planning teams met throughout the planning process for the 2026 LTGRP to identify opportunities where information sharing could potentially benefit the development of the long-term resource plans.

This collaboration effort was guided by the BCUC's Decision and Order G-78-24 on FEI's 2022 LTGRP, which encouraged FEI and BC Hydro to identify planning assumptions that are common to each plan, and provide information on those assumptions to facilitate a comparison of the approaches taken by each utility. The assumptions recommended by the BCUC were:

- Customer growth rates by region;
- Cross-price elasticity;
- Volume of fuel switching;
- Capture rates of new customers for major end-uses (e.g., space and water heating);
- Hydrogen production or other lower-carbon gas facilities located within BC; and
- Whether Provincial GHG emission reduction targets are assumed to be met in certain scenarios, and the relative contribution to emissions reductions in BC by gas and electric utilities. In addition to these recommendations, FortisBC identified other areas where information could be provided from FEI's long-term scenarios, developed on a timeline that lagged the creation of BC 26 Hydro's 2025 IRP scenarios, as follows:
- Marine and medium- and heavy-duty transportation demand; and
- Demolition rates. The subsections below provide the results of the collaboration and comparison efforts with BC 2 Hydro or reference the section in the 2026 LTGRP where the finalized information can be found.

22.1 Has Fortis BC gained access to BC Hydro's long-term electrification plans in all of the potential markets that these would compete against the FEI growth for natural gas use and or against the GHG emissions reductions initiative FEI is encouraging and has FEI been able to converge at all and in any respects on a coordinated

planning for GHG emissions reduction and or on the peak requirements reductions for either or both of the utilities and if so can FEI comment on the degree of effectiveness of such planning and if not what would appear to be impediments to the coordination of planning.

Response:

In the preamble to this question, CEC-COSCO-RCIA references the BCUC's Decision and Order G-78-24 on FEI's 2022 LTGRP and provides an incomplete summary of the BCUC's statements in the decision. As a portion of the preamble was not included in the BCUC's decision and may be misleading, FEI provides the full BCUC Panel discussion on page 54 of the Decision for clarification and context:

> Although the Panel views collaboration between the major utilities in BC as important, it does not make any determinations on this matter in this decision. Similar issues and submissions arose in the BC Hydro 2021 IRP, which were addressed in the BCUC's Decision and Order G-58-24 (IRP Decision). The Panel agrees with the comments regarding collaboration in the IRP Decision, which are equally applicable to FEI. In summary, greater collaboration between FEI and BC Hydro (and other utilities) on resource planning would be resource intensive and may not result in agreement between the utilities, and the BCUC should not be prescriptive on policy issues. The Panel endorses the proposal in the IRP Decision that in their next long-term resource plans, FEI and BC Hydro identify planning assumptions that are common to each plan, and provide information on those assumptions to facilitate a comparison of the approaches taken by each utility. These assumptions may include:
>
> - Customer growth rates by region;
> - Cross-price elasticity;
> - Volume of fuel switching;
> - Capture rates of new customers for major end-uses (e.g. space and water heating);
> - Hydrogen production or other low carbon gas facilities located within BC; and
> - Whether Provincial GHG emission reduction targets are assumed to be met in certain scenarios, and the relative contribution to emissions reductions in BC by gas and electric utilities.

While BC Hydro has not shared something it refers to as its "long-term electrification plans", FortisBC has been coordinating with BC Hydro and understands BC Hydro's 2025 Integrated Resource Plan (IRP)[22], as well the potential for electrification in the province, as reflected in FEI's 2026 LTGRP demand scenarios.

[22] FEI notes that Concordance Table 2 in Appendix I of BC Hydro's 2025 IRP states: "BC Hydro's Electrification Plan

As discussed in Section 8.6 of the 2026 LTGRP, FEI's and BC Hydro's resource planning teams met throughout the planning process of their respective resource plans. Further, as discussed in BC Hydro's 2025 IRP,[23] since May 2024, FEI (and FBC) and BC Hydro have been meeting regularly to share information on load forecasting approaches and assumptions. This engagement has improved mutual understanding of key technical elements of each utility's long-term resource plans, including demand forecasts, shared assumptions, and major drivers of uncertainty.

Additionally, as described in FortisBC's response to the BCUC letter dated April 1, 2026 requesting input regarding energy supply to the Okanagan region, BC Hydro, FEI and FBC currently collaborate on various activities where it is appropriate and beneficial for each utility's customers.[24] While in the context of the Okanagan region, FortisBC's letter provides detail on the coordination of planning between the utilities across their service territories. For example, the response highlighted FortisBC's and BC Hydro's efforts to explore the potential for a joint dual-fuel heating system incentive program, which is an example of coordinated planning to achieve GHG emissions reductions and mitigate electric peak demand growth.

Overall, FEI considers that its coordination with BC Hydro has been effective and does not see any material impediments to continued coordination with BC Hydro in the future.

22.2 If FEI had access to electrical power supply at approximately $56 MWh CAD at scale quantities and favourable locations, what would FEI do with regard to reducing GHG emission in BC and potentially elsewhere to optimize its ability to plan, promote and use natural gas cost-effectively. In answering this question please assume that such energy availability will be available in the near term (next 5 years) for the FEI planning horizon.

Response:

FEI provides gas service to its customers and does not acquire electrical power supply to provide this service. Accordingly, the scenario presented in this question is irrelevant to the 2026 LTGRP.

and associated expenditures to encourage electrification….as part of BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application."

[23] BC Hydro 2025 IRP, Section 2.9.2, pp. 2-90.

[24] BCUC Okanagan Energy Supply – FortisBC Submission, Response to Question 6: https://docs.bcuc.com/documents/other/2026/doc_87052_2026-04-27-fortisbc-submission.pdf.

23.0 Reference: Exhibit B-1, Pages 5-14, 5-15, 5-16

Preamble: Outlook and Key Signposts FEI views hydrogen as a strategic enabler of long-term GHG emissions reductions and system resilience, but its large-scale deployment will depend on a set of market, policy, technology and economic signposts that must align. These signposts reflect both indicators to monitor as well as elements of the broader enabling environment – policy stability, regulatory clarity, technological readiness, cost competitiveness, demand certainty, and market confidence – that must be built collectively to make hydrogen viable at scale. FEI's roadmap therefore outlines a potential trajectory rather than a fixed timeline, materializing only if critical conditions are met. A more detailed breakdown of the signposts is provided below: 25

- Economics
  - Delivered Cost: Hydrogen must approach cost competitiveness compared to other emissions abatement options to enable adoption across industrial and transportation sectors. Without this, large-scale investment risks stranded assets.
  - Demand Aggregation: Sustained offtake from multiple users is critical to justify infrastructure such as pipelines. This ensures projects operate at scale and 31 achieve economies of scale.
- Market Adoption
  - Municipal and Industrial Commitments: Integration of hydrogen into regional climate and lower-carbon energy strategies provides foundational demand and policy alignment.
  - Fleet Conversions: Early adoption in transit and freight sectors creates anchor loads and accelerates infrastructure viability.
  - Other Markets: Progress in adjacent jurisdictions can influence technology 3 availability, cost curves, and investor confidence.
- Policy and Regulatory
  - Carbon Price: A stable and predictable carbon-pricing framework that generates sufficient economic incentive for end-users to transition from conventional fuels toward lower-carbon alternatives, creating the demand certainty developers need to invest with confidence.
  - Directional Signals: Clear provincial and federal enabling strategies, such as the BC Hydrogen Strategy, will need to be in place to provide certainty for long-term planning.
  - Financial Support: Incentives, tax credits, and infrastructure funding reduce capital barriers and improve project economics.

- Regulatory Enablement: Regulatory approval of hydrogen infrastructure and/or 15 supply is essential for utility participation.

- Technology and Infrastructure
  - Production: Commercial demonstrations at scale validate cost and reliability assumptions.
  - Distribution: Successful blending trials confirm technical feasibility within existing networks and inform standards.
  - End-Use Technologies: Readiness of heavy vehicles, industrial burners, and blending infrastructure ensures demand can materialize as supply grows.

These signposts collectively determine whether hydrogen can progress beyond pilots to commercial-scale deployment. FEI's strategy is to advance readiness while monitoring these indicators, ensuring that when conditions align, the organization is positioned to enable a scalable hydrogen economy in a manner that is prudent, cost-effective, and aligned with provincial emissions reduction goals.

Based on these signposts, potential development phases for hydrogen are as follows:

- Feasibility and Pilots (2020s): Early-stage activities such as blending trials, industrial displacement pilots, and transportation demonstrations are underway to validate technology and economics. These efforts build operational knowledge and inform regulatory frameworks. Many of these efforts are underway for FEI as discussed above.
- Demonstration and Scale-Up (2030s): Subject to sustained demand and policy support, regional hydrogen hubs could emerge, starting with small-scale production and expanding to multi-spoke configurations serving industrial clusters.
- Commercial Roll-Out (2040s and Beyond): Full-scale infrastructure, including dedicated pipelines and multiple hubs, would only proceed if signposts confirm economic viability, regulatory enablement, and aggregated demand.

23.1 If hydrogen is viewed as a highly significant resources to be considered in the FEI gas supply framework for supporting its natural gas supply, what are the limits of the blending trials in percentage ability to have an impact and if limited versus other options why would this be the early stage focus or is FEI anticipating having H2 as a long term replacement solution.

Response:

Please refer to the response to BCSEA-MS2S IR1 11.2, including the discussion of hydrogen delivery pathways anticipated over the planning horizon. FEI expects that the hydrogen blending pathway will be limited to less than 20 percent by volume over the planning horizon; however, other pathways such as co-location of production and use and dedicated infrastructure are not limited in the same way.

23.2 Cost-effective sourcing of H2 can be done through electrolysis of pure water and the recent development of capillary technology for electrolysis Hysata has demonstrated substantial improvement in the cost-effectiveness of H2 production. Is FEI familiar with this technology development and taking this into account in it long term planning.

Response:

FEI is aware that electrolysis maximum system efficiency will likely peak at 70 to 75 percent for standard commercial technologies like Proton Exchange Membrane (PEM) and Alkaline systems.[25] FEI is also aware that next-generation electrolysis technologies such as capillary-fed systems (for example, Hysata technology) and high-temperature Solid Oxide Electrolysis Cells (for example, Topsoe[26]) can push efficiencies past 90 percent by recovering waste heat or lowering internal resistance.

FEI continues to monitor market and technology advancements at the pre-commercial and commercial level for consideration in near-term and longer-term planning.

23.3 With the production of H2 from electrolysis there is a pure O2 stream available, has FEI examined what would be the optimum use and value of such an O2 stream and how it would impact the cost-effectiveness of the H2 and if so can FEI provide its expected future costs for H2 and how this cost-effective H2 could be employed most cost-effectively to optimize FEI's GHG emissions reduction for its uses.

[25] US Department of Energy, Water Electrolyzer Technical Targets, online at: Technical Targets for Proton Exchange Membrane Electrolysis | Department of Energy.

[26] Topsoe, Press Release: Haldor Topsoe to build large-scale SOEC electrolyzer manufacturing facility to meet customer needs for green hydrogen production (March 2, 2021) online at: https://www.topsoe.com/news/haldor-topsoe-to-build-soec-electrolyzer-manufacturing-facility.

Response:

FEI has investigated potential industrial use cases and the potential value arising from the sale of oxygen that is co-produced with green (electrolytic) hydrogen production. An informative resource on this topic is the BC Ministry of Climate Solutions' Clean Energy and Major Projects Office sponsored research report, which examined hydrogen co-product materials including oxygen and its potential market applications.[27]

FEI considers the optimum use case would be to co-locate the electrolyzer facility beside an existing industrial operation that can use hydrogen to replace natural gas use and has onsite demand for oxygen. Examples of such industries in BC include pulp and paper and metal smelting, both of which can require very large volumes of oxygen. Typically, the oxygen supply is delivered by truck from a merchant oxygen supplier or generated using large onsite air separation units that filter oxygen from the atmosphere and make it available for onsite process use.

Revenue from the sale of oxygen that is co-produced with green hydrogen is valuable and could lower the cost of green hydrogen, potentially provide lower-cost oxygen supply and/or provide a backup oxygen source for the industrial business. The business model would require FEI or a third-party developer to partner with an industrial host site to co-locate a green hydrogen production facility that would supply hydrogen to replace existing natural gas use and supply oxygen to replace existing oxygen use. The prescribed undertaking for hydrogen in the GGRR is structured to facilitate this model and enable FEI to acquire low-carbon hydrogen that is produced adjacent to and consumed by industrial operations to replace their natural gas use.

FEI has analyzed project development and techno-economic data for two project concepts based on this model:

- A small-scale 10 MW green hydrogen project that would be constructed within an existing industrial operation, sell hydrogen to FEI, and sell co-produced oxygen to the industrial site hosting the project.
- A large-scale 250 MW green hydrogen project that would be constructed adjacent to multiple industrial operations, sell green hydrogen to FEI, and sell co-produced oxygen to adjacent host industrial operations.

Based on FEI's analysis, green hydrogen could be employed most cost-effectively for GHG emissions reduction when the green hydrogen production is co-located with industrial operations that can use all the hydrogen and oxygen generated. The goal would be to avoid wasted resources and maximize project revenues to achieve a levelized cost to produce hydrogen below the GGRR price cap.

FEI's analysis indicates that for every 1 kilogram of green hydrogen, approximately 8 kilograms of oxygen is produced. Therefore, revenue from oxygen sales is one of the most important

[27] Katherine Lunney, Opportunities for Hydrogen Co-Products Utilization in British Columbia (report sponsored by the Province of British Columbia) (July 30, 2024), online at: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/clean-energy-major-projects-office/opportunities_for_hydrogen_co-products_utilization_in_british_columbia.pdf.

economic drivers to potentially reduce the levelized cost of green hydrogen production to below the GGRR hydrogen acquisition price cap. Conversely, FEI's analysis indicates that, without oxygen sales revenue, it is not economically feasible for an electrolyzer facility (third-party or FEI-owned) to produce hydrogen with a levelized cost of production below the GGRR price cap. The following represents the top three key economic drivers to produce competitive green hydrogen:

- Maximize oxygen sales benchmarked against merchant supplier oxygen prices;
- Leverage Investment Tax Credit and other project development support policies; and
- Seek tailored industrial electrification tariffs such as the Clean Industry and Innovation Rate (Rate Schedule 1894).[28]

23.4 Also impacting the H2 production cost-effectiveness and the cost effectiveness of the O2 stream would be the electrical power costs used for powering the electrolysis process, has FEI determined what its optimal future source costs for electricity could be and how to acquire this and FEI has not considered this yet why not.

Response:

Electricity costs represent the largest component of electrolyzer operating expenses. FEI has considered the following factors which should be optimized through minimizing power requirements, minimizing power costs, and minimizing grid interconnect costs.

Power Requirements

Selecting the correct electrolyzer technology could reduce power requirements significantly. The production of 1 GJ of hydrogen from mature and emerging electrolyzer technologies are listed below. The best available emerging technology could reduce power requirements by 25 percent:[29]

- Alkaline electrolysis (mature technology): 381 kWh per GJ hydrogen
- Proton Exchange Membrane electrolysis (mature technology): 360 kWh per GJ hydrogen
- Solid Oxide Electrolyzer Cells electrolysis (early-stage commercialization): 282 kWh per GJ hydrogen

While power requirements are an important consideration, electrolyzer technology selection would also depend on project-specific factors such as operating profile, heat integration

[28] https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html.
[29] BC Centre for Innovation and Clean Technology, Carbon Intensity of Hydrogen Production Methods (March 2023), online at: https://www2.gov.bc.ca/assets/gov/business/natural-resource-industries/reports/carbon_intensity_of_hydrogen_production_methods.pdf.

opportunities, production scale, technology maturity, reliability, grid connection constraints, and compatibility with the host site's hydrogen and oxygen demand profile.

Power Costs

Power supply tariffs, such as the Clean Industry and Innovation Rate (Rate Schedule 1894),[30] could provide a discount from the standard transmission service rate on both energy charges and demand charges. In addition, as the power market starts to incorporate a greater share of fluctuating renewable generating capacity (wind and solar resources), an electrolyzer plant could benefit from tariffs that incentivize ancillary grid services provided by large dispatchable electrolyzer loads.

Interconnection Costs

Situating an electrolyzer plant at an industrial host site could allow grid connection "behind-the-meter" which would help reduce the upfront grid interconnection costs associated with green-field projects.

[30] https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html.