Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

August 4, 2021

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)

2021 Long-Term Electric Resource Plan (LTERP) and Long-Term Demand-Side Management Plan (LT DSM Plan)

On June 28, 2018, the British Columbia Utilities Commission (BCUC) issued Order G-117-18 and Decision which, among other things, accepted FBC's 2016 Long-Term Demand-Side Management (DSM) Plan and accepted the 2016 Long-Term Electric Resource Plan for the period through 2024. The Decision also directed FBC to file its next LTERP and LT DSM Plan no later than December 1, 2021.

In accordance with the BCUC's Resource Planning Guidelines and section 44.1 of the *Utilities Commission Act*, FBC respectfully submits the LTERP (as Volume 1) and LT DSM Plan (as Volume 2) for the BCUC's review.

FBC is seeking acceptance of this LTERP, including the LT DSM Plan, pursuant to section 44.1(6) of the UCA.

If further information is required, please contact Corey Sinclair at 250-469-8038.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to the FBC Annual Review for 2020 and 2021 Rates proceeding
2021 LTERP Resource Plan Advisory Group (RPAG) Members

FortisBC Inc.

2021 Long-Term Electric Resource Plan and Long-Term Demand-Side Management Plan

August 4, 2021

FORTISBC INC.

2021 Long-Term Electric Resource Plan

Volume 1

August 4, 2021

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EXECUTIVE SUMMARY

1. Introduction

The 2021 Long-Term Electric Resource Plan (LTERP) presents the FortisBC Inc. (FBC or the Company) long-term plan for meeting the forecast peak demand and energy requirements of customers with demand-side and supply-side resources over the 20-year planning horizon (2021 to 2040). The LTERP analyzes the external regulatory, policy, market supply and customer planning environment within which FBC operates, compares energy and capacity load forecasts against current resource capabilities and evaluates the potential for load reduction with demand-side management (DSM) initiatives and other options specific to electric vehicle (EV) charging. The LTERP then compares portfolios of supply-side resource options to meet remaining forecast customer needs under different scenarios. It also assesses the potential transmission and distribution system infrastructure requirements over the planning horizon. The LTERP includes an action plan that describes the activities that FBC intends to pursue over the next four years. The LTERP is intended to meet the following objectives:

- Ensure cost-effective, secure and reliable power for customers;
- Provide cost-effective demand side management and customer solutions that help meet FBC's and BC's environmental goals, and
- Ensure consistency with provincial energy objectives (for example, the applicable objectives in the CEA and the CleanBC Plan).

The analysis in this LTERP shows that FBC does not require any new supply-side resources until at least 2030, based on the Reference Case load forecast, existing resources and contracts in place, continued access to reliable and cost-effective market energy, and the proposed level of DSM. This is because optimization of market purchases and existing resources, including the power purchase agreement (PPA) with BC Hydro, provide FBC with enough energy and capacity until 2030 to meet customers' requirements in a cost-effective and reliable manner. After 2030, FBC requires additional generation resources, primarily for capacity purposes. However, this requirement could be delayed until 2031 or later depending on the amount of EV charging FBC is able to shift from peak demand periods. The portfolio analysis provided in Section 11 provides a high-level indication of the potential combination of resources that could meet future requirements.

FBC files this LTERP under section 44.1(2) of the *Utilities Commission Act* (UCA) and is seeking British Columbia Utilities Commission (BCUC or Commission) acceptance of the LTERP as being in the public interest pursuant to section 44.1(6). There are no approvals being sought by FBC as part of this LTERP submission. Any requests for approval of specific resource needs that are identified within this plan will be further evaluated and brought forward through a separate application to the BCUC if warranted in the future.

FBC has developed this LTERP to be consistent with the BCUC Resource Planning Guidelines and directives from the BCUC 2016 LTERP decision.

2. Planning Environment

Understanding the planning environment is the first step in FBC's resource planning process. The planning environment includes relevant external factors that impact FBC's demand-side and supply-side resource options and their future costs and prices as well as those factors that could influence customers' energy and capacity needs over the planning horizon. FBC focuses on three key areas in its assessment of the planning environment. These include the following:

- The relevant energy and environmental policies in both Canada and the United States and their potential impacts on resource options, market and carbon prices and customers' behaviour regarding energy use in the future;
- The customer demand environment, including how technology, customers' energy needs and the types of loads are changing and how the relationship between the customer and the utility is evolving; and
- The supply environment, in particular the changes occurring in British Columbia (BC), Alberta, California and the Pacific Northwest region that will influence FBC's resource options and market electricity prices.

Climate change is dramatically changing the external environment in which FBC operates and has prompted governments at all levels to enact environmental policies aimed at reducing greenhouse gas (GHG) emissions. Over the LTERP planning horizon, climate change has the potential to impact FBC's supply in terms of its hydro-electricity generation, how much electricity FBC customers require and FBC's transmission and system infrastructure planning. Energy and environmental policies in Canada and the US are constantly evolving as federal, provincial, state and municipal governments are implementing a number of initiatives to reduce GHG emissions. These policy actions will impact the electricity generation mix in western Canada and the US Pacific Northwest region as generators in the US and provinces like Alberta move towards greater adoption of renewable resources like wind and solar. This in turn will likely impact market electricity prices. The current gas market environment continues to experience relatively low price levels compared to those seen before the pre-shale gas era. The growth of renewable energy has diversified electricity generation capability in the region which, along with low market gas prices, has resulted in low market electricity prices. Market electricity prices continue to remain well below the cost of other supply-side resource options.

These environmental policies will also influence customer demand. In BC, the provincial government's emission targets require that GHGs in BC be 16 percent below 2007 levels by 2025, 40 percent by 2030, 60 percent by 2040 and 80 percent by 2050. To achieve these goals, the provincial government released its CleanBC provincial climate plan (the CleanBC Plan) in December 2018. The CleanBC Plan is aimed at reducing climate pollution while creating jobs and economic opportunities.

For the transportation sector, there is heavy emphasis on zero emission vehicles (ZEVs). The *Zero-Emission Vehicles Act* (ZEV Act) requirement is that 10 percent of new light-duty vehicles sold in 2025 be zero-emission, rising to 30 percent in 2030 and 100 percent by 2040. FBC has used these targets to inform the EV charging load portion of the Reference Case load forecast. FBC is preparing to meet the changing and future needs of customers as they relate to EVs and expects continued involvement in supporting transportation electrification to help meet provincial GHG emission reduction targets. FBC intends to pursue a software-based approach to help shift EV charging from peak demand periods and is planning to implement a pilot program beginning in 2021 to help determine how much shifting of EV charging from peak periods this strategy might be able to achieve. If successful, FBC anticipates implementing a program in the near term.

The customer demand environment continues to evolve as existing customers change the way they use, monitor and generate their own electricity and new large load customers emerge. This presents both challenges and opportunities for FBC in meeting the future needs of its customers.

Distributed generation technologies, such as rooftop solar PV combined with home battery storage, will also change customer demand and place different burdens on the distribution system. FBC continues to support customer-owned distributed generation through its net metering tariff. While customers may install their own distributed generation in order to save money or gain energy independence, small-scale distributed generation technologies present some challenges for FBC related to safety, grid stability and cost recovery through rates. FBC is continuing to monitor developments in distributed generation and will consider the role of distributed energy resources in optimizing system benefits for customers in its future planning.

FBC has seen an increase in recent years in large load requests relating to cannabis production, blockchain technology and decarbonization through hydrogen and RNG production. These emerging large loads can provide benefits of better system utilization, reduction in upward pressure on customer rates and economic development in FBC communities. FBC has responded to this evolving customer demand by reviewing and revising internal processes to better manage customer interconnections and is evaluating new rate structures that allow FBC to attract and connect these large baseload customers.

DSM also continues to evolve and remains important in meeting customer demand. Climate change and related regulatory requirements, the rising price of electricity, advanced analytics and engagement tools will enable and incent customers to reduce energy and peak demand while providing innovative, personalized experiences.

The supply environment is also evolving as the Pacific Northwest region is facing an upcoming period of resource adequacy concerns and price and reliability uncertainty. Natural gas fired-generation, increased renewable generation projects, and regional, provincial and state developments are expected to change the regions’ resource dynamics. The regional power marketplace has recently been in an energy and capacity surplus due to hydropower and gas-fired combined-cycle power generation. However due to coal plant retirements, lower hydro-generation, and greater summer demand, the Pacific Northwest is facing a potential shortfall in capacity resources. Capacity shortfalls could result in less reliability and greater price volatility in the wholesale market, creating uncertainty and reliability risk for FBC over the long term.

The majority of FBC's energy and capacity power supply requirements are met through the Company's own generation resources and long-term contracts, and FBC can choose to access the wholesale markets for energy requirements to displace higher cost purchases. Market energy access for the Company is expected to continue through transmission and power purchase agreements, and market energy can be available at attractive prices to FBC during periods of surplus power. Increased renewable penetration across the region may increase the surplus energy available through wind and solar resources; however, declining snowpack levels, persistent drought, and seasonal water shortages due to climate change could decrease the surplus hydropower available during spring freshet and summer periods. FBC will continue to monitor the price and availability of wholesale market energy, as well as any regional developments that would affect the Company's ability to purchase from the wholesale market.

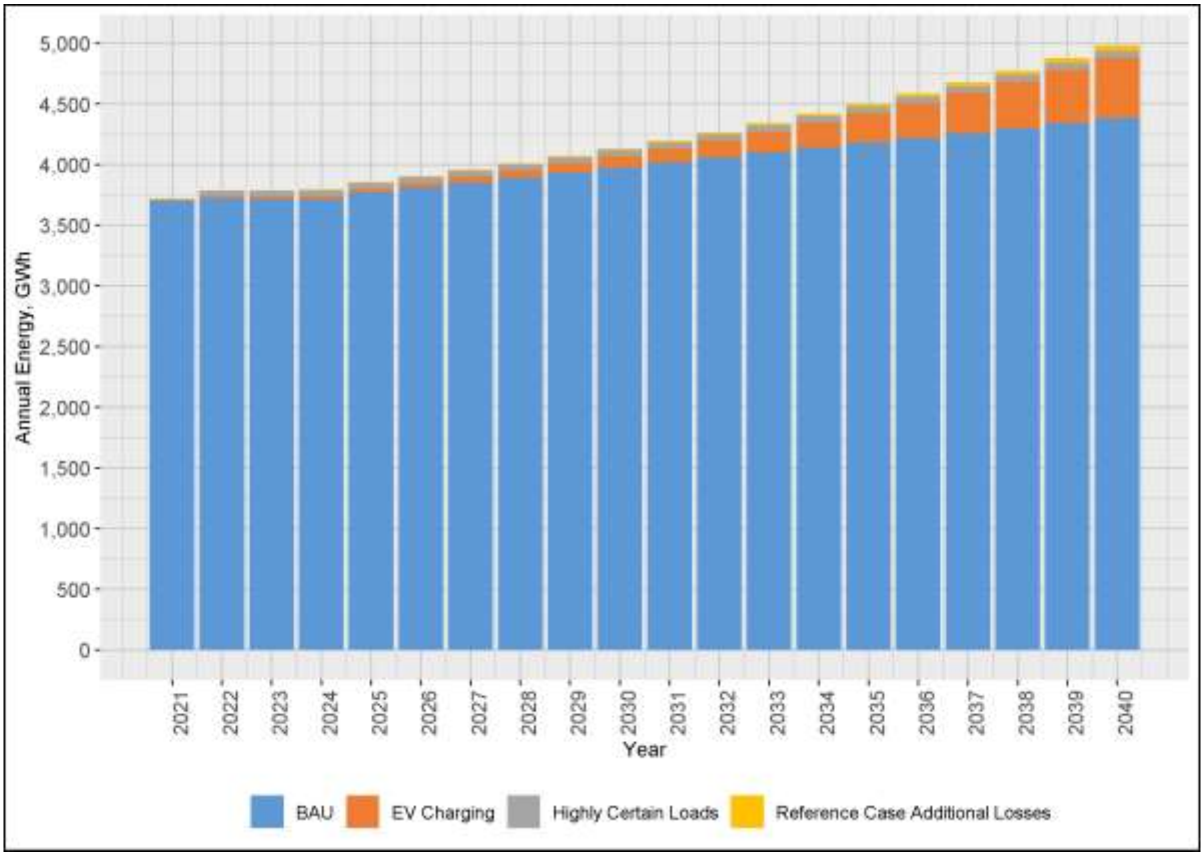
3. Long Term Load Forecast

FBC forecasts the expected load over the planning horizon in order to determine the annual energy and peak demand requirements of its customers. The Business As Usual (BAU) forecast is the forecast used for annual rate setting which is then extended out for the 20-year planning horizon. The Reference Case load forecast builds on the BAU forecast by including electric vehicle charging load and new industrial loads with high confidence of materializing. The Reference Case load forecast is the resulting forecast used for planning purposes in this LTERP.

FBC's BAU gross energy load forecast anticipates a modest rate of growth over the twenty-year planning horizon with an increase in gross energy load from 3,698 GWh in 2021 to 4,383 GWh by 2040, reflecting an average annual growth rate of 0.9 percent. The Reference Case load forecast shows annual energy growth from 3,717 GWh in 2021 to 4,983 GWh in 2040, reflecting an average annual growth rate of 1.6 percent.

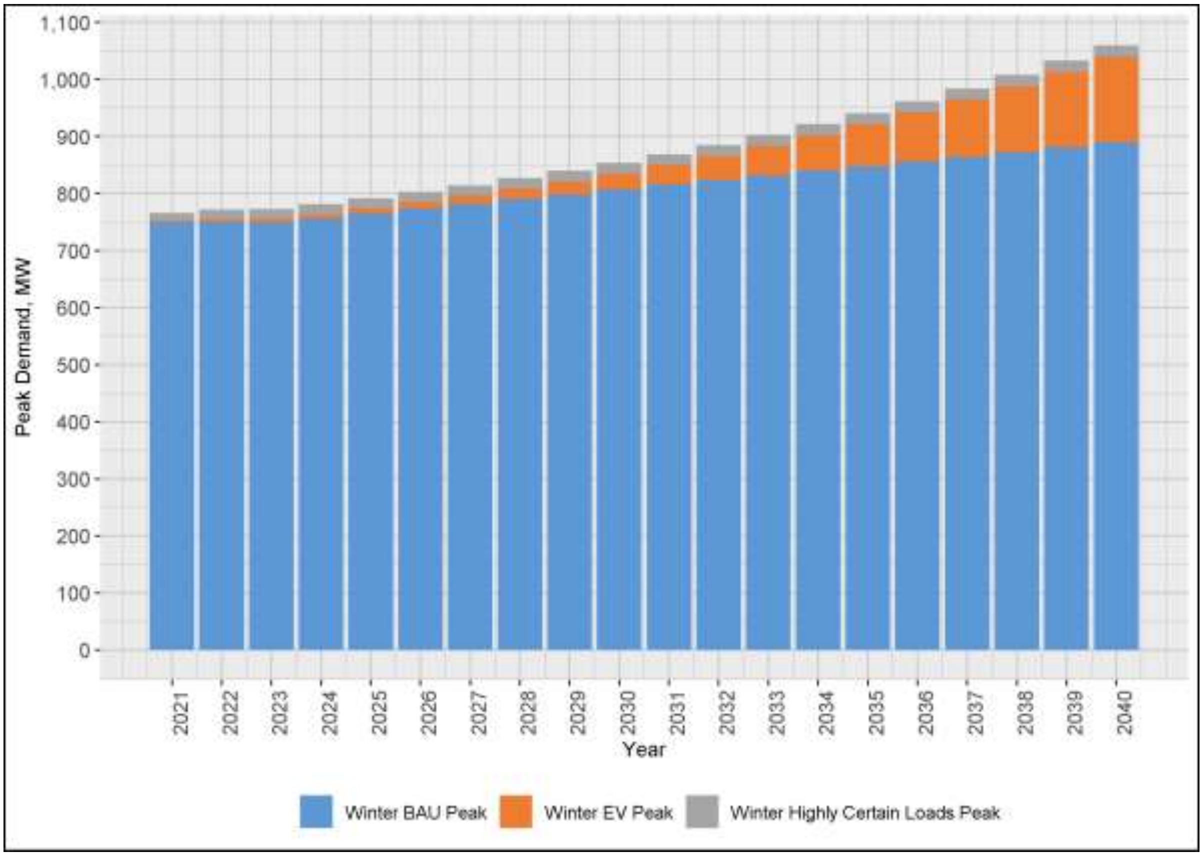
The following figure shows the BAU forecast and the additional EV charging and highly certain industrial loads which are included in the Reference Case load forecast.

Figure ES-1: Gross Energy Load Forecast (GWh)



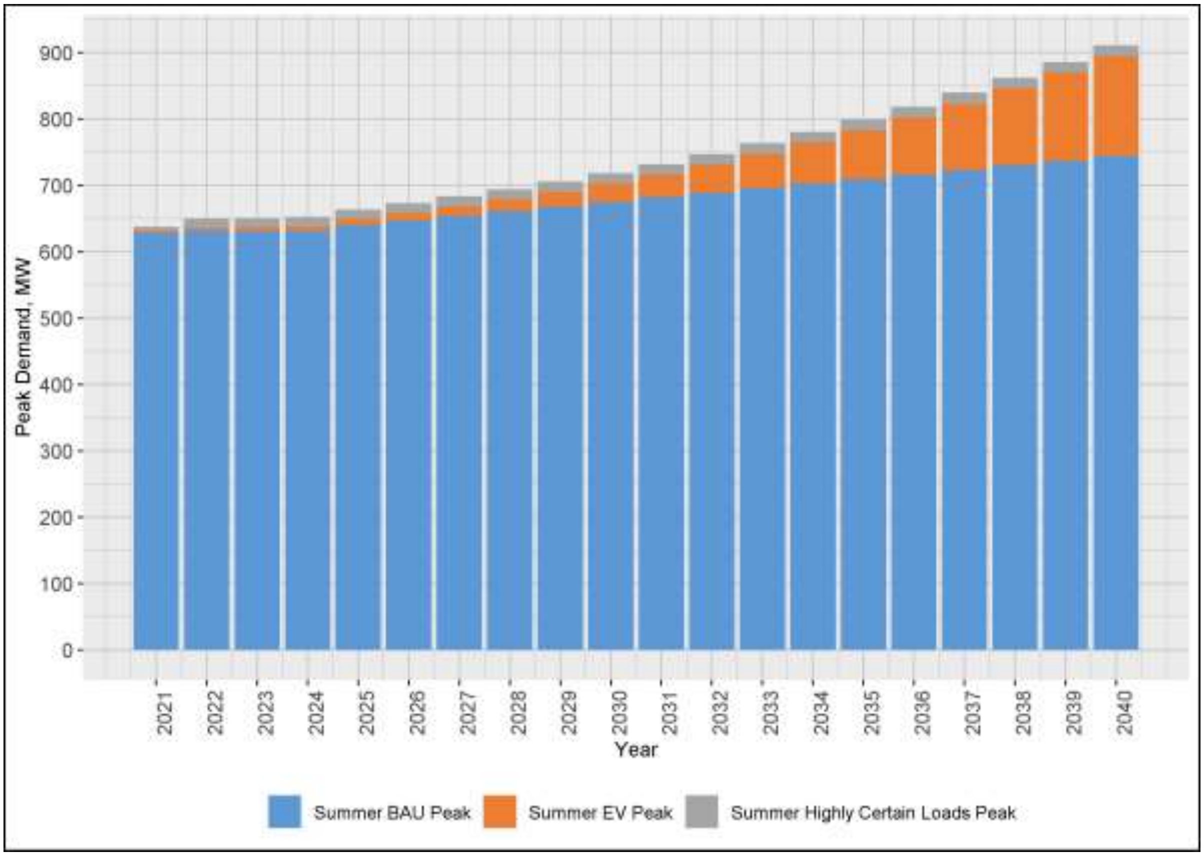
The BAU winter peak demand forecast increases from 749 MW in 2021 to 890 MW in 2040, increasing at an average annual growth rate of 0.9 percent. The Reference Case winter peak is forecast to increase from 766 MW in 2020 to 1,060 MW in 2040, at an average annual growth rate of 1.7 percent.

Figure ES-2: Winter Peak Forecast (MW)



The BAU forecast summer peak demand forecast increases from 628 MW in 2021 to 744 MW in 2040, increasing at an average annual growth rate of 0.9 percent. The Reference Case summer peak is forecast to increase from 638 MW in 2021 to 911 MW in 2040, at an average annual growth rate of 1.9 percent.

Figure ES-3: Summer Peak Forecast (MW)



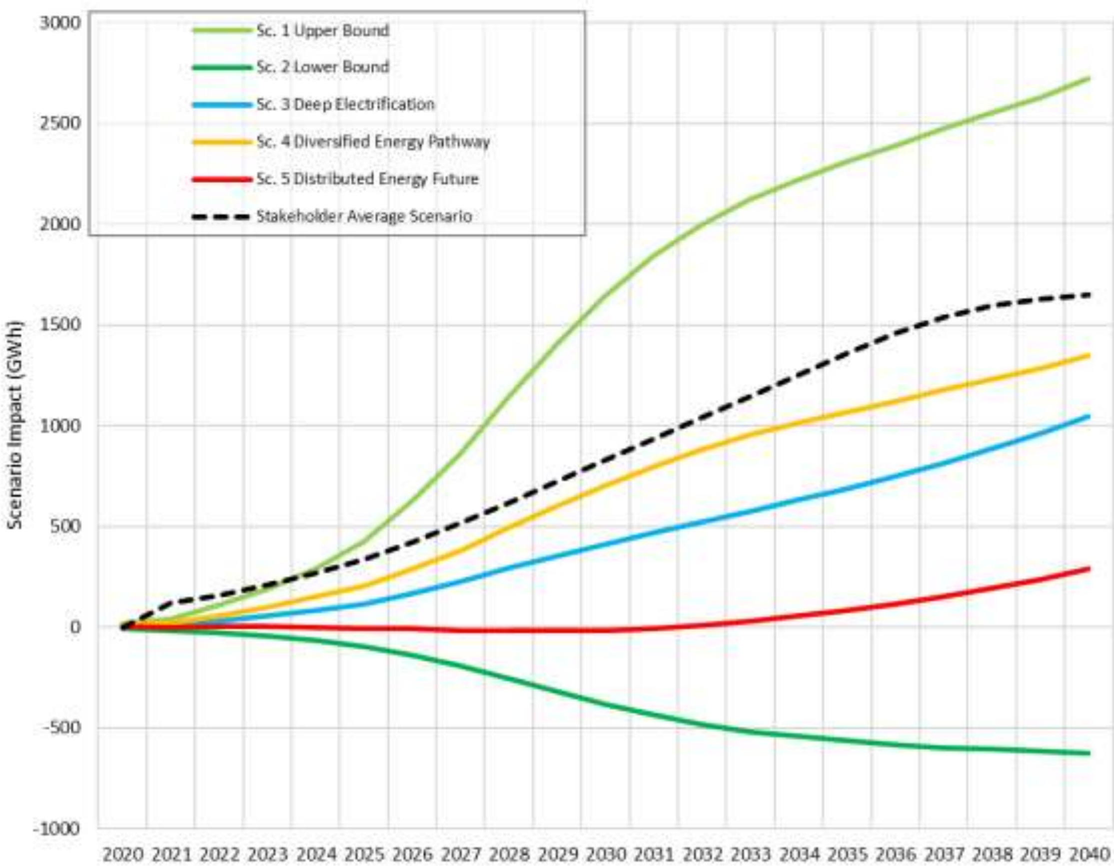
The Reference Case winter and summer peak forecasts do not include any electric vehicle charging peak mitigation (i.e. shifting EV charging loads from peak periods). This is because FBC currently has no EV charging mitigation programs in place and has no certainty, at this point, how much EV charging it will be able to shift off peak periods. The Reference Case load forecast is also presented before any DSM measures – these are discussed in Executive Summary, Section 8.

4. Load Scenarios

As part of its long-term resource planning, FBC explores alternate load scenarios to the Reference Case load forecast. In this LTERP, FBC explored two boundary scenarios and three intermediate scenarios as well as stakeholder scenarios. Load driver penetrations in the boundary scenarios help FBC understand the potential impact that each of these load drivers could have under extreme, but plausible, penetration scenarios, providing upper and lower limits for the other intermediate scenarios. The intermediate scenarios, which include combinations of load drivers that increase and decrease load, may be more reasonable potential future pathways. However, at this point in time, there is too much uncertainty to know which of the scenarios, if any, will occur in the future.

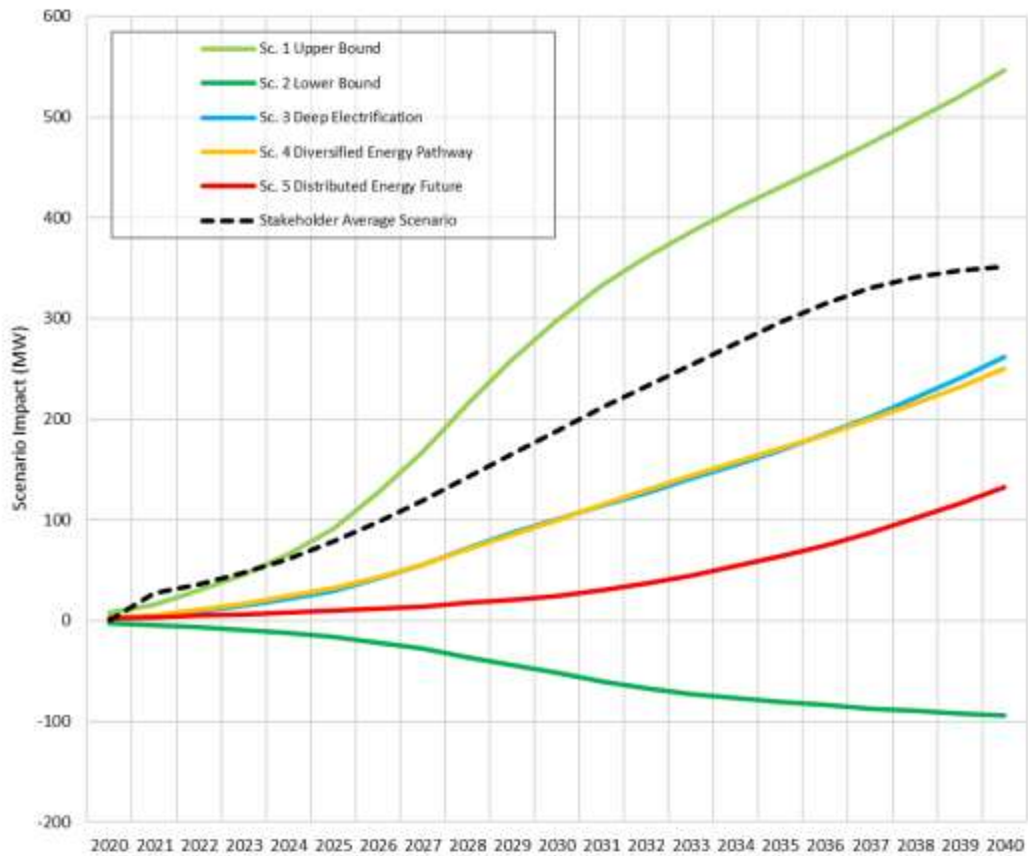
The principal finding for the intermediate load scenarios is that the load drivers that may have the most impact to FBC going forward include EV charging, large loads and hydrogen production. Lesser impacts were seen from fuel switching, rooftop solar, carbon capture and storage and climate change. While a load driver like EV charging would likely ramp up gradually over time as drivers transition from gasoline and diesel vehicles to EVs, hydrogen production and other large industrial loads could be load drivers that could come on relatively quickly with shorter lead times and with potentially large immediate impacts on the FBC load requirements. The results of the load scenarios, in terms of annual energy impacts relative to the BAU load forecast, are provided in the following figure.

Figure ES-4: Load Scenarios' Annual Energy Impacts



The results of the load scenarios, in terms of winter peak demand impacts relative to the BAU load forecast, are provided in the following figure.

Figure ES-5: Load Scenarios' Winter Peak Demand Impacts



There are several conclusions and recommendations arising from the load scenario analysis. First, electrification could require significant additional resource generation and system infrastructure in order to address growth in peaky loads, such as that from EV charging, if left unmitigated. Prudent management of such a transition could reduce the required capital investments and generation resources and impacts on customer rates. Second, distributed generation installed in residential households, with current rate structures, is unlikely to make any meaningful contribution to peak demand reductions, even when enabled with energy storage. FBC could consider initiatives to manage rooftop solar and energy storage to help optimize system benefits if distributed generation from rooftop solar becomes more significant on the FBC system. Third, initiatives to incent and properly manage potential growth in non-traditional high load-factor customer loads, such as hydrogen production, could improve system optimization and help reduce rate increases for all customers, particularly if these loads could be curtailed for short periods during system peaks.

The ability of FBC to meet customer load requirements that are significantly higher or lower than the Reference Case load forecast is included within FBC's portfolio analysis and helps determine the requirement for resource flexibility.

5. FBC Existing Supply-Side Resources

FBC meets its energy and capacity requirements primarily through a portfolio of FBC-owned entitlement resources, long-term entitlement purchase agreements and purchases under the BC Hydro Power Purchase Agreement (PPA). Any remaining energy needs are met through short- to medium-term market purchases and independent power producer (IPP) supply and other resources.

There are some important changes to FBC's existing portfolio of resources over the planning horizon. The Residual Capacity Agreement (RCA) relating to the Waneta Expansion Capacity Purchase Agreement (WAX CAPA) residual capacity sale expires September 30, 2025, and for the purposes of the 2021 LTERP, FBC is assuming that it is not renewed. FBC will sell the remaining surplus WAX CAPA residual capacity to Powerex on a day-ahead basis, under the terms of the CEPSA, if and when the capacity is not required to meet FBC load requirements. Brilliant Expansion (BRX) entitlement contracts with FBC and BC Hydro expire at the end of 2027 and renewal is not assumed beyond that date. The entire set of capacity and energy entitlements attributed to BRX will be assessed as a future option to meet FBC's resource needs. Additionally, the PPA agreement with BC Hydro expires in 2033. FBC's base assumption for its portfolio analysis in Section 11 assumes that the PPA will continue in a similar form past the current expiry date in 2033. FBC plans to begin review the PPA in 2023 to determine if negotiations should begin with BC Hydro to renew the PPA.

6. Transmission and Distribution System

FBC plans, constructs and operates its transmission and distribution system to safely and reliably deliver electricity to customers throughout the Company's service area under reasonably foreseen operating conditions and weather extremes. To accomplish this, FBC develops substation load forecasts, conducts computer-based system modelling and coordinates system planning and operations with neighbouring transmission entities. Infrastructure reinforcements are identified when load forecasts or new large capacity requests indicate that the system has insufficient capacity to meet planning criteria during normal or contingency operations.

The future system impacts from emerging technologies and loads, such as distributed generation, EVs and emerging large loads, are uncertain at this time and will depend on the rate of adoption by customers. FBC has simulated peak demand scenarios to help determine, at a high-level, the potential system impacts. This provides FBC with an indication of the potential incremental transmission and distribution infrastructure required in the event that higher load scenarios emerge over the planning horizon if mitigation measures are not implemented. This highlights the significant cost related to the electrification of loads and the importance of effectively managing peak demand on the system.

FBC will continue to assess climate change adaptation measures and consider risk mitigation investments for future capital planning. As the risks associated with climate change continue to increase, there is potential for the capital requirements related to resiliency to substantially increase.

7. Load-Resource Balance Before DSM

Section 7 identifies the load-resource balance (LRB) before incremental demand-side and supply-side resources are included to determine if there are any energy and/or capacity gaps over the planning horizon. This is accomplished by comparing the Reference Case load forecast to the existing and committed resources in FBC's portfolio. The comparison will identify any LRB gaps that need to be met through a combination of DSM, supply-side resource options and other initiatives.

The following table summarizes the forecast approximate 2040 load-resource balance gaps for annual energy and winter, summer and June capacity with and without the PPA renewal before any demand-side or supply-side resource options are included to meet the gaps.

Table ES-1: Load-Resource Balance Gaps

	First Year of Gap	2040 Gap With PPA Renewal	2040 Gap Without PPA Renewal
Annual Energy (GWh)	2023	1,410	2,450
Winter Capacity (MW)	2028	245	445
Summer Capacity (MW)	2028	240	440
June Capacity (MW)	2021	280	480

Section 8 describes the DSM options available to reduce these forecast energy and capacity gaps, while Section 9 provides the forecast gaps after DSM. Section 10 then discusses the supply-side resource options available to meet any remaining gaps.

8. Demand-Side Management

FBC has a number of different resource options to meet the future energy and capacity needs of its customers. These include demand-side as well as supply-side resource options. FBC first looks to demand-side resources to meet any future LRB gaps. In this LTERP and in the Long-Term Demand-Side Management Plan (LT DSM Plan), FBC has evaluated different levels of DSM to meet future load growth. The DSM program scenarios FBC considered are based on incentive levels increasing to cover ever-larger proportions of the incremental costs of DSM measures. The DSM program scenarios represent FBC paying levelized incentives to cover 50, 62, 72, 84 and 100 percent of incremental measure costs in FBC's DSM portfolio. The table below shows the projected energy and capacity savings and average resource cost of the various DSM scenarios, as well as the incremental cost of incurring higher incentive levels in Med, High and Max scenarios compared to the Base scenario.

Table ES-2: Key DSM Scenario Data

Category	DSM Scenario				
	Low	Base	Med	High	Max
Energy Savings, GWh					
Average per annum ('21 - '40)	21.0	21.8	22.4	23.4	25.2
Average per annum ('21 - '29)	26.8	28.0	29.4	31.4	34.5
Total (2021 to 2040)	421	435	449	468	503
Capacity Savings, MW					
Total (2021 to 2040)	61.6	64.0	65.6	68.1	72.7
Resource Cost, 2020 ($000s)					
Average Cost ($/MWh)	$38	$44	$49	$57	$75
Incremental cost compared to base case ($/MWh)	N/A	-	$183	$190	$234

FBC selected the Base DSM scenario as its preferred scenario in the LT DSM Plan. The Base DSM Scenario can be characterized as a continuation of the 2016 LT DSM Plan's "High" scenario, in which the target savings increased from 26.4 to 30.4 GWh by 2022 and which used a constant 32 GWh per year as a placeholder thereafter.

Though the Low DSM scenario was more cost effective than the Base scenario, it was not chosen because:

- The Base scenario maintains consistency with the previous DSM plan which had support from customers and stakeholders;
- Transitioning to the Low scenario may require FBC to remove existing program offerings or reduce program incentives, potentially resulting in a reputational impact with customers and trade allies;
- The Low scenario requires pullback of program offerings which limits FBCs ability to scale up programs in the future if new cost-effective measures are identified. Selecting the Base scenario provides flexibility to meet future market demands; and
- The Base scenario includes additional budget to further investigate demand response (DR) programs that have the potential to cost-effectively defer capacity costs.

The Med, High and Max DSM scenarios were not chosen for the following reasons:

- They are less cost-effective than other resource options. FBC would be paying an increased incremental incentive proportion of measure costs, especially in comparison to the relatively low cost of power supply options, such as market electricity purchases; and

- They present higher risks of insufficient customer participation. DSM participation is voluntary and FBC cannot have assurance that customer participation will be sufficient to meet the higher scenarios. The fact that FBC had below-target energy savings in recent program results indicates that it may not be readily feasible to achieve higher levels of DSM.

In addition to this base level of DSM, FBC is also exploring other programs to help manage peak demand. The Company is planning a residential demand response pilot where it will seek to control and shift key household end-uses such as space cooling, hot water and residential home EV charging.

9. Load-Resource Balance After DSM

Section 9 includes a discussion of the LRB for annual energy and capacity after the proposed level of DSM and also includes a discussion of the capacity LRB assuming some amount of EV charging shifting from peak demand periods.

It shows that, with the proposed level of DSM, energy gaps start in 2023 and increase to almost 950 GWh by 2040 if the PPA is renewed. If the PPA is not renewed, then the gaps after 2033 are more significant and increase to approximately 1,990 GWh per year by 2040.

It also shows that, with the proposed level of DSM, there are no winter capacity gaps that need to be filled until 2031. Until 2030, based on the peak load forecast after DSM, there would be surpluses of capacity for most years if the PPA is assumed to provide its full peak supply of 200 MW. After 2031, the capacity gaps increase until they reach approximately 175 MW by 2040 if the PPA is renewed. If the PPA is not renewed, then gaps in the order of approximately 375 MW occur by 2040. If FBC is able to shift the potential EV charging from peak demand periods, then the capacity gaps could be moved further out in time. With EV charging shifting of 50 percent, the capacity gaps begin in 2033 rather than 2031, increasing to approximately 100 MW by 2040 if the PPA is renewed.

In terms of summer capacity, with the proposed level of DSM, there are no gaps that need to be filled until 2030. Until 2029, based on the peak load forecast after DSM, there would be surpluses of capacity if the PPA is assumed to provide its full peak supply of 200 MW. After 2030, the capacity gaps increase until they reach approximately 180 MW by 2040 if the PPA is renewed. If the PPA is not renewed, then gaps of approximately 380 MW occur by 2040. With EV charging shifting of 50 percent, the capacity gaps appear in 2031 rather than 2030. They increase to approximately 110 MW by 2040 if the PPA is renewed.

In terms of June capacity, with the proposed level of DSM, there are gaps in all years through 2040. The capacity gaps increase until they reach approximately 230 MW by 2040 if the PPA is renewed. If the PPA is not renewed, then gaps of approximately 430 MW occur by 2040. FBC's total existing capacity resources are lower in June which results in larger gaps during this month than in winter and summer periods. With EV charging shifting of 50 percent, the capacity gaps are about 150 MW by 2040 if the PPA is renewed. If the PPA is not renewed, the gaps increase to about 350 MW by 2040.

The following table summarizes the forecast approximate 2040 load-resource balance gaps for annual energy and winter, summer and June capacity with and without the PPA renewal after the proposed level of DSM but before any supply-side resource options are included to meet the gaps.

Table ES-3: Load-Resource Balance Gaps

	First Year of Gap	2040 Gap With PPA Renewal	2040 Gap Without PPA Renewal
Annual Energy (GWh)	2023	950	1,990
Winter Capacity (MW)	2031	175	375
Summer Capacity (MW)	2030	180	380
June Capacity (MW)	2021	230	430

10. Supply-Side Resource Options

The LRB gaps that cannot be met with demand-side measures must then be met with supply-side resource options. There are many potential supply-side resource options available to FBC to meet its future energy and capacity gaps. These include base load, peaking and intermittent/variable generation resources as well as purchases from the market and supply from self-generators. Based on current market price forecasts and PPA rate scenarios, market purchases and the PPA are the lowest cost supply-side energy resources available to FBC. Market purchases of energy can be a cost-effective and reliable resource within the FBC portfolio. FBC has relied on short-term market electricity purchases in the past and this strategy has proven cost effective in recent years given the decrease in market gas and power prices relative to the costs of other resource options, such as the PPA with BC Hydro. While market energy purchases have an associated carbon footprint, clean energy specified source contracts are available in the market. These contracts sell at a premium above regular market prices. FBC has applied a clean market adder to the cost of its market purchases.

The PPA, battery storage and gas-fired power plants using conventional natural gas or renewable natural gas (RNG) as fuel are the lowest cost capacity resources available. Although FBC is currently comfortable with relying on market purchases for some of its energy needs, relying on market purchases for capacity over the long term can be risky in terms of availability. There is no guarantee that FBC will be able to access market capacity supply reliably and cost effectively. The month of June, however, is the exception to FBC requiring capacity self-sufficiency for LTERP planning purposes. Due to the availability of freshet power during the month of June and FBC's market import capacity, FBC expects that the June gaps (after DSM) up to the level of 75 MW could be met with market block purchases, contracted prior to the start of each June, rather than acquiring new resources, up until 2030. FBC cannot rely on abundant freshet market capacity for meeting winter and summer LRB gaps as it is not available during those periods. After 2030, FBC is assuming capacity self-sufficiency given the risks with long-term reliance on market capacity.

FBC has taken into account other attributes when evaluating the various resource options. In addition to financial attributes, such as unit costs, these include operational/technical characteristics and environmental and socio-economic impacts as well as developing, construction and permitting lead times. Geographic diversity of resources is also a consideration given that all of the generation plants FBC owns are located in the Kootenay region whereas most of the load and expected load growth is in the Okanagan region.

FBC's portfolio analysis, discussed in Section 11, assesses several portfolios of different resource options to determine the preferred portfolios to meet the LTERP objectives.

11. Portfolio Analysis

The portfolio analysis in Section 11 helps to determine the optimal mix of resources to meet customers' future energy and capacity requirements. It includes the development of several portfolios in order to determine the trade-offs between portfolios with different attributes. The portfolios are also subject to sensitivity analysis to determine how they perform under differing conditions in the future. These changing conditions could include, for example, changes in RNG costs, market power prices or PPA rates. The analysis includes portfolios that meet the Reference Case load forecast requirements as well as the load scenarios. The outcome of the portfolio analysis is a set of portfolios that meet the objectives of the LTERP. Another outcome is the Long Run Marginal Cost (LRMC) for each portfolio, which represents the cost to FBC of incremental generation resources needed to meet incremental load requirements over the planning horizon. The feedback FBC has received from stakeholders, Indigenous communities and customers then helps FBC determine the preferred portfolio(s).

FBC's portfolio model incorporates an optimization routine to find the lowest revenue requirement rate impact of satisfying the forecast load requirements given a set of constraints and determines what new resources should be acquired and when. The portfolio analysis takes into consideration BC energy and environmental policies, such as the objective of at least 93 percent of generation from BC clean or renewable resources in the CEA and the Bill 17 proposed amendment to the CEA for a 100 percent clean energy standard for BC electricity and the removal of the self-sufficiency requirement. It also includes constraints on the amount of wholesale market purchases FBC is able to import based on transmission limitations.

FBC has evaluated portfolios based on several different base characteristics and then explored sensitivities around these base characteristics. These characteristics and sensitivities include the following:

- Different levels of DSM;
- Market reliance versus self-sufficiency;

- Percentage of clean or renewable resources;
- Varying load requirements;
- Percentage of EV charging shifting, and
- Renewal versus non-renewal of the PPA.

The key results of the portfolio analysis are as follows.

First, based on the Reference Case load forecast, FBC has no need for incremental generation resources until 2030. If FBC is able to shift some level of EV charging from peak periods, the need for new resources could be pushed out until at least 2031. Under higher load scenarios, FBC may need new resources as early as 2025.

Second, FBC will continue to optimize market energy supply and PPA Tranche 1 energy in the short to medium term prior to 2030 as they are the most cost-effective options. The flexibility of the PPA enables FBC to increase its energy take when market prices are higher than the PPA rate and lower the PPA take when market prices are lower. FBC will continue to maintain capacity self-sufficiency, with the exception of June, until 2030, due to the risks of relying on market capacity.

Third, higher levels of DSM than the base DSM level are less cost effective than other resource options and so the base level has been assumed for the preferred portfolios.

Fourth, clean or renewable resource portfolios that include gas plants using RNG fuel are more cost effective than portfolios that exclude gas plants. Battery storage and gas plants are the most optimal capacity resource in terms of cost and meeting LRB gaps.

Fifth, renewing the PPA is more cost effective than replacing it with other resource options. FBC plans to explore renewing the PPA and has included this in its Action Plan.

Lastly, the LRMC values for the portfolios serve as a high-level point of reference when evaluating power supply options and are an appropriate metric for making long-term resource decisions. However, while a particular resource option may be cost effective relative to a given LRMC value, it may not fit the energy or capacity requirements of customers in the future. For this reason, FBC believes the LRMC values presented in this LTERP should be viewed as price signals, rather than threshold targets for resource options.

The preferred portfolio, applicable for new generation resources for 2030 and beyond, includes a mix of PPA, market energy, battery storage, gas plants using RNG fuel, solar, wind and run of river generation. Portfolio C3 is the preferred portfolio under current market conditions as it best meets the LTERP objectives in terms of balancing cost-effectiveness, reliability, inclusion of cost-effective DSM and consideration of BC's energy objectives. This portfolio is also aligned with the energy priorities as indicated by stakeholders, Indigenous communities and customers through FBC's LTERP engagement processes.

Portfolio C3 is similar to other portfolios in terms of its GHG emissions but has a lower environmental footprint. It also provides FBC with high levels of resiliency given that its resource mix provides high geographic diversity and high levels of operational flexibility due to two gas plants using RNG fuel, which is important for contingency planning. The inclusion of gas plants in the preferred portfolio provides some additional flexibility to handle new large or unexpected loads, as this resource has remaining ability to meet energy and capacity needs. The gas plants would also provide additional reliability in the event that the other renewable resources in the portfolio, wind and solar, do not provide dependable energy and capacity when required.

Should market conditions change such that market energy was no longer a reliable and cost effective resource, portfolio B2 would become the preferred portfolio. This portfolio has slightly higher costs and environmental impacts than portfolio C3, but it has a lower cost and provides higher resiliency and job creation than other portfolios considered for the preferred portfolio. In portfolio B2, FBC has assumed energy self-sufficiency after 2030. However, if market conditions changed prior to that, FBC would seek to implement this portfolio sooner than 2030 so that generation resources are put in place to mitigate this market risk.

12. Stakeholder, Indigenous and Customer Engagement

In the development of this LTERP, FBC has conducted effective stakeholder, Indigenous and community and customer engagement. In particular, for this LTERP, FBC has consulted a dedicated Resource Planning Advisory Group (RPAG) planning group, hosted a number of community engagement workshops to garner diverse perspectives on FBC's planning activities across the communities it serves, and conducted a direct customer survey to gain feedback directly from customers. FBC also hosted multiple resource planning meetings with Indigenous community representatives located within its electric service territory. Additionally, FBC met with BCUC staff to discuss various resource planning topics.

The information gathered through these activities is incorporated into the LTERP process in a number of ways, including informing FBC's planning and analysis, helping to determine preferred resource options and portfolios and identifying long-term planning opportunities and areas of concern. As part of its Action Plan, FBC plans to continue with its engagement activities as part of the next long-term resource planning development process.

13. Action Plan

The Action Plan describes the activities that FBC intends to pursue over the next four years based on the discussion and conclusions provided in this LTERP. It includes actions relating to monitoring the planning environment and strategies for optimizing short-term resource requirements as well as consideration of initiatives to manage EV charging and large loads. The specific action items include the following:

- Continue to monitor the energy planning environment;

- Monitor potential load drivers to determine if a particular load scenario is emerging;
- Contingency resources assessment;
- Implement program to help shift home EV charging;
- Consider initiatives to manage large loads;
- Continue to optimize the PPA and market purchases;
- Review PPA prior to expiry;
- Transition to clean market purchases;
- Monitor potential available power supply opportunities;
- Continue Stakeholder, Indigenous Community and Customer Engagement;
- Assess transmission and distribution capital infrastructure requirements, and
- Prepare Submission of next LTERP.

1. INTRODUCTION

FBC files this 2021 Long-Term Electric Resource Plan (LTERP) under section 44.1(2) of the *Utilities Commission Act* (UCA) and is seeking the BCUC's acceptance of the LTERP as being in the public interest pursuant to section 44.1(6). There are no approvals being sought by FBC as part of this LTERP submission. Any requests for approval of specific resource needs that are identified within this plan will be further evaluated and brought forward through a separate application to the BCUC if warranted in the future.

The LTERP presents a long-term plan for meeting the forecast peak demand and energy requirements of customers with demand-side and supply-side resources over the 20-year planning horizon (2021 to 2040). The LTERP analyzes the external regulatory, policy, market supply and customer planning environment within which FBC operates, compares energy and capacity load forecasts against current resource capabilities and evaluates the potential for load reduction with DSM initiatives, and other options specific to electric vehicle (EV) charging and portfolios of resource options to meet forecast customer needs under different scenarios. The LTERP includes an action plan that describes the activities that FBC intends to pursue over the next four years. This LTERP will enable FBC to achieve its primary objective of providing cost-effective, secure, and reliable power for customers.

The LTERP is consistent with the applicable sections of the *UCA*, the BCUC's Resource Planning Guidelines, and complies with directives and recommendations from the BCUC arising from its decision[1] regarding FBC's 2016 Long Term Electric Resource Plan (2016 LTERP), filed along with the 2016 Long Term Demand-Side Management Plan (2016 LT DSM Plan) on November 30, 2016. These requirements are discussed further in Section 1.4.

The LTERP is divided into two volumes, as follows:

- Volume 1 describes FBC's long-term planning environment, long-term load forecast, load scenarios and load-resource balance gaps based on existing and committed resources. FBC evaluates both demand-side and supply-side resources to determine the preferred portfolios to meet any load-resource balance (LRB) gaps, and considers options to help mitigate the potential impacts of home EV charging during peak demand periods. FBC explores alternative resource portfolios to determine any trade-offs between portfolios. FBC also provides a high-level assessment of impacts on the transmission and distribution system from emerging load drivers and scenarios. FBC includes contingency plans for the preferred portfolios to specify how FBC would respond to changed circumstances. The Action Plan discussion actions FBC plans to take over the next four years.
- Volume 2 describes the Company's Long-Term Demand-Side Management Plan (LT DSM Plan). DSM continues to be a cost-effective means of reducing customers' load requirements over the long-term planning horizon. The LT DSM Plan includes an

[1] BCUC Order G-117-18 dated June 28, 2018.

assessment of the energy efficiency and conservation potential for FBC customers, which is supported by the Conservation Potential Review (CPR) update concluded at the end of 2020 and determines cost-effective DSM programs. This provides FBC with different levels of demand-side resource options to assess along with supply-side resource options in meeting the load-resource balance gaps over the planning horizon identified within this LTERP.

The analysis in this LTERP shows that, based on the Reference Case load forecast, existing resources and contracts in place, continued access to market energy and the proposed level of DSM, FBC does not require any new supply-side resources until at least 2030. Optimization of market purchases and the power purchase agreement (PPA) with BC Hydro provide FBC with enough energy and June capacity until 2030 to meet customers' requirements in a cost-effective and reliable manner. After 2030, FBC requires additional generation resources primarily for capacity purposes. However, this requirement can be delayed until 2031 or later depending on the amount of EV charging FBC is able to shift from peak demand periods. The portfolio analysis provided in Section 11 provides a high-level indication of the potential combination of resources that could meet future requirements.

Any specific resource projects that are identified within this plan that require BCUC approval will be further evaluated and brought forward through a separate application to the BCUC if warranted in the future. The LTERP is not a substitute for the analysis done to support specific resource acquisitions, projects, programs or rate design in the future but rather it helps to inform the acquisition process or other initiatives.

1.1 *FBC OVERVIEW*

FBC is an integrated electric utility that generates, transmits, and distributes electricity to customers in the southern interior of BC. It is a subsidiary of Fortis Inc., the largest investor-owned gas and electric distribution utility company by assets in Canada. The following figure shows the FBC electric service area.

Figure 1-1: FBC Service Area

FBC currently serves approximately 144 thousand direct customers plus approximately 38 thousand indirect wholesale customers in the communities of Summerland, Penticton, Grand Forks and Nelson.[2] FBC's current forecast annual energy requirements for 2021 are 3,720 GWh while winter and summer peak capacity requirements are 766 MW and 638 MW, respectively.[3]

FBC owns four hydroelectric generating plants located on the Kootenay River between Nelson and Castlegar, BC which currently supply about 43 percent of FBC's energy requirements and about 28 percent of the Company's peak winter demand.[4] The remainder of FBC's energy and

[2] Customer counts as of end of December 2020.
[3] Appendix F, Tables 2.1 and 2.10.
[4] 1,596 GWh FBC generation (Table 5-1) ÷ 3,717 GWh 2021 forecast gross load (Appendix G, Table 2.1) = 43 percent. 208 MW FBC generation (Table 5.1) ÷ 749 MW 2021 forecast peak winter load (Appendix G, Table 2.10) = 28 percent.

capacity supply comes from power purchase agreements with Brilliant Expansion, BC Hydro and Columbia Power Corporation, the Waneta Expansion (WAX) capacity agreement, contracts for market power from Powerex Corporation (the wholly owned energy marketing subsidiary of BC Hydro) and a small number of Independent Power Producer (IPP) contracts. FBC owns and operates about 7,300 kilometres of transmission and distribution power lines.[5]

1.2 *LONG TERM RESOURCE PLANNING OBJECTIVES*

FBC's resource planning objectives form the basis for meeting any potential load-resource balance gaps in the future and for identifying and evaluating potential resource options and portfolios in the LTERP. These objectives reflect the Company's commitment to deliver quality service to customers, manage resources prudently, and operate a safe and reliable electricity system. The objectives of the LTERP are as follows:

- Ensure cost-effective, secure and reliable power for customers;
- Provide cost-effective demand side management and cleaner customer solutions, and
- Ensure consistency with provincial energy objectives (for example, the applicable objectives in the CEA and the CleanBC Plan).

These objectives are consistent with the objectives outlined in FBC's 2016 LTERP. For this 2021 LTERP, FBC has added 'cleaner customer solutions' to 'cost-effective demand side management' in the second objective to emphasize FBC's role in helping to meet its own as well as the BC government's environmental goals. In its decision regarding FBC's 2016 LTERP, the BCUC accepted the objectives as being in the public interest and stated: "The Panel finds that FBC's Overarching Objectives are consistent with the 2012 LTERP objectives, which have been accepted by the BCUC in the past. Further, the Overarching Objectives include due consideration for the provincial energy objectives".[6]

These objectives are also consistent with the BCUC's view of resource planning objectives as stated within the BCUCs Decision regarding the FBC 2012 Long Term Resource Plan: "*The Commission's mandate in assessing the resource plans of energy utilities is intended to assure the cost-effective delivery of secure and reliable energy services in a manner congruent with British Columbia's energy objectives*".[7]

FBC has not included in the list of objectives above an explicit objective relating to, for example, reducing GHG emissions or encouraging economic development and fostering the development of Indigenous and rural communities through the use and development of clean and renewable resources. This is because these, and other applicable objectives, are captured in FBC's objective of ensuring consistency with provincial energy objectives. The *CEA* includes provincial objectives relating to reducing GHG emissions and promoting community and

[5] https://www.fortisbc.com/about-us/corporate-information.
[6] BCUC Order G-117-18, page 4.
[7] BCUC Order G-110-12, page 143.

Indigenous economic development as well as several other objectives. Section 1.4 provides more discussion regarding FBC's adherence to these important objectives.

Section 12.4 of this LTERP discusses FBC's Statement of Indigenous Principles and support for the overarching principles outlined in the United Nations Declaration on the Rights of Indigenous Peoples (the UN Declaration). FBC acknowledges the principles of the UN Declaration will play a significant role in energy policy and the regulatory environment over the twenty-year planning horizon of this LTERP. FBC is committed to aligning its resource plans with provincial policy, and will continually review its engagement process to ensure that FBC is engaging in meaningful dialogue with Indigenous communities regarding its resource plans. As the Declaration for the Rights of Indigenous Peoples continues to be implemented across government through the development of action plans, FBC will continue to evolve its planning and business practises in alignment with this implementation.

Customers and stakeholders expect the Company to procure and deliver electricity in a cost-effective and efficient manner. FBC's existing resource base along with the preferred resource portfolios, if required in the future, will provide cost-effective, reliable and secure energy and capacity for customers over the next 20 years. DSM initiatives will reduce the Company's requirements for more costly supply-side resources and enable customers to reduce their electricity consumption. This is consistent with the *CEA*'s objective to take demand-side measures and conserve energy. The Company's DSM initiatives are governed in part by the *UCA* and the *Demand-Side Measures Regulation*. It is also important that the LTERP's conclusions are consistent with the provincial energy objectives. These are discussed in Section 1.4.

1.3 *RESOURCE PLANNING PROCESS*

The long-term resource planning process involves several iterative steps in identifying resource options to meet expected load requirements. This process is one that is used by many utilities in resource planning and is consistent with the steps included in the BCUC's Resource Planning Guidelines. The following figure shows the steps included in the FBC long-term resource planning process.

Figure 1-2: FBC Long-Term Resource Planning Process

The long-term resource planning process begins with examining the planning environment, which encompasses the external factors that will influence customers' load requirements, resource options decisions and present and future risks and opportunities.

Next, FBC determines its customers' energy and capacity needs over the planning horizon. This includes the development of the long-term reference load forecast as well as some load scenarios that provide insight into different potential futures for which FBC should be prepared.

To meet the future load requirements, FBC must determine DSM potential to help reduce the requirements for other potentially more costly supply-side resources. Additionally, various supply-side resource options are evaluated to help meet any load-resource balance gaps. To help manage the impacts of home EV charging on peak demand, FBC has also considered options to help shift EV charging from peak demand periods to off-peak times, thereby reducing the need for additional infrastructure and/or capacity resources.

FBC has also included a high-level assessment of the potential impacts of various load drivers and load scenarios on its transmission and distribution system. This helps identify the potential requirement for future infrastructure projects in the event that load requirements increase above the levels used for system planning.

Next, FBC evaluates alternate resource options portfolios to meet the resource planning objectives and selects a preferred portfolio. FBC develops contingency plans for the preferred portfolio to ensure that it can meet the objectives if assumptions and conditions change.

The process concludes with a four-year action plan to implement the LTERP's conclusions and to ensure continuing assessment of resource requirements and alternatives.

Stakeholder, Indigenous and customer engagement is an important element of FBC's long-term resource planning as resource planning decisions ultimately impact FBC's customers in terms of electricity rates and other preferences regarding electricity supply. FBC's stakeholder, Indigenous and customer engagement occurred throughout the 2021 LTERP planning process. In developing the LTERP, FBC met with BCUC staff, stakeholders representing customers and Indigenous representatives as part of the Resource Planning Advisory Group (RPAG). FBC held several workshop sessions to inform participants about various aspects of the LTERP and gather their input and feedback to help inform the LTERP. FBC also visited municipalities within the FBC service area as part of its community consultation. Online surveys were used to probe FBC customers directly on their thoughts regarding long-term resource planning objectives, resource options and interest in EVs and rooftop solar. More details regarding FBC's stakeholder, Indigenous and customer engagement are provided in Section 12.

1.4 *REGULATORY FRAMEWORK*

While it is considered good utility practice to conduct long-term resource planning, FBC is also required to file a long-term resource plan with the BCUC under section 44.1(2) of the *UCA*. The

UCA outlines the requirements for utilities' resource plans. The BCUC's Resource Planning Guidelines provide general guidance as to the BCUC's expectations for the development of resource plans. FBC must also adhere to any directives from the BCUC related to FBC's previously filed long-term resource plans. These requirements and guidelines are discussed in the following sections.

1.4.1 *Utilities Commission Act*

The UCA includes the requisite contents for a public utility's long-term resource plan, as set out in section 44.1(2) of the *Act*, "Long-term resource and conservation planning". The following table outlines the specific elements that are to be included in resource plans and indicates the corresponding sections of this LTERP in which these requirements have been met.

Table 1-1: Requisite Contents for a Long-Term Resource Plan

Section of the *UCA*	Requirement Defined in the *UCA*	Section of LTERP Addressing Requirement
44.1(2)(a)	An estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan	Load Forecast Section 3
44.1(2)(b)	A plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures	DSM Section 8, LT DSM Plan
44.1(2)(c)	An estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures	Load-Resource Balance After DSM Section 9
44.1(2)(d)	A description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c)	Transmission and Distribution Section 6, Portfolio Analysis Section 11
44.1(2)(e)	Information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c)	Portfolio Analysis Section 11
44.1(2)(f)	An explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures	Load-Resource Balance After DSM Section 9.3
44.1(2)(g)	Any other information required by the Commission	2016 LTERP Decision requirements: DSM section 8, LRMC and Portfolio framework Section 11; LTERP filed by December 1, 2021. More details provided in Section 1.5.2 below.

In determining whether to accept a long-term resource plan, section 44.1(8) of the *UCA* requires the BCUC to consider several items. These are listed in the following table along with the applicable sections of the LTERP where they have been addressed.

Table 1-2: BCUC Considerations for Accepting a Long-Term Resource Plan

Section of the *UCA*	Considerations for Acceptance	Section of LTERP Addressing Requirement
44.1(8)(a)	The applicable of British Columbia's energy objectives	Section 1.4.2 and 1.4.3 below discuss the BC energy objectives applicable to the LTERP.
44.1(8)(b)	The extent to which the plan is consistent with the applicable requirements of Sections 6 and 19 of the *CEA*	While sections 6 and 19 of the *CEA* do not apply directly to FBC, FBC has considered self-sufficiency and clean and renewable resources in its Portfolio Analysis Section 11.
44.1(8)(c)	Whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures	LT DSM Plan and Section 8 discuss demand-side measures.
44.1(8)(d)	The interests of persons in British Columbia who receive or may receive service from the public utility	Portfolio analysis results include DSM and supply-side resource options which are cost-effective, environmentally-sound and provide socio-economic benefits to the region and FBC's customers as discussed in Section 11.

FBC submits that this LTERP demonstrates that FBC has met the requirements of the *UCA* and complies with the BCUC's directives provided in the 2016 LTERP decision and is consistent with the BCUC's Resource Planning Guidelines.

1.4.2 BC Clean Energy Act Objectives

As discussed in Section 1.4.1 above, section 44.1(8) of the *UCA* requires the BCUC to consider certain factors when accepting a utility's long-term resource plan, including:

- The applicable of British Columbia's energy objectives as defined in the CEA, and
- The extent to which the long-term resource plan is consistent with the applicable requirements under sections 6 and 19 of the CEA.

Section 6 of the CEA deals with electricity self-sufficiency. While applicable directly only to the British Columbia Hydro and Power Authority (BC Hydro), other utilities such as FBC must take it into consideration. Section 19 of the CEA deals with clean or renewable resources, with requirements applicable to BC Hydro and other prescribed public utilities. There are, at this time, no prescribed utilities for the purpose of section 19 of the *CEA*.

The CEA contains a set of sixteen specific energy objectives for the Province of BC. It provides a guide to help the Province meet its self-sufficiency goals and to reduce greenhouse gas (GHG) emissions. The *CEA* includes several social and economic goals for the Province, including a greater focus on encouraging economic development, creating and retaining jobs, and encouraging economic development for Indigenous and rural communities through the development of clean or renewable power.

In June 2020, the NDP government proposed Bill 17 to amend the *CEA*. One of the key proposed amendments includes repealing the self-sufficiency planning requirement that BC Hydro's new generation resources must be located within BC. By removing the requirement for BC Hydro to achieve electricity self-sufficiency, Bill 17 would give BC Hydro more flexibility to purchase clean electricity from outside of BC, likely from the United States, to meet the demand for electricity in the province. The other key proposed amendment includes introducing a new objective for the province to serve grid-connected customers with clean electricity, effectively enabling the implementation of a 100 percent clean energy standard for BC. Clean electricity is defined as being generated from a clean resource or deemed under the regulations to be clean electricity.

On July 15, 2020, independent Member of the Legislative Assemble (MLA) Andrew Weaver proposed that Bill 17 be amended to maintain the province's energy objective of electricity self-sufficiency. Clean energy producers and Indigenous groups also opposed the removal of the self-sufficiency requirement on the basis that it would reduce opportunities for development of clean energy projects within BC.

At this time, the proposed *CEA* amendments have not been enacted into legislation and are not directly applicable to FBC. However, FBC has incorporated these proposed changes into its portfolio analysis (discussed in Section 11); specifically, FBC has included portfolios which include 100 percent clean and renewable resources and those which include a self-sufficiency requirement.

The following table lists the *CEA* objectives and describes how they are supported, if applicable, by the LTERP. It is important to note that these are provincial objectives and some of the objectives are specific to BC Hydro, as referenced in the *CEA* by the term 'the authority'.

Table 1-3: Applicable *CEA* Objectives Relevant to the LTERP

Section of the CEA	CEA Objective	How LTERP Supports Objective
2(a)	To achieve electricity self-sufficiency.	FBC interprets this to mean using generation resources located within BC. The requirement in section 6 of the *CEA* to achieve self-sufficiency by 2016 applies to BC Hydro only. For other utilities, self-sufficiency is an objective that must be considered. FBC's supply is currently mostly sourced from within BC with some market purchases outside BC. The Portfolio analysis includes portfolios with and without a self-sufficiency requirement (see Section 11).

Section of the CEA	CEA Objective	How LTERP Supports Objective
2(b)	To take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%.	The 66 percent target is specific to BC Hydro and does not extend beyond 2020. FBC has assessed several DSM scenarios (see Section 8).
2(c)	To generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity.	The requirement in section 19 of the *CEA* to take actions to meet this target applies only to BC Hydro or a prescribed utility. FBC-owned resources and long-term contracts are hydro-based. BC Hydro resources are currently nearly 98 percent clean.[8] FBC alternative and preferred portfolios include clean or renewable resources and the preferred portfolios are at least 99 percent clean.
2(d)	To use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources.	FBC's LT DSM Plan provides support for energy conservation and efficiency including the use and development of innovative technologies and the LTERP portfolio analysis includes clean or renewable resources.
2(e)	To ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers.	This objective is specific to BC Hydro. FBC ratepayers are indirect customers of BC Hydro and receive the benefits of BC Hydro heritage assets via the PPA Rate Schedule 3808 (see Section 2.2.1.2).
2(f)	To ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America.	This objective is specific to BC Hydro. FBC strives to provide cost-effective, secure and reliable service for its customers while also meeting other LTERP objectives.

[8] BC Hydro 2019 Carbon Neutral Action Report, May 2020, Page 8. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/environment-sustainability/environmental-reports/2019-carbon-neutral-action-report.pdf.

Section of the CEA	CEA Objective	How LTERP Supports Objective
2(g)	To reduce BC GHG emissions (i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007, (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007, (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007, (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and (v) by such other amounts as determined under the Greenhouse Gas Reduction Targets Act.	Provincial targets are not specific to individual utilities. FBC GHG emissions represent only about 0.082 percent of total provincial emissions.[9] FBC recommendations include DSM to encourage energy conservation and clean and renewable resources to continue keeping FBC emissions low. GHG emissions for the preferred portfolios including clean or renewable resources and gas-fired generation using RNG fuel are minimal. FBC provides mostly clean electricity for EV charging which is estimated to reduce GHG emissions in BC by 0.04 million tonnes CO2e by 2040 (see Section 2.2.6). FBC intends to provide mostly clean electricity to support the development of RNG and, if required, hydrogen production and carbon capture and storage (see section 3 regarding FBC's load forecast including RNG and section 4 regarding load scenarios including hydrogen and carbon capture and storage).
2(h)	To encourage the switching from one kind of energy source to another that decreases greenhouse gases in British Columbia.	FBC's Reference Case load forecast and load scenarios include EV growth which assumes switching from gasoline or diesel to mostly clean electricity, thereby decreasing GHG emissions. FBC is installing EV charging stations, administering charging rebates, developing fleet charging rates throughout its service area to meet the future needs of its customers (see Section 2.3.2). LT DSM Plan Section 5.1 discusses fuel switching related to gas to electric space heating.
2(i)	To encourage communities to reduce greenhouse gas emissions and use energy efficiently.	LT DSM Plan encourages conservation by providing local government capacity through funding Community Energy Specialists. EV charging (discussed in Load Forecast section 3 and Load Scenarios Section 4) reduces GHG emissions.

[9] Based on FBC 2019 GHG emissions of 0.056 million tCO_2e reported to the BC Ministry of Environment and the 2018 value of BC GHG emissions of 67.9 million tCO_2e in the BC Greenhouse Gas Inventory (https://www2.gov.bc.ca/gov/content/environment/climate-change/data/provincial-inventory).

Section of the CEA	CEA Objective	How LTERP Supports Objective
2(j)	To reduce waste by encouraging the use of waste heat, biogas and biomass.	FBC has included generation using biomass and RNG fuel in its assessment of resource options (see Section 10 and Resource Options Report in Appendix K).
2(k)	To encourage economic development and the creation and retention of jobs.	Socio-economic attributes, specifically job creation, for resource options are discussed in Section 10 and the Resource Options Report in Appendix K and included in the portfolio analysis evaluation in Section 11.3.8.
2(l)	To foster the development of First Nation and rural communities through the use and development of clean or renewable resources.	Section 10 and Resource Options Report discuss socio-economic development. FBC will consider opportunities with Indigenous and local communities in the future when such opportunities relating to the requirement for new resources arise (see Sections 10.9 and 11.3.8).
2(m)	To maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia.	LTERP provides a framework for agreements and strategies that maximize value. For example, FBC optimizes Waneta Expansion capacity surplus and coordinates with BC Hydro (e.g. Canal Plant Agreement, Residual Capacity Agreement) and Powerex Capacity and Energy Purchase and Sale Agreement (CEPSA) which help to maximize use of provincial hydro resources.
2(n)	To be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia.	FBC has limited export ability due to restrictions embedded within the BC Hydro PPA (see Section 5.4). Furthermore, current market price environment (see Section 2.4.1) limits any opportunities for exports.
2(o)	To achieve British Columbia's energy objectives without the use of nuclear power.	FBC does not use, or plan to use, nuclear power.
2(p)	To ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.	This objective is specific to BC Hydro and is not applicable for FBC.

1.5 BCUC GUIDELINES AND DIRECTIVES

1.5.1 BCUC Resource Planning Guidelines

In 2003, the BCUC issued Resource Planning Guidelines which outline a process to assist in the development of resource plans to be filed with the BCUC. According to the guidelines, "resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run." The BCUC reviews resource plans in the context of the unique circumstances of the utility in question. FBC adheres to the BCUC's Resource Planning Guidelines. The following table outlines the key elements of the Resource Planning Guidelines and the sections of the LTERP in which they are addressed.

Table 1-4: BCUC Resource Planning Guidelines

Resource Planning Guideline	Section of LTERP Addressing Guideline
1. Identification of the planning context and the objectives of a resource plan	Planning Environment Section 2 and Introduction Section 1.3
2. Development of a range of gross (pre-DSM) demand forecasts	Load Forecast Section 3 and Load Scenarios Section 4
3. Identification of supply and demand resources	DSM Section 8 and Supply-Side Resources Section 10
4. Measurement of supply and demand resources	DSM Section 8 and Supply-Side Resources Section 10
5. Development of multiple resource portfolios	Portfolio Analysis Section 11
6. Evaluation and selection of resource portfolios	Portfolio Analysis Section 11
7. Development of a four-year action plan, including contingency plan	Action Plan Section 13, Portfolio Analysis Section 11.3.9.1
8. Solicit stakeholder input during the planning process	Stakeholder, Indigenous, Community and Customer Engagement Section 12
9. Seek regulatory input from Commission staff	Stakeholder, Indigenous, Community and Customer Engagement Section 12
10. Consideration of government policy	Planning Environment Section 2.2
11. Regulatory review once resource plan is filed	Review process to be determined by the BCUC – FBC recommendations provided in Section 1.6

FBC submits that the 2021 LTERP is consistent with the resource planning guidelines.

1.5.2 BCUC Directives from 2016 LTERP Decision

The LTERP and LT DSM Plan address several BCUC directives included in the BCUC decision regarding the 2016 LTERP and LT DSM Plan. These directives are summarized in the following table and are discussed further below.

Table 1-5: BCUC Directives

BCUC Directive	Section of LTERP Addressing Directive
1. Develop a richer analysis of DSM alternatives for the first five years of the LT DSM Plan.	Section 8 and LT DSM Plan.
2. Consider excluding DSM in LRMC calculation method in next LTERP filing.	Portfolio Analysis Section 11.
3. Develop a LRMC framework that provides more consistency across its future applications.	Portfolio Analysis Section 11.2 and Appendix L.
4. Use average cost approach outlined in the DSM Regulation as the basis for its comparative analysis of DSM portfolios.	DSM Section 8.1 and LT DSM Plan.
5. Develop and apply a more transparent and balanced rating framework that consistently subjects all portfolio alternatives to the same evaluation rigor.	Portfolio Analysis Section 11.3.8.
6. File next LTERP and LT DSM Plan no later than December 1, 2021.	FBC filing 2021 LTERP and LT DSM Plan on August 4, 2021.

Each of the directives and FBC's response is discussed below.

The BCUC indicated that it expected that FBC will update its short-term market assumptions and develop a richer analysis of DSM alternatives for the first five years of the LT DSM Plan.[10] In the 2016 LT DSM Plan, FBC assessed several different levels of DSM load growth offset to help meet future LRB gaps. While the Low scenario included a 50 percent DSM offset target, the Base, High and Max scenarios began with 66 percent load growth offset and then the High and Max scenarios ramped up to higher offset levels after 2020. For the 2021 LT DSM Plan, each of FBC's DSM scenarios include different levels of load growth offset during the first five years and each year thereafter, based on the available DSM savings potential identified in the 2021 CPR update.

The BCUC was not persuaded of the benefit of including DSM in the estimate of FBC's LRMC and encouraged FBC to consider revising its LRMC calculation method in its next LTERP.[11] FBC had included DSM in its portfolios (besides those used to determine the LRMC based on clean or renewable resources in BC for the purposes of evaluating the cost effectiveness of DSM in accordance with the DSM Regulation) because FBC does not consider portfolios without DSM as being realistic. FEI expects that it will continue with its DSM programs and initiatives to help customers conserve electricity and help reduce their electricity bills. However,

[10] BCUC 2016 LTERP and LT DSM Plan decision, Order G-117-18 dated June 28, 2018, page 12.
[11] Ibid, page 21.

for the purposes of this 2021 LTERP, FBC has excluded DSM in all its alternative and preferred portfolios' corresponding LRMC values as discussed in Section 11.

The BCUC encouraged FBC to develop a LRMC framework that provides more consistency (and hence regulatory efficiency and clarity) across its future applications.[12] The BCUC noted that, for regulatory efficiency, the LRMC developed in the LTERP should be a key input in future FBC proceedings and it can serve as the base for making appropriate adjustments. FBC generally agrees with this recommendation. However, FBC notes that the LRMC is a high-level proxy for the long-term avoided cost of future generation requirements and is different and distinct from shorter-term avoided costs. For example, FBC's estimated avoided cost for the purposes of its Net Metering program should not be tied to the LRMC determined through its LTERP. FBC's appropriate avoided cost for Net Metering purposes is the BC Hydro PPA Tranche 1 Energy cost. The BCUC agreed with this in its decision relating to the Net Metering Program Tariff Update Application.[13] FBC provides more discussion of the difference between short-run and long run marginal costs in Appendix L.

The BCUC encouraged FBC to use the average cost approach outlined in the DSM Regulation as the basis for its comparative analysis of DSM portfolios.[14] The BCUC noted that while a discussion of the incremental costs does add some information, it does not itself satisfy the regulatory requirements of the cost-effectiveness test. FBC has employed this average cost method within Section 8.1 and the LT DSM Plan for the purposes of comparing the DSM portfolios. FBC has also provided the incremental portfolio costs for information purposes.

The BCUC encouraged FBC to develop and apply a more transparent and balanced rating framework that consistently subjects all portfolio alternatives to the same evaluation rigor. The BCUC noted that energy self-sufficiency was not used as a portfolio rating criteria. In its 2016 LTERP portfolio analysis, FBC assumed energy self-sufficiency as a base assumption for its preferred portfolio given that this is a *CEA* objective and section 6(4) of the *CEA* states: "A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for (a) the construction or extension of generation facilities, and (b) energy purchases, must consider British Columbia's energy objective to achieve electricity self-sufficiency."[15] FBC explored the impacts on required resource options of excluding self-sufficiency in alternative portfolios. Given the BCUC decision that a provincial target of self-sufficiency does not translate into a case for FBC to be self-sufficient, which was part of the reason for the BCUC not accepting the LTERP beyond 2024 to be in the public interest,[16] FBC has not made the same assumption of self-sufficiency for the portfolio analysis in this 2021 LTERP. However, given the possibility of changes to the self-sufficiency requirement in the CEA as discussed in Section 2.2.3.2 and the possibility of changes in FBC's current ability to reliably access the market for energy in the future as discussed in Section 2.4.4, FBC has also explored portfolios that include self-

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[12] Ibid, page 22.
[13] BCUC Order G-63-18, March 16, 2018, page 11.
[14] Ibid, page 23.
[15] BC 2010 Clean Energy Act, Section 6(4).
[16] BCUC Order G-117-18, June 28, 2018, page i.

sufficiency by a certain date. It is appropriate to apply self-sufficiency as a portfolio scenario rather than a portfolio attribute in the rating framework, as this will enable a comparison of portfolios with and without self-sufficiency, as discussed in Section 11.3.2.

The BCUC also felt that geographic diversity was given a hyper-sensitive rating and that FBC was inconsistent in its application of the attribute weightings between portfolios within the portfolio analysis rating framework. FBC has made adjustments with respect to these items in its 2021 LTERP portfolio rating framework, as discussed in Section 11.3.8.

FBC was also directed to file its next long-term resource plan by no later than December 1, 2021. FBC is filing this 2021 LTERP and LT DSM Plan on August 4, 2021 to align with FBC's intent to submit a multi-year DSM Expenditure filing for the period beyond the currently-approved DSM Expenditure Plan filing period of 2019 to 2022.

1.6 ORDER SOUGHT AND PROPOSED REGULATORY PROCESS

FBC submits that the 2021 LTERP meets the requirements of the *UCA* and seeks the BCUC's acceptance of the 2021 LTERP, including the LT DSM Plan, as being in the public interest for FBC to carry out pursuant to section 44.1(6) of the *UCA*. A draft Order is attached as Appendix P-2.

The Company submits that a written hearing process with two rounds of information requests (IRs) from the BCUC and interveners will provide for an appropriate and effective review of the LTERP. A similar process was deemed appropriate by the BCUC for the review of the 2016 LTERP. FBC proposes the following regulatory timetable. A draft Procedural Order is attached as Appendix P-1.

Table 1-6: Proposed Regulatory Review Timetable

Action	Date (2021)
FBC Publishes Notice of Application	Week of September 20
Intervener Registration	Wednesday, October 13
BCUC IR No. 1	Thursday, October 21
Intervener IR No. 1	Thursday, October 28
FBC Responses to BCUC and Intervener IR No. 1	Thursday, December 9
Intervener Notice of Intent to File Evidence	Thursday, December 16
	Date (2022)
BCUC and Intervener IR No. 2	Thursday, January 20
FBC Responses to BCUC and Intervener IR No. 2	Thursday, March 3
FBC and Intervener Submissions on Further Process	Thursday, March 10

2. PLANNING ENVIRONMENT

2.1 INTRODUCTION

Understanding the planning environment is the first step in FBC's resource planning process. The planning environment includes relevant external factors that could impact FBC's demand-side and supply-side resource options and prices for future market purchases as well as those factors that could influence FBC's customers' energy and capacity needs over the planning horizon.

This section describes the key factors of the planning environment and is organized as follows:

- It begins with an overview of the relevant energy and environmental policy in both Canada and the US, as this will impact resource options, market prices and influence customers' behaviour regarding energy use in the future.
- Then, the customer demand environment is examined to assess how technology, customers' energy needs and the types of loads are changing and how the relationship between the customer and the utility is evolving.
- Next, the supply environment is examined as the changes occurring in BC, Alberta, California and the Pacific Northwest region will influence FBC's resource options and market electricity prices.
- And finally, FBC presents long-term market forecasts for natural gas and electricity prices, renewable natural gas price forecasts as well as carbon price and rate scenarios under the PPA that impact the cost of existing and potential resource options in the future.

2.2 ENERGY AND THE ENVIRONMENT

Energy and environmental legislation, regulation and policies of municipal, provincial and federal governments directly impact FBC's resource planning process. Regional collaborative policy initiatives of provincial and state governments on each side of the Canada-US border are also directly relevant to FBC's planning process.

Various other legislative and policy initiatives of the federal and certain state governments in the US may affect the wholesale electricity market in the western US. This market operates adjacent to FBC's service territory and is currently a source of energy and capacity products for FBC. FBC must remain aware of, and where appropriate, responsive to, the changing regulatory regime governing US markets in order to adequately fulfill its planning mandate.

Relevant governmental initiatives are discussed in the following sections, following a discussion of climate change and its potential impacts for FBC.

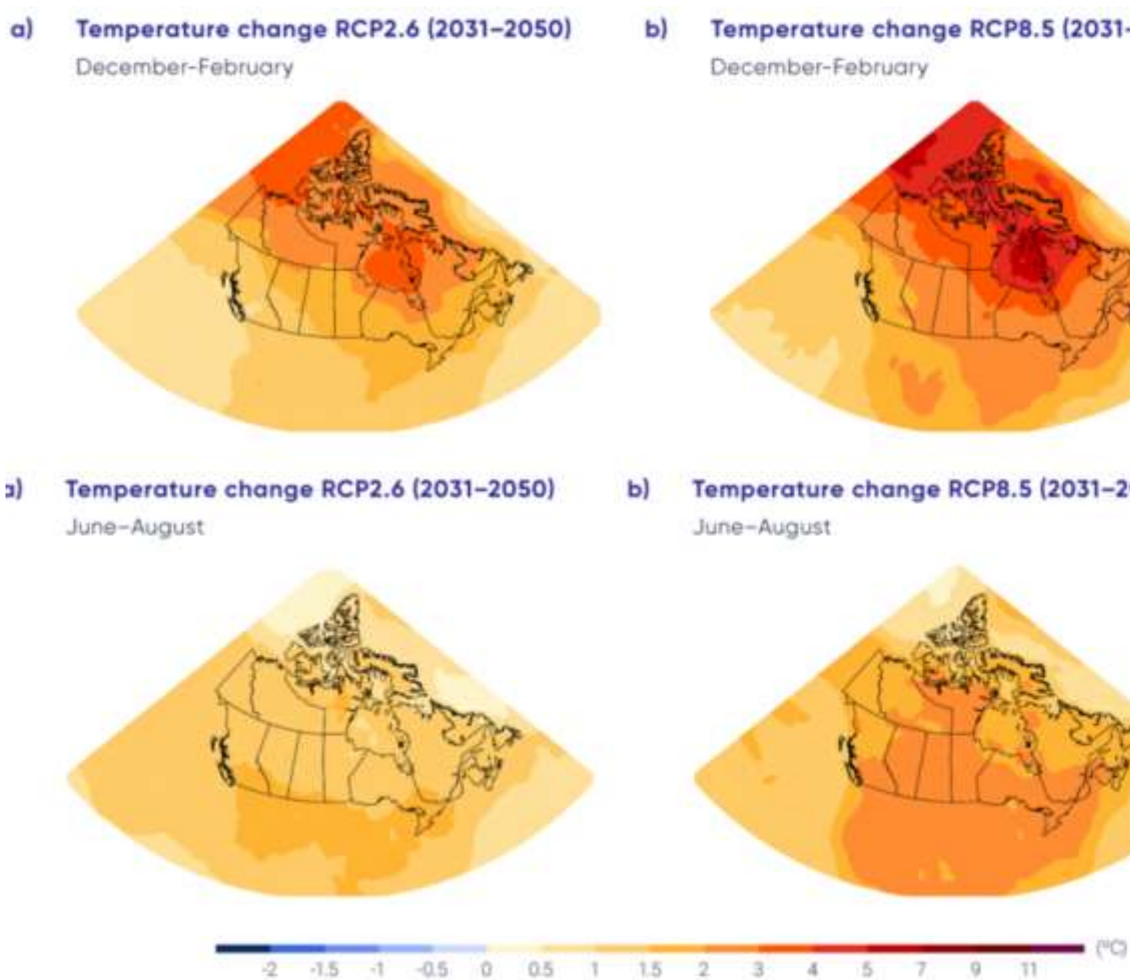
2.2.1 Climate Change

Climate change is dramatically changing the external environment in which FBC operates and has prompted governments at all levels to enact environmental policies aimed at reducing GHG emissions. Over the LTERP planning horizon, climate change has the potential to impact FBC's supply in terms of its hydro-electricity generation, how much electricity FBC's customers require, and FBC's transmission and system infrastructure planning. Recent studies indicate that rising temperatures and changes in precipitation patterns will occur over the next century.[17]

The following figure shows the projected future average temperature increases for winter and summer months in Canada. The figures with titles including 'RCP2.6' relate to a low GHG emission scenario while those including 'RCP8.5' relate to a high GHG emission scenario. The figures indicate average temperature increases in BC in the order of 1 to 2 degrees Celsius for summer and winter periods from 2031 to 2050. The figures are not specific to the FBC service area but do illustrate possible general trends for Canada and BC in the future and provide a useful range for informing FBC's climate change load driver within its load scenarios (discussed in Section 4). While the figures relate to average warming temperatures over time, they do not capture the increase in the weather and temperature volatility that has occurred in recent years and which is expected to continue in the future.

[17] Canada's Changing Climate Report, Government of Canada, 2019, pages 133 and 135. https://www.nrcan.gc.ca/climate-change/impacts-adaptations/canadas-changing-climate-report/21177.

Figure 2-1: Projected Winter and Summer Temperature Changes[18]



As recently as June 2021, FBC has experienced an extreme heat event, and notes that climate change has substantially increased the probability of such an event. As warming continues, it may become a lot less rare.[19] While FBC typically experiences its highest system loads for the summer during July or August and for winter during December or January, FBC recorded its all-time record highest load of 764 MW on June 29 2021, which exceeded the historical peak (winter) load of 746 MW set on December 20, 2008. FBC's previous June record high load was 594 MW set on June 6, 2016 and its previous record high summer load was 651 MW set on July 30, 2020. FBC was able to manage the load requirements during this June 2021 event through its supply portfolio of existing resources and by ramping up energy and capacity from its Power Purchase Agreement (PPA) with BC Hydro and market purchases (discussed further in Section 5). This event highlights the importance of the flexibility in FBC's supply portfolio to be able to manage unexpected events due to climate change or other sources. More discussion of this in

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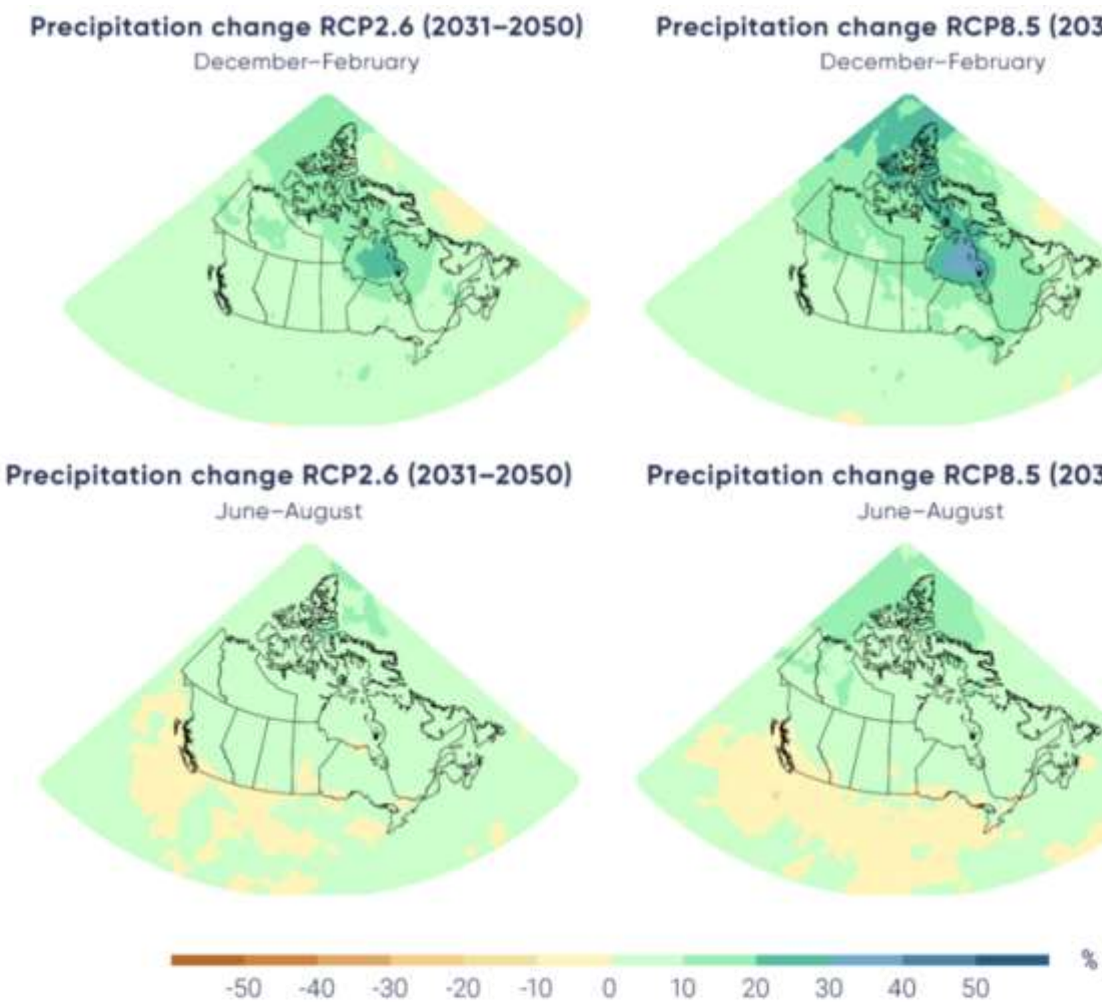
[18] Ibid, pages 133 and 135.

[19] https://www.worldweatherattribution.org/western-north-american-extreme-heat-virtually-impossible-without-human-caused-climate-change/.

the context of FBC's preferred portfolios and the ability of the portfolios to meet customers' load requirements for the next 20 years is provided in Section 11.

The following figure shows the projected future precipitation changes for winter and summer months in Canada. It indicates that southern BC could experience wetter winters (by up to 10 percent as indicated by the light green) and drier summer periods (by up to 10 percent as indicated by the light green) from 2031 to 2050.

Figure 2-2: Projected Winter and Summer Precipitation Changes[20]

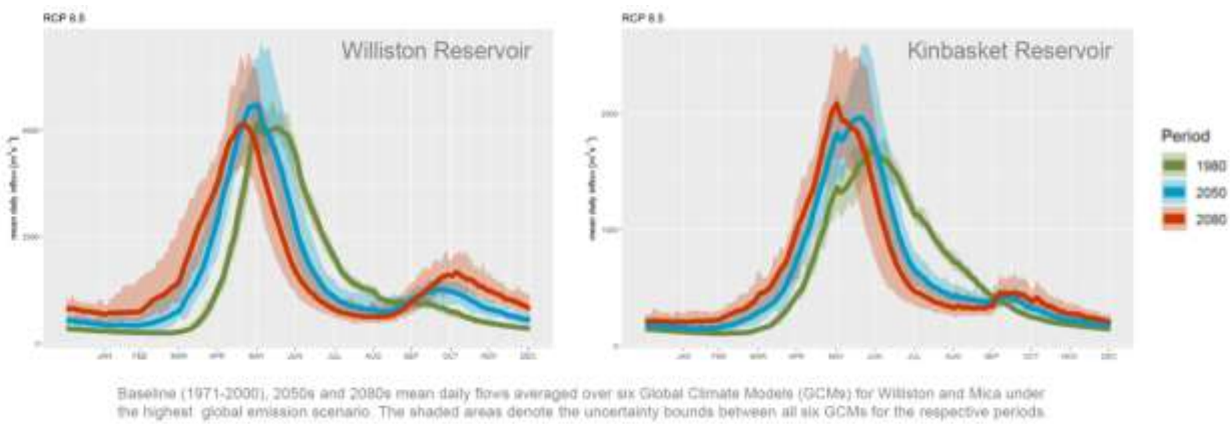


The following figure shows the projected future changes in precipitation patterns for two specific reservoirs in BC by 2050 and 2080. While the two reservoirs represented in the figure are in parts of BC outside the FBC service area, the figure provides an indication of the general pattern changes that BC could experience by 2050 and beyond. It shows that spring hydro

[20] Canada's Changing Climate Report, Government of Canada, 2019, pages 161 and 163. https://www.nrcan.gc.ca/climate-change/impacts-adaptations/canadas-changing-climate-report/21177.

freshet flows could increase above 1980 levels and occur earlier in the spring with less hydro flow available in the summer months.

Figure 2-3: Projected Winter and Summer Precipitation Pattern Changes[21]



The potential impacts of these temperature and precipitation pattern changes on FBC's supply resources are discussed in Section 5.1.1. Any changes to water availability for hydroelectric generation in the Pacific Northwest could open up the possibility of changes to the entitlements under the Canal Plant Agreement (CPA), thus impacting FBC's existing supply of power. The potential impacts of temperature changes on customers' annual energy and peak demand load requirements are explored in the load scenarios discussed in Section 4.1. FBC discusses the potential impacts from climate change on its transmission and distribution infrastructure in Section 6.6.

2.2.2 Canadian Federal Policies and Initiatives

There have been a number of Canadian federal policies and initiatives aimed at addressing climate change, reducing GHG emissions and developing cleaner energy sources. This section outlines some of the more recent items relevant to FBC.

In December 2020, the federal government released a plan called *A Healthy Environment and a Healthy Economy* (*HEHE*) that builds on the *Pan-Canadian Framework on Clean Growth and Climate Change (Framework)*. The *Framework* was Canada's first national climate plan and was released in 2016. The HEHE contains 64 strengthened and new federal policies, programs and investments to reduce pollution and build a cleaner economy. The plan includes reducing energy waste by increasing investments in energy efficiency, investing in zero-emission transit and vehicles, continuing to put a price on carbon, and encouraging low carbon "Made in Canada" products, services and technologies to encourage job growth.

[21] BC Hydro TAC Meeting #8 presentation on January 27, 2021, slide 37. Williston reservoir is located in the northern interior of B.C., north of Prince George. Kinbasket reservoir is located in southeast B.C., north of Revelstoke.

There has been a substantial proposed increase to the federal carbon price. In December 2016, the Canadian federal government announced that it planned to require the provinces to have a price of at least $10 per tonne of carbon dioxide equivalent emissions starting in 2018. At that time, the price would rise by $10 per tonne per year for the next four years, reaching $50 per tonne by 2022. In December 2020, under the *HEHE*, the Canadian federal government announced that it planned to increase the price on carbon as part of a push to meet and surpass Canada's goal of reducing greenhouse gas emissions by 30 percent below 2005 levels by 2030. The carbon price would rise by $15 per tonne per year for the next eight years beginning in 2023 to reach $170 per tonne in 2030. There are uncertainties related to the proposed federal carbon price. As the implementation date is in 2022, a possible Federal election in the fall of 2021 could affect the implementation of the policy, particularly in event of a change in government. It is also unclear how the price would be implemented in each province and territory. Options for BC could include increasing its own carbon tax at the federal schedule, adopting the federal price, or asserting that other policies in BC achieve the same price signal and would not necessitate a dramatic increase to the provincial carbon tax. FBC discusses the BC carbon tax in Section 2.2.3.4 and discusses its approach in developing its carbon price scenarios in Section 2.5.4.

The federal government also published a draft of its Clean Fuel Standard (CFS) at the end of 2020, which is central to the Liberal party's mandate to reduce GHG emissions 30 percent below 2005 levels by 2030. The CFS is meant to drive investment and growth in Canada's clean fuel sector by increasing incentives for the development and adoption of clean fuels.[22] Its proposed rules state that producers and distributors of fossil fuels must reduce their carbon content by 2.6 percent by 2022 and 13 percent by 2030. The scope of the CFS has been narrowed since it was first introduced in 2016, when the measure included liquid, gaseous and solid fuels. The 2020 update no longer includes the gaseous stream and only targets liquid fuels like gasoline, diesel and oil, which are mainly used in the transportation sector.

On November 19, 2020, the federal government took a first step in legislating Canada's goal of net-zero by 2050 by proposing the *Canadian Net-Zero Emissions Accountability Act*. This act will establish a series of interim emissions reduction targets at 5-year milestones towards the ultimate net-zero by 2050 goal. While the act is not yet finalized, the legislation requires the Government of Canada to mandate the first plan under this new legislation, for the 2030 target. The responsibility for this act lies with the Minister of Environment and Climate Change, who will report to Parliament progress on the national emissions target. The reports will include emissions reductions plans, interim progress reports, and final assessment reports that will indicate whether a target has been met.

Stated in the HEHE, the Federal government has committed to work with provinces, territories and utilities to ensure that Canada's electricity generation achieves net-zero emissions before 2050. This signals an intention to decrease and eventually phase out natural gas-fired generation and follows the theme of decarbonizing electricity grids in North America. This is

[22] https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard/about.html.

further evidenced by the Biden administration committing to aggressive climate action, putting pressure on Canada to increase its climate change ambition to keep pace. For example, Natural Resource Canada (NRCAN) and the U.S. Department of Energy recently signed an agreement with 15 areas of cooperation, including clean electricity transmission.[23]

As transportation accounts for a quarter of Canada's GHG emissions, the federal government has set ambitious federal targets for zero emission electric vehicles (ZEVs). The original targets included an increase in the percentage of light-duty vehicle sales that are ZEVs to 10 percent by 2025, 30 percent by 2030 and 100 percent by 2040, which were aligned with the BC *ZEV Act* targets (discussed in the next section). More recently, the federal government announced it is making 100 per cent ZEV sales mandatory by 2035 to meet Canada's national net-zero targets.[24] The federal government is also investing over $600 million in order to make ZEVs more affordable and infrastructure more accessible. This includes topping up the ZEV incentive program in the form of federal rebates for all Canadians that purchase a ZEV vehicle. The new Zero Emission Vehicle Infrastructure Program is the main funding source; it is a 5-year $280 million program ending in 2024, initiated to address the lack of charging and refuelling stations in Canada, one of the key barriers to ZEV adoption.

At the end of 2020, the Hydrogen Strategy for Canada was released by Natural Resources Canada (NRCAN) to help meet net-zero goals by 2050. Between 2021 and 2025, the strategy intends to lay the foundation for a hydrogen economy. This will involve planning for the development of hydrogen supply and distribution infrastructure and will focus on near commercial market readiness hydrogen applications. Between 2025 and 2030, the federal government will focus on stimulating growth and diversifying the hydrogen sector. Lastly, the long-term growth (2030-2050) will focus on rapid market expansion and further increasing hydrogen supply and distribution infrastructure.

2.2.3 Province of British Columbia

Energy policy in British Columbia has been historically rooted in the four cornerstones of low electricity rates, secure and reliable supply, private sector opportunities, and environmental responsibility. In the years between 2007 and 2010, the BC Government took aggressive action to align the province's energy policy with a plan to address the issue of climate change. During this time, the government's plan included a number of major climate change policies such as the *Carbon Tax Act* and the *CEA*. Since introducing the *CEA* in 2010, BC's energy policies have been largely directed towards the use of clean energy and economic growth with updated and longer-term emission reduction targets.

More recently, the CleanBC Plan provides a roadmap for reducing emissions in the transportation, building and industrial sectors while promoting economic growth in BC.

Key legislative and regulatory actions are outlined in the sections below.

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[23] https://www.nrcan.gc.ca/energy/resources/international-energy-cooperation/memorandum-understanding/23749.

[24] https://electricautonomy.ca/2021/06/29/federal-zev-mandate-2035/.

2.2.3.1 Clean Energy Act

The key legislative act supporting energy policy in BC is the *CEA.* Passed in April 2010, the *CEA* outlines 16 objectives aimed at turning BC into "a leading North American supplier of clean, reliable, low carbon electricity and technologies that reduce GHG emissions while strengthening [the] economy in every region."[25] A summary of the objectives follows:

- for BC to achieve energy self-sufficiency;
- to take demand-side measures and to conserve energy, including the objective for BC Hydro to reduce its expected increase in demand for electricity by the year 2020 by at least 66 percent;
- to generate at least 93 percent of the electricity in BC from clean or renewable resources;
- for ratepayers to continue to receive the benefits of BC Hydro's low-cost "Heritage Assets" (existing Hydro generation assets);
- to reduce BC greenhouse gas emissions;
- to ensure BC Hydro's rates remain among the most competitive of rates charged by public utilities in North America;
- economic development, including for First Nations and rural communities, and
- to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians.

In July 2012, the BC Government amended the *CEA* through BC's *Energy Objectives Regulation* to redefine natural gas as a clean energy source when used to generate power for liquefied natural gas (LNG) facilities. Since LNG facilities using electrically powered liquefaction equipment consume large amounts of electricity, the amendment to the *CEA* mitigates the pressure on BC Hydro to supply the requisite power to develop LNG exports from renewable energy sources.

2.2.3.2 Proposed Amendments to the CEA

The BC Government's interim report[26] from Phase 2 of the BC Hydro Review (BC Hydro Review) was released on March 6, 2020 and focused on leveraging BC's clean hydroelectricity to meet the Province's climate goals, support economic development, and make life more affordable.[27] The report includes a discussion of, and makes recommendations regarding, the *CEA* self-sufficiency objective as well as a clean electricity standard, both of which are relevant for FBC's resource planning.

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[25] Ibid, pages 161 and 163.

[26] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydro_cr_ph2_ir_mar06_2020_f.pdf.

[27] https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/electricity/bc-hydro-review-phase-2.

The report concludes that the self-sufficiency provision in the *CEA* restricts BC Hydro to planning to acquire resources within BC until self-sufficient, even in cases where clean and renewable resources in other jurisdictions could be more affordable. It finds that eliminating the self-sufficiency requirement could provide BC Hydro the flexibility to meet future demand at the least cost, as BC Hydro would be able to meet demand not only through electricity generating facilities within British Columbia but also through importing power from clean and renewable resources. Therefore, the report states that BC Hydro will consider the impact of the elimination of the self-sufficiency provision when developing its Integrated Resource Plan.

The report also notes that BC Hydro continues to exceed the objective of the *CEA* that at least 93 percent of electricity generation in the province be from clean or renewable resources. BC Hydro generated nearly 98 percent clean energy in 2019.[28] Building on the *CEA* and in line with neighbouring jurisdictions' goals of 100 percent clean energy, BC Hydro could become the first jurisdiction in the region to implement a 100 percent clean electricity standard. Therefore, the report states that BC Hydro will assume a 100 percent clean electricity standard for the integrated grid when developing its Integrated Resource Plan.

In June 2020, the NDP government proposed Bill 17 to amend the *CEA*. One of the key proposed amendments includes repealing the self-sufficiency planning requirement that BC Hydro's new generation resources must be located within BC. The other key proposed amendment includes introducing a new objective for the province to serve grid-connected customers with clean electricity, effectively enabling the implementation of a 100 percent clean energy standard for BC.

On July 15, 2020, independent MLA Andrew Weaver proposed that Bill 17 be amended to maintain the province's energy objective of electricity self-sufficiency. Clean energy producers and Indigenous groups opposed the removal of the self-sufficiency requirement on the basis that it would reduce opportunities for development of clean energy projects within BC.

At this time, the proposed *CEA* amendments have not been enacted into legislation. However, FBC has incorporated the proposed changes into its portfolio analysis (discussed in Section 11). Specifically, FBC has included portfolios which include 100 percent clean and renewable generation resources and those which include a self-sufficiency requirement.

2.2.3.3 The Heritage Contract and the BC Hydro Power Purchase Agreement

The *CEA's* treatment of BC Hydro's heritage resources[29] has an impact on FBC's resource planning process. The 2002 Energy Plan legislated a "Heritage Contract" for an initial term of ten years to ensure that BC Hydro's customers benefit from existing low-cost heritage resources. With the 2007 BC Energy Plan, the Government confirmed the Heritage Contract in perpetuity to ensure all of BC Hydro's customers will continue to receive the benefits of this low-cost electricity for generations to come.

[28] Ibid, page 22.
[29] Heritage Assets are those generation and storage assets identified in Schedule 1 to the *CEA*.

In May 2014, FBC entered into an agreement with BC Hydro to replace the 1993 PPA. The current PPA is a 20-year fixed term agreement that continues to provide for up to 200 megawatts (MW) of capacity and 1,752 gigawatt hours (GWh) per year of associated energy for FBC to meet a portion of its load service obligations. The PPA ensures that FBC and its customers, by virtue of receiving power under BC Hydro's Rate Schedule 3808 (RS3808), continue to benefit from BC Hydro's heritage energy.

2.2.3.4 BC Carbon Tax

On May 29, 2008, the Government of British Columbia enacted the *Carbon Tax Act*, which imposed a broad-based carbon tax on the purchase and use of fossil fuels in British Columbia such as gasoline, diesel, natural gas, heating fuel, propane and coal. The tax rates, effective July 1, 2008, were initially based on $10 per tonne of carbon dioxide equivalent (CO_2e) emissions from the combustion of each fuel. The tax rate then increased by $5 per tonne each year, reaching $30 per tonne in 2012. Specific tax rates apply for each type of fuel, depending on the amount of CO_2e emissions released as a result of its combustion. The carbon tax rate was then subject to further review pursuant to the development of BC's Climate Leadership Plan (CLP), released in August 2016. The CLP stated that the carbon tax rate could be increased from the current level of $30 per tonne in the future but only once other jurisdictions achieved a similar carbon tax level.

In December 2016, the Canadian federal government announced that it planned to require the provinces to have a price of at least $10 per tonne of carbon dioxide equivalent emissions starting in 2018. The price would rise by $10 per tonne each year for the next four years, reaching $50 per tonne by 2022.[30]

The BC government increased its carbon tax by $5 per tonne in 2018 and again in 2019 so that it was $40 per tonne effective April 1, 2019. The BC government had planned to increase the carbon tax by $5 per tonne in each of 2020 and 2021 to reach $50 per tonne by 2021. However, the 2020 increase was delayed by the BC government as part of COVID-19 pandemic relief policies. The increase of $5 per tonne has been implemented for 2021 and another increase of $5 per tonne has been planned for 2022.[31] After the planned increase in 2022, the BC carbon tax and the Canadian federal carbon tax will be equal at $50 per tonne.

As discussed above, in December 2020, the Canadian federal government announced that it is planning to increase the carbon tax as part of a push to meet and surpass Canada's goal of reducing greenhouse gas (GHG) emissions by 30 percent below 2005 levels by 2030. The price would rise by $15 per tonne per year for the next eight years beginning in 2023 to reach $170 per tonne in 2030.[32] It is uncertain at this time if the federal plan will be enacted; however,

30 http://www.cbc.ca/news/politics/canada-trudeau-climate-change-1.3788825.
31 https://www2.gov.bc.ca/assets/gov/taxes/sales-taxes/publications/notice-2020-002-covid-19-sales-tax-changes.pdf.
32 https://www.cbc.ca/news/politics/carbon-tax-hike-new-climate-plan-1.5837709.

if it is, it is likely that the BC carbon tax will align with this federal plan. FBC has used this information to develop its carbon price scenarios discussed in Section 2.5.4.

2.2.3.5 BC Provincial Climate Targets and the CleanBC Plan

The provincial government's emission targets require that GHGs in BC be 16 percent below 2007 levels by 2025, 40 percent by 2030, 60 percent by 2040 and 80 percent by 2050. To achieve these goals, the provincial government released its CleanBC provincial climate plan in December 2018. The CleanBC Plan is aimed at reducing climate pollution while creating jobs and economic opportunities. This Plan enables BC to reach 75 percent of the 2030 GHG reduction targets, with the means to achieving the remaining 25 percent still to be determined. Since the CleanBC Plan was released, the Climate Change Accountability Act was updated in 2020 to strengthen transparency and accountability relating to the CleanBC Plan, including establishing a requirement to set an interim province-wide target and sectoral targets for emission reductions.

The sectoral targets were released in March 2021 and the provincial government specified the reduction percentage ranges for each of the sectors outlined in the CleanBC Plan: transportation, buildings and industry. The reductions are 27 to 32 percent for transportation, 38 to 43 percent for industry, 33 to 38 percent for the oil and gas sector, and 59 to 64 percent for buildings and communities.[33]

For the transportation sector there is heavy emphasis on ZEVs. The requirement is that 10 percent of new light-duty vehicles sold in 2025 be zero-emission, rising to 30 percent in 2030 and 100 percent by 2040. This was legislated in 2019 in the *ZEV Act* to ensure a greater availability of ZEVs at more affordable prices, and to provide the legislation necessary to enable meeting GHG reduction targets. These ZEV targets will be met by incorporating electricity, hydrogen and other renewable fuels. FBC has used these targets to inform the EV charging loads portion of the Reference Case load forecast discussed in Section 3. FBC discusses its recent EV-related initiatives in Section 2.3.2.

For the buildings sector, the CleanBC Plan states that all new buildings will be mandated to be 80 percent more energy efficient by 2032 (compared to 2018 levels) and existing buildings will be retrofitted. This will be mandated through the BC Step Code, which is currently a voluntary measure. There is a target to make residential gas consumption cleaner by putting in place a minimum requirement of 15 percent to come from renewable gases. The CleanBC Plan also provides significant rebates for new residential heat pumps in order to reduce GHG emissions. FBC's LT DSM Plan includes programs aimed at improving building sector energy efficiency.

For the industry sector, there are new methane regulations that came into effect in 2020 that are intended to reduce methane emissions by 10.9 megatonnes of CO_2e over a 10-year period. Carbon tax revenues from industry are mandated to be used as an incentive to reward the

[33] https://news.gov.bc.ca/releases/2021ENV0022-000561?utm_source=All+Media&utm_campaign=cc65214715-EMAIL_CAMPAIGN_2019_04_17_05_48_COPY_01&utm_medium=email&utm_term=0_135bfb50a9-cc65214715-347685745.

lowest GHG emission performers. Lastly, there is also a goal to encourage widespread industrial electrification and, similar to the buildings sector, a minimum of 15 percent of industrial natural gas consumption to come from renewable gases.

FBC's Reference Case load forecast, discussed in Section 3, includes loads relating to a renewable natural gas facility while the load scenarios, discussed in Section 4, include the addition of large commercial and industrial loads relating to cannabis facilities, data centres, hydrogen production, and carbon capture and storage.

2.2.3.6 BC Hydro Electrification Plan

BC Hydro is currently developing its Electrification Plan, which is an initial five-year strategy to grow existing load, and secure new load on its system.[34] The CleanBC Plan and the BC Hydro review provide the regulatory context for the Electrification Plan. The objectives of the BC Hydro plan are to keep rates affordable, reduce emissions and meet provincial GHG targets, and support customer growth and attract new industries to BC. The plan focuses on industry, transportation, and buildings. At this time, it is uncertain what impact this plan will have on electrification and electricity supply requirements in BC as well as impacts on BC Hydro's rates, in both the short and long term. While this Electrification Plan is a five-year strategy, FBC expects that BC Hydro will implement programs, initiatives, and projects with longer-term impacts on the supply and demand requirements which will be addressed in BC Hydro's next IRP to be filed with the BCUC by December 31, 2021.

2.2.4 Initiatives by Other Provinces and Territories

Other Canadian provinces and territories have undertaken actions to address climate change by reducing greenhouse gas emissions and helping communities prepare for the impacts of climate change. They have adopted greenhouse gas reduction targets and have also established policies and incentives to promote zero-emitting electricity and deploy zero-emission vehicles.[35]

Six provinces, including BC, have set renewable energy standards that require electrical utilities to deliver a certain amount of electricity from renewable or alternative energy sources. In 2010, Nova Scotia enacted the Renewable Electricity Plan which set a goal of generating 40 percent of electricity from renewable resources by 2020, which was later extended to 2022 due to the COVID-19 pandemic. In 2015, New Brunswick enacted the Electricity from Renewable Resources Regulation, requiring that 50 percent of the province's electricity sales come from renewable energy by 2020. Also in 2015, SaskPower in Saskatchewan announced that it would increase renewable energy generation from 25 percent to 50 percent by 2030. In 2016, Quebec released its 2030 Energy Policy which set a goal to increase renewable energy output by 25 percent by 2030. In 2017, Alberta enacted the Renewable Electricity Act, which requires 30 percent of electricity produced in the province to come from renewable energy by 2030.

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34 https://www.bchydro.com/toolbar/about/planning-for-our-future/electrification-plan.html.

35 Canadian Province Climate Policy Maps. Available: https://www.c2es.org/content/canadian-province-climate-policy-maps/.

Alberta is planning to phase out most coal-fired sources of electricity by 2023, earlier than the initial Climate Leadership Plan's target of 2030. Alberta's Climate Leadership Plan is founded on four key pillars: capping oil sands emissions at 100 mega-tonnes per year, putting a price on greenhouse gas emissions, ending pollution from coal-fired electricity, and reducing methane emissions from industry by 45 percent by 2025.[36]

Ultimately, as discussed in Section 2.4.3.2, Alberta's conversion of coal-fired power plants to natural-gas fired power plants is expected to meet Alberta's own power needs. It remains to be seen if BC's forecast surplus of clean electricity will be utilized to help Alberta meet their own electricity needs through the province's clean electricity policies.

2.2.5 Municipal Policy Actions

Many municipalities in FBC's service area are developing updated versions of their climate action plans, with a major focus on reducing GHG emissions, setting ambitious targets out to 2050. Most of the targets address emissions in the transportation and building sectors, with the use of alternative energy sources and energy efficiency helping to reduce the reliance on fossil fuels. The climate related policies of key municipalities in FBC's service area are discussed below.

In June 2018, the City of Kelowna (CoK) announced its updated Community Climate Action Plan aimed at reducing its GHG emissions below 2007 levels by 4 percent by 2023, 25 percent by 2033 and 80 percent by 2050.[37] With transportation representing 55 percent of CoK's GHG emissions, an electric vehicle strategy is also being developed which will investigate policies for charging requirements for new residential and non-residential developments and expanding public charging infrastructure. With regard to existing buildings, opportunities exist for energy savings through retrofits, since the majority of homes in Kelowna were constructed prior to 2000. The CoK also updated its building bylaw to reference the Energy Step Code for new Part 9[38] buildings with planned implementation for Part 3[39] buildings in 2021. The BC Energy Step Code is aiming for all new buildings in BC to be net-zero energy ready by 2032.

To maximize GHG emission reductions, renewable energy actions in Kelowna will focus on substituting natural gas with heat pumps or renewable natural gas for space and water heating. The Kelowna residents contributing to Kelowna's Vision to 2040 through the Imagine Kelowna

[36] Alberta's Climate Leadership Plan. Available: https://open.alberta.ca/publications/alberta-s-climate-leadership-plan-progressive-climate-policy.

[37] https://www.kelowna.ca/sites/files/1/docs/community/community_climate_action_plan_june_2018_final.pdf.

[38] Part 9 Buildings include most buildings three storeys and under in height and with a footprint of 600 square metres or less, such as Single Family Dwellings, Duplexes, Triplexes, Quadruples, Carriage house and Townhouse / Low–rise buildings.

[39] Part 3 Buildings include most buildings over three storeys in height or over 600 square metres in footprint such as shopping malls, office buildings, condos, apartment buildings, hospitals, care facilities, daycares, schools, churches, theatres and restaurants.

initiative indicated that they wanted the city to invest in alternative energy sources to reduce GHG emissions.[40]

The City of Penticton plans to update its Community Climate Action Plan in 2021 in order to reduce community-wide greenhouse gas emissions and energy use and to consider actionable climate adaptation measures.[41] In its Electric Utility Master Plan 2020-2045,[42] adopted in December 2020, recommended capital upgrade expenditures are related to improving reliability and increasing the capacity of the system due to an increase in EV penetration.

Nine Kootenay municipal governments[43] have pledged to reach 100 percent renewable energy by 2050 as part of the West Kootenay 100% Renewable Energy Plan, released in October 2020.[44] The plan focuses on four 'big moves' relating to transportation, buildings, energy generation, and waste. In the transportation sector, the plan includes growth in passenger EVs, promoting active transportation and public transit, and eliminating emissions from commercial vehicles by facilitating the use of vehicles powered by electricity, renewable natural gas, or other renewable sources of energy. Focusing on upgrading energy efficiency standards for existing buildings and improving efficiency standards for new buildings is the plan for the building sector. The third big move includes expanding energy generation from renewable sources, mainly to reduce the reliance on fossil fuels for transportation in buildings. The last big move includes eliminating waste by diverting and composting organic waste from landfills and capturing the escaping methane to be used as RNG.

Nelson launched Canada's first community solar garden in June 2017. The project was developed through Nelson Hydro's EcoSave Energy Retrofits Program. Nelson's city council committed to a 100 percent renewable energy by 2050 target in January 2019. Since then, the City has been an active member in the 100% Renewables Working Group for the West Kootenay Region and part of the development, planning, and implementation of the West Kootenay 100% Renewable Energy Plan. In Nelson Next,[45] the City of Nelson's climate plan issued in February 2021, the City aims to achieve 75 percent reduction in community-wide GHG emission and a net zero target by 2040. Developing and implementing a 'Low Carbon Mobility Strategy' and expanding electric vehicle charging infrastructure to align with current and future demand are key tactics in Nelson's transportation plan. Developing 'Resiliency Design Standards' for new and renovated buildings, as well as accelerating the adoption of BC Energy Step Code beyond provincial requirements, are key tactics for buildings. The implementation of a district energy system and collaboration with regional energy providers will enable Nelson to explore new, renewable and alternative energy production opportunities.

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[40] https://www.kelowna.ca/sites/files/1/docs/related/imagine_kelowna_short_report_digital.pdf.
[41] https://www.penticton.ca/our-community/environment/community-sustainability.
[42] https://www.penticton.ca/sites/default/files/docs/city-hall/master-plans/CPEU%20Master%20Plan%202020-2045.pdf.
[43] Castlegar, Kaslo, Nelson, New Denver, Rossland, Silverton, Slocan, Warfield, and The Regional District of Central Kootenay
[44] https://westkootenayrenewableenergy.ca.
[45] https://www.nelson.ca/DocumentCenter/View/4920/Nelson-Next.

2.2.6 FortisBC Climate Initiatives

As part of the consultation for the BC government's CleanBC strategy, FortisBC (including FEI and FBC) released its *Clean Growth Pathway to 2050* (Clean Growth Pathway), which outlines the actions the Companies' plan to align with the provincial government's GHG reduction goals (provided in Appendix C). FortisBC's Clean Growth Pathway leverages the decarbonization potential of the both the gas and electric energy systems through four key pillars:

- Expanding the Company's low and zero carbon solutions in buildings. FortisBC has long invested in energy efficiency to ensure that customers have options to moderate their energy use and improve affordability. To make progress on the efficiency of buildings, FortisBC (the gas and electric utilities together) has tripled its total spend on efficiency and conservation to $368.5 million over the three year period from 2019 to 2022. In addition, FEI is piloting innovative technologies in the buildings sector such as building controls and gas heat pumps to leverage new emissions reduction energy technologies.
- Investing in renewable gases to decarbonize the gas supply. FEI's gas distribution infrastructure has a critical role in providing low carbon and renewable energy as renewable gas has enormous potential to reduce BC's GHG emissions by 2030. As FEI continues to develop Renewable Natural Gas for its customers, it is also looking at adding clean-burning hydrogen and other renewable gases such as those made from woody biomass (synthetic gas or syngas) and lignin to its renewable energy portfolio. Hydrogen has a number of benefits, one of which is that it is a versatile energy carrier that is carbon free at the point of use. It can also be made from a range of feedstocks that are abundant in BC. Hydrogen is poised to play a key role in decarbonizing the gas network and FEI is working to find the most cost-effective ways to integrate and scale up renewable gas resources.
- Supporting zero and low carbon transportation fleets and infrastructure. Transportation comprises the biggest share of provincial emissions (39 percent) and is one of the most challenging sectors to decarbonize. FEI is working to convert medium-duty and heavy-duty fleet vehicles and marine vessels to lower carbon alternative fuels like compressed and liquefied natural gas (CNG and LNG). In addition to a significant GHG reduction benefit, using CNG and LNG in vehicles and marine applications can dramatically improve air quality by cutting the particulate matter, sulfur and nitrogen oxides released into the environment. FBC is also investing in EV infrastructure and provides customers with clean electricity to support the transformation to zero and low carbon transportation in the passenger vehicle market.
- Positioning BC as a vital domestic and international LNG provider to lower GHG emissions in marine fueling and global markets. FEI's Tilbury LNG facility provides among the cleanest LNG in the world because it uses BC's clean electricity rather than natural gas-powered equipment. To support provincial and federal objectives to become

a world leader in LNG bunkering,[46] FEI is promoting this clean LNG for local marine and international use to replace the world's most carbon intensive fuels. In 2016, FEI was the first company globally to offer onboard truck-to-ship bunkering (or fueling). BC Ferries is now using LNG to fuel the entire Salish and Spirit classes of ships and Seaspan has two LNG-fueled vessels with two more set to join its fleet in 2021.

Building upon the Clean Growth Pathway, FortisBC established its first ever emissions reduction target, *30BY30*. The *30BY30* target represents a goal to reduce the GHG emissions associated with FortisBC's customers' energy use by 30 percent by the year 2030.[47] This equates to approximately 3.9 million tonnes of avoided carbon dioxide equivalent emissions by 2030. FortisBC plans to accelerate GHG emissions reductions across its customer base and lead the way to a lower carbon economy through active partnerships between customers, industry and government to help achieve the goal. Ultimately, the *30BY30* target demonstrates FortisBC's understanding of the importance of a lower carbon future and serves as a way to measure progress of the actions outlined in the Clean Growth Pathway.

This LTERP is aligned with and includes initiatives that support the Clean Growth Pathway and achieving the *30BY30* target. Each of the four initiatives is described below.

1. Expanding the Company's low and zero carbon solutions in buildings. FBC continues to expand on its energy efficiency programs to ensure that customers have options to moderate their energy use and improve affordability (as discussed in Section 2.3.7 and the LT DSM Plan).

2. Support for zero and low carbon transportation is provided directly by FBC as it provides clean electricity for FBC customers to power their EVs at home, business or through its public EV charging station network (discussed in Section 2.3.2). FBC estimates the GHG emission reduction due to the replacement of light-duty internal combustion engine (ICE) vehicle with light-duty EVs in its service area to be approximately 0.04 million tCO_2e by 2030. By 2040, the GHG emission reduction is about 0.20 million tCO_2e. With the addition of medium-duty and heavy-duty EVs (per the Diversified load scenario presented in Section 4), the estimated GHG emission reduction increases to about 0.25 million tCO_2e by 2040.

3. Investing in renewable gases to decarbonize the gas supply. FBC provides indirect support for FEI's initiatives to decarbonize the gas network. For example, FBC plans to provide electricity for the REN Energy International Corporation (REN) renewable natural

46 The province's CleanBC plan aims to "make our ports attractive to global shipping fleets transitioning to LNG as a lower cost, lower GHG transition fuel" (CleanBC, p.61). Further, in a news release issued in October 2019, the Province of B.C. announced its plan to partner with the Vancouver Fraser Port Authority and FortisBC to establish the first ship-to-ship LNG marine bunkering service on the west coast of North America, "which will allow B.C. to have a direct impact on global emissions by reducing the amount of greenhouse gas emissions from visiting vessels." The federal government also supports LNG marine bunkering goals, as the Prime Minister of Canada has directed the Minister of Transport to work with partners to support efforts to convert marine vessels and infrastructure toward "more environmental friendly fuels, like liquefied natural gas." Mandate Letter from Prime Minister Trudeau to the Minister of Transport, December 2019.

47 From a 2007 baseline year, which is used in B.C.'s provincially legislated emission targets.

gas project[48] being developed in Fruitvale, BC and has included its estimated electricity requirements in its Reference Case load forecast. FBC has also included the potential for increased electricity requirements on its system relating to hydrogen production and carbon capture and storage in its load scenarios (discussed in Section 4).

4. Positioning BC as a vital domestic and international LNG provider to lower GHG emissions in marine fueling and global markets. This initiative is applicable to FEI rather than FBC and so does not have any direct relevance for this LTERP.

2.2.7 Regulatory Framework in the US

Various legislative and policy developments of the federal and state governments in the US may affect renewable resources and therefore the wholesale electricity market in the western US. The US portion of the Pacific Northwest power system is adjacent to FBC's service territory and is currently a source of wholesale energy and capacity market purchases for FBC. FBC must remain aware of, and where appropriate, responsive to, the changing US regulatory environment governing that market as part of its prudent resource planning.

Since the Biden administration began in January 2021, the US has been rapidly introducing policies to address the effects of climate change. Two main goals of the new administration are to decarbonize the power sector resulting in net-zero emissions by 2035, and for the US to achieve net-zero emissions by 2050.

In March 2021 the Biden administration introduced the American Jobs Plan, which aims to invest $100 billion to achieve 100 percent carbon-free electricity by 2035. If enacted, this plan would build out the transmission system and extend tax and production credits for clean energy generation and storage.[49] The CLEAN Future Act was also introduced in March 2021, which would include a nationwide Clean Electricity Standard (CES) requiring that all retail electricity suppliers obtain 100 percent clean electricity by 2035. Targets under the CES begin in 2023 and rise to an 80 percent clean requirement by 2030, before reaching 100 percent by 2035.[50]

The outcome for these federal policy developments remain uncertain at this time, but the Biden administration is also leveraging organizations such as the Federal Energy Regulatory Commission (FERC) and Department of Interior to support clean energy ambitions. State regulations also support decarbonization in the US, along with corporations' own voluntary goals and renewable procurement plans.

[48] The project will produce RNG from wood waste and is expected to come online in 2022 and produce about 1 petajoule of RNG per year for the next 20 years.

[49] The American Jobs Plan Fact Sheet. Available: https://www.whitehouse.gov/briefing-room/statements-releases/2021/03/31/fact-sheet-the-american-jobs-plan/.

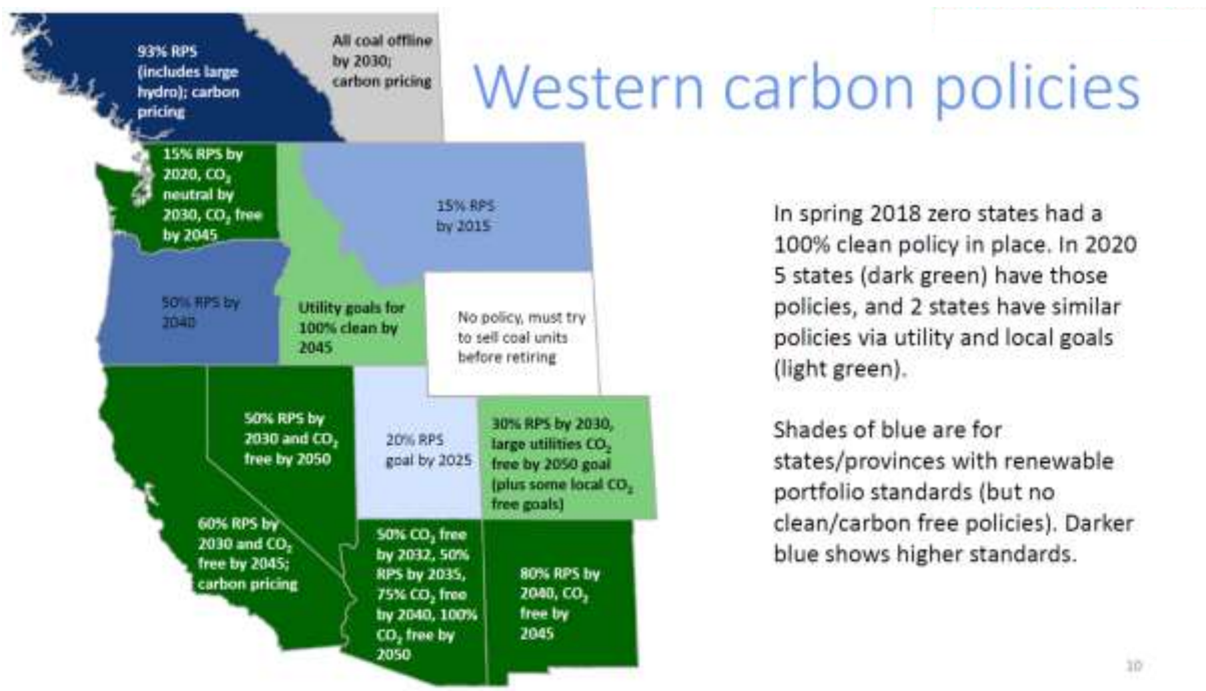
[50] https://energycommerce.house.gov/newsroom/press-releases/ec-leaders-introduce-the-clean-future-act-comprehensive-legislation-to.

2.2.7.1 US Renewable Portfolio Standards

Renewable portfolio standards (RPS) are regulatory mandates to increase generation of electricity from renewable resources such as wind, solar, biomass, and other alternatives to fossil fuel and nuclear electricity generation. US states can apply RPS requirements to all utilities, only investor-owned utilities, or only utilities serving a large number of customers, and can also define which technologies and resources are eligible to meet RPS standards.

The following figure shows the western US states with RPS or voluntary targets versus those without any standard or target.

Figure 2-4: Western Carbon Policies[51]



The adoption of state RPS in Washington, Oregon, and Montana in the mid-2000s led to a significant increase in renewable resource development.[52] Utilities in the Pacific Northwest have shifted towards fewer coal plants and a greater reliance on renewables, and this shift will continue through the next decade due to a combination of policy measures directed at reducing greenhouse gas emissions and the economics of less expensive resources. Some of these policy measures are government directives, but increasingly utilities are setting their own aggressive emission-reduction or clean energy goals[53] (also see Appendix D for a summary of recent regional utility IRP goals).

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[51] Northwest Power System Trends 2021, slide 10, as presented in Pacific Northwest Utilities Conference Committee System Planning Committee meeting December 16, 2020.

[52] Northwest Power and Conservation Council Seventh Power Plan Midterm Assessment, page 6-11.

[53] PNUCC 2020 Northwest Regional Forecast. Available: https://www.pnucc.org/wp-content/uploads/2020-PNUCC-NRF_0.pdf.

The majority of utilities met their state mandated targets in 2015 and 2020, and the following two sections detail recent policy action in two relevant Pacific Northwest states. The impact of RPS on resource adequacy and reliability in the Pacific Northwest is discussed later in Sections 2.4.2 and 2.4.3.3, and the impact on electricity market prices forecasts is discussed in Section 2.5.2.

2.2.7.2 Washington Policy Actions

The Washington State Energy Independence Act (WSEIA) in 2006 established RPS for 18 utilities in Washington with renewable energy targets as a percentage of customer load. The WSEIA set a final renewable energy target of 15 percent by 2020. The WSEIA is being updated to incorporate changes made in 2019 as part of the Clean Energy Transformation Act (CETA) process.

The CETA, enacted in 2019, committed Washington to an electricity supply free of GHG emissions by 2045.[54] By 2022, all electric utilities serving retail customers in Washington must prepare and publish a clean energy implementation plan. By 2025, utilities must eliminate coal-fired electricity from their state portfolios. Then, by 2030, utilities must be 100 percent greenhouse gas neutral, while still allowing the flexibility to have limited use of electricity from natural gas if offset by other actions. By 2045, all utilities must only have electricity that is 100 percent renewable or non-emitting, with no provisions allowed for offsets.

2.2.7.3 Oregon Policy Actions

Oregon established its initial RPS in 2007, but then updated requirements in 2016 through Senate Bill 1547. This update required utilities with 3 percent or more of the state's electrical load to generate 25 percent of electricity from renewable resources by 2025. By 2040, RPS requirements increase to 50 percent renewables, which would result in 50 percent of the electricity that Oregonian's use to come from renewable resources.[55]

2.2.8 Summary

Energy and environmental policy in Canada and the US is constantly evolving as federal, provincial, state, and municipal governments implement initiatives to reduce GHG emissions and transition to clean energy sources. These policy actions will impact the electricity generation mix in western Canada and the US Pacific Northwest region as generators in the US and provinces like Alberta move towards greater adoption of renewable resources like wind and solar. This, in turn, will likely impact market electricity prices and PNW regional resource adequacy and reliability. At the same time, these policies may also increase electricity demand in certain areas, such as the transportation sector, and impact the level of carbon pricing in BC. This could provide both challenges and opportunities for FBC. These evolving energy and environmental policies and developments are key factors in the LTERP planning environment and help inform FBC regarding potential impacts on future customer demand and supply over

[54] https://www.commerce.wa.gov/growing-the-economy/energy/ceta/.
[55] https://www.oregon.gov/energy/energy-oregon/pages/renewable-portfolio-standard.aspx.

the planning horizon. FBC's customer demand and supply are discussed in the following sections.

2.3 CUSTOMER DEMAND ENVIRONMENT

This section provides an examination of the customer demand environment to assess how technology, customers' energy needs, and the types of loads are changing and how the relationship between the customer and the utility continues to evolve. The ways in which customers use, monitor, and generate electricity is evolving, presenting both challenges and opportunities for FBC in meeting the future needs of its customers. Technology is a large driver in this evolution, impacting how customers connect and interact with FBC and influencing the supply of and demand for electricity on the system. This, in turn, has implications for FBC's services and rate offerings which need to appropriately reflect how customers use electricity.

FBC is continuing to meet customer demands in a number of ways, including by:

- Supporting EV adoption by funding charging stations, providing rebates for chargers and developing strategies for managing EV charging impacts during peak demand periods;
- Promoting informed electricity use by providing more detailed and up-to-date consumption and end use data;
- Supporting small customer-owned clean or renewable distributed generation with the net metering tariff;
- Improving the management of customer interconnections to accommodate and attract new emerging large loads, and
- Providing customers with cost-effective DSM programs to reduce their energy consumption.

The COVID-19 pandemic has impacted many customers' behaviour and their electricity use. While there have been some short-term impacts, it is uncertain how long some of the behavioural changes will last. These impacts are discussed in the next section.

2.3.1 The Impacts of the COVID-19 Pandemic

The COVID-19 pandemic has had unprecedented impacts on human health, our way of life, and the economy. At this time, it is uncertain how the pandemic may affect customer behaviour in terms of their energy use and the continued growth of EVs and emerging large loads over the next few years. The degree of future economic growth and recovery from the pandemic will likely play a role in customers' demand for electricity going forward. The economic impacts were most impactful during 2020 with global GDP contracting by 2.8 percent and Canadian

GDP contracting by 5.5 percent.[56] The GDP growth for BC declined by 5.1 per cent in 2020, the worst contraction since 1980.[57]

However, there are signs of recovery in 2021. The provincial economy is estimated to grow by 4.5 percent in 2021, with a slightly stronger growth performance expected in 2022.[58] Global trade is recovering, which supports BC's exports, which in turn will support the provincial economic recovery. Provincial employment has almost returned to its pre-pandemic level, although some sectors of the labour market are performing better (e.g. manufacturing and public sector) while others are performing worse (e.g. tourism and hospitality) than before the pandemic. Retail spending has rebounded and is on an upward trajectory in 2021. Construction will be a leading growth engine in 2021 and 2022 as several large capital projects (including the LNG Canada terminal, the Site C hydroelectric dam, and the Coastal Gas Link pipeline) resume full-scale activity and governments spend more on infrastructure. This economic recovery, however, is highly dependent on the success of the COVID-19 vaccination rollout and the easing of restrictions relating to social activities and inter-provincial travel. The progress of the economic recovery is expected to be clearer later in 2021.

At this time, it is uncertain if some of the behavioural changes resulting from the COVID-19 pandemic will be shorter term in nature or have longer lasting effects. For example, it is unknown if office workers currently working from home instead of the office will return to the workplace and if they will return to the typical five-days-a-week workplace pattern or something different. It is likely that the degree of economic recovery and growth will continue to influence the evolving customer electricity demand from drivers such as EVs and large load sectors.

FBC discusses the recent impacts of the COVID-19 pandemic in relation to its Reference Case load forecast in Section 3.2.

2.3.2 Electric Vehicles

The growth in EV sales in the FBC service area is expected to play a significant role in the demand for electricity related to EV charging over the planning horizon. BC currently leads the country in EV sales: as of December 30, 2020, EV sales accounted for 9.4 percent of all light-duty vehicle sales in BC.[59] The following figure compares EV sales as a percentage of light-duty vehicle sales in BC to EV sales in the FBC service area. EV sales, though accelerating, are still at the beginning of the adoption curve. Additionally, EV uptake in the FBC service area lags behind the province as a whole. EV sales as a percentage of light-duty vehicles sales in the FBC service area at the end of 2020 were approximately 4 percent. This is a slight drop from the 2019 EV sales percentage and is likely due to the short-term impacts from the pandemic.

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56 Business Council of British Columbia, February 4, 2021: https://bcbc.com/reports-and-research/the-race-between-the-virus-and-the-vaccines.

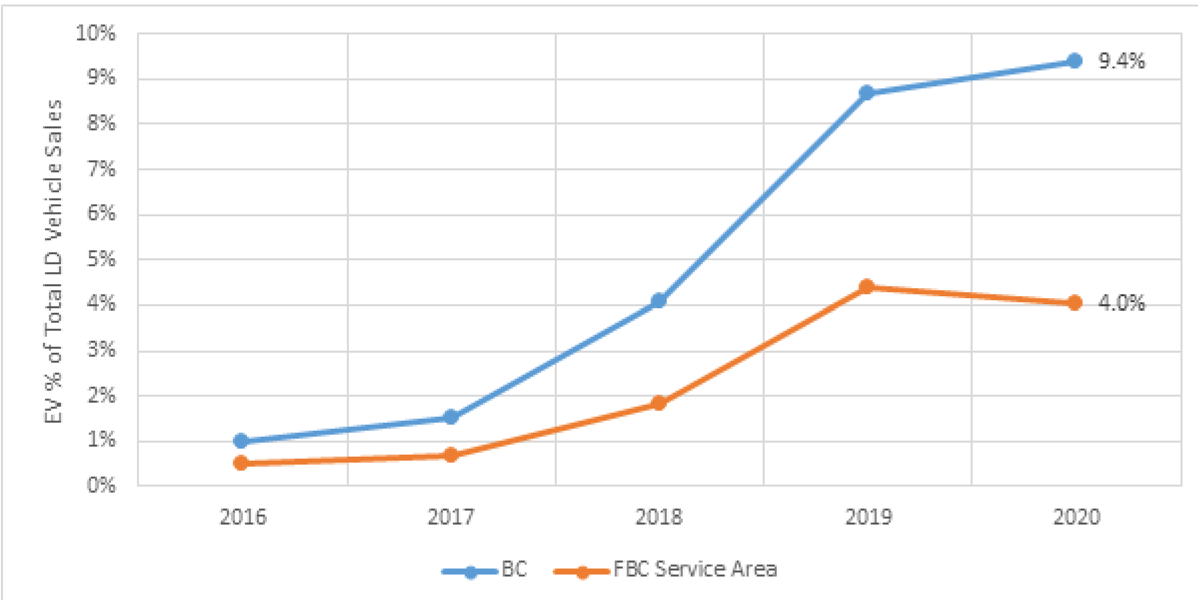
57 https://www.cbc.ca/news/canada/british-columbia/bc-economy-rebound-2021-1.5930352.

58 Business Council of British Columbia, February 4, 2021: https://bcbc.com/reports-and-research/the-race-between-the-virus-and-the-vaccines.

59 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/zev_2020_annualreport_march2021_v5.pdf.

FBC expects the EV sales percentage to resume its increasing trend in 2021 and beyond. As discussed in Section 2.2.3.5, the *ZEV Act* requires light-duty EV sales to reach 10 percent by 2025, 30 percent by 2030 and 100 percent by 2040. Given the current level of EV sales in the FBC service area, the *ZEV Act* targets are appropriate EV sales levels for FBC to determine the EV charging for the Reference Case load forecast.

Figure 2-5: Light-duty EV Sales as a Percent of Total Light-duty Vehicle Sales[60]

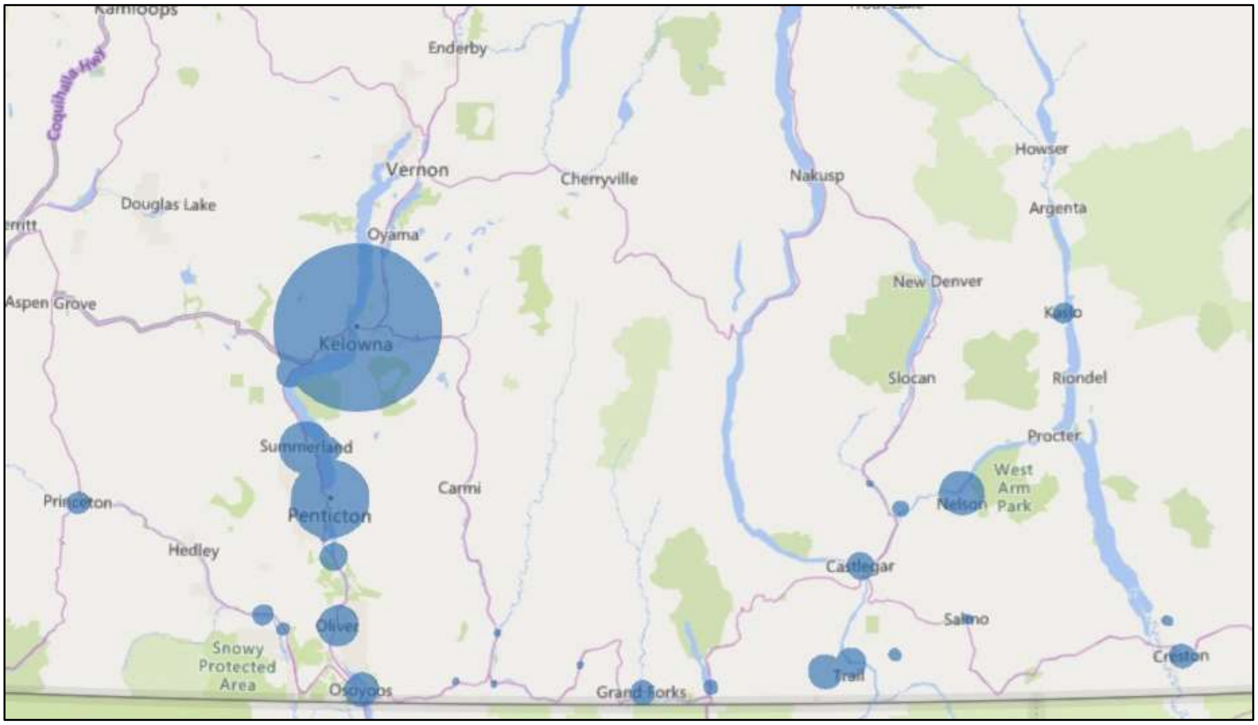


The preceding discussion demonstrates that EV adoption in the FBC service area lags behind the province as a whole to date. BC's overall adoption numbers are strongly influenced by the Lower Mainland and Vancouver Island, which have higher population densities compared to the FBC service area. Higher population densities (which generally result in shorter distances between chargers), along with the milder climates found in the Lower Mainland and Vancouver Island, are factors that can lead to a faster rate of EV adoption. This trend is also seen in the FBC service area, where the greatest number of EVs are found in the most heavily populated areas, including Kelowna, Summerland and Penticton. Figure 2-6 below shows the relative EV registrations throughout the FBC service area. The size of the circle is proportionate to the number of EVs registered in that particular municipality. [61]

[60] Based on Markit New Registration Data (Year End 2020) for the Province of British Columbia*. Figures and information sourced to Markit within this report (the "Markit Materials") are the copyrighted property and of Markit Ltd. And its subsidiaries ("Markit") and represent data, research, or opinions of Markit, and are not representations of fact. The information and opinions expressed in the Markit Materials are subject to change without notice and Markit has no duty or responsibility to update the Markit Materials. Moreover, while the Markit Materials reproduced herein are from sources considered reliable, the accuracy and completeness thereof are not warranted. No further reproduction of this material is allowed without the express written permission of Markit.

[61] https://public.tableau.com/app/profile/icbc/viz/VehiclePopulation-ElectricVehicles/2016-2020ElectricVehicles.

Figure 2-6: Number of Registered EVs in FBC Service Area

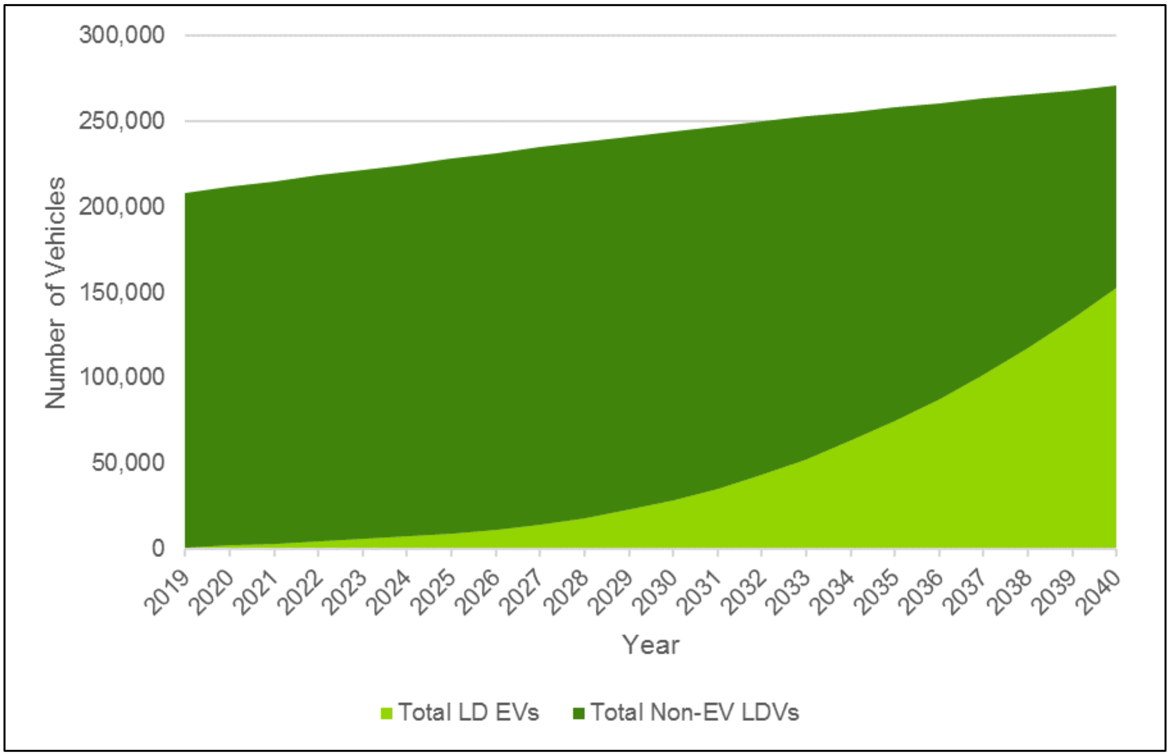


FBC expects that as vehicle manufacturers continue to introduce EVs that have greater range and that are priced at a level that targets mass market adoption, consumer uptake of EVs will continue to increase. FBC's recent customer survey, provided in Appendix N, shows that 43 percent of residential and 37 percent of commercial survey participants are likely to buy or lease an EV in the next three years.[62] FBC must be prepared to meet the changing and future needs of customers as they relate to EVs and the associated charging infrastructure.

The following figure shows the forecast light-duty vehicle stock out to 2040 for the FBC service area. The growth in light-duty EVs reflects the *ZEV Act* sales targets. It indicates that light-duty EVs will total approximately 150,000 by 2040, which will be approximately 56 percent of the projected light-duty vehicle stock. As discussed in Section 3.4.1, the annual energy related to this EV charging is approximately 500 GWh by 2040, which is approximately 10 percent of the total FBC annual energy requirements (before DSM) in 2040. The peak demand associated with EV charging - without any initiatives to shift home EV charging from peak demand periods, as discussed further below - is approximately 150 MW in 2040, or approximately 14 percent of the winter peak demand (before DSM) in 2040 (see Section 3.4.2).

62 Long-Term Electric Resource Planning Survey provided in Appendix N, page 8.

Figure 2-7: Forecast Light-Duty Vehicle Stock in FBC Service Area



FBC is preparing to meet customer needs for EV transportation in several ways.

First, FBC is providing financial, logistical, and engineering support for federal/provincial direct current fast-charging (DCFC) programs. This has resulted in the installation of 30 Level 3 DCFC stations at 19 sites in 17 communities across the FBC service area. An additional 10 DCFC stations, including six 100 kW stations, are scheduled to be installed in 2021. Figure 2-8 shows a map of FBC existing and proposed public DCFC stations.

Figure 2-8: FBC Existing and Proposed Public DCFC Stations

FBC's continued involvement in supporting transportation electrification will help to ensure the development of a robust EV charging network that appropriately takes into consideration the forecast number of EVs expected to replace conventional internal combustion engine vehicles.

Second, FBC is developing a rate for commercial customers who wish to install fleet or employee charging infrastructure for light-duty fleet and workplace vehicles. The rate will be designed to remove two of the barriers to fleet/workplace electrification: the upfront capital cost of installing EV chargers and ongoing charging station management. FBC intends to apply to the BCUC for approval of this new rate in the near future.

Third, FBC is administering provincial and municipal government funds through the CleanBC – Go Electric program.[63] This program promotes EV adoption by providing rebates for single-family homes, multi-unit residential buildings (e.g. condominiums and apartments) and workplaces to install Level 2 chargers.

Fourth, FBC is exploring various strategies that aim to shift at-home EV charging from peak times. Increased consumer adoption of EVs in BC, with their associated energy and demand charging requirements, has the potential to place significantly greater demands on utility infrastructure, as discussed in Section 6.5.2, and increase the requirement for future generation resources, as discussed in Section 11.3.5. This is particularly the case if charging behaviour is left unmanaged and the majority of EV owners charge their EVs at the end of the workday,

[63] https://goelectricbc.gov.bc.ca/.

adding significant load to the system during FBC's peak demand periods (typically 5 to 7 pm) (see Figure 9 on page 17 of Appendix H – Load Scenario Assessment Report for home EV charging profiles). However, depending on customers' charging behaviour, there is the opportunity for strategies to manage these types of loads to improve the utilization of the electric grid without significantly impacting infrastructure. One of the recommendations from Guidehouse in the development of the load scenarios (discussed in Section 4.1.5) is that FBC consider studying a time of use (TOU) rate designed for EV drivers and encourage electric vehicle supply equipment (EVSE) distributors to promote enabling technologies (such as timers) that could allow customers to take advantage of such rates. Guidehouse also suggests FBC should consider other programmatic options for reducing the impact of potential future EV growth. FBC has considered several types of options to mitigate the potential impacts of home EV charging on peak demand and intends to pursue a software-based approach which could include incentives to encourage home EV charging off peak periods.

FBC provides a comparison and discussion of the possible strategies to manage EV charging peak demand. These include rate-based, hardware-based and software-based approaches presented in Table 2-1 below.

Table 2-1: Strategies for mitigating EV peak demand impacts

	Rate-based approach	Hardware-based approach	Software-based approach
Description	Shift loads via opt-in time-based rates, such as time of use (TOU) rates.	Shift loads via hardware, such as smart charger. Utility provides rebate for purchase and installation of hardware, as well as rebate/bill credit for continued participation.	Shift loads via software that controls charging directly through vehicle or through EV charger. Utility provides rebate/bill credit upon verification that peak load has been shifted on a continuous basis.
Pros	Widely used by other utilities. Easy to administer once implemented.	Utility has direct control (with ability for customer to override), which increases load-shifting effectiveness and enables demand response opportunities.	Utility has direct control (with ability for customer to override), which increases load-shifting effectiveness and enables demand response opportunities. Ease of implementation (e.g. no hardware to purchase/install, software works with multiple chargers/vehicles) which may lead to higher adoption rates.

	Rate-based approach	Hardware-based approach	Software-based approach
Cons	Utility has no direct control over charging, limiting the effectiveness of peak load shifting and demand response programs. Potential for free ridership where some customers are rewarded for existing behaviour, without the benefit to the grid of any new peak-load shifting. Difficult to implement without separate meter, resulting in low adoption. Cost basis for justifying significantly differentiated time-based rates is limited/insufficient.	High cost of smart charging equipment (even with rebate) could discourage adoption. Only a limited number of smart chargers are compatible with utility control, again limiting participation (i.e. customers may not want to be forced into being a specific charger).	Not yet widely used by utilities in North America, therefore limited data available to verify effectiveness.

FBC intends to pursue the software-based approach to help shift EV charging off peak demand periods. This approach is easier to implement for both FBC and customers than the other options, provides the flexibility for utility control or customer control (which allows FBC to implement program changes over time if required, including demand response), and has no direct cost impacts on EV customers. For these reasons, FBC believes this approach will be the most effective in shifting EV charging.

FBC's recent customer survey (see Appendix N) indicates that those residential customers likely to buy or lease an EV in the next three years prefer lower electricity rates as an incentive to charge during off peak times.[64] The software-based approach could include providing electricity bill rebates for charging during off-peak times and so this would effectively achieve the same results as lower electricity rates.

FBC is planning to implement a pilot program later in 2021 to help determine how much shifting of EV charging from peak periods it might be able to achieve. If successful, FBC will implement a program in the near future and will include it in a future DSM Expenditure filing with the BCUC. More details are provided in Section 2.3.7. If unsuccessful, FBC may consider the other options in the table above to meet the objective of shifting EV charging from peak demand periods.

At this time, FBC does not expect that it will be able to shift 100 percent of the EV charging peak demand of 150 MW by 2040 given that it is expected that some of the EV charging will occur at public charging stations and also possibly the workplace. For the load scenarios work (results provided in Appendices H, I and J), Guidehouse estimated that 80 percent of the light-duty EV charging would occur at home, 10 percent at public charging stations, and 10 percent at work. Furthermore, some light-duty EVs would likely be charged at home using Level 1 rather than Level 2 chargers, although FBC expects as EV driving ranges increase more EV owners would be likely to install Level 2 chargers. FBC expects that programs aimed at shifting home EV

[64] Long Term Electric Resource Planning Survey provided in Appendix N, page 8.

charging to off-peak periods would be directed towards Level 2 chargers and therefore may be able to shift up to a maximum of about 75 percent rather than 100 percent of peak demand resulting from EV charging.

As discussed in Section 3.5, FBC has included light-duty EV charging based on *ZEV Act* sales targets in its Reference Case load forecast. In Section 4, FBC explores load scenarios that include various levels of light-duty EV penetration as well as medium-duty and heavy-duty EV charging to determine potential impacts on the FBC system in terms of annual energy load and peak demand.

2.3.3 Connected Home and Business

Technology is changing the way customers interact with FBC and the information available to both customers and FBC regarding energy use.

FBC's Advanced Metering Infrastructure (AMI) system provides customers with access to real-time, detailed load data, allowing them to better manage their electricity use. FBC customers have access to hourly or 15-minute granularity consumption data through the Customer Information Portal (CIP). Hourly electricity use data is generally available to radio-on customers within 24 hours after usage, which meets the needs of most customers. Usage of this service has steadily increased since 2017 when the service was introduced, with 1,845 monthly transactions recorded in January 2021.

Hourly electricity usage data will also be used to enhance the My Energy Use (MEU)[65] functionality that is available to FBC's customers starting in June 2021. The more detailed data will allow users to better track improvements in energy-use-driven behavioural changes and energy-efficiency equipment investments.

The increased availability of "smart" home apps is likely to drive customers' interest in controlling their energy use. Remote monitoring and control of energy-consuming devices is becoming increasingly commonplace with the advent of products such as "smart" thermostats. These thermostats monitor building occupancy patterns and will change temperature setpoints to reduce energy use when buildings are unoccupied. They also allow remote temperature adjustments via a web browser or mobile phone app. Automation technology also allows better control of devices other than thermostats in customers' homes and businesses. Lighting controls can turn off or dim lighting based on room occupancy. Hot water controls could anticipate higher demand periods, reducing temperature setpoints at other times. Further discussion of this smart home technology as it relates to FBC's DSM programs and incentives is provided in Section 2.3.7.

[65] My Energy Use is an enhancement to online account management that provides customers with a better understanding of their home's energy use.

2.3.4 Small-Scale Distributed Generation

Generation technologies continue to evolve, both at the utility-scale level and in terms of smaller scale distributed generation by customers. Technologies such as micro-hydro and solar photovoltaic have made residential-scale generation more feasible, reducing customer demand from the utility, and placing different burdens on the distribution system.

Small-scale distribution-level generation installations continue to be installed by customers driven primarily by the following considerations:

- The perception that distributed generation is "greener" than utility generation.
- The desire to become more energy-independent.
- The perception that they are saving money.[66]

Small-scale distributed generation technologies present some challenges for FBC both from a technical standpoint and in terms of customer equity. These include the following:

- Safety – potential for back-feeding onto the distribution grid must be properly addressed.
- Grid stability – distribution grid must be able to handle unpredictable distributed generation output without causing power quality problems for other customers.
- Equity – the structure of current rates can lead to net metering customers avoiding the cost of being connected to the FBC system – meaning those costs must be recovered through the rates of non-net metered customers.

Despite these challenges, FBC has been supporting customer-owned distributed generation through its Net Metering tariff since 2009. The key features of the program currently are that it is:

- Available to residential, smaller commercial, and irrigation customers;
- Available for installations defined as a clean or renewable resource in the CEA;
- Limited to annual consumption and a capacity of not more than 50 kW;
- Available for installations located on the customer's premises;
- Required to operate in parallel with the Company's distribution facilities, and
- Intended to only offset part or all of the customer's requirements for electricity.

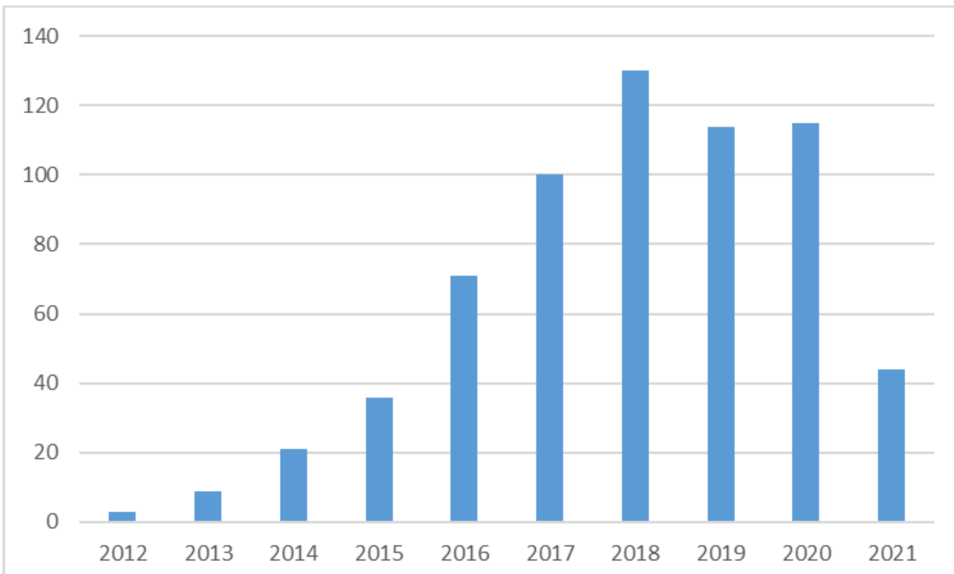
As of mid-June 2021, about 660 customers are enrolled in the Net Metering Program, with the majority generating power using small-scale residential solar photovoltaic installations. The

[66] Based on an 8 kW system in the South Okanagan costing $18,000 (generating 9,481 kWh per year https://pvwatts.nrel.gov/), and valued at the Rate Schedule 3 rate of $0.12383/kWh, the simple payback remains in excess of 15 years.

approximate total capacity of these facilities is about 6 MW; however, the majority of them provide no capacity in peak winter evening demand periods and the capacity contribution in the summer is diminished during peak evening hours as the sun begins to set. The estimated annual energy generation is currently about 6 GWh per year,[67] or less than 0.2 percent of FBC's total annual energy requirement in 2020.[68]

The following figure shows the FBC net metering facilities additions by year (up to mid-June for 2021) since 2012.

Figure 2-9: FBC Net Metering Facilities Additions



Customer participation has been trending upwards from 2012 to 2018 and then additions declined to lower levels in 2019 and 2020. At this point, it is uncertain what the trend for net metering facilities growth going forward will be. FBC's recent customer survey (see Appendix N) shows that 34 percent of residential customers and 49 percent of commercial customers are likely to install rooftop solar panels, with similar percentages for installing battery storage, in the next five years.[69]

In Section 4, FBC explores load scenarios that include various levels of residential rooftop solar penetration, combined with battery storage, to determine potential impacts on the FBC system in terms of annual energy load and peak demand. As a result of the development of the load scenarios, Guidehouse has three recommendations relating to distributed generation energy storage (discussed in Section 4.1.5), which include the following:

67 Assuming systems generate up to 1,150 kWh/year for each 1 kW installed (based on NRCan municipal solar potential data https://open.canada.ca/data/en/dataset/8b434ac7-aedb-4698-90df-ba77424a551f) and that each install is not ideal in terms of solar exposure and angle.

68 6 GWh divided by total annual energy in 2020 of 3,616 GWh (per Table 2.1 of Appendix G) equals 0.17 percent.

69 Long Term Resource Planning Survey provided in Appendix N, page 8.

- Continue to monitor developments in distributed energy storage, including the use of EV batteries as distributed energy resources and consider formalizing an approach to leveraging such resources for system benefit;
- Consider the value of energy storage in relieving localized distribution constraints and, if justified, identify how best to unlock that value through incentives or program intervention; and
- Consider whether revisions to the existing net metering tariff to encourage the adoption of energy storage to support rooftop solar generation may be appropriate.

At this time, FBC is continuing to monitor developments in distributed energy storage and will consider the role of distributed energy resources in optimizing system benefits for customers in its future planning.

Section 6.4.1 discusses, at a high level, potential impacts of higher levels of distributed generation on FBC's distribution system. Section 10.7 discusses FBC's treatment of DG as a load-reducing driver rather than as a supply-side resource option for the purposes of this LTERP.

2.3.5 New Emerging Large Loads

For many years, FBC has generally experienced modest and consistent load growth across large commercial and industrial sectors. However, since 2019, FBC has seen an increase in large load requests due to three emerging industries.

1. After the legalization of cannabis in Canada, many craft producers in the FBC service area are now participating in the legal market. Funding is readily available from investors, so growers have built facilities to increase production. Many producers use greenhouses or warehouses for their crops, which require a substantial amount of electricity.
2. The cannabis industry growth has coincided with the rise in value of cryptocurrency and blockchain technology proliferation. The FBC system offers mostly clean and renewable power, which is attractive for some companies in the blockchain industry. These companies are also part of the new load requests and are some of FBC's largest customers.
3. The prospect of decarbonizing the FEI natural gas system has spurred potential development of green energy projects such as hydrogen and renewable natural gas production. FBC is currently working with customers in these sectors, which could become some of FBC's largest energy consumers in the coming years. Carbon capture and storage may also emerge as technologies that help with the goal of decarbonisation in the future and could provide additional electricity demand within the FBC service area.

The loads associated with these emerging industries could provide a variety of benefits to FBC's existing customers. These large customer loads are typically non-weather dependent and relatively stable throughout the year, which makes them predictable and not peaky in nature. Further, some types of new large customers may be amenable to having their loads curtailed during times when FBC system loads are at their peak, thereby allowing FBC to avoid the incremental peaking resources or system upgrades which would result in higher costs for all customers. As a result, the system infrastructure serving these large load customers and FBC's other customers would be more fully utilized throughout the year. Customers in these sectors would provide high and consistent revenues to FBC which would helps reduce rate pressures for existing customers.

The Reference Case load forecast reflects these new large emerging customer loads, includes loads relating to the requirements from cannabis and blockchain facilities and a renewable natural gas project. Potential loads relating to hydrogen production and carbon capture and storage are included in the load scenarios discussed in Section 4.

FBC has responded to this evolving customer demand by reviewing and revising internal processes to better manage customer interconnections. The following includes several examples of this:

- FBC has modified the transmission interconnection request process, which now has a defined timeline and workflow to facilitate customers' visibility of the process;
- FBC proactively engages with customers in the early phases of potential projects to educate them on power availability and guide them through the service connection process; and
- FBC communicates system constraints to the customers in the conceptual or design phases and works with them to provide innovative solutions such as seasonal load allowances or alternative locations.

As a result of growing demand from these emerging sectors, FBC is at the early stages of a number of further initiatives to allow it to accommodate new loads. FBC is evaluating the connection contribution model to find ways to balance prospective, new, and current customer needs.

One of the recommendations from Guidehouse in the development of the load scenarios (discussed in Section 4.1.5) is that FBC consider what ratepayer benefits could exist in developing (or refining any existing) economic development rates that target such industries conditional on where on the system these customers connect. Potential rate design considerations are discussed further in the following Section 2.3.6.

FBC will continue to work with new customers in order to attract new loads and more fully optimize its system, providing benefits to all customers.

2.3.6 Rate Design Considerations

FBC's practice with regard to the design of rates is to allocate costs to customer rate classes on the basis of cost-causation and not simply with regard to the end use of the power. That is, rates are typically designed such that the revenues collected from a rate class will recover the costs that have been allocated to it, within a range of reasonableness, and not to promote or discourage a particular end-use in the absence of a legislative or policy-driven consideration.

Should an emerging use, such as EVs for example, be shown to have a unique usage profile that impacts costs, the Company may need to consider rate options that reflect such new or changing electricity use by its customers. By designing and pricing rates on a cost basis, any benefits or incremental costs that result from the widespread adoption of new technologies will predominantly accrue to those customers that choose to participate without unduly impacting the rates of other customers.

As discussed in Section 2.3.5, new large baseload customers may offer rate mitigation by leveraging existing infrastructure and raising the system load factor to the benefit of all customers. FBC is monitoring developments in other jurisdictions and evaluating new rate structures, such as an interruptible rate, that would allow FBC to attract and connect these large baseload customers. Initially, offering interruptible service would enable FBC to connect customers in situations where there may not otherwise be the capacity available under normal system planning standards. FBC would be able, for example, to interrupt such customers in order to maintain system integrity during a contingency event. Over the longer term, such a rate may also be used to allow load curtailment when FBC system loads are at their peak, thereby enabling FBC to avoid incremental peaking resources or system upgrades, further mitigating costs and rate increases for all customers.

In the near term, FBC will monitor emerging market trends and consider new or amended rate structures as part of a future rate design process.

2.3.7 Demand-Side Management Trends

Advances in technology and new behaviour research and marketing approaches are impacting DSM strategies and practices. The following outlines some of these developments and how they may impact DSM program delivery over the next several years. FBC will continue to monitor these trends and may implement future change to address the changing market if warranted.

2.3.7.1 Climate Change and Regulatory Requirements

With increasing federal, provincial and local government interest and development of new regulatory frameworks to reduce GHG emissions, FBC anticipates that there may be a greater requirement for DSM programming.

With increasing BC building code baselines and the anticipated adoption of "stretch" building codes to improve the energy performance of new homes in BC, it will become more challenging to achieve energy savings within DSM programs. Increased customer communications, more creative program planning and higher rebate values may be needed to drive greater participation and to move market transformation.

2.3.7.2 Rising Price of Electricity

The Company anticipates that electricity prices will continue to rise over the next decade. Although electricity prices are considered fairly inelastic amongst middle and upper-income households, these rate conditions should help drive DSM participation. FBC's New Home Program has seen a surge in Step Code participation indicating builders are receptive to corresponding program offers. Previous research shows a tendency for homeowners to value energy efficiency in their homes, particularly when purchasing a new home.[70]

Although the rising price of electricity and a general interest in energy efficiency in homes are signals that more customers will invest in energy efficiency measures in the future, low-income households, with limited access to capital, may experience an increased "energy burden". DSM programs may have to focus more resources on this customer segment.

2.3.7.3 Advanced analytics

Customer engagement tools (CETs) provide customers with deeper insights into their energy use and are changing the way DSM programs are marketed to customers. With the ability to operate across digital channels, CETs are improving customer experience and driving greater DSM program participation. For example, CETs can provide:

- The Company's MEU program recently began issuing Home Energy Reports, to randomized cohorts of customers, which gives recipients a personalized view of their energy use and customized tips and relevant program offers.
- Advanced web portals, such as MEU, provide self-guided home energy audits to provide a way for customers to better understand and take control of their energy use.
- Gamification (e.g. energy saving competition with neighbours or other social groupings) to create interest in energy efficiency topics and to drive customers online and to improve DSM program participation.
- Measurement and verification (M&V) of individual customer savings and a roll-up of program energy savings. CET programs designed with control groups provide baseline usage against which to measure verifiable energy savings.
- Integrated DSM by combining different elements — energy efficiency assessment (reports), program offers (conservation, demand response), savings confirmation (M&V) etc. — resulting in a series of customer interactions.
- Cost-effective and personalized marketing efforts to grow DSM program participation. This can be accomplished through improved:

[70] Survey indicates 4 of 10 of the preferred new home features are energy-efficiency related. CHBA, *Home Owner Preference Survey*, 2016, retrieved from: http://ottawacitizen.com/life/homes/survey-says-chba-looks-at-what-buyers-want-in-new-homes.

- Customer segmentation;
- Two-way and personalized communication, and
- Social media – sharing.

2.3.7.4 Becoming part of the utility's customer engagement strategy

Increasingly, DSM is being used to build long-term relationships with customers. Whether through participation in rebate programs or the use of CETs, customers report higher levels of satisfaction when the utility helps them better understand how they use and can manage their energy use. Other elements of CETs, like gamification, market segmentation and two-way and personalized messaging, and the use of social media help build a sense of community.

2.3.7.5 Connecting homes and businesses to energy services they need

A limited number of utilities are starting to enter the marketplace and selling energy efficiency products like LED lamps, low-flow showerheads and smart thermostats.[71] In addition to on-line stores, utilities are providing information and/or promotion about trade allies' businesses and forwarding offers from third parties. They are also making appliance and equipment comparisons and giving recommendations. Utilities that provide these services are perceived, by customers, to be the energy efficiency authorities and are helping to meet customer demand.

FBC's DSM residential programs include incentives for qualified smart thermostats, connected heat pump water heaters, and lighting controls. A pilot is currently underway with Wi-Fi enabled hot water tank controls. Non-commercial customers often have a building automation system to manage their heating, cooling and lighting schedules. These can be connected to the building metering to manage or optimize the building load.

With increased customer interest and the provincial mandate regarding EV sales, the Company needs to find ways to manage and mitigate the anticipated peak load impacts on the system. FBC is undertaking a residential DR pilot that includes load shifting of key end-uses including participants' EV chargers. Additionally the Company will continue to monitor other opportunities for EV programs.[72]

It is expected that by promoting efficiency offers beyond traditional types of programs, utilities will enable customers to reduce energy demand while providing innovative, personalized experiences.

2.3.8 Summary

The customer demand environment continues to evolve as existing customers change the way they use, monitor and generate their own electricity and new large load customers emerge.

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[71] For example, Central Hudson launched its CenHub on-line store in early 2016: www.cenhubstore.com.
[72] Dr. Mladen Kezunovic, Electric Vehicles Could Offer More Gain than Drain, as referenced at http://www.electricenergyonline.com/show_article.php?mag=88&article=741.

This presents both challenges and opportunities for FBC in meeting the future needs of its customers.

FBC expects consumer uptake of EVs to increase in the future as vehicle manufacturers continue to introduce EVs with more range and priced at a level that targets mass market adoption. FBC is preparing to meet the changing and future needs of customers as they relate to EVs and expects continued involvement in supporting transportation electrification to help meet provincial GHG emission reduction targets. FBC intends to pursue a software-based approach to help shift EV charging from peak demand periods and is planning to implement a pilot program beginning in 2021 to help determine how much shifting of EV charging from peak periods it might be able to achieve. If successful, FBC anticipates implementing a program in the near term.

Distributed generation technologies, such as rooftop solar PV combined with home battery storage, will also change customer demand and place different burdens on the distribution system. FBC continues to support customer-owned distributed generation through its Net Metering tariff. While customers may install their own distributed generation in order to save money or gain energy independence, small-scale distributed generation technologies present some challenges for FBC related to safety, grid stability and cost recovery through rates. FBC is continuing to monitor developments in distributed generation and will consider the role of distributed energy resources in optimizing system benefits for customers in its future planning.

FBC has seen an increase in recent years in large load requests relating to cannabis production, blockchain technology and decarbonization through hydrogen and RNG production. These emerging large loads can provide benefits of better system utilization, reduction in upward pressure on customer rates and economic development in FBC communities. FBC has responded to this evolving customer demand by reviewing and revising internal processes to better manage customer interconnections and is evaluating new rate structures that allow FBC to attract and connect these large baseload customers.

DSM also continues to evolve and remains important in meeting customer demand. Climate change and related regulatory requirements, the rising price of electricity, advanced analytics and engagement tools will enable and drive customers to reduce energy and peak demand while providing innovative, personalized experiences.

2.4 *MARKET SUPPLY ENVIRONMENT*

An important part of FBC's long-term resource planning is monitoring developments in the regional power marketplace. Market purchases can account for a portion of FBC's resource portfolio and FBC needs to understand any potential changes that may impact market pricing and supply availability. FBC stays apprised of market developments through subscription to third-party market reports, research and review of regional planning documents, such as the Northwest Power and Conservation Council (NPCC) power plans, attending conferences and forums focused on relevant market topics, and monitoring other Pacific Northwest utilities' planning requirements as published in their Integrated Resource Plans (IRPs). FBC also belongs to a number of organizations involved in regional resource planning such as the Northwest Power Pool (NWPP), Northwest Gas Association (NWGA), and the Western Energy Institute (WEI).

The Pacific Northwest region is facing resource adequacy concerns due to recent coal retirements and uncertainty around price and reliability because of intermittent renewable resources and greater interdependency on natural-gas fired power plants. Natural gas continues to be the primary driver of electricity prices in the short-term; however, policy and renewable project developments are expected to change the resource mix in the region and affect this dynamic. FBC currently continues to see an opportunity for accessing the wholesale market for some of its energy needs, but its assessment does not support relying on the wholesale market for capacity purposes.

The key resource drivers to FBC's market price environment are discussed in Sections 2.4.1 and 2.4.2. Developments shaping the regional power marketplace are then discussed in Section 2.4.3, and the opportunities and risk to FBC are discussed in Section 2.4.4. A summary of other regional utilities' latest IRPs is provided in Appendix D.

2.4.1 Regional Gas Market Environment

Natural gas prices continue to remain low relative to historical values prior to the shale gas surge beginning in 2008. Advances in drilling technology and cost reductions for producers have led to an abundance of low-cost shale gas in North America and production is expected to remain near or just below the record high levels reached in 2019. Low gas prices are providing opportunities for increased natural gas use, particularly in power generation, LNG exports, and the transportation sector. Natural gas supply has kept up with this increased demand, keeping prices at low levels.

The Sumas hub is a key location where much of the natural gas is bought and sold in the Pacific Northwest. While no production sources exist near Sumas, it is located on the Canadian/US border where Enbridge Energy's T-South pipeline interconnects with Williams' Northwest Pipeline. The Sumas hub is a key point through which natural gas flows south to serve demand in the I5 corridor. The following figure shows the Pacific Northwest gas infrastructure and capacities.

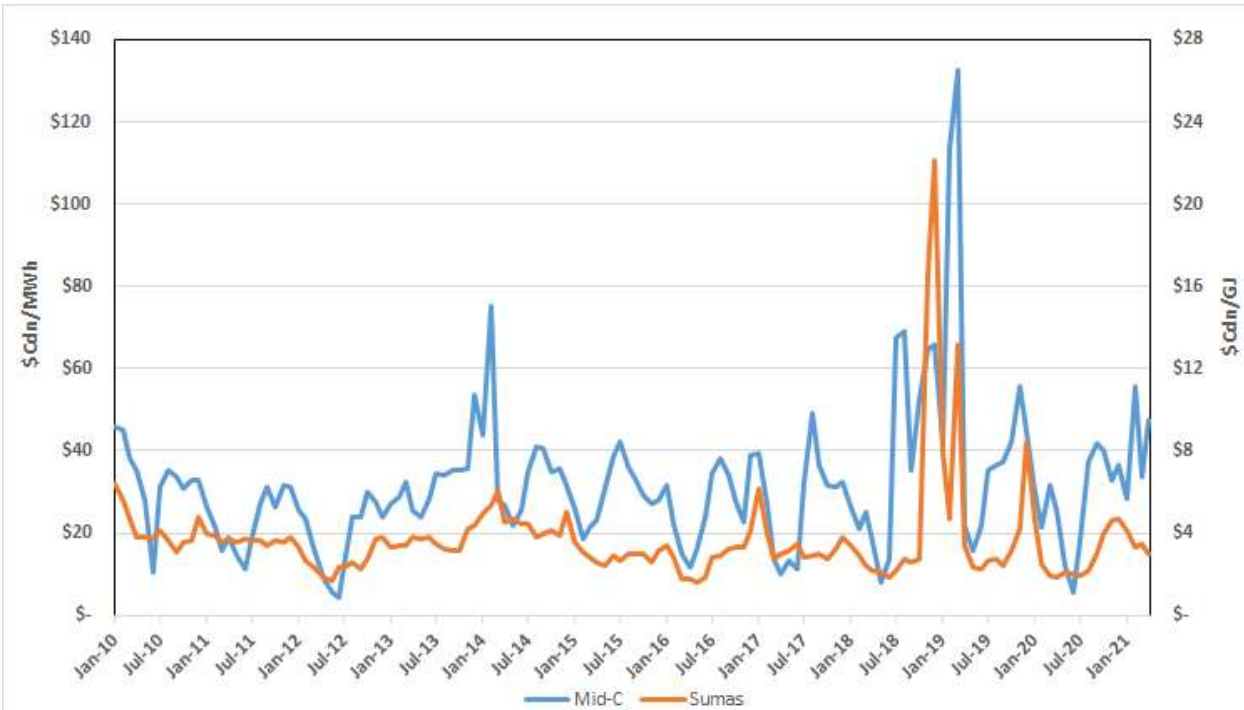
Figure 2-10: Pacific Northwest Natural Gas Infrastructure and Capacities (Million Decatherms/day)[73]

In the Pacific Northwest, regional market electricity prices continue to be correlated with regional natural gas prices. This dynamic is largely because natural-gas fired power plants are most frequently the marginal generating unit for generating electricity, especially during periods of higher demand in the winter and summer that cannot be met with just hydropower, coal and renewable resources. As illustrated in the figure below, price increases at the Sumas hub can follow increases to regional power prices at the Mid-Columbia (Mid-C) market hub, as power

[73] Northwest Gas Association "2020 Pacific Northwest Gas Market Outlook".

prices rise high enough to incentivize natural-gas fired generation to come online. Constraints in the regional pipeline infrastructure can also impact the pricing dynamics.

Figure 2-11: Monthly Mid-C and Sumas Prices



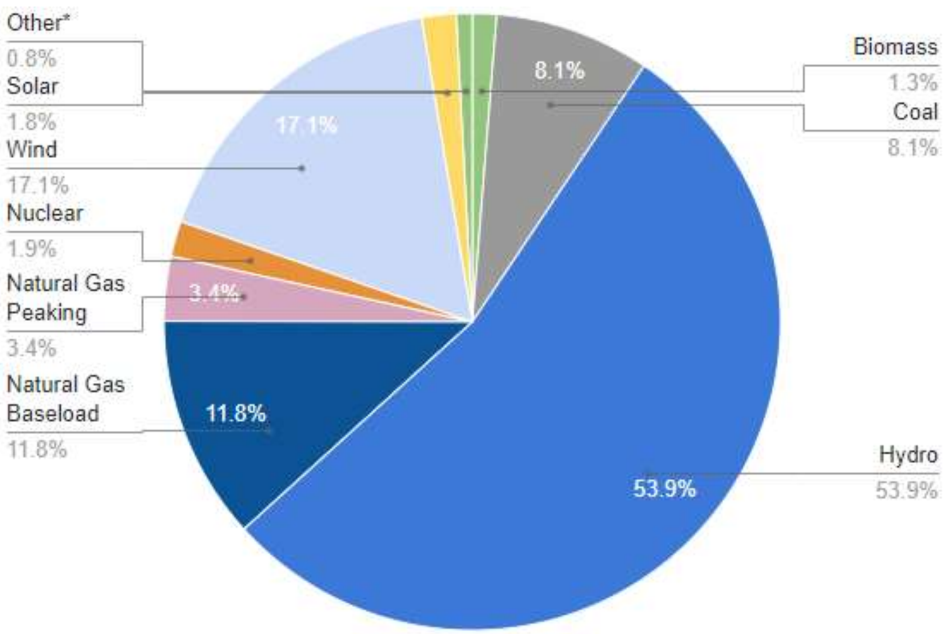
The following section discusses how natural gas and electricity prices are expected to continue to be integrated, and discusses the Pacific Northwest's electricity generation mix.

2.4.2 Pacific Northwest Electricity Generation

As shown in Figure 2-12 below, the Pacific Northwest power system is largely composed of hydroelectric generation which accounts for approximately 54 percent of the region's firm generation capacity.[74] Natural gas-fired generation (shown as Natural Gas Peaking and Natural Gas Baseload in the figure below), provides 15 percent of the region's capacity, and solar and wind together comprise 19 percent of the total. The total generating capability in Figure 2-12 below is 64,340 MW, and the aforementioned resources total 56,544 MW. Coal accounts for about 8 percent of the total or 5,241 MW.

[74] Average hydro generation capacity is based on the five year average of actual hydroelectric generation, as hydroelectric generation can vary depending on the water year.

Figure 2-12: Pacific Northwest Electricity Generating Capacity[75]



In 1983, hydropower made up approximately 78 percent of the region's energy generation capability.[76] Since 2016, the decrease in hydro's share of the generation capacity to about 54 percent has largely been due to the addition of renewable resources, namely solar and wind generation. Although there has been more solar than wind generation resources built in the Pacific Northwest in some recent years, wind still makes up a larger portion of the region's generating capacity. Overall, renewable resources (e.g., hydro, wind, solar, and biomass) represent approximately three-quarters of the region's installed generating capacity.

The Pacific Northwest is a winter peaking region; however, river flows and consequent hydropower generation are highest in late spring when electricity demand is typically at its lowest. During periods when hydropower, coal, and renewable resources cannot meet the region's electricity demand, natural gas-fired power generators are the marginal generating unit that sets prices. Natural gas-fired power plants provide baseload electricity but also peaking capacity, and, as a result, the variable cost of fuel for these power plants exerts a strong influence on the region's wholesale electricity prices.[77] This integration between natural gas and electricity can cause volatile Mid-C capacity prices, and therefore FBC does not support relying on the wholesale market for capacity purposes.

The Western US energy crisis of the early 2000s resulted in an expansion of new gas-fired combined-cycle power plants in order to meet the market's capacity deficit. As a result, the Mid-C power market has generally been in an energy and capacity surplus since the mid-2000s.

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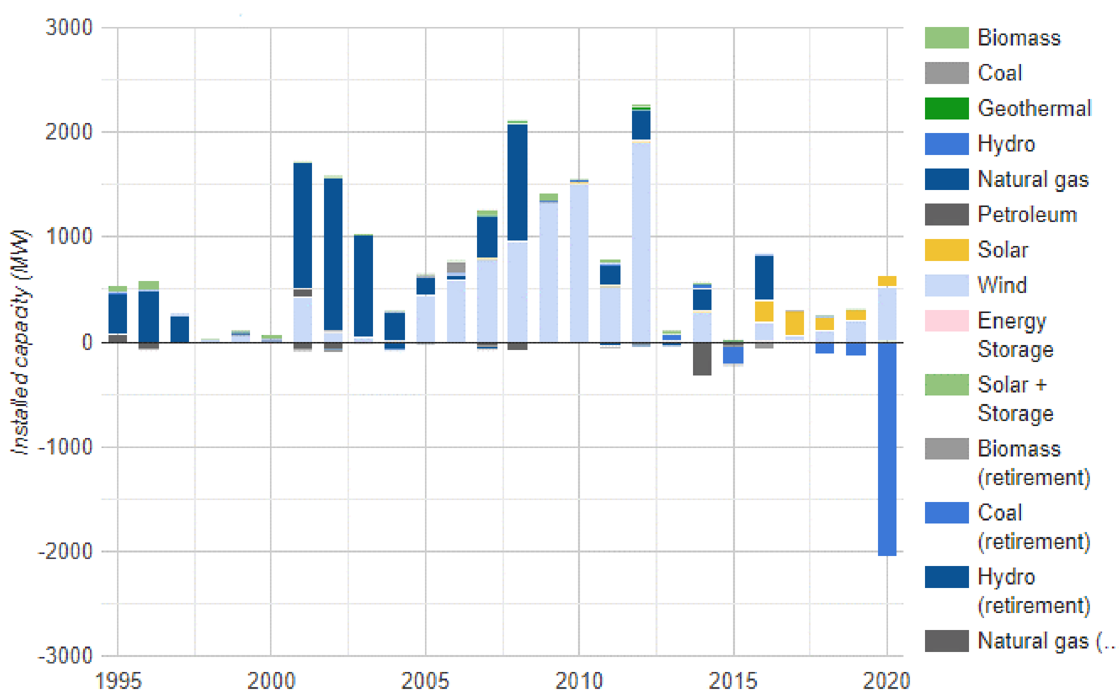
[75] https://www.nwcouncil.org/energy/energy-topics/power-supply.

[76] Northwest Power and Conservation Council Seventh Power Plan, page 9-5. Capability is the maximum amount of energy the plants are capable of producing over an average year.

[77] Northwest Power and Conservation Council Seventh Power Plan Midterm Assessment, page 3-6.

This has provided a cost effective way for utilities in the region to meet their load as it has generally been cheaper to buy energy and capacity in the wholesale market rather than building new generation plants.[78] However, with coal plant retirements since 2018, lower hydro-generation on average, and greater summer demand, the Pacific Northwest is facing a potential shortfall in resources. These recent developments are illustrated in Figure 2-13 below. Consequently, utilities are increasingly looking towards new renewable resources and battery storage to meet their energy and capacity needs as illustrated in the comparison table in Appendix D.

Figure 2-13: Pacific Northwest Generating Capacity Additions and Retirements[79]



Several coal plants in the Pacific Northwest have been retired in the past few years: Talen Energy's Colstrip Units 1 and 2 were retired as of January 2020, Portland General Electric's Boardman plant was retired in October 2020, and Unit 1 at TransAlta's Centralia was retired as of December 2020. Cumulatively, 1,600 MW capacity of coal-fired power generation in the NWPP region has been retired since 2018.[80] As additional coal plants are retired into 2030, the region's coal-fired capacity will drop from nearly 7,000 MW in 2019 to less than 2,500 MW by 2030.[81] Primarily due to these retirements, power supply in the Pacific Northwest potentially becomes inadequate as early as 2021, with large resource gaps to manage until utilities can

[78] Puget Sound Energy 2015 Integrated Resource Plan, page G5-G8, https://pse.com/ABOUTPSE/ENERGYSUPPLY/Pages/Resource-Planning.aspx.
[79] https://www.nwcouncil.org/energy/energy-topics/power-supply.
[80] Northwest Power and Conservation Council Pacific Northwest Power Supply Adequacy Assessment for 2024, page 26.
[81] https://www.pnucc.org/wp-content/uploads/2020-PNUCC-NRF_0.pdf.

build or contract additional generation.[82] The region can replace most of the energy needs from coal retirements with new renewables; however, due to the variable nature of wind and solar, they cannot as easily replace the capacity that is needed for resource adequacy.[83]

Due to the Pacific Northwest's proximity to natural gas producing regions in the WCSB and the US Rocky Mountain region along with low natural gas prices, gas-fired power plants have been a low-cost alternative to coal for power generation. In the current decade, gas-fired generation is expected to replace the capacity shortfall caused by coal retirements and load growth, which further reinforces the interdependency between natural gas and electricity prices in the Pacific Northwest region.

In the latter half of the current decade, renewables could replace a portion of the natural gas share in the region's resource portfolio as new solar and wind resources, along with any batteries and pumped storage projects are built in the Pacific Northwest. There is also the potential for gas-fired plants to operate on other renewable gaseous fuels. The wholesale power market could trend towards renewables as the marginal generating unit that sets prices, but this could create greater price volatility during periods when renewables cannot meet the marginal load and natural gas has to meet peaking net load.[84] Increased renewable generation could result in low priced power in the middle of the day, creating an even greater dependency on natural gas during ramping periods for capacity power prices.[85] Ultimately, market participants and wholesale market dynamics will determine regional prices, and it is impossible to predict at this time how markets will adapt.

2.4.3 Regional Power Developments

FBC is a member of the Western Electricity Coordinating Council (WECC), which is a voluntary organization responsible for coordinating and promoting electric system reliability in the region that includes BC and Alberta, the northern portion of Baja California and all or portions of the 14 western US states in between. WECC's purpose is to support efficient, competitive power markets, to ensure open and non-discriminatory transmission access among members, to provide a forum for resolving transmission access disputes, and to provide an environment for coordinating the operating and planning activities of its members. WECC has been delegated authority from the North American Electric Reliability Corporation (NERC)[86] to monitor and enforce compliance with US reliability standards.

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[82] Resource adequacy is an electric system's ability to meet demand under a broad range of conditions. Inadequate conditions create risks for extraordinary price volatility and unacceptable loss of load probability that could lead to blackouts.

[83] Northwest PowerPool Exploring a Resource Adequacy Program for the Pacific Northwest, page 10.

[84] Northwest Power and Conservation Council 2021 Power Plan Draft Wholesale Electricity Price and Avoided CO2 Emissions Rate Forecast https://www.nwcouncil.org/meeting/council-meeting-august-11-2020.

[85] Northwest Power and Conservation Council March 9, 2021 Meeting – https://www.nwcouncil.org/sites/default/files/2021_03_p1.pdf.

[86] NERC, a nonprofit corporation based in Princeton, NJ, was formed by the electric utility industry to promote the reliability and adequacy of bulk power transmission in the electric utility systems of North America.

The WECC region is dual peaking; the southern part is summer peaking while the northern part is winter peaking. At present, FBC is primarily concerned about the availability and cost of energy and capacity during the winter months, but is monitoring any seasonal changes to the Company's summer load and cost of the wholesale market during the summer. In recent years, FBC's summer peak loads have grown faster than winter peaks, but net demand is forecast by WECC to grow faster on the winter peak hour than the summer peak hour,[87] and it is important that both are monitored for supply reliability.

The following sections discuss provincial and state developments within the broader WECC region.

2.4.3.1 BC Developments

Developments in BC that could impact FBC include expiring Electricity Purchase Agreements (EPAs), large generation projects, and policy initiatives which influence the timing and amount of potential surplus electricity available in the province.

As of February 2020, BC Hydro had a total of 127 electricity purchase agreements with independent power producers. About 70 of these agreements are expiring over the next 20 years, representing approximately 9,100 GWh of firm energy and 1,300 MW of dependable capacity. The expiring agreements are primarily small run-of-river facilities as well as some are larger run-of-river, storage hydro, biomass, municipal solid waste, wind, solar, waste heat, biogas, and gas-fired generation facilities.[88] According to BC Hydro's Draft 2021 Integrated Resource Plan (Draft 2021 IRP), at a system-wide level, before demand-side measures, BC Hydro's new energy needs are not expected to occur until fiscal 2029, while its capacity needs are not expected to occur until fiscal 2032. However, growing demand for electricity on the South Coast of the province means BC Hydro expects to need additional regional capacity resources in fiscal 2027.[89]

BC Hydro indicates that it plans to offer a market-price based renewal option to existing clean or renewable independent power producers with electricity purchase agreements expiring in the next five years. There are approximately 20 existing clean or renewable projects, that produce a total of roughly 900 GWh, with electricity purchase agreements set to expire before April 1, 2026.[90] Depending on how many expiring EPAs are renewed by BC Hydro, there may be opportunities for FBC to acquire power relating to these expiring EPAs on a cost-effective basis in the future.

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87 https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Western%20Assessment%20of%20Resource%20Adequacy%20Report%2012-18%20%28Final%29.pdf.pdf&action=default.

88 BC Hydro Draft 2021 Integrated Resource Plan, Section 5.3, page 19: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/draft-integrated-resource-plan.pdf.

89 Ibid, page 1.

90 Ibid, page 30.

Site C is still under construction by BC Hydro and expected to come online in 2025 and provide approximately 5,100 GWh per year of energy and 1,100 MW of capacity.[91] As well, Revelstoke Unit 6 is currently planned to be constructed in 2029, which would provide an additional 500 MW of capacity.

Since 2015, BC has been a net exporter of electricity, and is well supplied given annual load growth, current and planned generation construction, and projected retirements. However, economy-wide electrification initiatives supported by the CleanBC Plan could increase demand faster to meet GHG emission reduction targets by 2030, which could reduce BC's surplus supply position and increase the energy and capacity requirements for FBC, as contemplated in the load scenarios discussed in Section 4. In its Draft 2021 IRP, BC Hydro notes that the accelerated electrification load scenario would result in a BC Hydro system capacity deficit in fiscal 2028 and a system energy deficit in fiscal 2024, with the South Coast region moving into a capacity deficit starting in fiscal 2026.[92] Additionally, the proposed Bill 17 amendment[93] of the *CEA* in June 2020 would remove the requirement for self-sufficiency in clean power, which could put pressure on expiring EPA agreements competing for wholesale power contracts. However, as discussed in Section 1.4.2, the proposed amendment has not been enacted into legislation.

2.4.3.2 Alberta Developments

Recent utility natural gas conversion projects in Alberta outlined the intent to retire 5,700 MW or most of the remaining coal-fired power plants by 2023, earlier than the province's initial timeframe of 2030. However, the Renewable Electricity Program which intended to add 5,000 MW of renewable generation by 2030 was cancelled in June 2019,[94] and only the 1,360 MW already awarded through the program will continue to be built. Although provincial policy support for renewables no longer exists, utilities and projects are still moving forward as economics become more attractive.

Alberta continues to develop its own electricity generation within the province through planned coal to natural gas conversions and renewable generation. As BC is expected to be a net exporter of electricity into the 2030s, significant surplus electricity could be exported to Alberta if additional transmission were built in the Peace Region upon completion of Site C. If these developments were to occur, the additional exports to Alberta could reduce BC's surplus position. It is uncertain what impact, if any, this would have on Mid-C pricing or FBC's ability to import power from BC or the Pacific Northwest.

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91 https://www.sitecproject.com/about-site-c/project-overview.

92 BC Hydro Draft 2021 Integrated Resource Plan, page 58: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/draft-integrated-resource-plan.pdf.

93 https://www.leg.bc.ca/parliamentary-business/legislation-debates-proceedings/41st-parliament/5th-session/bills/first-reading/gov17-1.

94 https://www.aeso.ca/market/renewable-electricity-program/#:~:text=On%20June%2010%2C%202019%20the,proceed%20with%20additional%20competition%20rounds.

2.4.3.3 Pacific Northwest Developments

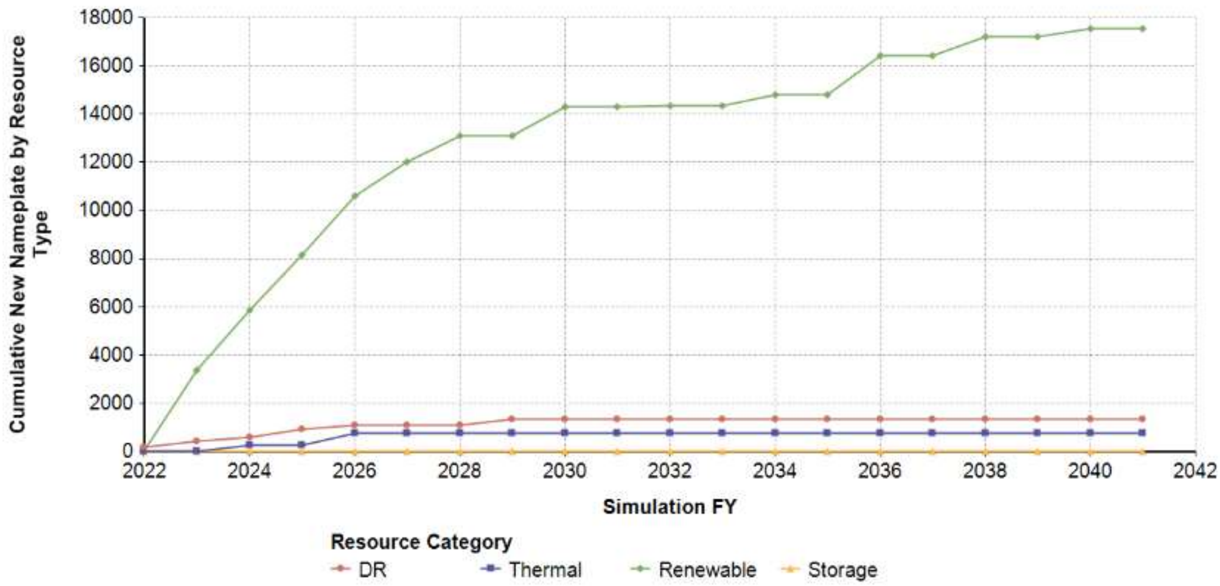
Since 2016, additional retirements of coal generation have been announced in the Pacific Northwest, and there has been a greater than expected cost reduction for wind and solar generation.[95] State renewable portfolio standards, along with the aforementioned generation retirements, cost reductions, utility green tariff energy programs, and utility resource needs have driven additional and earlier renewable resource development.[96]

Although a moderate level of new resources have been developed in the region, and the 1,400 aMW[97] of cost effective DSM from NPCC's Seventh Power Plan is achievable by 2021, the most recent adequacy assessments continue to show an expected deficit of capacity resources from 2021 to 2023.[98] If the Pacific Northwest faces critical water conditions through a low water year, lower than anticipated electricity imports, or greater than anticipated demand growth, the region still faces the probability of a peak capacity shortfall until new resources can be built and resource adequacy programs[99] are developed to prevent this from occurring.

Whether this potential capacity shortage for the region can be met without new natural gas developments remains to be seen, but most Pacific Northwest utilities' recent IRPs (see table in Appendix D) and requests for proposal (RFPs) do not contain any new natural gas in their preferred resource strategies. Additionally, the NPCC's preliminary findings for the 2021 Power Plan contain limitations in the allowable amount of natural gas builds,[100] and other studies have found that additional wind imports from Montana together with long-duration pumped-hydro and/or battery storage are potential alternatives to natural gas as effective sources of firm capacity for the Pacific Northwest.[101] The figure below from the NPCC illustrates the potential resource build-out over the next twenty years. 'DR' in the below figure is Demand Response, and 'Thermal' is natural gas-fired generation.

95 Northwest Power and Conservation Council Seventh Power Plan Midterm Assessment, page 1-1.
96 Northwest Power and Conservation Council Seventh Power Plan Midterm Assessment, page 6-2.
97 One Average MW is equivalent to 8,750 MWh, which is the energy produced by 1 MW if run all hours in the year.
98 Northwest Power and Conservation Council Seventh Power Plan Midterm Assessment, page 7-2.
99 The Northwest Power Pool announced in August 2020 that they hired the Southwest Power Pool as a program developer, and are planning to implement a resource adequacy program through mid-2021 to 2024.
100 Northwest Power and Conservation Council Update on Wholesale Power Price Forecast and Avoided Emissions Rate Study https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-november-30-2020
101 https://www.wecc.org/Administrative/Carr%20-%20WIEB%20Flexibility%20Study.pdf.

Figure 2-14: Pacific Northwest Capacity Resource Requirements[102]



In December 2020, the WECC released a Western Assessment of Resource Adequacy report,[103] which assessed resource adequacy across the entire Western Interconnection for the next 10 years. This report concluded that increasing levels of variable resources will drive resource adequacy issues, and that the NWPP sub-region requires additional resources to remain adequate over the next four years. A NWPP resource adequacy symposium in October 2019 also stated that multiple studies agree that the Pacific Northwest is approaching a period of capacity shortfalls.[104]

2.4.3.4 California Developments

The California Independent System Operator (CAISO) operates a competitive wholesale electricity market for the majority of the state of California,[105] and has undergone significant reform over the prior two decades, including becoming an Independent System Operator (ISO) in 2008 and forming the Energy Imbalance Market (EIM) in 2014. Rolling blackouts in August 2020 highlighted an urgent policy need for resource adequacy amid climate change, and for meeting reliability criteria alongside environmental policy to meet the state's clean energy standards. Decarbonization policies in California will continue to expand renewable generation and limit the development of new thermal resources. These policies must work within the context of sufficiently meeting resource adequacy metrics. Future widescale blackouts or

[102] Northwest Power and Conservation Council – Review of Baseline Conditions Modeling Results https://www.nwcouncil.org/sites/default/files/2021_01_p4.pdf.

[103] https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Western%20Assessment%20of%20Resource%20Adequacy%20Report%2012-18%20%28Final%29.pdf.pdf&action=default.

[104] https://www.nwpp.org/private-media/documents/2019.10.02_Resource_Adequacy_Symposium_ALL_SLIDES.pdf

[105] https://www.ferc.gov/industries-data/market-assessments/electric-power-markets.

similar reliability concerns in California, or the Desert Southwest, will likely impact the Western wholesale electricity market hub prices during extreme weather events.

CAISO plans to expand their EIM to its day-ahead market operations by the end of 2022, on a voluntary basis, which would lay the foundation for the deeper coordination of regional grids. The extended day-ahead market would improve market efficiency by integrating renewable resources using day-ahead unit commitment and scheduling across a larger area.[106]

Additional developments in California that may be beneficial to the Pacific Northwest would be policy changes to enhance the amount of exported solar energy from California. In May 2020,[107] CAISO proposed market rule changes to establish more robust incentives for market participants to deliver their scheduled intertie transactions with other markets, and provide system reliability and price stability. This was accepted in October 2020[108] for implementation in January 2021, and has been considered part of CAISO's broader strategy of more effectively managing imports and exports in California.

Additionally, a study[109] was undertaken by CAISO in 2019 that analyzed the potential to increase capabilities for transfers of carbon-free electricity between the Pacific Northwest and California through increasing the rated capacity of the Pacific AC and DC Interties.[110] Increasing the interties' capacity would allow greater coordination in resource shaping for daytime renewable generation in California and flexible hydro-generation in the Pacific Northwest, which could further benefit the utilization of power between the two regions.

2.4.4 Regional Market Opportunities and Risks

FBC currently relies on its own generation resources and long-term contracts to meet the majority of its power supply requirements – both energy and capacity. The Company also accesses the wholesale electricity market on an operational basis to meet power supply gaps. This is done primarily for energy needs but also for short-term capacity needs as required or when it is economical to do so. FBC's strategy of purchasing from the market to address the gap between its supply and demand has been successful historically. However, as discussed in the subsections above, the Pacific Northwest region's increased interdependency with natural gas markets can cause volatile Mid-C capacity prices. The region is also facing resource adequacy concerns, primarily around firm capacity generation shortfalls. As such, it is FBC's view that there is too much uncertainty to rely on the wholesale market for capacity purposes.

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106 https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

107 California ISO – Tariff Amendment to Enhance Intertie Transaction Market Rules http://www.caiso.com/Documents/May22-2020-TariffAmendmentIntertie-Deviation-Settlement-ER20-1890.pdf

108 http://www.caiso.com/Documents/Sep29-2020-ComplianceFiling-IntertieDeviationSettlement-ER20-1890.pdf.

109 http://www.caiso.com/Documents/AppendixH-Draft2018-2019TransmissionPlan.pdf.

110 The AC and DC Interties are collectively the Pacific Northwest/Pacific Southwest high-voltage transmission lines that allows the Columbia River region to deliver electricity to California. https://www.nwcouncil.org/reports/columbia-river-history/intertie.

2.4.4.1 Market Capacity

As other Pacific Northwest utilities have identified, relying too heavily on wholesale markets to purchase capacity, especially during peak periods, could significantly increase price and reliability risk.[111] Additionally, if the potential capacity shortage in the Pacific Northwest becomes more pressing and is not addressed early enough such that capacity remains adequate, peak demand periods will have greater risk for volatile power prices and grid reliability through loss of load or blackouts. As additional renewables are built in the region, greater price volatility could occur during evening periods when renewables cannot meet the marginal load, and natural gas has to ramp to meet peaking net load.

With recent coal plant retirements and the variability of renewable energy, reliance on natural gas-fired generation is expected to increase during peak demand periods in the WECC region. This could lead to higher volatility in natural gas prices and in turn increased wholesale power prices if multiple regions within the WECC experience increased demand at the same time, as occurred during the rolling blackouts in California in August 2020 and the Polar Vortex in February 2021. Following these events, there have been higher wholesale market forward prices, primarily for Q3 2021 capacity power prices. These higher prices demonstrate ‘scarcity pricing’ and potential supply shortages, as utilities and wholesale buyers are concerned about the inability to meet load during peak demand periods, which could lead to loss of load or blackouts. A market facing adequacy concerns and volatile market prices should not be relied upon to meet expected load.

Therefore, FBC plans to ensure it has sufficient capacity resources available in place to meet forecast peak demand. The month of June is an exception due to the abundant freshet hydropower available in the market. For the purposes of this LTERP, FBC assumes that it will be able to purchase a limited amount of June capacity from the market, on a forward block basis as opposed to in ‘real time’, reliably and cost-effectively until 2030. After that time, FBC has assumed capacity self-sufficiency for all months, including June, given the longer-term market risks.

2.4.4.2 Market Energy

Currently, FBC plans to meet its incremental load requirements through the BC Hydro Power Purchase Agreement (PPA) or firm energy fixed price market blocks if they are economic compared to the PPA. Under the PPA, FBC is required to purchase a minimum of 75 percent of the nominated energy, and therefore can choose to draw upon a large wholesale electricity market to purchase market energy and displace PPA purchases if it is economic.

Market energy access is expected to remain adequate through the short-term, particularly if the CEPSA agreement with Powerex remains in place. Energy is available in the market from various utilities and independent power producers that have surplus power available for sale. These surpluses are typically the result of either other utilities’ own loads not being as high as forecast or their supplies of electricity being higher than forecast, such as may be the case

[111] NorthWestern Energy – 2019 Electricity Supply Resource Procurement Plan.

during a wet or windy period. These large amounts of clean or renewable energy tend to be highly variable in energy output with the result that, at certain times, energy can be purchased at very attractive prices by a market buyer such as FBC. Alternatively, energy may be procured from independent asset owners such as self-generators that have under-utilized capacity and available fuel. Along with any wholesale market opportunities, FBC also has to consider the cost and risk of rate increases from the PPA, which is discussed further in Section 5.5.

Surplus power is typically available in BC and the Pacific Northwest from hydroelectric plants during the spring freshet in years of above-average precipitation. Some utilities, BC Hydro being the most prominent, can store energy in their hydroelectric reservoirs and are usually able to provide power to the market at any time for the right price. The market price of energy and capacity is directly related to the amount and timing of this surplus power, the (fuel) input costs, the availability of fuel to generate the surplus power (for example, water stored in a reservoir), and the cost of transmission between the buyer and seller.

Relying on the wholesale market for energy purposes does introduce some risk to the Company. In the latter half of the century, BC and the Pacific Northwest could face seasonal or annual water shortages, which could disrupt hydroelectricity production.[112] Additionally, if snowpack levels decline further across the West due to climate change, or drought persists throughout the year, this could reduce the amount of surplus power availability during spring freshet and add upwards pressure into summer market prices in a low water year. As discussed in Section 2.2.1, climate change impacts could also result in wetter winters and earlier spring freshets, which could change the availability and timing of surplus power through hydroelectric generation.

The Company mitigates risk to wholesale market energy prices by relying on firm forward fixed price market energy blocks, rather than leaving forecast load requirements to the day-ahead or real-time markets. If the Pacific Northwest region continues to experience drought conditions and affects from climate change this could reduce the amount of surplus energy available in the market. Furthermore, as the US region continues to build renewable resources to meet state-mandated clean energy policies, adequate transmission will also be required to alleviate system constraints and serve load centres in the west.

2.4.4.3 Market Access

Market shortages and transmission constraints can limit the physical availability of power in the wholesale electricity market. This can impact the price of power as well as the duration, terms and conditions of any purchases. Market shortages occur when supply is inadequate to meet load and mandatory operating reserves. This can be caused by a number of factors, including extreme or extended hot or cold weather conditions, regional drought conditions, generating unit or transmission outages, and structural changes in load growth.

[112] https://www2.gov.bc.ca/gov/content/environment/climate-change/adaptation/risk-assessment.

Finally, another key consideration for FBC is the transmission transfer limit and market access availability at the three interconnections on the BC/US border.[113] These transmission interconnections often operate at their maximum available transfer limits, and therefore wheeling additional power across the border into BC is frequently impossible. FBC has no transmission facilities that connect directly with markets outside of BC, and is dependent on the availability of third-party transmission capacity to serve its customers' needs, putting at risk the long-term reliable availability of wholesale market electricity to serve its growing demand. However, for the purposes of the LTERP, FBC is assuming continued transmission access to the wholesale market through Teck's 71L and the CEPSA agreement with Powerex.

2.4.5 Summary

The Pacific Northwest region is facing an upcoming period of resource adequacy concerns and price and reliability uncertainty. Natural gas fired-generation, increased renewable generation projects, and regional provincial and state developments are expected to change the regions resource dynamics. The regional power marketplace has recently been in an energy and capacity surplus due to hydropower and gas-fired combined-cycle power generation, however due to coal plant retirements, lower hydro-generation, and greater summer demand, the Pacific Northwest is facing a potential shortfall in resources. Capacity shortfalls could result in greater price volatility in the wholesale market, greater independency between natural gas and electricity markets, and there is too much uncertainty and reliability risk for the Company to rely on the wholesale market for capacity purposes.

The majority of FBC's energy and capacity power supply requirements are met through the Company's own generation resources and long-term contracts, and FBC can choose to access the wholesale markets for energy requirements to displace higher cost purchases. Market energy access for the Company is expected to continue through transmission and power purchase agreements, and market energy can be available at attractive prices to FBC during periods of surplus power. Increased renewable penetration across the region may increase the surplus energy available through wind and solar resources, however, declining snowpack levels, persistent drought, and seasonal water shortages due to climate change could decrease the surplus hydropower available during spring freshet and summer periods. FBC will continue to monitor the price and availability of wholesale market energy, as well as any regional developments that would affect the Company's ability to purchase from the wholesale market.

2.5 *PRICE FORECASTS AND RATE SCENARIOS*

This section examines the key forecast cost inputs required for the evaluation of resource options in the portfolio analysis discussed in Section 11 of this LTERP. These include the long-term price forecasts for natural gas and electricity based on the discussions in Section 2.4 regarding the changing market supply environment, and for renewable natural gas (RNG). Also included are carbon pricing scenarios, based on the discussion in Section 2.2 regarding

[113] Including the one merchant transmission line, owned by Teck Resources Limited at Trail, BC.

environmental policy in BC and Canada, and PPA rate scenarios based on potential rate increases for BC Hydro customers. The natural gas and RNG price forecasts are used as inputs to estimate the costs for gas-fired generation while the electricity price forecast is used to provide a cost for market purchases. The carbon price scenarios are also inputs into the cost of gas-fired generation. The PPA rate scenarios provide potential future costs of the PPA over the planning horizon beyond what has already been targeted by BC Hydro for rates until March 2024 (BC Hydro year F2024) and based on BC Hydro's long run marginal cost (LRMC). Assumptions regarding exchange and inflation rates and other adders are also included in this section.

As in any long-term market price forecast or rate scenario, certain assumptions about supply and demand factors have been made based on current information. As these factors constantly change over time, it is not likely that these price forecasts and rate scenarios will be accurate over the long run. They are merely an indication, based on current information, of where prices and rates could be in the future. Because of this uncertainty, the market price forecasts and rate scenarios include high and low ranges to cover a wide range of potential circumstances that could occur over the planning horizon. In the case of the market price forecasts, FBC does not develop its own market price forecasts but rather relies on market price forecasts produced by others in the energy industry. FBC also provides forecasts from different sources for comparison purposes. FBC has incorporated these price and rate uncertainties within its portfolio analysis (discussed in Section 11) by assessing the impacts of the different levels of prices and rates on specific portfolios.

With the increase in renewable energy resources in the region, FEI developed an RNG price forecast for the purposes of this LTERP. It is used as an input for renewable natural gas as a fuel source for gas-fired generation.

For the carbon price scenarios, FBC has made assumptions based on the current price of carbon in BC and the Canadian federal government announcement in December 2020 regarding the federal government's proposal to increase carbon pricing to reach $170 per tonne by 2030.

With regard to the PPA rate scenarios, FBC has made assumptions in terms of future rate increases based on recent historical rate increases for BC Hydro customers and expectations discussed in BC Hydro's F2022 Revenue Rate Application[114] as well as BC Hydro's proxy for the LRMC for energy.

All forecasts and rate scenarios in the LTERP are in 2020 real Canadian dollar terms. In most cases, FBC has presented a low, base and high case to provide a range of possible prices and rates. The market, RNG and carbon price forecasts, and PPA rate scenarios were presented to the RPAG stakeholders and discussed in the November 25, 2020 workshop.

[114] https://www.bcuc.com/Documents/Proceedings/2020/DOC_60299_B-2-BCH-F22-RRA-Application.pdf.

This section includes the price forecasts and rate scenarios on an annual basis. Appendix E provides the price forecasts and rate scenarios data on a monthly basis.

2.5.1 Natural Gas Market Price Forecasts

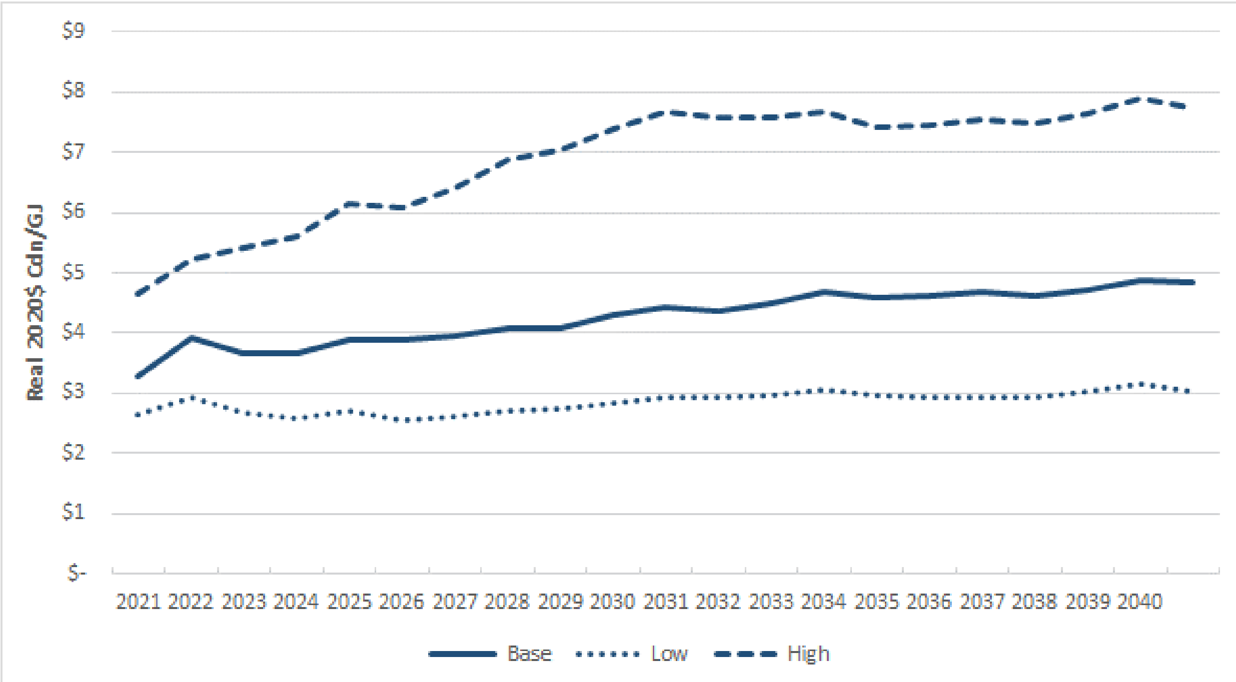
The natural gas market price forecasts are based on an average of the market price forecasts provided within the Northwest Power and Conservation Council (NPCC) 2021 Eighth Power Plan (2021 Power Plan) and the long-term North American Gas Market Outlook from IHS Markit (IHS), released in February 2021.

Every five years, the NPCC develops and updates a Power Plan to ensure reliable power supply adequacy for the region (including Washington, Oregon, Montana and Idaho) and acquire cost-effective energy efficiency and resources. The process relies on broad public participation to inform the plan and build consensus on its recommendations. The NPCC forecasts regional demand for electricity, as well as wholesale market prices for natural gas and electricity in developing its Power Plan. The forecasts are also used by utilities, regulatory agencies, state energy policy offices, and other organizations in their planning.

IHS is a third-party market subscription service used by FEI and FBC. IHS provides market analysis and data as part of the subscription service. In particular, on a semi-annual basis, IHS produces a long-term market outlook that includes thirty-year market gas and power price forecasts.

Both the 2021 Power Plan and the long-term market outlook from IHS include a market price forecast based on the Sumas market price hub, located on the BC-Washington border. The Sumas market hub is one of the main natural gas market trading hubs in the Pacific Northwest and is the transfer point for northern BC gas flowing south across the border. The average of these two price forecasts is used as the price forecast for the 2021 LTERP and is presented in real Canadian dollars per gigajoule (GJ) in the following figure. This annual average does not show the variability in prices that could occur on a daily, weekly and monthly basis during each year.

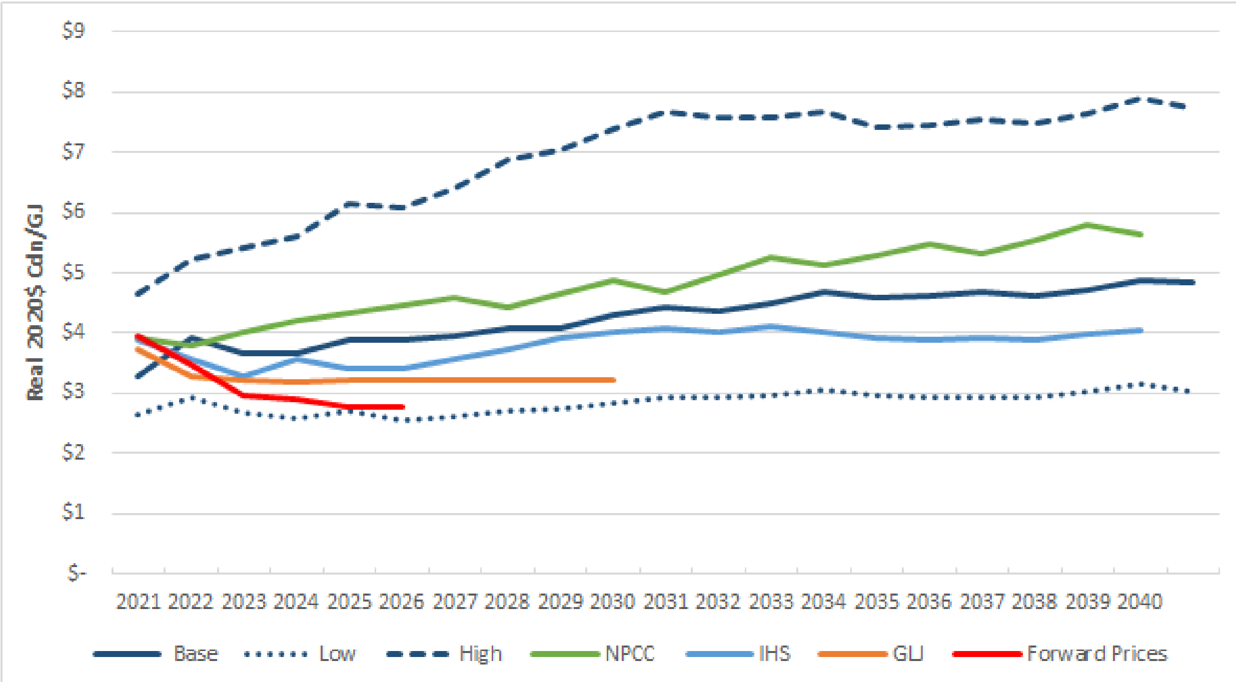
Figure 2-15: Sumas Natural Gas Annual Price Forecast



The base case is based on current expectations for natural gas prices, with prices increasing most years as demand increases due to LNG exports from BC and coal plant retirements in the PNW. The high and low price forecasts provide reasonable extremes of possible future prices. The high case assumes rapid world economic growth, increasing the demand for natural gas supplies. The low case assumes slow economic growth with reduced demand for natural gas in favour of lower-carbon renewable energy sources.

Also, FBC examined the GLJ Petroleum Consultants (GLJ) (April 1, 2021 forecast) price forecast and forward market prices to see how they compare to the base case and high and low price forecasts. The figure below includes the base case, high and low price forecasts, as well as the NPCC, IHS, GLJ and the forward market prices as of June 17, 2021. In general, the GLJ price forecast and the forward market prices are lower than the base case forecast but higher than the low price forecast. Both the GLJ price forecast and forward market prices do not extend out for the full twenty-year period.

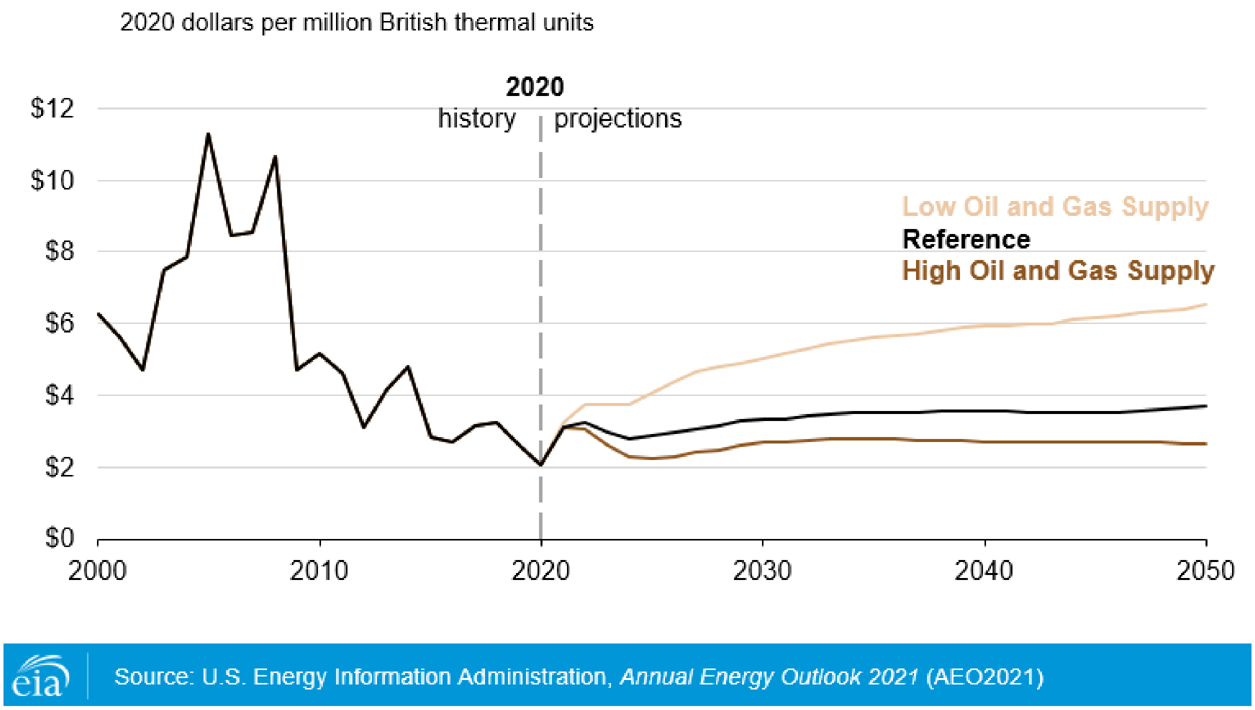
Figure 2-16: Comparison of Sumas Price Forecasts and Forward Prices



FBC also reviewed the US Energy Information Administration (EIA) Henry Hub market price forecast, which includes Low Oil and Gas Supply and High Oil and Gas Supply scenarios for future market prices, as provided in their 2021 Annual Energy Outlook (AEO) data.[115] As the EIA does not produce a long-term price forecast for Sumas, FBC has instead provided the Henry Hub reference price forecast and scenarios for comparison purposes (which are presented in real 2020 US dollars per million British thermal unit (Btu)). In general, on average over the next 20 years, the Sumas annual average basis to Henry Hub, as forecast by IHS, is close to zero; i.e. Sumas prices will be similar to Henry Hub prices over the long term.

[115] EIA Annual Energy Outlook 2021 Narrative, February 3, 2021, slide 3, https://www.eia.gov/outlooks/aeo/pdf/03%20AEO2021%20Natural%20gas.pdf.

Figure 2-17: EIA Henry Hub Price Forecasts[116]



The Sumas base gas price forecasts, on average, are slightly higher than the EIA's Henry Hub price forecast cases, on an equivalent Canadian dollar per GJ basis.

2.5.2 Electricity Market Price Forecasts

The Mid-C market price forecast is the result of averaging the Mid-C price forecasts from the 2021 Power Plan and the long-term North American Power Market Outlook from IHS, released in December 2020.[117] Mid-C is the primary market electricity trading hub for the Pacific Northwest. In past years, the Mid-C electricity market price forecast was largely based on the Sumas natural gas price forecast because natural gas-fired plants are often the marginal generating resource in the region to meet load requirements. During periods when hydro and renewable resources cannot meet the region's electricity demand, natural gas-fired power generators often remain the marginal generating resource that sets prices. However, the growth of renewable energy has caused some electricity market price forecasts to be less connected with natural gas pricing on an annual basis in the long-term. The high and low cases for the forecast electricity prices assume lower renewable energy resources and higher gas prices for the high case and higher renewable energy resources and lower gas prices for the low case. The Mid-C market annual price forecasts in real Canadian dollars per megawatt-hour (MWh) are presented in the following figure.

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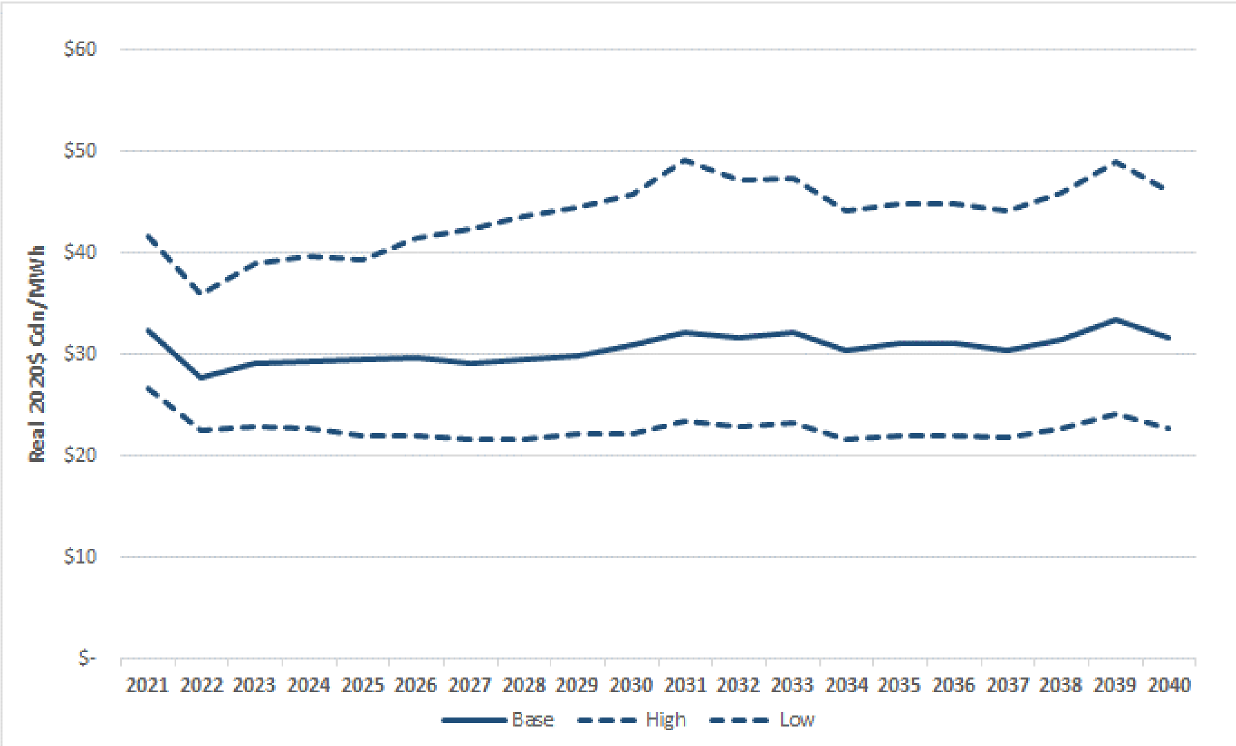
[116] EIA Annual Energy Outlook 2021, February 3, 2021, slide 2, https://www.eia.gov/outlooks/aeo/pdf/03%20AEO2021%20Natural%20gas.pdf.

[117] NPCC 2021 Power Plan, https://www.nwcouncil.org/2021-northwest-power-plan. IHS Markit's price forecast is not public as it is part of a subscription service.

Figure 2-18: Mid-C Electricity Annual Price Forecasts



2.5.3 Renewable Natural Gas Price Forecasts

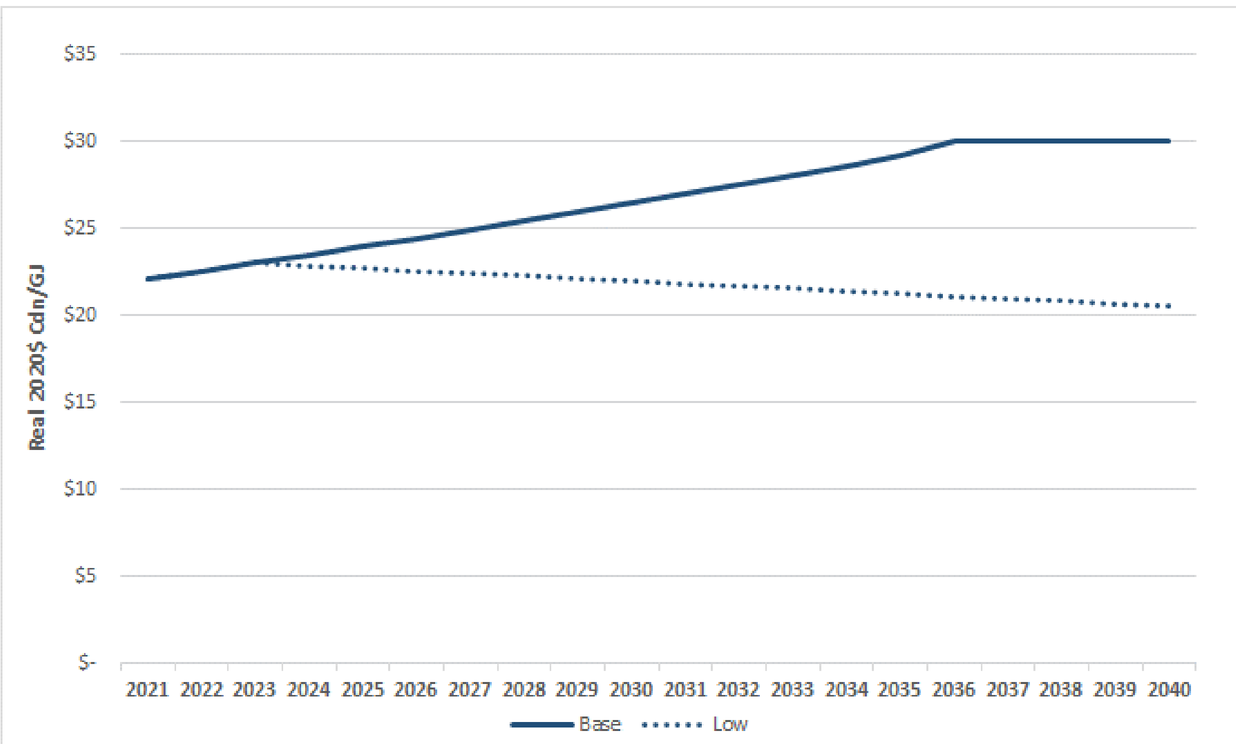
FEI developed an RNG price forecast for the purposes of this LTERP. It is used as an input for RNG as a fuel source for gas-fired generation. The base case, as shown below, is based on the cost of the weighted average of known FEI RNG supply contracts as of 2020 plus an inflation rate of 2 percent annually for each forecasted year. The maximum price for the base case does not exceed $30 per GJ, consistent with the maximum price in the Greenhouse Gas Reduction Regulation (GGRR) for public utility RNG purchases and production up to March 31, 2021.[118] The GGRR was amended on May 25, 2021 by Order in Council No. 306, such that the maximum price for RNG increases to $31 per GJ for purchase agreements signed after March 31, 2021 or, where FEI is producing the RNG, where FEI decides to undertake the production facility by this time. The maximum price increases for each subsequent fiscal year. The GGRR amendment also includes the option for FEI to acquire other forms of renewable gas such as green hydrogen. FBC has not incorporated this GGRR amendment dated May 25, 2021 into its RNG price forecast due to the timing of the amendment being too close to the filing of this LTERP to enable FBC to update the RNG price forecast and recalculate the portfolio analysis. Regardless, FBC would not expect the amendment to have a material impact on the RNG price forecast and portfolio analysis results.

[118] https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/102_2012.

FBC's low RNG price case is the same as the base case until 2023, as the bulk of supply with the signed contracts are already in place until 2023. The low case forecast assumes supply will increase due to economies of scale with advancements made in technology; as such, the low case has prices dropping by 15 cents per GJ annually to reach close to $20 per GJ by the end of the forecasted period.

FBC notes that both price forecasts do not include the potential of other forms of renewable gases, such as green hydrogen, which may be acquired at different prices than RNG. These other forms of renewable gases could potentially be acquired at lower prices, which would have the effect of lowering the future RNG total portfolio cost. As FBC is filing this LTERP at a time so close to the new GGRR amendment, the future impact of these different forms of renewable gas has not been modelled for this LTERP. The forecast, therefore, relies upon the current range of expected RNG costs of between about $20 to $30 per GJ over the planning horizon. The RNG annual price forecast in real Canadian dollars per GJ is presented in the following figure.

Figure 2-19: Renewable Natural Gas Price Forecasts



2.5.4 BC Carbon Price Scenarios

The BC carbon tax was introduced in 2008 at a level of $10 per tonne and currently is set at $45 per tonne effective April 1, 2021. The BC government plans to increase the carbon tax by $5 per tonne effective April 1, 2022 but nothing further has been announced at this time.

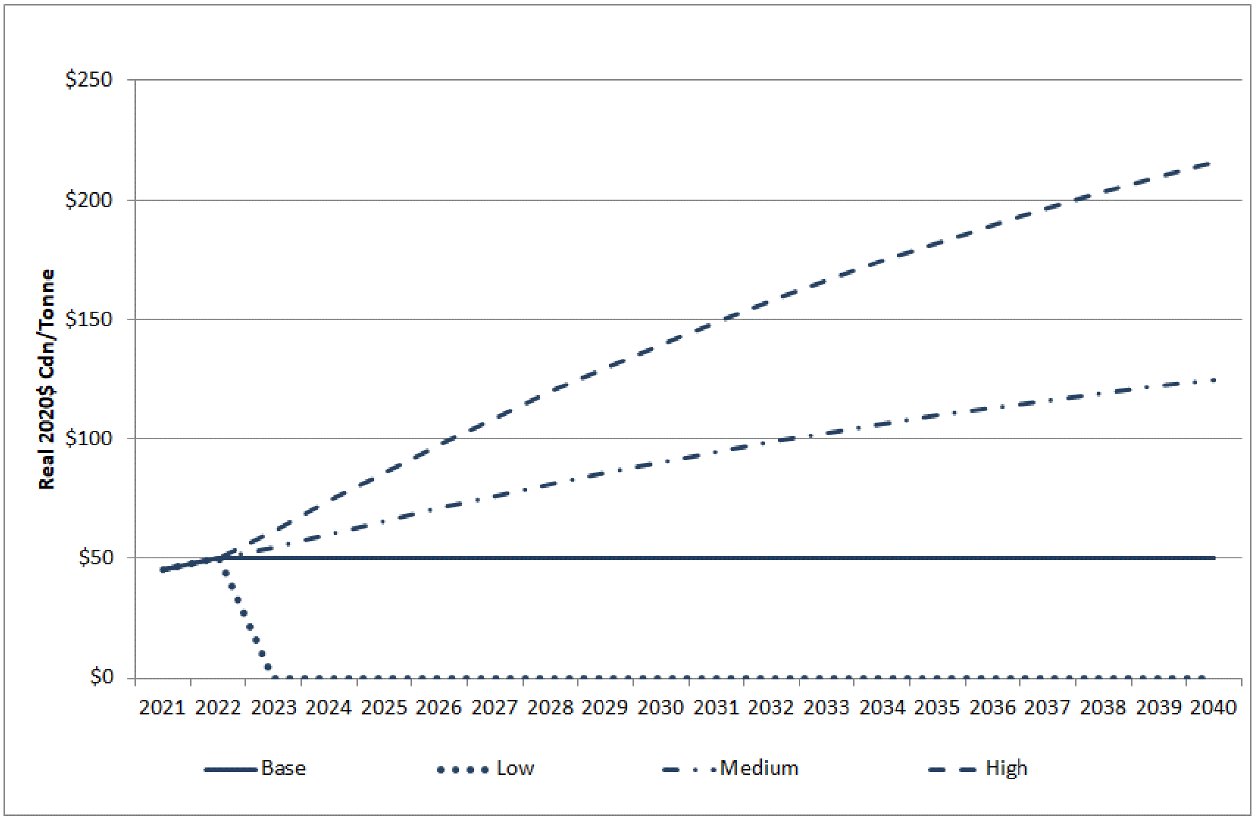
In recent years, the Canadian federal government has proposed changes to the federal carbon price. In December 2016, the Canadian federal government announced that it planned to require the provinces to have a price of at least $10 per tonne of carbon dioxide equivalent emissions starting in 2018. The price would rise by $10 per tonne per year for the next four years, reaching $50 per tonne by 2022.[119] The current federal carbon tax is $40 per tonne. After the planned increase in 2022, the BC carbon tax and the Canadian federal carbon tax will be equal at $50 per tonne.

In December 2020, the Canadian federal government announced that it is planning to increase the carbon tax beyond the $50 per tonne level as part of a push to meet and surpass Canada's goal of reducing GHG emissions by 30 per cent below 2005 levels by 2030. The price would rise by $15 per tonne per year for eight years beginning in 2023 to reach $170 per tonne in 2030.[120] This carbon tax increase has not yet been enacted into legislation and, if it is, it is uncertain how BC will incorporate this into its own carbon tax plans.

FBC has developed its carbon price scenarios based on this information. FBC has assumed the 2021 carbon tax of $45 per tonne (in nominal terms) as the base case after which time it increases by $5 per tonne to reach $50 per tonne (in nominal terms) in 2022. After this time, the base case holds the carbon price constant in real terms, assuming that the carbon tax is increased to keep up with inflation over time. FBC has also included a high case based on the assumption of annual increases of $15 per tonne (in nominal terms) and reaches $140 per tonne (real terms) in 2030, which is equivalent to $170 per tonne proposed by the federal government. Also, FBC has included a more moderate medium case assuming annual increases of half of the $15 per tonne increases, or $7.50 per tonne (in nominal terms). The low case scenario is based on the assumption the carbon tax will be removed beginning in 2023. While this is not a likely scenario at this time, it is possible with a change in government to one that is less focused on environmental issues.

[119] http://www.cbc.ca/news/politics/canada-trudeau-climate-change-1.3788825.
[120] https://www.cbc.ca/news/politics/carbon-tax-hike-new-climate-plan-1.5837709.

Figure 2-20: BC Carbon Price Scenarios



2.5.5 BC Hydro PPA Rate Scenarios

In order to estimate the potential costs for the BC Hydro PPA in the future, FBC has developed PPA scenarios based on annual percentage increases in BC Hydro rates and BC Hydro's LRMC. The percentage increases in the PPA Tranche 1 energy and capacity rates are the same as those applicable to BC Hydro's customers. In December 2020, BC Hydro filed its Fiscal 2022 RRA, which included a proposed rate increase of 1.16 percent as of April 1, 2021. BC Hydro also previously set out forecast rate changes up to F2024 in their Fiscal 2020-2021 Revenue Requirements Application (RRA). The BCUC approved the 1.16 percent increase for F2022,[121] however the forecasted 0.3 percent decrease for F2023 and 3.0 percent increase for F2024[122] are subject to BCUC review and approval. FBC has assumed these are nominal, not real, rate increases. At this point in time, there is less certainty in terms of rate increases beyond March 2024.

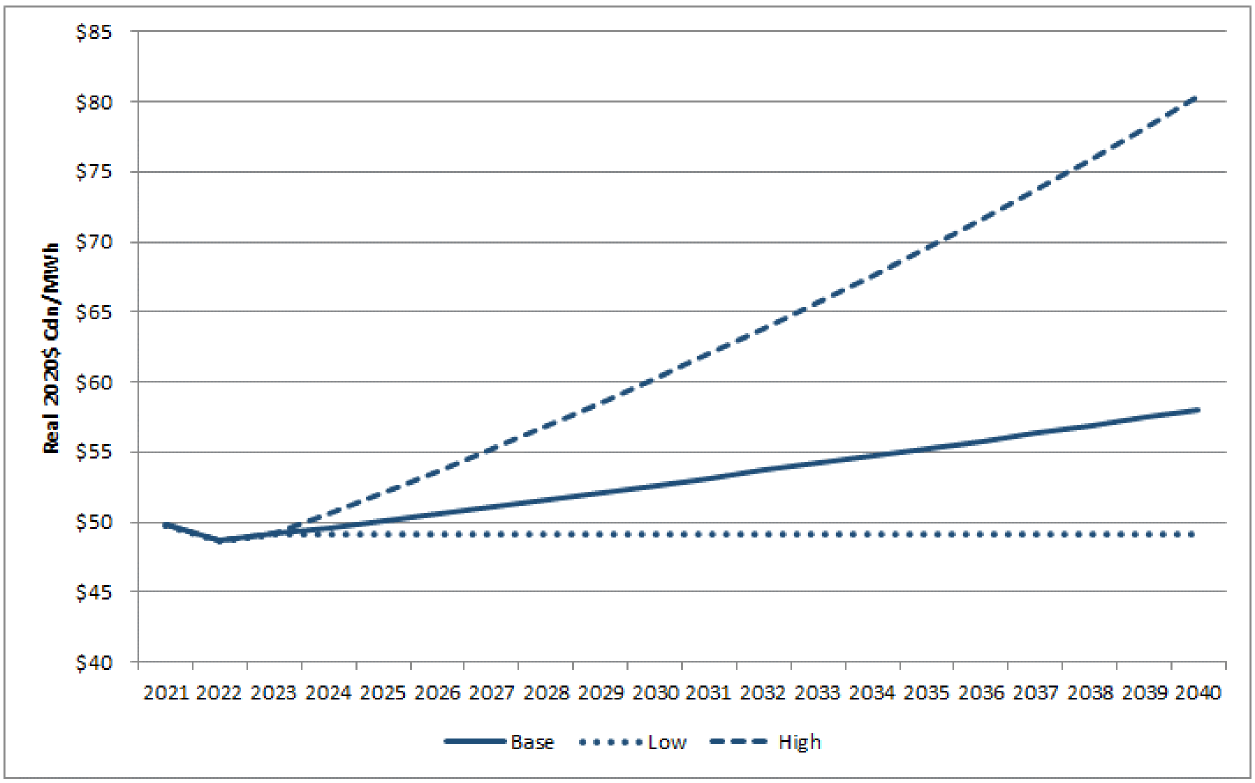
In developing its PPA rate scenarios, FBC has made the following assumptions that it believes are reasonable given the recent historical rate increases by BC Hydro and the target rate increases to F2024. In the low case, rate increases keep up with inflation of about 2 percent per

[121] The 1.16 percent increase on April 1, 2021, as part of BC Hydro's Fiscal 2022 Revenue Requirements Application dated December 22, 2020, was approved by Order G-187-21 on June 17, 2021.

[122] The forecast rate changes in the subsequent two years were included in the Evidentiary Update for BC Hydro's Fiscal 2020-2021 Revenue Requirements Application dated August 22, 2019 (Exhibit B-11, Figure 1, Section 1).

year and so rates do not increase in real terms (see Section 2.5.6 below regarding the inflation rate forecast). In the base case, rate increases are 1 percent per year in real terms. In the high case, rate increases are 3 percent per year in real terms. The high case reflects the potential for higher rate increases driven by higher costs for electricity generation and infrastructure under a future with significant electrification of transportation, industry and buildings. The following figure shows the PPA rate scenarios for Tranche 1 Energy, which is at a rate of $50.73 per MWh as of April 1, 2021.[123]

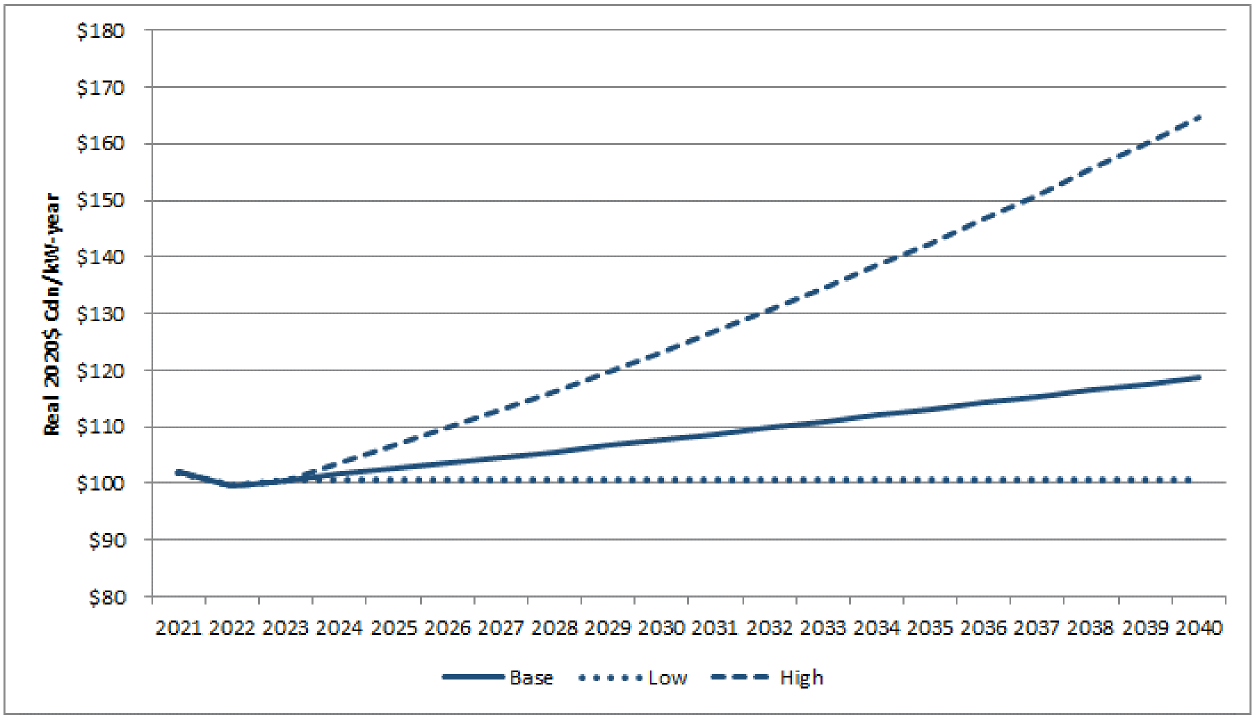
Figure 2-21: PPA Rate Scenarios for Tranche 1 Energy



The rate scenarios for capacity under the PPA use the same annual percentage increases. The following figure shows the PPA capacity rate scenarios, which is at a rate of $103.86 per kW-year as of April 1, 2021.[124]

[123] BC Hydro's Fiscal 2022 Revenue Requirements Application dated December 22, 2020 (Exhibit B-2-2, Appendix Y, pg. 649).
[124] Ibid.

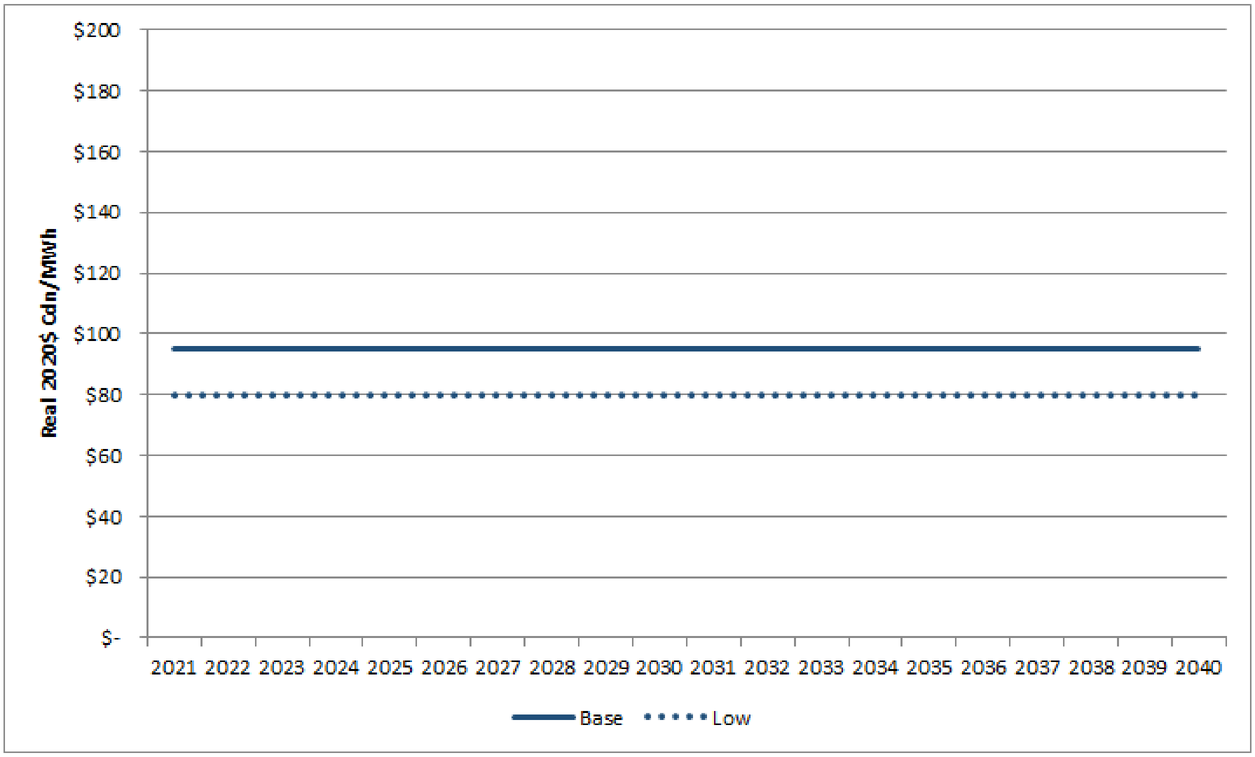
Figure 2-22: PPA Capacity Rate Scenarios



The PPA Tranche 2 Energy rate, which is currently $95.09 per MWh, is tied to BC Hydro's proxy for their LRMC.[125] FBC has assumed that the PPA Tranche 2 energy rate could be further lowered to the high end of the PPA Tranche 1 energy rate scenario, at a value near $80 per MWh in 2040, and has treated this as a PPA Tranche 2 low rate scenario. FBC has assumed that both the base case and low rate scenario are adjusted for inflation and therefore do not increase in real terms. The following figure shows the base case $95.09 per MWh PPA Tranche 2 rate and the $80 per MWh low rate scenario.

[125] BC Hydro Rate Schedules effective April 1, 2021, Schedule 3808 – Transmission Service – FortisBC. The LRMC is currently tied to BC Hydro's RS 1823 Tier 2 rate, which was approved on May 15, 2018 by Order G-95-18.

Figure 2-23: PPA Rate Scenarios for Tranche 2 Energy



FBC believes that these scenarios provide a reasonable range for the potential cost of the PPA energy and capacity over the next twenty years.

2.5.6 Financial assumptions

FBC has made assumptions regarding future exchange rates and inflation factors in order to develop the price forecasts and PPA rate scenarios.

2.5.6.1 Exchange Rate Forecast

In order to convert the NPCC and IHS market price forecasts for natural gas and electricity from US dollars to Canadian dollars, FBC used a Canadian/US dollar exchange rate forecast. The forecasts used projections from Canadian Chartered banks and the BC Ministry of Finance that were available at the time of developing the LTERP models.

Table 2-2: Canadian/US Dollar Exchange Rate Forecast[126]

Year	Exchange Rate
2021	1.35
2022	1.33
2023	1.32
2024 to 2040	1.31

2.5.6.2 Inflation Rate Forecast

FBC requires an inflation rate forecast in order to convert the price forecasts and PPA rate scenarios into real 2020 dollars. Similar to the exchange rate forecasts discussed above, FBC used the projections available from Canadian Chartered banks, the Conference Board of Canada, and the BC Ministry of Finance at the time of developing the LTERP models.

Table 2-3: Inflation Rate Forecast[127]

Year	Inflation Rate (percent)
2021	1.9
2022 to 2040	2.0

2.5.7 Adders to the Market Price Forecasts

The market price forecasts presented in the previous sections are based on the market hub locations and do not include any costs to move the commodity supply of natural gas or electricity to the FBC service area.

To move gas purchased at Sumas to the FBC electric service area for consumption by a natural gas-fired generator, gas pipeline transportation needs to be added to the commodity cost of the gas. FBC has estimated this to be in the order of $1.83 per GJ (in real $2020 terms) including Westcoast Energy Inc. T-South toll and fuel costs (about $0.73 per GJ)[128] and FEI interior system transmission tariff ($1.10 per GJ).[129]

In order to move market electricity purchases from the Mid-C market hub to the FBC service area, FBC incurs additional wheeling costs under the CEPSA with Powerex and 71L Letter

[126] Based on average forecast from Chartered Canadian Banks (TD Bank, Royal Bank of Canada, Bank of Nova Scotia, Bank of Montreal, and Canadian Imperial Bank of Canada) as of April 2020, and British Columbia Ministry of Finance – Budget and Fiscal Plan 2020/21 to 2022/23.

[127] Based on average forecast from Chartered Canadian Banks (TD Bank, Royal Bank of Canada, Bank of Nova Scotia, Bank of Montreal, and Canadian Imperial Bank of Canada) as of April 2020, Conference Board of Canada, Long-term Forecast (2020) and British Columbia Ministry of Finance – Budget and Fiscal Plan 2020/21 to 2022/23.

[128] Based on Westcoast Energy Inc. 2021 Final Transmission Tolls for T-South Huntingdon delivery April 1, 2021 and fuel costs.

[129] Per FortisBC Energy Inc. Rate Schedule 22 delivery charge per GJ of $1.09 (inclusive of applicable rate riders), for the Mainland Service Area, effective January 1, 2021.

Agreement with Teck Resources (Teck). As the CEPSA is assumed to continue indefinitely, and comparable market access to Teck's 71L transmission line is assumed as well, these wheeling costs are continued for the planning period.

A clean market price adder as a proxy for purchasing clean energy is added to the electricity market price forecast and is based on a forecast from IHS. The Mid-C market price forecast is based on current and expected supply in the Pacific Northwest, which includes coal and gas resources, and therefore a clean market adder is used to represent the cost of purchasing only clean market power. The clean market adder forecast from IHS reflects the assumption of a renewable energy credit (REC) oversupply in the Mid-C market, as utilities in the Pacific Northwest are planning to exceed state-mandated renewable portfolio standards. Purchasing a REC certifies that the power is clean electricity and represents the clean energy attributes of renewable electricity. An organized REC market with published prices does not currently exist in the Pacific Northwest and the clean market adder forecast is merely indicative at this time. If states adopt stricter or accelerate decarbonization mandates, the oversupply of renewable generation could decrease closer to 2040 and increase REC costs. The clean market price adder is approximately $2 per MWh.[130] Within its portfolio analysis discussed in Section 11, FBC has included these market price forecast adders. The PPA rate and carbon price scenarios do not require any adders as the prices for these are already based on energy and capacity within BC and the FBC service area. In addition, FBC assumed that the RNG price scenarios do not require any adders as the RNG supply could be within the FBC service area.

2.5.8 Conclusions

Based on the information presented in the previous sections, FBC draws several conclusions regarding the market price forecasts and rate scenarios.

First, the current gas and power market environment continues to experience relatively low price levels compared to those seen before the pre-shale gas era.

Second, the growth of renewable energy will help further diversified electricity generation capacity in the region. This has resulted in low market electricity prices, which are reflected in the market price forecasts. Market purchases, at least in the short to medium term, continue to remain well below the cost of other supply-side resource options, discussed in Section 10.2.

Third, there is uncertainty regarding the carbon price, as all levels of government look for approaches to reduce GHG emissions in order to meet climate targets. An increase in the carbon price would increase the variable cost of gas-fired generation using conventional natural gas as fuel.

Fourth, RNG provides a carbon-neutral alternative as a fuel source for gas-fired generation. While the RNG price is currently higher when compared to conventional natural gas, there may be specific applications and commercial structures to enable a transition from gas-fired

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resources. Prices could also go lower if supply were to increase due to economies of scale and with advancements in technology. The degree of impact RNG fuel costs have on the variable cost of gas-fired generation depends on how much the gas-fired plant is utilized.

Finally, PPA Tranche 1 Energy is also a cost-effective resource relative to most other supply-side resource options (also discussed further in Section 10.2). However, there is uncertainty regarding the PPA rate increases beyond 2023 and it is possible that the cost of the PPA may exceed that of other resource options by the end of the planning horizon.

3. LONG-TERM LOAD FORECAST

3.1 INTRODUCTION

FBC forecasts the expected load over the planning horizon in order to determine the annual energy and peak demand requirements of customers. All forecast loads presented in this section are before adjustments for incremental DSM, which is discussed in Section 8 and the LT DSM Plan.

Both gross and net loads include the residential, commercial, wholesale, industrial,[131] irrigation and lighting customers. However, gross load includes system losses while the net load excludes system losses. Further information regarding the load forecast methods and detailed forecasts by customer class are found in Appendix F.

This section provides the following information:

- The business as usual (BAU) forecast for gross energy load, net energy load and peak demand;
- The Reference Case (expected) forecast for gross energy load, net energy load and peak demand;
- The factors and conditions that influence FBC's load growth over the planning horizon for the BAU and reference case, and
- The load forecast drivers that result in variability of the forecast and provide a probability range around the Reference Case load forecast.

The BAU is the forecast used for annual rate setting which is then extended out for the 20-year planning horizon. The Reference Case load forecast builds on the BAU forecast by including electric vehicle charging load, and new industrial loads with high confidence of materializing, which are discussed in detail in Appendix F, Section 3.1.3 and 3.4. The Reference Case load forecast is the resulting forecast used for planning purposes in this LTERP.

The methods used to develop the BAU forecast are consistent with those used to develop the 2016 LTERP. In the Decision and Order G-117-18 relating to the 2016 LTERP and LT DSM Plan, the BCUC accepted the load forecast and method.

3.2 RECENT IMPACTS OF THE COVID-19 PANDEMIC IN RELATION TO LOAD FORECAST

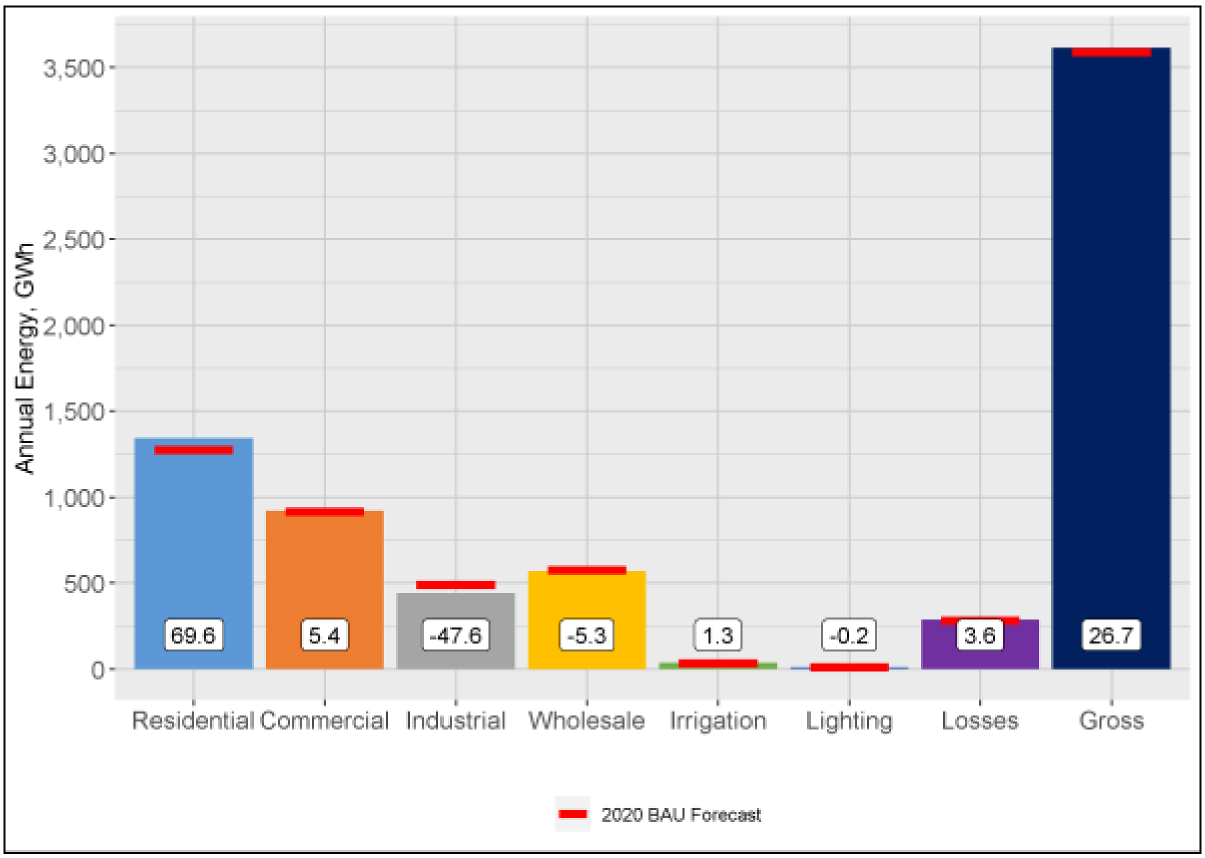
FBC developed the LTERP BAU forecast in April 2020 (using actual data through the end of 2019) so that it could be used to develop the elements of the LTERP which rely on the load forecast, and so that the LTERP could then be ready to file in 2021 (consistent with past

[131] FBC uses the term 'industrial class' for those customers that are served under the large commercial rate schedules

practice). Section 3.3 below shows the processes that rely on and follow the development of the load forecast. At the time FBC was developing the load forecast, the COVID-19 pandemic was emerging in BC and its effects continued to ramp up through the rest of 2020. In light of this, FBC reviewed its 2020 load forecast against the 2020 actual customer loads to determine if the 2020 load forecast required any adjustments. The results of this review are summarized below.

The following figure shows the actual weather normalized load for 2020, represented by the coloured columns, compared to the 2020 BAU forecast developed with 2019 weather normalized actual, pre-COVID-19 pandemic data, represented by the red lines. The data labels within each column show the differences between the forecast and actual data.

Figure 3-1: Comparison of 2020 BAU Forecast to Actuals (GWh)



The Figure 3-1 shows the following:

- Actual residential load was approximately 70 GWh higher than the 2020 BAU forecast;
- Actual commercial and wholesale loads were close to forecast;
- Actual industrial load was approximately 48 GWh lower than forecast, and
- Actual irrigation and lighting variances from forecast were negligible.

The aggregate actual gross load was approximately 27 GWh, or 0.75 percent, higher than forecast. FBC notes that the average absolute percent error in the six prior annual forecasts was slightly higher at 1.6 percent. Therefore, despite the pandemic impacts, the overall forecast performance for 2020 was better than average.

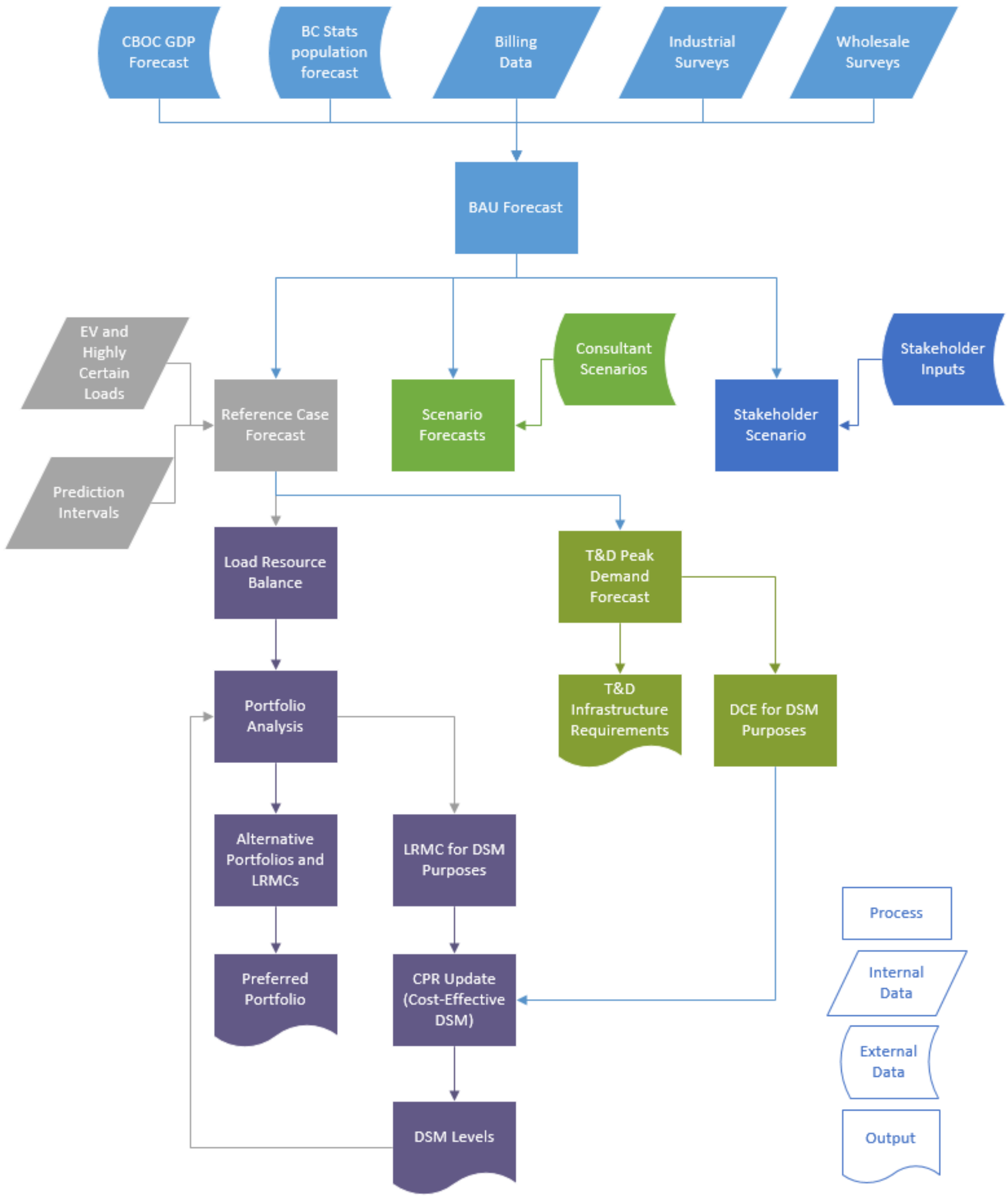
At this time, FBC expects that 2021 actual loads may show similar effects for the customer classes, with residential annual energy being higher than forecast and industrial annual energy being lower than forecast, given the current pandemic-related restrictions. In the Planning environment Section 2.3.1, FBC discusses the uncertainty regarding the COVID-19 pandemic's potential impacts on economic growth and customer behaviour. FBC notes that at this time there is not enough clear evidence that there will be any permanent or material long-term changes impacting the load forecast. Therefore, FBC expects a trend towards normal, pre-pandemic conditions after this year.

As a result, FBC concluded that the 2020 long-term forecast, prepared using the 2019 actual data, is appropriate to use for this LTERP.

3.3 LOAD FORECAST PROCESS

The Reference Case load forecast is the forecast FBC uses for planning purposes in this LTERP. The BAU forecast is developed first and then the Reference Case load forecast, as well as various load scenarios and other outputs, can be completed. The flow chart below shows the LTERP development process and how the load forecast development is a key initial determinant of the subsequent components.

Figure 3-2: LTERP Development Flow Chart



The BAU forecast is completed early in the process to allow time for the preparation of the remainder of the LTERP components. The amount of time from the development of the BAU forecast to the completion of the portfolio analysis is in the order of half a year, involving work by FBC staff as well as consultants updating their models. As such, FBC developed the LTERP load forecast in April 2020 so that it could be used to develop the other elements of the LTERP with the goal of filing the LTERP by mid-2021.

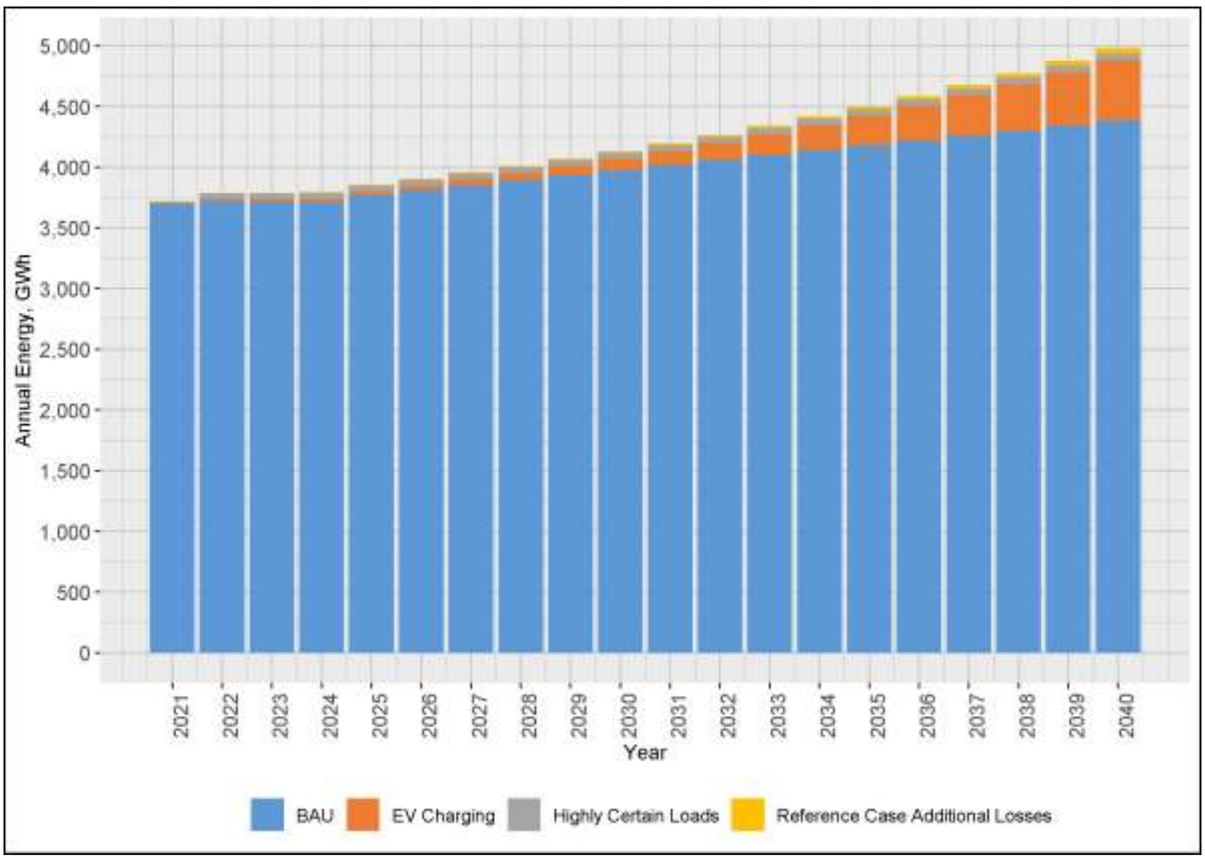
3.4 *LOAD FORECAST SUMMARY*

3.4.1 Gross Energy Load Forecast

FBC's BAU gross energy load forecast anticipates a modest rate of growth over the twenty-year planning horizon. FBC is forecasting an increase in gross energy load from 3,698 GWh in 2021 to 4,383 GWh by 2040, reflecting an average annual growth rate of 0.9 percent.

The reference case forecast uses the BAU as the base and then adds EV charging and new highly certain industrial loads and is forecast to grow from 3,717 GWh in 2021 to 4,983 GWh in 2040, reflecting an average annual growth rate of 1.6 percent. The following figure shows the BAU forecast and the additional EV charging and highly certain industrial loads which are included in the Reference Case load forecast.

Figure 3-3: Gross Energy Load Forecast (GWh)



Losses are 7.6 percent of gross energy load plus company use of 13 GWh a year. Losses are discussed in Section 4.7 of Appendix F.

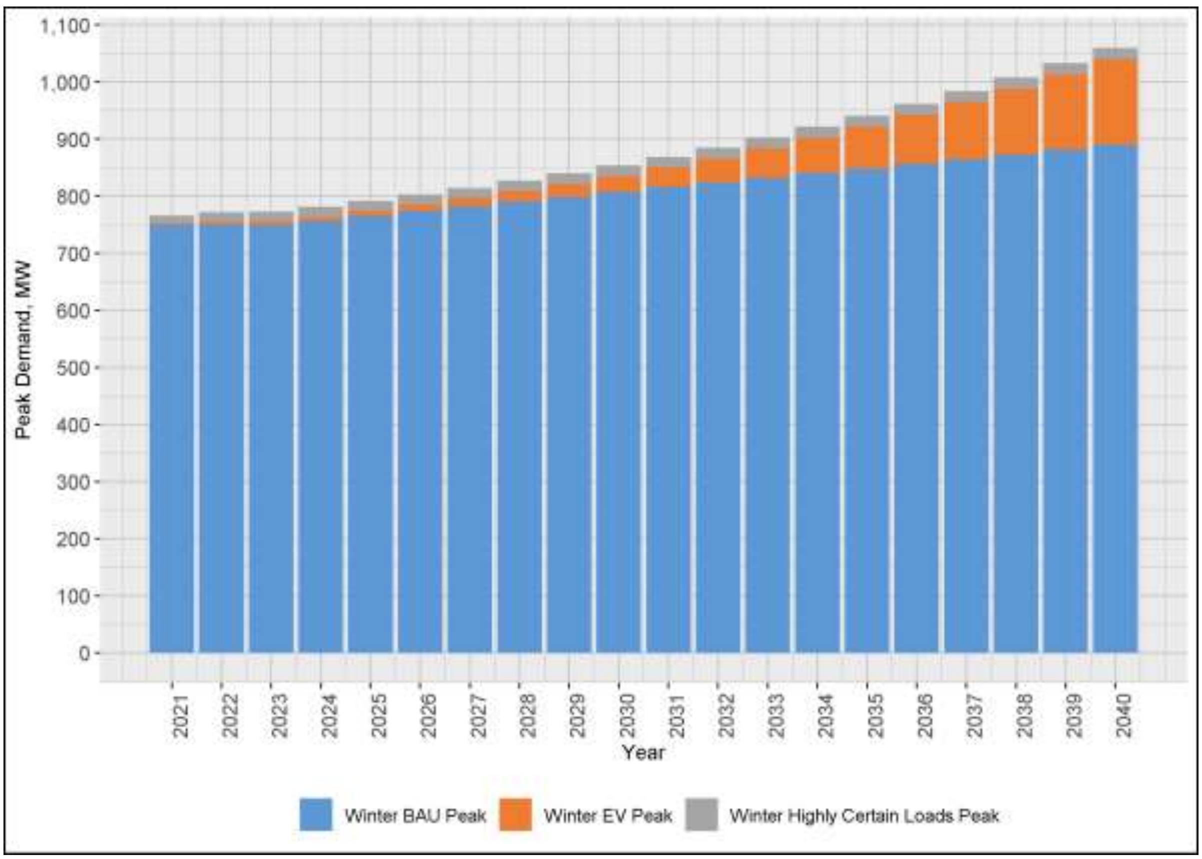
3.4.2 Peak Demand Forecast

The peak demand forecast is the highest level of capacity expected to be needed at one point in time on the FBC system due to high customer demand, which is affected by weather and customer growth. FBC's system is dual peaking, with annual winter and summer peaks. Winter peaks have historically been larger than the summer peaks and are forecast to continue to be larger in the future.

The winter peak is when the most capacity is needed at a single point in time, and typically occurs during the months of November to February and usually on one of the coldest days of the year. The BAU winter peak demand forecast increases from 749 MW in 2021 to 890 MW in 2040, increasing at an average annual growth rate of 0.9 percent.

The Reference Case winter peak is forecast to increase from 766 MW in 2020 to 1,060 MW in 2040, at an average annual growth rate of 1.7 percent.

Figure 3-4: Winter Peak Forecast (MW)

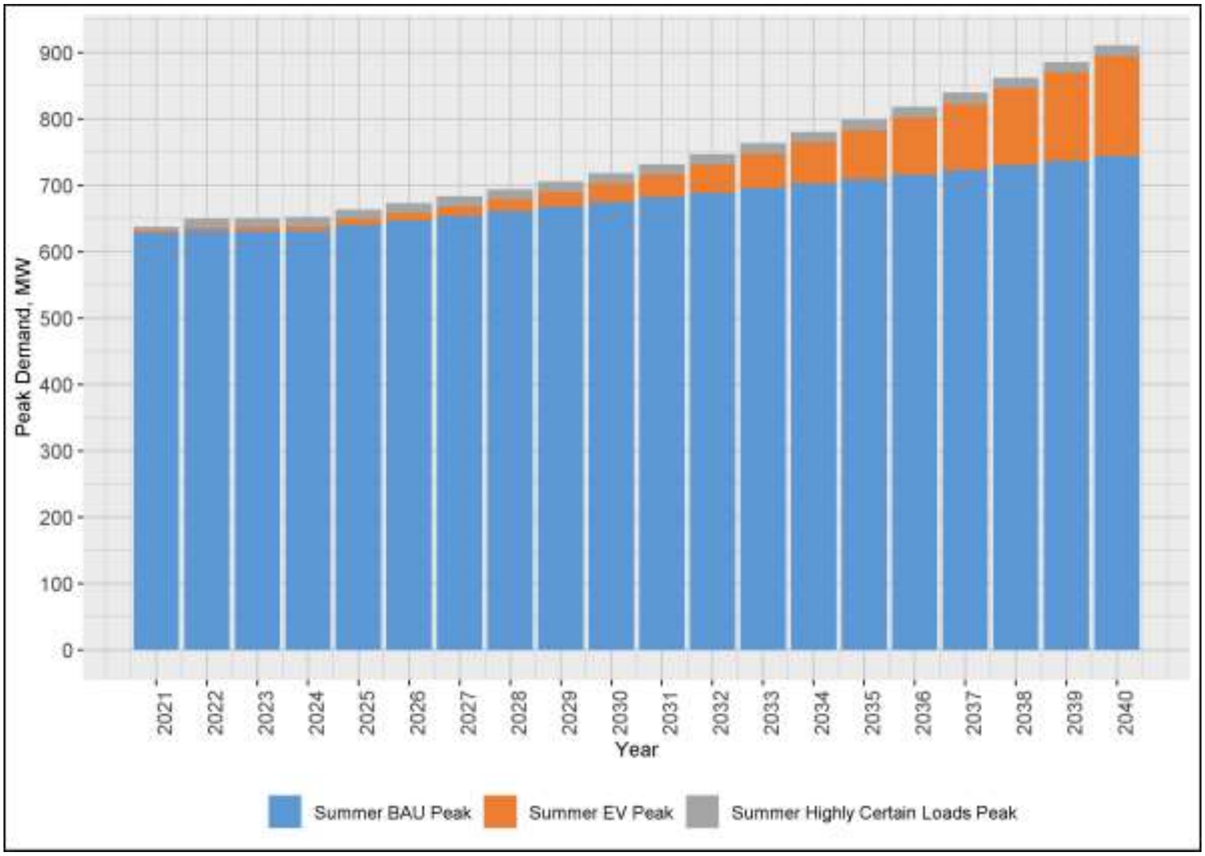


The summer peak is when the most capacity is needed at one point in time during the summer months, between July and August, and usually occurs on one of the hottest days of the year. The warmer the weather, the more energy is required to cool homes and businesses, which increases capacity requirements on the FBC system.

The BAU forecast summer peak demand forecast increases from 628 MW in 2021 to 744 MW in 2040, increasing at an average annual growth rate of 0.9 percent.

The Reference Case summer peak is forecast to increase from 638 MW in 2021 to 911 MW in 2040, at an average annual growth rate of 1.9 percent.

Figure 3-5: Summer Peak Forecast (MW)



The Reference Case winter and summer peak forecasts do not include any EV charging peak mitigation (i.e. shifting EV charging loads off peak periods). This is because FBC currently has no EV charging mitigation programs in place and has no certainty, at this point, how much EV charging it will be able to shift off peak periods. FBC's mitigation options and plans are discussed in Section 2.3.2.

As discussed in Section 2.2.1, FBC experienced an extended heat event and set a summer peak record of 764 MW on June 29, 2021, which exceeded the levels included in the summer peak forecast above, at least for 2021 through 2032. The data from this event will be captured in FBC's historical data and will be considered in future long-term forecasts.

3.5 DETERMINANTS OF ENERGY LOAD GROWTH

The BAU forecast is based on traditional load drivers inherent in the actual data, as well as third party forecasts of the economic drivers of load growth for the FBC service area. The Reference Case load forecast adds new emerging load drivers for electric vehicle charging and highly certain industrial loads not inherent in the actuals used for the BAU. The inputs to the BAU and Reference Case load forecast are the following:

- BAU load forecast:
  - BC Gross Domestic Product (GDP) as forecast by the Conference Board of Canada (CBOC).[132] The CBOC forecast provides an outlook for the expected economic climate, and is used directly in the forecasts of the load growth in FBC's commercial and industrial rate classes;
  - FBC's service territory population as forecast by the Ministry of Technology, Innovation & Citizens' Services, BC Statistics branch (BC Stats), which is used to forecast the number of residential customers FBC will serve over the planning horizon;
  - Forecasts provided through annual surveys for individual wholesale and industrial customers.
- Reference Case load forecast:
  - Electric Vehicle charging load forecast based on the *ZEV Act* light-duty EV sales targets (discussed in Section 2.2.3). These loads are included only in the Reference Case load forecast.
  - New highly certain industrial customer loads, determined by FBC key account managers, include loads from a waste water treatment facility, a renewable energy facility and long term increases from a current forestry sector customer.

3.5.1 Economic Conditions

FBC uses GDP as a quantitative measure of economic activity. GDP forecasts from the CBOC are used to forecast load for both the commercial and industrial classes.

The CBOC forecasts the annual GDP growth rate to decline from approximately 6.3 percent in 2021 to 1.8 percent in 2040 with an average annual growth rate of 2.0 percent over the planning horizon.

The CBOC's analysis further predicts that the forestry sector will see minimal gains over the planning horizon due to log shortages resulting from the mountain pine beetle infestation. The

[132] Provincial Outlook Long-Term Economic Forecast 2020 by the Conference Board of Canada, May 31, 2020 and British Columbia Preliminary Economic Forecast Spring 2020 by the Conference Board of Canada April 6, 2020.

mining sector is forecast to see moderate growth over the planning horizon as prices rebound due to developing countries providing markets for these resources.

3.5.1.1 Commercial Energy Load

The commercial class includes a diverse mix of businesses, from small retail stores and restaurants to larger operations such as hotels and ski resorts. In 2020, there were 16,165 customers in the commercial class, representing about 25 percent of FBC's gross energy load. The BAU and Reference Case commercial load forecasts are identical.

Commercial annual energy load is expected to increase at an average annual growth rate of 1.3 percent over the planning horizon.

3.5.1.2 Industrial Load

In 2020, there were 43 customers in the industrial class, representing approximately 12 percent of FBC's gross energy load. The BAU industrial load forecast is developed using a survey sent to each industrial customer. The survey provides load estimates from 2020 to 2024. The response rate to the industrial survey used for the BAU forecast was 80 percent, which represented 92 percent of the total industrial load.

Individual sector GDP projections from the CBOC are used to forecast the load for industrial customers who do not return their annual FBC industrial survey. The survey and individual sector GDP projections are used for the first five years and the CBOC composite GDP growth rate is used to develop a forecast for the remainder of the planning horizon.

The BAU forecast includes new projects with near one hundred percent certainty of completion, and in the current forecast includes primarily cannabis production facilities.

Loads from new industrial customers included in the Reference Case forecast were based on estimates provided directly from customers to FBC key account managers. The key account managers worked closely with these customers to determine their requirements and project timing. FBC then assessed the probability of the various projects successfully moving ahead and connecting to the FBC system for future electricity supply. The reference case forecast includes projects with a seventy-five percent certainty of moving forward, and includes a waste water treatment plant, a renewable natural gas facility, and the expansion of the operations of an existing forestry customer. Aggregate industrial energy load growth in the reference case forecast is expected to increase at an average annual growth rate of 1.1 percent over the planning horizon. Further information about the industrial energy load forecast method can be found in Appendix F.

3.5.2 Population Growth

FBC receives a custom population forecast for its service territory from BC Stats. Annual population growth is forecast to start at 0.9 percent and then fall gradually to 0.5 percent by

2040. The BC Stats forecast does not include any commentary about or explanation for the predictions.

FBC's service area population is used to forecast the residential customer count which, along with customer usage, is used to forecast residential energy loads. Customer usage is forecast by applying a ten-year trend to the normalized historical UPCs and then holding the UPC constant after the first five years. The calculations for the residential energy load are further explained in section 1.4.1 of Appendix F.

The residential energy load for the BAU forecast is expected to increase at an average annual rate of 0.4 percent over the planning horizon. The residential customer short-term[133] growth rate is forecast to be minus 0.5 percent at the start of the planning horizon and grow at an annual rate of 0.7 percent for the remainder of the planning horizon.

The Reference Case residential energy load is forecast to increase at an average annual rate of 2.0 percent over the planning horizon. In the short term, the energy load is forecast to be flat, while the medium to longer term energy load growth is expected to average 2.8 percent per year. The increase is primarily a result of EV charging.

3.6 *LOAD FORECAST UNCERTAINTY*

In order to account for future variability in the reference case load forecast, FBC developed uncertainty bands around the Reference Case forecast comprised of three elements:

1. Prediction intervals computed for the BAU forecast at the 90 percent confidence level;
2. An upper and lower EV charging load forecast, and
3. An upper and lower highly certain industrial loads forecast.

Prediction intervals for each customer rate group in the BAU forecast were computed using Excel and ten years of historic actual data by rate class, as described in Appendix F, Section 5.

The Reference Case EV charging load forecast assumes light-duty EV sales targets per the *ZEV Act*. There is little historical data for this forecast component so prediction intervals cannot be calculated directly. For the upper band, FBC assumed that light-duty EV sales would grow at a faster rate than the *ZEV Act* sales targets with 100 percent of vehicle sales being EVs by 2035 (instead of by 2040 per the *ZEV Act*). For the lower band, FBC assumed a slower rate of light-duty EV sales growth such that only 50 percent of new light-duty vehicle sales were electric by 2040.

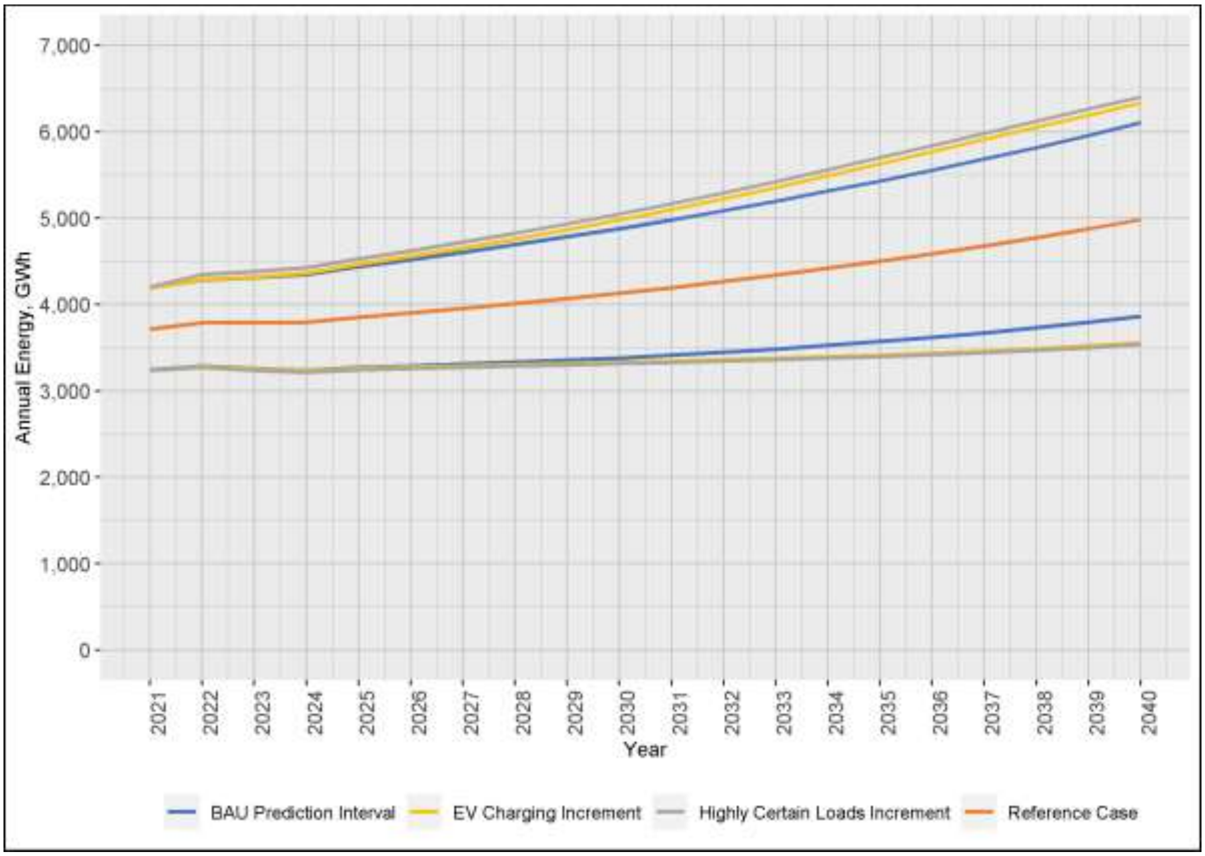
The Reference Case highly-certain industrial loads forecast assumes 75 percent of known future loads will materialize. As there is no historical data for this forecast component, the prediction intervals could not be calculated directly. FBC assumed that 50 percent of known

[133] Short-term covers years 2021-20256, medium-term covers years 2026-2030 and long-term covers years 2031-2040.

future loads will materialize for the lower band while 100 percent of known future loads would materialize for the upper band.

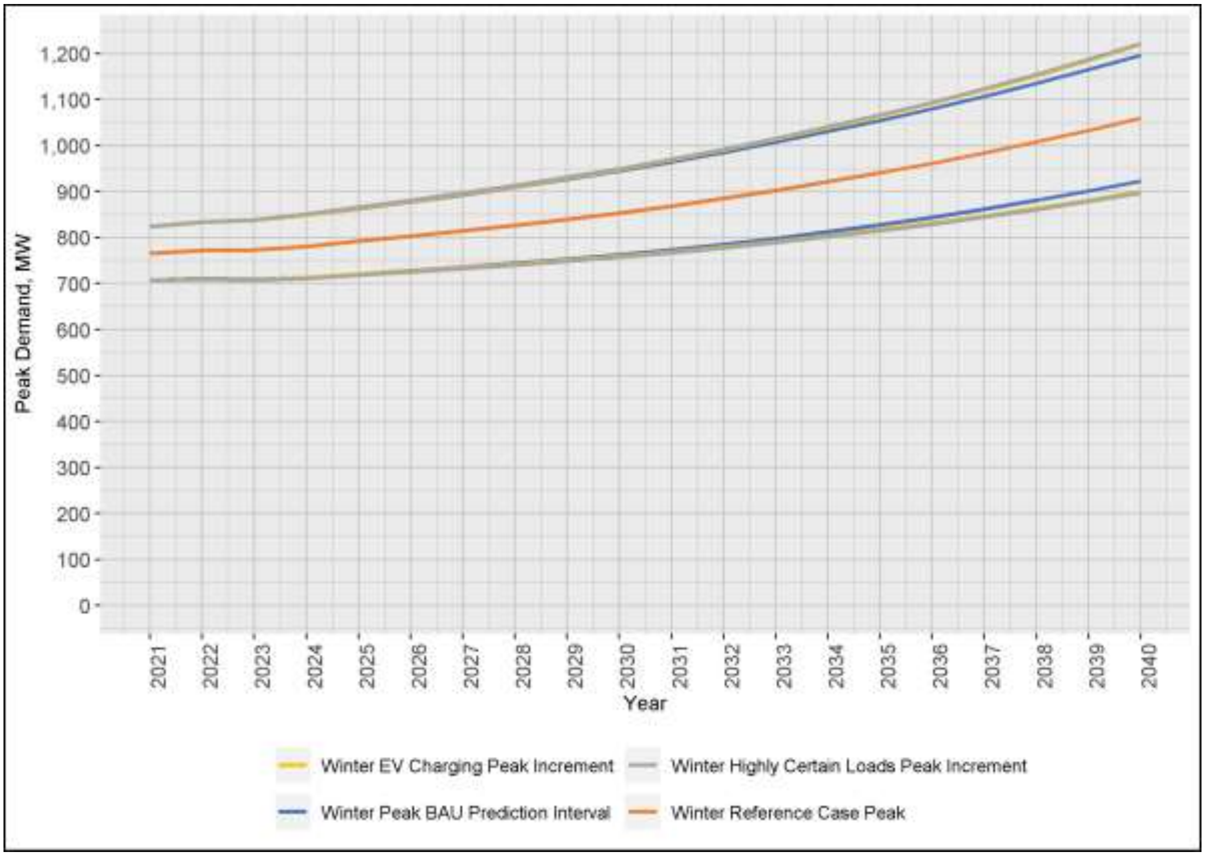
These three elements of uncertainty were then applied to the reference case load forecast to provide the uncertainty bands. The method and assumptions used to develop the prediction intervals are provided in Section 5 of Appendix F. The following figure shows the annual energy uncertainty bands for the BAU forecast as well as the increment from EV charging and highly certain industrial loads.

Figure 3-6: Annual Energy Uncertainty Bands (GWh)



The following figure shows the winter peak demand uncertainty bands for the BAU forecast as well as the increment from EV charging and highly certain industrial loads.

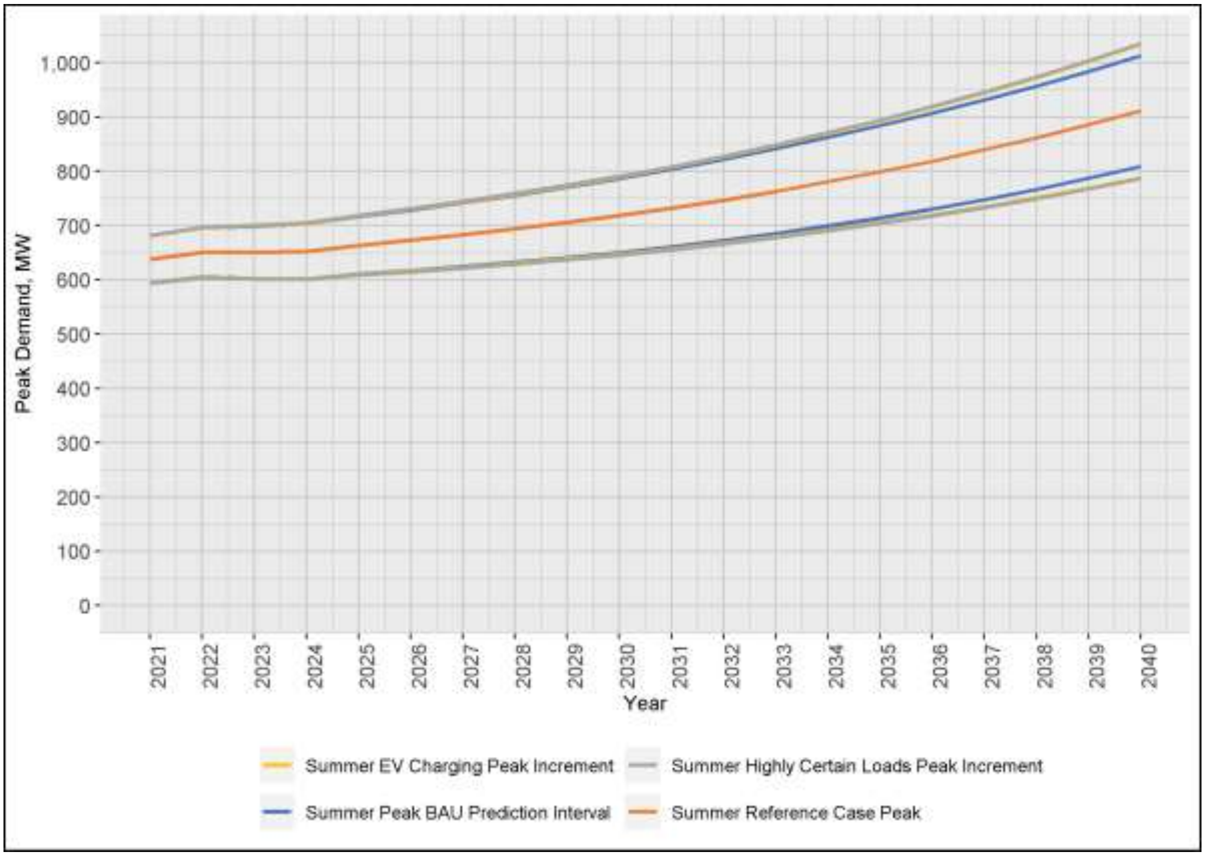
1 **Figure 3-7: Winter Peak Uncertainty Bands (MW)**



2

3 The following figure shows the summer peak demand uncertainty bands for the BAU forecast as
4 well as the increment from EV charging and highly certain industrial loads.

Figure 3-8 – Summer Peak Uncertainty Bands (MW)



3.7 SUMMARY

As discussed in Section 2.2.1 and 3.4.2 above, FBC experienced an extended heat event and set a summer peak record of 764 MW on June 29, 2021. This peak demand exceeded the upper confidence band for summer as presented in the figure above. FBC notes that the Summer Peak BAU prediction interval is based on a 90 percent confidence level and extreme events such as the June 2021 one are expected to exceed the confidence bands.

FBC has forecast the Reference Case load for its customers' annual energy and peak demand requirements over the next twenty years. FBC is forecasting gross loads to increase by an average annual growth rate of 1.6 percent per year. Growth will be stronger in the near to medium term and then begin softening due to slower economic conditions and lower population projections. Winter and summer peaks are projected to increase at an average annual growth rate of 1.7 percent and 1.9 percent respectively, and remain relatively constant for the planning horizon. Further information on the load forecasts and methods used to develop them is included in Appendix F. The load forecast data is provided in Appendix G.

In Section 7, FBC compares these Reference Case load forecasts against existing and contracted resources to derive the Load-Resource Balance. This helps FBC to determine when gaps between loads and existing resources may occur in the future and how significant these gaps may be. FBC then examines the demand-side resources in Section 8 and supply-side resource options in Section 10 that were assessed to fill the gaps.

4. LOAD SCENARIOS

Section 3 described the long-term Reference Case load forecast which is based on historical load drivers included in the BAU forecast plus any new highly-certain loads and light-duty EV charging load. FBC recognizes, however, that emerging technology, government policies, climate change and changes in how customers use and provide energy could impact load drivers that are not captured in the Reference Case forecast. This section of the LTERP discusses these emerging load drivers and some alternative load scenarios.

FBC employed the consulting services of Guidehouse Canada Ltd. (Guidehouse) (formerly Navigant Consulting Ltd.) to identify emerging trends and technologies not reflected in the reference case load forecast and to examine their potential uptake or penetration levels. Guidehouse developed several alternative scenarios based upon these potential load drivers, which may increase or decrease FBC's load requirements relative to the BAU forecast in the future. As there is significant uncertainty in how these scenarios will actually play out in the future, FBC has not assigned any probabilities to them. The scenarios provide examples of what the impacts on FBC's future load requirements might be if specific load drivers occurred at specific growth or penetration levels. They are not alternate load forecasts, but are rather possible future pathways for electricity use.

FBC also engaged stakeholders in the development of alternate future load scenarios through its RPAG process (discussed further in Section 12). In the June 2020 RPAG meeting, Guidehouse presented the results of its load drivers and scenarios assessment. Then stakeholders were provided access to a crowdsource input forecasting tool, developed by FBC staff utilizing the same load drivers employed by Guidehouse, which enabled them to vary the impacts of the load drivers to come up with their individual load scenarios.

These Guidehouse and stakeholder load scenarios will help inform FBC's potential future resource requirements and how FBC might adapt its resource portfolio if they were to occur. FBC's portfolio analysis, discussed in Section 11, includes alternative resource portfolios to meet the Reference Case load forecast as well as the alternative load scenarios discussed in this section. This may include, for example, more generation resources to meet higher than Reference Case loads or ensuring flexibility in FBC's resource portfolio to handle decreasing load requirements. To complement this analysis, FBC also discusses the potential transmission and distribution infrastructure requirements under some of these load scenarios to provide an idea of the timing and costs relating to future system projects. This is provided in Section 6.5.

There is uncertainty in terms of the potential impacts and timing of the emerging load drivers. For example, FBC's service area currently contains low amounts of residential rooftop solar installations and FBC does not expect them to ramp up significantly in the near future. However, rooftop solar could be a significant driver over the longer term within the LTERP's twenty-year planning horizon. On the other hand, FBC has seen steady growth in EVs within its service area in recent years and expects this steady growth to continue in the future. Some of the other load drivers could result in more significant, immediate impacts to FBC's load requirements. For example, if a large data centre or hydrogen production facility were built in

FBC's service area within the planning horizon, electricity requirements could significantly increase within a short period of time as a result. FBC needs to plan for both the short-term and long-term requirements of its customers and needs to have an understanding of what actions it might need to take under alternative scenarios.

The Guidehouse and stakeholder load scenarios are based on load requirements before DSM initiatives and are consistent with the BCUC *Resource Planning Guidelines* (discussed in Section 1.5.1), in particular the development of a range of gross (pre-DSM) demand forecasts (item 2 of the *Resource Planning Guidelines*).

The load scenarios were discussed in detail with the RPAG stakeholders in the June 25, 2020 workshop. At that session, FBC received questions and feedback regarding the load drivers and scenarios. FBC also provided stakeholders with a load scenario tool to allow them to develop their own load driver penetration levels and scenario impacts. This feedback and a discussion of the stakeholders' load scenarios are presented in Section 4.3 below.

The following sections describe the development of the load drivers and the alternative scenarios, as well as the results of Guidehouse's analysis of their potential impacts on FBC's future energy and capacity requirements for its customers. More details, including the assumptions used for the load drivers within each scenario, are provided in Guidehouse's Load Scenario Assessment Report, which is included in Appendix H, and Guidehouse's Load Scenarios Presentation to the RPAG in Appendix I.[134] The data relating to the energy and capacity impacts of the load scenarios is provided in the Load Scenarios Modelling Outputs in Appendix J.

4.1 *GUIDEHOUSE LOAD DRIVERS AND SCENARIOS*

In developing the load scenarios, Guidehouse and FBC focused on determining the impacts of various plausible future scenarios on FBC's energy and capacity requirements rather than attempting to address all potential factors that might influence the load drivers included in the scenarios. FBC believes this to be more efficient and appropriate for high-level long-term resource planning. The scenarios can be refined over time and in future resource plans as better information becomes available.

FBC engaged Guidehouse to:

- Work with FBC staff and obtain feedback from the RPAG to select a group of nine load drivers to include in the study;
- Develop, in collaboration with FBC staff, and in consultation with RPAG stakeholders, a set of five scenarios, each of which assumes a different level of penetration by each of the load drivers;

[134] Note that some of the figures in the Load Scenarios Presentation dated June 25, 2020 were preliminary and have been updated in the Load Scenario Report dated November 22, 2020.

- Estimate the unit impacts of the load drivers and;
- Model the potential impacts of these drivers as part of the five load scenarios.

The purpose of Guidehouse's Load Scenario Assessment Report was to provide an indication of the magnitude of the impact on FBC's peak demand and annual energy if a given set of circumstances were to arise. It is important to note that the scenarios were developed without determining and measuring the impacts of all of the potential drivers. For example, the impact of a substantial increase in the penetration level of rooftop solar in FBC's territory is quantified; however, determining what might drive increased uptake in rooftop solar, such as the cost of solar panels, related equipment and installation, was beyond the scope of the work.

The future impact of the load drivers included in these scenarios is, at present, so uncertain that no objective probabilities can be assigned to the scenarios. It is for this reason that these load drivers are included in this exercise, as opposed to a more formal empirical forecast.

FBC's purpose in engaging Guidehouse was to help understand and quantify the potential impacts of the load drivers and scenarios. Guidehouse has also identified several key findings stemming from the load scenarios work and provided FBC with several recommendations relating to the various load drivers (discussed further in section 4.1.5). FBC has no immediate plans to adjust its current resource requirements in response to these scenarios but intends to monitor load driver developments to help determine if a particular scenario or dominant load driver is emerging and will take the recommendations into consideration. FBC will explore the impacts of the load scenarios on its preferred resource portfolios as part of its portfolio analysis as discussed in Section 11.

4.1.1 Load Drivers

Nine specific load drivers were included to develop the load scenarios. These drivers are believed to have the potential for the most substantial impact on future loads. The nine load drivers are:

1. **Residential Integrated Photovoltaic Solar and Storage:** Behind-the-meter rooftop solar photovoltaic (PV) generation installed by residential customers. Some proportion of customers are assumed to support their PV generation with battery storage, referred to in this report as Integrated Photovoltaic Storage Systems (IPSS).
2. **Commercial Integrated Photovoltaic Solar and Storage:** Behind-the-meter solar PV generation installed by larger commercial (Rate Schedule 21) customers. This load driver includes some instances of customers supporting their PV with battery storage.
3. **Electric Vehicles:** Light-duty electric vehicles (LD EVs) and medium-duty and heavy-duty (MHD EVs). LD EVs were assumed to charge from a mix of Level 1, Level 2, and DC Fast Charging (DCFC)[135] stations, located at the driver's residence, workplace, or

[135] Level 1 includes 120-volt alternating current (AC) with a 1.4 kilowatt (kW) charging capacity; Level 2 includes 240-volt AC with a 6.9 kW charging capacity; Direct current (DC) Fast Charging (DCFC) includes DC charging station with a 5038 kW or greater charging capacity.

some other public location (no DCFC was assumed for residence-located charging). MHD EVs include three types of vehicles: buses, return-to-base fleet vehicles, and combination tractors (sometimes referred to as tractor-trailers).

4. **Fuel Switching – Gas to Electricity:** Residential fuel switching from gas-fired to electric space and water heating.

5. **Fuel Switching – Electricity to Gas:** Residential fuel switching from electric to gas-fired space and water heating.

6. **Climate Change:** Increasing average annual temperatures, increases in average temperatures during the 10 hottest days of the year, and decreases in average temperatures during the 10 coldest days of the year.

7. **Large Load Sector Transformation:** Substantial growth in the data centre and cannabis cultivation loads in FBC's service territory.

8. **Hydrogen Production**: The production of "green" hydrogen[136] for injection into the natural gas distribution system to help with decarbonization.

9. **Carbon Capture and Storage:** The electricity consumption driven by the power requirements of carbon capture and storage technologies used to capture carbon emissions from industrial processes.

These load drivers are the building blocks for the five scenarios modeled by Guidehouse. The assumed uptake, or penetration, of each load driver will vary from scenario to scenario, from zero in some scenarios to a very aggressive level in others. Because the load scenarios developed by Guidehouse identify potential impacts of light-duty EV charging per the *ZEV Act* that are already included in the FBC Reference Case load forecast, these light-duty EV charging loads should be considered incremental to the BAU forecast but not the Reference case forecast. The directional impacts of the load drivers on the FBC system load are summarized in the following table.

[136] "Green" hydrogen is hydrogen obtained from water via electrolysis. In contrast, "blue" hydrogen is made from natural gas through a process of steam methane reforming (SMR). The SMR process typically releases considerable amounts of carbon dioxide into the atmosphere.

Table 4-1: Load Drivers Directional Impacts

Load Driver	Effect on System Load (+/-)
Residential Integrated Photovoltaic Solar and Storage	▼
Commercial Integrated Photovoltaic Solar and Storage	▼
Electric Vehicles, Light Duty and Medium/Heavy Duty	▲
Fuel Switching – Gas to Electricity	▲
Fuel Switching – Electricity to Gas	▼
Climate Change	▼ ▲
Large Load Sector Transformation	▲
Hydrogen Production	▲
Carbon Capture and Storage	▲

4.1.2 Scenario Descriptions

Each of the five scenarios modelled is comprised of a different combination of load drivers. Although an infinite number of potential combinations of load drivers into scenarios is possible, the five scenarios selected for this analysis were chosen based on two guiding principles:

1. **The analysis should include "boundary" scenarios.** Boundary scenarios are those scenarios that define major deviations from existing empirical forecasts driven by the cumulative effects of emerging technologies and structural shifts that significantly impact system load in one direction or the other. These scenarios, Scenario 1 (the "Upper Bound"), and Scenario 2 (the "Lower Bound") each only consider driver impacts that push load in one direction. In other words, the Upper Bound considers only drivers that increase load, the Lower Bound considers only drivers that reduce load.

2. **The analysis should include scenarios consistent with the FortisBC Pathways analysis provided by Guidehouse.** FortisBC recently undertook a province-wide scenario analysis seeking to identify different decarbonization strategies.[137] Two of

[137] Guidehouse Canada on behalf of FortisBC, *Pathways for British Columbia to Achieve its Greenhouse Gas Reduction Goals*, 2020.

the scenarios in this analysis were specified to be aligned with those of the Pathways report: Scenarios 3 (“Deep Electrification”) and 4 (“Diversified Energy Pathway”). An alternate scenario not contemplated by the Pathways study was also developed - Scenario 5 (“Distributed Energy Future”) assumes an increased level of customer-owned distributed generation.

It is also important to note the following assumptions made when the scenarios were developed:

- **The scenarios presented are cause-agnostic.** For example, the scenario results quantify what the impact might be of a substantial increase in the penetration of roof-top solar photovoltaic (PV) distributed generation and energy storage. Determining what might drive such increased uptake in PV and storage is beyond the scope of the analysis.
- **No probabilities have been be assigned to these scenarios.** The future development of the load drivers included in these scenarios is sufficiently uncertain that no objective probabilities have been assigned to the scenarios. It is for this reason that the load drivers are included in this exercise, as opposed to a more formal empirical forecast.

The descriptions of the five scenarios are as follows:

- **Scenario 1 – Upper Bound:** This scenario is not intended to reflect a single coherent narrative of a future possible world, but rather to understand the notional upper limit of increases that could be expected under the (highly improbable) confluence of load drivers that only increase load.

- **Scenario 2 – Lower Bound:** As in the case of Scenario 1 (the Upper Bound), this Lower Bound scenario is not intended to reflect a single coherent narrative of a future possible world, but rather to understand the notional upper limit of decreases that could be expected under the (highly improbable) confluence of load drivers that only decrease load.

- **Scenario 3 – Deep Electrification:** This scenario imagines a future world with a deliberate focus on decarbonization via electrification, partially supported by an increase in distributed generation. With a focus on the electrification of space and water heating, the societal requirements for hydrogen production and carbon capture and storage are relatively lower than in some other scenarios. Although demand and energy consumption would both grow considerably, there is an incentive to improve the overall system load factor and so a modest increase in large loads (e.g., data centres, cannabis production) is observed, perhaps as a result of economic development rates.

- **Scenario 4 – Diversified Energy Pathway:** This scenario imagines a future world in which decarbonization is pursued in large part through renewable natural gas, hydrogen production and carbon capture and storage. Assumed growth in EVs, though less than Scenario 3 (Deep Electrification), is considerable: 95 percent of light-duty vehicle, and 20 percent of medium-duty and heavy-duty vehicle sales are EVs by 2040. The addition of this large, "peaky" EV load is expect to result in rising electricity prices. To mitigate this, a concerted effort to attract large loads (data centres and cannabis production) to help flatten the utility's load profile would have the potential to reduce rates for all ratepayers.

- **Scenario 5 – Distributed Energy Future:** This scenario imagines a future world in which highly favourable contracts with distributed energy (rooftop solar) producers (i.e., the consumers and businesses associated with the residential and commercial integrated photovoltaic solar and storage load drivers) would result in a steep increase in electricity rates due to FBC's fixed operating costs being distributed across lower energy sales volumes. As a consequence, the adoption of EVs would fall below the required levels of the *ZEV Act* mandate and residential customers would convert from electric to gas-fired heat. The cost of power would discourage growth in data centres and cannabis production.

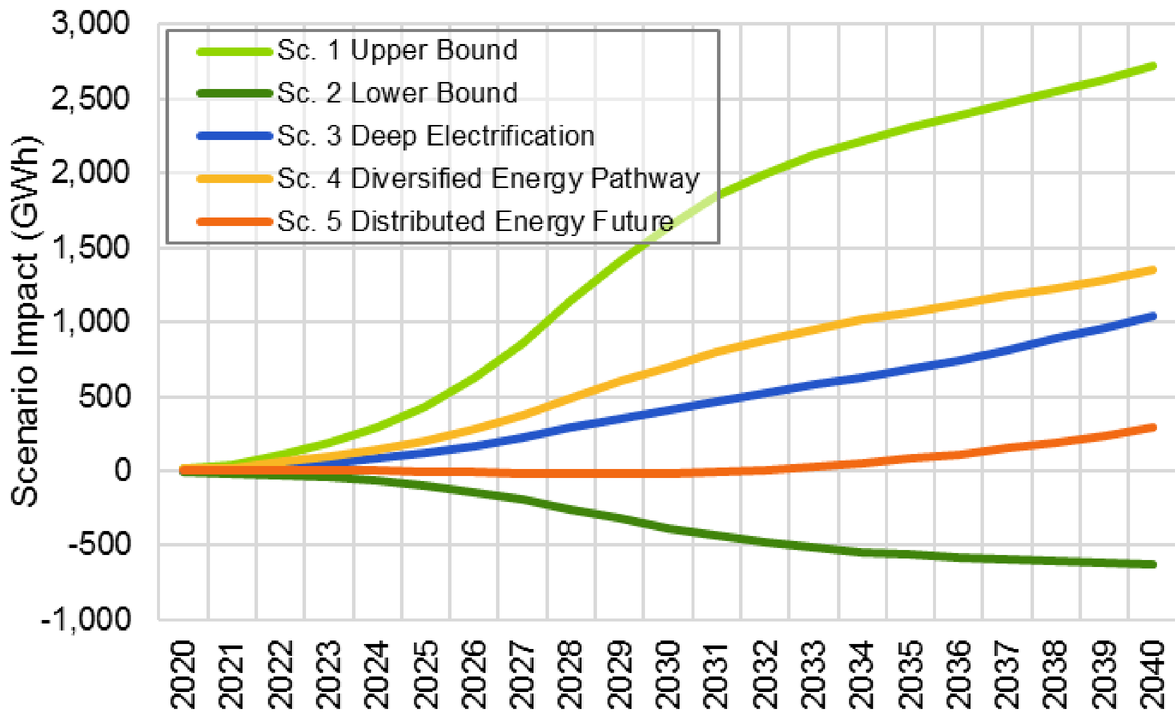
4.1.3 Load Scenarios Results

This section discusses the results of the load scenarios analysis in terms of the potential impacts to FBC's energy and capacity requirements. The data relating to the individual load driver's contribution to each of the load scenarios is provided in Appendix J.

The following figure shows the overall energy consumption impact of each scenario relative to the BAU forecast (at zero on the vertical axis), by year.[138]

[138] Losses have not been included in the scenario impacts presented in this figure as they reflect energy consumption. FBC has grossed-up the impact of losses to determine supply generation requirements as part of its portfolio analysis involving the scenarios as discussed in Section 11.

Figure 4-1: Annual Energy Impacts by Scenario

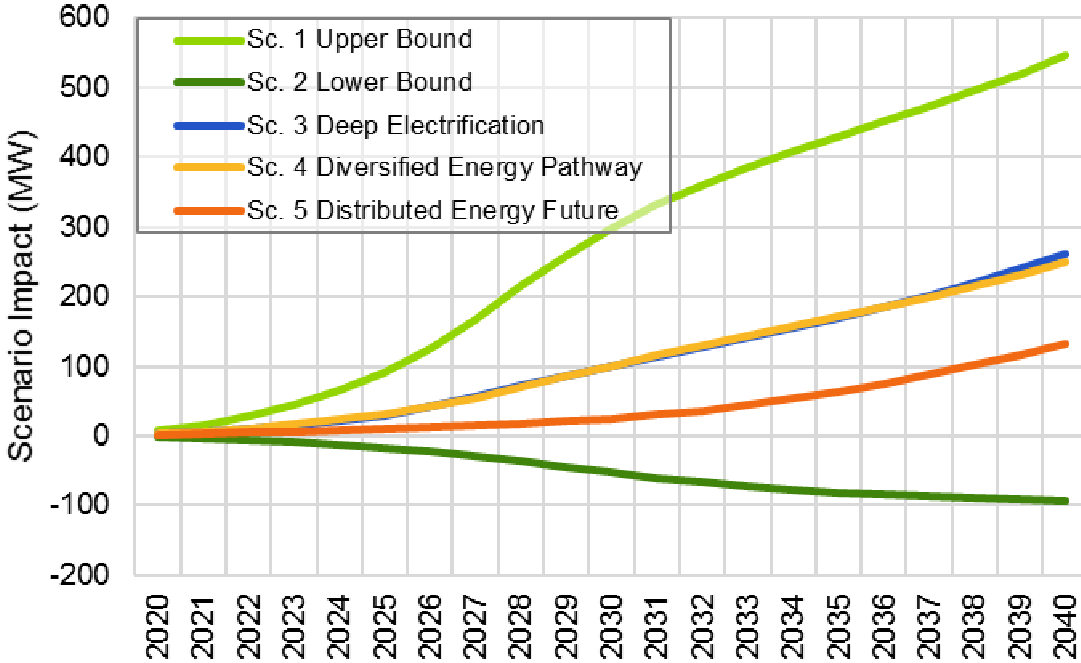


As shown in this figure, Scenario 1 results in an increase in energy consumption of over 2,500 GWh by 2040 compared to the BAU forecast, an increase of about 57 percent above the BAU 2040 annual energy forecast of 4,383 GWh, whereas Scenario 5 results in a decrease of over 500 GWh by 2040 compared to the BAU forecast, a decrease of about 11 percent below the BAU 2040 annual energy forecast. The intermediate scenarios all fall somewhere in the middle, with Scenario 5 having the least impact, Scenario 4 having the most, and Scenario 3 falling in between these two scenarios.

The following figure shows the overall winter peak demand impact of each scenario relative to the BAU forecast, by year.[139]

[139] Losses have not been included in the scenario impacts presented in this figure as they reflect peak demand consumption. FBC has grossed these impacts up for losses to determine supply generation requirements as part of its portfolio analysis involving the scenarios discussed in Section 11.

Figure 4-2: Winter Peak Demand Impacts by Scenario and Year



As shown in Figure 4-2, Scenario 1 results in an increase in peak demand of over 500 MW by 2040 compared to the BAU forecast, an increase of about 56 percent above the BAU 2040 winter peak demand forecast of 890 MW, whereas Scenario 5 results in a decrease of approximately 100 MW by 2040 compared to the BAU forecast, a decrease of about 11 percent below the BAU 2040 winter peak demand forecast. As with energy consumption, the intermediate scenario impacts fall in the middle between these two extremes.

While the energy impacts of Scenario 4 (Diversified Energy Pathway) are higher than those of Scenario 3 (Deep Electrification), Figure 4-2 shows that the two scenarios are roughly the same when considering winter peak demand. This is for the following reasons:

- Integrated Photovoltaic Solar and Storage does not deliver any peak demand reductions in winter – it is dark too early and storage is insufficient (under the behaviours assumed) to shift PV output to peak demand hours later in the day.
- Scenario 4 includes higher penetrations for a number of load drivers that, though they consume a great deal of electricity (hydrogen production and large load sector transformation), also have very flat loads. This is in contrast with Scenario 3 in which loads, in particular, the electrification of transportation and space-heating, are potentially highly peak-coincident.

Scenario 3 would have higher winter peak demand than Scenario 4 if other factors were included. For example, while Scenario 3 does include some fuel switching from natural gas to electricity for residential customers, it does not include any fuel switching from natural gas to electricity for commercial or industrial customers. This is because residential fuel switching is the largest portion of the potential customer fuel switching potential and the purpose of the load scenarios analysis was to determine the most impactful load drivers for FBC while also exploring a wide variety of load drivers. Additionally, Scenario 4 includes a larger amount of large load sector transformation drivers, such as data centres and hydrogen production, than Scenario 3. As discussed in Section 2.3.5, it is possible that some of these types of large loads could be curtailable, or interrupted, during FBC's peak demand periods. If commercial and industrial fuel switching had also been included in Scenario 3 and if some proportion of large load curtailment had been included in both Scenarios 3 and 4, the difference in the peak demand impacts for Scenario 3 relative to Scenario 4 would be greater than presented in the figure above. Significant electrification of peak loads, such as those included in Scenario 3, can significantly increase costs relating to generation resources as well as transmission and distribution infrastructure, which is further discussed in Section 6.5.

4.1.4 RPAG Feedback

The load scenarios described above were discussed with the RPAG stakeholders in the June 25, 2020 meeting. At that session, FBC received feedback regarding the load drivers and scenarios. For example, one stakeholder asked if the 2021 LTERP included identification of TOU rates or other EV charging mitigation options to shift home charging from peak periods. FBC responded that the 2021 LTERP will discuss the various options which might be considered but that specifics in terms of exactly how much charging load could be shifted and the preferred option is properly the subject of a future regulatory application.

Another stakeholder asked if there has there been consideration of the penetration of air conditioning which could increase as climate change temperatures increase and have a non-linear impact on the climate change load driver. FBC noted that the 2017 REUS indicates that FBC customer air conditioning penetration is already at a high level, meaning that climate change warming temperatures are likely to have a linear effect on customer loads. Historical air conditioning load impacts are already taken into account in the BAU load forecast.

Another stakeholder asked if the amount of hydrogen production in the scenarios is based on the FEI requirements for 15 percent renewable gas content. FBC explained that the hydrogen production is based on the assumptions used for the Guidehouse Pathways study. The specific mix of hydrogen and renewable natural gas is yet to be determined by FEI – but 5 percent hydrogen is a reasonable initial assumption, given limitations of hydrogen blending in the natural gas system.

One stakeholder commented that the potential for a global recession, such as due to the COVID-19 pandemic, will certainly impact the load scenarios. FBC agrees but notes that there is still significant uncertainty in terms of COVID-19 impacts on the economy and changes in people's behavior – for example, workers may have shorter or less frequent commutes, reducing home and work EV charging loads but increasing other home electricity loads. The FBC Reference Case load forecast prediction intervals (discussed in Section 3.6) provide a range which may capture higher or lower economic growth than expected. A future LTERP could capture any permanent changes in behavior patterns that significantly impact load growth.

Finally, FBC notes that its power supply portfolio has the flexibility to manage variances in loads (as discussed in Section 5).

4.1.5 Guidehouse Key Findings and Recommendations

Guidehouse identified three key findings as part of its load scenarios analysis. Each finding is accompanied by one or more recommendations below.

#	FINDING	RECOMMENDATION
1	Electrification will require additional capital investment in order to address growth in "peaky" loads. Prudent management of such a transition could reduce the required capital investments and impacts on customer rates.	1.1. FBC should explore approaches to shifting EV charging to off-peak periods. FBC should consider studying a TOU rate designed for EV drivers and encourage electric vehicle supply equipment (EVSE) distributors to promote enabling technologies (such as timers) that could allow customers to take advantage of such rates. FBC should additionally consider other programmatic options for reducing the impact of potential future EV growth. 1.2. If FBC expects a large-scale electrification of residential water-heating, it should consider developing a water heater demand response (DR) program. Such direct load control is unobtrusive, tends not to inconvenience customers, has a long history of reliable performance in jurisdictions with high levels of electric water heater penetration (e.g., Florida, western North Carolina, etc.), and can substantially reduce peak contributions from this end-use. Additionally, FBC may wish to consider energy efficiency as well as DR as an option here, and encourage the adoption of heat pump water heaters. 1.3. If FBC expects large-scale electrification of space heating, it should consider studying whether peak demand impacts could be mitigated by encouraging "hybrid" electrification, in which residents maintain existing gas heating equipment to supplement new electric equipment on the coldest days. FBC may also wish to consider exploring the possibilities offered by electric thermal storage heating systems.[140]

[140] Electric thermal storage is a form of electric resistance heating that aims to shift demand. During off-peak periods electricity is used to heat a high-density ceramic brick. During on-peak periods, heat released from the brick is used to meet thermal requirements. For example, Nova Scotia Power currently offers time of day (TOD) rates to customers that have such equipment and offers on-bill financing to encourage their adoption. See:
Nova Scotia Power, *Electric Thermal Storage*, accessed August 2020.
https://www.nspower.ca/your-home/energy-products/electric-thermal-storage

#	FINDING	RECOMMENDATION
2	Distributed generation installed in residential households – with current incentives in place – is unlikely to make any meaningful contribution to peak demand reductions, even when enabled with energy storage.	2.1 FBC should continue to monitor developments in distributed energy storage, including the use of EV batteries as distributed energy resources (DERs) and consider formalizing an approach to leveraging such resources for system benefit. 2.2 FBC should consider the value of energy storage in relieving localized distribution constraints and, if justified, identify how best to unlock that value through incentives or program intervention. FBC should also consider whether revisions to the existing net metering tariff to encourage the adoption of energy storage to support rooftop solar generation may be appropriate.
3	There is potential for substantial growth in non-traditional high load-factor customer loads. If properly managed such loads may deliver substantial benefits to rate-payers.	3.1 The energy impacts of the growth of hydrogen production and data centres for FBC could be considerable. Given the very favourable load profiles of these two drivers and the potential growth of these industries (to support the decarbonization of the natural gas supply, and the ongoing growth in global data storage and processing requirements), FBC may wish to consider what ratepayer benefits could exist in developing (or refining any existing) economic development rates that target such industries conditional on where on the system these customers connect.

FBC has considered these recommendations and includes a discussion of them in Section 2.3.

4.2 STAKEHOLDER SCENARIOS

FBC also provided RPAG stakeholders with a crowdsource load scenarios tool to give them the opportunity to model their own load driver penetration levels and scenario impacts. The tool allowed stakeholders to adjust the growth rate of the load drivers based on their own views of the driver growth and penetration levels over time. Ten stakeholders used the tool provided and submitted their results to FBC. The average of the individual stakeholder scenarios (stakeholder average scenario) was determined by averaging the sum of the individual stakeholders' responses for each load driver in each year. The stakeholder average scenario compared to the Guidehouse scenarios are presented in the following figures.

1 **Figure 4-3: Stakeholder and Guidehouse Load Scenarios – Annual Energy Impacts**

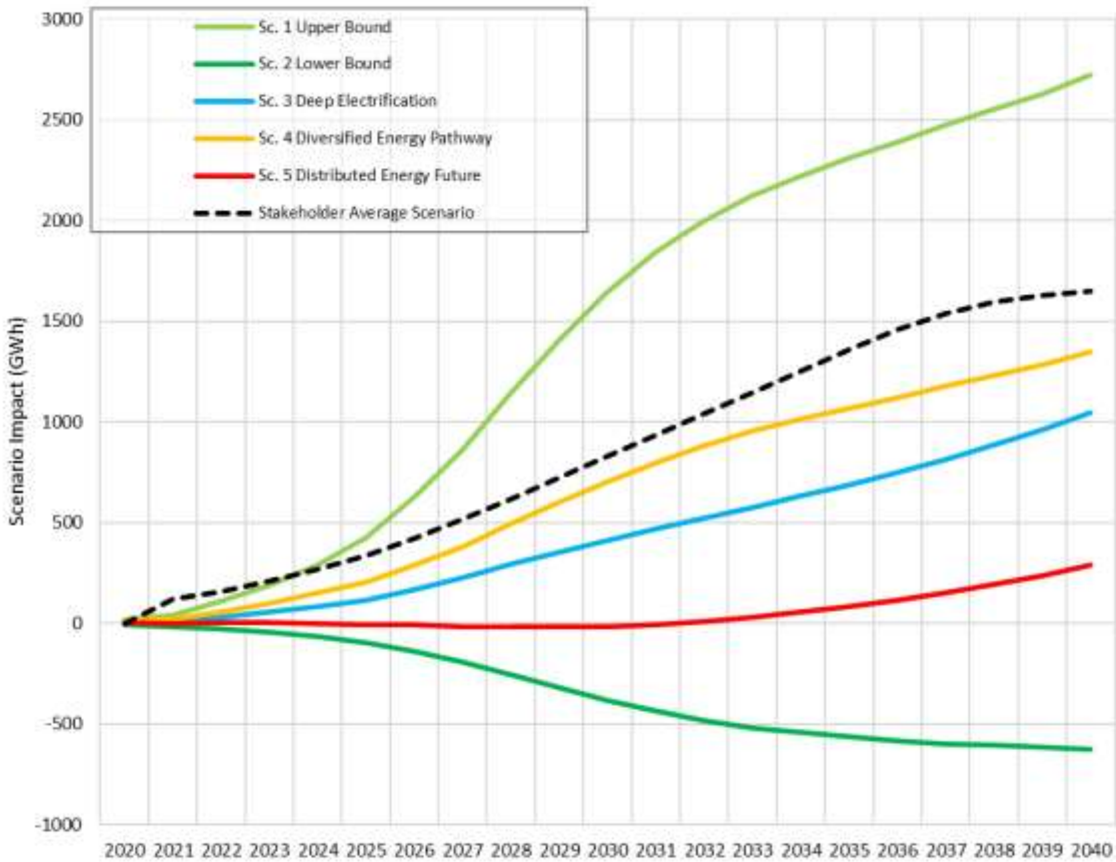


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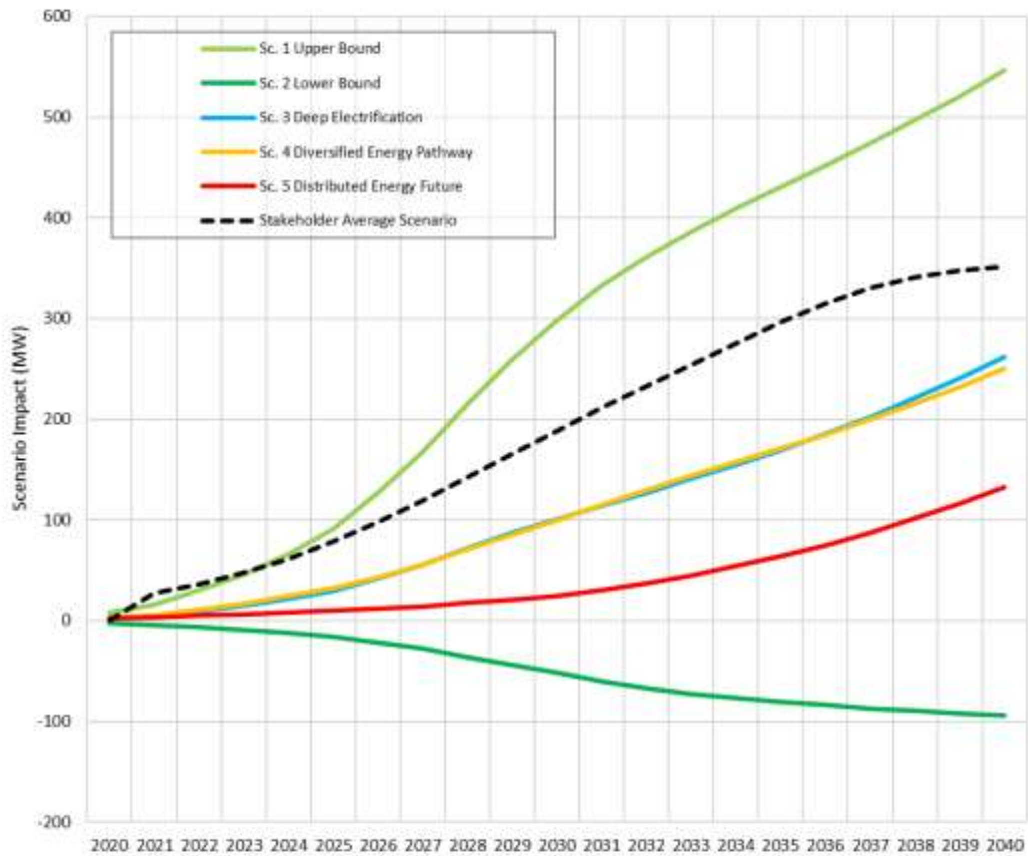
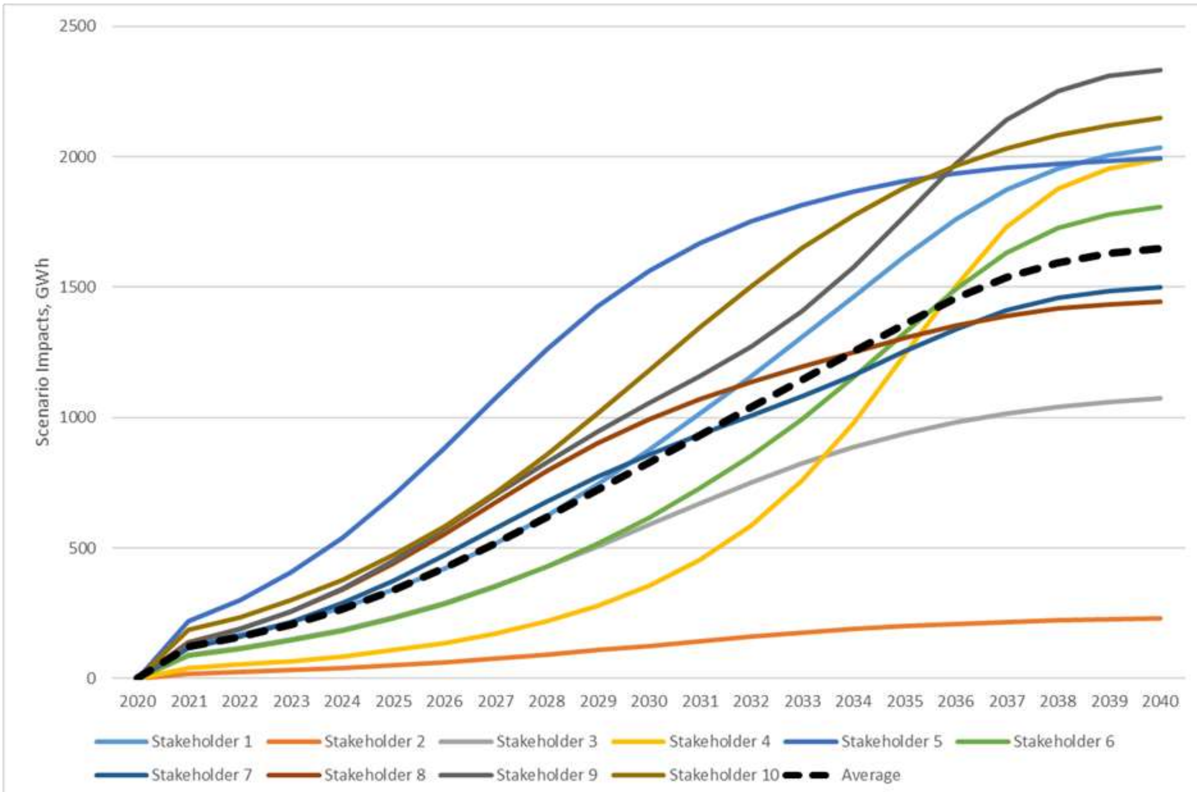
Figure 4-4: Stakeholder and Guidehouse Load Scenarios – Winter Peak Demand Impacts



The figures above show that the stakeholder average scenario trends with and then rises above the Guidehouse Diversified Energy Pathway scenario for annual energy and is well above the Guidehouse Diversified scenario for winter peak demand impacts. The reason for the higher annual energy and peak demand impacts for the stakeholder average scenario is due to stakeholders selecting larger amounts of MHD EV charging, large load additions, and gas-to-electric fuel switching, somewhat offset by more residential and commercial rooftop solar plus storage. The stakeholder average scenario results indicate annual energy loads about 1,650 GWh higher than the BAU forecast and winter peak demand loads about 350 MW higher than the BAU forecast. The details of the Guidehouse and stakeholder average scenarios are provided in Appendix J.

When looking at the individual stakeholder scenario results rather than the stakeholder average scenario results, there is a wide variety of opinions on the future load requirements. The following figure shows the individual stakeholder scenarios compared to the stakeholder average scenario for annual energy. The individual stakeholder entity names have been kept anonymous.

Figure 4-5: Stakeholder Individual vs. Average Load Scenarios – Annual Energy Impacts



Several conclusions can be drawn from the individual stakeholder load scenarios.

First, the wide range of scenarios provided by stakeholders indicates a lack of consensus on the likelihood and magnitude ascribed to the load drivers in each case. This supports FBC's belief that it is difficult to assign probabilities to the load scenarios given the high degree of uncertainty and difference of opinion regarding how the drivers will play out over time.

Second, stakeholders believe there is more potential for increased energy and peak capacity requirements above the BAU forecast rather than decreased requirements given that all of the individual scenarios have net positive energy impacts.

Third, while there are some differences between Guidehouse and the stakeholders in terms of the potential impacts from the individual load drivers, there is some degree of consensus that EV charging, hydrogen production, and large loads will be important load drivers shaping future load requirements.

FBC has included the stakeholder average scenario as well as the Guidehouse scenarios in its portfolio analysis (discussed in Section 11.3.4). Also, FBC's contingency planning will assess the impacts of scenarios that both increase and decrease load (see Section 11.3.9.1).

4.3 CONCLUSION

As part of its load scenario analysis, FBC explored two boundary scenarios and three intermediate scenarios as well as stakeholder scenarios. Load driver penetrations in the boundary scenarios help FBC understand the potential impact that each of these load drivers could have under extreme, but plausible, penetration scenarios, providing upper and lower limits for the other intermediate scenarios. The intermediate scenarios, which include combinations of load drivers that increase and decrease load, may be more reasonable potential future pathways. However, at this point in time, there is too much uncertainty to know which of the scenarios, if any, will occur in the future.

The principal finding for the Guidehouse intermediate scenarios is that the load drivers that may have the most impact to FBC going forward include EV charging, large loads, and hydrogen production. Lesser impacts were seen from fuel switching and rooftop solar. Carbon capture and storage, and climate change have the lowest impacts. This finding is generally aligned with the load drivers that stakeholders feel will be most important. While a load driver like EV charging would likely ramp up gradually over time as people transition from gasoline and diesel vehicles to EVs, hydrogen production, and large loads could be load drivers that could come on relatively quickly with shorter lead times and with potentially large immediate impacts on the FBC load requirements.

There are several recommendations arising from the load scenario analysis. First, electrification could require significant additional resource generation and system infrastructure in order to address growth in peaky loads, such as that from EV charging, if left unmitigated. Prudent management of such a transition could reduce the required capital investments and generation resources and impacts on customer rates. Second, distributed generation installed in residential households, with current rate structures, is unlikely to make any meaningful contribution to peak demand reductions, even when enabled with energy storage. FBC could consider initiatives to manage rooftop solar and energy storage to help optimize system benefits if distributed generation from rooftop solar becomes more significant on the FBC system. Third, initiatives to incent and properly manage potential growth in non-traditional high load-factor customer loads, such as hydrogen production, could improve system optimization and help reduce rate increases for all customers, particularly if these loads could be curtailed for short periods during system peaks. These are discussed in more detail in Section 2.3.5.

The ability of FBC to meet customer load requirements that are significantly higher or lower than the Reference Case load forecast is part of FBC's portfolio analysis and helps determine the requirement for resource flexibility. FBC has included this portfolio analysis within Section 11. The potential impacts of the load drivers and scenarios to the transmission and distribution system have also been considered and are discussed in Section 6.

5. EXISTING SUPPLY-SIDE RESOURCES

This section describes FBC's existing and committed supply-side resources as well as any constraints that these resources impose on FBC's resource planning. These include resources owned by FBC as well as contracts FBC has with other parties to provide energy and capacity to FBC. FBC resources consist of:

- FBC-owned generating plants and the associated entitlements under the Canal Plant Agreement (CPA);
- Brilliant Power Purchase Agreement (BPPA) entitlements;
- Brilliant Expansion (BRX) entitlement purchases;
- Waneta Expansion Capacity Purchase Agreement (WAX CAPA) entitlements;
- Purchases under the BC Hydro PPA;
- Purchases from IPPs; and
- Market and other contracted purchases.

Each will be further explained below. Graphs of FBC's annual energy and winter peak capacity resources expected to be utilized through 2040 are presented in Section 7. FBC's existing available energy and dependable capacity resources as of 2021 are provided in the following table.

Table 5-1: FBC's 2021 Available Energy and Dependable Capacity Resources[141]

FBC Existing Resources (2021)	Available Energy (GWh)	Dependable Capacity (MW)
FBC CPA Entitlements	1,596	208
BPPA	919	138
BRX	79	45
PPA (Tranche 1 Energy)	1,041	-
PPA (Tranche 2 Energy)	711	-
IPP	1	-
Market and Other Contracted	302	-
PPA Capacity	-	200
WAX (net of RCA)	-	218
Total Resources	4,648	810

[141] FBC is not required to utilize all available energy resources. Dependable capacity is after expected maintenance and operating reserve requirements and therefore is less than maximum generating capacity.

5.1 FBC-OWNED GENERATION FACILITIES AND ASSOCIATED ENTITLEMENTS UNDER CPA

FBC owns the Corra Linn, Upper Bonnington, Lower Bonnington, and South Slocan generating plants (collectively, the FBC Plants) located on the Kootenay River between Nelson and Castlegar, BC. The FBC Plants supplied approximately 44 percent of FBC's energy requirements and approximately 28 percent of the Company's peak demand in 2020.

The Company operates the FBC Plants in accordance with the CPA. The original CPA was entered into in 1972 to enable the Province of British Columbia to obtain the benefits of the improved water flow control provided by the construction of the Libby Dam in Montana and the Duncan Dam in BC. The original CPA became effective in 1975 and expired in 2005 and ensured that FBC received entitlements of both energy and capacity equal to the average that would have been available to FBC without the Libby and Duncan Dams. In 2005, BC Hydro, FBC, Teck Metals Ltd. (Teck), Brilliant Power Corporation, and Brilliant Expansion Power Corporation entered into a renewed CPA, which amended, restated, and extended the original CPA for a further 30 year term. The parties other than BC Hydro are referred to in the 2005 CPA as the "Entitlement Parties". In 2011, the CPA was further amended to incorporate the WAX plant and its owner, the Waneta Expansion Limited Partnership.

The CPA enables BC Hydro and the Entitlement Parties (collectively, the CPA Parties), through coordinated use of water flows and storage reservoirs, and through coordinated operation of generating plants, to generate more power from their combined generating resources than they could have if they operated independently. Under the CPA, BC Hydro takes into its system all power actually generated by the Entitlement Parties' respective plants. In exchange for permitting BC Hydro to determine the output of these facilities, the Entitlement Parties are contractually entitled to their respective "entitlements" of energy and capacity from BC Hydro. The Entitlement Parties receive their entitlements irrespective of actual water flows to the relevant generating plants and are thus insulated from the annual hydrology risk of water availability.

For the purposes of its 2021 LTERP, FBC is proceeding on the expectation that the CPA will continue indefinitely in its current form. However, there is some uncertainty in this regard. The main risk is that, pursuant to the terms of the 2005 CPA, any time after December 31, 2030, any party to the agreement is able to deliver a five-year termination notice. Given the degree to which the operations of the CPA Parties are interconnected, it would be very difficult to separate them to operate without the CPA or a similar agreement. It is far more likely that rather than resulting in termination, any major issue would be resolved through negotiation and could therefore potentially take effect within the time horizon of the LTERP. It is possible that such a negotiation could result in a reduced FBC entitlement or additional restrictions on how the existing entitlement is used. If this were to occur, additional resources could be required to make up the difference. An example of an issue that could bring this scenario about is if climate change results in significant changes to the amount and timing of water availability as compared to that assumed under the CPA.

5.1.1 Impacts of Climate Change and Water Availability

As discussed in Section 2.2.1, climate change could have a material impact on water availability for hydroelectricity generation in the Pacific Northwest. Correspondingly, any changes to water availability could open up the possibility of changes to the entitlements under the CPA. The CPA entitlements were originally determined using water inflows prior to 1988 – and climate change may result in more precipitation as rain instead of snowpack during the winter months, which would change the monthly profile and availability of water flow, potentially leading to an earlier freshet period and decreased flows during the summer as well.[142]

In addition, it is not known how potential changes to the Columbia River Treaty (CRT) between Canada and the United States might impact FBC CPA entitlements. While the CRT will not directly impact FBC CPA entitlements since Kootenay Lake is outside the CRT, indirect impacts may be possible. For example, if salmon runs were to be restored to the Canadian Upper Columbia as part of the CRT, then Kootenay River operations may need to be modified to support that change. Depending on the nature of what modifications may be required, there may or may not be a risk to FBC entitlements. CRT negotiations between Canada and the US are ongoing. In January 2021, the Columbia River Treaty Local Governments Committee released their updated recommendations,[143] which included integrating climate change-related information into the CRT, and exploring the technical and financial feasibility for pursuing salmon restoration to the Canadian portion of the Columbia River.

Finally, Kootenay Lake levels are governed by the 1938 International Joint Commission (IJC) order on Kootenay Lake.[144] In recent years, there has been discussion on the possibility of re-opening the 1938 Order with the intention of widening the scope to include more objectives than just flood control and power generation. Additionally, the IJC has directed all boards[145] to assess climate change impacts, and whether or not the IJC order on Kootenay Lake should be modified as a result.[146] If the 1938 Order were to be reopened, it is expected that various proposals to modify the order would be brought forth by external stakeholders. Any changes to the IJC order would have the potential to either increase or decrease the available generation and therefore the FBC entitlements as well. A similar risk arises if a water use plan for Kootenay Lake was mandated by the BC government, which could occur to avoid fish stranding, among other reasons. While the LTERP does not directly consider these risks, it is important that any new resources that are acquired be as flexible as possible to assist in meeting any future uncertainties that may occur.

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[142] Columbia River Basin Impact Assessment, Final Report, March 2016, page ES-10.

[143] https://akblg.ca/columbia_river_treaty.html.

[144] The IJC order for Kootenay Lake can be found at https://ijc.org/en/klbc/1938-kootenay-lake-order. Kootenay Lake storage operations resulting from the FBC owned Corra Linn Dam impact Kootenay/Kootenai River levels in the United States. Therefore, Canada and the US have agreed that the IJC has jurisdiction over Kootenay Lake levels and the IJC has ordered the limits to which FBC can store water in Kootenay Lake.

[145] The IJC studies and recommends solutions to transboundary issues when asked to do so by the national governments. When the IJC receives a government request, called a reference, it appoints a board with equal numbers of experts from each country.

[146] https://ijc.org/en/klbc/record-annual-public-meeting-nelson-bc-september-19-2019.

5.2 BRILLIANT POWER PURCHASE AGREEMENT

FBC is party to the BPPA, a power purchase agreement with Brilliant Power Corporation made as of April 4, 1996. Under the BPPA, which expires in 2056, FBC has agreed to purchase (a) the energy and capacity entitlement allocated to the Brilliant Plant[147] pursuant to the CPA and (b) after the termination, if any, of the CPA, the actual electrical output generated by the Brilliant Plant. The BPPA uses a take-or-pay structure which requires that FBC pay for the Brilliant Plant's entitlement, irrespective of whether FBC actually takes it.

Included in the BPPA is an amendment made in May 1996 (Second Amendment) that added an additional 65 GWh of energy and 20 MW of capacity through the term of the agreement once the Brilliant Plant unit upgrades were fully completed. The Brilliant Plant provided approximately 26 percent of FBC's energy requirement and 19 percent of the peak capacity needs in 2020.

5.3 BRILLIANT EXPANSION AGREEMENT

FBC has entered into a ten-year power purchase agreement with Columbia Power Corporation (CPC), as of June 10, 2017. Under this agreement, FBC has agreed to purchase a portion of the capacity and energy entitlements attributed to BRX from Brilliant Power Corporation. This agreement expires as of December 31, 2027, and within this Application, renewal is not assumed beyond that date. Furthermore, the remaining portion of BRX entitlements are under contract to BC Hydro and also expire in a similar time frame. This means that the entire set of capacity and energy entitlements attributed to BRX may be available as a future resource option for FBC. This power could be an opportunity to secure cost-effective, locally-generated power to meet FBC's resource needs.

The BRX agreement provided approximately 2 percent of FBC's energy requirement and 4 percent of the peak capacity needs in 2020.

5.4 WANETA EXPANSION CAPACITY PURCHASE AGREEMENT

The WAX Plant is a second powerhouse at the Waneta Dam on the Pend d'Oreille River south of Trail, BC. Constructed from 2010 to 2015, the WAX plant is located immediately downstream from the Waneta Dam and its existing powerhouse, the 335 MW expansion shares the existing dam's hydraulic head and generates power from water flows that would otherwise be spilled. Output from the units is delivered to BC Hydro's Selkirk Substation through a 10-kilometre transmission line. Columbia Power Corporation (CPC) and Columbia Basin Trust (CBT) formed a partnership with FBC's parent company Fortis Inc. (the Waneta Expansion Limited Partnership) for the project. On January 28, 2019, Fortis Inc. announced that it had entered into a definitive agreement with CPC and CBT to sell its 51 percent interest in the WAX. The sale closed on April 16, 2019. As a result of the sale, the Waneta Expansion Capacity Purchase Agreement (WAX CAPA) was assigned to WEPC (Waneta Expansion Power Corporation),

[147] The Brilliant Plant is located on the Kootenay River downstream of the FBC plants and just above Castlegar where the Kootenay River joins the Columbia River.

wholly owned by CPC and CBT, and there was no subsequent change to FBC's energy portfolio.

Under the WAX CAPA, FBC has agreed to purchase from the Waneta Expansion Power Corporation all unused WAX-related capacity (residual capacity) that remains after BC Hydro has acquired the energy entitlements associated with the plant (as defined by the CPA). FBC began receiving power under the WAX CAPA on April 2, 2015, and the agreement is for a 40 year term that expires on April 2, 2055. The capacity entitlements obtained by FBC under the WAX CAPA vary by month and are suitably shaped to meet FBC's winter and summer peak demand requirements when capacity is needed the most and provides less capacity during the three freshet months when it is needed the least. This capacity profile is an ideal match for FBC's seasonal load shape. The WAX CAPA was reviewed by the BCUC in 2010, and accepted pursuant to Order E-29-10.

The amount of residual capacity provided under the WAX CAPA is greater than FBC's current capacity requirements in most months and, as a result, FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to sell a 50 MW block of WAX CAPA residual capacity to BC Hydro under the Residual Capacity Agreement (RCA), entered into as of July 15, 2013. The BCUC approved the RCA in Order G-161-14. The RCA expires September 30, 2025, and for the purposes of the 2021 LTERP, FBC is assuming that it is not renewed. FBC will sell the remaining surplus WAX CAPA residual capacity to Powerex Corp. (Powerex) on a day-ahead basis, under the terms of the Capacity and Energy Purchase and Sale Agreement (CEPSA), dated February 17, 2015, if and when the capacity is not required to meet FBC load requirements. The BCUC accepted the CEPSA for filing in Order E-10-15. The CEPSA currently expires on September 30, 2022, but can be renewed on an annual basis through September 30, 2025 by mutual agreement. For the purposes of the 2021 LTERP, FBC is assuming that the CEPSA will continue indefinitely after 2025 in its current form.

5.5 *BC HYDRO POWER PURCHASE AGREEMENT*

Under the PPA, FBC's customers have access to BC Hydro supply up to a maximum of 200 MW and 1,752 GWh of annual energy. The term of the PPA continues through to September 30, 2033. In 2020, the PPA supplied 18 percent of FBC's energy requirement and 18 percent of the Company's peak capacity needs.

FBC's access to BC Hydro's embedded cost energy (at a rate of $50.73 per MWh as of April 1, 2021) under the PPA is limited to 1,041 GWh (Tranche 1 Energy). Above 1,041 GWh and up to the maximum of 1,752 GWh, the energy cost increases to $95.09 per MWh (Tranche 2 Energy), which is tied to BC Hydro's proxy for long run marginal cost for firm energy and is equal to BC Hydro's RS 1823 Tier 2 rate.[148] FBC is required to submit a nomination by June 30th of each year for PPA energy deliveries in the following October to September period (PPA Nomination). Regardless of the PPA Nomination, FBC maintains access to 1,752 GWh of energy under the

[148] https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/310251/index.do.

PPA in that year and is free to schedule in any amount of energy that is required up to the 1,752 GWh. Only the cost of the energy will change depending on the PPA Nomination. If energy is delivered above the PPA Nomination, but below the Tranche 1 Energy limit of 1,041 GWh, there is an additional surcharge of 50 percent to the Tranche 1 rate. Energy delivered above the PPA Nomination and above the Tranche 1 Energy Limit is subject to a 15 percent surcharge on the Tranche 2 Energy rate.

FBC is required to take or pay for 75 percent of the PPA Nomination, even if it does not schedule the energy. FBC manages its portfolio in a manner that ensures it uses at least 75 percent of the PPA Nomination in order to avoid paying for energy that it does not require. The difference between the PPA Nomination and the 75 percent minimum take provides the flexibility to manage the variability of actual annual loads compared to forecast. If actual load is close to forecast load, FBC has the ability to displace the 25 percent variability with market purchases if market conditions would create additional savings for FBC customers compared to PPA energy rates.

FBC cannot change the annual PPA Nomination by more than 20 percent from the previous year. This needs to be considered when FBC sets the PPA Nomination in each year to ensure that the most cost effective firm resources are in place to meet the expected load, without relying on higher cost PPA deliveries above the PPA Nomination in future years.

The Energy Export Agreement (EEA) was entered into at the same time as the PPA as one of the related agreements connected to the PPA. The EEA allows, at FBC's option, to export any surplus from new resources if that is the most cost effective usage, as long as it does not result in increased PPA load compared to if the new resource had not been obtained. This agreement protects against the export of PPA energy, and ensures that the actual cost of entering into new resources is not artificially higher than it should be by forcing BC Hydro purchases to be displaced.

FBC's base assumption for its portfolio analysis in Section 11 assumes that the PPA will continue in a similar form past the current expiry date in 2033. FBC will begin to review the current PPA Agreement in 2023, 10 years before the expiry, to determine the Company's position on renewal. Any negotiations to renew will begin well before 2033. The portfolio analysis also includes a scenario where the PPA is not renewed beyond 2033 to provide an indication of the resources that would be required to replace the PPA energy and capacity.

5.6 *SHORT TO MEDIUM TERM MARKET PURCHASES*

FBC has short to medium term fixed price contracted purchases from the wholesale market for the delivery of electricity that have been accepted by the BCUC. The power markets are influenced by several factors that are reviewed in Section 2.4 and a forecast of market prices is presented in Section 2.5.

FBC can also choose to purchase energy and capacity from the wholesale market when it is more competitively priced than purchases under the PPA, or when FBC does not have sufficient resources to meet peak demand requirements. Real-time market purchases are able to be made using the 25 percent flexibility of the PPA, and therefore, any market purchases are back-stopped by the PPA. If any market shortages or transmission constraints were to occur, as discussed in Section 2.4.4.3, the replacement energy would likely be available through the PPA. In 2020, market and contracted purchases accounted for 10 percent of FBC's annual energy requirements.

FBC access to the market is mainly through its transmission rights on the Teck-owned 71 Line, which provides transmission from across the BC/US border to the FBC system. For long-term planning purposes such as the 2021 LTERP, this access is treated as firm but it must be recognized that the Company does not own this transmission line. FBC retains access to the wholesale market on Teck's 71 Line for a 20-year period at minimum, as discussed in Section 2.4.4, and comparable market access afterwards is assumed for the planning period. Also, additional US transmission is required to access the Mid-C trading hub, which is located along the Columbia River on the border between Washington and Oregon. Additional firm transmission cannot be reliably obtained on the US side of the border and as such, while the market currently remains an excellent source of energy to meet FBC customer requirements and could meet the energy gaps that the Company expects through 2040, it cannot be considered a long-term resource to meet capacity requirements (as described in more detail in Section 2.4.4). The Company intends to continue to explore what BC-based market options may be available to meet future needs.

5.7 *INDEPENDENT POWER PRODUCERS AND OTHER RESOURCES*

The Company purchases energy through five power purchase contracts with IPPs located within the FBC service area. IPPs provide less than 1 percent of FBC annual energy requirements. In the future, this could also potentially include larger purchases of power from FBC self-generation customers.

FBC also receives physical loss deliveries from transmission service customers taking service under FBC's Rate Schedules 100, 101, and 102. These customers deliver energy to FBC in accordance with Rate Schedule 109. Loss Recoveries[149] provide less than 0.1 percent of FBC's annual energy requirements.

5.8 *SUMMARY*

FBC meets its energy and capacity requirements primarily through a portfolio of FBC-owned entitlement resources, long-term entitlement purchase agreements, and purchases under the

[149] Transfer of electrical energy between power plants, substations and customers is impossible without some energy loss. The quantity that is lost during transmission and distribution of electricity across the electric grid is referred to as line losses. Loss compensation is required for all transactions under RS 100, RS 101 and RS 102. These losses are scheduled to the Company under the existing loss compensation service, RS 109. FBC was directed to forecast Loss Recoveries through Order G-246-18.

BC Hydro PPA. Any remaining energy needs are met through short to medium term market, IPP, and other resource purchases.

There are some important changes to FBC's existing portfolio of resources over the planning horizon. The RCA relating to the WAX CAPA residual capacity sale expires September 30, 2025, and for the purposes of the 2021 LTERP, FBC is assuming that it is not renewed. FBC will sell the remaining surplus WAX CAPA residual capacity to Powerex on a day-ahead basis, under the terms of the CEPSA, if and when the capacity is not required to meet FBC load requirements. BRX entitlement contracts with FBC and BC Hydro expire at the end of 2027 and renewal is not assumed beyond that date. The entire set of capacity and energy entitlements attributed to BRX will be assessed as a future option to meet FBC's resource needs. Additionally, the PPA agreement with BC Hydro expires in 2033. FBC's base assumption for its portfolio analysis in Section 11 assumes that the PPA will continue in a similar form past the current expiry date in 2033. FBC plans to review the PPA in 2023 to determine if negotiations should begin with BC Hydro to renew the PPA in its current form or some alternate form.

6. TRANSMISSION AND DISTRIBUTION SYSTEM

6.1 *INTRODUCTION*

A key aspect of ensuring cost-effective, secure and reliable supply of electricity to customers is identifying the transmission and distribution system infrastructure that FBC may need to upgrade or construct over the planning horizon. This section discusses FBC's examination of the power system and identification of any system resource needs in terms of peak capacity to ensure that the FBC system continues to serve the needs of its customers.

This section includes a system overview as well as a discussion of planning criteria and studies that help define the requirements of FBC's power system over the planning horizon. Potential impacts from emerging technologies such as solar PV, EVs and large load sector transformation, including data centres and hydrogen production, are also described. While there is uncertainty regarding the adoption and penetration of new technologies, FBC will continue to monitor developments in order to plan system requirements appropriately.

Given the potential for higher customer peak demand than is expected in the system planning load forecast, this section also includes a high-level assessment of possible system impacts resulting from some of the load scenarios discussed in Section 4 as well as an alternate load scenario which including impacts from EV charging and fuel switching only. This provides FBC with an indication of the potential incremental transmission and distribution infrastructure required in the event that higher load scenarios emerge over the planning horizon and if mitigation measures are not implemented. This highlights the significant cost related to the electrification of loads and the importance of effectively managing peak demand on the FBC system.

This section provides a level of detail that FBC considers appropriate for long-term resource planning with respect to transmission and distribution infrastructure. More specific information with respect to detailed transmission and distribution capital infrastructure additions and upgrades will be provided separately in future capital forecasts and brought forward in CPCN applications to the BCUC as necessary.

6.2 *TRANSMISSION AND DISTRIBUTION SYSTEM OVERVIEW*

FBC operates in the southern interior of B.C. transporting and distributing energy within and between communities including Kelowna, Oliver, Osoyoos, Trail, Rossland, Castlegar, Creston, and Princeton and surrounding areas. In addition, FBC supplies/wheels power to the District of Summerland, the cities of Grand Forks, Penticton and Nelson, as well as to BC Hydro near the communities of Kaslo, Lake Country, Creston and Yahk-Kingsgate. Figure 1-1 in Section 1.1 provides a map outlining FBC's service area.

As a system overall, FBC is a winter peaking utility, with winter peak demand typically being higher than summer peak demand. The transmission and distribution system has been designed and constructed to meet both peak demand during extreme low temperature conditions during winter as well as extreme hot temperatures in the summer. Although the trends are evolving, there is some evidence that in some areas of the system the summer peaks are growing faster than the winter peaks. At the end of June 2021, FBC's service area, the Okanagan in particular, experienced an unprecedented rise in temperature (as discussed in Section 2.2.1). This caused the system to undergo record peak summer demands (with peak demand reaching a record level of 764 MW on June 29) and equipment temperatures well beyond expectations and design conditions. The system was able to meet this peak demand without experiencing any power supply or system reliability issues. FBC intends to assess the impacts, if any, on its system infrastructure over the next year to determine if any further actions may be needed to improve system resiliency against these types of events which could be incorporated into FBC's future system capital planning.

The following subsections provide further details on FBC's transmission system, transmission interconnections and recent system upgrades and expenditures.

6.2.1 Transmission Network

FBC's high voltage transmission lines are vital for the integration of the energy resources needed to serve FBC customers and other municipalities. FBC's bulk transmission system is operated fully meshed[150] from Kelowna through to the Kootenay River generating stations, which improves system reliability and reduces transmission system losses. FBC's transmission network consists of approximately 1,300 kilometres of high voltage transmission lines. Table 6-1 below provides the length of overhead transmission lines by voltage class for each FBC region.

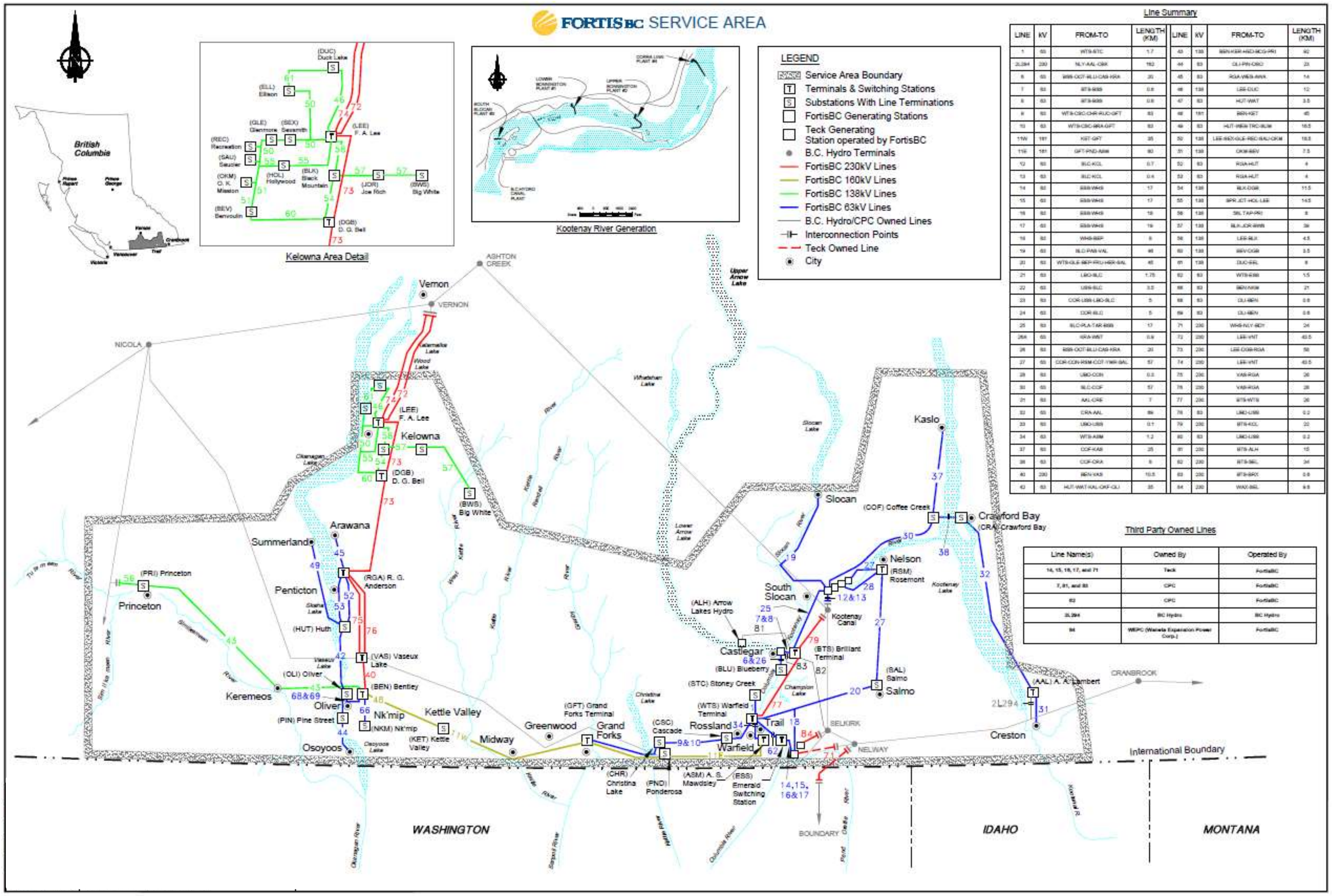
Table 6-1: Transmission Line Lengths by Region and Voltage Class (kilometres)

Region	63 kV	138 kV	160 kV	230 kV	Total
North Okanagan	0	120	0	114	234
South Okanagan	123	103	16	99	341
Kootenay	455	0	23	50	528
Boundary	83	0	103	0	186
Total	661	223	142	263	1,289

Figure 6-1 below is a high-level overview of the FBC transmission network showing key transmission lines.

[150] In a meshed system, transmission lines to substations operate in parallel. As a result, if an outage occurs to one of the transmission lines supplying a substation, then an alternate line is immediately available to provide continued supply - no manual reconfiguration of the system is necessary and no customer outages occur.

1 **Figure 6-1: FBC Transmission System Map**



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6.2.2 Transmission Interconnections

There are a total of eight transmission interconnections between the FBC system and the systems of neighbouring transmission entities, including BC Hydro. FBC transmission interconnections improve reliability by providing the flexibility to move energy between FBC and other utilities (primarily BC Hydro), to transfer FBC's own resources from the point of generation in the Kootenays to its major load centre in the Okanagan,[151] to import market power and also provide economic benefits based on the ability to share generation operating reserves. FBC's ability to import and export electricity from other members of the Western Interconnection[152] improves system reliability and has economic benefits for FBC by allowing the Company to access transmission and generation resources that it would not otherwise be able to access.

As shown in Figure 6-1, the FBC system is connected to the following five major BC Hydro transmission stations:

- Kootenay Canal Generating Station (at 63 kV and 230 kV);
- Vaseux Lake Terminal Station (500 kV);
- Vernon Terminal Station (230 kV;
- Selkirk Substation (230 kV), and
- Nelway Substation (230 kV).

In addition, there are two area specific interconnections with BC Hydro at Princeton and Creston that are only used radially to supply local FBC load.

These transmission interconnections and the surrounding BC Hydro bulk transmission system are critical to the reliable operation of the FBC system. The only FBC-owned interconnection between the Okanagan and Kootenay networks is a single 160 kV transmission line. The Okanagan region has about 65 percent of the FBC load, but all FBC generation resources are in the Kootenay region. As the Okanagan region has no generation resources, all demand is met by external generation delivered either directly through FBC's system or wheeled via the BC Hydro network.

6.2.3 Recent System Upgrades and Expenditures

To ensure ongoing safe and reliable operation of the electric system, FBC undertakes capital investments in the transmission and distribution system on an continual basis. Some of the more significant transmission projects completed within the last five years include:

[151] FBC owns and operates a single 160 kV transmission line between the two regions and this line has insufficient capacity to supply the Okanagan load.

[152] The Western Interconnection refers to the interconnected electric transmission grid which stretches from Western Canada south to Baja California in Mexico, and from the Pacific Coast reaching eastward over the Rockies to the Great Plains. All of the electric utilities in the Western Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency.

- The Ruckles Substation Rebuild Project (Ruckles Project) was completed in July 2018 on the existing substation site, and was necessary to continue to safely and reliably supply electricity to the City of Grand Forks' municipal electric utility, an industrial sawmill and the surrounding FBC service area. As the substation site is located within the flood zone of the Kettle River, the substation was raised to address the related risks. The increased capacity of the substation has improved as well as the reliability of electricity supply in the area.
- The addition of a second transformer at the Grand Forks Terminal Substation was completed in February 2021 on the existing substation site. This addition will now provide reliable back-up power to the 63 kV system in the Grand Forks area in the event of a Grand Forks Terminal transformer (GFT T1) outage or failure.
- The addition of a second transformer at Sexsmith substation was completed in October 2020 on the existing substation site. This addition enables FBC to continue to maintain the current levels of system reliability and meet the planning criteria for this area of Kelowna.

Table 6-2 below outlines capital expenditures for the period 2016 to 2021 ('A' after the year indicates actual, and 'P' indicates projected). FBC's anticipated system reinforcements are discussed in section 6.4 below.

Table 6-2: Transmission and Distribution Capital Expenditures 2016 – 2021 ($000s)

Expenditure categories	2016A	2017A	2018A	2019A	2020A	2021P
Transmission, Stations, Protection & Control, Telecommunications	8,952	12,811	11,804	13,867	27,361	34,581
Distribution	29,199	34,456	36,956	33,399	41,420	40,641
Total	**38,151**	**47,267**	**48,760**	**47,266**	**68,781**	**75,222**

6.3 *SYSTEM PLANNING METHODOLOGY*

6.3.1 Load Forecasting for System Planning

In order to ensure that FBC's network infrastructure is sufficient to provide a safe and reliable electricity supply to all customers, the transmission and distribution system must be planned, constructed, and operated to meet peak load requirements during extreme weather conditions. This contrasts with the resource planning requirement to acquire energy resources to meet energy and peak demand requirements under "normal" or "expected" weather conditions as set out in the Reference Case load forecast presented in Section 3.[153] Consequently, FBC requires and develops load forecasts for two different purposes: system planning (for transmission and

[153] This is also referred to as a "top-down" forecast since it presents the entire FBC system as a single load quantity.

distribution infrastructure planning) and resource planning (for capacity and energy resource planning).

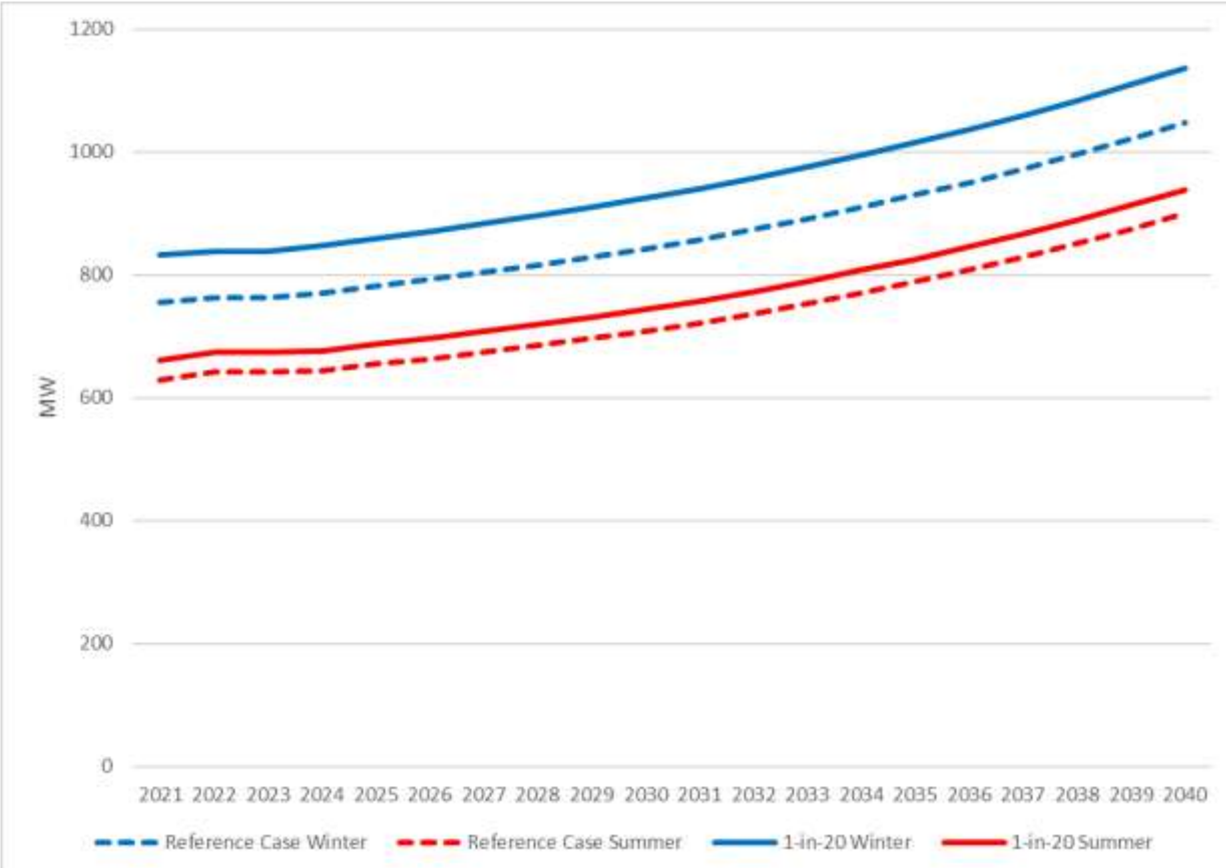
The system planning forecast is a per-substation forecast that is developed from the “bottom up” using historical per-feeder peak demand data. The per-feeder data is aggregated to the substation level and then by area for use in transmission and distribution infrastructure project identification and planning. The feeder and substation forecasts are based on actual demand peaks, which are typically recorded during weather extremes in the summer (June through August) and in the winter (November through February). The substation forecast forms the basis for the expected future winter and summer peak loads and is used to determine the adequacy of the transmission, substation, and distribution infrastructure required to supply FBC’s customers during peak demand periods.

Recognizing that these per-substation forecasts represent load peaks that may or may not occur at the same time, it is necessary when aggregating the per-substation forecasts to account for customer load diversity[154] within the system. This is achieved by forecasting the total system load from the “top down” under extreme (i.e. one occurrence in 20 years) weather conditions, and then rationalizing the two forecasts by uniformly scaling the per-substation peak forecasts such that their total load matches the total winter and total summer peak loads given in the system load forecast. The result is a “1 in 20” peak demand forecast which is not the same as the “expected” peak demand forecasts per the Reference Case load forecast shown in Section 3 of this LTERP.

The following figure shows a comparison of the Reference Case and the 1 in 20 peak demand forecast for winter and summer. The forecasts are presented excluding losses as the 1 in 20 forecast does not include losses as they are calculated and incorporated in the FBC system power flow simulation which captures the variable nature of the losses depending on the specific system configuration.

[154] Diversity refers to the concept that the potential customer load always exceeds the actual demand at any given time. This is because usage patterns vary (i.e. heating loads are cyclical) and, as a result, not all customers consume energy at the same time. This diversity effect occurs not just from customer to customer, but also between rate classes; residential, commercial, irrigation, etc. have differing usage patterns. Consequently, different feeders and substations typically experience their peak loads at different times.

Figure 6-2: Reference Case vs. 1 in 20 Peak Demand Forecast



The load forecast methodology for system planning purposes was reviewed in conjunction with the Company's 2012 Integrated System Plan (ISP).[155]

6.3.2 Transmission Planning Criteria

FBC's planning criteria require that the system be planned, designed and operated to serve all customer loads both during normal operations and during contingency operations (i.e. one or more system elements out of service). The most basic criterion is that the system infrastructure must be sufficient to meet all reasonably forecast customer demand with all system components (e.g. transmission lines and transformers) in service. This is referred to as "all elements in-service" or N-0[156] operation. The next, more limiting, condition is single contingency (N-1)[157] operations where FBC's planning criteria state that the transmission system infrastructure must also be sufficient to meet all reasonably forecast customer demand even with the single most limiting transmission component out of service. Exceptions are allowed for customer loads

155 See BCUC Order G-110-12 dated August 15, 2012, page 143.
156 N-0 refers to there being some number ("N") of system elements, with zero of them out of service.
157 N-1 refers to there being some number ("N") of system elements, with one (typically the most impactful) element out of service.

supplied radially by the faulted element or affected area. For double contingency (N-2)[158] and higher conditions, the criteria allow planned and controlled disconnection of customer loads. Remedial Action Schemes[159] may be employed during system operations to minimize the scope of customer outages for N-2 contingencies. These planning criteria are consistent with those used by other utilities in the Western Interconnection.

The task of providing reliable and cost-effective electric service requires the ability to assess the reliability of performance of various system configurations. FBC transmission planners employ both deterministic and probabilistic methods to assess system reliability. The contingency analysis used in transmission system assessment is deterministic, as the required infrastructure needs to be in place to meet the most adverse operating conditions. If necessary, probabilistic analysis is used for selecting the optimal solution once a need or constraint has been identified.

6.3.3 Transmission Planning Studies

The FBC Transmission Planning group conducts system studies to ensure that the system will continue to reliably meet capacity demand in the presence of growing customer load during the planning horizon used for these studies, typically 20 years. These studies are performed annually and result in the identification of transmission system upgrades required in the short and medium term. The intent of these long-term studies is not necessarily to identify specific system upgrades but, rather, the system load levels at which a new set of reinforcement options must be considered. The results of these annual studies are shared with BC Hydro as the Balancing Authority[160] to coordinate the overall FBC and BC Hydro electrical system.

Transmission studies are based on computerized power flow and transient stability analyses conducted using power systems simulation software. In the current FBC study cycle, FBC conducted the following transmission studies:

- power flow analysis for 2022, 2026 and 2030, for both winter and summer peak conditions;
- power flow analysis for 2022 light load conditions;
- transient stability analysis for 2022 winter peak, summer peak and light load conditions; and
- longer-term power flow studies of the bulk system beyond the 20-year planning horizon to determine the potential need for future large transmission upgrades.

FBC's power flow studies include an analysis of all possible single contingencies (N-1) in the FBC system. Thermal violations, or overloads, are recorded on elements that show a power

[158] N-2 refers to there being some number ("N") of system elements, with two elements out of service.

[159] A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation, tripping load, or reconfiguring a system.

[160] "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." Glossary of Terms Used in NERC Reliability - Updated October 1, 2014.

flow exceeding 90 percent of their respective winter or summer emergency rating. Voltage violations are also flagged on system buses that show a voltage less than 90 percent or greater than 110 percent of nominal voltage. All buses at and above 63 kV in the FBC system and major 230 kV and 500 kV buses of neighbouring systems are monitored in the study.

The transient stability study is based on simulations of three-phase and single-line-to-ground faults. Both normal fault clearing as well as the slower backup clearing is simulated, followed by the tripping of the faulted line. The dynamic performance of the system is assessed based on observations of post-fault behavior of important system quantities, such as generator rotor angle, power flows, bus voltages and system frequency. Analysis of post-fault oscillations in these studies will reveal how quickly the oscillations stabilize, leading to a quick system recovery from the disturbance.

An assessment of reactive power[161] capabilities is also necessary. As previously noted, the FBC system consists of two areas, the Kootenay region, with surplus generation, and the Okanagan, with an absence of generation. The lack of dynamic reactive support in the Okanagan (due to absence of generation resources that can respond to load changes in real-time) can lead to low voltages or voltage collapse during contingency conditions.

Each thermal or voltage violation found in the steady state analysis is then analyzed in order to define the most cost-effective mitigation plan. These studies identify a collection of transmission reinforcement projects that are required within the 20-year planning horizon.

Projects are identified as the system reaches various load thresholds to mitigate violations and for continued reliable operations. The timing for projects changes as annual studies are completed with updated information. Longer-term projects are subject to further review as load growth trends become more certain in the future.

6.4 ANTICIPATED SYSTEM REINFORCEMENTS

FBC assesses the timing of projects annually based on the updated 1 in 20 peak demand forecasts and consequently the timing of some projects may either be advanced or delayed. FBC's most recent project assessment spanned the 20-year planning horizon out to 2040.

At the present time, six transmission reinforcement projects have been identified for the FBC system within the next ten years of the 20-year planning horizon; one of these projects was submitted to the BCUC as a CPCN (Kelowna Bulk Transformer Addition).[162] The other projects could be the subject of future CPCN applications. Given the greater amount of uncertainty regarding the projects for the last ten years of the planning horizon, FBC has only included the planned projects for 2021 to 2030 in the table below.

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[161] Reactive power flow occurs in power systems containing reactive (inductive or capacitive) components and can be either produced or consumed by different load/generation elements.
[162] Approved November 30, 2020 by BCUC Order C-4-20.

Table 6-3: Transmission Reinforcement Projects

Time Frame	Project	Purpose	Primary Driver	
			Capacity	Reliability
2021-2022	Kelowna Bulk Transformer Capacity Addition	Add additional 230/138 kV transformation capacity in Kelowna to adequately supply area load	X	X
2024-2025	Replace AS Mawdsley (ASM) Transformer T1	To provide adequate transformation capacity during normal and contingency conditions	X	X
2027-2028	52L & 53L Upgrade	To provide adequate capacity during single contingency	X	X
2028-2029	Replace AS Mawdsley (ASM) Transformer T2	To provide adequate transformation capacity during normal and contingency conditions	X	X
2028-2029	60L & 51L Upgrade	To provide required capacity when either LEE T3, T4 or T5 is out of service and there is an outage of another LEE transformer		X
2028-2029	20L Upgrade	To provide adequate capacity during normal and single contingency conditions	X	X

The high-level preliminary estimated cost of the projects included in the table above is approximately $128 million. This estimated cost may change over time. As noted above, changes in peak demand forecasts may result in the advancement or deferral of some projects. This has occurred in the case of the Kelowna Bulk Transformer Capacity Addition Project and, potentially, could occur for the 20L upgrade project or other projects.

Until recently, system studies indicated that the Kelowna Bulk Transformer Capacity Addition project would be required due to equipment loading constraints during winter peak load conditions. In the 2014 FBC Performance-Based Rate (PBR) application, this reinforcement project was identified as required by 2019 and was to be the subject of a future CPCN. Subsequent to the PBR application, as the winter load forecasts decreased, studies indicated that the project would not be required until the mid-2020s.[163] However, updated summer peak demand forecasts and the constraints associated with equipment emergency loading limits indicated that this project or an alternative project or resource[164] could be required sooner. Based on the more recent information, the FBC CPCN for the Kelowna Bulk Transformer

163 In the Application for Approval of Treatment for Major Project Capital Expenditures under the Multi-Year Performance Based Ratemaking Plan for 2014-2019, FBC indicated that the Kelowna Bulk Transformer Capacity Addition was deferred beyond PBR Term.

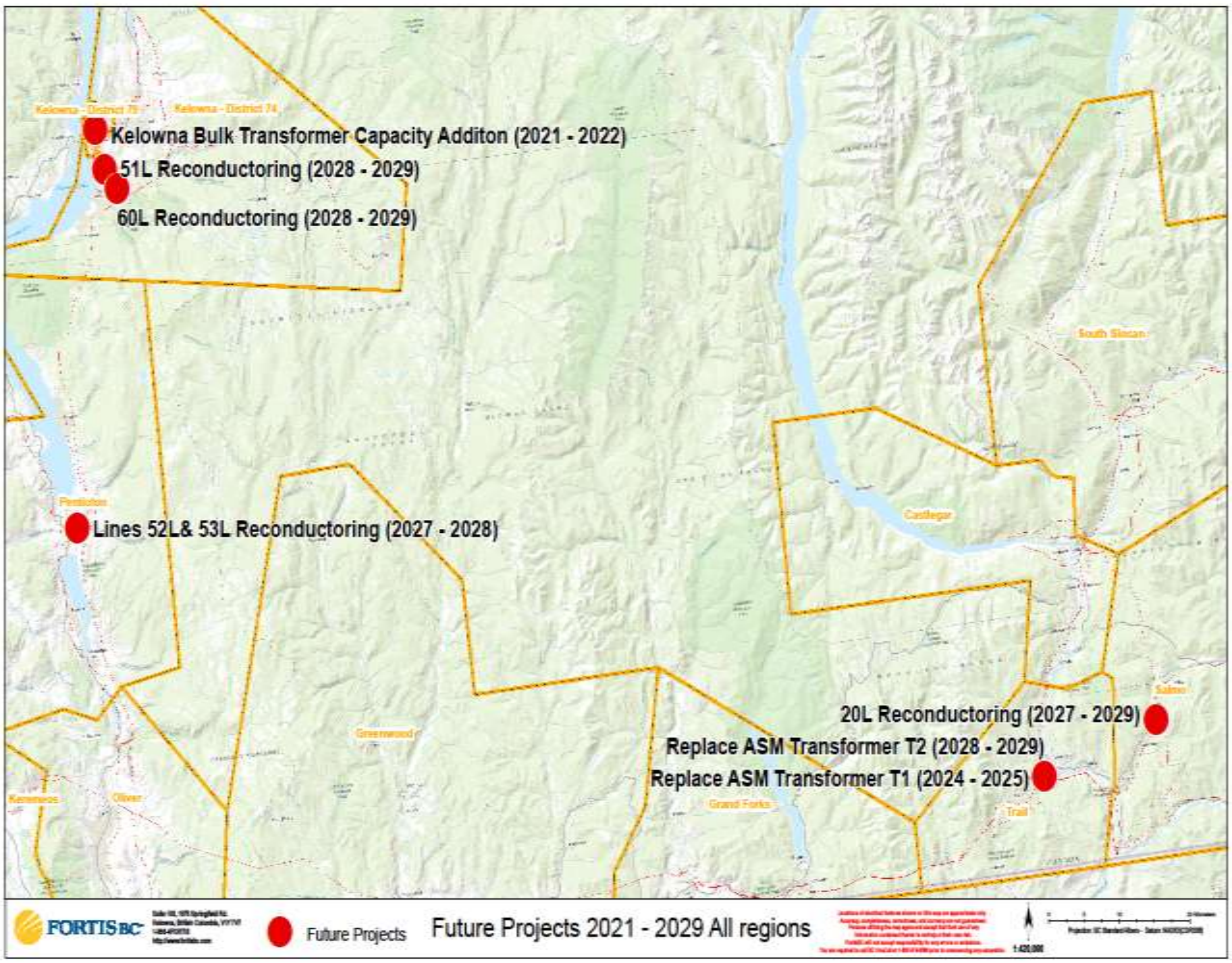
164 Project alternatives that could be considered include the addition of a third bulk transmission transformer, reinforcement of existing transmission lines, or adding a generation resource in the Kelowna area.

Addition project was approved by the BCUC in November 2020 and the project is currently in the construction phase.

As shown in Table 6-3 above, recent system studies indicate that the 20L Upgrade project will not be required until the late-2020s based on recent load forecasts. However, due to recent transmission interconnection requests and interest from new large load customers in 2021, this project may be required sooner. FBC is currently considering options and may bring forward a CPCN application to the BCUC if necessary.

The following figure shows the locations of these transmission reinforcement projects.

Figure 6-3: Location of Transmission Reinforcement Projects



6.5 *POTENTIAL IMPACTS OF EMERGING LOAD/GENERATION TECHNOLOGIES*

As part of the system planning process associated with the development of the LTERP, FBC has explored the potential impacts from various load drivers and scenarios that could materialize in the future (see Section 4). Load drivers in particular that could have significant impacts are distributed generation (DG), electric vehicles, fuel switching and new large commercial and industrial loads. The DG, EV and large load drivers have specific considerations for FBC's system that must be taken into account and so their potential impacts on the transmission and distribution system are discussed in this section. While the increase or decrease in peak load requirements resulting from these scenarios has implications for transmission and distribution system planning, the potential impact of the individual load drivers on system requirements is also important.

6.5.1 Distributed Generation (DG)

As of mid-June 2021, FBC has approximately 660 Net Metering Program customers with DG facilities (mostly rooftop solar PV installations) interconnected on the distribution system.[165] Combined, these facilities represent about 6 MW of non-firm generating capacity, which is less than one percent of the current system winter peak demand requirements of 732 MW.[166] As a result, the near-term impacts of existing DG facilities on transmission and distribution grid operations and reliability are currently relatively low.

There have been increasing numbers of DG interconnections over the past few years, although the growth rate has slowed since 2018 (see Figure 2-9 in Section 2.3.4). Recent studies predict further cost declines in solar PV and associated increases in solar PV penetration rates. Additionally, provincial or federal incentives and/or federal tax credits, *CEA* or RPS legislation or feed-in tariffs for the purchase of renewable generating capacity from small facilities could make solar PV more cost-effective for customers. Further study of solar PV, and its pairing with battery storage, will be required to ensure that potential system impacts and necessary mitigation are understood and addressed in the FBC system.

DG facilities could provide value if they are able to generate or provide electricity during peak demand times. This would be beneficial because it could reduce the need for FBC to purchase energy from BC Hydro or other parties and decrease transmission or distribution line congestion. By meeting customer electricity needs closer to the point of consumption, DG facilities could reduce FBC incremental resource requirements and reduce loading on distribution and transmission lines. However, for DG systems to operate in this way, they must be interconnected, controlled, measured and operated as an integral part of the FBC electricity system. The pairing of batteries with solar PV could enable them to discharge stored solar energy during peak demand periods. This type of solar PV plus battery installation could provide a more reliable reduction in FBC system peak demand in a way that solar PV alone cannot.

[165] FBC also has two interconnected independent power producers (one transmission and one distribution) which use FBC facilities to wheel generated power to BC Hydro.

[166] Per Appendix F, Section 2.10, January 2020 winter peak demand.

Not withstanding the limited impacts at current adoption rates, the potential future impacts on transmission and distribution system planning and operations are more complex. Intermittent renewable generation creates many new challenges not experienced with conventional distributed generation. Distributed solar PV increases the complexity of managing voltage regulation on distribution feeders due to its intermittent nature. These facilities will have increasing impacts on the distribution system first and then the transmission system later as DG growth continues.

The extent to which DG affects power losses and voltage profiles depends on the type of DG technology, penetration levels, and the location of its connection to the grid. Depending on its location, the integration of DG can reduce power losses on the transmission and distribution network, but as the penetration level increases, the power losses may begin to increase.

If DG uptake increases significantly in the future, FBC transmission and distribution planners will need to have the tools and knowledge for planning and modeling a high-penetration of solar PV, alone or paired with batteries, or other DG technology into the system. Alternative engineering designs, technology solutions, and new and updated planning and operations practices that have been implemented in other jurisdictions may be needed for the FBC transmission and distribution system of the future.

6.5.2 Electric Vehicles

Currently, the pace of EV uptake within FBC's service territory is increasing. As discussed in Section 2.3.2, FBC is monitoring its charging station installation usage and EV registrations within its service area and analyzing the impact on its distribution networks.

The peak demand imposed by an EV on the grid depends on the size of the on-board battery, the owners' driving patterns, the charging strategy and the charger characteristics. With improvements in battery efficiency and longer ranges on an increasing number of EV models, customers will require higher electricity demand than that imposed by charging through a conventional 120 V (level 1) outlet. Several electric vehicles on one residential street could overload the local distribution transformer unless demand management measures are implemented to enforce load diversity and prevent a possible overload.

Connecting EVs (on Level 2 chargers) to the infrastructure in many older neighbourhoods requires planning and support from FBC. Transformer and conductor capacity in these areas could be an issue. Increasing the capacity of several transformers on a circuit may not be sufficient to address all issues, and a circuit rebuild may be required to mitigate overloaded conductors.

The following list includes some of the key items for consideration in managing EV charging loads:

- Diversity of vehicle location, charging time, and energy demand will impact the utility distribution systems;

- Level 1 (standard residential voltage; no extra cost) charging generates the fewest distribution system impacts;
- Higher power (Level 2) charging generates stronger system impacts;
- Short-term EV impacts for most utility distribution systems are likely minimal and localized to areas where the available capacity per customer is already low; and
- Controlled or managed charging could defer system impacts for a significant period of time.

The potential stresses on the electric grid can be mitigated through asset management, system design practices, and managing the timing of charging EVs to shift the load away from system peak by implementing programs or incentives for EV charging customers. A proactive approach that includes understanding where EVs are appearing in the system, addressing near-term localized impacts, and developing both customer programs and technologies for managing long-term charging loads will effectively and efficiently support EV adoption. Further discussion regarding FBC's proposed customer program is provided in section 2.3.2 and 8.2.

6.5.3 Large Scale Customers

Over the past few years, FBC has received an increasing number of capacity requests for service for large scale customers. These requests have come from potential customers requesting service relating to blockchain technology, renewable natural gas, cannabis, data centres, forestry operations, hydrogen production and carbon capture (also discussed in Section 2.3.5). The load scenarios (discussed in Section 4) include consideration of the potential impacts from these types of large load drivers.

To accommodate these service requests and depending on the site selected by the customer, infrastructure reinforcements may be required to meet planning criteria during normal or contingency operations. These infrastructure reinforcements may include, but are not limited to, upgrading substation capacity or upgrading transmission lines. As a result of these requests, the planned infrastructure reinforcements identified in Section 6.3 may be required sooner than expected (i.e. the 20L upgrading project) or entirely new reinforcements may be identified.

Over the past few years, the capacity requests from large commercial services have ranged from 0.5 MW to 250 MW. Of these requests, a single transmission customer and five distribution customers have been connected. There is currently a single transmission customer and four distribution customers with a total requested load of 18 MW that have a high likelihood of connecting in the next few years.

The following section explores the potential system impacts from these types of large loads as well as EV charging.

6.5.4 Impacts of Load Scenarios

As discussed in Section 4, load scenarios that were based on combinations of multiple specific load drivers were developed to provide insight into the potential impacts on FBC's future generation and infrastructure requirements if load drivers with specific growth or penetration levels occurred. This section explores the potential peak demand impacts of some of these scenarios on FBC's system, in terms of potential projects required to meet the additional load and their associated costs.

Section 11 provides analysis regarding the supply-side generation options required to meet the increased loads and is complementary to the results of the transmission and distribution system impacts provided in this section.

FBC modeled the peak demand impacts from four scenarios as part of this simulation exercise:

1. Deep Electrification;
2. The Diversified Energy Pathway;
3. The Distributed Energy Future; and
4. A separate winter peak-demand alternate scenario, which includes only EV charging and gas-to-electric fuel switching load drivers.

6.5.4.1 Assumptions

In each scenario, FBC simulated the impacts of the load scenarios only on the Kelowna area. This is because Kelowna is the area of FBC's system that is experiencing the most significant load growth and would likely have more significant impacts than other parts of the system. FBC did not include the rest of the system in this exercise and assumed that fifty per cent of the scenario loads would materialize in the Kelowna area based on the current proportion of system loads between the Kelowna area and the rest of the FBC system.

In addition, in order to determine the system impacts from the individual scenario peak-demand forecasts, FBC used the following assumptions:

1. 100 percent of the new generation resources required come from FBC-BCH tie lines (i.e. outside the Kelowna area) to isolate the impacts without including generation within the Kelowna area;
2. The existing generation resource dispatch (i.e. scheduling of output) will use the most recent typical peak winter and summer dispatch;
3. Additional peak demand for each scenario has been proportionally allocated to the LEE 138 kV and DGB 138 kV busses in order to simplify the simulations; and
4. Typical transmission planning criteria, as outlined in Section 6.2.2, were applied.

FBC notes this simulation exercise was designed to provide high-level estimates of the potential impacts on the system and was not subject to the rigour of FBC's typical in-depth modelling process. Therefore, the results presented here should not be interpreted as concrete plans for system changes but more as indications of what system requirements might look like if certain load scenarios play out in the future.

6.5.4.2 Results

In the simulation, FBC added 50 percent of the load scenarios' peak demand to the current Kelowna area peak demand forecast, based on the 1 in 20 forecast, to produce a total peak demand requirement for the Kelowna area. The total peak demand forecasts for 2040 under the scenarios are shown in the following table.

Table 6-4: Illustrative Peak Demand Forecast (MW)

2040 Peak Demand (MW)	Deep Electrification	Diversified Energy Pathway	Distributed Energy Future	Alternate Scenario
1 in 20 Peak	428	428	428	428
Additional Scenario peak	141	136	74	144
Total Peak	569	564	502	572

The additional peak demand for the Deep Electrification, Diversified Energy Pathway and Distributed Energy Future scenarios was based on 50 percent of the winter peak demand for each of the scenarios (provided in Appendix J) grossed up for system losses. The Alternate scenario additional peak demand was based on 50 percent of the Deep Electrification EV peak demand impacts of 150 MW by 2040 and ten per cent of the forecast peak gas demand for the Kelowna area[167] converted to an equivalent amount of electric energy to represent the impact of fuel switching electrification (69 MW).[168]

All of the scenarios except for the Distributed Energy Future exceed 550 MW of peak demand by 2040. This level would require significant additional transmission projects to be completed to meet the Kelowna area peak demand. If mitigation strategies were employed to reduce these peak demand requirements, then the additional projects could be deferred. More discussion of this is provided in the following sections.

6.5.4.3 Potential System Impacts

Based on the 1 in 20 system peak forecast, FBC is currently planning to implement the following projects in the Kelowna area. The values in the table below are high-level estimates and may change as more detailed analysis for each of the projects is conducted in the future.

[167] Based on FEI 2020 Peak Demand Forecast.

[168] The residential peak gas load forecast for the Kelowna area is forecast to be 2,479 gigajoules (GJ) per hour in 2040. This peak gas demand (in GJ) was converted to an equivalent amount of electric demand (in MW) by dividing by 3.6 (2,479 GJ / 3.6 = 689 MW). For purposes of this case study, it was assumed that 10% of this theoretical load in MW would materialize as additional peak demand in the Kelowna area (689 MW * 0.1 = 69 MW).

Table 6-5: Planned Projects (1-in-20 Peak Demand Forecast by 2040)

Project	Cost ($ Millions)
Static VAR Compensator (SVC)	30
DG Bell 230 kV Ring Bus	10
Kelowna Bulk Transformer Capacity Addition	21
Re-conductor 51L & 60L (DG Bell-OK Mission)	9
Ellison Second Distribution Transformer Addition	8
Benvoulin Second Transformer Addition	8
Saucier Second Distribution Transformer Addition	7
DG Bell 138 kV Breaker and Voltage Transformer Addition	1
DG Bell Second Distribution Transformer Addition	6
FA Lee Distribution Transformer Addition	8
Duck Lake Second Transformer Addition	6
Glenmore Third Transformer Addition	6
Hollywood Third Transformer Addition	8
Total	**128**

Table 6-6 includes additional projects required to meet the additional peak demand requirements of the Kelowna area at the 550 MW level. The Deep Electrification, Diversified Energy Pathway and Alternate scenarios each exceed 550 MW by 2040, before mitigation, and so would have an additional estimated project cost of $710 million in order to meet the additional peak demand by 2040. The cost for all of the projects in the table are high-level indicative costs.

Table 6-6: Additional Projects Required to meet 550 MW Peak Demand by 2040 ($ millions)

Project	Cost ($millions)
New Distribution Stations	60
New Distribution feeders	40
Meshing Kelowna 138 kV Transmission System	20
138kV Transmission Line Re-conductor	40
138kV Transmission Line Addition	30

Project	Cost ($millions)
Ashton Creek to Vaseux Lake (ACK-VAS) 500 kV Transmission Line	500
DG Bell Second 230/138 kV Transformer Addition	20
Total	**710**

6.5.4.4 Discussion

Of the projects already identified for the 1-in-20 peak demand forecast, the majority are scheduled for completion before the year 2030. The additional projects would primarily be completed after 2030. This is because the load scenarios have significantly more peak demand being added to the system from years 2031 to 2040 than from years 2021 to 2030. The timing of these additional projects is very dependant on the peak demand forecast and how it materializes over time.

For the additional projects identified in Table 6-6, the most significant cost is related to the ACK-VAS 500kV Transmission Line project. This project is required only when the Kelowna area peak demand reaches approximately 550 MW. Once the Kelowna area peak demand reaches 550 MW, a reinforcement is required which would include a new 500 kV line from Ashton Creek substation to Vaseux Lake substation and a 500 kV tap to a new terminal station in the Kelowna area.

The additional costs related to the scenarios are significantly higher than for FBC's currently planned projects. For comparison purposes, FBC's total asset rate base is approximately $1,479 million for 2021.[169] As a solution to meet the increased load, the additional projects identified above could be implemented if required, through a significant amount of additional system planning, analysis and construction.

Alternatively, should these scenarios begin to emerge, FBC could implement measures to mitigate the increases in system peak demand requirements. Mitigation measures could include large load curtailment during peak demand periods, shifting EV charging loads off peak periods and installing a large capacity generation resource in the Kelowna area.

The Deep Electrification, Diversified Energy Pathway and Distributed Energy Future scenarios includes peak demand relating to cannabis production, data centres, carbon capture and hydrogen production. It is possible that these loads, or a portion of them, could be curtailed, or interrupted, during peak demand periods in order to reduce the peak demand impacts on the system. The level of curtailment is something that FBC would likely negotiate with the customer. In addition, FBC has plans to implement programs designed to reduce the peak demand impacts on the system relating to EV charging. FBC discusses this further in Section 2.3.2 and

[169] FBC 2021 approved rate base of $1,479 million included in FBC Annual Review for 2020 and 2021 Rates application approved by the BCUC per Order G-42-21 dated February 12, 2021.

8.2. These mitigation measures (load curtailment and EV charging load shifting) could reduce the peak demand requirements of the scenarios such that they were below the 550 MW level by 2040, thereby deferring the need for the additional projects required as well as the associated costs. The following table illustrates the effects of these mitigation measures, highlighted by the red and yellow rows, on the scenarios' peak demand requirements. While FBC plans to assess the potential for demand response relating to customer space and water heating, it is not yet known how much peak demand could be reduced in this manner and so this potential mitigation measures has not been included in the table.

Table 6-7: Scenario Peak Demand Impacts after Mitigation Measures

2040 Peak Demand (MW)	Deep Electrification	Diversified Energy Pathway	Distributed Energy Future	Alternate Scenario
1 in 20 Peak	428	428	428	428
Additional Scenario peak	141	136	74	144
Total Peak	569	564	502	572
Large Load Curtailment	-23	-49	-16	0
Net Peak after curtailment	546	515	486	572
LD EV charging 50% shift	-41	-39	-36	-41
Net Peak after EV charging shift	505	476	450	531

As can be seen in Table 6-7 above, the Deep Electrification and Alternate scenarios,[170] which include fuel switching from gas to electricity for space and water heating, have the highest peak demand requirements after mitigation measures applicable to those scenarios. Under these two scenarios, the additional projects identified in Table 6-6 would not be deferred as much as under the Diversified Energy Pathway or Distributed Energy Future scenarios. This indicates that the Diversified Energy Pathway, which is focused on decarbonization of the natural gas system rather than significant electrification of homes and buildings, can be a better outcome for customers in terms of avoiding or deferring additional generation resources or infrastructure.

A possible alternative to the large ACK-VAS 500kV Transmission Line project would be to install a large generation capacity resource in the Kelowna region. This generation resource would have to be sized large enough to fulfill its economic life cycle as well as have enough volt-ampere reactive (VAR) capacity to support voltage in the event of the Kelowna Static VAR Compensator (SVC) outage. FBC estimates that approximately 100 MW of total installed firm, dispatchable generation capacity would be needed to accomplish this. Installing a large amount of battery storage, instead of capacity generation, would not be an appropriate solution as battery storage would not be able to provide voltage support during a Kelowna SVC outage. As an example, the capital cost for a capacity generation resource such as a 100 MW gas-fired power plant (which could use RNG as fuel) is estimated to be about $200 million and so could be significantly lower than the estimated cost of the additional transmission line project.

[170] The mitigation measures result in peak demand requirements below the 550 MW level for the alternate scenario as shown by the green row in the table above. Mitigation for this scenario would come only from shifting EV charging because this scenario includes only fuel switching and EV load drivers and does not include additional large loads and so there is no curtailment potential under this scenario.

6.6 *IMPACTS OF CLIMATE CHANGE*

The threat that global climate change presents to FBC infrastructure and operations is a continuing reality that FBC is taking seriously. FBC identifies wildfires as the most significant climate-related risk, while others include flooding and extreme weather. FBC has been building climate resiliency using its standards and practices over time, but, as climate change related risks increase, additional adaptation methods may need to be implemented.

The utility industry, including regulators, continues to discuss the need to be proactive in preparing and taking action to respond to climate change and improve the resiliency of the grid. Industry standards and organizations such as the Institute of Electrical and Electronics Engineers (IEEE) and Canadian Standards Association (CSA) have discussed adopting standards to support utilities in integrating considerations of climate change impacts.

FBC invests in the asset resiliency of its transmission and distribution system to maintain reliable and resilient assets and mitigate climate-related risks. FBC's electric system is regularly maintained, improved and replaced, so it can continue providing its customers with reliable, safe and affordable energy solutions for today and for years to come.

Depending on the climate change related risk, adaptation measures could result in installation of new equipment, the use of new technologies, changes to FBC operating procedures and updates to the FBC distribution, transmission, or station standards. FBC will assess the risk to specific assets and estimate costs for climate change adaptation measures and risk mitigation investments. Costs associated with the recommended adaptation measures and risk mitigation investments, and/or the impact on the transmission and distribution reliability and resilience will be considered in future capital planning. As the risks associated with climate change continue to increase, there is potential for the capital requirements related to resiliency to substantially increase.

FBC participates in various climate adaptation groups at a national level to share and implement best practices. In collaboration with industry partners, FBC is working to implement strategies to adapt to and mitigate climate risks.

6.7 *SUMMARY*

FBC plans, constructs and operates its transmission and distribution system to safely and reliably deliver electricity to customers throughout the Company's service area under reasonably foreseen operating conditions and weather extremes. To accomplish this, FBC develops substation load forecasts, conducts computer-based system modelling and coordinates system planning and operations with neighbouring transmission entities. Infrastructure reinforcements are identified when load forecasts or new large capacity requests indicate that the system has insufficient capacity to meet planning criteria during normal or contingency operations.

The future system impacts from emerging technologies and loads, such as distributed generation, electric vehicles and large load sector transformation, are uncertain at this time and will depend on the rate of adoption by customers. FBC has simulated peak demand scenarios to help determine, at a high-level, the potential system impacts. This provides FBC with an indication of the potential incremental transmission and distribution infrastructure required in the event that higher load scenarios emerge over the planning horizon and if mitigation measures are not implemented. This highlights the significant cost related to the electrification of loads and the importance of effectively managing peak demand on the system. FBC will continue to assess the risks to specific assets and estimate costs for climate change adaptation measures and risk mitigation investments and take them into consideration in future capital planning. As the risks associated with climate change continue to increase, there is potential for the capital requirements related to resiliency to substantially increase.

7. LOAD-RESOURCE BALANCE

This section identifies the load-resource balance (LRB) before incremental demand-side and supply-side resources are included to determine if there are any energy and/or capacity gaps over the planning horizon. This is accomplished by comparing the long-term reference case load forecast to the existing and committed resources in FBC's portfolio. The comparison will identify any LRB gaps that need to be met through a combination of DSM, supply-side resource options and other initiatives.

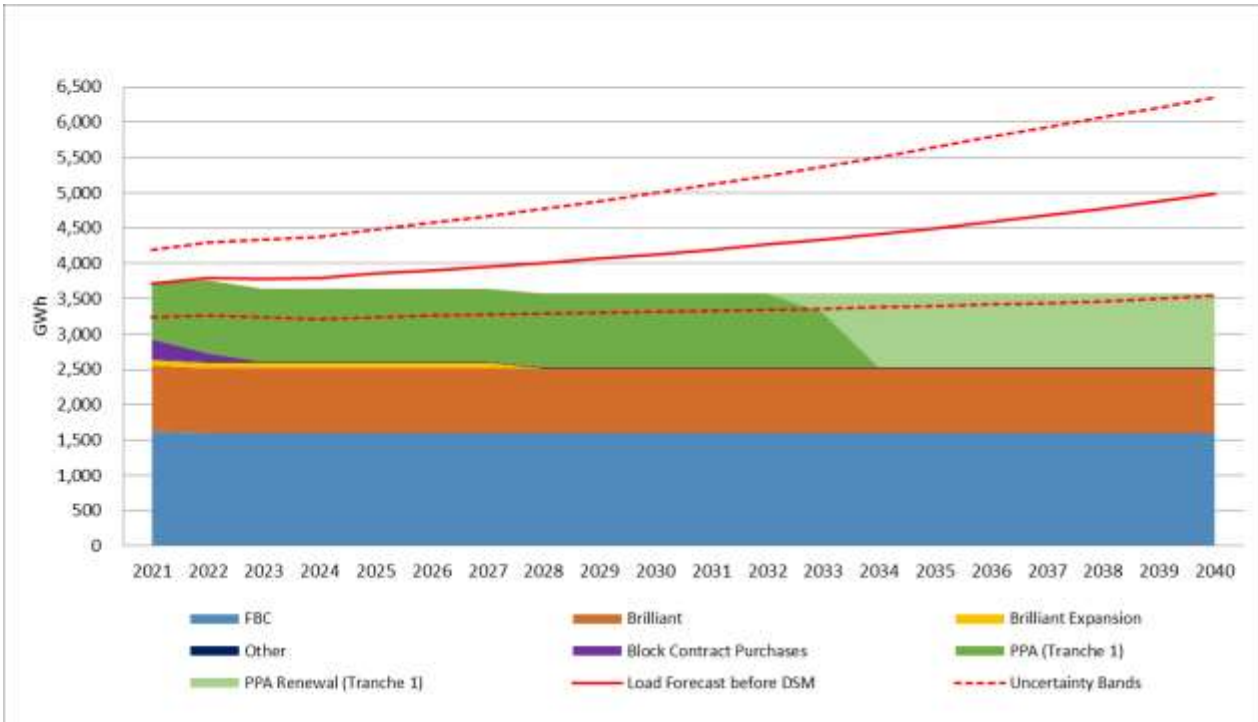
Section 9 identifies the DSM resources that FBC proposes to apply to reduce the LRB gap and the resulting after-DSM LRB which shows the remaining gaps to be filled with supply-side resource options and/or other initiatives. Section 2.3.2 discusses FBC's recommended strategy to help mitigate the impacts of EV charging during peak demand periods, thereby reducing any potential capacity LRB gaps. The portfolio analysis in Section 11 evaluates several alternative portfolios including DSM and supply-side resources to meet any future energy and capacity gaps. This approach is consistent with the BCUC Resource Planning Guidelines described in Section 1.4.2.

The annual energy LRB is presented first in Section 7.1, followed by the winter, summer and June capacity LRBs in Section 7.2. The LRB analysis has been developed using the long-term Reference Case load forecast discussed in Section 3 and the existing/committed resources discussed in Section 5. The resource options considered to meet any LRB gaps include new generation or market purchases (discussed in Section 10) and DSM-related initiatives, including those to mitigate home EV charging during peak periods.

7.1 *ENERGY LOAD-RESOURCE BALANCE*

The following figure illustrates the annual energy load-resource balance and potential gaps over the 20-year planning horizon.

Figure 7-1: Annual Energy Load-Resource Balance (GWh)



The red line in the figure above represents the Reference Case load forecast before new DSM resources. The dashed red lines represent the uncertainty bands for the reference case load forecast, as discussed in Section 3.4.

The coloured areas in Figure 7-1 represent FBC's physical and contractual supply-side resources, which are discussed in Section 5.

A number of assumptions regarding FBC's current long-term energy supply contracts have been made for the purposes of the resource stack in the LRB:

- With respect to the PPA with BC Hydro, FBC's base assumption is that the agreement is renewed and continues beyond the current September 2033 expiration date. As part of the scenario analysis in Section 11, FBC has developed a scenario which includes non-renewal of the PPA. Therefore, in the figure above, the PPA is shown in dark green until 2033 and a lighter green beyond that to reflect this uncertainty.
- As discussed in Section 5, FBC has assumed that the Brilliant Expansion contract discontinues after its expiry in 2027.
- With regard to the BC Hydro PPA, the figure reflects PPA Tranche 1 Energy available to FBC up to the maximum of 1,041 GWh. In the portfolio analysis discussed in Section 11, the portfolio model will optimize the amount of PPA Tranche 1 Energy with the other resource options available to FBC and, as a result, the maximum Tranche 1 Energy available may not always be selected within the various alternative portfolios. PPA

Tranche 2 Energy is also available to FBC but at a much higher cost, as discussed in Section 2.5.5. Based on the supply-side resource options presented in Section 10, FBC expects that it would be able to build or contract for new energy resources at a lower cost than the PPA Tranche 2 Energy cost. For this reason, the energy LRB is presented here with only the PPA Tranche 1 Energy amount.

- For the first year in the LRB figure (2021), the amount of PPA Tranche 1 Energy has been reduced from its maximum amount to match FBC's energy load requirements. If the PPA Tranche 1 Energy was included at the maximum amount of 1,041 GWh per year, FBC would have excess energy. This excess energy would be very difficult to manage in a cost-effective manner under the terms of the PPA, which restrict FBC exports while purchasing PPA energy. Instead, FBC would reduce its PPA Tranche 1 Energy take from BC Hydro so that energy surpluses do not occur.

Figure 7-1 shows that, even if the PPA is renewed, there are gaps starting in 2023 based on the Reference Case load forecast which increase to approximately 1,410 GWh by 2040. If the PPA is not renewed, then the gaps are more significant after 2033, increasing to about 2,450 GWh per year by 2040 under the Reference Case load forecast. At the high end of the uncertainty band, the gap is approximately 2,800 GWh by 2040. At the low end of the uncertainty band, there are no gaps by 2040. The demand-side and supply-side resource options available to meet these LRB gaps are discussed in Sections 8 and 10.

7.2 CAPACITY LOAD-RESOURCE BALANCE

For long-term planning purposes, FBC assesses both its winter and summer capacity LRB. While FBC's highest peak demand during the year typically occurs in the winter months, it also experiences significant demand during the summer period. In addition, FBC assesses the capacity LRB for the other months of the year to determine other material gaps. In particular, FBC experiences significant LRB gaps in June due to the lower monthly shaping of its existing generation resources and supply contracts. This seasonal temporary reduction in resources is a characteristic of hydroelectric generation in BC. High water flows that occur during the spring freshet result in high water elevations downstream of the generating plants. This reduces the overall hydraulic head (the water level difference between the forebay[171] and the tailrace[172]) and hence the plant output.

Figures 7-2, 7-3 and 7-4, presented below, include FBC generation, the Brilliant contract, BRX capacity, PPA capacity and WAX CAPA. As the three figures illustrate, the FBC committed supply resource capacity amounts differ throughout the year. So, while the peak demand during summer periods and June is lower than during winter periods, the available capacity supply is also lower. During winter periods, FBC has more capacity entitlement available from its own generation and the Brilliant, BRX and WAX CAPA contracts. The WAX CAPA is presented net

[171] Forebay is defined as an artificial pool of water ahead of a larger body of water.
[172] Tailrace is defined as a channel that carries water away from a hydroelectric plant or water wheel.

of the RCA sale of 50 MW to BC Hydro until 2024 and therefore increases after 2024 when the RCA expires. The Brilliant Expansion contract expires after 2027, but a minimal amount of tailrace capacity associated with the Brilliant Expansion plant continues after 2027. The capacity LRB figures assume that 200 MW of capacity is available to FBC from the PPA, but can be reduced if not required to meet the load forecast. Therefore, to avoid holding surplus capacity, the winter and summer capacity LRB figures above reflect FBC reducing the amount of the capacity it would take under the PPA during 2021 to 2027 so that its resource portfolio matches the peak capacity load requirements. As with the energy LRB figure 7-1, Figures 7-2, 7-3 and 7-4 also assume the renewal of the BC Hydro PPA so that it continues beyond 2033.

Figure 7-2 below illustrates the winter capacity LRB and potential gaps by year over the 20-year planning horizon before any new DSM. The winter capacity requirements, which are represented in the figure by the solid and dashed red lines, are based on FBC's peak demand requirements during each year's winter period.

Figure 7-2: Winter Capacity Load-Resource Balance (MW)

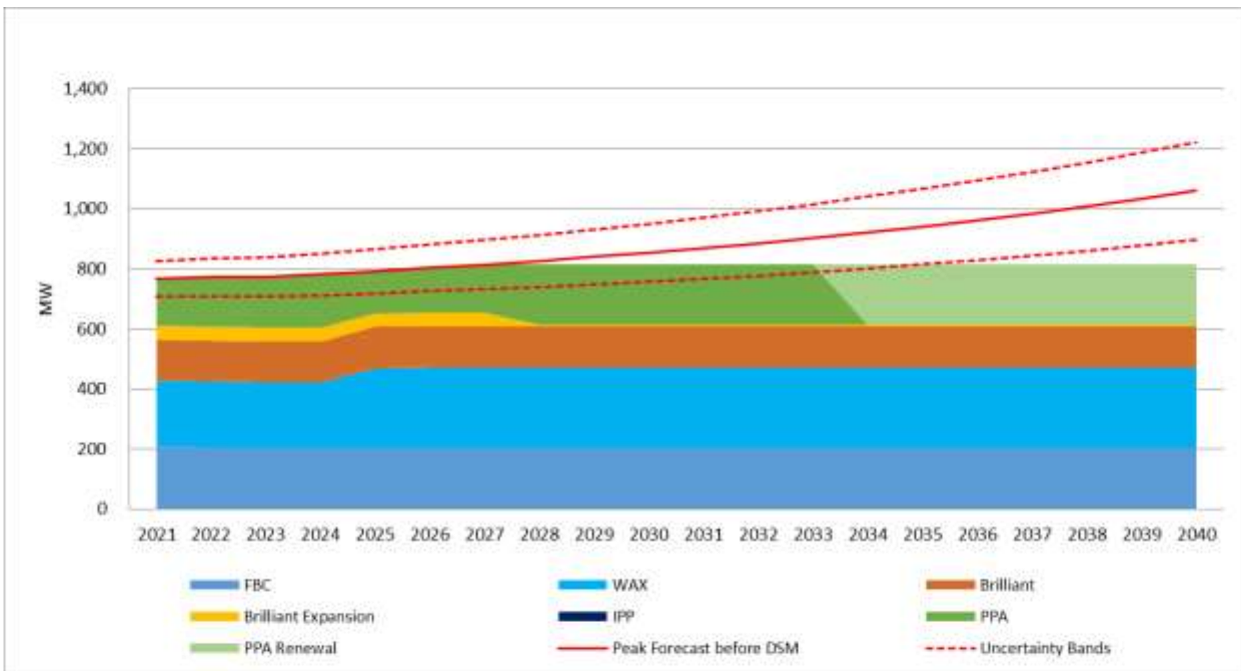


Figure 7-2 shows that, based on the Reference Case forecast, minimal winter capacity gaps start in 2028 and increase up to about 245 MW by 2040 if the PPA is renewed. More significant gaps, in the order of 445 MW, appear if the PPA is not renewed based on the Reference Case forecast. At the low end of the uncertainty band, the gaps are about 80 MW by 2040. At the high end of the uncertainty band, the gaps are about 400 MW by 2040.

Figure 7-3 below illustrates the summer capacity LRB. The summer capacity requirements, which are represented in the figure below by the solid and dashed red lines, are based on FBC's peak demand requirements during each year's summer period.

Figure 7-3: Summer Capacity Load-Resource Balance (MW)

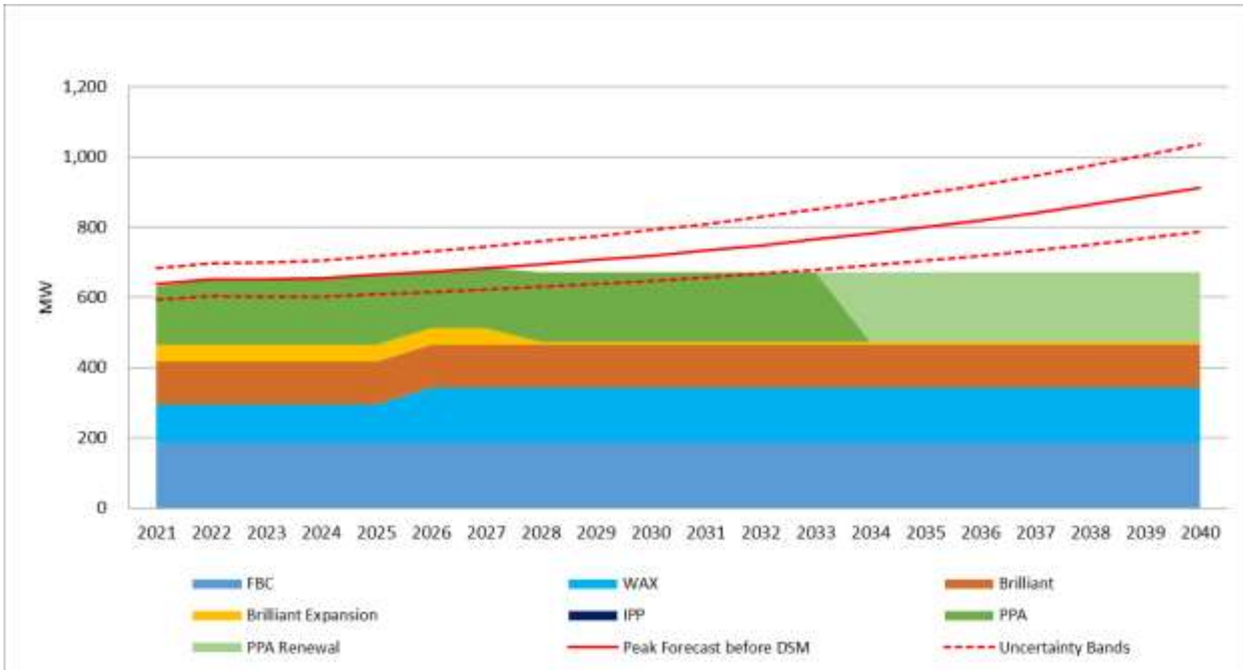


Figure 7-3 shows that, based on the Reference Case forecast, minimal summer capacity gaps start in 2028 and increase up to about 240 MW by 2040 if the PPA is renewed. More significant gaps, in the order of 440 MW, appear if the PPA is not renewed based on the Reference Case forecast. At the low end of the uncertainty band, the gaps are about 110 MW by 2040. At the high end of the uncertainty band, the gaps are about 360 MW by 2040.

Figure 7-4 below illustrates the June capacity LRB. The June capacity requirements, which are represented in the figure below by the solid and dashed red lines, are based on FBC's peak demand requirements during each June of the planning horizon period.

Figure 7-4: June Capacity Load-Resource Balance (MW)

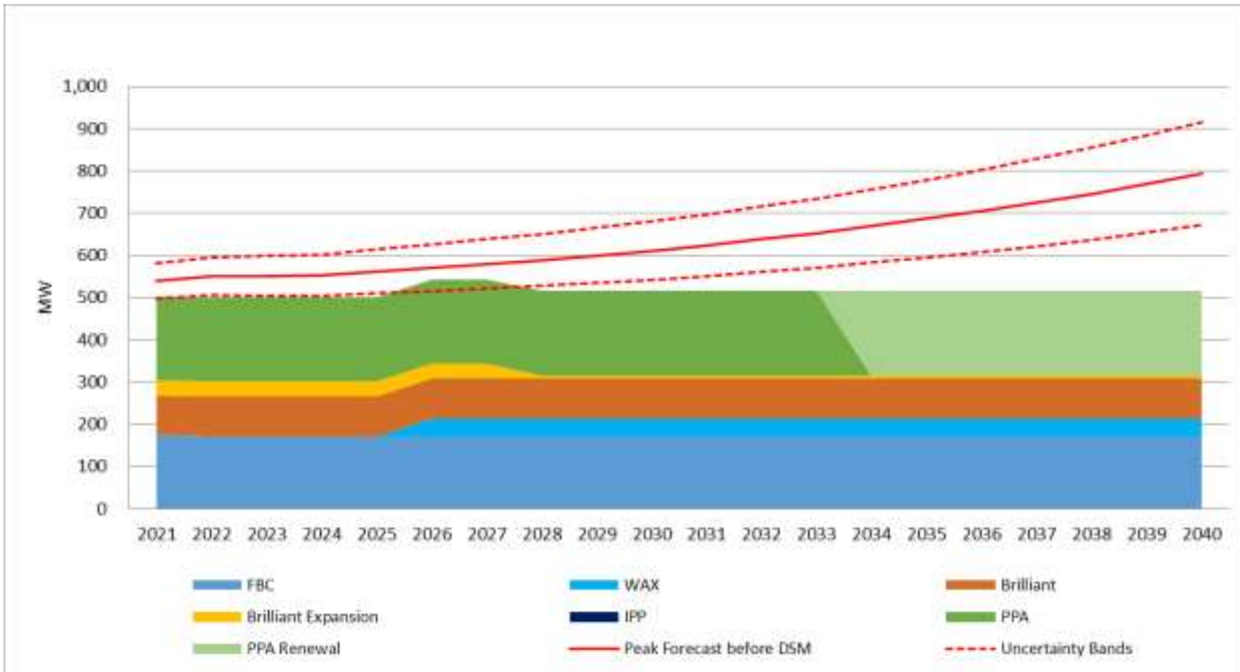


Figure 7-4 shows that, based on the Reference Case forecast, June capacity gaps start in 2021 and increase up to about 280 MW by 2040 if the PPA is renewed. More significant gaps of about 480 MW appear if the PPA is not renewed based on the reference case forecast. At the low end of the uncertainty band, the gaps are about 155 MW by 2040. At the high end of the uncertainty band, the gaps are about 400 MW by 2040.

7.3 SUMMARY

The following table summarizes the forecast approximate 2040 load-resource balance gaps for annual energy and winter, summer and June capacity with and without the PPA renewal before any demand-side or supply-side resource options are included to meet the gaps.

Table 7-1: Load-Resource Balance Gaps

	First Year of Gap	2040 Gap With PPA Renewal	2040 Gap Without PPA Renewal
Annual Energy (GWh)	2023	1,410	2,450
Winter Capacity (MW)	2028	245	445
Summer Capacity (MW)	2028	240	440
June Capacity (MW)	2021	280	480

Section 8 describes the DSM options available to reduce these forecast energy and capacity gaps, while Section 9 provides the forecast gaps after DSM. Section 10 then discusses the supply-side resource options available to meet any remaining gaps.

8. RESOURCE OPTIONS – DSM

FBC has a number of different resource options to meet the future energy and capacity needs of its customers. These include demand-side as well as supply-side resource options. FBC first looks to demand-side resources to meet any future LRB gaps. In addition to reducing demand to help meet energy and capacity needs, DSM can include programs that encourage customers to shift their energy consumption from peak demand periods. For example, DSM could include incentives for EV owners to shift their EV charging from peak demand periods to other times of the day or night. Demand-side resource options can also be more cost effective than new supply-side resource options and enable customers to reduce their energy consumption, thereby reducing their energy costs.

In this LTERP and in the LT DSM Plan, FBC has evaluated different levels of DSM to meet future load growth. Customer load that cannot be met with demand-side measures must be met with supply-side resource options, which are discussed in Section 10. FBC includes a discussion of why all load growth is not met with DSM in Section 9.3.

Section 8.1 below summarizes the DSM level scenarios considered for this LTERP, which are discussed in detail in Section 3 of the LT DSM Plan, including the load reductions, in terms of energy and capacity, provided by different levels of DSM over the planning horizon. Section 8.2 discusses FBC's plans for Demand Response pilots designed to help manage loads during peak demand periods.

8.1 *DSM LEVELS*

This section describes how FBC developed and analyzed DSM scenarios to plan for its long-term resource needs. FBC developed five different DSM scenarios, including Low, Base, Medium (Med), High, and Maximum (Max) cases, that were subsequently tested with various supply-side resource options in FBC's resource planning portfolio analyses (Section 11.3.1 of the LTERP).

The DSM program scenarios FBC considered are based on incenting ever larger proportions of the DSM measures' incremental costs. The same DSM measures were included in all scenarios, and the uptake was based on the market potential. This approach supplants the prior metric of expressing DSM savings targets as a percent of load growth offset. That metric, which originated in the 2007 BC Energy Plan, included targets only to the end of 2020. New load growth forecasts are significantly impacted by electric vehicle growth, which DSM has no energy savings measures thus the existing approach was abandoned in favour of one that aligns with incremental costing, similar to other utility conservation potential reviews, including FEI.

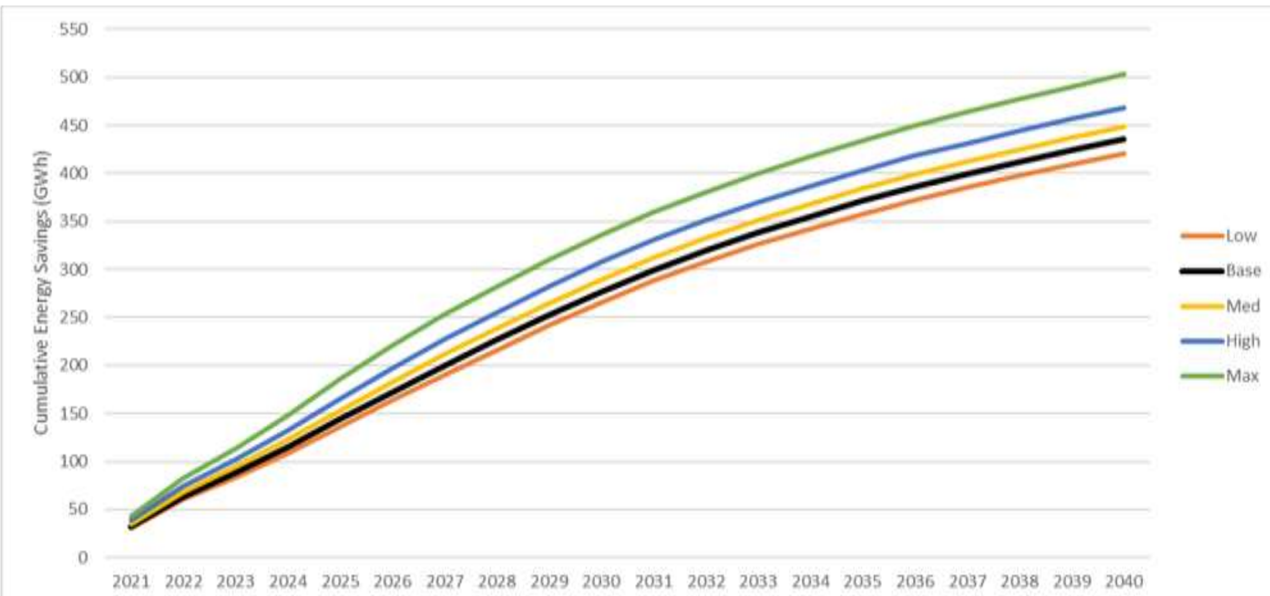
The DSM program scenarios represent FBC paying levelized incentives[173] to cover 50, 62, 72, 84 and 100 percent of incremental measure costs respectively. The Conservation Potential

[173] Levelized incentives refer to the principle that incentives support the most cost-effective measures. In the lower DSM program scenarios, the measures that are less cost-effective receive lower levels of funding.

Review (CPR) model estimates the additional take-up and timing of measure installations based on the proportion paid by FBC. The non-linear response to the increasing incentive levels paid results in relatively small incremental savings at significantly higher portfolio costs (see Table 3.1 in the LT DSM Plan).

Figure 8-1 shows the cumulative results of the five DSM program scenarios considered, over the LTERP planning horizon. As shown in the figure, the cumulative energy savings increases as the incentive level increases.

Figure 8-1: Low, Base, Med, High and Max DSM Scenarios



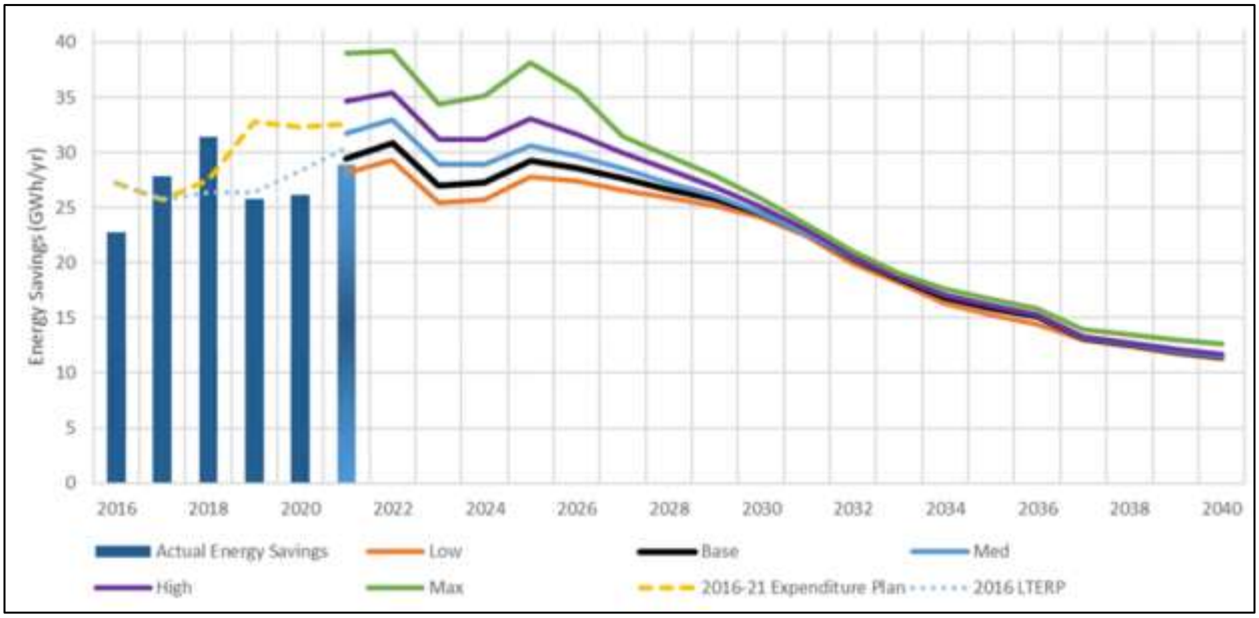
As can be seen in the figure above, the various scenarios follow a similar trend of the energy savings achieved, and the higher scenarios (where more incentive dollars were spent) result in greater cumulative energy savings. Despite the increase of incentive dollars spent across the various portfolios, the cumulative energy savings differentials are not very substantial between the various scenarios, especially within the first five years of the plan. In the final year, 2040, there is a modest 15 percent savings differential between the Max and Base DSM scenarios.

Figure 8-2 below shows the results of the five DSM program scenarios considered in terms of their annual energy savings, over the LTERP planning horizon. The left-hand side of Figure 8-2 shows the following over the period 2016-2021:

1. 2016 LTERP savings target trajectory (blue dotted line) to 2021;
2. expenditure plan saving targets (yellow dotted line);
3. actual results (blue bars) up to 2020 inclusive; and
4. 2021 year-end forecast energy savings results.

The right-hand side of Figure 8-2 shows the trajectory of the five DSM program scenarios modelled by increasing the incentive portion of incremental measure costs. The current 2019-2022 DSM Plan target savings of approximately 32 GWh generally aligns with the Med scenario curve. However the actual reported results in 2019 and 2020 were approximately 26 GWh per year and, together with the 2021 year-end forecast of 29 GWh per year, better aligns with the Base scenario.

Figure 8-2: Annual Energy Savings (Plan, Actual, DSM Scenarios)



The DSM Scenario curves in the figure above are all relatively flat in the first five years (2022-2026), then begin to decline and converge in the next five years, with little differential evident in the final ten years. The decline in annual savings indicates the market take-up of available measures in the first period, followed by declining potential and take-up activities. The decline is a natural attribute of the Bass diffusion curve upon which the CPR model is built, as it follows a bell curve shape.

The table below shows the projected energy and capacity savings and average resource cost of the various DSM scenarios, as well as the incremental cost of incurring higher incentive levels in Med, High and Max scenarios compared to the Base scenario.

Table 8-1: Key DSM Scenario Data

Category	DSM Scenario				
	Low	Base	Med	High	Max
Energy Savings, GWh					
Average per annum ('21 - '40)	21.0	21.8	22.4	23.4	25.2
Average per annum ('21 - '29)	26.8	28.0	29.4	31.4	34.5
Total (2021 to 2040)	421	435	449	468	503

Category	DSM Scenario				
	Low	Base	Med	High	Max
Capacity Savings, MW					
Total (2021 to 2040)	61.6	64.0	65.6	68.1	72.7
Resource Cost, 2020 ($000s)					
Average Cost ($/MWh)	$38	$44	$49	$57	$75
Incremental cost compared to base case ($/MWh)	N/A	-	$183	$190	$234

The table above further highlights the similarities between energy savings across the various scenarios, while highlighting the differences between the costs to achieve these incremental energy savings. Notably, the incremental energy savings above the Base scenario are substantially more expensive per MWh than the average cost of savings.

FBC selected the Base DSM scenario as its preferred scenario in the LT DSM Plan. The Base DSM Scenario can be characterized as a continuation of the 2016 LT DSM Plan's "High" scenario, in which the target savings increased from 26.4 to 30.4 GWh by 2022 and which used a constant 32 GWh per year as a placeholder thereafter. As shown in Figure 8-2, the energy savings achieved to date and forecast in 2021 align with the Base scenario.

Though the Low DSM scenario was more cost effective than the Base scenario (see Section 11.3.1), it was not chosen because:

- The Base scenario maintains consistency with the previous DSM plan which had support from customers and stakeholders;
- Transitioning to the Low scenario may require FBC to remove existing program offerings or reduce program incentives, potentially resulting in a reputational impact with customers and trade allies;
- The Low scenario requires pullback of program offerings which limits FBC's ability to scale up programs in the future if new cost-effective measures are identified. Selecting the Base scenario provides flexibility to meet future market demands; and
- The Base scenario includes additional budget to further investigate DR programs that have the potential to cost-effectively defer capacity costs.

The Med, High and Max DSM scenarios were not chosen for the following reasons:

- They are less cost-effective than other resource options. FBC would be paying an increased incremental incentive proportion of measure costs, especially in comparison to the relatively low cost of power supply options, such as market electricity purchases. The *Incremental cost compared to base case ($/MWh)* row in Table 8-1 highlights the resource cost of the additional savings; and

- They present higher risks of insufficient customer participation. DSM participation is voluntary and FBC cannot have assurance that customer participation will be sufficient to meet the higher scenarios. The fact that FBC had below-target energy savings in recent program results indicates that it may not be readily feasible to achieve higher levels of DSM.

8.2 *DEMAND RESPONSE PILOTS*

In its 2019-2022 DSM Expenditure Plan, FBC included funding to conduct Demand-Response (DR) pilot projects to test the opportunity, and customer willingness, to undertake load shifting during peak demand periods. In 2019-2020, the Company undertook the first phase of a DR pilot with commercial and industrial customers that focused on (but was not limited to) offsetting summer loads in the Kelowna area, the results of which are summarized in the 2019 and 2020 DSM reports.

The Company currently has a residential DR pilot phase out to tender. It will seek to control and shift key household end-uses such as space cooling, hot water and possibly other devices such as pool pumps. Importantly, the scope includes controls of residential home EV charging, which has been identified as the largest demand growth factor in this LTERP.

The DR pilots are intended to provide proof of concept, i.e. magnitude of load shifted and propensity of customers to participate. This will provide FBC an indication of the level of EV charging it might be able to shift from peak demand periods. FBC provides examples of this potential EV charging shifting in Section 9. The results will inform a business case for an ongoing DSM program to scale up DR capacity over time, the benefits of which may include deferral of new capacity generation resources and transmission and distribution infrastructure upgrades. In FBC's portfolio analysis in Section 11, FBC assesses portfolios of resources based on different percentages of EV charging shifting to provide an indication of the differences in generation resources and their costs under different EV charging shifting scenarios. Section 6 discusses EV charging shifting as a mitigation strategy in deferring the requirement for future transmission and distribution system projects and their related costs.

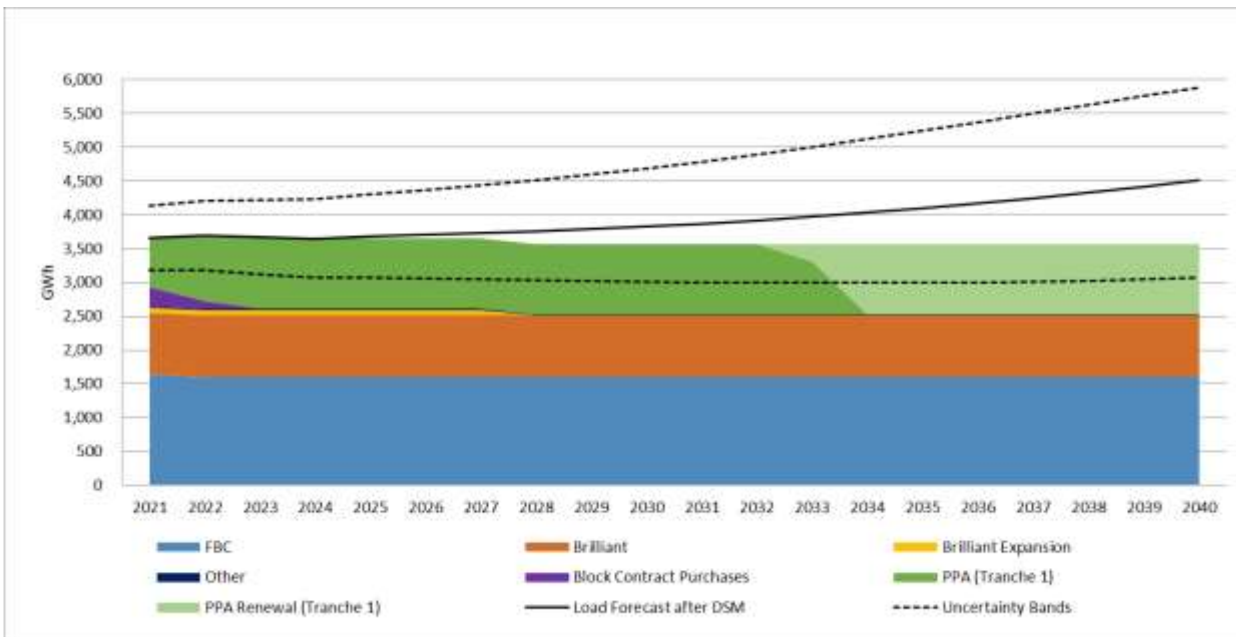
9. LOAD-RESOURCE BALANCE AFTER DSM

This section of the LTERP addresses Section 44.1(2)(c) of the *UCA*, which requires FBC to include an estimate of the demand for energy that it expects to serve after taking cost-effective demand side measures. It includes a discussion of the LRB for annual energy and capacity after the proposed level of DSM and also includes a discussion of the capacity LRB assuming some amount of EV charging shifting from peak demand periods.

9.1 *ENERGY LOAD-RESOURCE BALANCE AFTER DSM*

The following figure shows the LRB for annual energy after netting off the proposed level of DSM savings from the Reference Case load forecast.

Figure 9-1: Energy Load-Resource Balance after DSM



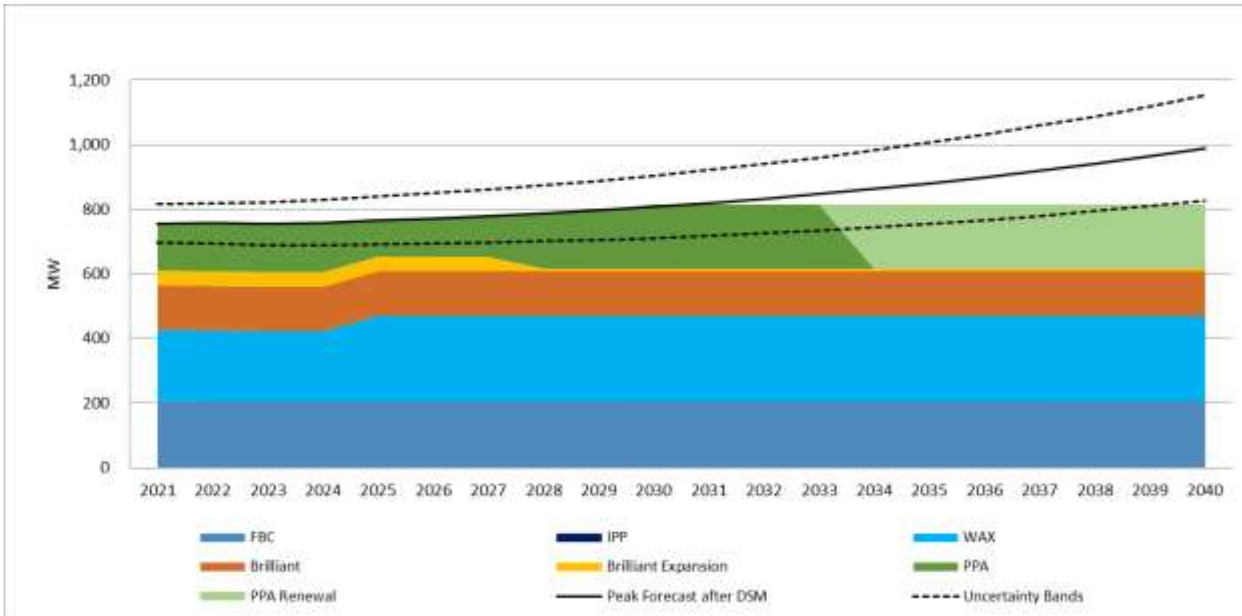
The dashed lines in the figure above show the uncertainty band range for the Reference Case load forecast after the proposed level of DSM. The solid line shows that, with the proposed level of DSM, energy gaps start in 2023 (although not large enough to show in the graph) and increase to almost 950 GWh by 2040 if the PPA is renewed.

If the PPA is not renewed, then the gaps after 2033 are more significant and increase to approximately 1,990 GWh per year by 2040. The low end of the uncertainty band indicates that no new resources are required and surpluses of energy will occur if the maximum amount of PPA Tranche 1 Energy is used. At the high end of the uncertainty band, the energy gaps occur throughout the next twenty years and increase to approximately 2,300 GWh by 2040 even if the PPA is renewed.

9.2 *CAPACITY LOAD-RESOURCE BALANCES AFTER DSM*

The following figure shows the LRB for peak capacity during the winter after netting off the proposed level of DSM from the reference case forecast.

Figure 9-2: Winter Capacity Load-Resource Balance after DSM

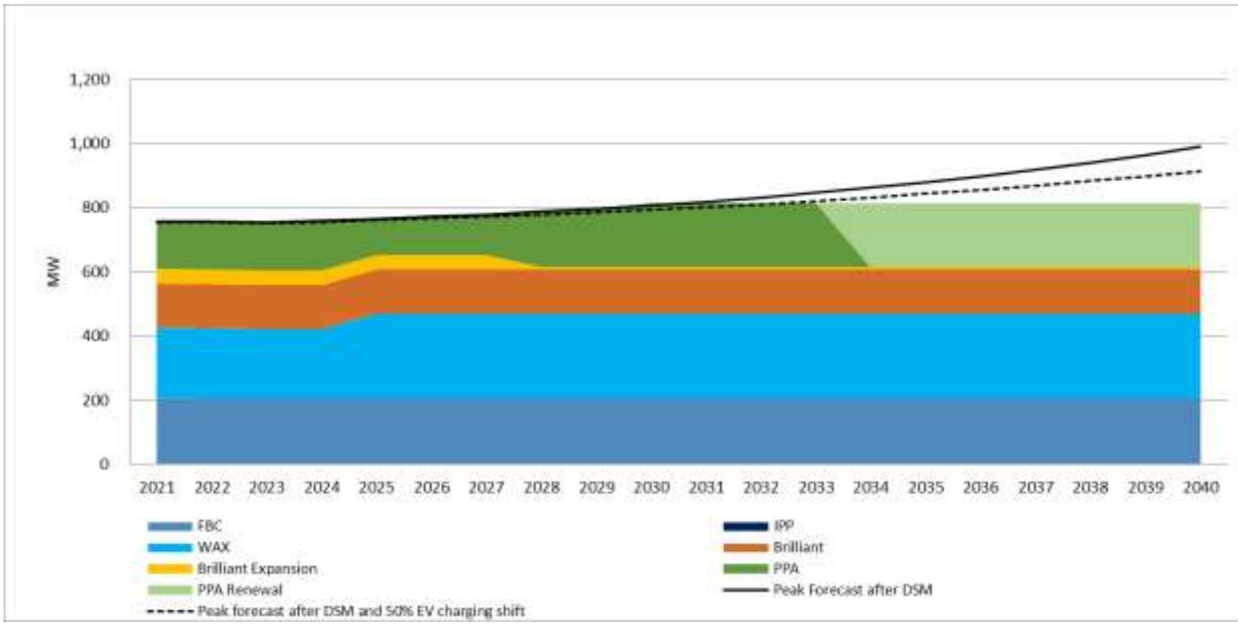


The figure above shows that, with the proposed level of DSM, there are no capacity gaps that need to be filled until 2031. Until 2030, based on the peak load forecast after DSM, there would be surpluses of capacity for most years if the PPA is assumed to provide its full peak supply of 200 MW. However, the figure reflects the reduction in the PPA to match what is required to meet the peak demand forecast. After 2031, the capacity gaps increase until they reach approximately 175 MW by 2040 if the PPA is renewed. If the PPA is not renewed, then gaps in the order of approximately 375 MW occur by 2040.

At the low end of the uncertainty band range, assuming PPA renewal, the PPA would have to be reduced further to avoid surplus capacity until 2040. On the high end of the uncertainty band range, capacity resources would be needed each year, increasing to approximately 340 MW by 2040.

If FBC is able to shift the potential EV charging from peak demand periods, then the capacity gaps could be moved further out in time. Figure 9-3 below provides an example of this, assuming 50 percent of the EV charging load is shifted.

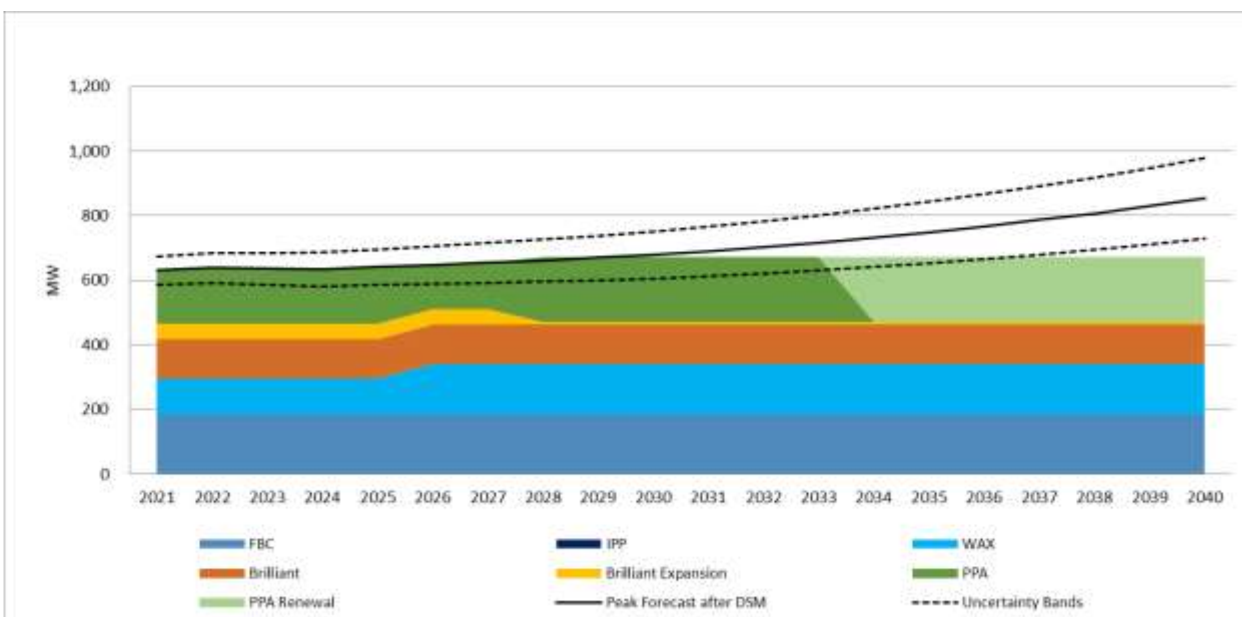
Figure 9-3: Winter Capacity Load-Resource Balance after DSM and EV Charging Shifting



The figure above shows that, with EV charging shifting of 50 percent, the capacity gaps begin in 2033 rather than 2031, increasing to approximately 100 MW by 2040 if the PPA is renewed.

Figure 9-4 below shows the LRB for peak capacity during the summer after netting off the proposed level of DSM from the Reference Case load forecast.

Figure 9-4: Summer Capacity Load-Resource Balance after DSM

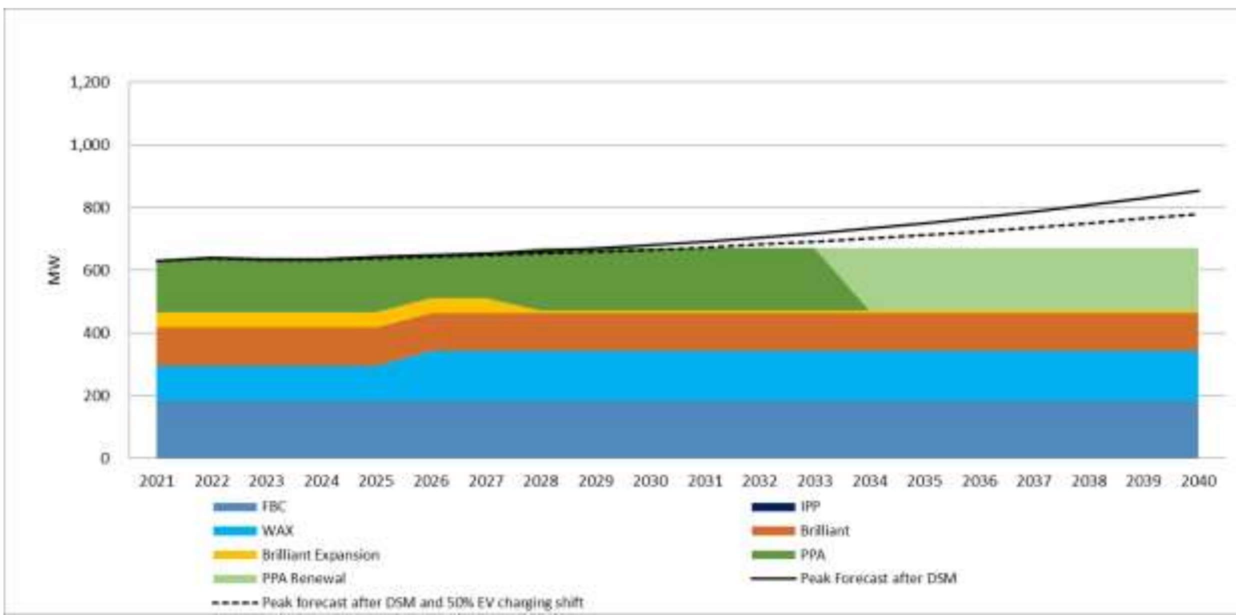


The figure above shows that, with the proposed level of DSM, there are no gaps that need to be filled until 2030. Until 2029, based on the peak load forecast after DSM, there would be surpluses of capacity if the PPA is assumed to provide its full peak supply of 200 MW. However, Figure 9-4 reflects the reduction in the PPA to match what is required to meet the peak demand forecast. After 2030, the capacity gaps increase until they reach approximately 180 MW by 2040 if the PPA is renewed. If the PPA is not renewed, then gaps of approximately 380 MW occur by 2040.

At the low end of the uncertainty band range, assuming PPA renewal, the PPA would have to be reduced further to avoid surplus capacity until 2037. On the high end of the uncertainty band range, capacity resources would be needed each year of the planning horizon, increasing to approximately 340 MW by 2040.

If FBC is able to shift the potential EV charging from peak demand periods, then the capacity gaps would appear later. Figure 9-5 below provides an example of this assuming that 50 percent of the EV charging load is shifted.

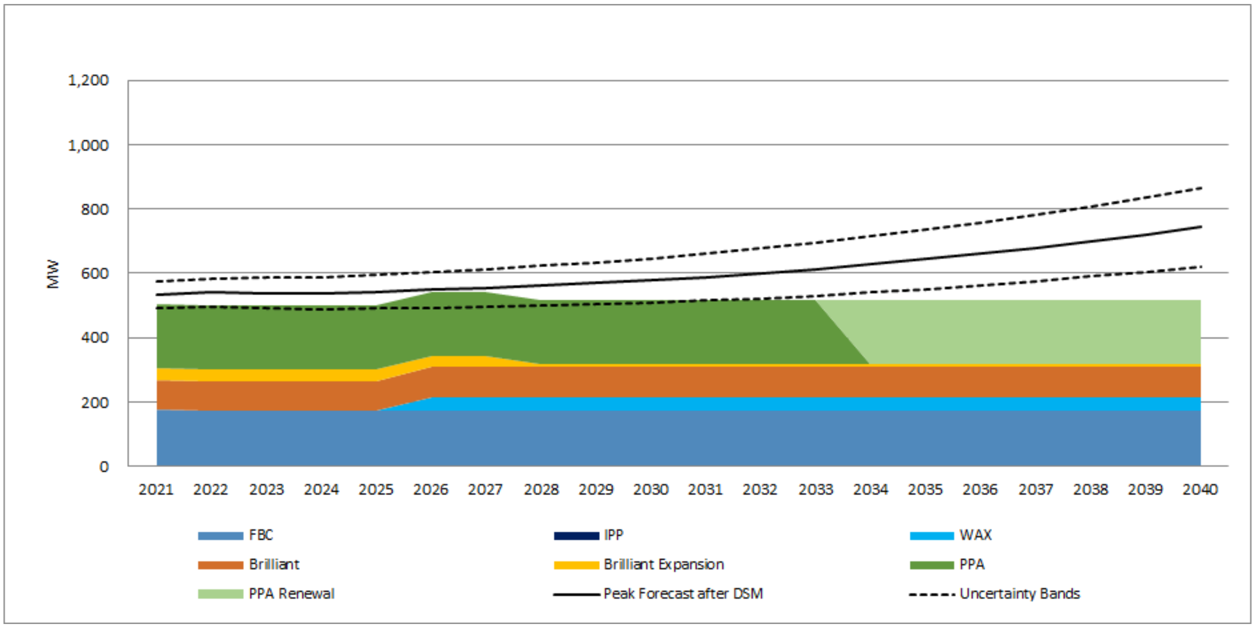
Figure 9-5: Summer Capacity Load-Resource Balance after DSM and EV Charging Shifting



The figure above shows that, with EV charging shifting of 50 percent, the capacity gaps appear in 2031 rather than 2030. They increase to approximately 110 MW by 2040 if the PPA is renewed.

Figure 9-6 below shows the LRB for peak capacity during June after netting off the proposed level of DSM from the Reference Case load forecast.

Figure 9-6: June Capacity Load-Resource Balance after DSM

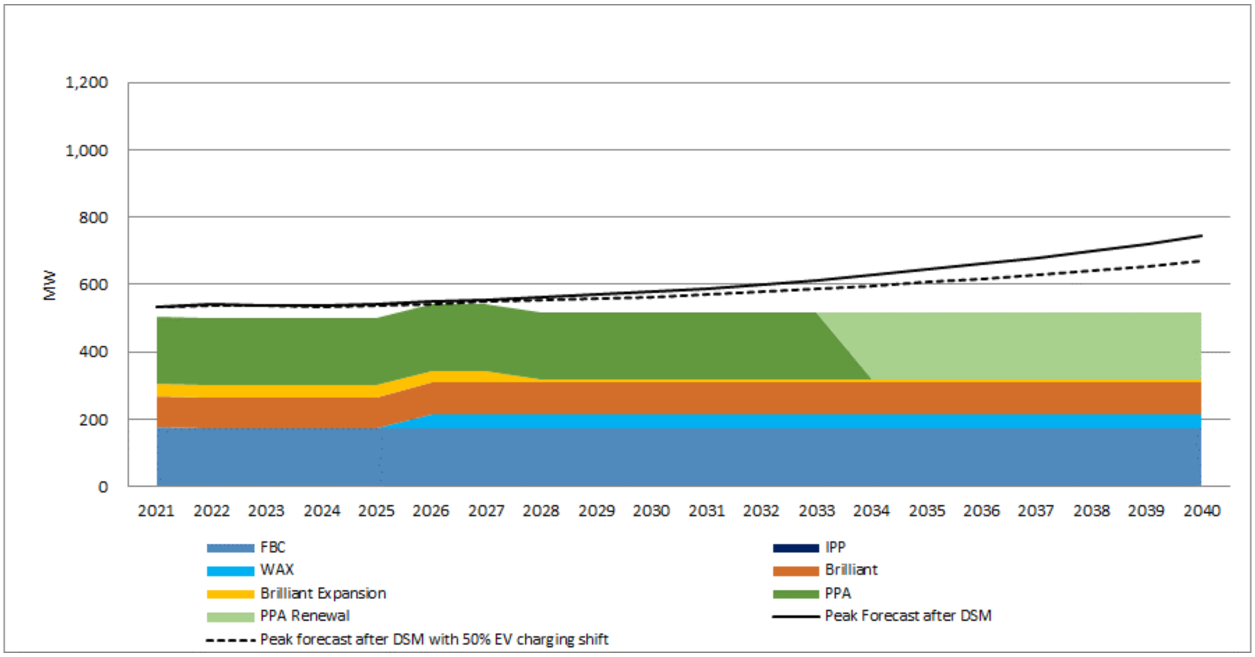


The figure above shows that, with the proposed level of DSM, there are gaps in all years through 2040. The capacity gaps increase until they reach approximately 230 MW by 2040 if the PPA is renewed. If the PPA is not renewed, then gaps of approximately 430 MW occur by 2040. As discussed in Section 7.2, FBC's total existing capacity resources are lower in June which results in larger gaps during this month than in winter and summer periods.

At the low end of the uncertainty band range, assuming PPA renewal, gaps begin in 2032 and increase to about 105 MW by 2040. On the high end of the uncertainty band range, capacity gaps occur in each year of the planning horizon, increasing to approximately 350 MW by 2040.

If FBC is able to shift the potential EV charging from peak demand periods, then the capacity gaps are reduced. Figure 9-7 below provides an example of this assuming that 50 percent of the EV charging load is shifted.

Figure 9-7: June Capacity Load-Resource Balance after DSM and EV Charging Shifting



The figure above shows that, with EV charging shifting of 50 percent, the capacity gaps are about 150 MW by 2040 if the PPA is renewed. If the PPA is not renew, the gaps increase to about 350 MW by 2040.

The following table summarizes the forecast approximate 2040 load-resource balance gaps for annual energy and winter, summer and June capacity with and without the PPA renewal after the proposed level of DSM but before any supply-side resource options are included to meet the gaps.

Table 9-1: Load-Resource Balance Gaps

	First Year of Gap	2040 Gap With PPA Renewal	2040 Gap Without PPA Renewal
Annual Energy (GWh)	2023	950	1,990
Winter Capacity (MW)	2031	175	375
Summer Capacity (MW)	2030	180	380
June Capacity (MW)	2021	230	430

9.3 *WHY SUPPLY-SIDE RESOURCES ARE NEEDED*

This section of the LTERP addresses section 44.1(2)(f) of the *UCA*, which requires a long term resource plan to include an explanation of why the demand for energy to be served by supply-side resources are not planned to be replaced by demand-side measures.

The proposed base level of DSM offset discussed above, and in Section 3 of the LT DSM Plan, satisfies the requirement to provide cost-effective DSM. The average cost of the proposed DSM level is $38 per MWh, which is well below the DSM cost-effectiveness threshold LRMC of approximately $90 per MWh. However, higher DSM scenarios were not chosen for the following reasons, as discussed in Section 8.1 and Section 3 of the LT DSM Plan:

- They are less cost-effective than other resource options. FBC would be paying an increased incremental incentive proportion of measure costs, especially in comparison to the relatively low cost of power supply options, such as market electricity purchases. This is discussed in Section 11.3.1, which shows that the LRMC values for the portfolios with the higher DSM levels are higher than for the portfolio with the proposed level of DSM; and
- They present higher risks of insufficient customer participation. DSM participation is voluntary and FBC cannot have assurance that customer participation will be sufficient to meet the higher scenarios. The fact that FBC had below target energy savings in recent program results indicates that it may not be readily feasible to achieve higher levels of DSM.

Based on the analysis in this LTERP and the discussion in Section 3 of the LT DSM Plan, FBC considers its proposed level of DSM to be appropriate. FBC does not consider it prudent to replace cost-effective supply-side resources with additional, higher-cost, DSM measures to meet forecast load over the planning horizon.

In Section 10, FBC discusses the supply-side resource options that FBC has considered to meet the remaining LRB gaps.

10. SUPPLY-SIDE RESOURCE OPTIONS

10.1 *OVERVIEW*

This section discusses the various supply-side energy and capacity resource options that are available to FBC to meet any load-resource balance gaps over the 20-year resource planning horizon covered by this LTERP. These options include resources that could potentially be available either within or outside of FBC's service area. Resources from outside the FBC service area would require external transmission arrangements to serve FBC load. Available resource options include several types of generation, as well as market purchases and supply from larger, industrial self-generating customers. Distributed generation, available from residential or commercial customers self-generating their own electricity, can also be considered a form of supply. However, for the purposes of this LTERP and as discussed in Section 10.7 below, FBC has treated distributed generation as a driver that reduces load rather than as a supply-side resource option. More details regarding the resource options discussed in this section are provided in the Resource Options Report (ROR) of Appendix K.

The supply-side resource options discussed in this section and in the ROR are included, along with demand-side resource options discussed in Section 8, in the portfolio analysis provided in Section 11. The technical, financial, environmental and socio-economic characteristics of various resource options are also included in this section to help evaluate portfolios to meet future load-resource balance gaps.

The resource options information is provided at a level appropriate for long-term resource planning. If and when additional resources are required in the future, approval will be sought from the BCUC through CPCN applications or through acceptance of energy supply contracts, as appropriate.

The supply-side resource options and their costs and energy and capacity profiles were developed in collaboration with BC Hydro as it updated its Resource Options Inventory in 2019 and 2020. The costs in the Resource Options Inventory were adjusted, where appropriate, to reflect FBC costs and assumptions regarding market price and rate forecasts.[174]

FBC has taken into account a number of attributes when evaluating the various resource options. In addition to financial attributes (i.e. costs), these include operational/technical characteristics and environmental and socio-economic impacts, which are discussed in the following sections. New to this LTERP is the consideration of power plant footprint in the evaluation of environmental impacts. Geographic diversity of resources is also a consideration given that all of the generation plants FBC owns are located in the Kootenay region whereas most of the load and expected load growth is in the Okanagan region. Locating new generation resources closer to the primary load centres would help mitigate risks relating to transmission

[174] For example, the FBC Weighted Average Cost of Capital (WACC) was utilized rather than the BC Hydro WACC. FBC's market price and rate forecasts are discussed in Section 2.5.

disruptions and reliability in the future and also potentially avoid or defer the need for additional transmission infrastructure and its associated costs.

A number of financial assumptions must be made in order to cost the resource options, such as wholesale market gas and electricity prices, renewable natural gas costs, PPA rates and the cost for carbon emissions. These forecasts, scenarios and assumptions are provided in Section 2.5.

FBC has pre-screened the resource options for any emerging resource technologies that are not yet viable or cost effective or those that are not consistent with the *CEA*. This does not mean that some of these resource options could not be considered in the future; however, for the purposes of this LTERP, these resources have not been evaluated as identified in the Resource Options Summary Table 10-1. These non-viable resource options are discussed in Section 3 of the ROR in Appendix K.

10.2 *RESOURCE OPTIONS ATTRIBUTES*

The following is a summary of the various attributes FBC takes into consideration when evaluating supply-side resource options.

10.2.1 Technical Attributes

FBC has grouped its resource options into three distinct dispatch categories: base load resources, peaking resources and variable/intermittent resources.

Base load resources provide dependable capacity[175] and are expected to operate at a high capacity utilization factor,[176] generating significant amounts of electrical energy over the entire year.

Peaking resources can be dispatched to provide dependable capacity, but are expected to operate at a low capacity utilization factor, generating electricity when it is needed. Peaking resources typically have a low cost to construct per unit of capacity, but high per unit energy costs. These resources can also act as planning reserve margin assets that can be brought into service quickly following a contingency event (e.g. loss of a base load facility), to meet sudden changes in customer load requirements, help firm up intermittent resources, or provide short term energy storage. Although these resources can produce energy when generating, they are primarily evaluated for their capacity attributes. For this LTERP, FBC has included battery storage as a capacity resource option. While batteries can provide capacity during peak demand hours, the duration of the capacity provided is limited by the discharge capability of the batteries. FBC has included batteries with 4-hour discharge capability, after which time they must be re-charged before they can be discharged again. In this way, battery storage is similar

[175] Dependable Capacity is defined as the generation capacity available for the peak hours during each month of the year.

[176] Capacity utilization factor is the ratio of the actual output from a plant over the year to the maximum possible output from it for a year under ideal conditions.

to pumped hydro storage, which has a limited capacity generation period before the reservoir must be re-filled to provide capacity again. This is in contrast to some other peaking resources, such as a Simple Cycle Gas Turbine (SCGT) plant. An SCGT plant can provide capacity for any peak demand duration period as long as the fuel source, including conventional natural gas or RNG, is consistently available. Therefore, capacity duration is an important factor when assessing peaking resource options.

Variable/intermittent resources provide less dependable capacity and typically operate at lower capacity utilization rates than base load resources. Variable/intermittent resources are often renewable resources and generate electricity when their fuel source is available; therefore, generation from these resources cannot be increased on-demand in response to changes in customer load. For example, generation from wind or solar resources is determined by external environmental factors such as wind speeds and amount of sunshine. Generation from these resources may not coincide with high system load demand or high market prices. Variable/intermittent resource generation is more consistent and predictable when averaged over a long period or when bundled into a portfolio of geographically diverse intermittent resources. Although some variable/intermittent resources can provide at least a small quantity of dependable capacity, they cannot ramp up or down on demand in response to customers' load requirements and therefore are primarily valued for their energy attributes.

10.2.2 Financial Attributes

To enable comparisons of the costs of resources that represent a wide range of technologies and fuel sources, capital and operating costs and project lifespans, the financial characteristics of the different resource options are described by two simplified cost metrics: unit capacity cost (UCC) and unit energy cost (UEC). UCC is the annualized cost of providing dependable capacity for each resource option, expressed in $ per kW-year. UEC is the annualized cost of generating a unit of electrical energy using a specific resource option, expressed in $ per MWh. As these metrics both include common costs, the value of a project can only be expressed as one or the other; they should not be added.

The UCC and UEC values are based on a levelized net present value (NPV) cost basis in order to enable comparison between the different resources with different cost structures and energy and capacity values. The UECs and UCCs are presented in real 2020 dollars. FBC has assumed a WACC of 3.69 percent[177] after tax (in real terms) as the discount rate in determining the UECs and UCCs. FBC specific adders, such as those relating to transmission wheeling costs, are also included in the UEC and UCC values. More discussion of these assumptions is provided in the ROR in Appendix K.

[177] Based on FBC's after-tax WACC, per the FBC Annual Review for 2020 and 2021 Rates, Schedule 26. Exhibit B2. July 20, 2020.

10.2.3 Environmental Attributes

Environmental considerations are an important objective of the *CEA* and energy policy in BC. Environmental attributes describe the estimated environmental impact of the various resource options. While DSM resources are assumed to have no negative environmental impacts, some supply-side resources can. For the purposes of this LTERP and the portfolio analysis in Section 11, FBC has characterized resource options as either clean or renewable, or not, according to what the *CEA* defines as clean or renewable resources generated in BC. The *CEA* defines clean or renewable resources as including biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. An SCGT plant using RNG as fuel is considered a clean resource option as biogas and biomass are considered clean or renewable per the *CEA* definition. For the purposes of this LTERP, FBC also considers energy and capacity under the PPA to be clean and renewable, although there is a carbon footprint associated with the PPA as the resource is 98 percent clean.[178] For non-renewable resources, FBC has considered both direct GHG emissions from burning fossil fuels (i.e. scope 1 emissions) and indirect GHG emissions associated with the production of the fossil fuel (i.e. scope 3 emissions). Other environmental attributes, such as plant land or water footprint, have also been considered. Based on the regional electricity generation source mix as discussed in Section 2.4.2, market purchases could include a mix of clean or renewable and non-clean or renewable resources. For the purposes of this LTERP, as discussed in Section 2.5.7, FBC has applied a clean adder to its market purchase prices to serve as a proxy for the purchase of only clean and renewable power from the market.

10.2.4 Socio-Economic Attributes

Social and economic development and job creation are included among BC's energy objectives in the *CEA*. Socio-economic development attributes include contributions to provincial GDP, employment and government revenue and supporting community and Indigenous community development. FBC has categorized the socio-economic development attributes for each resource option into low, medium and high impact categories using employment contributions as a proxy for all the socio-economic development benefits. A high impact rating means that a particular resource option contributes more to provincial job creation than a resource option categorized as low impact (in terms of construction and operating jobs). Details are provided in Section 2.2.5 of the Resource Options Report in Appendix K.

10.2.5 Development, Permitting and Construction Lead Time

The development lead time for a generation project will vary with the technology utilized as well as the scale of the project. Development and permitting lead times are an important consideration in the planning process because, for most projects, the lead time could be a minimum of 4 years, and up to 8 years for complex projects. FBC's portfolio analysis provided

[178] BC Hydro 2019 Carbon Neutral Action Report, May 2020, Page 8. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/environment-sustainability/environmental-reports/2019-carbon-neutral-action-report.pdf.

in Section 11 provides an indication of when new generation resources will be required to meet any future load-resource balance gaps. This information, along with the estimated lead times for the resources, helps determine when FBC may need to file a CPCN application for specific generation resources that might be required.

10.3 RESOURCE OPTIONS EVALUATION

Table 10-1 provides a summary of the resource options evaluated in the FBC portfolio analysis including their resource type, dependable capacity, and annual energy. Some resource options show a range of capacity and energy, indicating that a number of different-sized plants were considered for that particular resource option. For gas-fired generation, FBC has included both Combined Cycle Gas Turbine (CCGT) plants as well as SCGT plants using conventional natural gas (NG) or RNG as fuel as described in the ROR. The resources are sorted in the table by type with the PPA energy and capacity in green, market purchases in orange and generation resources in blue. The resource option short names are consistent with those used in the portfolio analysis figures shown in Section 11.

Table 10-1: Resource Options Type and Size Summary

Resource Option[179]	Portfolio Analysis Short Name	Type	Number of Plants in FBC Portfolio Analysis	Average Dependable Capacity (MW)	Annual Energy (GWh)
PPA Tranche 1 Energy	PPA	Baseload	N/A	N/A	Up to 1,041
PPA Tranche 2 Energy	PPA	Baseload	N/A	N/A	Up to 711
PPA Capacity	PPA	Baseload	N/A	Up to 200	N/A
Market Purchases	Market	Baseload	N/A	Up to 75	Up to 3,241
Wood-Based Biomass	Biomass	Baseload	3	9 – 30	73-237
Geothermal	Geothermal	Baseload	4	15 – 75	130 - 657
Gas-Fired Generation (CCGT)	CCGT	Baseload	3	67 – 279	528 – 2,201
Small hydro with storage	Hydro	Baseload	4	8 - 50	77 - 443
Gas-Fired Generation (SCGT) - NG	SCGT	Peaking	3	48 – 100	75 – 158
Gas-Fired Generation (SCGT) - RNG	RNG_SCGT	Peaking	3	48 - 100	75 - 158
Pumped Hydro Storage	PSH	Peaking	2	100 – 1,000	N/A
Onshore Wind[180]	Wind	Intermittent	13	21 – 133	196 – 1,239

179 The FBC Resource Option Report and the portfolio analysis include projects outside the FBC service territory and assume there will be BC Hydro long-term transmission available to deliver the power from these projects to the FBC grid.

180 On-shore wind options included in the FBC Resource Option Report include projects greater than 100 MW. FBC's Scheduling Agreement with BC Hydro currently only allows wind projects up to 100 MW. Section 5 of the Scheduling Agreement also requires 100% back-up of wind resources which has not been factored in the analysis

Resource Option[179]	Portfolio Analysis Short Name	Type	Number of Plants in FBC Portfolio Analysis	Average Dependable Capacity (MW)	Annual Energy (GWh)
Run-of-River Hydro	RoR	Intermittent	3	2 – 6	16 - 52
Utility Scale Solar	Solar	Intermittent	11	4 - 107	28 - 754
Distributed Solar[181]	DistSolar	Intermittent	3	0 - 2	2 - 15
Battery Storage[182]	Battery	Peaking	1	39	N/A
Distributed Battery Storage[183]	DistBattery	Peaking	1	24	N/A

Table 10-2 shows the unit energy and capacity costs for the resource options (in real $2020). The range of unit costs reflects the different plant sizes available for some of the resource options. No UEC is presented for capacity resources including SCGT gas-fired generation, Pumped Hydro Storage or battery storage because these resources are primarily used for providing capacity and not energy. There is no UCC value for market purchases as FBC has assumed capacity self-sufficiency for the purposes of this LTERP for the reasons discussed in Section 2.4.4. The UEC and UCC ranges for market purchases and PPA Tranche 1 and 2 energy and PPA capacity reflect the high and low range of market price forecast scenarios and PPA rate scenarios as described in Section 2.5.5. The table also includes the unit costs for the DSM scenario options, shown in yellow, discussed in Section 8.

Table 10-2: Supply-Side Resource Options Unit Cost Summary

Resource Option	UEC ($/MWh)	UCC ($kW-year)
Low DSM	$33	N/A
Base DSM	$38	N/A
Med DSM	$40	N/A
High DSM	$45	N/A
Max DSM	$58	N/A
PPA Tranche 1 Energy	$49 - $60	N/A
PPA Tranche 2 Energy	$80 - $95	N/A
PPA Capacity	N/A	$101 - $123
Market Purchases	$28 - $49	N/A
Wood-Based Biomass	$121 - $173	$682 - $719

as this does not reflects the current operating environment in North America, and FBC would seek to renegotiate that requirement if it were to add a wind resource to its resource stack.

181 For modelling purposes, distributed solar is defined as less than 10 MW of installed capacity and connected to the distribution system.

182 For modelling purposes, a Battery Storage is defined as 50 MW and connected to the transmission system.

183 For modelling purposes, a distributed battery is defined as 25 MW installed capacity and connected to the distribution system.

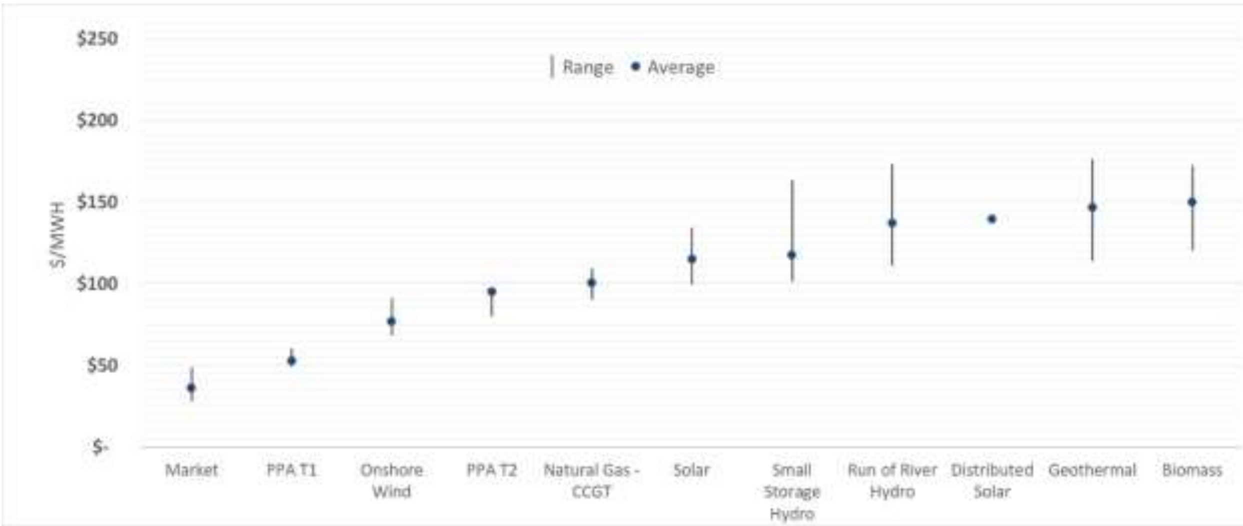
Resource Option	UEC ($/MWh)	UCC ($kW-year)
Geothermal	$114 - $176	$863 - $1,377
Gas-Fired Generation (CCGT) - NG	$90 - $109	$150 - $287
Gas Fired Generation (SCGT) - NG	N/A	$131 - $148
Gas Fired Generation (SCGT) - RNG	N/A	$131 - $148
Small Hydro with Storage	$101 - $163	$687 - $1,271
Pumped Hydro Storage	N/A	$102 - $540
Onshore Wind	$68 - $91	$509 - $734
Run-of-River Hydro	$111 - $173	$817 - $1,330
Utility Scale Solar	$99 - $134	$686 - $863
Distributed Solar	$137 - $141	$829 - $882
Battery Storage	N/A	$267
Distributed Battery Storage	N/A	$226

When looking at the unit costs in Table 10-2 above, it is important to remember that a resource option with the lowest unit cost may not be the best fit for FBC in terms of meeting customers' load requirements. For example, while pumped storage hydro has one of the lowest UCCs of about $102 per kW/year at the low end of the range due to economies of scale, the size of this resource option, with a capacity of 1,000 MW and no energy contribution, makes it an impractical option for FBC's current requirements. It would provide FBC with too much capacity, given the size of the Company's projected capacity gaps, and no energy. The portfolio analysis in Section 11 helps determine the optimal mix of resources based on cost and FBC's monthly energy and capacity requirements.

The UCCs for intermittent renewable energy resources and the UECs for strictly capacity resources should be viewed with caution. This is because, in the former, there is very little capacity associated with the production of energy, producing a high UCC result, and, for the latter, there is little incremental energy produced (or negative net energy in the case of pumped storage hydro or battery storage), creating a high UEC.

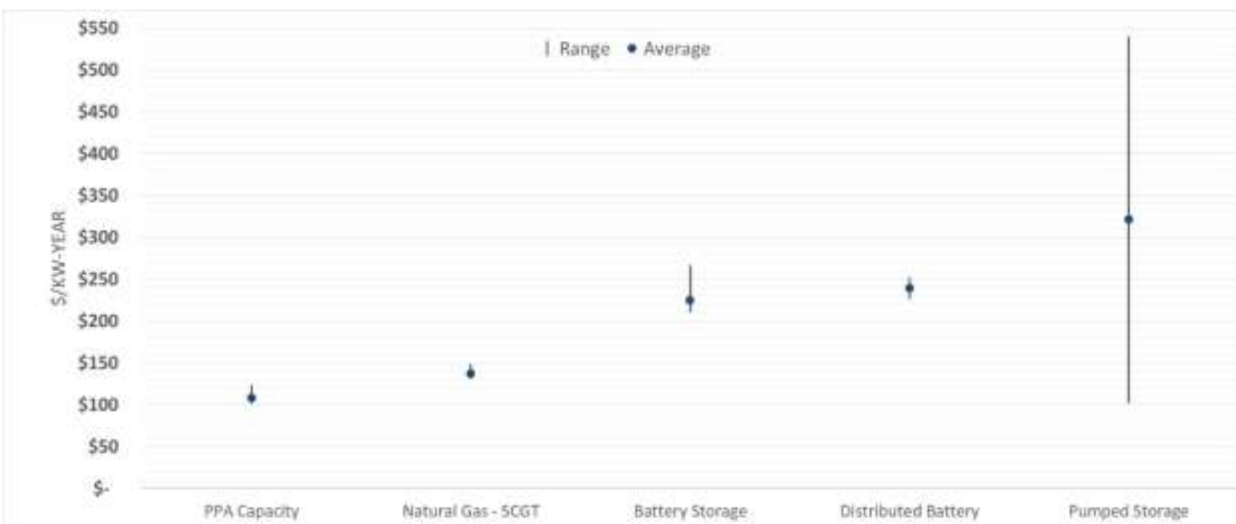
The following figures graphically show the range of unit costs for the resource options that were considered and included in the table above. These figures help illustrate the costs of the various resource options relative to each other. The resource options show projects of various sizes and economies of scale, so a range of unit costs are shown in addition to the average. Resources are sorted from lowest to highest average unit costs. The unit energy costs are provided in Figure 10-1.

Figure 10-1: Resource Options Unit Energy Costs



The unit capacity costs are provided in Figure 10-2. The unit capacity costs for an SCGT gas plant using conventional natural gas or using RNG as fuel are the same.

Figure 10-2: Resource Options Unit Capacity Costs



Additional attributes considered in the portfolio analysis are summarized in the table below. A more detailed discussion is provided in the Resource Options Report in Appendix K.

Table 10-3: Environmental, Socio-Economic and Lead Time Attributes Summary

Resource Option	Clean/ Renewable	GHG Emissions[184]	Plant Footprint[185]	Job Creation[186]	Lead Time (Years)[187]
PPA Tranche 1 Energy[188]	Yes	Low	N/A	N/A	N/A
PPA Tranche[189] 2 Energy	Yes	Low	N/A	N/A	N/A
PPA Capacity[190]	Yes	Low	N/A	N/A	N/A
Market Purchases	Yes	Low	N/A	N/A	N/A
Wood-Based Biomass	Yes	Low	Medium	High	4
Geothermal	Yes	Low	Medium	High	5 - 8
Gas-Fired Generation (CCGT)	No	High	Low	Medium	5
Small Hydro with Storage	Yes	Low	High	High	6
Gas-Fired Generation (SCGT) - NG	No	High	Low	Low	4
Gas-Fired Generation (SCGT) - RNG	Yes	Low	Low	Low	4
Pumped Hydro Storage	Yes	Low	Medium	Low	7 - 8
Onshore Wind	Yes	Low	Medium	Medium	5
Run-of-River Hydro	Yes	Low	High	Medium	5 - 6
Utility Scale Solar	Yes	Low	High	Low	5
Distributed Solar	Yes	Low	High	Low	5
Battery Storage	Yes	Low	Low	Low	2
Distributed Battery Storage	Yes	Low	Low	Low	2

10.4 *MARKET PURCHASES*

Market purchases of energy can be a cost-effective and reliable resource within the FBC portfolio. FBC has relied on short-term market electricity purchases in the past and this strategy has proven cost effective in recent years given the decrease in market gas and power prices relative to the costs of other resource options, such as the PPA with BC Hydro. On an annual

[184] Assumes direct emissions except in the case SCGT using RNG, which includes indirect emissions created in the production of RNG.
[185] Calculated as nameplate capacity/hectare.
[186] Calculated as person-years. Based on both construction and operating jobs.
[187] Based on permitting and construction time.
[188] BC Hydro purchases are currently 98% clean.
[189] BC Hydro purchases are currently 98% clean.
[190] BC Hydro purchases are currently 98% clean.

basis, FBC determines the optimal amount of market purchases within its Annual Electric Contracting Plan (AECP), taking into account its forecast load requirements, the annual PPA energy nomination and the price of market supply compared to the PPA tranche 1 energy rate.

On a long-term planning basis, FBC can compare the forecast price of market purchases to the forecast price of the PPA and other resources to help evaluate market purchases within the resource options portfolio. Based on current base forecasts for market prices, and provided that energy purchase from the market continue to be reliable and cost-effective as discussed in Section 2.4.4, some reliance on market purchases of energy is more cost-effective than energy delivered to the FBC service area from other resource options, at least over the short to medium term. Figure 2-18 in Section 2.5.2 shows the base case long-term market price for electricity at Mid-C, before the applicable adders such as wheeling costs and a clean market adder discussed in Section 2.5.7 are applied. The levelized unit energy cost for market purchases in the base case is approximately $36 per MWh, including wheeling transmission costs and the addition of a clean market adder. This is significantly lower than the energy unit costs of the other supply-side resource options listed in Table 10-2 which have energy unit cost ranges of $68 per MWh to $176 per MWh (excluding the BC Hydro PPA).

The market price range (plus transmission costs) is also lower than the base case PPA Tranche 1 Energy rate. The PPA Tranche 1 expected levelized unit cost over twenty years is approximately $52 per MWh. The PPA Tranche 1 scenarios are discussed in Section 2.5.

The levelized market prices in Table 10-2 and discussed above reflect the cost of market energy including a clean market adder. While market energy purchases have an associated carbon footprint, clean energy specified source contracts are available in the market. These contracts sell at a premium above regular market prices. As discussed in Section 2.5.7, FBC has applied a clean market adder of approximately $2 per MWh to the cost of its market purchases. Although FBC is currently comfortable with relying on market purchases for some of its energy needs, relying on market purchases for capacity in peak hours over the long term can be risky in terms of availability, as discussed in Section 2.4.4. There is also no guarantee that FBC will be able to access market capacity supply reliably, especially if there is no access to long-term firm transmission. FBC relies on Line 71 to access US market supply, and there can be transmission constraints both on Line 71 and on the US transmission south of the border that can interrupt that supply when FBC needs it for capacity purposes, as discussed in Section 5.5. Therefore, FBC does not believe that market supply can be relied on as a long-term capacity resource option.

The month of June, however, is the exception to FBC requiring capacity self-sufficiency for LTERP planning purposes. Due to the availability of freshet[191] power during the month of June and FBC's market import capacity, FBC expects that the June gaps (after DSM) up to the level of 75 MW could be met with market block purchases, contracted prior to the start of each June,

[191] The term freshet is most commonly used to describe a spring thaw resulting from snow and ice melt in rivers. Freshet power is typically abundant in the Pacific Northwest during spring months when this thaw results in higher levels of hydro-electric generation than in other times of the year.

rather than acquiring new resources, up until 2030. This is consistent with FBC's past practice of purchasing June freshet power and has been a cost-effective option to meet June requirements as market capacity purchases during this period are typically among the lowest cost that occur during the year. To fill gaps above this level, other resource options need to be considered. FBC cannot rely on abundant freshet market capacity for meeting winter and summer LRB gaps as it is not available during those periods. After 2030, FBC is assuming capacity self-sufficiency given the risks with longer term reliance on market capacity.

10.5 *BC HYDRO PPA*

The PPA with BC Hydro provides long-term dependable capacity and energy. FBC has access to up to 200 MW of capacity, up to 1,041 GWh of Tranche 1 Energy and up to 711 GWh of Tranche 2 Energy. The cost for this energy and capacity is provided in Table 10-2 and discussed in Section 2.5.5. The PPA is a very flexible resource in the FBC portfolio, enabling FBC to increase or decrease the amount of the energy and capacity requirement from year to year, subject to specific limits. Because of this flexibility, FBC has included the PPA in its list of resource options even though it is already an existing contract. More details regarding the PPA are provided in Section 5.5.

10.6 *EXPIRING ENERGY PURCHASE AGREEMENTS*

As of February 2020, BC Hydro had a total of 127 electricity purchase agreements with independent power producers. About 70 of these agreements are expiring over the next 20 years, representing approximately 9,100 GWh of firm energy and 1,300 MW of dependable capacity. The expiring agreements are primarily small run-of-river facilities as well as some are larger run-of-river, storage hydro, biomass, municipal solid waste, wind, solar, waste heat, biogas, and gas-fired generation facilities.[192] Energy currently provided to BC Hydro from these IPPs may become available when these EPAs expire.

There may be opportunities for FBC to acquire power from these expiring EPAs on a cost-effective basis in the future. FBC will continue to monitor the BC Hydro contract renewals for any resource option opportunities.

10.7 *DISTRIBUTED GENERATION*

Distributed generation, such as residential or commercial rooftop solar power, can be either a supply-side resource or a variable that reduces customer demand. While a unit cost value of this distributed generation to FBC as an energy supply-side resource can be determined for illustrative purposes, doing so requires caution for resource planning because distributed generation is not within FBC's control and is not a reliable resource option for long-term

[192] BC Hydro Draft 2021 Integrated Resource Plan, Section 5.3, page 19: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/draft-integrated-resource-plan.pdf.

planning purposes. FBC has no assurances that the customer-generated electricity will be available on its system when needed, or in the appropriate location. Furthermore, distributed rooftop solar generation provides no capacity during winter peak-demand periods unless paired with appropriate levels of battery storage. FBC discusses the current amount of distributed generation on its system in Section 2.3.4, noting that its overall contribution to meeting FBC's total customer load is not significant at this time. Therefore, for the purposes of this LTERP, FBC has treated distributed generation as a driver that reduces load rather than as a supply-side resource option. This is consistent with FBC's approach to distributed generation in the 2016 LTERP. In its decision regarding the 2016 LTERP, the BCUC was satisfied that FBC had appropriately factored distributed generation into the LTERP planning environment.[193] FBC has captured the distributed generation potential for the FBC system as a load-reducing driver within its load scenarios as discussed in Section 4 of this LTERP.

As approved by BCUC Order G-63-18 dated March 16, 2018 regarding FBC's Application for Reconsideration and Variance of Order G-199-16,[194] FBC reimburses net metering customers based on the BC Hydro PPA Tranche 1 Energy rate of $50.73 per MWh (as of April 1, 2021 as discussed in Section 2.5.5). Therefore, the rate for Tranche 1 Energy is essentially the cost of distributed generation to FBC for the short term.

10.8 *PURCHASES FROM SELF-GENERATORS*

Electricity purchases from self-generating customers may be a supply option for FBC in the future. Self-generating customers, for the purposes of this LTERP, refers to larger, industrial customers that can provide electricity to FBC as opposed to smaller, residential or commercial customers that could provide distributed generation to FBC. Self-generation supply, in addition to benefitting the self-generator, can also have the following benefits for FBC and its customers:

- self-sufficiency and less reliance on market supply;
- reduction of transmission losses depending on location on the FBC system; and
- improved reliability depending on location.

When assessing the value of self-generation supply, in addition to these benefits, FBC must consider other relevant criteria in terms of its supply requirements and its LTERP objectives, as it does with other supply-side resource options. These criteria include the energy and capacity profile (i.e. when the electricity is provided to FBC during each month of the year), adherence to provincial energy and environmental policy, and cost effectiveness. The energy and capacity profile of the self-generation supply needs to meet FBC's customer load requirements, providing energy throughout the year and capacity during peak demand periods. Any self-generation must be consistent with BC's energy and environmental policies, such as meeting clean or renewable generation requirements. In terms of cost, long-term self-generation supply would

[193] BCUC 2016 LTERP decision, Order G-117-18, June 28, 2018, page 26.
[194] BCUC Order G-199-16 resulted from FBC's Net Metering Update Application dated April 15, 2016.

need to meet FBC's LRMC requirements, as discussed in Section 11, to be considered cost effective. If the self-generation supply is short term in nature, then FBC would compare the cost to its short-term resource options, such as market supply or PPA.

At this point in time, FBC does not have any specifics or indications of costs or other attributes such as environmental or socio-economic characteristics. FBC is not seeking additional sources of supply at this time and is therefore not actively looking to purchase power from self-generator customers. However, if a self-generator could provide power at a cost lower than FBC's alternatives, there may be an opportunity for FBC to purchase the output of the self-generation.

10.9 *FIRST NATIONS AND COMMUNITY RESOURCE DEVELOPMENT*

The FBC portfolio analysis, discussed in Section 11, determines the different bundles of resource options required to meet future energy and capacity gaps when they occur. The LRB provided in Section 9 indicates that, after incremental DSM, FBC does not have significant resource needs in the short to medium term and that new resources are not expected to be required until at least 2030. As FBC moves closer to the period when new resource options are required, further portfolio analysis can be done to determine the resource requirements and optimal mix of incremental DSM and/or generation.

Section 12.5 describes FBC' Statement of Indigenous Principals, and discusses FBC's support of the UN Declaration for the Rights of Indigenous Peoples, and local communities' and Indigenous communities' energy priorities. FBC will consider partnerships with local and Indigenous communities when new supply-side resources are needed to be developed in the future.

10.10 *SUMMARY*

As discussed throughout this section and the ROR, there are many potential supply-side resource options available to FBC to meet its future energy and capacity gaps. These include base load, peaking and intermittent/variable generation resources as well as purchases from the market and supply from self-generators. Based on current market price forecasts and PPA rate scenarios, market purchases and the PPA are the lowest cost resources available to FBC.

However, it is important to remember that unit cost alone is not the only factor to consider when selecting resources. The size and generation profile of the resource option needs to match FBC's monthly energy and capacity gaps to be of value to FBC in meeting customer loads. Environmental and socio-economic attributes must also be considered in meeting the LTERP objectives. The portfolio analysis, discussed in Section 11, will help to determine the optimal mix of these various resource options and their attributes, taking into account the resource planning objectives.

11. PORTFOLIO ANALYSIS

Portfolio analysis helps to determine an optimal mix of resources to meet customers' future energy and capacity requirements. It includes the development of several portfolios in order to determine the trade-offs between portfolios with different attributes. For example, how does a portfolio including only clean and renewable resource options compare to one with gas-fired generation in terms of meeting the LTERP's objectives such as reliability, cost effectiveness and consistency with BC's energy policy objectives? The portfolio scenarios also encompasses high level sensitivity analysis to determine how they differ under changing conditions in the future. These changing conditions could include, for example, changes in RNG costs, market power prices or PPA rates. The analysis includes portfolios that meet the reference-case load forecast requirements as well as the load scenarios discussed in Section 4. The outcome of the portfolio analysis is a set of portfolios that meet the objectives of the LTERP. Another outcome is the Long Run Marginal Cost (LRMC) for each portfolio which represents the cost to FBC of incremental resources needed to meet incremental load requirements over the planning horizon (discussed further in Section 11.2). The feedback FBC has received from stakeholders, Indigenous communities and customers then helped FBC determine the preferred portfolio(s).

This approach to portfolio analysis is consistent with the BCUC Resource Planning Guidelines discussed in Section 1.4.2.

In this section, FBC will first describe its methodology for the portfolio analysis and will communicate the purpose and values of the LRMC as determined by the portfolio analysis. FBC then discusses the alternative portfolios, assessment of results, and the preferred portfolios. This section also includes a discussion of how the preferred portfolios meet the requirements for the Planning Reserve Margin, which is further discussed in Appendix L. FBC also discusses contingency plans for the preferred portfolios to provide an indication of their ability to adapt to changing conditions.

It is important to note that the portfolio analysis presented in this section provides a high-level indication of how load-resource balance gaps may be filled in the future. It is likely that before specific resource options are required, load forecasts, load-resource balances and resource options and costs will change. Based on the portfolio analysis results presented in this section, and assuming the reference case load forecast, proposed DSM level and continued market access, FBC will not require any new generation resources until at least 2030. If conditions arise in the future such that incremental generation resources are required sooner than expected, FBC expects that additional specific analysis regarding options will be performed and requests for approval will be brought forward in a separate application to the BCUC.

11.1 *PORTFOLIO ANALYSIS METHODOLOGY*

FBC has assessed different portfolios of resource options to meet its potential load-resource balance gaps as described in Section 9. The resource options available include different levels of DSM, as discussed in Section 8.1 and the LT DSM Plan Section 3, and supply-side resources, discussed in Section 10. The available resources also include the existing PPA, which includes energy and capacity that FBC can adjust up or down subject to the conditions therein. The portfolios are designed to meet both energy and capacity gaps on a monthly and annual basis for the reference-case load forecast as well as the load scenarios for the twenty-year planning horizon.

FBC's portfolio model incorporates an optimization routine to find the lowest power supply revenue requirement of satisfying the forecast load requirements given a set of constraints, which lead to what new resources should be acquired and when. The portfolio analysis takes into consideration BC energy and environmental policies, as discussed in Section 2.2, such as the objective of at least 93 percent of generation from BC clean or renewable resources in the *CEA* and the Bill 17 proposed amendment to the *CEA* for a 100 percent clean energy standard for BC electricity and the removal of the self-sufficiency requirement. It also includes constraints on the amount of wholesale market purchases FBC is able to import based on transmission limitations. The costs and the LRMC values of the various portfolios FBC evaluated are based on the Average Incremental Cost (AIC) approach as discussed below in Section 11.2 and in Appendix L regarding the LRMC.

11.1.1 Alternative Portfolios and Sensitivities

FBC has evaluated portfolios based on several different base characteristics and then explored sensitivities around these base characteristics. These characteristics and sensitivities are outlined in the following table.

Table 11-1: Portfolio Analysis Base Characteristics and Sensitivity Cases

Portfolio Base Characteristics	Sensitivity Cases
DSM Level • Proposed Base level	• No DSM (for DSM LRMC purposes) • Low DSM • Med DSM • High DSM • Max DSM
Reliance on Market Purchases • Capacity self-sufficiency starting in 2021 (except for June, which has a limit of 75 MW until 2030 and 0 MW thereafter) • No energy self-sufficiency	• Energy self-sufficiency by 2030 • No energy or capacity self-sufficiency • No clean adder for market energy • High market and carbon prices with no clean adder for market energy
Percent Clean or Renewable • Minimum 93 percent clean or renewable • Gas-fired generation permitted	• 100 percent clean or renewable including SCGT using RNG • 100 percent clean or renewable with no SCGT using RNG • High market and carbon prices • High clean resource option costs
Load Requirements • Reference Case load forecast	• Guidehouse load scenarios • Stakeholder average scenario

Portfolio Base Characteristics	Sensitivity Cases
EV charging shifting • No shifting from peak periods	• 25 percent shifting • 50 percent shifting • 75 percent shifting • 100 percent shifting
PPA Renewal • PPA renewed in 2033	• PPA not renewed, replaced with clean resources • PPA not renewed, replaced with clean resources and excluding SCGT using RNG • PPA renewed, high Tranche 1 pricing • PPA renewed, low Tranche 2 pricing

FBC's proposed base DSM level is outlined in Section 8.1 and in the LT DSM Plan, Section 3. FBC has also explored different sensitivity levels of DSM in the portfolio analysis per the DSM scenarios discussed in Section 3 of the LT DSM Plan. These sensitivities include no DSM at all, as well as Low, Med, High and Max DSM levels. The portfolio with no DSM is used to determine the LRMC based on clean or renewable resources in BC for the purposes of evaluating the cost effectiveness of DSM in accordance with the Demand-Side Measures Regulation.[195] This portfolio without DSM is not a realistic portfolio as it is expected that FBC will continue with its DSM programs and initiatives to help customers conserve electricity and reduce their electricity bills. The maximum DSM level is based on FBC incurring 100 percent of the incentive costs and sets the upper boundary for the various DSM levels. The base DSM level is FBC's proposed DSM level given that higher levels of DSM are less cost-effective than other resource options (as discussed in Section 11.3.1 below) and is closest to FBC's current level of DSM.

FBC currently accesses market supply to complement its existing resources with reliable and low-cost power. There is no indication at this time the average price of market energy supply will increase significantly or that FBC will not be able to access it reliably over the next ten years. However, market conditions can change over time, market prices and access could change in the future. FBC's base assumption is that it will be able to access low-cost and reliable market energy supply for the planning horizon. However, as discussed in Section 2.4.4, there are risks with relying on the market for capacity over the longer term. Correspondingly, FBC has assumed that it will be capacity self-sufficient throughout the planning horizon, with incremental capacity supply coming from its own generation and/or long-term contracts from BC suppliers until new resources are needed. The exception to this capacity self-sufficiency is the month of June, when abundant freshet hydropower has historically been available. For June, FBC has assumed that it can access market capacity up to 75 MW until 2030, after which time there is no June capacity market access, for the purposes of its portfolio analysis in this LTERP. As sensitivity cases, FBC has developed portfolios that do not include capacity self-sufficiency within the planning horizon (i.e., long-term market capacity reliance is an option) and capacity and energy self-sufficiency. FBC has also modelled the impacts of higher market power and

[195] Demand-Side Measures Regulation, B.C. Reg. 326/2008 (including amendments up to B.C. Reg. 141/2014), section 4(1.1) (Cost effectiveness).

carbon prices based on the price forecasts and scenarios provided in Section 2.5 and the removal of the clean energy market adder.

The minimum level of clean and renewable resources in the base resource portfolio is 93 percent, which is based on the current requirement for BC Hydro under the *CEA*. Note that this is a minimum level for clean or renewable resources and all the FBC portfolios exceed the 93 percent level and are closer to being 100 percent clean or renewable. For the purposes of this LTERP and its portfolio analysis, FBC assumes clean or renewable resources are those included in the *CEA* - biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource.[196] Given the proposed amendment to the *CEA* for BC Hydro to target 100 percent clean and renewable resources, FBC has also modelled a portfolio based on 100 percent clean and renewable resources. An SCGT plant using RNG as fuel is considered a clean resource option for the portfolio analysis (as biogas and biomass are considered clean or renewable per the CEA definition) and therefore can be included in a portfolio that is 100 percent clean and renewable. FBC also modelled a clean and renewable portfolio without an SCGT plant. FBC has also modelled high cost scenarios for market, natural gas, RNG and carbon prices to determine the effects on a portfolio that includes gas-fired generation, and also modelled the impacts of higher costs for clean and renewable resource options.

The base load forecast assumed in the portfolio analysis is the Reference Case load forecast as presented in Section 3. As sensitivity cases, FBC has also modelled the effects of higher and lower loads using the load scenarios presented in Section 4. The higher load scenario portfolios provide an indication of the extra resources FBC may require in the future if load drivers such as medium and heavy duty EVs, fuel switching from gas to electricity, hydrogen production or additional large industrial or commercial facilities increase the load requirements of FBC's customers above the Reference Case load forecast level. FBC has also modelled the effects of the stakeholder average scenario, discussed in Section 4.2.

FBC's base assumption is that there is no shifting of EV charging from peak periods. As discussed in Section 2.3.2, FBC does not currently have any programs or measures in place to manage EV charging. However, FBC has assessed several options and is planning to implement pilot programs in the near future to help assess how much EV charging can be potentially shifted to off peak times. Therefore, as sensitivity cases, FBC has modelled portfolios that include different percentages of EV charging shifting, including 25, 50, 75 and 100 percent.

As discussed in Section 5.4, the PPA expires in 2033. FBC's base case assumption is that the PPA is renewed as it provides a cost-effective, reliable, flexible and clean and renewable supply of energy and capacity. However, there is the possibility that the PPA is not renewed, and FBC will require other resources to meet customers' requirements. FBC has included non-renewal of the PPA in 2033 as a sensitivity case in the portfolio analysis and assumed different types of resources to meet the future gaps.

[196] BC 2010 CEA, Definitions, page 2.

All of the portfolios presented in Section 11.3 have met FBC's planning reserve margin requirements, which set a minimum level of portfolio reliability. This is discussed further in Section 11.3.10. FBC does not consider a portfolio to be viable for inclusion as an option if it does not meet this minimum reliability standard.

11.2 *LONG RUN MARGINAL COST*

The LRMC values represent the cost to FBC of incremental resources needed to meet incremental load requirements over the planning horizon. The LRMC includes both energy and capacity generation components. FBC's LRMC values are outcomes of the portfolio analysis and are dependent upon which demand-side and supply-side resource options are included within a particular portfolio.

The LRMC is distinct and calculated separately from the long run avoided cost of transmission and distribution infrastructure, referred to as the Deferred Capital Expenditure (DCE) value. The DCE value is discussed in Section 2.4 of the LT DSM Plan. The DCE is a measure of avoided system infrastructure while the LRMC is a measure of energy and capacity generation. The LRMC is reported as a dollar ($) per MWh, reflecting an emphasis placed on energy. The drivers for transmission and distribution planning have a locational aspect and are based only on peak demand rather than both peak demand and energy.

The LRMC is applicable for the 20-year planning horizon and reflects the variable resourcing decisions available to FBC during that period (as discussed in Appendix L). In other words, FBC can change the PPA nomination subject to constraints[197] and/or procure varying amounts of market energy. Additionally, FBC could purchase or acquire new firm energy or capacity resources during the next 20 years. This is in contrast to FBC's other shorter-term avoided costs during which time period FBC is not able to adjust all resources to the same degree or acquire new resources. FBC's use of shorter-term avoided costs may be more appropriate for situations where the energy provided is not considered firm, where delivery is not within the control of FBC, and includes no long-term commitment, such as with FBC's net metering program (discussed in Section 1.5.2).

The LRMC values determined in the portfolio analysis serve two distinct purposes. As discussed above, the LRMC for the portfolio with no DSM is used in the cost-effectiveness test for DSM in accordance with the Demand-Side Measure Regulation. The LRMC values for the portfolios that include DSM serve as a point of reference reflecting the general level and trend of future costs. Power supply options with costs below the LRMC values could be considered viable resource options for FBC provided that they also meet FBC's monthly and annual energy and capacity requirements and LTERP objectives. The performance profiles (and risks) of different technologies need to be taken into account when calculating marginal costs as a combination of resources will be required to address gaps at certain times over the planning horizon. The identified incremental resource(s) of the preferred portfolio have attributes that

[197] FBC currently maintains a PPA Nomination that can be increased to the Tranche 1 limit of 1,041 GWh within a maximum of four years, which results in a minimum PPA Nomination in each year of 603 GWh at this time.

complement existing resources within the context of the portfolio. While a particular resource option may be cost effective relative to a given LRMC value, it may not fit the energy or capacity requirements of customers. For this reason, FBC believes the LRMC values presented here should be viewed as price signals, rather than threshold targets for resource options.

FBC has adopted the Average Incremental Cost (AIC) approach to estimating the LRMC values. The AIC approach takes the present value of the incremental costs expected to be incurred over the planning horizon and divides the incremental costs by the present value of the additional load expected to be served within the same period. More details regarding the LRMC, including definitions, methodology and background information, are provided in Appendix L. As discussed in Section 1.5.2, FBC has excluded DSM costs in the determination of the LRMC values for the portfolios in this LTERP.

The next section discusses the results of the portfolio analysis including the LRMC values associated with the various portfolios.

11.3 *PORTFOLIO ANALYSIS RESULTS*

The portfolio analysis results are presented based on the categories discussed in Table 11-1. The results show the incremental resources included within each portfolio, the year in which they are required, and the LRMC values for each portfolio. The generation resource options considered in the portfolio analysis, including their unit costs and abbreviations used in the figures in this section, are provided in Table 10-1, Table 10-2 and Table 10-3 in Section 10.3. Based on these results, a set of portfolios are selected from which the preferred portfolios are determined (discussed in Section 11.3.8).

11.3.1 DSM Levels

The following figures show the results of portfolios with varying levels of DSM.

Figure 11-1: Portfolios with Varying DSM Levels

The first portfolio in the figure above, portfolio A1, represents the base portfolio with the base level of DSM as discussed in Section 8.1. This portfolio includes PPA, market energy, battery storage, solar and SCGT plants using conventional gas and RNG to meet the LRB gaps and has a LRMC of $78 per MWh. Portfolio A2 includes the PPA and only clean or renewable resources without any DSM, which, as described above, is used to determine the LRMC for the purposes of evaluating cost effective DSM (per the DSM Regulation). The LRMC for this portfolio is $90 per MWh and is a higher cost than portfolio A1 due to no market access,[198] no DSM and more costly generation resources.

The other portfolios A3 to A6 include different levels of DSM. Each level of DSM contain all cost effective DSM measures. The various DSM scenarios investigate what additional uptake the cost effective measures would attract, and therefore increase savings, if the utility was to pay an increasingly larger portion of the measure cost. These portfolios have LRMC values that range from $77 per MWh to $83 per MWh and all include, in addition to various DSM levels, market energy, PPA, battery storage, solar and SCGT plants with and without RNG. The least-cost portfolio A3 includes the lowest amount of DSM savings while the highest cost portfolio A6

[198] More precisely, the very least amount of market access to achieve a feasible solution, which resulted in an average of approximately 25GWh of energy in the month of June between the years 2021 and 2025.

(other than portfolio B2 which includes no DSM) includes the maximum level of DSM savings. The LRMC increases as the costs of higher DSM levels is greater than alternative supply-side resource options, including lower-cost market energy.

The Base Case portfolio contains spending levels and target savings in line with existing DSM programs (i.e. DSM "High" scenario in the 2016 LTERP) and is more cost effective than higher DSM scenarios.

11.3.2 Market Access versus Self-Sufficiency

FBC has assessed portfolios that include access to the market for energy and capacity as well as those assuming a self-sufficiency requirement. The results are provided in the following figure.

Figure 11-2: Portfolios with Market Access versus Self-Sufficiency

The results show that portfolio A1 with market energy throughout the planning horizon has a lower LRMC of $78 per MWh than portfolio B2 with market energy self-sufficiency by 2030 which has a LRMC of $82 per MWh. Portfolio A1 has a lower LRMC because of the low cost of market supply relative to the cost of other resource options. In portfolio B2, more expensive resource options, like solar, wind and run of river generation are required to fill the gaps without market energy after 2030. Portfolio B2 contains capacity resources as well as a larger wind resource to provide winter energy. As discussed in Section 2.4.4, FBC has identified potential risks with relying on market capacity and energy. Should market energy become less reliable in the future, FBC expects that a portfolio like B2 would be a preferred option.

Portfolio B3 includes access to market energy but assumes that market energy purchases are not from clean or renewable sources and so the clean market adder has been removed. This increases the LRMC of this portfolio to $82 per MWh which is higher than the LRMC for portfolio A1 because of the higher cost incurred to offset the carbon attributes associated with market energy. For scenario purposes, FBC has conservatively assumed that non-clean market energy would be subject to a carbon tax in the future. In addition to an increase in cost, the reportable GHG emissions in this portfolio would be materially higher.

Portfolio B4 assumes higher market energy prices and higher carbon costs (based on the scenarios in Section 2.5) for non-clean market energy purchases. This increases the LRMC for this portfolio to $90 per MWh. Given the low market price forecast and the volume of market energy dispatched in the base case, this scenario essentially investigates what the portfolio would look like is market energy costs were less favourable. This portfolio dispatches more PPA energy and begins to include energy resources in addition to capacity resources near the end of the planning horizon.

FBC did explore a portfolio that did not have a self-sufficiency requirement for both energy and capacity. However, since accessing market capacity to meet expected load utilizes the same resource (i.e. transmission to the US market) that is used to provide reliability to ensure planning reserve margin targets are met (discussed in Section 11.3.10), it is not an appropriate portfolio in FBC's view. Furthermore, relying on capacity from the US market for long-term planning is not appropriate given the risks FBC has identified in Section 2.4.4. FBC recognizes that market capacity may be available from within B.C., thereby avoiding this issue. However, FBC has no information at this time about what, if any, B.C.-based market capacity resources may be available.

11.3.3 Clean versus Non-Clean

FBC has evaluated portfolios which include only clean or renewable resources and those that include some resources that are not clean or renewable. The results are provided in the following figure.

Figure 11-3: Portfolios with varying levels of Clean or Renewable Resources

As discussed above, portfolio A1 includes SCGT plants that use natural gas and RNG as fuel. Portfolio C2 assumes higher natural gas, carbon price, and RNG fuel costs for the SCGT plants resulting in a higher LRMC of $80 per MWh. The LRMC for portfolio C2 is only slightly higher than that for portfolio A1 due to the minimal use of the SCGT plants from their first year of requirement to the end of the planning horizon. In other words, the SCGT plants are used sparingly to meet peak capacity requirements, and the amount of electricity generated is minimal such that the higher fuel costs increase the LRMC of portfolio C2 by only $2 per MWh above that of portfolio A1.

Portfolio C3 includes only clean or renewable resources, including SCGT plants using RNG as fuel. The LRMC for portfolio C3 is higher than that for portfolio A1 mainly due to the higher cost of RNG versus natural gas as fuel for the SCGT plants and more solar and wind resources being selected.

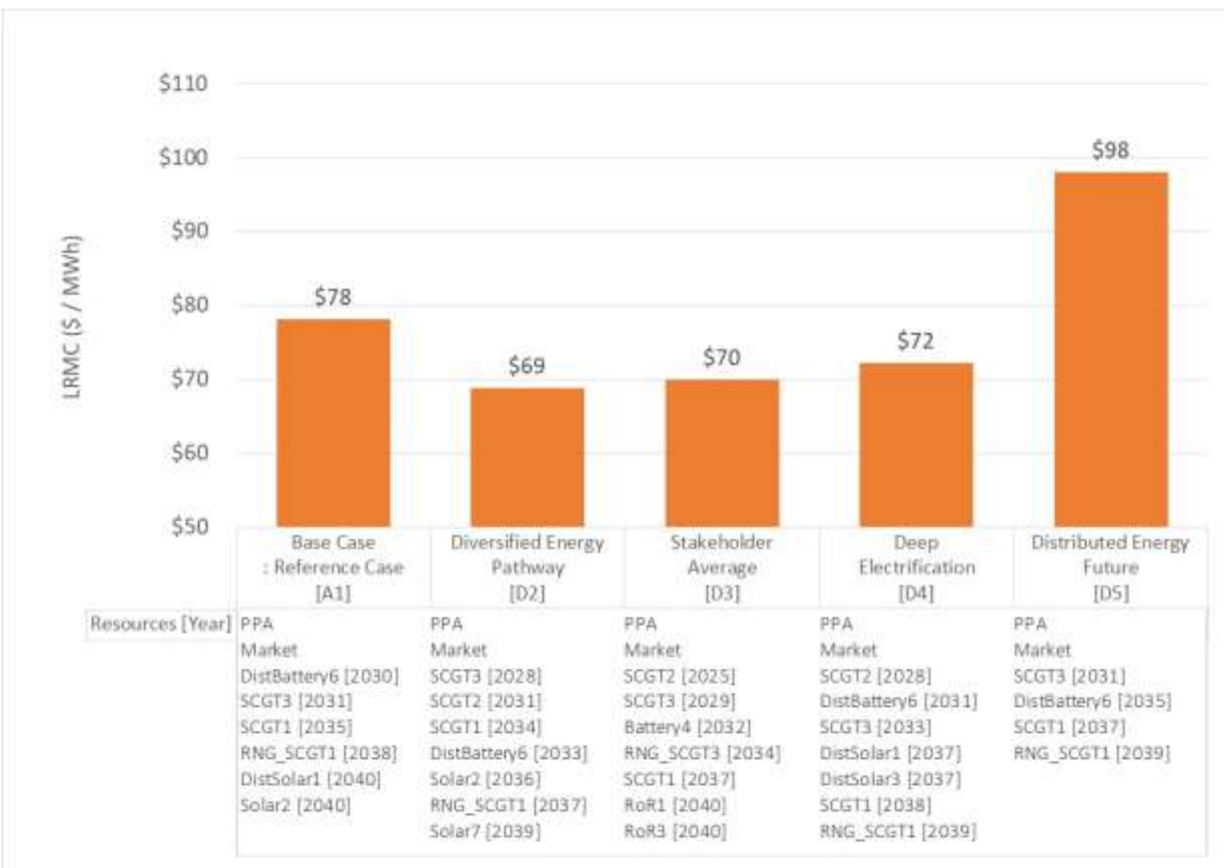
Portfolio C4 includes only clean and renewable resources and excludes SCGT plants. The LRMC for this portfolio is significantly higher than portfolios A1 and C3, which allow for SCGT plants using RNG as fuel, due to the higher cost of the other resources being selected, which include more solar, wind, run of river, and biomass. The Clean portfolio without RNG SCGTs requires a large and diverse amount of renewable resources to replace the year round dependable capacity that is provided by peaker plants. Generally speaking, the wind resources provide capacity in the peak hours of the winter and solar resources provide capacity in the peak hours of the summer. This portfolio is also supported by a larger sized battery.

Portfolio C5 also includes only clean and renewable resources and excludes SCGT plants but also assumes higher resource costs for particular resource options than in the base A1 portfolio. For example, in portfolio C5, the costs for wind and solar are assumed to decline at a slower rate over time than in portfolio A1. The base assumption is that the costs for these resource options continue to decline in the future, as discussed in Sections 3.3.1 and 3.3.3 of the Supply-Side Resource Options Report Appendix K.

11.3.4 Load Scenarios

FBC's base case assumption for load requirements is the reference case load forecast for energy and capacity as provided in Section 3. FBC has also modelled the effects of the load scenarios provided by Guidehouse and the stakeholder average scenario presented in Section 4. The results are provided in the following figure.

Figure 11-4: Portfolios based on Load Scenarios



The results show that the portfolio D2 for the Diversified Energy Pathway scenario has the lowest LRMC of $69 per MWh compared to portfolio A1 based on the Reference Case load forecast (A1) and the other load scenario portfolios D3, D4 and D5. Portfolio D2 has the highest amount of energy of the load scenario portfolios as a result of the combination and penetration of load drivers. For example, the diversified pathway load forecast contains more hydrogen production, which is energy intensive. Since these portfolios allow cost-effective market energy, the incremental costs to satisfy the capacity requirements are allocated over a higher GWh amount, driving down the price.[199] In other words, the diversified energy pathway portfolio has greater incremental energy requirement than the base case scenario, which is leading to a larger denominator in the LRMC calculation, and therefore a smaller cost per MWh.

In contrast, Portfolio D5, based on the Distributed Energy Future scenario, has the highest LRMC while requiring fewer resources than portfolios D2 to D4 because it has lower energy requirements, given greater amounts of customer generated energy, but still has significant capacity requirements due to distributed solar generation's inability to meet all of the peak demand. In other words, the Distributed Energy Future scenario reduces the amount of energy the utility serves, but does not proportionally reduce the capacity requirements. As a result, the utility is still required to build capacity resources to meet load during winter peak hours, which adds costs into the numerator of the LRMC calculation, but the denominator (the incremental energy over the planning horizon) is smaller, resulting in a higher long run marginal cost. Portfolios D2, D3 and D4 all contain higher energy and capacity requirements, which lead to new resources before 2030, with portfolio D3 indicating new generation required as early as 2025.

It may be possible that more DSM could be used to offset some of the incremental load growth requirements and thereby reduce some of the need for incremental supply-side resource options. However, there is uncertainty in terms of how much, if any, DSM could offset the load requirements from load drivers such as hydrogen production or carbon capture and storage. This could be assessed in future long-term resource and DSM planning if the higher load growth scenario starts to emerge. However, it is possible that these types of loads may be curtailed, or interrupted, during peak demand periods, thereby lessening the incremental generation resource requirements for peak capacity purposes (as discussed in Section 2.3.5). At this point in time, FBC does not yet know what levels of large load curtailment might be achievable.

FBC has separately assessed possible peak demand reduction from shifting EV charging in the following section.

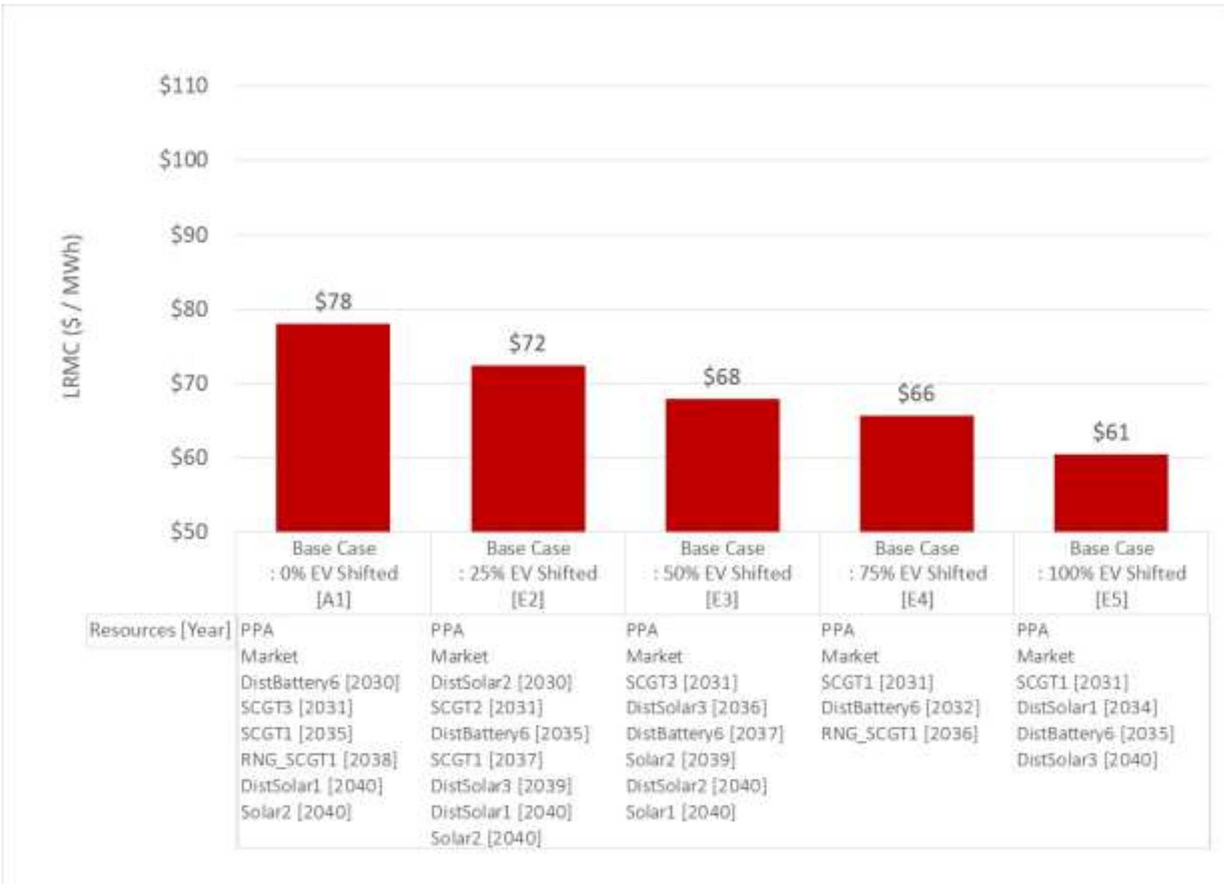
11.3.5 EV Charging Shifting

As discussed in Section 2.3.2 and 6.4.4, shifting EV charging loads from peak demand periods could become important in the future. As EV growth continues, the timing of EV charging has the potential to strains distribution infrastructure and increase the requirement for new capacity

[199] These high volumes of market energy may not be available at the assumed price if these higher load scenarios emerge.

generation resources. Therefore, FBC has also modelled portfolios based on the load requirements resulting from different levels of EV charging shifting. This helps provide some indication of the level of incremental resources and costs associated with shifting EV charging loads. The results for portfolios that shift different percentages of EV charging from peak periods to off peak periods, or equally how the portfolio would change if EV charging load does not materialize to the degree forecasted, is provided in the following figure.

Figure 11-5: Portfolios based on Different Percentages of EV Charging Shifting



The figure above shows that more EV charging shifting from peak periods results in fewer capacity resource requirements and therefore lower LRMC values. As the portion of EV charging is shifted into off peak hours increases, less resources or resources that are smaller in size are required. The LRMC for the portfolio E5 assuming 100 percent of the EV charging is shifted from peak periods is $61 per MWh, compared to the LRMC of $68 per MWh for the portfolio E3 that assumes 50 percent shifting, and the LRMC of $78 per MWh for the portfolio A1 that assumes no shifting. The difference in the net present value of the additional resource costs required over the planning horizon for portfolio A1 compared to portfolio E3 (50 percent EV charging shifted from peak hours) is in the order of about $50 million.

Both energy and capacity requirements are driving future costs, but not in equal proportions. Given FBC's access to the market over the planning horizon for energy purposes, and the market price forecasted to be low cost source of energy, growth in capacity requirements are strongly influencing the incremental resources and costs. By shifting EV charging load to the off peak hours, the utility is able to utilize existing capacity resources and while delivering more energy to customers over the year. This is reducing costs in the numerator of the LRMC, while serving the same incremental energy requirements.

11.3.6 PPA Renewal Versus Non-Renewal

FBC has evaluated portfolios that include renewal of the PPA beyond 2033 and those that do not include renewal of the PPA. The results are provided in the following figure. FBC has also analysed a portfolio based on higher Tranche 1 and lower Tranche 2 energy rates for the PPA, as described in Section 2.5.5.

Figure 11-6: Portfolios with and without PPA Renewal

The LRMC values for the portfolios without PPA renewal (F4 and F5) are higher than those with PPA renewal. The PPA is one of the lowest cost resource options and replacing it with other supply-side resource options increases the LRMC value. Portfolio F5 has the highest LRMC of $157 per MWh and assumes the PPA is replaced with only clean or renewable resources and excludes SCGT plants. Replacing the dependable capacity of the PPA while also accommodating the incremental capacity requirements of the reference case load forecast requires a large and diverse portfolio intermittent renewable resources.

As discussed in Section 2.5.5, FBC's base case assumption for future increases in the PPA rates is 1 percent per year (in real terms) for PPA Tranche 1 energy and capacity. If BC Hydro rates increase by 3 percent per year (in real terms) as per the high PPA rate scenario, the LRMC value for the portfolio with PPA renewal (F2) increases only slightly due to more lower-cost market energy being selected and less PPA energy being selected to meet the incremental load requirements above the current load served. However, the average cost for portfolio F2 would increase to $79 per MWh from $75 per MWh, as the high PPA rates would impact the costs to serve the current load more than the incremental load as a result of the minimum PPA nomination.

Portfolio F3 assumes a lower PPA Tranche 2 energy rate than the base portfolio A1 assumption. In portfolio A1, the Tranche 2 energy rate is about $95 per MWh, whereas it is about $80 per MWh in portfolio F3 (per the PPA Tranche 2 rate scenarios in Section 2.5.5). The LRMC for portfolio F3 does not change compared to that of portfolio A1 at $78 per MWh because the same resource options are selected instead of the PPA Tranche 2 energy, even if its rate is lowered. In others words, based on the available options, PPA Tranche 2 energy, even at the lower cost level, is not selected in these portfolios as market energy at $36 per MWh is more cost effective to utilize.

11.3.7 Portfolio Analysis Key Findings

Based on the portfolio analysis presented in the previous sections, several key findings are identified. These include the following:

- Higher levels of DSM than the base DSM level are less cost effective than other resource options;
- Based on current price forecasts, market energy is more cost effective than other resource options;
- Clean or renewable resource portfolios that include SCGT plants using RNG are more cost effective than portfolios that exclude SCGT plants;
- Shifting EV charging loads from peak periods reduces the need for capacity resources and lowers portfolio costs;
- Renewing the PPA is a more cost effective and flexible option than replacing it with other resource options;

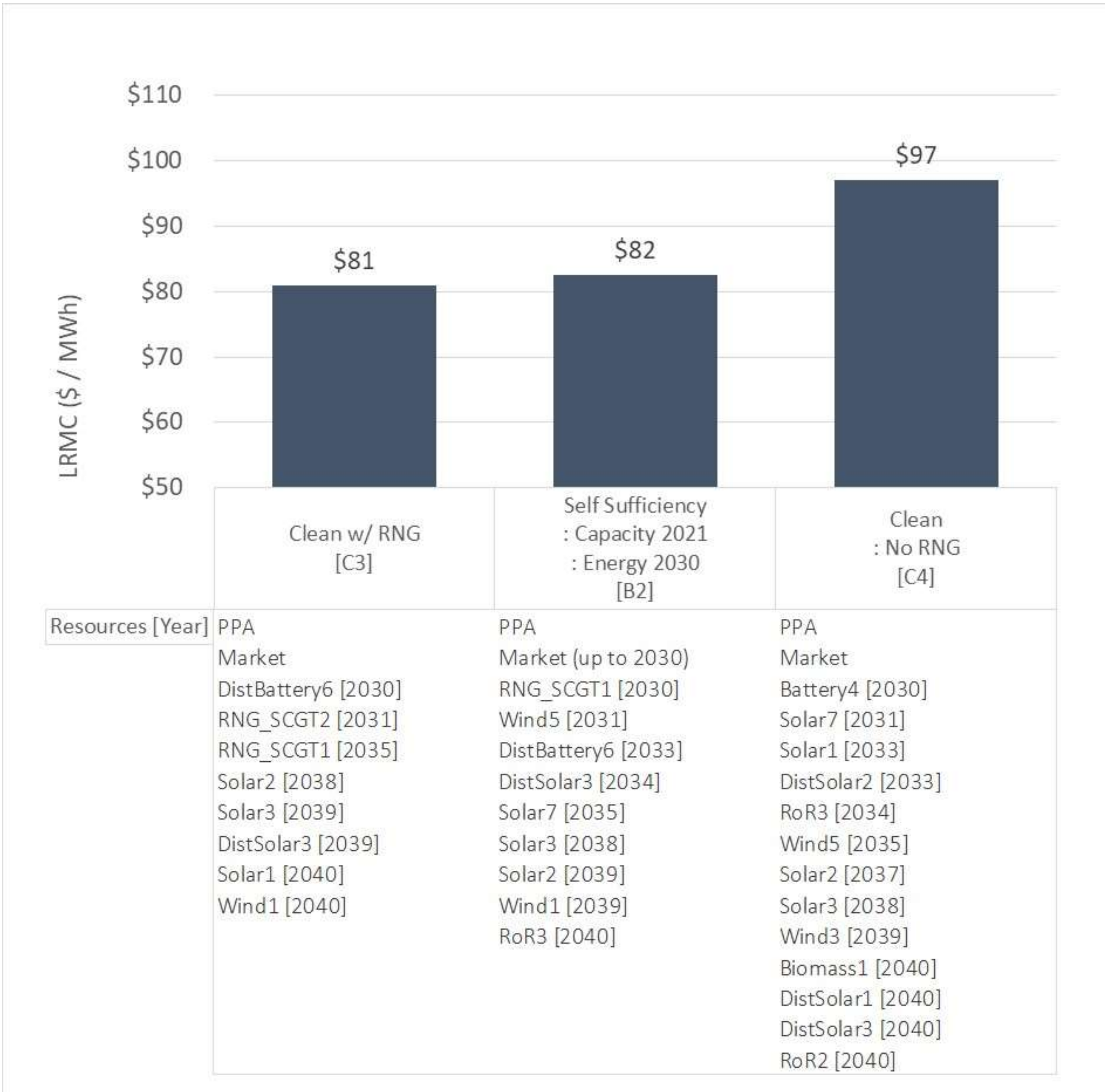
- No new generation resources are required before 2030 except for portfolios based on higher load scenarios, which require new resources in 2025 or 2028;
- The PPA and market energy are the most optimal energy resources while batteries and SCGT plants are the most optimal capacity resource in terms of cost and meeting LRB gaps.

These key findings helped to inform FBC's selection of portfolios considered for the preferred portfolios, discussed in the next section.

11.3.8 Portfolios Considered for Preferred Portfolios

Based on the portfolio analysis presented in the previous sections, FBC has determined a set of portfolios that are considered for the preferred resource portfolios. The preferred portfolios are those that meet the LRB gaps based on the Reference Case load forecast, includes cost effective DSM, and best meet the LTERP objectives of cost-effectiveness, reliability, and consideration of BC's energy objectives. The preferred portfolios are selected from the discussion and figures in the previous sections and are presented in the following summary figure.

Figure 11-7: Portfolios Considered for Preferred Portfolios



The recommended portfolios considered for selection as the preferred portfolios are portfolios C3, B2 and C4. Portfolio C3 has the lowest LRMC of the portfolios including only clean or renewable resources. It includes market energy throughout the planning horizon but maintains a capacity self-sufficiency requirement.[200]

Portfolio B2 also includes only clean or renewable resources, maintains a capacity self-sufficiency requirement throughout the planning horizon, but additionally includes an energy

[200] All preferred portfolio maintain capacity self-sufficiency with the exception of June, which permits 75MW of market capacity up to 2030.

self-sufficiency requirement starting in 2030. Portfolio B2 would likely be a preferred option for FBC in the event that market conditions changed such that market energy was no longer a reliable or cost-effective option in the future. The LRMC of $82 for portfolio B2 reflects the incremental cost to serve incremental load. The LRMC alone does not reflect the full costs of this portfolio as an energy self-sufficient policy would also increase the costs of serving existing load in addition to incremental load, which is reflected in the average costs of the portfolio.

Portfolio C4 also includes only clean or renewable resources but excludes SCGT plants, even those using RNG as fuel. Portfolio C4 maintains a capacity self-sufficiency requirement, but allows market energy throughout the planning horizon. This portfolio requires a collection of resource options that are more costly than SCGT plants to maintain capacity self-sufficiency. FBC has included portfolio C4 in the preferred portfolios as FBC recognizes that there may be social licensing issues with the permitting and construction of an SCGT plant in its service area, even if the plant were to use a renewable fuel like RNG.

FBC has not included portfolios with SCGT plants using conventional natural gas as fuel, such as portfolio A1, in its set of preferred portfolios based on the feedback received during the June 2021 RPAG meeting. FBC believes that portfolios only including clean or renewable resources best reflects the energy priorities of its customers, stakeholders and Indigenous communities based on their feedback discussed in Section 12.

The criteria to determine the preferred portfolios are based on the LTERP objectives which include cost, environmental impacts, resiliency and economic impacts, as shown in Table 11-2 below.

In terms of cost, FBC has included LRMC, average cost and rate impacts to provide a complete picture of the portfolio cost impacts. While the LRMC represents the incremental costs needed to meet the incremental load growth over the planning horizon, the average cost value represents the cost impacts of existing and incremental resources to meet the current load and future load growth. This is required since certain changes to portfolio variables, such as PPA and market costs, impact how the existing load is met in addition to the incremental load and those cost impacts are not reflected in the LRMC calculation. The compound annual growth rate (CAGR) reflects the average annual rate increases for each year of the planning horizon for each portfolio. The estimated rate increases assume FBC constructs and rate bases the selected resource options and therefore includes additional costs such as depreciation.

Environmental attributes include the percentage of clean or renewable energy in the portfolio, the GHG emissions over the planning horizon and the land or water footprint (in hectares) associated with the new resources in each portfolio. All three portfolios in Table 11-2 below are about 99 percent clean and are not considered 100 percent clean as the PPA is 98 percent clean (as discussed in Table 1-3 in Section 1.4.2). The PPA could become 100 percent clean in the future if BC Hydro adopts a 100 percent clean electricity standard, as discussed in Section 2.2.3.2. The GHG emissions attribute includes scope 1 and scope 3 emissions. Scope 1 refers to GHG emissions produced directly by FBC resource generation while scope 3 are indirect GHG emissions produced by another party providing supply to FBC. All three portfolios have minimal scope 1 GHG emissions and have similar scope 3 emissions due to the inclusion of the PPA in each portfolio. The footprint increases as the number of resources in the portfolios increase. In general, wind and solar have larger footprints relative to their energy and capacity contribution.

The resiliency attribute includes operational flexibility and geographic diversity. Operational flexibility refers to the ability of the portfolio to manage higher than expected energy and capacity loads. These loads may occur over a short period of time such as occurred this past June 2021 with record setting daily loads or over a longer period of time due to unexpected load growth. A portfolio with a 'high' rating means that it has more flexibility to meet higher than expected loads than a portfolio with a 'low' rating. Geographic diversity reflects whether or not the portfolio resources are located within or near the Kootenay or Okanagan regions of FBC's service area. As discussed in Section 5.1, FBC's existing generation resources are located within the Kootenay region, while most of FBC's customer load requirements are in the Okanagan. Therefore, adding resource options to the Okanagan improves FBC's resource diversity. All three portfolios in the table below have 'high' geographic diversity ratings given that they contain solar resources, which are located in the Okanagan, as well as battery and SCGT plants, which could be located in either region and most likely closer to key load growth centres, like Kelowna.

The economic attribute included in the portfolio evaluation is BC employment in terms of job person years (job persons),[201] or full time equivalents (FTEs), resulting from the resources included in the portfolios. Portfolios with more generation resources will typically require more construction and operating FTEs and so will have higher ratings for this attribute.

FBC received stakeholder feedback at the RPAG meetings to include an Indigenous community development attribute in the portfolio evaluation criteria. FBC considered this but since the benefits of Indigenous participation are common to all portfolios, it is not required as an independent measure. It is FBC's view that the BC employment provides a similar measure. As discussed in Section 10.9, FBC will consider partnerships with local and Indigenous communities when new supply-side resources are developed in the future.

[201] One person-year is equivalent to one FTE for the period of one year. For example, construction jobs that occur only during the construction phase, 40 person-years may be equivalent to 20 FTEs over a 2-year construction period. For a single full-time operator of a power plant with a life of 30 years, that one FTE has an equivalent of 30 person-years of employment.

Table 11-2: Attributes of Portfolios Considered for Preferred Portfolios

Portfolios	Resource Mix	Portfolio Attributes								
		Cost			Environment			Resiliency		Economic
		LRMC ($/MWh)	Average Cost ($/MWh)	Rate Impacts (CAGR)	% Clean Resources	GHG Emissions	Footprint (Hectares)	Operational Flexibility	Geographic Diversity	BC Employment (Job Persons)
Clean [C3]	PPA Market DistBattery6 [2030] RNG_SCGT2 [2031] RNG_SCGT1 [2035] Solar2 [2038] Solar3 [2039] DistSolar3 [2039] Solar1 [2040] Wind1 [2040]	$81	$76	1.58%	99%	6.5 CO2e tonne/GWh Scope 1: 122 Scope 3: 355,480	292	High	High	1346
Energy Self Sufficiency 2030 [B2]	PPA Market (up to 2030) RNG_SCGT1 [2030] Wind5 [2031] DistBattery6 [2033] DistSolar3 [2034] Solar7 [2035] Solar3 [2038] Solar2 [2039] Wind1 [2039] RoR3 [2040]	$82	$79	2.01%	99%	7.4 CO2e tonne/GWh Scope 1: 19 Scope 3: 404,297	597	Medium	High	1915
Clean No RNG SCGT [C4]	PPA Market Battery4 [2030] Solar7 [2031] Solar1 [2033] DistSolar2 [2033] RoR3 [2034] Wind5 [2035] Solar2 [2037] Solar3 [2038] Wind3 [2039] Biomass1 [2040] DistSolar1 [2040] DistSolar3 [2040] RoR2 [2040]	$97	$78	2.10%	99%	6.4 CO2e tonne/GWh Scope 1: 0 Scope 3: 353,609	723	Low	High	2504

Portfolio C3 is the lowest cost portfolio of the three portfolios considered for the preferred portfolio. It has the lowest LRMC, average cost and rate impacts. It is also comparable to the other portfolios in terms of some of its environmental attributes, with almost 100 percent clean or renewable resources and minimal GHG emissions over the planning horizon. Portfolio C3 has the lowest environmental footprint, in terms of land area, because it has more SCGT plants using RNG fuel and relies on clean market energy, which in turn requires less total land area than the resources contained in portfolio B2 and portfolio C4. Portfolio C3 rates 'high' in terms of operational flexibility because of its two SCGT plants using RNG as fuel. The SCGT plants are used minimally, based on the Reference Case load forecast and corresponding LRB gaps starting in 2031, but could be utilized more frequently to meet higher load requirements if needed given their ability to generate energy when dispatched. Portfolio C3 rates lowest in terms of job creation given its greater reliance on market energy than portfolio B2 and fewer resources than portfolio C4. The estimated RNG usage for portfolio C3 for the two SCGT plants is about 750,000 GJ total between 2031 and 2040.

Portfolio B2 has a LRMC of $82 per MWh that is slightly higher than that for portfolio C3 of $81 per MWh but has a higher average cost and higher rate impacts than portfolio C3. The 2030 energy self-sufficiency requirement of portfolio C3 leads to other resources being dispatch in place of market energy to meet both existing and future load requirements. FBC currently utilizes market energy as a resource to meet existing loads and would incur additional costs if that energy was required to be replaced with energy from other resources such as the PPA. Portfolio B2 is also mostly clean but has slightly higher scope 3 GHG emissions as more PPA is required due to the energy self-sufficiency requirement. It also has a higher footprint and job creation as no access to market energy after 2030 requires more generation resources in the portfolio. The operational flexibility of portfolio B2 is 'medium' given it includes only one SCGT plant, but its geographic diversity rating is also 'high'. The estimated RNG usage for portfolio B2 for its SCGT plant is about 113,000 GJ total between 2030 and 2040. In portfolio B2, the SCGT plant is required a year earlier, in 2030, than for portfolio C3.

Portfolio C4 has the highest LRMC value of the three portfolios in the table above, due to the portfolio not including the lower-cost SCGT plants and therefore requiring a collection of renewable resources that are a more costly to meet the capacity requirements. Its average cost is similar to that of portfolio B2 but its rate impacts are the highest of the three portfolios. Portfolio C4 is 99 percent clean and has zero scope 1 GHG emissions and similar scope 3 GHG emissions to the two other portfolios. It has a higher environmental footprint than portfolios C3 and B2 due to the greater number of resource options. Portfolio C4 has a 'high' geographic diversity rating but has the lowest level of operational flexibility of the three portfolios due to the minimal level of extra capacity generation available from the renewable resources in the portfolio. Portfolio C4 ranks highest of the three in terms of job creation given the greater number of resource options required.

11.3.9 Preferred Portfolios

Based on the information presented in the previous section and stakeholder feedback, FBC recommends that Portfolio C3 is the preferred portfolio, assuming current market access conditions. Portfolio C3 includes FBC accessing clean market energy and so has the lowest cost in terms of LRMC, average costs and rate impacts for the three portfolios considered for the preferred portfolios. Portfolio C3 is similar to the other two portfolios in terms of its GHG emissions but has a lower environmental land footprint. This portfolio also provides FBC with high levels of resiliency given that its resource mix provides high geographic diversity and higher levels of operational flexibility with the to two SCGT plants using RNG fuel, which is important for contingency planning as discussed in more detail in Section 11.3.9.1. The inclusion of SCGT plants in the preferred portfolio provides some additional flexibility to handle new large or unexpected loads as these resources have some remaining availability at the end of the planning horizon to accommodate additional energy and capacity growth. The SCGT plants would also provide added reliability in the event the wind and solar resources in the portfolio do not provide energy and capacity when required.

Portfolio C3 is ranked lower in terms of job creation than the other two portfolios, but it does enable job creation of an estimated 1,346 job person years starting after 2030 relating to the construction and operation of resources. It is expected that these jobs would benefit local and Indigenous community development.

In addition, the two SCGT plants using RNG fuel included in Portfolio C3 provide significant dependable capacity that could help to defer more costly transmission and distribution infrastructure in the event that loads increase significantly beyond the Reference Case load forecast in the future, as discussed in Section 6.4.

In the event that market conditions change such that accessing market energy was no longer reliable and cost effective, portfolio B2 would be the preferred portfolio. This portfolio has a slightly higher LRMC and environmental impacts than portfolio C3, but it has a lower LRMC than portfolio C4 and provides higher resiliency and job creation than portfolio C4. In portfolio B2, FBC has assumed energy self-sufficiency after 2030. However, if market conditions changed prior to that, FBC would seek to implement this portfolio sooner than 2030 so that generation resources are put in place to mitigate identified market risks.

Portfolio C3 best meets the LTERP objectives in terms of balancing cost-effectiveness, reliability, inclusion of cost-effective DSM and consideration of B.C.s energy objectives. This portfolio is also aligned with the energy priorities as indicated by stakeholders, Indigenous communities and customers through FBC's LTERP engagement processes. As discussed in Section 12, FBC's community and Indigenous engagement revealed their priorities are related to cost-effectiveness, reliability and protecting the environment. One Indigenous group also indicated that economic growth and partnership opportunities help community development and therefore indirectly help address affordability. The customer survey indicates priorities of cost-effective and reliable power rank above reducing GHG emissions, conservation and energy management solutions and job creation. Some of FBC's RPAG members have indicated a preference for cost-effective and reliable resources with some prioritizing protecting the environment. Some members of the RPAG have indicated their support for SCGT plants using RNG fuel as a cost-effective and environmental alternative to SCGT plants using natural gas but did note that it may still be difficult to permit and construct such plants from a social licensing perspective.

Portfolio B2 is the next best alternative to portfolio C3 in terms of meeting the LTERP objectives in the event that market conditions change such that market energy was no longer reliable or cost effective.

11.3.9.1 Contingency Plans

This section discusses contingency plans for the preferred portfolios C3 and B2 to ensure that they can meet the objectives previously discussed if assumptions and conditions change (i.e. changes beyond those covered by the PRM discussed below). Such changes could include, for example, increases in market power prices or RNG costs, permanent increases in load requirements over time, unexpected temporary load events such as the June 2021 heat wave discussed in Section 2.2.1 or lower customer load requirements than those in the Reference Case load forecast. It is important that FBC's existing resources and the preferred portfolios have the flexibility to handle unexpected changes in order to continue to meet the LTERP objectives.

The preferred portfolios include a diverse mix of resource options, including the PPA, market energy, battery storage, SCGT plants using RNG, solar, wind and run of river generation. This diversity means that FBC is less exposed to potential changes in the cost of any one particular resource type than if FBC had a less-diverse resource mix. Increases in PPA rates, such as the Tranche 1 energy rate, do not materially increase the LRMC as indicated by the slight increase in the LRMC for portfolio F2 to $79 per MWh relative to the LRMC of $78 per MWh for portfolio A1 (see Figure 11-6) as incremental load is primarily being served with market energy, but increases to PPA energy costs would increase total portfolio costs as FBC maintains minimum PPA nominations for risk management. Alternatively, FBC could reduce its PPA energy and instead increase its market energy purchases. Increases in market energy prices could have a more material impact on the portfolio costs as market energy will likely become an increasingly larger component of the portfolio. Portfolio B4 includes higher market energy prices as well as higher carbon prices for non-clean market energy and has a LRMC of $90 per MWh (see Figure 11-2). However, given that the preferred portfolios include clean market energy, and therefore not subjected to increasing GHG costs, the cost impact on the preferred portfolios from an increases in market energy prices would likely be less than indicated by portfolio B4. Alternatively, FBC could reduce its market purchases and increase its PPA energy if that was a more cost-effective option. As portfolio C2 with a LRMC of $80 per MWh indicates (see Figure 11-3), the impact of higher RNG fuel costs are not material given the minimal anticipated usage of the SCGT plants using RNG.

Changes in customer load requirements will influence the timing of the resource requirements of the preferred portfolios. Section 3.6 discusses the uncertainty bands around the Reference

Case load forecast, while Section 9 provides an indication of the potential range for higher or lower loads, after DSM, than expected. Section 4 discusses load scenarios and the potential for increased load due to load drivers such as fuel switching, medium and heavy duty EV charging and the addition of new large loads on the FBC system. While the load increases from fuel switching from gas to electricity and EV charging would likely occur gradually over time, a new large load addition, for example from a data centre or hydrogen production facility, could create a step change. As indicated by the portfolios D2 to D5 in Figure 11-4, higher load scenarios could require new generation resources be in place sooner than 2030, and as early as 2025, depending on the scenario. Therefore, in this case, FBC expects that the preferred portfolios, or some alternate portfolio depending on the specific energy and capacity requirements of the additional load requirements, would be need to be implemented sooner than expected under the Reference Case load forecast. However, as portfolios E2 to E5 in Figure 11-5 indicate, some level of EV charging shifting from peak periods could help delay this accelerated resource requirement.

In the event that the PPA is not renewed effective 2033, FBC will require additional generation resources beyond those included in the preferred portfolios. As portfolio F4 in Figure 11-6 indicates, another SCGT plant using RNG fuel and more renewable resources would be required to meet the higher LRB gaps.

To address load increases greater than the Reference Case in the shorter term, FBC has several options as part of its contingency planning. These include the following, which could be implemented separately or in combination, depending on the specific energy and capacity requirements:

- Increase market energy purchases;
- Increase PPA energy and capacity (if not already at its maximum);
- Implement other EV peak shifting options discussed in Section 2.3.2;
- Ramp up DSM to higher incentive levels, and
- Accelerate new resources from the preferred portfolios which require shorter lead times, such as an SCGT plant using RNG or battery storage units.

In the event of lower loads than expected under the Reference Case load forecast prior to one of the preferred portfolios is implemented, FBC has several options which include the following:

- Decrease market energy purchases;
- Decrease PPA energy and capacity (if not already at its minimum), and
- Defer implementation of resources identified in the preferred portfolios.

These options enable FBC to reduce its resources to match load requirements and avoid the risk of implementing stranded resources that are not required, perhaps until much later.

11.3.10 Planning Reserve Margin

Planning Reserve Margin (PRM) is the dependable capacity above the expected peak demand and is measured in MW or percentage of the expected peak. PRM's role is to ensure resource adequacy when dealing with variations in demand and forced outages in the system. It serves the ultimate goal of "keeping the lights on" over the planning horizon. Negative PRM indicates that the system capacity is not sufficient to meet the expected demand. A PRM that is positive but falling below some targeted margin signals that additional capacity in the future is likely needed to meet a resource adequacy target. The Company adopted Loss-Of-Load-Expectation (LOLE), or the expected number of days in a year the generation capacity fails to meet load, as the reliability metric for PRM, and targets 1 day in 10 years or 0.1 day per year as used by many utilities in its evaluation of resource adequacy.

FBC has applied the LOLE resource adequacy test to the preferred portfolios to ensure that they meet the PRM requirements. In these portfolios, market supply is utilized to meet any unforeseen increases in demand or forced outages of plants. Therefore, at this time, FBC has no incremental requirements or costs relating to PRM. This is consistent with FBC's PRM approach in the 2016 LTERP. In its decision regarding the 2016 LTERP, the BCUC accepted FBC's PRM methodology, noting it is consistent with industry practice.[202]

FBC has provided a PRM report describing its methodology and results for the preferred portfolio in Appendix M.

11.4 *CONCLUSIONS*

Based on the analysis of the various portfolios and determination of the preferred portfolios, the following conclusions can be stated.

First, based on the Reference Case load forecast, FBC has no need for incremental generation resources until 2030. If FBC is able to shift some level of EV charging from peak periods, the need for new resources could be pushed out until at least 2031. Under higher load scenarios, FBC may need new resources as early as 2025.

Second, FBC will continue to optimize market energy supply and PPA Tranche 1 energy in the short to medium term prior to 2030 as they are the most cost-effective options. The flexibility of the PPA enables FBC to increase its energy take when market prices are higher than the PPA rate and lower the PPA take when market prices are lower. FBC has assumed capacity self-sufficiency over the planning horizon due to the risks with relying on market capacity.

Third, higher levels of DSM than the current or base DSM level are less cost effective than some other resource options and so the base level has been assumed for the preferred portfolios.

[202] BCUC 2016 LTERP Decision per Order G-117-18, June 28, 2018, page 26.

Fourth, clean or renewable resource portfolios that include SCGT plants using RNG are more cost effective than portfolios that exclude SCGT plants. Battery storage and SCGT plants are the most optimal capacity resource in terms of cost and meeting LRB gaps.

Fifth, renewing the PPA is more cost effective than replacing it with other resource options. FBC plans to explore renewing the PPA and has included this as an action item in Section 13.2.

Lastly, the LRMC values for the portfolios serve as a high-level point of reference reflecting the general level and trend of future costs. While a particular resource option may be cost effective relative to a given LRMC value, it may not fit the energy or capacity requirements of customers in the future. For this reason, FBC believes the LRMC values presented in this section should be viewed as price signals, rather than threshold targets for resource options.

The preferred portfolios include a mix of PPA, market energy, battery storage, SCGT plants using RNG fuel, solar, wind and run of river generation. Portfolio C3 is the preferred portfolio under current market conditions. Should market conditions change such that market energy was no longer a reliable and cost effective resource, portfolio B2 would become the preferred portfolio. As the cost for the portfolio and other resources as well as the Reference Case load forecast may change over time, FBC will continue to assess resource options and examine the LRB to determine which new resources may be required and when. Updates will be provided in FBC's next LTERP. FBC's contingency planning will help it manage any unexpected changes in market conditions or load requirements. Also, as discussed in Section 10.2.6, local BC supply options may arise in the future as BC Hydro's expiring EPAs may provide FBC with the opportunity to acquire power from EPA facilities on a cost-effective basis. FBC will continue to monitor BC Hydro contract renewals for any resource option opportunities.

The following table provides a summary of these conclusions.

Table 11-3: Portfolio Analysis Conclusions

Time Frame	Conclusion
Short Term (2021 - 2025)	• Optimization of PPA and market purchases • Monitor expiring EPAs and other market opportunities within BC • Assess resource options and be prepared to implement contingency plans if market conditions or loads increase
Medium Term (2026 - 2030)	• Optimization of PPA and market purchases • Assess resource options in next LTERP • Be prepared to implement contingency plans if market conditions or loads increase • Begin development of new generation resources, such as those included in the preferred portfolios
Long Term (2031 - 2040)	• Optimization of PPA and market purchases if market continues to be cost-effective and reliable • Implement new generation resources, such as those included in the preferred portfolios • Plan for new generation resources, beyond the preferred portfolios, for 2033 or sooner if PPA not renewed

12. STAKEHOLDER, INDIGENOUS AND CUSTOMER ENGAGEMENT

Connecting with customers, communities, other stakeholders and Indigenous groups on long-range planning issues provides FBC with valuable insight and feedback that can impact the energy planning process, including load forecasting and scenario analysis, DSM program development, as well as the development of portfolios and determination of a preferred portfolio and an action plan.

When seeking input and feedback during the resource planning process, the BCUC's Resource Planning Guidelines encourage utilities to "focus such efforts on areas of the planning process where it will prove most useful and to choose methods that best fit their needs." For this 2021 LTERP, FBC pursued various activities to offer customers, stakeholders and Indigenous groups the opportunity to participate in discussions that have informed the planning process. These activities included:

- Meetings with the RPAG;
- Community engagement meetings with communities served by FBC;
- Multiple meetings with First Nations community representatives;
- Customer engagement through an online survey; and
- Other activities that indirectly inform the resource planning process, including dialogue with BCUC staff and other stakeholders.

Prior to 2020 and the start of the COVID-19 pandemic, FBC had been engaging in person with stakeholders and First Nations representatives through the RPAG and community meetings. However, in 2020 and 2021, engagement has been through virtual meetings. While in-person engagement is preferred, virtual meetings have continued to promote stakeholder and First Nations community engagement and enabled them to provide valuable feedback and input into the 2021 LTERP development process.

FBC created an external website for its electricity planning and stakeholder engagement, which includes FBC's presentation materials and meeting notes from its engagement sessions: https://www.fortisbc.com/about-us/projects-planning/electricity-projects-planning/electricity-planning-and-stakeholder-engagement.[203]

The subsections below summarize the range of stakeholder and Indigenous engagement initiatives leading up to the 2021 LTERP.

[203] FBC confirms that, by providing this link, it considers the webpage and the documents linked on the webpage to be part of the record of this proceeding.

12.1 RESOURCE PLANNING ADVISORY GROUP

The RPAG engages representatives from local governments, provincial government, Indigenous groups, customers, associations and organizations in the development of the LTERP. The RPAG consists of members with interest and experience in the resource planning process and significant industry knowledge that provide key insight and feedback to FBC. The following table lists the organizations represented in the RPAG.

Table 12-1: RPAG Members

Organization
B.C. Ministry of Energy & Mines - Electricity & Alternate Energy Division
B.C. Municipal Electric Utilities
B.C. Public Interest Advocacy Centre
B.C. Sustainable Energy Association
B.C. Utilities Commission
BC Hydro
Clean Energy Association of B.C.
Commercial Energy Consumers Association of B.C.
First Nations Energy & Mining Council
Friends of Kootenay Lake Stewardship Society
Industrial Customers Group
Lower Similkameen Indian Band
MoveUp
Nelson Hydro
Okanagan Indian Band
Residential Consumer Intervenor Association
Pembina Institute
K'ul Group (formerly Penticton Indian Band Development Corporation)

The RPAG meetings provided a forum for discussing many broad themes, including, but not limited to, the following:

- Resource planning process, inputs and assumptions;
- Planning environment, including energy and environmental policy and regulation;

- Long term load forecasting;
- Demand-side management;
- Supply-side resource options;
- Development of load scenarios;
- Transmission and distribution;
- Long Run Marginal Cost;
- Portfolio analysis and results, and
- Other FBC initiatives.

FBC held four RPAG meetings between 2019 and 2021 to review key steps in the LTERP process, discuss inputs into the 2021 LTERP and gather feedback on the results. The following table provides the meeting dates and list of major topics discussed. Engagement from attendees was in the form of questions and discussion throughout each presentation and also included an interactive load scenario tool (discussed in Section 4.2) to gather more feedback regarding load drivers and scenarios.

Table 12-2: RPAG Meetings and Major Topics Covered

RPAG Meeting Date	Topics Discussed
November 26, 2019	• Resource planning process and objectives • Planning environment • Load forecasting • Load scenarios • DSM overview • FBC generation resources • Regional power markets • Portfolio analysis • Load-Resource Balance
June 25, 2020	• BAU and Reference Case Load forecasts • Load drivers and scenarios • Stakeholder load scenario tool • Load-Resource Balance • EV charging impacts on peak demand
November 25, 2020	• Stakeholder load scenario results • Market price and rate forecasts • Supply-side resource options and unit costs • DSM update • Portfolio analysis approach • Portfolio characteristics • Portfolio evaluation framework

RPAG Meeting Date	Topics Discussed
June 15, 2021	• DSM scenarios • EV charging peak demand mitigation • Load-Resource Balance after DSM • Preliminary portfolio analysis results • Transmission and distribution

The feedback received by FBC from the RPAG has been useful in developing the 2021 LTERP. Through the RPAG workshop sessions and meetings, stakeholders and Indigenous groups provided FBC with input and feedback on areas such as the load forecasting method, load drivers and scenarios, assessment of the portfolios considered for the preferred portfolio, and demand-side and supply-side resource options preferences. More specifically, some of the feedback and areas of stakeholder and rights holder interest in the workshops included the following items:

- Degree of integration between FBC LTERP and FEI LTGRP development process;
- Value in looking at individual as well as average stakeholder load scenario results;
- Consideration of DSM contribution to mitigating higher load scenario impacts on supply-side resource requirements;
- Plans to manage EV peak charging could including technology, time-based rates or other options;
- Consideration of EV impacts exceeding those derived from the ZEV Act mandate;
- Comparison of the estimated GHG emission reductions resulting from the various load scenarios;
- The Diversified Energy Pathway load scenario as a useful counter-scenario to the Deep Electrification scenario;
- Creating multiple portfolio metrics in addition to cost is useful in order to make an informed decision that is not only motivated by lowest cost;
- Inclusion of Indigenous collaboration/opportunities as a portfolio attribute in the portfolio evaluation rating framework;
- Consideration of potential changes to the CEA and a clean energy requirement for customers resulting in a clean portfolio option;
- Potential impacts on Reference Case load forecast in light of COVID-19 pandemic;
- Impacts of climate change on FBC's current supply resources;
- Consideration of rate design, demand management and customer-owned rooftop solar as resource options;

- Consideration of using percentage of Conservation Potential Review (CPR) achievable potential to determine DSM portfolios;
- Benefits and risks of portfolio including gas-fired generation, and
- Determination of the trigger point for when new resources are required.

As resource planning is an iterative and ongoing process, some of the feedback and recommendations received from the RPAG during this planning period will also be considered by FBC in the next iteration of the resource planning process to the extent they remain relevant.

In addition to the RPAG meetings described above, FBC also invited its RPAG members to a meeting regarding the Guidehouse 'Pathways For British Columbia To Achieve Its GHG Reduction Goals' (Guidehouse Pathways) study (provided in Appendix O) on February 12, 2021. Members of FEI's Long Term Gas Resource Plan (LTGRP) RPAG and FEI's Energy Efficiency and Conservation Advisory Group (EECAG) were also invited to the session. In this meeting, FBC provided some background information on the long-term resource planning process and objectives, an overview of the Guidehouse Pathways study regarding the comparisons of the Diversified and Electrification pathways for BC to achieve its GHG reduction goals and the implications for FBC's 2021 LTERP and FEI's 2022 LTGRP. FBC discussed how it incorporated various components of the Guidehouse Pathways study and FortisBC's Clean Growth Pathways pillars, such as the inclusion of EV charging, renewable natural gas and hydrogen production, within its LTERP load forecasts and scenarios.

Some of the feedback in this session related to the opportunities and risks for customers and stakeholders under the different pathways. For example, there was mention by some stakeholders of the economic development potential relating to the Diversified Pathway for communities, such as through the development of RNG and hydrogen production. Some stakeholders commented on the rising cost of energy that could come with significant electrification and the importance of affordable and reliable energy and the benefits of the resiliency of a diversified energy delivery system within BC.

12.2 *COMMUNITY ENGAGEMENT WORKSHOPS*

FBC recognizes the importance of considering diverse community perspectives when planning for the future, and has established resource planning community engagement workshops and meetings to inform and gather feedback from stakeholders and Indigenous groups throughout FBC's service area. Individuals from a variety of roles and backgrounds were invited to participate in these ongoing events, including:

- Community planners and developers;
- Energy and sustainability managers and professionals;
- First Nations community representatives;

- Local government community leaders;
- Energy and sustainability non-profit organizations;
- Real estate builders and developers;
- Large businesses and manufacturers;
- Local businesses and business associations; and
- Other interested parties.

Three community engagement workshops were held in person within the FBC electricity service area in the fall of 2019 and two online workshops were held in the fall of 2020, involving a total of 48 registered participants. These meetings were conducted in collaboration with the FEI gas resource planning group and therefore included presentations and discussions regarding FBC electricity resource planning as well as FEI gas resource planning. This made for the most efficient use of stakeholders' and Indigenous groups' time for those within the combined gas and electric service area and also reduced costs related to the workshops. The following table provides the dates and locations of the meetings.

Table 12-3: Community Engagement Workshops

Meeting Date	Location
October 8, 2019	Kelowna
October 9, 2019	Osoyoos
October 10, 2019	Rossland
December 2, 2020	Online
December 3, 2020	Online

These workshops sought input on a variety of topics related to electricity resource planning, including the planning environment, load forecasting, load scenarios and resource options. FBC presented plans to meet the future needs of customers and communities, and discussed issues affecting energy supply and demand. Also discussed were other FBC initiatives to help meet future energy needs and community GHG emission goals, such as energy efficiency and conservation programs and electric vehicle infrastructure. The meetings included interactive sessions to promote discussions about potential electricity demand and scenarios and resource options.

Some key themes and areas of interest that were identified as important to stakeholders and Indigenous groups included:

- Continuing to receive reliable and affordable electricity supply;

- Programs, funding and incentives to help customers and communities manage energy costs;
- Finding solutions to reduce GHG emissions;
- Fuel switching potential, challenges and opportunities between natural gas and electricity for space and water heating as well as transportation;
- Pilot project opportunities relating to new technologies like battery storage;
- Proactive management of EV charging loads at peak times;
- Proactive approach to managing climate change disruptions on the electricity system, and
- Educational resources for customers and communities regarding energy savings and new technologies.

Overall, the community engagement workshops facilitated the sharing of valuable long term planning information between stakeholders, Indigenous groups and FBC and FEI. In particular, the meetings assisted FBC in identifying energy issues or planning opportunities in municipalities throughout B.C. Stakeholders and Indigenous groups indicated that they appreciated the opportunity to learn about FBC's initiatives, make direct connections with FBC staff, and offer feedback on the utilities' future plans. Attendees gave positive feedback and overwhelmingly stated that they found the meetings both valuable and informative. The meeting discussions were robust and customer-focused, and they demonstrated that FBC's long-term planning considerations align well with stakeholder and Indigenous groups' expectations. FBC has taken the feedback received from the community session participants regarding the LTERP objectives into consideration in the determination of the preferred portfolio discussed in Section 11.

12.3 *DIRECT CUSTOMER SURVEYS*

To complement FBC's community engagement and RPAG workshops, FBC also conducted an online survey during April and May 2021 on a number of key items related to resource planning. A total of 379 residential and 61 commercial customers of FBC responded to the survey. FBC used Sentis Research to conduct the survey, with FBC providing essential background information and questions for the participants. The surveys probed customers on their thoughts about FBC's LTERP objectives, resource options, EV ownership and charging and rooftop solar and battery storage. The results are provided in Appendix N.

The survey results show that customers prioritize the resource planning objectives of cost-effectiveness and reliability over those related to reducing GHG emissions, conservation and energy management solutions and job creation in B.C. communities. Customers favoured using a mix of resource options to meet future load requirements that result in the lowest possible cost to customers while maintaining reliability, regardless of whether the resources are renewable (using wind or solar, for example) or non-renewable (using natural gas-fired generation, for example).

In terms of EV ownership, 43 percent of residential and 37 percent of commercial customers indicated that they are likely to purchase or lease an EV within the next three years. The preferred approaches for managing EV charging by those indicating they are likely to buy or lease an EV include incentives for charging during off-peak times and rebates to customers who buy EV chargers that automatically charge during off-peak times. The survey also indicates that 34 percent of residential and 49 percent of commercial customers are likely to install rooftop solar panels on their home or business in the next five years, with similar percentages indicating a likelihood of also installing battery storage. Preferred incentives include rebates for installation of equipment and FBC purchasing surplus energy from solar panel owners.

FBC has used the results of the survey regarding the LTERP objectives and preference for resource options to help inform its determination of the preferred portfolio discussed in Section 9. FBC has used the survey results regarding preferences for managing EV charging to help inform its recommended approach discussed in Section 2.3.2. As discussed in Section 2.3.4, FBC is continuing to monitor the growth of its net metering program applications and rooftop solar installations and may consider ways to optimize this potential resource in the future.

12.4 *DIALOGUE AND ENGAGEMENT WITH FIRST NATIONS COMMUNITIES*

12.4.1 Overview

FBC recognizes and respects the constitutional rights of Indigenous Peoples in their territory. FBC's Statement of Indigenous Principles aims to ensure the Company's business operations are conducted with respect for Indigenous people's social, economic and cultural interests.[204] To support meeting this objective, FBC establishes an open dialogue with First Nations communities at the earliest planning stages to ensure that Indigenous engagement requirements are met and Indigenous input is incorporated in the LTERP.

FBC is committed to developing and maintaining relationships with First Nations communities within whose territories FBC works and operates. Understanding, respect, open communication and trust continue to be FBC's aim when working with Indigenous peoples and First Nations communities throughout the province. In keeping with FBC's Statement of Indigenous principles, FBC, including its resource planning team:

- Upholds a high standard of engagement, through clear and open communication on an ongoing and timely basis;
- Encourages awareness and understanding of Indigenous issues within its work force, industry and communities where FBC operates; and

[204] Appendix D-29: https://www.fortisbc.com/in-your-community/indigenous-relationships-and-reconciliation/our-statement-of-indigenous-principles.

- Works to better understand Indigenous culture, values and world views through ongoing community engagement on matters including, but not limited to, FBC's resource planning process.

12.4.2 UN Declaration for the Rights of Indigenous Peoples

FBC supports the implementation of UN Declaration for the Rights of Indigenous Peoples into law in BC under Bill 41: Declaration on the Rights of Indigenous Peoples Act. FBC also recognizes the elevated status of the UN Declaration at the federal level of government, where Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples, passed into law on June 21, 2021. This legislation builds off the legislative framework developed in BC.

FBC continues to learn from the UN Declaration and is committed to actions that move towards reconciliation with Indigenous Peoples. FBC acknowledges the principles of the UN Declaration and the Declaration on the Rights of Indigenous Peoples Act will play a significant role in energy policy and the regulatory environment over the twenty-year planning horizon of this LTERP. FBC is committed to aligning its resource plans with provincial policy, and will continually review its engagement process to ensure that FBC is engaging in meaningful dialogue with Indigenous communities regarding its resource plans. As the Declaration for the Rights of Indigenous Peoples continues to be implemented across government through the development of action plans, FBC will continue to evolve its planning and business practises in alignment with this implementation.

12.4.3 Engagement Sessions

FBC strives to meaningfully engage with Indigenous communities to gather input and feedback on the Company's various planning initiatives. The RPAG includes a member organization that represents B.C. First Nations communities as well as three other First Nations communities, which ensures that First Nations communities play an active role in the ongoing resource planning process. In addition, all Indigenous communities from within the electric service area, including representatives from the Ktunaxa Nation and the Okanagan Nation Alliance, were invited to attend the Community engagement meetings throughout the preparation of this LTERP. While FBC invited several communities to participate in the process, only so many communities responded to FBC correspondence regarding LTERP engagement opportunities. For this reason, FBC engaged directly with community representatives who identified interest in the LTERP engagement sessions, and planned workshops directly with these communities accordingly.

FBC held two meetings for First Nations community representatives on February 4, 2021 and March 3, 2021. These sessions were attended by community representatives from within FBC's electric service territory, including the Ktunaxa Nation and the Okanagan Nation Alliance. The meetings included an overview of the Guidehouse Pathways study and an overview of FBC's long-term gas and electric resource planning process. FBC provided an overview of its outlook for customer demand, including the Reference forecast, potential load drivers and scenarios, demand side management and supply-side resource options. FBC sought feedback from these groups on their energy priorities for the future.

One community who was unable to attend the February 4 session requested a third session, which FBC accommodated at their request on April 15, 2021. This presentation focused solely on the long-term electric resource plan.

Some key themes and areas of interest that were identified as important to community representatives in the first two meetings included:

- Ensuring the UN Declaration and Indigenous energy priorities are key objectives of the LTERP;
- How the LTERP informs the planning process for specific FBC capital projects;
- Cost and affordability are key priorities, as many community members deal with high electricity bills;
- Opportunities for additional energy efficiency partnerships between FBC and local communities as a means to reduce high energy bills, support local housing improvements and/or community development projects;
- Interest in expanding natural gas service to communities not currently served by FEI;
- Electric vehicles as a key driver of future electricity demand; and
- Interest in distributed energy systems - particularly residential and utility scale solar.

Other key energy priorities identified during the February 4, 2021 meeting included cost-effectiveness, reliability, protecting the environment, and economic growth. One group indicated that economic growth and partnership opportunities help community development and therefore indirectly help address affordability. One representative mentioned that supply-side resource diversity would be favoured to help with reliability. Another representative raised questions regarding the cost-effectiveness and environmental footprint of both EV charging infrastructure and rooftop solar. FBC provided further information on the typical lifecycle and payback periods of both EV charging infrastructure and rooftop solar technologies. Multiple representatives also identified interest in FBC's involvement in hydrogen development and potential future partnership opportunities as these technologies develop.

During the March 3, 2021 meeting, community representatives expressed their main priority as having access to cost-effective energy. Economic growth for the community is also an important consideration. One representative inquired about FBC's TOU payment structure for utility EV charging stations. Another representative requested information on current provincial rate regulations and total power generated through FBC-owned generation facilities. Another representative asked FBC about its discussions on reclamation and GHG reduction initiatives with industrial partners in the region. FBC provided further information on each of the above items and re-iterated its ongoing partnerships with customers, including industrial ones, to continue to explore opportunities for decarbonizing the natural gas system.

Community representatives also raised concerns about past grievances relating to the construction of existing hydroelectric generation facilities in the province. Representatives in the meeting expressed that communities were not properly reimbursed for the lands and culturally significant sites impacted or disrupted through the construction of these facilities. It was raised to FBC that the inability to resolve these grievances makes it challenging for communities to discuss energy planning issues and opportunities for the future. Later in the meeting, another representative identified the need for FBC to continue discussions with the communities on beneficial opportunities and how future benefits can be paired to reconcile past grievances. Housing improvement projects that leverage community trade labour and utility funding support were identified as an example of how this could be conducted. FBC acknowledged the representatives concerns, and reiterated the importance of having engagement sessions such as this to receive key community feedback on energy issues and plans for the future.

Discussion during these sessions broadened the knowledge towards the importance of the UN Declaration and FBC will continue to assess its resource planning process to ensure that Indigenous energy objectives and the UN Declaration are considered in FBC's future project plans. FBC re-iterated its commitment to acting on the key principles of the UN Declaration and ensuring that FBC's engagement is conducted in alignment with the values of its Statement of Indigenous Principles. FBC clarified that any capital projects that may result from the findings of the LTERP would require separate BCUC approval, including future engagement related to those applications. FBC also acknowledged that the LTERP objectives are aligned with current BC energy policy and the *CEA*, which encourage the development of clean and renewable resources and support for development of First Nations communities (also see Sections 1.1 and 1.4).

Overall, these engagement sessions provided a critical forum for FBC to receive input on its long-term resource plans and for FBC to learn more about the key energy priorities of local First Nations communities within its service territory. Multiple representatives thanked FBC for the opportunity to participate in these sessions and FBC believes this type of engagement is valuable to continue for future resource plans. Upon completion of these sessions, FBC followed up directly with community representatives to answer any outstanding questions and to explore potential opportunities identified during the sessions. FBC continually engages with community representatives from the Ktunaxa Nation and the Okanagan Nation Alliance to explore options to help meet their energy needs. FBC has used the feedback provided by the First Nations communities to help inform its determination of the preferred portfolio discussed in Section 11.

12.5 *DISCUSSIONS WITH BCUC STAFF*

The BCUC's Resource Planning Guidelines encourage utilities to seek regulatory input from BCUC staff during resource plan preparation. FBC met virtually with BCUC staff on October 13, 2020 and June 18, 2021 to discuss various components of the LTERP. This was to inform BCUC staff of LTERP developments and obtain comments and feedback. The following table details the meeting dates and topics discussed.

Table 12-4: Meetings with BCUC Staff

Meeting Date	Topics Discussed
October 13, 2020	• BCUC 2016 LTERP decision • Planning environment • Load forecasting • Load scenarios • Load-Resource Balance • DSM overview • Supply-side resource options • Portfolio analysis • Stakeholder consultation • LTERP timelines
June 18, 2021	• DSM scenarios • EV charging peak demand mitigation • Load-Resource Balance after DSM • Portfolio analysis results • Transmission and distribution • LTERP timelines

Feedback and comments from BCUC staff in these meetings included the following items:

- FBC updating its LRMC value
- Ensuring the LTERP includes plans for adapting to a changing environment
- The role of battery storage compared to other capacity resources
- The certainty of cannabis facility loads
- Whether or not gas-fired generation was still a resource option
- Amount of RNG fuel used by a SCGT plant
- The inclusion of hydrogen production as a load driver
- EV charging impacts on loads

As noted in Table 12-1 above, BCUC staff were also represented on the RPAG.

12.6 *SUMMARY*

FBC has a strong record of conducting effective stakeholder and Indigenous engagement. In particular, for this LTERP, FBC has consulted a dedicated RPAG planning group, hosted a number of community engagement workshops to garner diverse perspectives on FBC's planning activities across the communities it serves, and conducted a direct customer survey to gain feedback directly from customers. FBC hosted multiple resource planning meetings with First Nations community representatives located within the electric service territory. This Indigenous engagement and stakeholder consultation adheres to the BCUC's stakeholder input guidelines and has been beneficial to the development of this LTERP. FBC met with BCUC staff to discuss various resource planning topics and obtain feedback and conducted an online survey to directly gain the opinions of residential and commercial customers on some key resource planning items.

The information gathered through these activities is incorporated into the LTERP process in a number of ways, such as by informing FBC's planning and analysis, helping to determine the preferred resource option portfolios, identifying long term planning issues of concern to a number of stakeholder and Indigenous groups, and identifying interested stakeholders who may become more engaged in the LTERP process. FBC recommends continuing with the RPAG, community and Indigenous engagement activities as part of the Company's next long-term resource planning process in order to build on the interest and feedback gained through these initiatives.

13. ACTION PLAN

The action plan describes the activities that FBC intends to pursue over the next four years based on the discussion and conclusions provided in this LTERP. It includes actions relating to monitoring the planning environment and strategies for optimizing short-term resource requirements as well as consideration of initiatives to manage EV charging and large loads. Contingency plans that enable FBC to respond to changing circumstances have been discussed in Section 11 as they relate to the preferred portfolios. This 2021 LTERP action plan is consistent with the requirements of the BCUC *Resource Planning Guidelines.* FBC also provides a discussion of the status of the 2016 LTERP action plan in the following section.

13.1 *2016 LTERP ACTION PLAN*

This table below summarizes the status of the action plan from the 2016 LTERP.

Table 13-1: 2016 LTERP Action Plan Status

2016 Action Item	Status
1. Continue to monitor the energy planning environment	FBC monitors the planning environment on a continuous basis. FBC staff involved in resource planning and power supply monitor regional developments through discussions and meetings with other utilities and industry forums and webinars. The FBC external and Indigenous relations group monitors and analyses policy developments that impact FBC. Section 2 provides the results of FBC's monitoring of the energy planning environment.
2. Monitor potential load drivers to determine if a particular load scenario is emerging	FBC monitors load drivers that may have significant impacts on its system and resources on a continuous basis. FBC tracks its public EV charging stations' usage, EVs registered within the FBC service area and rooftop solar uptake through its net metering program. FBC also tracks potential large load additions including requests from cannabis, data centre and block chain facilities. The reference load forecast (Section 3) and load scenarios (Section 4) include FBC's latest forecast and scenarios relating to these load drivers.
3. Continue to assess the potential requirements and timing for new resource options within B.C.	On a periodic basis, FBC develops an updated long-term load forecast to provide a comparison to its 2016 LTERP load forecast and tracks DSM actual load reduction to the 2016 LT DSM Plan to help determine if the Load-Resource Balance and timing for new resources has changed. FBC's 2019 forecast update indicated that load requirements had decreased compared to the 2016 LTERP forecast and DSM actuals were close to forecast and so the requirement for new resources was likely pushed further out in time than indicated in the 2016 LTERP. FBC has updated its load forecast and DSM load reduction in 2020 as part of this 2021 LTERP and LT DSM Plan and includes updated Load-Resource Balances in Section 7 and Section 9.
4. Continue to optimize the PPA and market purchases in the short term	FBC's Annual Electric Contracting Plan provides an annual update on FBC's optimization of the PPA and market purchase strategy for the next operating year based on current market conditions, FBC's load requirements and available resources.

2016 Action Item	Status
5. Complete final phase of BC CPR	The final phase of the BC CPR was completed in May 2019. This included conservation potential related to fuel switching and demand response, and was used to inform the FBC 2019-2022 DSM Expenditure Plan filing and demand response potential estimate for the Kelowna area.
6. Prepare submission of next long term electric resource plan and long term DSM plan	FBC began development of the 2021 LTERP and LT DSM Plan in 2019, including customer, stakeholder and Indigenous community engagement and the development of the load forecast, load scenarios and assessment of supply-side resource options through 2019 to 2021 (discussed in Sections 12, 3, 4 and 10, respectively).

13.2 *2021 LTERP ACTION PLAN*

The following items are the actions relating to this LTERP that FBC intends to pursue over the next four years.

1. Continue to monitor the planning environment

Being aware of and understanding the many factors that influence FBC's planning environment is critical for long-term resource planning and is an ongoing activity for FBC. FBC will continue to monitor energy and environmental policy in Canada and the US as well as regional market developments that may impact market supply, demand and pricing, resource options and costs. FBC's preferred portfolios include a portfolio based on energy and capacity self-sufficiency in the event that electricity market conditions change from the current environment such that energy no longer becomes a reliable and cost-effective option for FBC. In addition, FBC will continue to monitor and examine emerging technologies and changing demand and uses for electricity by its customers. FBC's monitoring activities will ensure that it is aware of and able to respond to relevant changes in the planning environment to meet the LTERP objectives.

2. Monitor potential load drivers to determine if a particular load scenario is emerging

The LRB presented in Section 9 of this LTERP indicates that new supply-side resources other than market energy purchases are not required until at least 2030 based on existing resources and committed contracts, the Reference Case load forecast, current market energy conditions and the proposed level of DSM. However, actual load requirements and DSM program uptake by customers may not match the forecasts, meaning that resources may be needed sooner or later than expected. As part of its ongoing resource planning activities, FBC will continue to assess the LRB on a periodic basis to see if any changes in resources might be required.

As discussed in respect of the Load Scenarios (Section 4), there are a number of load drivers that have the potential to significantly impact FBC's load requirements over the planning horizon. FBC will continue to monitor the various load drivers and, in particular, the drivers that may have the most impact on FBC's loads in the next few years, such as EV growth or the addition of new large loads. This will enable FBC to determine if a particular scenario is emerging or if penetration levels and growth for a particular driver are occurring faster than expected and if the forecast LRB gaps are changing, potentially moving the requirement for new resources sooner than indicated by the Reference Case load forecast. The portfolio analysis presented in Section 11 includes contingency planning to address the potential impact of higher load scenarios than the Reference Case load forecast on the timing and requirement for new resources.

3. Contingency resource(s) assessment

As part of the contingency planning discussed in Section 11, new generation resources or power supply contracts may be required sooner than is contemplated in this LTERP based on the Reference Case load forecast. Recent events like the extreme heat and record loads for FBC in June 2021 (discussed in Section 2.2.1) highlight the need for FBC's resource portfolio to be flexible and adaptable to unexpected changes in loads. As part of a prudent approach to manage future system loads, FBC intends to explore its potential resource options identified in this LTERP in more detail in the next few years so that FBC is ready, if required, to bring forward an application for a new resource to the BCUC for approval prior to the development of the next LTERP. As part of this assessment, FBC may require funding for any costs above approved capital and O&M budgets. FBC expects to review its financial forecast in its Annual Review of rates and if necessary, file an updated forecast of expenditures to account for any material changes to the forecast and to either ask for approval of the changes or indicate that a separate supplemental filing for this work will be required.

4. Implement program to help shift home EV charging

As discussed in Section 2.3.2, EV growth is continuing within the FBC service area and EV charging, if left unmitigated, could significantly increase peak demand on the system. This could lead to the requirement for additional capacity generation resources and/or transmission and distribution infrastructure, increasing rates for customers. FBC's preference is to implement a software-based incentive program in order to encourage shifting home EV charging from peak demand periods while requiring minimal customer involvement. As part of this initiative, FBC intends to implement an EV charging pilot project as part of a wider residential demand-response pilot. Section 4.6.3 of the LT DSM Plan discusses this further.

5. Consider initiatives to manage large loads

Section 2.3.5 discusses the emergence of new large loads and potential benefits for FBC customers from increasing managed load growth on its system. FBC is at the early stages of a number of further initiatives to allow it to accommodate large loads on its system. FBC is evaluating its connection contribution model to find ways to balance prospective, new, and current customer needs. FBC may also consider rates or incentives for large load customers that enable FBC to curtail them during peak demand periods, thereby deferring or avoiding the requirement for new capacity generation resources or additional system infrastructure.

6. Continue to optimize the PPA and market purchases

As explained in Section 5.4, FBC is required to submit an annual nomination for PPA energy deliveries in the following operating year, but retains the ability to displace up to 25 percent of the amount nominated with market purchases, if market conditions would create additional savings for FBC customers compared to PPA energy rates. The Company will continue to purchase market power when it will result in savings to customers and doing so is in accordance with the Company's overall resource requirements.

7. Review PPA prior to expiry

As discussed in Section 5.4, the PPA expires in 2033. The PPA provides a significant amount of energy and capacity to FBC while also providing valuable flexibility in terms of the ability to adjust the amount of the PPA nomination from year to year. It is prudent for FBC to begin a review of the PPA ten years from its expiry in 2023 to determine if negotiations should begin to renew the PPA in its current form or some alternate form. This will provide FBC with enough time before the PPA expiry to either renew the PPA or begin arrangements for some other form of purchase agreement or new generation resources.

8. Transition to clean market purchases

As discussed in Section 10.4, FBC has assumed for the purposes of this LTERP that future market energy purchases are sourced from clean or renewable generation and, as such, has applied a clean market adder to the cost of its market purchases. FBC intends to pursue this option with Powerex, its current market supplier per the CEPSA, and plans to provide an update on its status in a future FBC Annual Electric Contracting Plan filing.

9. Monitor potential available power supply opportunities

While Section 10 assesses possible future generation resource options, other opportunities for additional power supply for FBC may become available in the future. One example relates to the expiry of the BRX agreement in 2027, discussed in Section 5.3. The entire set of capacity and energy entitlements attributed to BRX may be available as a future resource option for FBC and could be an opportunity to secure cost-effective, locally-generated power to help meet FBC's resource needs. Other examples may be the acquisition of power supply from potential generation projects with Indigenous Nations interests in the region or projects that contribute to signficant GHG reduction to meet the Province's climate action goals as well as FBC's LTERP objectives. FBC intends to continue to monitor developments regarding potential future resource options.

10. Continue Stakeholder, Indigenous Community and Customer Engagement

As part of the development of its next LTERP and LT DSM Plan, FBC expects that it would continue its engagement with customers, Indigenous communities and stakeholders to ensure their energy and conservation priorities are understood and feedback is gathered as part of the development of the next LTERP. As discussed in Section 12, FBC is committed to developing and maintaining relationships with stakeholders, customers, local and Indigenous communities within whose territories FBC works and operates.

11. Assess transmission and distribution capital infrastructure requirements

As discussed in Section 6.5, FBC's system planning indicates several projects are required over the next decade based on the 1 in 20 forecast used for system planning. Additional projects may also be required later in the planning horizon if higher than expected loads materialize and capacity generation resources are not put in place or are not sufficient to manage peak demand growth. FBC also plans to assess the risk to specific assets and estimate costs for climate change adaptation resiliency measures and risk mitigation investments. Additionally, in light of the June 2021 extreme temperatures experienced in the FBC service area (discussed in Section 6.2), FBC intends to assess the impacts of this event on its system infrastructure. FBC plans to conduct further analysis beyond what has been presented in this LTERP over the next few years to help assess future system infrastructure requirements. FBC expects that it will submit CPCN applications to the BCUC for any applicable projects in a timely manner.

12. Prepare Submission of next LTERP

Given that no new supply-side resources are required before 2030, FBC expects that it would submit its next LTERP in approximately five years from the submission date of this LTERP, in 2026. This would provide FBC with enough lead-time to assess the load drivers and load forecast, updated LRB, assess transmission and distribution requirements and DSM and available supply-side resource options and costs before any new resources may be required after 2030. If FBC's periodic assessment of the LRB indicates the need for new resources sooner than contemplated in this LTERP or if FBC's access to market energy changes such that it is no longer reliable or cost effective, FBC would likely submit a LTERP or supplemental update filing sooner than five years from the submission of this LTERP in order to meet the LTERP objectives in the interests of its customers.

Appendix A

GLOSSARY OF TERMS AND ACRONYMS

APPENDIX A – GLOSSARY OF TERMS AND ACRONYMS

Acronym or Term	Definition
30BY30	FortisBC's emissions reduction target, achieved though the Clean Growth Pathways to 2050 pillars. The target represents the goal to reduce the GHG emissions associated with FortisBC's customers' energy use by 30 percent by the year 2030.
AECP	Annual Electric Contracting Plan – document prepared by FBC which outlines plans to meet the peak demand and annual energy requirements for the next operating year.
AIC	Average Incremental Costs - approach takes the present value of the incremental costs expected to be incurred over the planning horizon and divides the incremental costs by the present value of the additional load expected to be served within the same period.
AMI	Advanced Metering Infrastructure Project – replacement of electricity meters with new advanced meters across the FBC service territory. In order for the meters to communicate with FBC, software infrastructure was also installed along with a communications network. The project provides real-time and more granular load data from customer endpoints and reduces theft on the system.
Baseload Resources	Resources that provides dependable capacity and are expected to operate at a high capacity utilization factor, generating significant amounts of electrical energy over time.
BAU Forecast	Business As Usual load forecast which uses time series method to extrapolate historical trends into the future. The BAU forecast is used for annual rate setting which is then extended out for the LTERP 20-year planning horizon.
BC Clean or Renewable Resource	The *Clean Energy Act* definition includes biomass, biogas, geothermal heat, hydro,solar, ocean, wind or any other prescribed resource.
BC Hydro PPA	Power Purchase Agreement between BC Hydro and FBC - 20-year agreement that expires in 2033 and that provides up to 200 MW of capacity and 1,752 GWh peryear of associated energy to FBC from BC Hydro.
BCUC	British Columbia Utilities Commission - independent regulatory agency of the B.C. government that operates under and administers the *Utilities Commission Act*. The Commission regulates B.C.'s natural gas and electricity utilities, intra-provincial pipelines and universal compulsory automobile insurance.

Acronym or Term	Definition
BEV	Battery Electric Vehicle - type of electric vehicle (EV) that uses chemical energy stored in rechargeable battery packs.
BPA	Bonneville Power Authority – non-profit power marketing administration based in the Pacific Northwest, which includes Washington, Oregon, Idaho and B.C.
BPPA	Brilliant Power Purchase Agreement - agreement with Brilliant Power Corporation where FBC has agreed to purchase the energy and capacity entitlement allocated to the Brilliant Plant pursuant to the CPA and after the termination of the CPA, the actual electrical output, if any, generated by the Brilliant Plant.
BRX	Brilliant Expansion Agreement - a ten-year power purchase agreement with Columbia Power Corporation where FBC has agreed to purchase capacity and energy CPA entitlements made available from Brilliant Power Corporation on behalf of Columbia Power Corporation. The agreement expires at the end of December 2027.
Canal Plan Agreement Entitlement	The average water year generation of the generating facilities included in the CPA. Provided each unit is in-service, the related entitlements are provided by BC Hydro regardless of the actual generation dispatched by BC Hydro from the facilities.
Capacity	The instantaneous output of a power plant or system electricity demand at any given time, normally measured in kilowatts (kW) or megawatts (MW).
Capacity Utilization Factor	The ratio of the actual output from a plant over the year to the maximum possible output from it for a year under ideal conditions.
CBOC	Conference Board of Canada - non-profit organization dedicated to researching and analysing economic trends, as well as organizational performance and public policy issues.
CBT	Columbia Basin Trust - created by the *Columbia Basin Trust Act* in 1995 to benefit the region most adversely affected by the Columbia River Treaty (CRT) in the province of B.C.
CCGT	Combined Cycle Gas Turbine - natural gas-fired generation resource that couples a combustion turbine with a steam cycle plant, in order to generate electricity.
CCS	Carbon capture and storage technology includes capturing carbon emissions from industrial processes and storing them underground.
CEA	*Clean Energy Act* - legislation outlining the BC government's commitment to clean energy and the environment which includes key objectives relating to GHG emissions, clean or renewable resources, DSM and socio-economic development.

Acronym or Term	Definition
CEPSA	Capacity and Energy Purchase and Sale Agreement - agreement between Powerex and FBC where FBC will sell the remaining surplus WAX CAPA residual capacity to Powerex on a day-ahead basis.
CET	Customer Engagement Tools - DSM tool with the ability to operate across digital channel which improves customer experience and drives greater DSM program participation. Some examples of CET's are digital or paper home energy reports and advanced webpotals.
CHBA	Canadian Home Builders' Association - not-for-profit organization that brings together builders and industry experts from across the country to share information and ideas, and to formulate recommendations to governments to improve the quality and affordability of homes for Canadians.
CIP	Customer Information Portal – online tool that allows customers to view historic billing and consumption data, which can result in behavioural changes in energy use.
CleanBC Plan	The BC Government provincial climate plan released in December 2018 aimed at reducing climate pollution while creating jobs and economic opportunities. The three main priorities relate to the areas of transportation, buildings and industry.
Clean Growth Pathway to 2050	FortisBC's plan which outlines the actions to take in order to align with the provincial government's GHG reduction goals. It includes four key pillars: expanding low and zero carbon solutions in buildings, investing in renewable gases, supporting zero and low carbon transportation and positioning BC as a vital domestic and international LNG provider.
CPA	Canal Plant Agreement - enables BC Hydro and the Entitlement Parties (collectively, the CPA Parties), through coordinated use of water flows and storage reservoirs, and through coordinated operation of generating plants, to generate more power from their combined generating resources than they could if they operated independently.
CPC	Columbia Power Corporation - crown corporation that develops, owns and operates hydro power projects in the Columbia Basin.
CPCN	Certificate of Public Convenience and Necessity - a certificate obtained from the BCUC under Section 45 of the *Utilities Commission Act* for the construction and/or operation of a public utility plant or system, or an extension of either, that is required, or will be required, for public convenience and necessity.
CPR	Conservation Potential Review – study that determines cost-effective demand-side management potential for FBC.

Acronym or Term	Definition
CRT	Columbia River Treaty - a treaty signed in 1961 between Canada and the U.S. that enables storage reservoirs to be built and operated in BC to regulate Columbia River flows into the U.S. for power production and flood control.
Dependable Capacity	The generation capacity available for the peak hours during each month of the year.
DG	Distributed Generation – Individual-use generation resource, such as solar or small wind turbines, distributed amongst and utilized by residential and small commercial customers. Typically offset individual customer power consumption and is connected to the utility system via some form of net metering facility.
DR	Demand Response – programs targeted towards consumers to reduce or shift their electricity usage during peak periods in response to time-based rates or other forms of financial incentives.
DSM	Demand-Side Management - actions that modify customer demand for electricity helping to reduce their consumption and defer the need for new utility energy and capacity supply additions.
Energy	The electricity produced or used over the a period of time, usually measured in kWh, MWh or GWh.
EPA	Electricity Purchase Agreement - a contract between two parties, one which generates electricity (the seller) and one which is looking to purchase electricity (the buyer).
EV	Electric Vehicles - a vehicle that uses one or more electric motors or traction motors for propulsion. It may be powered through a collector system by electricity from off-vehicle sources, or may be self-contained with a battery or generator to convert fuel to electricity.
FBC	FortisBC Inc. – the utility that provides electricity service in the southern interior of BC.
FEI	FortisBC Energy Inc.- the utility that provides natural gas service in BC and propane service for Revelstoke.
FERC	Federal Energy Regulatory Commission - independent US federal agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects.
FortisBC	Includes both FBC and FEI utilities.
GHG	Greenhouse Gas - any gaseous compound in the atmosphere that is capable of absorbing infrared radiation, thereby trapping and holding heat in the atmosphere. The primary greenhouse gases in Earth's atmosphere are water vapor, carbon dioxide, methane, nitrous oxide, and ozone.

Acronym or Term	Definition
GJ	Gigajoule - a unit of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).
GLJ	GLJ Petroleum Consultants Ltd. - a private energy industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis.
GWh	Gigawatt hour - a unit of energy equal to 1 million kilowatt-hours.
Henry Hub	Distribution hub on the natural gas pipeline system in Erath, Louisiana. The Henry Hub price is the benchmark price of natural gas in North America and is the point of delivery used in the New York Mercantile Futures Exchange (NYMEX) futures contract.
Heritage Contract	A per year contract (in perpetuity) between BC Hydro's Generation and Distributed Lines of Business to ensure BC Hydro customers (including FBC) benefit from the existing low-cost hydroelectric and thermal resources in the BC Hydro system.
HLH	Heavy Load Hours - The time of day in which peak demand occurs from 0600h through 2200h, Monday to Saturday, excluding holidays.
Huntingdon/Sumas	Natural gas market hub on either side of the B.C. /Washington state (US) border through which much of the Pacific Northwest regional gas supply is traded.
IHS	Energy market subscription service used by FEI and FBC as part of its monitoring of energy market developments.
IJC	International Joint Commission - Commission to help prevent and resolve disputes about the use and quality of boundary waters and to advise Canada and the US on questions about water resources.
Installed Capacity	The maximum rating of a generator or transmission station equipment as identified by the manufacturer under specified conditions.
IPP	Independent Power Producer - privately owned electricity generating facility that produces electricity for sale to utilities or other customers.
IPSS	Integrated Photovoltaic Storage Systems - power system designed to store and supply usable solar power by means of photovoltaics (PVs).
IRP	Integrated Resource Plan - document that details the resource planning process and outcomes that guide a utility in planning to serve its customers over the long term.

Acronym or Term	Definition
kW	Kilowatt - unit of energy equal to one thousand watts, the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.
kWh	Kilowatt hour - equal to one thousand watts used for a period of one hour - the basic unit of measurement of electric energy. On average, residential customers in BC use about 10,000 kWh per year.
LD EV	Light-duty electric vehicle. Vehicles under 4,000 kilograms and includes passenger cars, SUVs and trucks.
Levelized Cost, Levelized Price	Levelizing is a method of converting a non-uniform stream of energy costs (or prices) into a present value equivalent uniform cost or price.
LLH	Light Load Hours - all hours that are not Heavy Load Hours (HLH).
LLST	Large Load Sector Transformation - growth of large load customers not associated with traditional energy intensive industries.
LNG	Liquefied Natural Gas - natural gas stored under high pressure, which turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state.
LOLE	Loss of Load Expectation - the expected number of days in a year the generation capacity fails to meet load.
Losses	Loss of electric energy due to line losses, losses due to wheeling through the BC Hydro system, company use, and unaccounted for energy (meter inaccuracies and theft).
LRB	Load-Resource Balance – difference between existing and committed resources and load forecast. Used to determine quantity and timing of new resources.
LRMC	Long Run Marginal Cost - the cost of incremental resources to meet load requirements over the planning horizon.
LT DSM Plan	Long Term Demand Side Management Plan which outlines DSM potential, scenarios and programs on a long-term basis.
LTERP	FBC Long Term Electric Resource Plan - examines future demand and supply resource options over the 20-year planning horizon to cost effectively and reliably meet customers' energy and capacity electricity needs.
LTGRP	FEI Long Term Gas Resource Plan - examines future demand and supply resource options over the 20-year planning horizon to cost effectively and reliably meet customers' energy and capacity gas needs.

Acronym or Term	Definition
MHD EV	Medium and heavy duty electric vehicles. Vehicles over 4,000 kilograms and includes combination tractors, return-to-base fleet vehicles and buses.
Mid-C	Mid-Columbia River electricity trading hub located along the Columbia River on the border between Washington and Oregon. One of the top three electricity trading hubs in North America by volume.
MW	Megawatt - a unit of power equal to one million watts or one thousand kilowatts, commonly used to measure both the capacity of generating stations and the rate at which electric energy can be delivered.
MWh	Megawatt Hour (MWh) - one million watts, one thousand kilowatts. A unit commonly used to measure both the capacity of generating stations and the rate at which energy can be delivered.
NM	Net metering refers to the billing process where customers who generate their own energy are compensated by the utility. FBC's Net Metering program is available to residential, smaller commercial, and irrigation customers for installations providing clean or renewable electricity located on the customer's premises with a capacity of not more than 50 kW.
NPV	Net Present Value – the sum of the present values of a series of individual cash flows. Present value is the value in the present of a sum of money or cash flow, in contrast to some future value it will have when it has been invested at compound interest.
Peak Demand	The largest amount of capacity needed at one point in time on the electrical system.
Peaking Resources	Resources that can be dispatched to provide dependable capacity but are expected to operate at a low capacity utilization factor generating electricity only when it is needed.
PEV	Plug-in Electric Vehicle - any motor vehicle that can be recharged from an external source of electricity and the electricity stored in the rechargeable battery packs drives or contributes to drive the wheels (also see EV).
PHEV	Plug-in Hybrid Electric Vehicles - electric vehicle that uses rechargeable batteries, or another energy storage device, that can be recharged by plugging it in to an external source of electric power. A PHEV shares the characteristics both of a conventional hybrid electric vehicle, having an electric motor and an internal combustion engine.
PHS	Pumped Hydro Storage – electricity generation facility that stores and produces electricity to supply high peak demands by moving water between reservoirs at different elevations.

Acronym or Term	Definition
Planning Horizon	The 20-year time period covered by the LTERP. This 2021 LTERP covers 2021 through 2040.
PNW	Pacific Northwest - a region that is commonly referred to as the three northwestern states of Washington, Oregon, Idaho and the Province of B.C.
PPA	See BC Hydro PPA.
Prediction Intervals	Upper and lower ranges applied to a BAU load forecast to reflect future levels of uncertainty.
PRM	Planning Reserve Margin - dependable capacity above the expected peak demand and is measured in MW or percentage of the expected peak. PRM is to ensure resource adequacy when dealing with unforeseen increases in demand and forced outages in the system.
PV	Photo-Voltaic - includes the conversion of light into electricity using semiconducting materials that exhibit the photovoltaic effect. Commonly used when referring to rooftop solar energy generation.
REC	Renewable energy credit – represents the clean energy attributes of renewable electricity generation.
Reference Case Load Forecast	The Reference Case Load Forecast builds on the BAU forecast by including electric vehicle charging load and new industrial loads with high confidence of materializing. The Reference Case Load Forecast is the resulting forecast used for planning purposes for the LTERP.
RNG	Renewable natural gas is a carbon-neutral pipeline-quality gas that is fully interchangeable with conventional natural gas. RNG is created by capturing methane emissions from organic waste, landfills, wastewater treatment plants and wood waste.
RPAG	Resource Planning Advisory Group - group of stakeholders and rights holders representing municipalities, government, Indigenous communities, customers, associations and organizations that provide feedback and advise in the development of the LTERP.
RPS	Renewable portfolio standards - policies designed to increase generation of electricity from renewable resources in the US.
SCGT	Simple Cycle Gas Turbine - gas-fired generation resource used for capacity purposes during peak demand periods that operates by propelling fuel gas through a turbine in order to generate electricity. The fuel gas could include conventional natural gas, renewable natural gas or blending hydrogen with other fuels.

Acronym or Term	Definition
SG	Self-generation. For the purposes of this LTERP, refers to larger, industrial customers that can provide electricity to FBC as opposed to smaller residential or commercial customers that could provide distributed generation (DG) to FBC.
tCO2e	Tonnes of carbon dioxide equivalent – used as a measure of GHG emissions.
UCA	*Utilites Commission Act* - legislation which provides the BCUC with the authority to oversee natural gas and electricity utilities, intra-provincial pipelines and universal compulsory automobile insurance in B.C.
UCC	Unit Capacity Cost - the annualized cost of providing dependable capacity for a specific resource option, expressed in $ per kW-year.
UEC	Unit Energy Cost - the annualized cost of generating a unit of electrical energy for a specific resource option, expressed in $ per MWh.
UPC	Use per customer. The quantity of energy used by a FBC electricity customer over a fixed time period, normally one year.
WACC	Weighted Average Cost of Capital - the rate that a company is expected to pay on average to all its security holders to finance its assets.
Watt	The basic unit of measurement of electric power, indicating the rate at which electric energy is generated or consumed.
Watt-hour (Wh)	An electrical energy unit measure equal to one watt of power supplied to, or taken from, and electric circuit steadily for one hour.
WAX	Waneta Expansion - the addition of a second powerhouse located immediately downstream of the Waneta Dam on the Pend d'Oreille River. The expansion shares the existing hydraulic head and generates power from water that would otherwise be spilled.
WAX CAPA	The Waneta Expansion Capacity Purchase Agreement - a 40-year capacity purchase agreement with the Wanata Expansion Power Corporation to purchase all unused WAX-related capacity that remains after BC Hydro has acquired the energy entitlements associated with the plant (as defined by the CPA).
WECC	The Western Electricity Coordinating Council - a non-profit corporation that assures a reliable Bulk Electric System in the geographic area known as the Western Interconnection. The WECC Region extends from Canada to Mexico and includes the provinces of Alberta and BC, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.

Acronym or Term	Definition
ZEV	Zero emission vehicle. The *ZEV Act* defines ZEV as a motor vehicle that is propelled by electricity or hydrogen from an external source and emits no greenhouse gases at least some of the time while the motor vehicle is being operated, or a prescribed type of motor vehicle.
ZEV Act	The BC Zero Emission Vehicle Act, introduced in 2019, which requires automakers to meet an escalating annual percentage of new light-duty ZEV sales and leases. The targets include 10% by 2025, 30% by 2030 and 100% by 2040.

Appendix B

CLEANBC PLAN


cleanBC
our nature. our power.
our future.
BRITISH
COLUMBIA

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MESSAGE FROM THE PREMIER

There's nothing more important than taking care of the place we call home.

No matter where you live, no matter your age or background, you want a good life and a secure future in the community you've chosen to live and work in. For today, and for your kids and grandkids tomorrow.

That's why we are bringing forward our CleanBC plan.

It's a plan about climate and science, actions and targets. But ultimately, CleanBC is about putting our province on the path to a cleaner, better future – with a low-carbon economy that creates opportunities for all while protecting our clean air, land and water.

The roots and inspiration for this plan are many. It acknowledges the accomplishments of Premier Gordon Campbell's government a decade ago in making B.C. a leader in reducing greenhouse gas emissions. It reflects the global commitment established three years ago in Paris to save our planet's future by acting on climate change now. But ultimately, CleanBC is inspired by the aspirations of the people of British Columbia, who work hard every day to help build our province and who ask for nothing more than a secure, sustainable future.

CleanBC directly addresses the challenges before us.

It holds that by working together, we can meet the increasing demand for an economy that is productive and forward-looking, while reducing pollution and protecting our climate. With the right path forward, business, industry, Indigenous peoples, workers and communities can come together to unlock B.C.'s full economic potential in a world that's beginning to embrace urgent climate action and eager for low-carbon products, services, and energy inputs.

It argues that transitioning to a low-polluting economy will deliver more and higher-value jobs for British Columbians in resource industries, the service economy, and in emerging and growing sectors. By positioning B.C. as a low-carbon leader, we will attract increased and new investment from around the globe – opening the door to more opportunities for people and companies, large and small, throughout our province.

Finally, CleanBC embraces all that makes British Columbia special – the nature, the people, the spirit of community – and demands we do more to protect it from the dangers posed by climate change. The unprecedented droughts, wildfires and floods we've seen in recent years must serve as notice. Our obligation to this province must be to improve how we live, work and commute – moving forward on a path that makes clean, renewable energy and pollution reduction the norm.

CleanBC is an outcome of the contribution of many, in particular the Climate Solutions and Clean Growth Advisory Council, convened by Minister George Heyman to provide strategic advice to government on climate action and low-carbon economic growth. I'm proud also that we have developed this plan in concert with our partners in the B.C. Green Caucus, who work tirelessly to bring forward the voices of so many British Columbians who care deeply about our province's future.

This plan is now public. Let the dialogue and solutions begin. And let's work together to build a better B.C. for everyone.

Honourable John Horgan
Premier of British Columbia

Climate change will challenge our economy, environment, and communities. Yet, in every challenge lies opportunity. CleanBC offers a pathway that will enable our province to seize opportunities for innovation and growth.

By coming together to enact this plan, we are charting a path that will advance a high quality of life for British Columbians well into the future. The work is just beginning, but for the first time in many years it is looking promising.

Dr. Andrew Weaver
Leader, B.C. Green Caucus; MLA – Oak Bay-Gordon Head

The CleanBC plan sets our province on a cleaner path over the next decade and beyond, reducing climate pollution and making cleaner solutions more convenient, available and affordable for British Columbians.

Within a global commitment to address climate change, B.C. must do its part by changing how we power our province, manage our waste, and protect our air, land and water. The change we need to make is already underway, as we move towards a cleaner, healthier and more sustainable future for ourselves and our children.

Honourable George Heyman
Minister of Environment and Climate Change Strategy

B.C. is a leader in generating clean, renewable energy. With CleanBC, we will use our abundant carbon-free electricity to power our province's future.

Working together, we can create a future defined by cleaner energy, reduced pollution, and new opportunities and jobs for all British Columbians.

Honourable Michelle Mungall
Minister of Energy, Mines and Petroleum Resources

British Columbia will be a leading global destination for industry planning to drive low-carbon economic growth and opportunities.

Putting British Columbia on the world stage as a leader in clean energy, products and services will open doors to new investment in established companies and start-ups alike: delivering more good-paying jobs for British Columbians.

Honourable Bruce Ralston
Minister of Jobs, Trade and Technology

EXECUTIVE SUMMARY

CleanBC is a pathway to a more prosperous, balanced, and sustainable future. Over the next decade and beyond, we must grow the use of clean and renewable energy in how we get around, heat our homes, and fuel our industry – making things better and more affordable for people. Our work is already underway, and we are making the most of it to benefit people and communities everywhere – from rural and remote B.C. to Indigenous communities and our growing urban centres.

Along with our actions to reduce greenhouse gas (GHG) emissions, CleanBC provides an effective blueprint to build our economy. Rising to meet the global challenge of climate change is an opportunity for British Columbia to mobilize our skilled workers, natural resources, and booming technology sector to reduce climate pollution and create good jobs and economic opportunities across B.C. The same innovations that reduce our emissions and improve our quality of life can drive economic growth and help businesses succeed in the global market for clean energy, technologies, products and expertise.

CleanBC describes how, together, we can make things more efficient, use less energy and waste less, while making sure that the energy we use is the cleanest possible and to the greatest extent possible made-in-B.C.

Our strategy reduces GHG emissions by shifting away from fossil fuels and towards clean and renewable energy. We first focus on some of the sectors that most affect our daily lives:

- For transportation – with cleaner fuels, cleaner vehicles and more support for measures that get people out of their cars
- For the buildings where we live and work – raising our standards for new construction and encouraging energy-saving improvements in existing homes and workplaces
- By reducing emissions from organic waste and diverting it from landfills
- By reducing emissions from industry with targeted incentives
- By working with employers, Indigenous communities, labour groups and others to make sure people throughout B.C. can get the skills they need for the jobs of the future

Making these changes cannot leave anyone behind. Switching to cleaner energy needs to be affordable for people across B.C. That's why we are helping with the upfront costs that come with home improvements, using cleaner energy, and zero-emission vehicles – giving people more affordable choices to save energy over the long run.

The full scope of actions envisioned in CleanBC – on the part of citizens, industry and business, and local and provincial government – will accomplish our 2030 GHG reduction goals. This plan describes specific reductions from the first set of actions totaling more than 75 per cent. Over the next 18 to 24 months we will identify additional reductions across more sectors of our economy with the strong potential to exceed the remaining 25 per cent of our 2030 goals. These include:

- cleaner public transportation,
- cleaner and more efficient technology,
- the introduction of new clean energy options,
- reducing and making better use of waste,
- significantly increasing industrial electrification,
- reducing emissions from forestry, land use and agriculture, and
- improving community design and services.

As each new initiative is developed we will put it into action, so we are not waiting to get good ideas underway. We want to hear from the public and will be seeking input in the next year on initiatives that get us to our climate goals. Together, in collaboration with Indigenous peoples, we will work to build more resilient communities, where everyone benefits from a cleaner future.

What's in this plan:

- Our goal is to make every new building constructed in B.C. "net-zero energy ready" by 2032. Along the way we're requiring new buildings to be more efficient, and ramping up funding for renovations and energy retrofits to our existing homes and offices, including $400 million to support retrofits and upgrades for B.C.'s stock of publicly funded housing.
- We're speeding up the switch to cleaner fuels at the gas pump – with further reductions to the carbon intensity of our transportation fuels.
- Just over 20 years from now, every new car sold in B.C. will be a zero-emission vehicle. We are helping people to afford cleaner cars and save money on fuel with incentive programs, and making it easier to charge or fuel them.
- We're giving people the skills they need, making sure that British Columbians can lead the clean transition.
- We're reducing residential and industrial organic waste and turning it into a clean resource.
- We're helping industry lower their emissions and reduce their pollution.

These initiatives won't just protect our environment and clean our air – they will help create new economic opportunities for people and spur innovation to grow our world–leading technology and clean energy sectors.

Together, we can rise to the challenge of global climate change and build a better life for people in this province.

KEY ACTIONS

Cleaner Transportation

Bring down the price of clean vehicles	Just over 20 years from now, every new car will be a zero-emission vehicle (ZEV) with phased-in increases to the ZEV standard	1.3
	Help people to afford cleaner cars and save money on gasoline bills with ZEV incentives	0.3
	Make it easier to charge or fuel a ZEV	
Speed up the switch to cleaner fuels	Make our fuel cleaner by increasing the low carbon fuel standard to 20% by 2030 and increasing the production of renewable transportation fuels	4.0
	Make vehicles run cleaner by increasing tailpipe emissions standards for vehicles sold after 2025	0.4
	GHG Mt reduced by 2030	**6.0**

Improve where we live and work

Better buildings	Make every building more efficient by improving the Building Code and increasing efficiency standards	0.5
Support for better buildings	Incentives to make homes more energy-efficient and heat pumps more affordable	
	Upgrade public housing to make it more comfortable and energy-efficient	
	Make residential natural gas consumption cleaner by putting in place a minimum requirement of 15% to come from renewable gas	1.5
Support for communities	Help remote communities reduce dependence on diesel and support public infrastructure efficiency upgrades and fuel switching to biofuels with the CleanBC communities fund	
	GHG Mt reduced by 2030	**2.0**

Cleaner Industry

Ramp up the CleanBC program for industry	Direct a portion of B.C.'s carbon tax paid by industry into incentives for cleaner operations	2.5
Improve air quality by cutting air pollution	Clean up air pollution in the lower mainland with a pilot project to test options to switch 1,700 freight trucks to cleaner or zero-emission fuel	
Reduce methane emissions from natural gas development	Reduce methane emissions from upstream oil and gas operations by 45%	0.9
Industrial electrification	Provide clean electricity to planned natural gas production in the Peace region	2.2
	Increase access to clean electricity for large operations with new transmission lines and interconnectivity to existing lines	1.3
Carbon capture and storage	Ensure a regulatory framework for safe and effective underground CO_2 storage and direct air capture	0.6
Cleaner fuels for industry	Make industrial natural gas consumption cleaner with a minimum 15% to come from renewable gas	0.9
	GHG Mt reduced by 2030	**8.4**

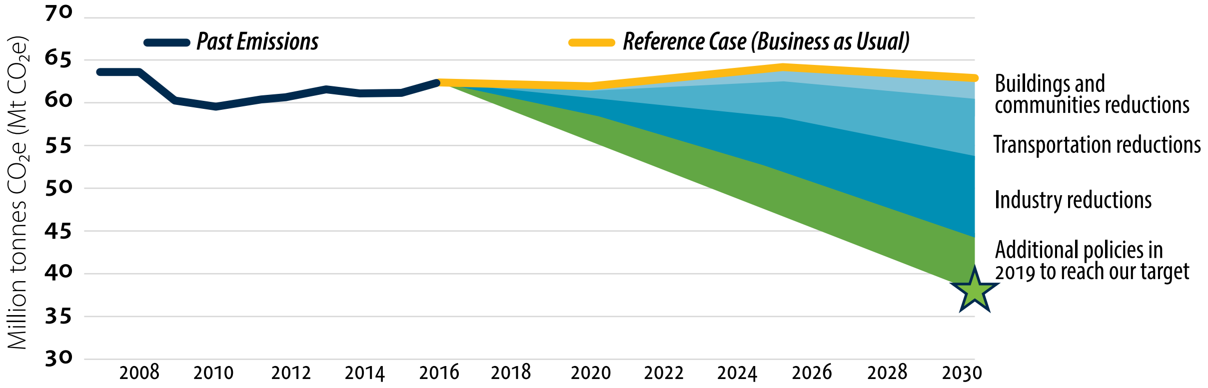
Reduce emissions from waste

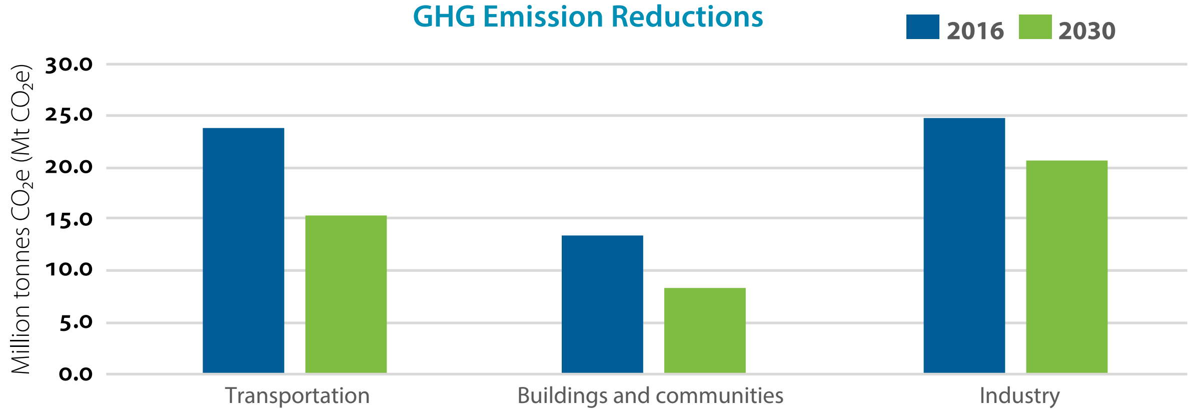
Reduce waste and turn it into a clean resource	Help communities to achieve 95% organic waste diversion for agricultural, industrial, and municipal waste – including systems in place to capture 75% of landfill gas	0.7
	Waste less and make better use of it across all sectors of our economy, like forestry, agriculture, and residential areas, including renewing the B.C. Bioenergy Strategy and building out the bioenergy and biofuels cluster	
	GHG Mt reduced by 2030	**0.7**

Continue the successful carbon pricing framework, with rebates for low and middle income British Columbians and support for clean investments	1.8

TOTAL GHG Mt reduced by 2030	**18.9**
The legislated target for 2030 is a reduction of 25.4 Mt GHG from a 2007 baseline	

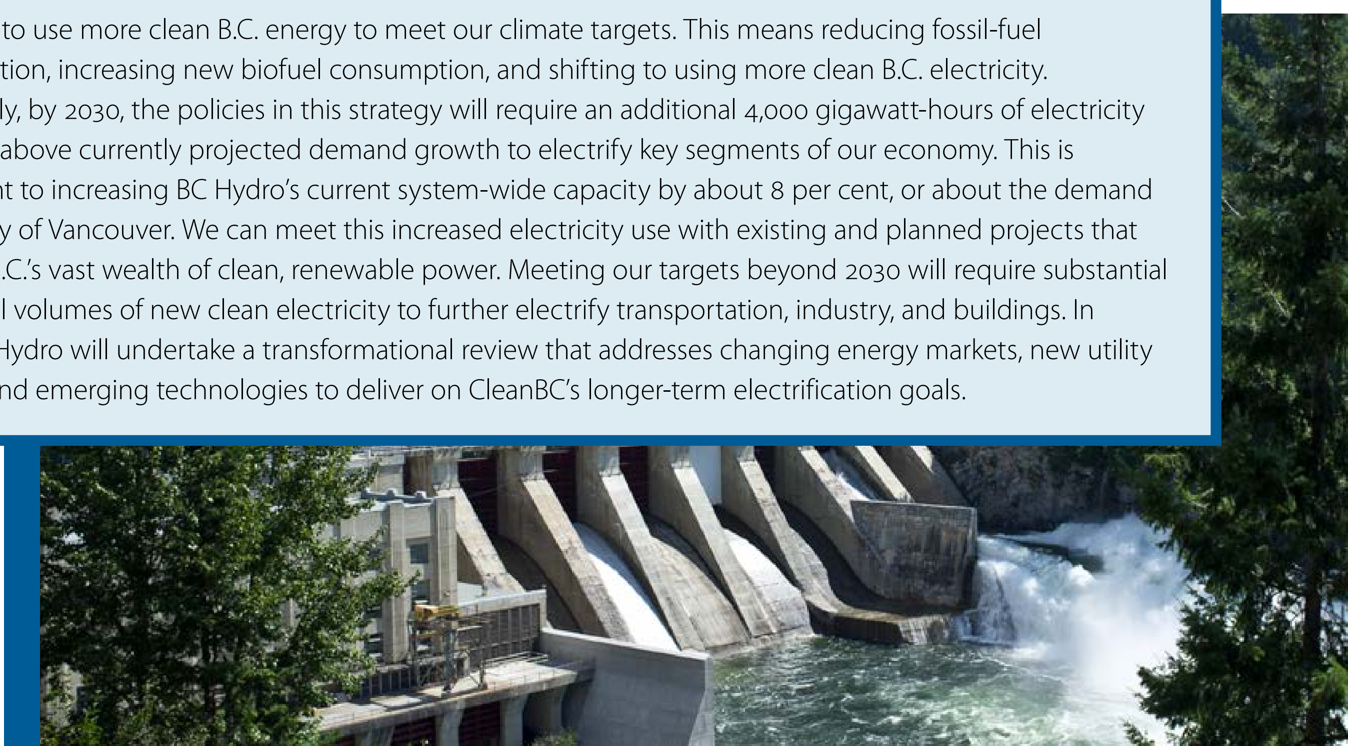
** Policy line items represent individual reduction potential estimates. Subtotals and totals are derived from combined modeling and may be lower than the sum of policies because of policy interactions (two policies contribute to the same reduction)*





ELECTRIFICATION: BY THE NUMBERS

We need to use more clean B.C. energy to meet our climate targets. This means reducing fossil-fuel consumption, increasing new biofuel consumption, and shifting to using more clean B.C. electricity. Specifically, by 2030, the policies in this strategy will require an additional 4,000 gigawatt-hours of electricity over and above currently projected demand growth to electrify key segments of our economy. This is equivalent to increasing BC Hydro's current system-wide capacity by about 8 per cent, or about the demand of the City of Vancouver. We can meet this increased electricity use with existing and planned projects that harness B.C.'s vast wealth of clean, renewable power. Meeting our targets beyond 2030 will require substantial additional volumes of new clean electricity to further electrify transportation, industry, and buildings. In 2019, BC Hydro will undertake a transformational review that addresses changing energy markets, new utility models and emerging technologies to deliver on CleanBC's longer-term electrification goals.



1 INTRODUCTION: POWERING OUR FUTURE

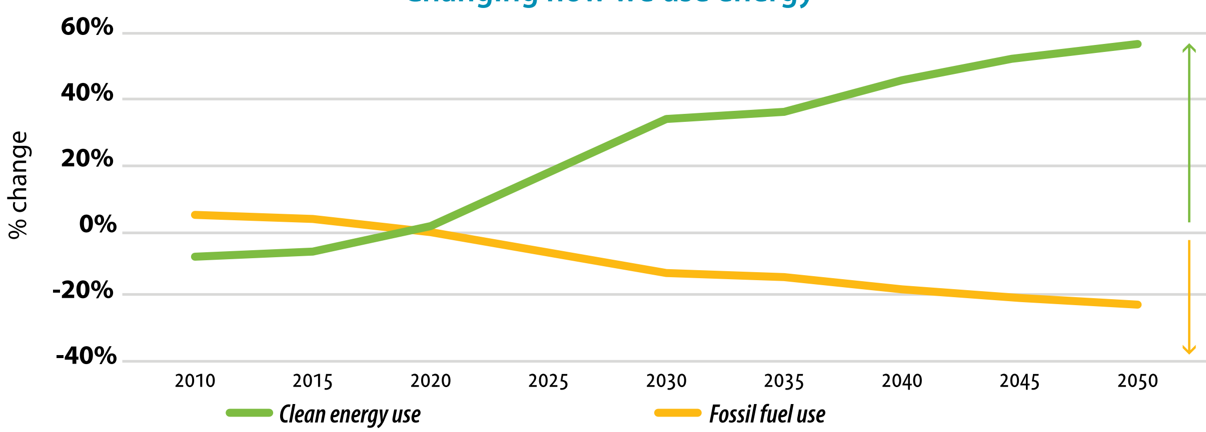
Our CleanBC plan protects what we care about and invests in steps that will make life more affordable, healthier and more comfortable, while creating a stronger economy and good jobs for the people of this province.

From fossil fuels to clean energy

Our lives and our economy are growing more and more reliant on energy. Thanks largely to the legacy of BC Hydro, we are already a clean-energy powerhouse. Almost all the electricity we produce is from clean and renewable resources. But when it comes to the energy we consume in our buildings, cars and industrial operations – nearly three quarters of the energy used across our economy still comes from fossil fuels.

To meet our goals we must increase our use of cleaner energy, especially electricity, in our lives and in key sectors of our economy – shifting away from our reliance on fossil fuels for transportation, industry, and housing. Together, we can make these sectors more efficient, so we use less energy and waste less, and make sure the energy we do use is the cleanest possible. People will benefit with more comfortable buildings, cleaner air, and more transportation options.

Changing how we use energy



We're working towards a future where clean energy powers our homes, businesses and vehicles; where we use energy more efficiently; where more and more people have the skills and jobs of the future; where our natural resource industries have the smallest possible environmental footprint; where we work in full partnership with Indigenous peoples; where we use our position as a clean energy leader to grow our innovative technology sector; where we export our expertise and products to make a difference in the lives of hundreds of millions; and where we all enjoy cleaner air and a healthier natural environment.

Focusing on affordability

The move to more clean energy must be fair and affordable. We are focused on lowering energy use and making it easier to heat and power our buildings – and helping with those upfront costs. As we bring more and more zero-emission vehicles onto the market, we will expand incentives to make them more

CLEANBC: RENEWING OUR COMMITMENT TO CLIMATE ACTION

2008: B.C. gets a head start on climate action, introducing North America's first comprehensive price on carbon along with a wide-ranging climate action plan supported by legislated GHG reduction targets; the Province, UBCM, and local governments sign the BC Climate Action Charter that commits them to take action on climate change.

2009: B.C. introduces Renewable and Low Carbon Fuel Requirements to spur the supply of cleaner fuels.

2010: The *B.C. Clean Energy Act* requires at least 93 per cent of our electricity to be generated from clean or renewable sources (BC Hydro has since achieved 98 per cent); all B.C. public-sector organizations achieve carbon neutrality.

2011: The Province launches the Clean Energy Vehicle (CEV) program; the First Nations Clean Energy Business Fund is also launched.

2012: B.C. meets its first interim target, reducing province-wide GHG emissions to six per cent below 2007 levels (though emissions began to rise again in later years).

2015: B.C. has seen decoupling of GHG emissions from economic and population growth. Between 2007 and 2015, our net greenhouse gas emissions declined by 4.7 per cent; at the same time, our GDP grew by 16 per cent – proving that climate solutions and clean growth can go hand in hand.

2016: B.C. and its partners in the Pacific Coast Collaborative – Washington, Oregon and California – sign the Pacific Coast Climate Leadership Action Plan.

2017: The BC Energy Step Code is introduced, providing a voluntary path to achieving net-zero energy ready buildings; the BC Indigenous Clean Energy Initiative is launched.

2018: B.C.'s price on carbon is increased for the first time since 2012 to $35 per tonne, and set to increase by $5 per tonne per year until it reaches $50 per tonne in 2021; new revenues from B.C.'s carbon tax are dedicated to supporting measures that drive down GHG emissions and make life more affordable for British Columbians; new climate targets are legislated under the *Climate Change Accountability Act*; the Climate Solutions and Clean Growth Advisory Council is established to provide strategy advice on climate action and clean economic growth; the Province works with people to develop CleanBC, a long term strategy to meet our climate targets while building a stronger, more sustainable economy.

British Columbia has more than a decade of experience in driving down greenhouse gas emissions. During that time, we've seen our economy grow even as emissions have declined. We've expanded the climate action tax credit for low-income British Columbians. We've spurred the growth of a cutting-edge technology sector, renewed commitment from business and industry to building a cleaner B.C. brand, and further developed our clean B.C. energy resources, from electricity to biofuels to hydrogen fuel cells. These are strengths we can build on.

affordable while also expanding public transit. These should be accessible to people across this province. Our targeted incentives will be in place to help people make the switch to cleaner choices until these options become more common and more affordable.

Growing the economy as we build a cleaner future

Doing our part to address climate change means finding cleaner, more efficient solutions that will help us build and broaden our economy. We are well positioned to seize the opportunities emerging as people look for new solutions to the challenges of climate change, which in turn will provide good jobs for the people of B.C. The global market for clean energy, technologies, products and services is valued in the trillions of dollars and we have a head start on meeting that demand.

Reaching our targets and building resilient communities

There's more to do, especially when it comes to community development and infrastructure, public transportation, industrial waste, generating yet more clean energy, and working with B.C.'s Indigenous communities. Further action in these key areas over the next eighteen to twenty-four months will get us closer to our climate goals – while providing an unprecedented economic opportunity for our people, innovators and businesses. We will analyze these opportunities to determine where the strongest job growth is likely to be, and work with employers, labour groups, post-secondary institutions and Indigenous communities to identify the skills and training needed to meet this demand.

We also must prepare for, and adapt to, the unavoidable effects of climate change already impacting our province. Across B.C., average temperatures are increasing and extreme weather is becoming more frequent, with communities devastated by floods and forest fires. Managing these risks – and recognizing that they will have a range of impacts on British Columbians and the communities we live in – is essential to protecting our health and well-being and ensuring our communities and economy continue to thrive.

Working towards reconciliation

We will work in collaboration with Indigenous peoples to seize new clean economy opportunities and help communities adapt to the impacts of climate change. This will include collaboration on a climate change adaptation strategy to be developed for 2020. This collaboration and partnership will be based on reconciliation, respect and the shared goal of a better future for everyone in B.C. CleanBC initiatives must reflect government's commitment and obligation to support the implementation of the United Nations Declaration on the Rights of Indigenous Peoples and the Calls to Action of the Truth and Reconciliation Commission.

Public engagement

We heard from British Columbians in 2018 (*https://engage.gov.bc.ca/cleangrowthfuture/*) and we'll continue to listen as we explore solutions. A new round of engagement will begin in 2019 to inform the next steps of CleanBC, including collaboration with Indigenous peoples. This approach will allow us to update and expand the strategy.

Working together, we can make these changes and reap huge benefits for people across this province. We will continue to collaborate with the federal government. We will build stronger relationships with Indigenous communities. We will work with local governments, businesses, and British Columbians from a range of backgrounds. And we will continue to receive advice from the Climate Solutions and Clean Growth Advisory Council.

MOUNTAIN ADVENTURER GOES ELECTRIC

As one of Canada's leading ski mountaineers, Revelstoke's Greg Hill has travelled the globe. "I realized all that travel was destroying the thing I love most," he says. So he set out to inspire others by completing 100 mountain summits using an electric vehicle.

Greg bought a Chevrolet Volt with help from the $5,000 rebate offered under B.C.'s CEVforBC Program. He has already driven it 50,000km.

"If I can do my job with an electric car, anyone can," Greg says. "It costs me $7 to travel around 400km. And it's a great drive – instant torque, you just put the pedal to the metal and zip away."

2 A CLEAR PATH TO A CLEANER B.C.

This document you're reading now is a pathway to a cleaner future for B.C. It sets out the first part of a long-term strategy for key sectors of our economy – from transportation to industrial processes to our built environment – to use less carbon-intensive energy. The Province has committed to fully funding initiatives that get us to our 2030 climate goals, recognizing that the strategy will be continually updated and expanded as new opportunities arise.

Our work is guided by three goals:

- Protect B.C.'s unique environment to guarantee clean air, land and water for future generations
- Leverage our actions on behalf of the environment to build a stronger, more diverse and more sustainable economy in every part of the province
- Provide the supports people need to make sure that everyone can benefit as we move to a cleaner, healthier B.C.

We're laying out a clear path to meeting our climate action targets by 2030. We're moving forward with a range of new and ambitious actions focusing on transportation, buildings and the CleanBC program for industry. These were developed through public consultations with the people of British Columbia and are targeted to deliver the greatest GHG reductions at the lowest cost while generating jobs and opportunities.

Together, the actions outlined in this document will get us 75 per cent of the way to our 2030 GHG target. Further actions will deliver a plan for the remaining 25 per cent of reductions. Additional engagement will begin in 2019 to ensure that future actions reflect the diverse needs and priorities of British Columbians.

Indigenous peoples will play a significant role in this next chapter. In the past, programs that support sustainable communities and more efficient choices haven't always been available to Indigenous communities – that won't be the case with CleanBC. We recognize the value of Indigenous knowledge. Through the actions we take together in our strategy we will ensure that the values and aspirations of Indigenous peoples are included in the future we are building together.

Going forward, we will continue to engage and collaborate with our partners and consult with the public on how we address our climate goals beyond 2030, to meet our targets for 2040 and 2050.

What this could look like in 2030

Here are some of the things that could be different because of the actions we're taking.

Cleaner transportation and better air quality

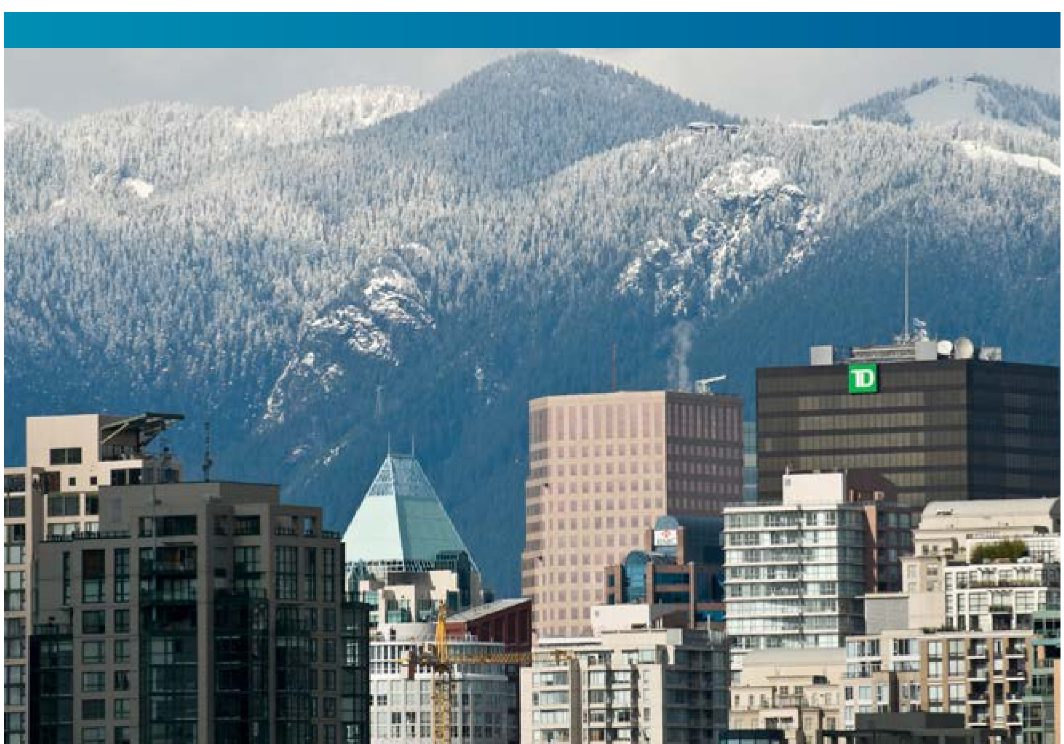
- Almost 500,000 new light duty zero-emission vehicles (ZEVs) and 140,000 plug-in hybrids on the road.
- 15% of the passenger vehicles could be all-electric, 4% plug-in hybrid, and 33% hybrids. That means less than half (48%) would be conventional gas-powered vehicles.
- Over 40% of diesel and 10% of gasoline comes from biofuels.

Healthier, more energy-efficient buildings

- 160,000 new residential heat pumps for space heating instead of natural gas furnaces – a 60% increase covering 600,000 m^2 or more floor space each year from 2019 -2030.
- 53 million m^2 of commercial floor space heated by heat pumps, that's fifteen times as much as today.
- For heating water - 150,000 new residential heat pumps in place of natural gas appliances.

Cleaner industry that cuts pollution

- 60 large industrial operations using heat pumps instead of natural gas.
- Over 55% of natural gas compressors in the oil and gas sector are electric.
- Emissions from 580,000 tonnes of CO_2e are prevented because of innovative technology like carbon capture and storage.



2.1 Getting Around

Whether it's getting the kids to school or getting goods to market, transportation is part of daily life. In B.C. we've done a lot to make it cleaner, from investing in transit and regulating cleaner fuels to providing incentives for zero-emission vehicles.

People are making cleaner choices, and those choices are making a difference: between 2007 and 2016, we lowered our per-person fossil fuel consumption by 10 per cent. That's progress we can build on.

To meet our targets, we must decouple the effects of population and economic growth from emissions growth, while delivering real emission reductions relative to our 2007 base year. Between 2007 and 2016, our economy grew by 19 per cent and our population by 11 per cent. As a result, emissions from the transportation sector rose, with the largest increase – 14.6 per cent – in emissions from regular passenger vehicles. Heavy-duty transport emissions rose by 7.7 per cent. We need to accelerate our move to less polluting and lower-carbon transportation.

With this strategy, we're moving to a future where new vehicles produce no emissions at all – starting with the following actions. Lowering our fuel consumption means lowering fuel costs, which is good for families and businesses. Along the way, the build out of new cleaner transportation technology and infrastructure will stimulate new economic opportunities and development in communities throughout B.C.

2.1.1 *More Zero-Emission Vehicles (ZEVs) on the way*

ZEV standard

Ensuring an ever-greater portion of our personal and commercial vehicle fleet is powered by clean B.C. electricity, hydrogen and renewable fuels is one of the most important steps we can take to reduce our carbon footprint.

Just over 20 years from now, all new light-duty cars and trucks sold in British Columbia will run on clean electricity from batteries or hydrogen fuel cells. Between now and then many of us will be driving plug-in electric hybrids with internal combustion engines as a back-up to ensure we can get where we're going in remote areas. By 2030 or earlier, we expect the price of ZEVs to be about the same as for conventional vehicles – and we can drive the price even lower by drawing more supply to our province.

CleanBC puts B.C. on a path for all new light-duty car and truck sales to be Zero-Emission Vehicles (ZEVs) by the year 2040.

By 2020, we will put in place a ZEV standard to make sure British Columbians have access to the numbers and types of zero-emission vehicles they want. The standard will require automakers to meet an escalating annual percentage of new light-duty ZEV sales, reaching:

- 10 per cent in 2025
- 30 per cent in 2030 and
- 100 per cent by 2040.

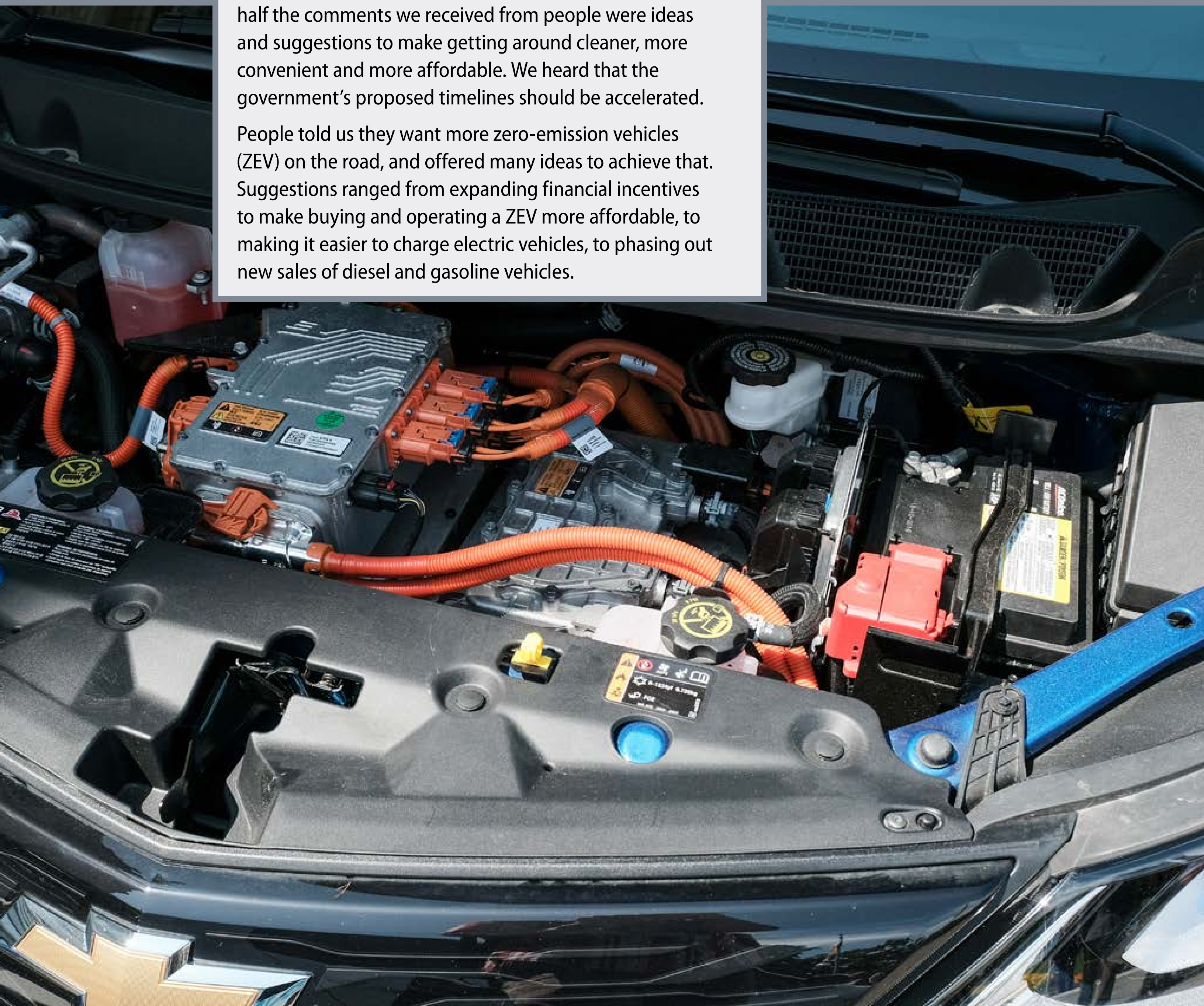
Bringing in the standard over time will allow automakers to offer a greater diversity of models and vehicle types that can meet the needs of drivers throughout B.C.

This ZEV standard is a market transformation tool, helping to ensure that cleaner vehicles are as widely available and competitively priced as possible. It will also support the growth of B.C.'s broader clean energy vehicle (CEV) sector, which includes 198 companies and 3,850 employees. This number will continue to rise as we expand the clean energy vehicle automotive curriculum across the province, as well as support electricians to upgrade their skills to support ZEV infrastructure. The CEV sector contributes approximately $700 million a year in direct economic activity to the province.

WHAT WE HEARD ABOUT CLEAN TRANSPORTATION

No other topic in our public engagement grabbed people's attention like clean transportation. Well over half the comments we received from people were ideas and suggestions to make getting around cleaner, more convenient and more affordable. We heard that the government's proposed timelines should be accelerated.

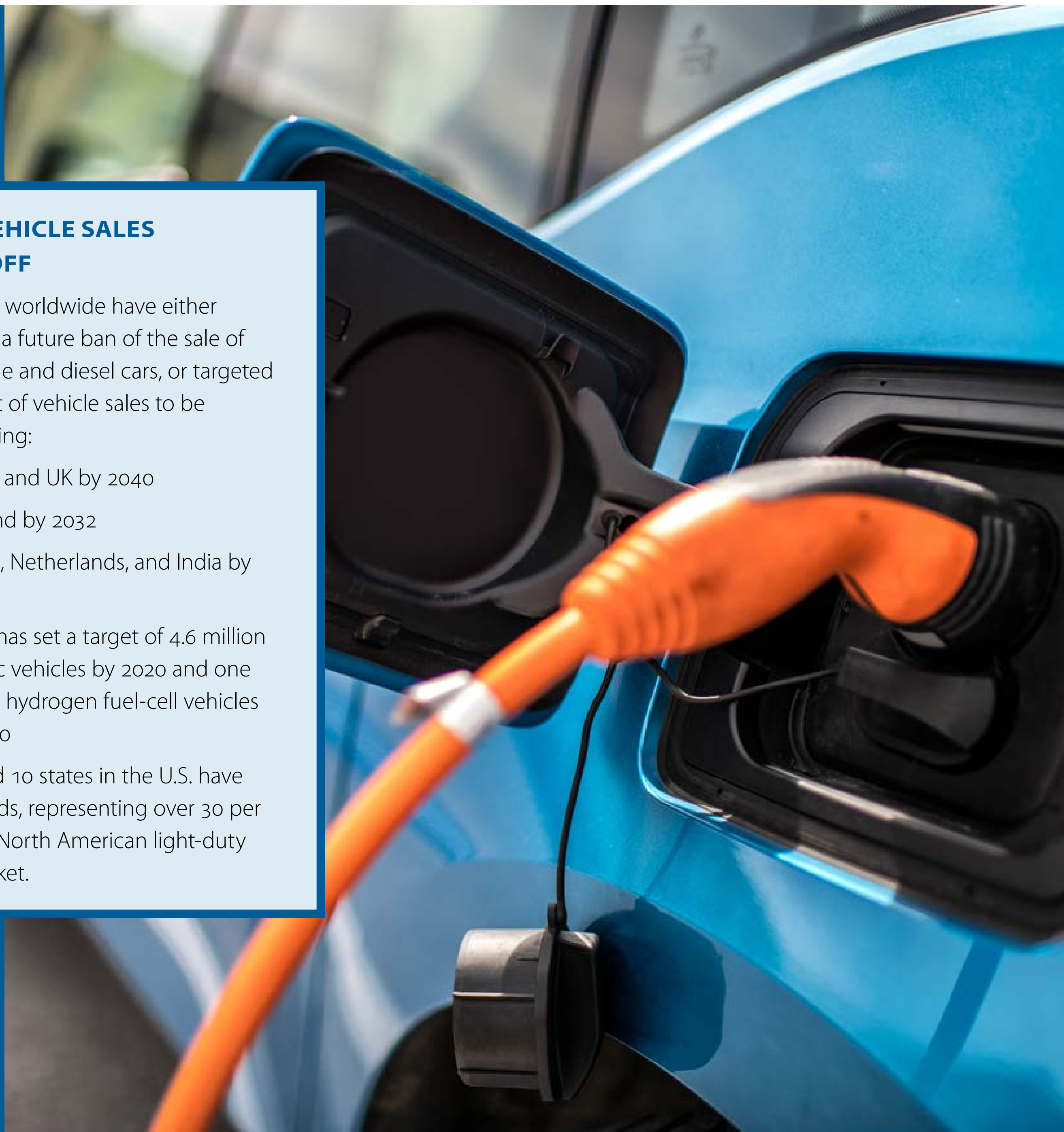
People told us they want more zero-emission vehicles (ZEV) on the road, and offered many ideas to achieve that. Suggestions ranged from expanding financial incentives to make buying and operating a ZEV more affordable, to making it easier to charge electric vehicles, to phasing out new sales of diesel and gasoline vehicles.



Expanding clean vehicle infrastructure

As part of the move to ZEVs, we're making new investments in home and workplace charging, public charging stations and hydrogen fueling stations, so that British Columbians can charge-up in the convenience of their own home or workplace, and anyone can travel throughout the province in their ZEV. The private sector has a big role to play in this new clean energy infrastructure development, and the Province will be addressing barriers to investment in commercial charging, and hydrogen fueling, further expanding consumer choice and confidence for drivers.

We're also exploring ways to help make sure that people in multi-unit housing can charge their cars at home. This will be explored further as we implement CleanBC.



CLEAN VEHICLE SALES TAKING OFF

16 countries worldwide have either announced a future ban of the sale of new gasoline and diesel cars, or targeted 100 per cent of vehicle sales to be ZEVs, including:

- France and UK by 2040
- Scotland by 2032
- Ireland, Netherlands, and India by 2030
- China has set a target of 4.6 million electric vehicles by 2020 and one million hydrogen fuel-cell vehicles by 2030

Quebec and 10 states in the U.S. have ZEV standards, representing over 30 per cent of the North American light-duty vehicle market.

Making the transition towards ZEVs more affordable

Zero-emission vehicles use cleaner energy, improve air quality, and cost dramatically less over time to fuel and operate. But they come with an upfront cost that can be out of reach for many families. Over time, as more makes and models come onto the market, there will be greater choice for consumers and costs will come down. In the meantime, we are committed to helping families make the switch.

ZEV owners save on fuel costs – saving approximately $1,500 every year for the average B.C. driver. And because electric vehicles have fewer moving parts, they typically require less maintenance.

Since 2011 the Province has provided incentives to encourage clean vehicle deployment and technology innovation within British Columbia. Under the CEVforBC program, qualifying British Columbians can get up to $6,000 off the cost of a new clean energy vehicle. Since its inception, the program has helped about 12,000 B.C. residents and businesses.

CleanBC will keep the momentum going by expanding and redesigning the program to offer a new range of incentives for:

- vehicles,
- infrastructure, such as charging stations,
- commercial fleets, and
- public education.

Expanding the program will support the growth of B.C.'s ZEV infrastructure and the broader CEV sector, creating jobs and economic opportunities for companies and organizations involved in all aspects of the supply chain – from raw materials to final consumer products – related to vehicles or vehicle components, fuel and charging infrastructure and transferable technologies and services.

EXTENDING THE RANGE OF LONG-HAUL TRUCKS

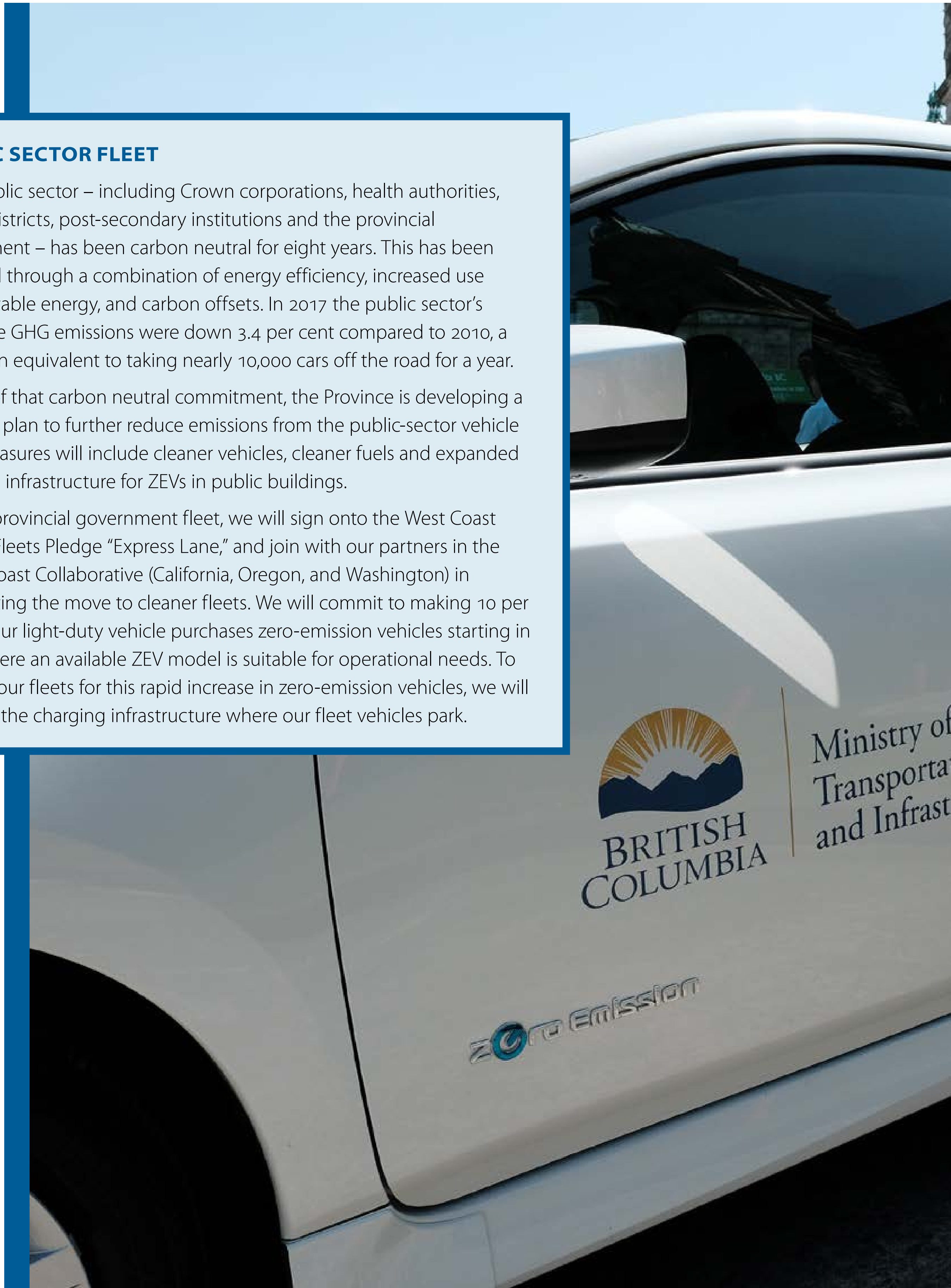
A B.C. company is developing solutions for long-haul trucks with demanding road operations, towing up to 80,000 pounds of freight throughout the San Diego and Los Angeles regions. Loop Energy's fuel cell technology is part of a range of technological advancements used in the hybrid-configured trucks to extend their operating range beyond 200 miles (322 km) – without the need for refueling or recharging. Based in Burnaby, Loop develops and supplies this innovative technology and other zero-emission products for vehicle manufacturers.

PUBLIC SECTOR FLEET

B.C.'s public sector – including Crown corporations, health authorities, school districts, post-secondary institutions and the provincial government – has been carbon neutral for eight years. This has been achieved through a combination of energy efficiency, increased use of renewable energy, and carbon offsets. In 2017 the public sector's collective GHG emissions were down 3.4 per cent compared to 2010, a reduction equivalent to taking nearly 10,000 cars off the road for a year.

As part of that carbon neutral commitment, the Province is developing a five-year plan to further reduce emissions from the public-sector vehicle fleet. Measures will include cleaner vehicles, cleaner fuels and expanded charging infrastructure for ZEVs in public buildings.

For the provincial government fleet, we will sign onto the West Coast Electric Fleets Pledge "Express Lane," and join with our partners in the Pacific Coast Collaborative (California, Oregon, and Washington) in accelerating the move to cleaner fleets. We will commit to making 10 per cent of our light-duty vehicle purchases zero-emission vehicles starting in 2020, where an available ZEV model is suitable for operational needs. To prepare our fleets for this rapid increase in zero-emission vehicles, we will improve the charging infrastructure where our fleet vehicles park.



CLEANER FERRIES

BC Ferries is joining the move to cleaner fuels and cleaner vessels, with three new intermediate-class "dual fuel" ships, capable of operating on liquified natural gas (LNG) or marine diesel. It's also converting the second of its two largest Spirit Class vessels to dual fuel, with a return to service planned by summer 2019.

For our inland ferry fleet, the future is electric. The Province is taking incremental steps in that direction as available technology increasingly supports ongoing safe, reliable and efficient service. We aim to achieve full electrification of the inland ferry fleet by 2040.

BUILDING ON OUR LEGACY OF MARINE TRANSPORTATION

Richmond's Corvus Energy has become a world leader in energy storage systems, including batteries for marine vessels. These systems cut carbon pollution, improve safety, and protect our clean air – while saving on fuel costs.

Corvus is growing rapidly. Their revenue has increased tenfold since 2016. To keep up, Corvus has quadrupled their production capacity, creating new jobs in B.C. Now, Seaspan Ferries is using this homegrown clean technology in two of their vessels, with plans for electricity to power future vessels. BC Ferries is also including it in their fleet upgrade.

2.1.2 *Speeding up the switch to cleaner fuels*

Zero-emission vehicles will do a lot to clear the air and bring down B.C.'s GHG emissions. But that transition will take time, and there will still be cases where liquid transportation fuels are needed. So we are also taking steps to reduce emissions from conventional vehicles so that they burn cleaner fuel.

Expanding B.C.'s low-carbon fuel standard

First, we're expanding the Province's Renewable and Low Carbon Fuel Standard. Low carbon fuels are created by blending in fuels from renewable sources such as vegetable oils, waste cooking oil, and forest and municipal organic waste. We currently require a 10 per cent reduction in the carbon intensity of fuels by 2020.

CleanBC increases the low-carbon fuel standard to 20% by 2030.

Moving forward, the standard will require suppliers to reduce the carbon intensity of diesel and gasoline by 20 per cent by 2030. Carbon intensity is measured on a lifecycle basis, taking into account all emissions including those from fuel production.

By further decreasing the carbon intensity over time, we can reduce carbon pollution even more. This one step achieves significant reductions in B.C.'s impact on the environment and the climate.

Increasing the supply of renewable fuels

To meet the increased demand for cleaner fuels, we will work with renewable fuel providers to ramp up new production of 650 million litres of renewable fuels by 2030. That's about eight per cent of our total annual fuel use.

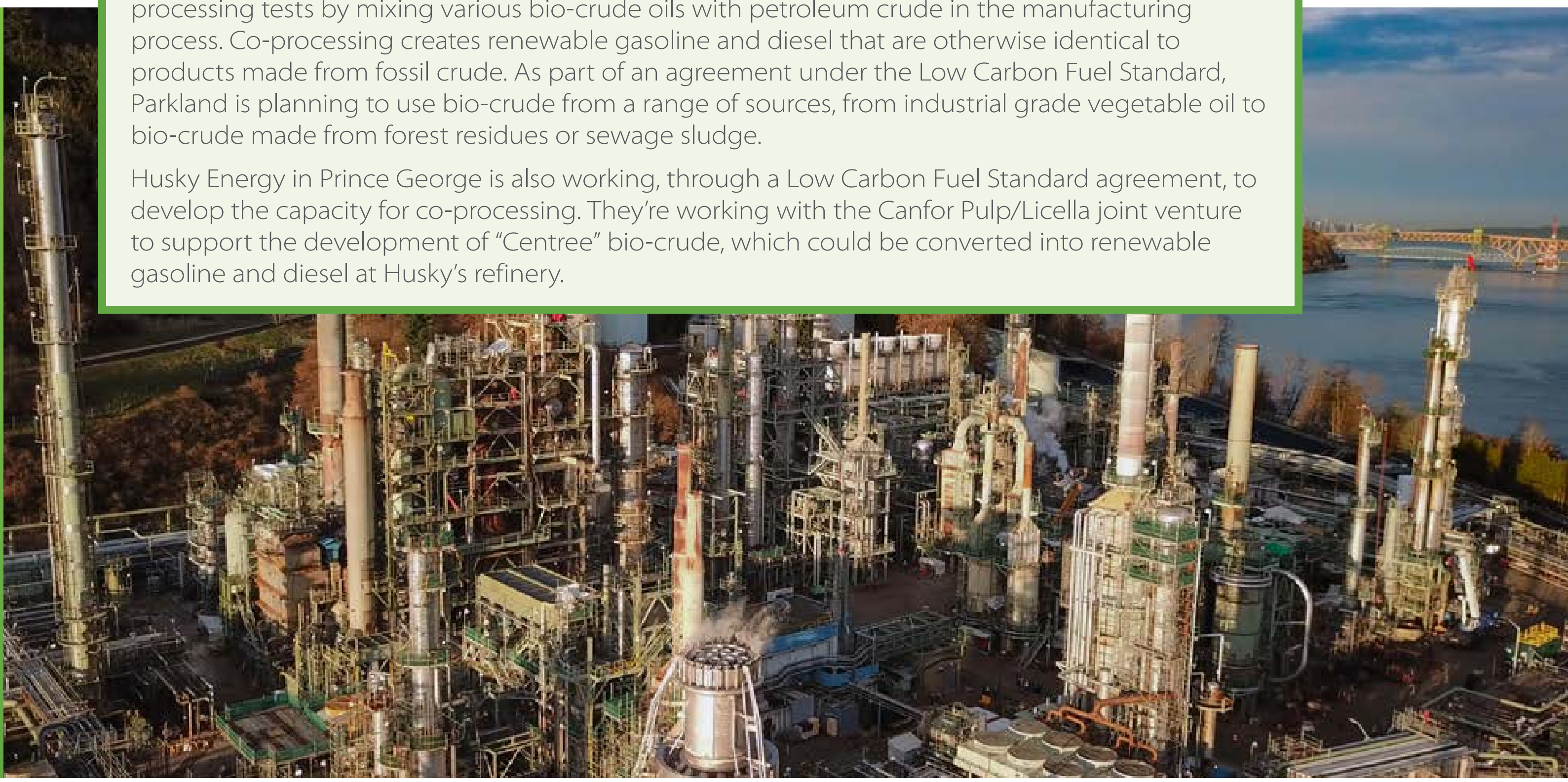
The good thing is that there are plenty of sources for bio-fuels that are underused – including forest and municipal organic waste. We are also working with our two B.C. refineries in Burnaby and Prince George to develop the ability to refine both fossil crude and green crude made from a variety of waste and renewable sources.

Together these two initiatives will deliver major improvements by cutting emissions and air pollution province-wide. They will also have a significant economic impact. Refining our own renewable fuels, with B.C. materials and B.C. workers, will lead to job growth and reduce the need to import fossil fuels and feedstock from other jurisdictions.

REFINING RENEWABLE FUELS

Over the last two years, Parkland Refining in Burnaby has been running commercial scale co-processing tests by mixing various bio-crude oils with petroleum crude in the manufacturing process. Co-processing creates renewable gasoline and diesel that are otherwise identical to products made from fossil crude. As part of an agreement under the Low Carbon Fuel Standard, Parkland is planning to use bio-crude from a range of sources, from industrial grade vegetable oil to bio-crude made from forest residues or sewage sludge.

Husky Energy in Prince George is also working, through a Low Carbon Fuel Standard agreement, to develop the capacity for co-processing. They're working with the Canfor Pulp/Licella joint venture to support the development of "Centree" bio-crude, which could be converted into renewable gasoline and diesel at Husky's refinery.



HESQUIAHT FIRST NATION CREATES CLEAN ELECTRICITY

The Hesquiaht First Nation is building a small hydropower plant to take advantage of their abundant hydro resources and create clean electricity. This energy will replace 70 per cent of the Hot Springs Cove community's diesel use, supporting local employment while cutting carbon pollution.

By reducing their reliance on diesel, the community will also save money, eliminate the noise from generators, and remove associated environmental and health concerns. The Hesquiaht First Nation is demonstrating how we can protect our natural environment, while seizing the opportunity of clean economic growth.

Showing the value of clean energy

B.C.'s carbon tax is designed to apply to all fossil fuels used in the province. In the transportation sector, carbon tax rates on gasoline and diesel were reduced to align with the introduction of the renewable fuel standard in 2010, which mandated renewable content in fuels sold in B.C.

As the portion of renewable fuels grows and a variety of fuel blends become available across the province, we'll examine ways to make the carbon price on fuels easy to identify and easy to understand. We will also look at ways to enhance the value of low carbon choices for consumers and for industry.

2.1.3 Less time in gridlock

It's not an option for everyone, but driving less can help reduce costs, stress and the risk of accidents, not to mention cutting back on greenhouse gas emissions and air pollution. In 2019, the Province will establish an active transportation strategy with measures to support new infrastructure, education and incentive programs, and safety improvements for people walking, cycling and using other kinds of active transportation. The Province will also offer incentives to local governments and public-sector organizations to reduce the need for commuting – so people can spend less time in their cars.

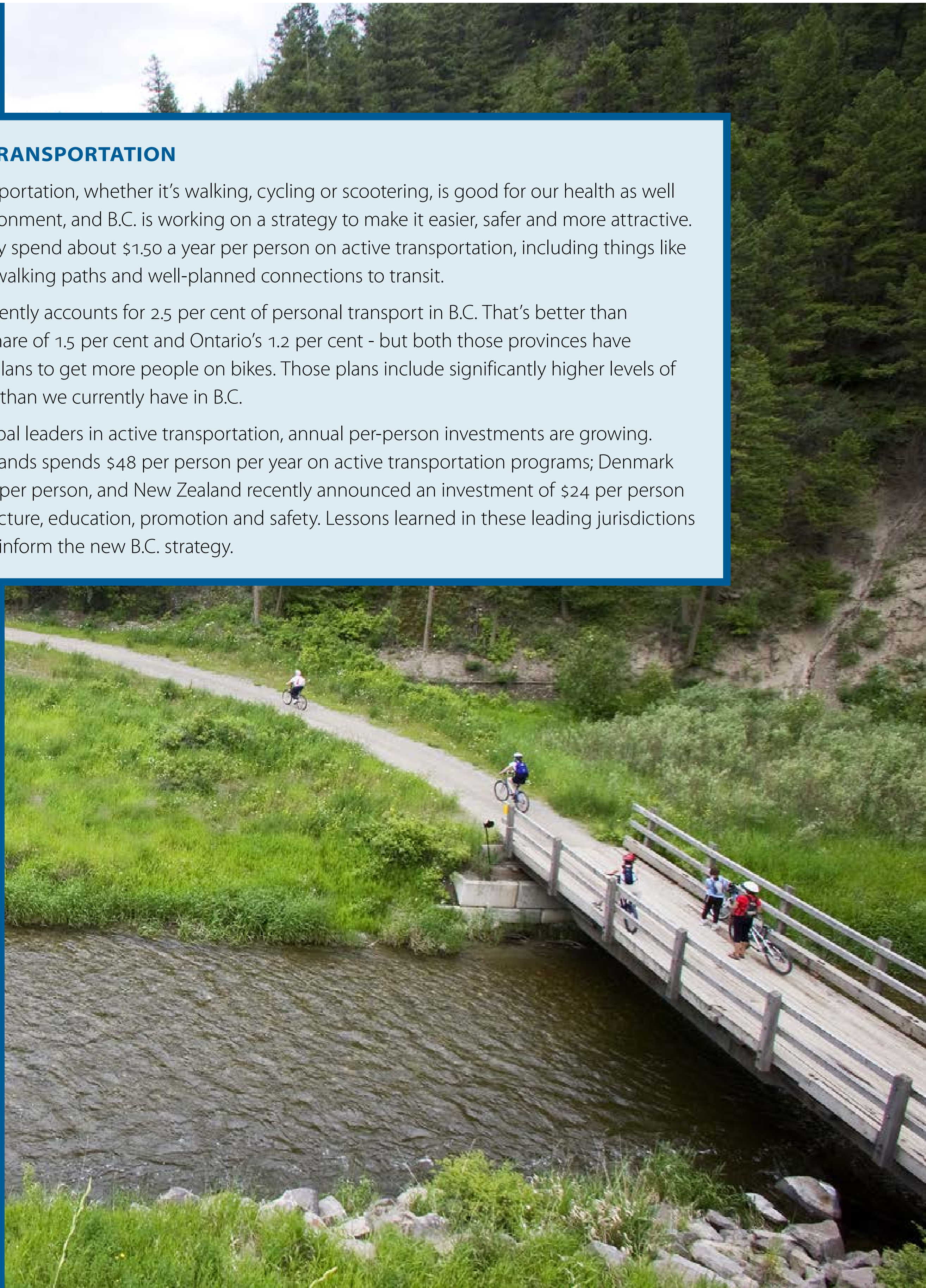
CleanBC will build on the comprehensive range of initiatives already well underway in the province to cut congestion, pollution and GHG emissions. For example, in the next 10 years, B.C., the federal government and local governments will invest more than $8 billion under the Public Transit Infrastructure Fund and the Investing in Canada Infrastructure Program to expand and improve public transit in B.C. with new rapid transit lines, new SkyTrain cars in Metro Vancouver, and new buses across the rest of the province. Other investments will include system and facility upgrades, better communications technology, and new transit exchanges, park and rides, and bus shelters.

We are committed to making transit more accessible and efficient. We're also making it cleaner. BC Transit is continually monitoring the market for ways to improve fuel efficiency and reduce emissions on older buses. Meanwhile TransLink is on its way to phasing out the purchase of diesel buses altogether. More than a quarter of its overall fleet already runs on electricity.

As we expand our transportation infrastructure, we're making sure that major projects like new bridges and interchanges are designed to make walking, cycling and transit use as safe and convenient as possible. Since 2014, we've also provided more than $30 million in grants to communities through BikeBC to support cycling infrastructure and cycling tourism.

In 2019, we will be engaging British Columbians on more ways to reduce traffic, congestion and transportation costs including community design and lifestyle choices.

By 2030, these initiatives are projected to achieve 6.0 Mt of GHG reductions



ACTIVE TRANSPORTATION

Active transportation, whether it's walking, cycling or scootering, is good for our health as well as the environment, and B.C. is working on a strategy to make it easier, safer and more attractive. We currently spend about $1.50 a year per person on active transportation, including things like bike lanes, walking paths and well-planned connections to transit.

Cycling currently accounts for 2.5 per cent of personal transport in B.C. That's better than Quebec's share of 1.5 per cent and Ontario's 1.2 per cent - but both those provinces have ambitious plans to get more people on bikes. Those plans include significantly higher levels of investment than we currently have in B.C.

Among global leaders in active transportation, annual per-person investments are growing. The Netherlands spends $48 per person per year on active transportation programs; Denmark invests $34 per person, and New Zealand recently announced an investment of $24 per person on infrastructure, education, promotion and safety. Lessons learned in these leading jurisdictions will help to inform the new B.C. strategy.

2.2 Improving Where We Live and Work

Our homes, schools, workplaces and other buildings play a big role in a cleaner province and a stronger economy.

For example, the green building industry now employs approximately 32,000 British Columbians in jobs ranging from architecture to manufacturing to installation. These are jobs in communities across B.C. Every dollar we invest in energy efficiency generates up to four times its value in economic growth. Then there are the benefits of living and working in a greener building, like greater comfort, lower energy use, and better air quality – both indoors and in your neighbourhood.

Every dollar we invest in energy efficiency generates up to four times its value in economic growth.

We've been moving in this direction for a while and our actions are making a difference. Between 2007 and 2016, greenhouse gas emissions from residential buildings shrank by more than 11 per cent, while emissions from commercial buildings were down 6 per cent.

When we build better buildings, we are putting new skills and newly skilled workers to work, and the building or home owner is going to save money in the long run. Building technologies are a place where the B.C. technology sector excels. We have been a proving ground for building energy management systems and low carbon building materials, and now we will build on that foundation of innovation. CleanBC will help us move forward to a future where buildings produce no emissions at all – starting with the following actions.

2.2.1 *Better Buildings: every building is more energy efficient*

By 2032, all new buildings constructed in B.C. will be "net-zero energy ready." Net-zero energy ready buildings are designed to be so efficient that they could meet all or most of their own energy consumption requirements with onsite renewable energy technologies. The change will be enacted step by step through the BC Building Code, which applies to all new construction in the province. Compared to the current base BC Building Code, new homes will be:

- 20 per cent more energy efficient by 2022,
- 40 per cent more energy efficient by 2027, and
- 80 per cent more energy efficient by 2032 – the net-zero energy ready standard.

New standards for building upgrades will be developed by 2024, guided by the model National Energy Code. Under this new code, upgrades to existing buildings will bring them up to modern standards for efficiency and comfort. This approach is designed to make the benefits of upgrading affordable and accessible, regardless of whether you own or rent.

Between 2022 and 2025, new energy efficiency standards will be set for space heaters, water heaters and residential windows. These will build on improvements introduced in 2018, which set new standards for lighting, air source heat pumps and gas fireplaces.

B.C. is also exploring an energy rating requirement for homes and buildings across the province at the point of sale or lease, similar to what we've seen on vehicles and appliances for many years. The process for generating ratings will be developed in consultation with stakeholders, with the goal of making it as simple and inexpensive as possible. The rating system would make it easier for buyers and renters to factor energy costs into their decisions while giving owners another incentive to make their buildings more efficient.

ENERGY EFFICIENCY UPGRADES IMPROVE LIFE FOR SENIORS

Creston's Erickson Golden Manor houses a vibrant community of seniors. They received a grant for energy efficiency upgrades, including replacing their "window shaker" air conditioners with heat pumps that both warm and cool.

"The quality of life of the tenants has improved 100 per cent," says Irene Walker, Chair of the Erickson Golden Agers Association. "We are reducing our energy consumption and saving money. It doesn't get any better than that."

The Columbia Basin Trust's Energy Retrofit Program improved the energy efficiency of 46 buildings in 16 communities, representing over 930 affordable housing units.

WHAT WE HEARD ABOUT HOME AND BUILDING RETROFIT SUPPORT

During our 2018 online engagement about Clean, Efficient Buildings, British Columbians were clear they could use some help in paying for upgrades that would make their homes and buildings more energy efficient. In fact, this was one of the most popular topics of the whole engagement.

While people acknowledged that retrofits will reduce their energy use, they were concerned that these improvements require upfront costs that can be out of reach. To that end, people suggested government not only continue but expand incentives and other financing options to help home and building owners improve energy efficiency.

2.2.2 *Supporting Better Buildings now*

Changing codes and standards will make our buildings more efficient in the years to come. In the meantime, there's a lot we can do to improve the buildings we already have. For example, replacing an old natural gas furnace with an energy efficient heat pump can cut a building's space heating energy needs by 50 per cent or more, helping to make life more affordable over the long term. High efficiency windows and doors not only keep you comfortable but also shut out noise and UV rays. On a smaller scale, smart thermostats can help home and business owners reduce energy costs by up to 15 per cent, recouping their investment within months.

The Province has created the EfficiencyBC program to help people conserve energy and make their buildings healthier and more comfortable.

Launched in September 2018 with matching federal funds, EfficiencyBC offers:

- Rebates for homeowners to lower the cost of heat pumps and windows; these are integrated with incentives from utilities for insulation and other energy-saving upgrades
- Financial incentives for commercial and multi-unit residential buildings to do energy-saving studies and upgrades
- A single application for EfficiencyBC, BC Hydro, FortisBC, and local government incentives
- Free energy coaching services for homes and businesses, including a phone and email hotline staffed by energy coaching specialists
- A one-stop-shop website with an incentive search tool and useful information on options for energy efficiency upgrades
- Rebates and direct installations of energy efficiency improvements for lower-income households, starting in 2019.

These measures are helping but we need to do more to make energy-saving improvements accessible and affordable for all British Columbians. In the next three years, EfficiencyBC will expand significantly to reach more homes and businesses. It will also offer:

- targeted low-interest financing – allowing people to make improvements and pay for them over time with savings from their energy bills,
- specialized support for small businesses, and rental housing,
- specialized support for Indigenous and non-Indigenous communities, and
- high-efficiency equipment incentives for new construction.

HIGH-EFFICIENCY HEAT PUMPS

Heat pumps work by extracting heat from the air or ground outside and pushing it inside to heat your home – or pushing it out in the warmer months to keep your home cool. Because they move heat directly, rather than converting fuel into heat, they're more efficient than baseboard heaters or furnaces. When properly installed they use a third to a half as much energy. And heat pumps can be enhanced with filters that keep out pollution, dust and pollen.

As more people consider heat pumps, the Province is helping to make them more affordable. Through EfficiencyBC you can now access:

- Up to $1,200 for replacing your electric heating system with a heat pump
- $2,000 for replacing your oil, propane, or natural gas heating system with a heat pump

Some local governments offer up to an additional $2,000 for converting from natural gas, oil, or propane to an electric air-source heat pump

For more on heat pumps, including help to decide which type is right for you, go to *EfficiencyBC.ca/heatpumps*. For more on incentives, go to *EfficiencyBC.ca/incentives.*

Renewing public housing

Energy performance is a key part of B.C.'s work to improve public housing. The Province has launched a $1.1 billion, 10-year Capital Renewal Fund to support the improvement and preservation of existing, aging public housing stock in B.C. Of this, $400 million is targeted to energy performance improvements that will lead to greenhouse gas emission reductions.

Cleaner public-sector buildings

New schools, hospitals and other facilities continue to be built in B.C. to achieve high levels of environmental performance, meeting Leadership in Energy and Environmental Design (LEED) Gold certification or equivalent. On average, these facilities have been designed to perform 40 per cent better than LEED's reference energy standard.

With this strategy we're also taking steps to make our existing stock of buildings cleaner, smarter and more energy efficient by taking advantage of the latest proven technologies. Early analysis of net-zero construction shows that savings more than make up for any added costs. As we retrofit older public buildings in communities throughout B.C. we'll create opportunities for local businesses, Indigenous peoples, professions and trades to develop the new energy step code skills and expertise to retrofit other buildings in their communities. For every one per cent improvement in its energy efficiency, including buildings and vehicles, B.C.'s public sector reduces its energy costs by an estimated $4 million a year.

BIG ENERGY SAVINGS FOR UVIC STUDENT HOUSING

A new student housing project at the University of Victoria will accommodate 782 students – it'll be built to the Passive House standard, the world's leading standard for energy-efficient construction and equivalent to the highest step of the BC Energy Step Code. The building will use 75% less energy for heating, and at least 50% less overall energy than a typical construction design. The project replaces three aging buildings, helping the university to save on energy costs and provide more comfortable housing for students. During their construction, the new buildings will provide apprenticeships, project work and supply opportunities for local people and businesses.

Low Carbon Buildings Innovation Program

Starting in 2019, the Province will offer new incentives for builders, developers and manufacturers to stimulate the development and demonstration of innovative, low-carbon building solutions. The Low Carbon Buildings Innovation Program will accelerate the availability, acceptance and affordability of high performance solutions such as advanced building designs, advanced construction methods and ultra-efficient building components.

Funding will be available for projects in three categories, through bi-annual competitive calls:

- Research – building solutions that show promise but may require further innovation before being commercialized (e.g. vacuum insulated wall panels and windows, natural gas heat pumps);
- Commercialization – building solutions that have been tested and are ready to be scaled up for wider application (e.g. high-performance prefabricated external insulation systems); and
- Demonstration – building solutions currently available in the marketplace that require demonstration to build industry capacity and public acceptance (e.g. such as net-zero energy ready construction).

Along with stimulating the development of new ideas, the program will prove to the market that existing technologies work and deliver their intended benefits. This will increase the capacity of B.C.-based industries, generate consumer confidence, and help to lower the costs of new technologies and building approaches over time.

WOOD FIRST

B.C. wood is a natural choice for low carbon building. Wood is the only building material grown by sunlight, with a lighter carbon footprint than other common building materials, and is much less greenhouse gas intensive on a life cycle basis. It's also the only structural building material with third-party certification systems to verify that products have come from a sustainably managed resource.

Through its Wood First program, the Province encourages the forest industry, researchers and design professionals to innovate in B.C.'s built environment through value-added wood products – helping to grow local and global markets, while promoting climate-friendly construction and supporting our forest sector.

2.2.3 *Help for communities*

Support for remote communities

Most people in B.C. have no trouble plugging into clean electricity. It's a different story in remote and off-grid communities – many of which are Indigenous communities – where power has to be generated locally, typically with diesel-fired generators.

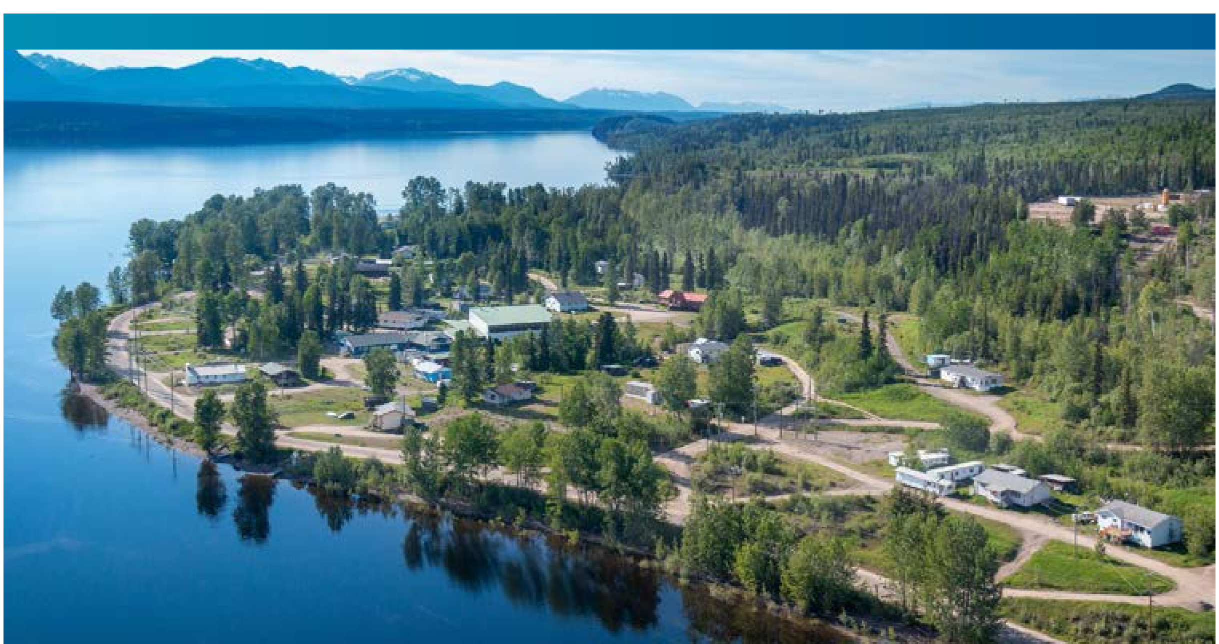
Apart from causing harmful air pollution and greenhouse gas emissions, burning diesel is the most expensive way to generate electricity. It also limits communities' potential growth and development opportunities.

As part of CleanBC, we're investing to help remote communities reduce or eliminate diesel generation and replace it with energy from cleaner sources. The funding will support a new Remote Community Clean Energy Strategy in partnership with utilities and the federal government. The four pillars of action under the Strategy are:

- support communities to develop expertise and experience in energy efficiency and clean generation;
- retrofit existing homes and buildings to make them highly energy efficient;
- develop renewable heating systems, including heat pump technology and district energy systems; and
- implement renewable energy projects to offset all or most remaining diesel generation, including rooftop solar photovoltaic and community-scale renewable systems.

By 2030, the Strategy targets the implementation of all four pillars in the remote communities served by the 22 largest diesel-powered electricity generation stations in B.C. (12 BC Hydro stations and 10 Indigenous Services Canada stations). The Strategy aims to reduce province-wide diesel consumption for generating electricity in remote communities by 80 per cent by 2030.

Additional support will be directed to the BC Indigenous Clean Energy Initiative, with matching funding from the federal government. The money will support project planning, feasibility and design in on-grid and off-grid Indigenous communities who are working to advance energy efficiency and clean energy projects.



KWADACHA FIRST NATION TURNS WOOD WASTE INTO ELECTRICITY

The Kwadacha First Nation is a community only accessible by logging roads or air. In the past, this meant relying on diesel power. Today, the Kwadacha have built a biomass plant that generates electricity and heat, cutting carbon emissions by approximately 20%.

This is the first known remote, off-grid application of biomass gasification-to-electricity in North America, and probably the world. The plant generates heat and power using wood chips from the abundant supply of trees killed by the pine beetle. The heat is used by a nearby school and greenhouses.

"We ran off diesel for too long, and this project brings some much-needed infrastructure to our very remote community," said Kwadacha Nation Chief Donny Van Somer. "Thank you to all those who helped along the way – this has created a few much-needed jobs and is a step closer to our vision of self-sustainability."

CleanBC Communities Fund

With this strategy, we're also investing – in partnership with the federal government –$63 million to help local governments and Indigenous communities develop energy efficiency and clean energy projects. The CleanBC Communities Fund (CCF) will encourage investments in small-scale, community-owned energy generation from sources such as biomass, biogas, geothermal heat, hydro, solar, ocean or wind power to offset community energy use. The fund will start accepting applications this year with $63 million of combined federal and provincial funding available for the first wave of capital funding. Projects will have to achieve at least one of the following outcomes:

- Increase the community's capacity to manage renewable energy,
- Increase access to clean energy transportation,
- Increase the energy efficiency of buildings, or
- Increase generation of clean energy.

Encouraging investments in small-scale, Indigenous and non-Indigenous community-owned projects will help all British Columbians make the transition away from fossil fuels. It will also generate new economic activity, new jobs, and advance B.C.'s clean energy sector.

By 2030, these initiatives are projected to achieve* 2.0 Mt *of GHG reductions

2.3 Reducing Waste And Turning It Into A Resource

Waste is an issue of great concern for British Columbians and can be expensive and difficult to manage for many communities. Organic waste now makes up 40 per cent of municipal landfills. Industrial and agricultural organic waste is also increasing, generating methane – a powerful greenhouse gas. This plan includes targeted measures to reduce the amount of organic waste we produce and to make better use of it. Preventing waste in the first place remains key to emission reductions, while in some cases organic waste can be used to generate cleaner sources of energy for use in homes and transportation.

Addressing organic waste is a component of a larger approach to a "circular economy" that we will address in coming initiatives. A circular economy approach values waste as a resource and moves away from the throw-away model we are used to. Growing our economy doesn't have to mean using more

COFFEE ROASTER GOES GREEN AND GROWS BUSINESS

In 2009, B.C.'s Oughtred Coffee began a journey to measure and reduce their carbon footprint. They started with waste management, where they were able to divert over 90 per cent of their waste to recycling, while also helping start a social enterprise that turns burlap coffee sacs into reusable totes and backpacks.

They reduced both emissions and costs by investing in energy and water efficiency, as well as upgrading to a new roaster. Now, the company has cut emissions by 50 per cent and been carbon neutral for a decade, all while growing the volume of coffee they roast.

SURREY TURNS ORGANIC WASTE INTO RENEWABLE FUEL

As organic landfill waste breaks down, it creates biogas, a significant source of emissions. At the new Surrey Biofuel Facility, this waste is turned into clean products – biogas is used to make renewable natural gas, while the solid remains become compost for farms and gardens.

Surrey is putting this renewable fuel to good use, using it in garbage trucks and service vehicles, and in the future, to power a District Energy System for their City Centre. Surrey is showing communities across B.C. how they can close the loop on waste.

energy and resources. By designing waste out of the system, we will gradually transition to re-using more materials and creating more renewable energy sources that support our climate and economic goals.

Using our waste to increase our supply of renewable fuels

Not only is methane a powerful greenhouse gas, it's a source of energy we can't afford to waste. While we are producing natural gas for use in B.C. and for export, millions of cubic metres of methane are escaping into the atmosphere from our landfills, agricultural operations and sewage treatment plants. This is the same methane as the natural gas in pipelines, and we can use it to meet the same cooking and heating needs. When we capture methane from organic sources such as farms and landfills it reduces carbon emissions and becomes a renewable source of energy.

CleanBC will put in place a minimum requirement for 15 per cent renewable content in natural gas by 2030.

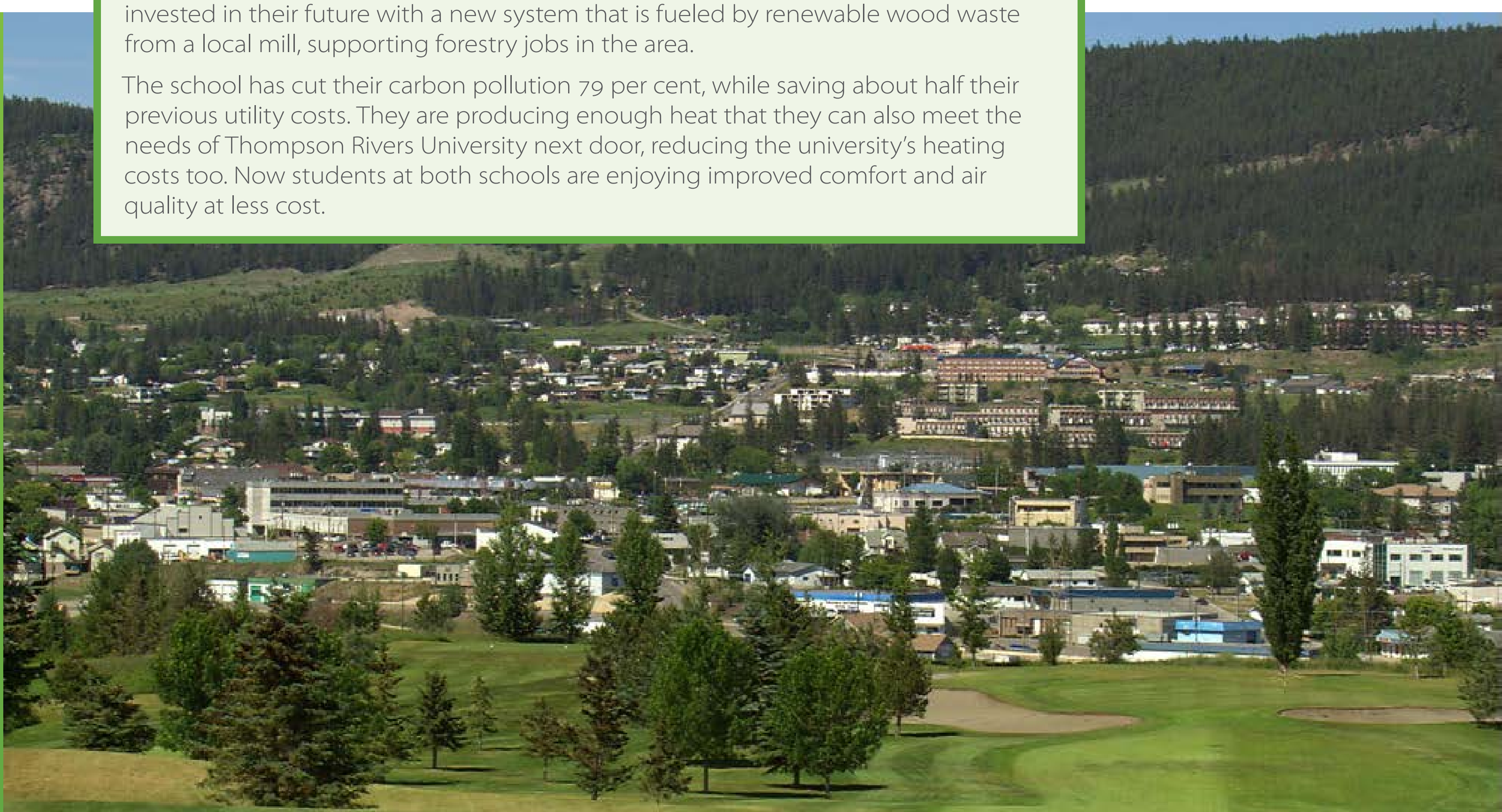
As part of CleanBC, we will work with natural gas providers to put in place a minimum requirement for 15 per cent renewable content in natural gas by 2030. That means the gas we use in our furnaces, water heaters, dryers, stoves and other gas appliances will have less impact on the environment, and the methane that is wasted from agriculture, sewage and landfills will be significantly reduced. Waste hydrogen can also be mixed with the natural gas we use in our homes and will provide additional renewable natural gas for our needs.

We will work with communities and support them to achieve 95 per cent organic waste diversion from municipal, industrial, and agricultural sources by 2030 – some of which will supply the new standard for renewable content – and maintain our commitment to capture 75 per cent of landfill gas.

WOOD WASTE KEEPS WILLIAMS LAKE STUDENTS WARM

Cataline Elementary School's outdated heating system needed replacement. So, they invested in their future with a new system that is fueled by renewable wood waste from a local mill, supporting forestry jobs in the area.

The school has cut their carbon pollution 79 per cent, while saving about half their previous utility costs. They are producing enough heat that they can also meet the needs of Thompson Rivers University next door, reducing the university's heating costs too. Now students at both schools are enjoying improved comfort and air quality at less cost.

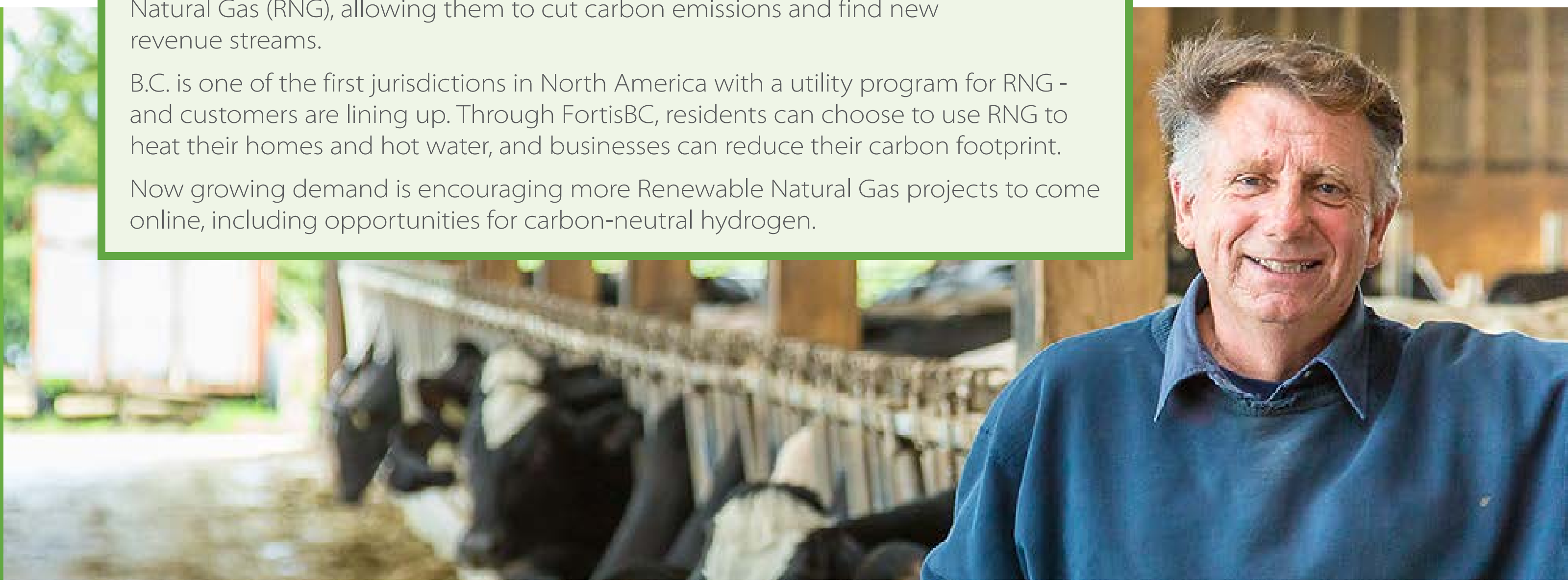


GROWING DEMAND FOR RENEWABLE NATURAL GAS

Across B.C., farms, landfills and other facilities are turning waste into Renewable Natural Gas (RNG), allowing them to cut carbon emissions and find new revenue streams.

B.C. is one of the first jurisdictions in North America with a utility program for RNG - and customers are lining up. Through FortisBC, residents can choose to use RNG to heat their homes and hot water, and businesses can reduce their carbon footprint.

Now growing demand is encouraging more Renewable Natural Gas projects to come online, including opportunities for carbon-neutral hydrogen.



Renewing our bioenergy strategy

With growing requirements for renewable energy and fuel sources, B.C. will renew its bioenergy strategy, creating opportunities to turn organic waste into products and energy in areas such as agriculture, forestry and municipal organics. Key components of the strategy will include:

- investing in new biocrude refining capacity to meet our production target of 650 million litres
- helping communities develop and deploy clean technologies
- investing in bioenergy technologies and companies
- expanding production of renewable natural gas
- establishing a Centre of Excellence for Biofuels that leverages the work of the BC Bioenergy Network
- identifying and developing viable sources of hydrogen
- working with the forest sector, Indigenous and non-Indigenous communities, and the technology sector to advance the use of forest residuals for advanced building materials, commercial products and renewable fuels

Engagement, collaboration, and consultations on the strategy will begin in Spring 2019.

By 2030, these initiatives are projected to achieve 0.7 Mt of GHG reductions

2.4 Cleaner Industry

An economic opportunity for all British Columbians

Along with our actions to reduce GHG emissions, CleanBC provides an effective blueprint to grow our economy. Working to create the cleanest industries in the world, B.C. companies can be first movers and capture a significant share of the growing clean energy and low-carbon products market.

A strong economy means thriving industry, a well-educated and diverse workforce, good jobs and sustainable growth. For the past decade and beyond, B.C. industry have worked to reduce their carbon footprint, and have become models internationally for how to lower emissions. There is still work to do. As industry grows, so too do their emissions, making the actions in this plan all the more important. As industry continues to work with the clean tech sector to develop innovative solutions to reducing emissions, we can market our products, services, and technology to a world that is more and more interested in clean solutions.

The global market for clean tech solutions is projected to be worth $3 trillion by 2020. B.C. already has a global brand that's recognized for quality. CleanBC provides another opportunity to build that brand and increase global market penetration while stable, efficient companies and industries will ensure a continuing supply of good jobs for British Columbians across the province.

Towards a low-carbon industrial strategy

As part of CleanBC, the Province has signed a Memorandum of Understanding with the Business Council of British Columbia, setting out a framework for a joint approach to unlocking B.C.'s full economic potential. Together, we will develop a low-carbon industrial strategy that builds on our competitive advantages and leverages further advancements to position and market B.C. companies to the world.

The strategy will focus on:

- Positioning B.C. as a destination for new investment and industry looking to meet the growing global demand for low-carbon products, services, and pollution-reducing technologies
- Enhancing British Columbia's competitive advantages while reducing our own GHG emissions intensity and helping avoid carbon leakage
- Advancing innovation that's focused on lowering emissions and reducing climate pollution
- Supporting economic opportunities for Indigenous peoples and communities, and
- Enhancing and marketing a clean B.C. brand internationally.

The MOU acknowledges that energy-intensive, trade-exposed industries may face unequal pressure from jurisdictions without carbon taxes, and commits both parties to keeping our industries competitive.

B.C. is already home to many world leaders in innovative technology and clean energy innovations. We account for nearly 35 per cent of Canada's clean tech firms. These 270 plus companies generate $1.8 billion in revenues and employ more than 8,500 people across the province.

By supporting the good work that's already happening, and providing support and incentives for all sectors to lower their environmental impact, we will create a larger customer base and new markets across B.C., enabling our clean tech companies to test their products, scale-up, employ more people and expand their sales to a global marketplace. All of this helps us grow and diversify our already world-leading clean tech sector.

For example, initiatives related to low carbon transportation and energy efficient home and business retrofitting will rapidly expand demand for products and services in communities across B.C. New businesses will be needed to meet this demand and they will provide good, sustainable jobs for British Columbians.

To further assist in these efforts, the Province will continue to align our innovation and entrepreneurship investments so that we can provide essential supports for the development and commercialization of the clean energy products and technologies industry needs. This approach will allow us to build on the global achievements of successful B.C. technology companies and support new and existing small and medium-sized enterprises as they capture new opportunities.

Markets for clean technology are expected to grow as millennials have indicated an even higher willingness to reduce GHG emissions. As we move forward with CleanBC, we will be reaching out to younger British Columbians to engage them directly in building our cleaner future.

CLEAN TECH COMPANIES LEADING THE WAY

Led by Ballard Power Systems, a global innovator in fuel cell technology, B.C. companies are developing new clean energy solutions for everything from portable electronics to transit bus applications. Ballard has designed and shipped over 400 megawatts of fuel cell technology to date. That's roughly equal to the annual energy needs of 80,000 homes.

In Vancouver, Corinex Communications develops and manufactures solutions for smart metering and smart grid infrastructure projects. To help homeowners reduce energy costs, Neurio delivers intelligent home energy management hardware, software and analytics.

Ostara helps cities, industries, and farms around the world protect water and food resources with game-changing technology that recovers valuable nutrients from wastewater streams and transforms them into a premium fertilizer that reduces agricultural runoff. And D-Wave is the only company in the world to sell commercial computers which use quantum mechanics to dramatically reduce the amount of time and energy required to solve complex computational problems.

In the Kootenays, Metal Tech Alley brings together partners from Trail, Rossland, Fruitvale, Montrose and Warfield to make new advances in digital fabrication and advanced materials, industrial recycling and the circular economy, which is designed to eliminate waste.

All of these advances are fueling our economy while helping us reduce greenhouse gas emissions.

2.4.1 CleanBC program for industry

The CleanBC program for industry announced in Budget 2018 directs a portion of B.C.'s carbon tax paid by industry into incentives for cleaner operations. The program is designed for regulated large industrial operations, such as pulp and paper mills, natural gas operations and refineries, and large mines.

In 2018, B.C.'s $30 carbon tax rate was raised to $35 per tonne, and it is set to increase by $5 every year until 2021. As the price of carbon rises, the CleanBC program will offer incentives to further reduce emissions, funded by the carbon tax industries pay above $30 a tonne.

The program includes:

- an Industrial Incentive that reduces carbon-tax costs for operations meeting world leading emissions benchmarks, and
- a Clean Industry Fund that invests some industrial carbon tax revenue directly into emission reduction projects, helping to make our traditional industries cleaner and stronger.

The fund and incentive work together: the fund supports projects to reduce emissions, and industrial operations with lower emissions pay less carbon tax and receive larger incentives. Initially, the fund will support the implementation of readily available technology. It will also be designed to leverage additional investments from facilities, partners, and other levels of government.

The incentive program and the fund will begin operating in 2019. Through collaboration with each industrial sector in B.C., greenhouse gas benchmarks will be identified for key products and services. The benchmarks will be based on all emission sources from a facility, including combustion, venting, flaring, fugitives, and industrial process emissions needed to compare performance across similar facilities.

Greenhouse gas emissions information is audited and reported annually for all large industry in B.C., and the CleanBC program will be based on that foundation of data. Benchmarks will be reviewed and updated regularly to ensure we keep pace with global technology development.

Requirements to apply for the fund will include:

- A detailed project plan that outlines the technologies or improved processes the facility wants to implement and the amount of emissions they expect to reduce; and,
- A business case for the project with financial details, outlining the need for funding support and justifying the request for funding.

The program will help our industries and workers thrive, create a clean industry brand for B.C., and help our traditional industries compete in a global market where consumers are demanding cleaner solutions. It will include an eligibility threshold to ensure the poorest performers have an incentive to invest in cleaner operations.

The CleanBC program for industry provides incentives for emitters to find innovative solutions to reduce GHG emissions. This will provide opportunities for a new generation of entrepreneurs who can focus their efforts on solving the problems industry has identified. This type of clarity will make it easier for B.C. companies to raise funds from investors who in turn will face less risk knowing there are willing customers.

It will also provide new opportunities and a larger market for B.C.'s innovative technology companies, supporting their development and demonstrating clean tech advantages to the world.

2.4.2 *Making industrial transportation cleaner*

Heavy duty transport is essential to our economy, and heavy trucks are becoming a testing ground for devices and strategies that reduce GHG emissions. Increased fuel efficiency means fewer emissions, and the industry has been developing and adopting efficiency measures for years. Every drop of fuel saved is money in the pocket, and that can mean a lot to an independent operator who measures every investment and closely manages the return on every trip.

Most highway truck tractors are shaped to make them aerodynamic and, over the past decade, we've seen new improvements such as trailer side skirts, boat tails and wide-base single tires. Truck manufacturers are also working on electric and hybrid zero-emission Class 8 tractors, known as the highway workhorse.

To further support and accelerate this clean transition, the Province is:

- Creating a new heavy-duty vehicle incentive program. This program will provide funding to promote the purchase of energy efficient equipment for large transport trucks.
- Expanding the Clean Energy Vehicle Medium/Heavy-Duty program to offer more incentives to support a transition to zero-emission vehicles and fuels in trucking, buses, port and airport ground equipment, and marine vessels. It will also support electric and hydrogen charging infrastructure for these vehicles at ports, service yards and truck stops.
- Supporting new training for heavy-duty vehicle drivers to help them make the most of new approaches and technologies.
- Partnering with the Vancouver Fraser Port Authority on a Clean Trucking pilot project to reduce emissions from drayage – the short-distance hauling of goods between terminals and other facilities such as distribution centres. The intent of the pilot is to make the latest in clean trucks and fuels available for drivers to start test driving in 2019. The lessons learned from the pilot project can be applied to other freight vehicles that operate in similar stop and go traffic environments in B.C.

Cleaner trade corridors and ports

B.C.'s transportation trade corridors and ports connect local businesses to global markets, facilitate trade and underpin both provincial and national economic growth. With trade volumes forecast to continue increasing over the next decade, key transportation sector stakeholders have formed the B.C. Clean Transportation Trade Corridors Advisory Council to address the following issues:

- Reducing absolute emissions while balancing economic growth along the corridors
- Promoting the use of clean fuel sources in transportation trade corridors and ports
- Improving efficiency of each mode of transportation involved
- Capitalizing on innovation and technology to advance clean transportation and support economic growth

The advisory council will collaborate with government and business to ensure B.C. has globally competitive, clean and efficient trade corridors.

HEALTH BENEFITS FROM REDUCING EMISSIONS FROM CONVENTIONAL DIESEL

Diesel is more efficient than gasoline but generates much more hazardous pollution. Along with its characteristic odour, diesel exhaust contains:

- **Particulate matter** that can cause or aggravate cardiovascular and lung diseases, heart attacks and arrhythmias. It can also cause cancer and may lead to atherosclerosis (hardening of the arteries), adverse birth outcomes and childhood respiratory disease.
- **Ground level ozone**, which can decrease lung function and aggravate asthma and other lung diseases.
- **Nitrogen oxides**, associated with increased deaths from heart and lung disease, and respiratory illness.
- **Polyaromatic hydrocarbons**, which have been linked to cancer.

The actions in this strategy will reduce the use of conventional diesel across B.C. and across our economy, targeting reductions in both transportation and energy-generation.

Renewable diesel – blended with fuels from renewable sources – is less carbon intensive. So are vehicles powered by natural gas. Both are important transitional fuels that can provide emission reductions while cleaner heavy-duty vehicles are being developed.

REDUCING EMISSIONS AT VANCOUVER INTERNATIONAL AIRPORT

With a record 24.2 million passengers in 2017, YVR is one of the fastest-growing airports in Canada – and it's taking action to ensure that growth is energy efficient and sustainable. For example:

- fully-electric buses, which create zero emissions, are used to move passengers between the airfield and the terminal building
- gates are provided with pre-conditioned air and ground power, which allows aircraft to use electricity instead of jet fuel
- 37 per cent of the ground handling fleet and 51 per cent of baggage support equipment now runs on electricity, and
- by 2022, a new GeoExchange system will use the earth's renewable energy to heat and cool the terminal building.

Overall, YVR has set an ambitious goal to reduce its greenhouse gas emissions by 33 per cent by 2020.

2.4.3 *Making B.C. industries the cleanest in the world – industrial and upstream electrification*

Electrification of industry is critical to meeting our climate commitments and reducing air pollution. Our goal is to make B.C. industries the cleanest in the world by using our clean energy to power our industrial economy.

Industrial processes often require large amounts of energy, with complex demands for delivery, infrastructure, and timing. To make it easier for large operations to access clean energy, BC Hydro will add new transmission lines and interconnect existing lines.

For areas like the Peace Region, this means electrifying industrial operations which up until now have depended on carbon-intensive fuels. In the South Peace, demand for electricity is growing faster than in any other part of British Columbia, largely due to natural gas exploration and development in the nearby Montney region. The Dawson Creek/Chetwynd Area Transmission Project has doubled electricity capacity in the area, allowing natural gas activities to be powered by clean electricity and avoid millions of tonnes of new greenhouse gas emissions.

In the meantime the Peace Region Electricity Supply (PRES) project will make it easier to replace natural gas combustion with electricity. Switching to clean electricity will make B.C.'s natural gas the cleanest in the world.

CUTTING EMISSIONS WITH UPSTREAM ELECTRIFICATION

In 2010, ARC Resources committed to building their Dawson Creek natural gas processing plant to produce fewer GHG emissions than was standard at the time. Electric-driven compressors were installed instead of gas-powered models and in 2018, ARC connected two more natural gas plants to B.C.'s clean electricity, significantly reducing emissions at those facilities. To reduce methane emissions, ARC is also developing a program to replace equipment with lower-emission or zero-emission pneumatics where possible.

These projects, supported by B.C.'s offset and infrastructure royalty programs, are helping drive the innovation needed to cut carbon during production.

2.4.4 Reducing methane emissions from natural gas production

Methane, which has a much higher GHG impact than carbon dioxide, is generated in many processes, from landfills to agriculture. The Province has been working in collaboration with the natural gas sector, environmental organizations and the federal government to establish new rules to reduce methane emissions in the upstream production of natural gas by 45 per cent by 2025. Using new and upgraded technologies and leak detection and repair programs, methane emissions can be reduced while keeping natural gas production economic for companies. Provincial regulations are being developed by the BC Oil and Gas Commission and are expected to be passed by 2019. The Province will pursue an equivalency agreement with the federal government to ensure our regulations and oversight remain in force for the B.C. natural gas sector.

British Columbia and the federal government are also improving our understanding of how much methane may be escaping from the natural gas sector. Through field work in 2018 we are developing an updated assessment of fugitive methane releases, equipment counts and potential leaks. We will be further investigating leading technology and evolving best practices – including detection and repair of leaks in the natural gas sector – and will assess these with a view to adapting and applying those new best technologies to B.C.'s resources beginning in 2023. With this new information we will be able to calibrate our response to ensure we capture the most methane for the least cost, keeping the sector economic while reducing carbon pollution from major emitters.

ADDRESSING EMISSIONS FROM LIQUIFIED NATURAL GAS (LNG) DEVELOPMENT

One of the conditions for LNG development in B.C. is that it fits within the Province's climate commitments. While LNG Canada is working to make its Kitimat facility the world's cleanest in terms of greenhouse gas (GHG) emissions intensity, the project could add up to 3.45 megatonnes of carbon emissions to the province's total.

Recognizing that natural gas can be a transitional fuel on the path to less carbon-intensive options, the CleanBC program for industry will encourage the use of the greenest technology available in the sector to reduce emissions and encourage economic and job growth. More reductions from LNG's climate impact will be achieved through investments in electrification of upstream oil and gas production so extraction and processing are powered by electricity, instead of burning fossil fuels.

2.4.5 *Technological innovation including carbon capture, utilization and storage*

Carbon capture utilization and storage is a GHG emissions-mitigation measure that integrates with B.C.'s energy systems to recycle carbon into other forms of energy or to store it permanently deep underground.

Natural gas processing plants in northern B.C. have been doing this for decades, capturing carbon dioxide and sulphur dioxide from raw natural gas and pumping it back underground. As the technology to capture and reinject carbon dioxide becomes more economic and the geologic storage is better understood, the Province is taking action to ensure it can continue to be implemented safely and securely. We will develop a safe, effective regulatory framework for underground carbon dioxide storage, not just for the natural gas sector, but also for direct air capture.

This is a growing opportunity for British Columbia. Organizations like the Carbon Capture and Conversion Institute, a collaborative venture between CMC Research Institutes and BC Research Inc, are providing the test bed for the greenhouse gas reduction technologies of the future. The alliance of research and commercialization organizations creates a unique ecosystem of experts and equipment that is unparalleled in Canada.

The Institute's mission is to accelerate the development, piloting, scale-up, and validation of new carbon capture and conversion technologies. They offer clients access to a comprehensive set of facilities for pilot project design, fabrication, testing and refinement. At the University of British Columbia, technology developers can work with faculty on early-stage, bench-scale technologies while the pilot project facility has infrastructure and utilities allowing for long-term trials.

This commitment to advancing technology is already paying off. For example, Squamish-based Carbon Engineering takes CO_2 out of the atmosphere and converts it into ultra-low emission transportation fuel. The company is a world leader in large-scale negative emissions technology.

B.C. COMPANY PULLS CARBON OUT OF THE AIR

Squamish's Carbon Engineering Ltd. (CE) is a clean tech company that is getting global attention. With support from B.C.'s Innovative Clean Energy Fund, they developed technology that pulls carbon emissions out of the air. They can then safely store it underground or turn it into a carbon-neutral fuel that works in any engine. By reusing existing carbon little or no additional emissions are created when this fuel is burned.

CE is now in early discussions to build commercial facilities. CE's game-changing Direct Air Capture facilities could enable the large-scale capture of carbon needed to offset emissions that may not be able to be addressed directly. Their facilities also have the potential to create 400 construction jobs and 100 permanent jobs each. Carbon Engineering is another example of B.C.'s growing clean technology.

2.4.6 Hydrogen economy

Hydrogen can play a major role in B.C.'s low-carbon energy systems. It's versatile, safe and clean when produced from B.C. electricity or renewable natural gas. It produces zero-emissions when it's used and can be stored and transported as a liquid or a gas.

Blending hydrogen with natural gas can significantly reduce emissions and provide an even cleaner transitional option where liquid fuels are needed. Clean hydrogen generated in B.C. would be among the least carbon-intensive energy products available in the world and could be used to lower the GHG intensity of LNG production.

As part of CleanBC, we will accelerate development of B.C.'s hydrogen economy with:

- financial supports for the deployment of fuel cell electric vehicles and infrastructure;
- support for centralized hydrogen production; and
- injection of sustainable hydrogen into the natural gas grid.

A B.C. Hydrogen Roadmap will be released in 2019 to grow the new low-carbon economy and identify economic opportunities throughout B.C. For example, off-grid Indigenous and non-Indigenous communities could host hydrogen fuel cell pilot projects. These new approaches could leverage our leadership in fuel-cell development to create more jobs in technology and innovation while reducing emissions across our economy.

By 2030, these initiatives are projected to achieve 8.4 Mt of GHG reductions

3 HELPING PEOPLE GET THE SKILLS THEY NEED

Whether it's generating clean energy, retrofitting buildings or designing new technologies, making B.C. cleaner will create good jobs that support families and sustain our communities. We need new skilled workers, and new skills to equip those already at work across the province.

As new jobs and professions emerge, post-secondary education and training need to keep pace. So the Province is working with employers, Indigenous communities, labour groups and post-secondary institutions to analyze the labour market and identify:

- where the strongest job growth is likely to be,
- what skills are needed to meet the demand,
- what specific training we need to develop and deliver in our communities, and
- what support students and apprentices need to excel in these programs

As a first step, we are investing in two key sectors where we already know demand is strong and growing – cleaner buildings and cleaner transportation. This includes:

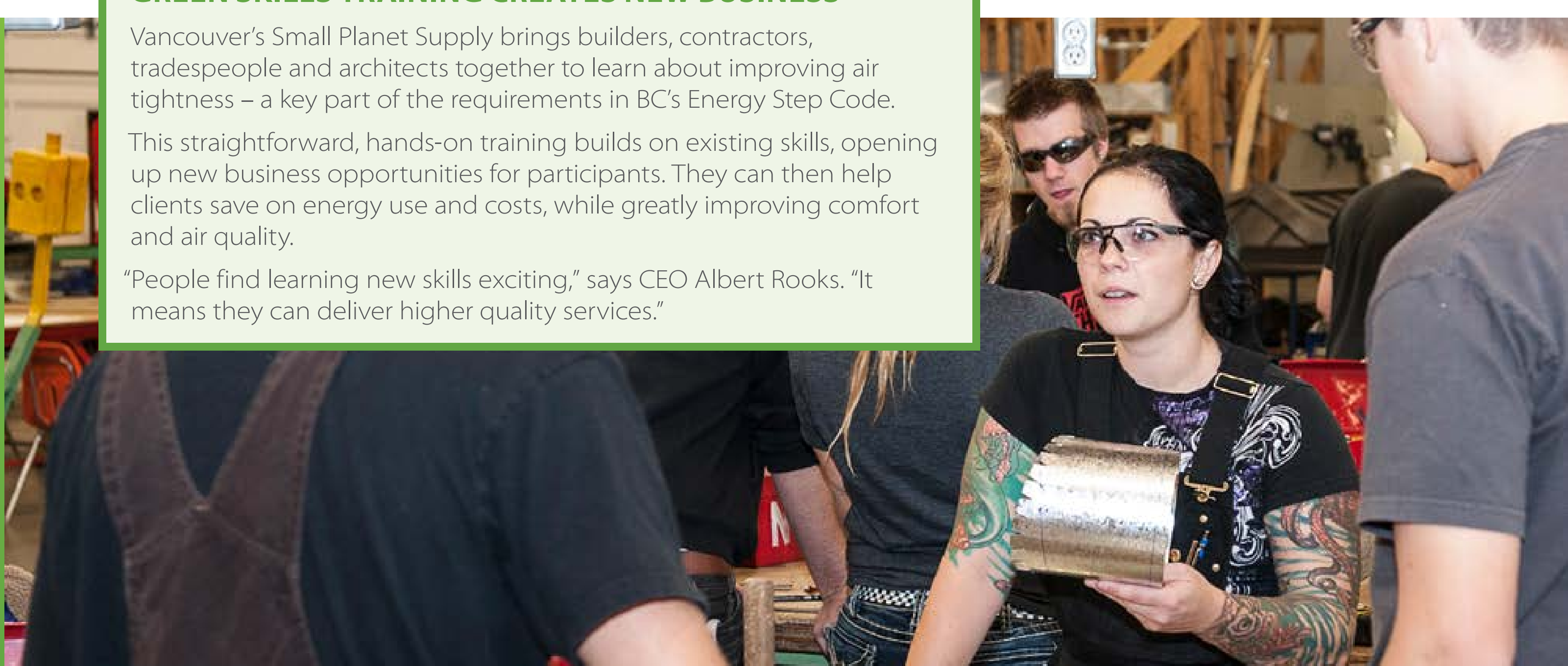
- **Training and certification for Energy Step Code professionals.** Since 2017, local governments have had the option of adopting the voluntary BC Energy Step Code (ESC). The ESC sets energy performance targets for new buildings, provides a technical roadmap for users and supports continuous improvements to the BC Building Code. The highest step of the ESC for any building type is "net-zero energy ready," which is up to 80 per cent more efficient than the current base BC Building Code. The technologies and techniques needed to design and build these new buildings will be developed right here in B.C., and with the right training for our building professionals, it will mean new opportunities across the province.

GREEN SKILLS TRAINING CREATES NEW BUSINESS

Vancouver's Small Planet Supply brings builders, contractors, tradespeople and architects together to learn about improving air tightness – a key part of the requirements in BC's Energy Step Code.

This straightforward, hands-on training builds on existing skills, opening up new business opportunities for participants. They can then help clients save on energy use and costs, while greatly improving comfort and air quality.

"People find learning new skills exciting," says CEO Albert Rooks. "It means they can deliver higher quality services."

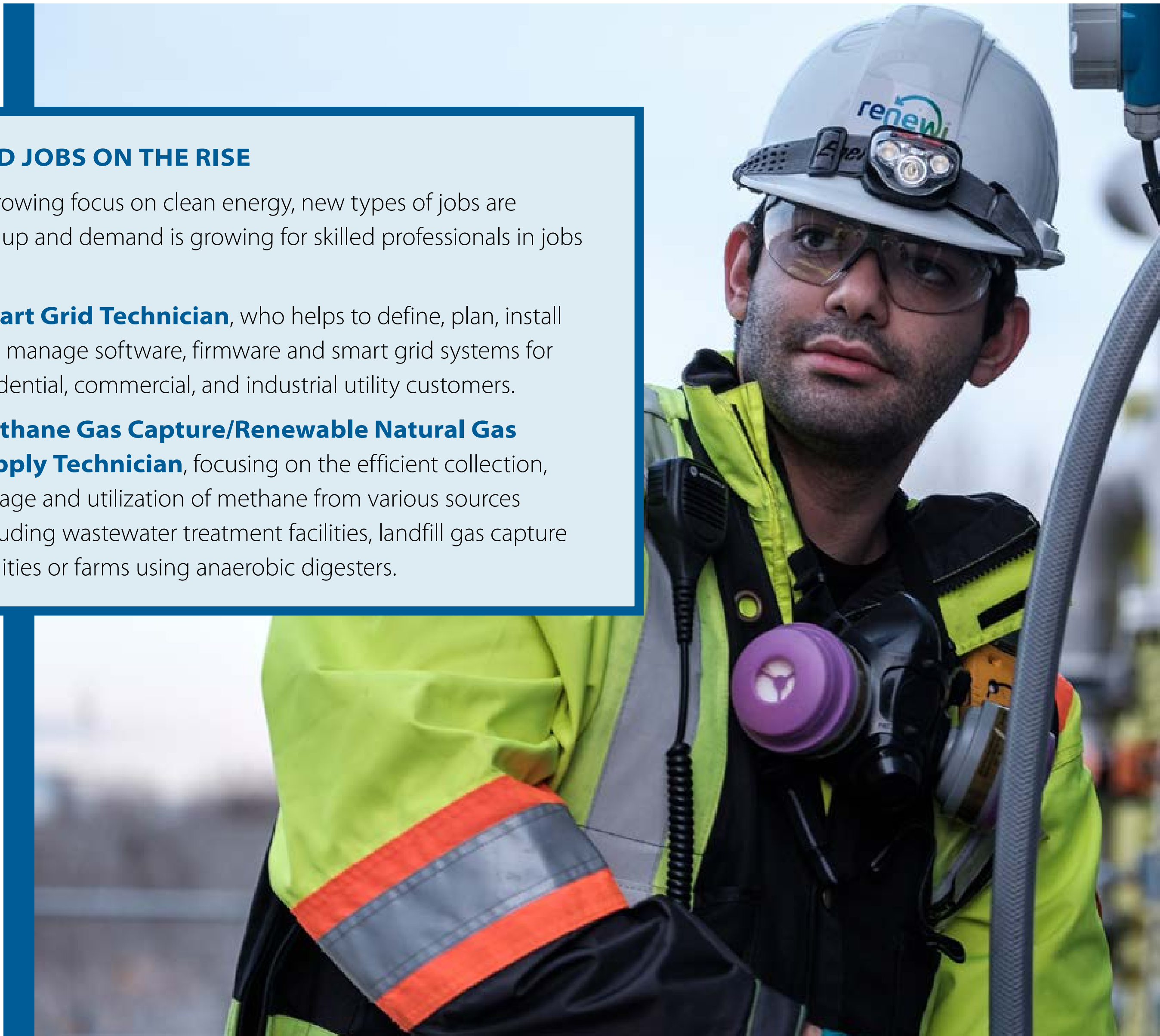


Now, with support from the Province, they have taken a mobile version of the course across B.C.

- **More training for ZEV-related work.** Expansion of the clean energy vehicle automotive curriculum across the province and support for electricians to upgrade their skills with the Electric Vehicle Infrastructure Training Program.

  Clean vehicles present a significant economic opportunity for the province. B.C. has a highly skilled workforce and research, development activities and expertise in niche sectors that are critical to the deployment of clean vehicles and related infrastructure. This, combined with key deposits of minerals used in manufacturing of clean vehicle technologies, means B.C. is well positioned to capitalize on a global market for ZEVs and their related technologies.

  Having the skilled mechanics available to keep a new clean fleet performing, and the skilled electricians to help build out supporting infrastructure, will be critical to the successful deployment of millions of vehicles across the province by 2040. Our training and apprenticeship programs will be designed to deliver the technical skills and certifications needed by this new segment of the transportation system.



SKILLED JOBS ON THE RISE

With a growing focus on clean energy, new types of jobs are opening up and demand is growing for skilled professionals in jobs such as:

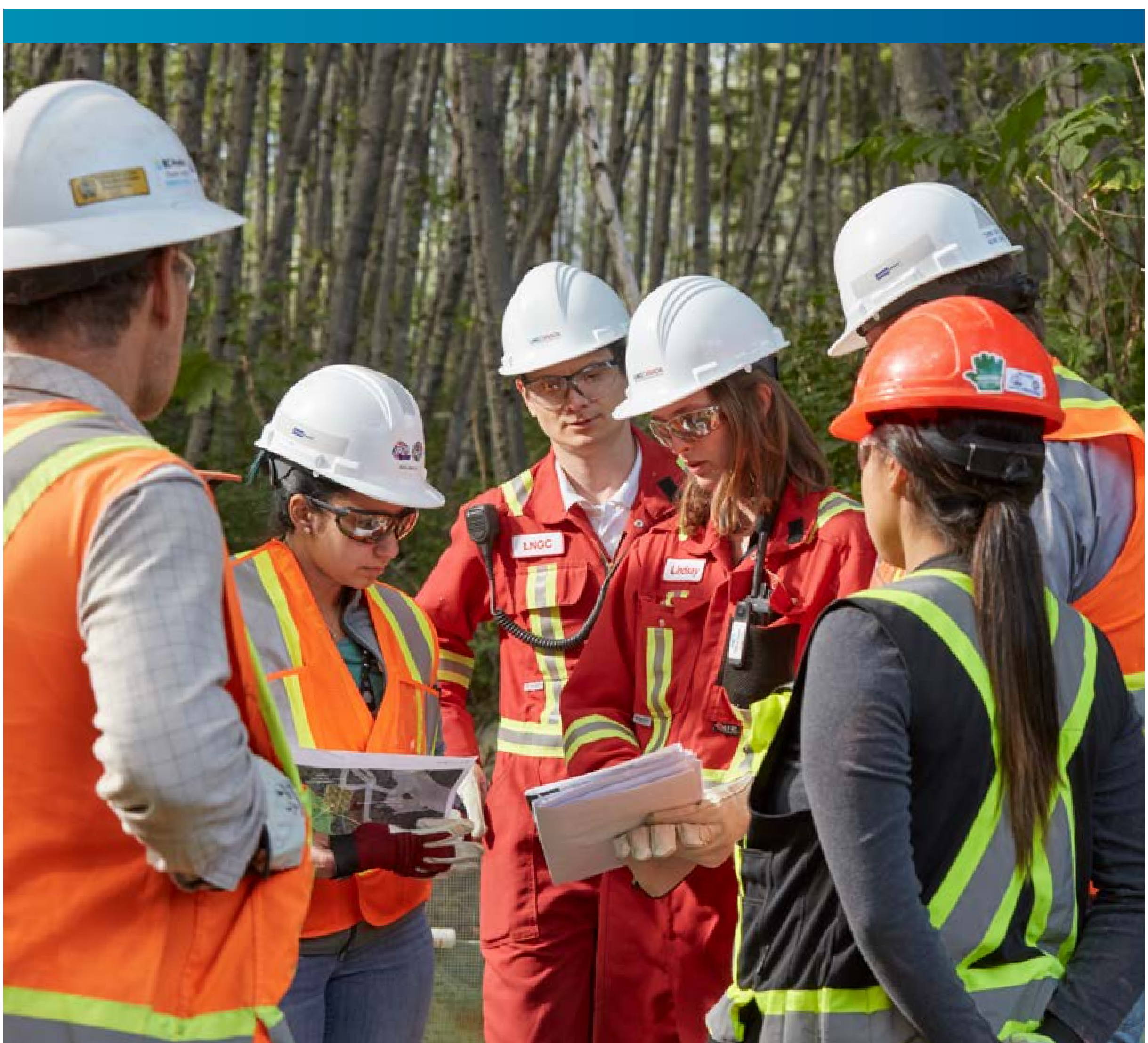
- **Smart Grid Technician**, who helps to define, plan, install and manage software, firmware and smart grid systems for residential, commercial, and industrial utility customers.
- **Methane Gas Capture/Renewable Natural Gas Supply Technician**, focusing on the efficient collection, storage and utilization of methane from various sources including wastewater treatment facilities, landfill gas capture facilities or farms using anaerobic digesters.

As part of this strategy, the Province is developing a CleanBC Labour Readiness Plan to address the labour and workplace opportunities that will emerge through the implementation of CleanBC. The plan will identify future occupational and skills profiles relevant to the transition to a low carbon economy, including where jobs may be located, and opportunities for mid-career workers to develop new skills.

Public engagement in 2019, including an online portal, will be used to gather public and professional input from a range of backgrounds to inform the plan's development. In addition, collaboration with Indigenous peoples on the plan will include community and regional meetings across the province.

The plan will incorporate public input, detailed assessments of labour market conditions and economic trends, address the participation of women and other under-represented communities in these roles, and respond to issues that could affect people's opportunities to participate. It will provide a framework for sector specific actions to equip British Columbians with the skills and experience they need to power our future.

The CleanBC Labour Readiness Plan will identify where additional support may be needed for lower income students, and tailored to meet the needs of Indigenous peoples, rural communities and workers. We will work with post-secondary institutions to implement the plan, developing new, skilled workers, and providing training opportunities for today's workers.




Schneider
Electric

4 MEASURING OUR PROGRESS

Since 2008, B.C. has been tracking its GHG emissions and setting long-term targets for reductions. Measuring our progress towards those targets helps make sure we stay on track by adjusting and refining our approaches over time.

In May 2018 – recognizing the impacts of our growing economy and population – the Province set new targets for GHG emissions. Compared to 2007 levels, we are now committed to reductions of:

- 40 per cent by 2030,
- 60 per cent by 2040, and
- 80 per cent by 2050.

These new targets reflect the fact that early progress to meet our commitments has stalled in recent years – we are not on track to meet our goals if we don't change the way we use energy across key sectors. Compared to 2007, total net GHG emissions were down 3.7 per cent in 2016 according to our latest assessment (*https://www2.gov.bc.ca/gov/content?id=50B908BE85E0446EB6D3C434B4C8C106*).

Emissions have risen in several areas, driven by economic and population growth and a slowdown of reduction measures since 2011.

CHANGES IN EMISSIONS BY SECTOR 2007 – 2016

HIGHER		LOWER	
Passenger vehicles	↑ 14.6%	Metal and mineral process emissions	↓ 22.3%
Oil, gas and mining	↑ 10.9%	Commercial buildings	↓ 6.5%
Heavy duty trucks	↑ 7.7 %	Residential buildings	↓ 11.1%
		Off-road transportation	↓ 14.5%
		Waste	↓ 14.3%

While the slow rate of emissions decline is troubling, we also see signs that our actions are paying off, thanks in large part to the choices made by British Columbians. For example, since 2007, emission intensities have fallen significantly in some sectors:

- GHG emissions per person have fallen by 12 per cent
- Fossil-fuel use per person is down by 10 per cent
- Overall, the carbon intensity of our economy – measured by the relationship between greenhouse gas emissions and economic growth – has decreased by 19 per cent
- In the oil and gas sector, carbon intensity has dropped by half in the last 10 years

CleanBC protects our communities and sets us on a path to a stronger, more sustainable future. The measures announced in this plan include ambitious goals for transforming the buildings we work and live in, how we get around, and how we power our economy and use cleaner energy.

Goal snapshot

Where we live and work By 2030, emissions from buildings dropped by 40%.	■ By 2032, new buildings will be 80% more efficient than a home built today (highest tier of B.C. energy step code) ■ By 2030, 70,000 homes and 10 million m² of commercial buildings will be retrofitted to use clean electricity in space heating ■ 60% of homes and 40% of commercial buildings will be heated with clean electricity ■ Public buildings will lead the way, reducing emissions by 50% by 2030 ■ Overall, emissions from buildings will drop by 40%
Getting around By 2030, fossil fuel use for transportation has dropped 20%	■ By 2030, 30% of all sales of new light-duty cars and trucks will be zero-emission vehicles, rising to 100% by 2040 ■ To help meet increased demand for lower-carbon fuels, B.C. will support the production of 650 million litres of renewable fuels per year ■ The Province will reduce GHG emissions from government vehicles by 40% ■ Overall, fossil fuel use for transportation will drop by 20%
Cleaner Industry	■ The CleanBC program for industry will reduce industrial emissions by 2.5 Mt per year ■ By 2025, methane emissions from the natural gas sector will drop by 45%
Reduce waste and turn it into a resource	■ By 2030, 95% of organic waste (including municipal, industrial, and agricultural) will be diverted from landfills and turned into other products ■ By 2030, 75% of landfill methane will be captured
Adaptation	■ By 2020, the Province will develop an Adaptation Strategy based on a province-wide climate risk assessment

Transparent, forward-looking and independent public reporting

Under the *Climate Change Accountability Act*, B.C. reports on its GHG emissions every year. However, it takes two years to gather the necessary data. That's why our latest *Progress to Targets report* is for 2016.

As part of CleanBC, we're committed to doing better. We're developing a new accountability framework to make sure people have access to the latest, most relevant information as soon as possible. We will continue to provide comprehensive reports on our progress under the *Climate Change Accountability Act*. We will also:

- table in the Legislature an annual report of spending, program results and anticipated reductions from the previous year,
- forecast emissions for three years in the future, based on strategic initiatives and modelling, and
- publish emissions results as we get the information.

Having more information sooner will allow our partners across all sectors to see how well their efforts are paying off, and to make early adjustments where needed.

The independent Climate Solutions and Clean Growth (CSCG) Advisory Council will provide a review of government's progress in reducing emissions as well as advice on future actions. Their first report will be available in 2019. The council includes members from Indigenous communities, environmental organizations, industry, academia, labour and local government.

Climate Change Accountability Process

GOVERNMENT DIRECTION

MINISTRY OF FINANCE
Annual Budget Document

- Will include a topic box that describes the fiscal plan funding for climate change
- Consistent with the previous government's legislated commitment to transparency on use of carbon tax revenue

PROGRAM DELIVERY

MINISTRIES
Annual Service Plans

- Reflect commitment to CleanBC funded & approved policies and programs in Service Plans
- Implement funded and approved policies & programs
- Track results (emissions, reductions or activity data)

DATA COLLECTION & REPORTING OF RESULTS

MINISTRY OF ENVIRONMENT AND CLIMATE CHANGE STRATEGY
Inventory & Reports

- Assemble annual GHG emission information for the latest verified year
- Legislative requirement to table an annual report of GHG spending, program results and anticipated reductions in GHG emissions and climate risk from the previous year

CROSS-GOVERNMENT ALIGNMENT & ADVICE

CSCG ADVISORY COUNCIL
Advice to Government

- Reports publicly on government's progress
- Reviews ongoing policies and programs
- Undertakes independent review of proposed climate actions against carbon budgets
- Advises on adjustments to remain on track to targets and manage climate change risks

5 WORKING TOGETHER

We will need to work together to protect what we care about and move towards a cleaner future. As part of this strategy we will build new – and strengthen existing – relationships with partners, including:

- **Indigenous peoples.** Working together for a cleaner future is an opportunity to advance lasting reconciliation with, and self-determination for, Indigenous peoples. Accordingly, and consistent with our commitments and obligations, we will work together with Indigenous peoples to develop a collaborative approach to engagement on the concepts and initiatives in this strategy. Collaboration with Indigenous peoples will include initiatives to build resilient communities, participate in new clean economy opportunities, recognize traditional knowledge, and help communities adapt to the impacts of climate change. This will include collaboration on a climate change adaptation strategy to be developed for 2020 and the CleanBC Labour Readiness Plan.
- **Business adaptation and industry.** B.C.'s business sector is serious about establishing the province as a world leader in supplying low carbon goods and services. And B.C. industries want to press their comparative advantages and build a clean B.C. brand. As new markets develop, business and industry leaders continue to work collaboratively with government and communities to protect jobs and ensure industries remain competitive.

  By focusing on coordinated action in the near term, we can maintain and enhance our competitive advantages while building a cleaner future. For example, a newly-signed Memorandum of Understanding commits the Province and the Business Council of British Columbia to working jointly on a low-carbon industrial strategy to help our industries compete and win in the global marketplace.
- **Technology and innovation.** With hundreds of companies and thousands of employees, clean tech is one of our fastest-growing industries. Along with providing good jobs and business opportunities, the sector produces technologies that contribute to a cleaner, more sustainable world. Demand for these technologies is expected to rise significantly in the years ahead.
- **Educators and workers.** This includes working with labour groups, employers and post-secondary institutions to identify, and provide training for, new job opportunities for both new workers and mid-career workers of all backgrounds. This is consistent with the government's commitment to a fair and just transition to a cleaner economy.
- **The federal government and other jurisdictions.** Since 2016, federal, provincial and territorial governments have been guided by the Pan-Canadian Framework on Clean Growth and Climate Change, which sets out a national plan to reduce greenhouse gas emissions, grow the economy and build resilience to a changing climate.

  The framework includes measures such as performance standards and regulations to encourage energy efficiency. It also includes commitments to reduce reliance on diesel fuel in northern and remote communities and fund smart grid deployment across the country. The Province and Ottawa are partners in a Forest Carbon Initiative, which invests in projects that sequester forest carbon and reduce carbon emissions – promoting the improved use of forest fibre for biofuels and longer-lived wood products.

Climate change is a global issue and no jurisdiction can tackle it alone. B.C. is also working closely with western U.S. states through the Pacific Coast Collaborative and with governments worldwide through initiatives such as the Paris Agreement. Joining forces allows us to increase our impacts and learn from one another's experiences.

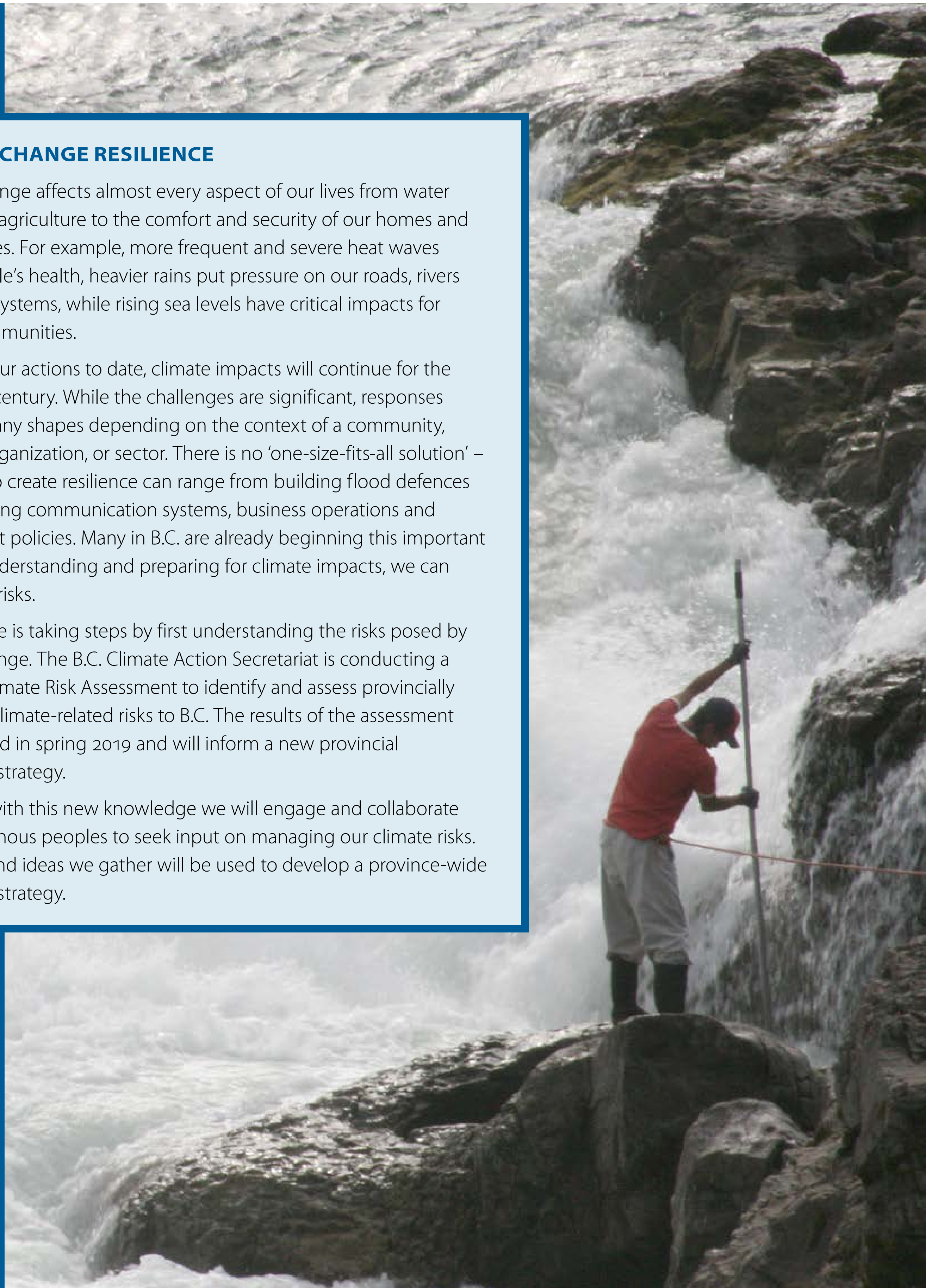
- **Local governments.** From land-use planning to citizen engagement, local governments are often best positioned to make a difference in our daily lives. As we continue down the path to a cleaner future, they will play a critical role in areas such as developing new clean energy sources, supporting active and cleaner transportation options and helping B.C. transition to zero waste. Their ongoing efforts to make communities more compact, complete and energy-efficient are essential to this strategy's success.

  B.C. local governments are leaders on climate action, managing their corporate and community wide GHG emissions and creating clean, compact, more energy efficient communities. CleanBC will leverage partnerships with B.C. local governments. Both urban and rural communities have a role to play as part of CleanBC and will be further engaged to help inform the next initiatives in the plan.

- **Utilities.** BC Hydro and FortisBC have a long history of partnering with people and communities to help conserve energy and switch to cleaner options. For example, FortisBC offers rebates on high-efficiency appliances, equipment and more. Meanwhile, BC Hydro has 900 customers on its net metering program, which allows them to generate their own electricity and sell what they don't use back to BC Hydro. As we move forward with CleanBC, utilities will continue to support, encourage and enable the transition to clean energy as we ensure their policies align with the Province's electrification goals and emission reduction targets.

- **Academics and non-governmental organizations.** B.C.'s post-secondary institutions are home to world-leading researchers and students that are exploring and advancing clean solutions, spanning technology and policy solutions. We are also home to active and engaged civil society organizations who have a long history working with British Columbians and all levels of government to address climate change. The input and advice of knowledgeable and engaged British Columbians has bolstered these initiatives and will continue to do so as we move forward.

We're also continuing to talk to British Columbians, as we begin to implement these activities and continue our work on remaining sectors.



CLIMATE CHANGE RESILIENCE

Climate change affects almost every aspect of our lives from water supply and agriculture to the comfort and security of our homes and communities. For example, more frequent and severe heat waves affect people's health, heavier rains put pressure on our roads, rivers and sewer systems, while rising sea levels have critical impacts for coastal communities.

Even with our actions to date, climate impacts will continue for the rest of this century. While the challenges are significant, responses can take many shapes depending on the context of a community, business, organization, or sector. There is no 'one-size-fits-all solution' – measures to create resilience can range from building flood defences to redesigning communication systems, business operations and government policies. Many in B.C. are already beginning this important work. By understanding and preparing for climate impacts, we can reduce the risks.

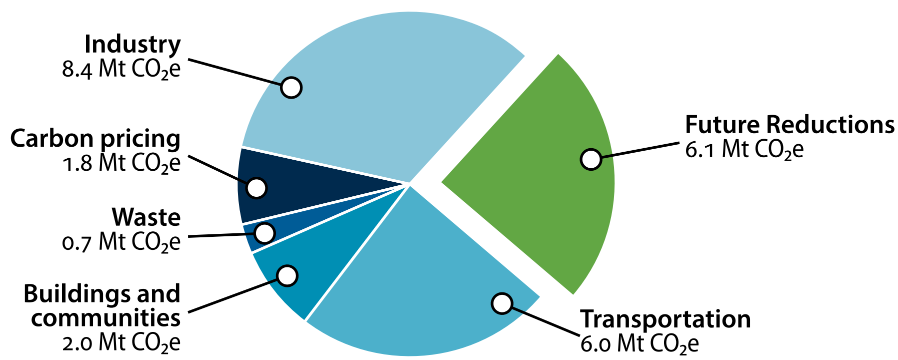
The Province is taking steps by first understanding the risks posed by climate change. The B.C. Climate Action Secretariat is conducting a Strategic Climate Risk Assessment to identify and assess provincially significant climate-related risks to B.C. The results of the assessment are expected in spring 2019 and will inform a new provincial adaptation strategy.

Equipped with this new knowledge we will engage and collaborate with Indigenous peoples to seek input on managing our climate risks. The input and ideas we gather will be used to develop a province-wide adaptation strategy.

6 REACHING OUR TARGETS

The industry, buildings and transportation initiatives laid out in this plan combine to reduce our emissions by 18.9 Mt, getting us 75% of the way to our 2030 climate targets.

Reductions to achieve 2030 target



The remaining 6.1Mt in reductions will be achieved through initiatives identified over the next 18-24 months, including:

- reducing and making better use of waste,
- improving community planning, active transportation, and transit
- cleaner heavy-duty vehicles and freight
- significantly increasing industrial electrification,
- meeting our demand for clean electricity,
- maintaining a resilient agricultural sector, and
- cleaner, more efficient technology.

Work to achieve additional emission reductions in these and other areas will continue throughout this period.

To make our 2040 and 2050 targets achievable we need additional reductions through innovation and investment. New technologies mean new jobs – good jobs that didn't exist before. They involve new equipment, new ways of doing things, and new products that save energy and money for families. As the strategy develops there will be many opportunities for new enterprise and community development.

Areas where there are still significant GHG emissions will be the focus of future actions. These remaining emissions come from fossil fuels or result from chemical or biological processes. They will not be easy to address, but we are committed to finding solutions.

We are committed to making sure that these actions achieve the emissions reductions we need. Not every step is likely to turn out as planned; some will achieve even greater results and others may need a new approach. As research and innovation deliver more solutions, we will review and update our plans.

In 2019, a renewed cross-government effort will begin to roll-out the initiatives that will get us the 6.1 million tonnes we need to reach our targets. We will continue working with British Columbians to identify and seize further opportunities in the months and years ahead, and we will take these steps in cooperation and collaboration with B.C.'s Indigenous peoples. In 2020, as part of our new accountability framework, the Minister of Environment and Climate Change Strategy will report on the new initiatives and how much closer they will bring us to our targets. Each year will have an update on what's working and what needs more attention.

Engagement, collaboration, and public consultations in 2019 will focus on topics including:

Reducing waste

Imagine living in a world without waste, where by-products of all kinds are reused, recycled and reconstituted as raw materials. Where no other option exists, they are used a source of energy. That approach, known as a "circular economy" is what we are adopting in British Columbia, recognizing its potential for creating jobs, promoting innovation, and protecting the environment by harnessing the full value of resources.

Overall, waste is still a 1.5 million tonne problem for greenhouse gas emissions, and the negative effects of managing waste of all kinds continue to be an expensive part of our lives. Our strategy for waste will focus on prevention, which has the greatest potential for reducing GHG emissions, including those emissions that occur beyond our borders where many of the products we use are manufactured.

British Columbia's Extended Producer Responsibility program is an example of the way we will encourage manufacturers and retailers to prevent waste at the source, and we will look at new products and approaches for prevention. We'll also look at actions to increase reuse and recycling combined with key downstream mitigation measures, such as reducing methane emissions from landfills.

Other waste streams come from industry, like bark and other milling waste in the forestry sector, or manure and agricultural waste that can lead to environmental problems if we don't manage it well. We will explore solutions for these more difficult waste streams so they don't just pile up. Renewable natural gas, liquid biofuels and local bioenergy systems may be some of the solutions that also help reduce the use of higher carbon fuels.

Community planning, active transportation and transit

Community planning decisions can go a long way toward reducing our environmental impacts. For example, compact communities reduce the need to drive by having housing, shops, workplaces, schools, parks and civic facilities within easy walking distance of each other. Similarly, focusing development along existing transit routes can make daily travel easier, cleaner and more convenient. Generally, the urban planning and design choices that make communities livable also make them less energy and emissions intensive, benefiting everyone.

Future initiatives with CleanBC will include a plan for a clean communities and transportation system network, supporting industry and people of all ages and abilities to efficiently access the goods, services and markets they need. Our work in this area will focus on land-use; transportation network infrastructure, including options for active transportation such as cycling and walking; and transportation demand management. We will address policies, programs, services and products that encourage people to use sustainable modes of transportation rather than driving alone, or to make fewer trips by car.

As part of this new plan, the Province will support local governments, the Nisga'a Lisims Government, and Treaty First Nations to use their policy tools and purchasing power to help reach our 2030 target while developing more compact communities and providing safe, convenient and affordable zero-emission transportation options.

Cleaner heavy-duty fleets and freight

Light-duty cars and trucks are only a part of our province's transportation story, and at present they are the most advanced in terms of options, affordability and near-term solutions. Lower carbon alternatives are still in development for commercial and heavy-duty vehicles, which contribute 8.1 million tonnes per year to our greenhouse gas emissions.

Next, we will be exploring new fuel and transportation alternatives for freight, including trucks and heavy equipment used in industrial operations like mining and logging. We will also be working with small business to find clean transportation options across B.C. We will build on our global transportation hubs to lower fuel costs and air pollution while making our ports attractive to global shipping fleets transitioning to LNG as a lower cost, lower GHG transition fuel.

Cleaner fuels like LNG and biofuels may be powering these fleets for some time, but we will also be attracting the leading heavy electric vehicle manufacturers to deploy their first fleets here and contribute to our climate goals.

Further industrial electrification

Just as the move to electric cars reduces emissions from transportation, switching from fossil fuels to clean electricity can make a big difference for industry and manufacturing. The industrial sector is forecast to contribute over 20.7 million tonnes of GHGs in 2030, but transitioning to electricity can be a challenge and each industry will face different technical and economic conditions.

The Province is committed to working with B.C. industries and manufacturers to identify the best pathway for each, recognizing that there are often lower carbon prices in competing jurisdictions. We will work with the Business Council of British Columbia and Indigenous businesses to find new ways to reduce emissions and develop a low carbon industrial strategy that supports a strong, sustainable economy.

We will also be working with our tech sector to find more ways to use our clean electricity to benefit B.C. and seek the advice of British Columbians on how best to support this fast-growing sector of our economy.

Electricity supply

With clean electricity as the foundation for the prosperous and sustainable future for this province, BC Hydro is taking steps to position us for enduring success in the rapidly changing global energy sector. We have begun a structural review with an eye towards reducing costs, increasing revenues and keeping rates affordable for British Columbians.

Results of this focused review will inform a broader review that identifies key B.C. and North American trends, like the falling cost of renewables and alternative visions for BC Hydro's long-term role. These include both generating and acquiring energy, maximizing B.C.'s capacity advantage, supporting clean economic development, and adapting to growth in distributed and district energy and new digital technology. This work will be carried out over the course of 2019.

Incorporating these findings and the strategic direction set by CleanBC, BC Hydro will prepare a new Integrated Resource Plan to incorporate new objectives and develop a new path forward for electricity in B.C.

Maintaining a resilient agricultural sector

The B.C. agricultural sector is already taking action to enhance agriculture's ability to adapt to climate change and contribute to reducing the province's emissions. The BC Agriculture and Food Climate Action Initiative has been working with local agricultural producers to understand the potential future impacts of a changing climate, including increasing temperatures, variable rainfall and extreme weather events. By developing Regional Adaptation Strategies, our farming communities will have the information and tools they need to maintain a resilient agricultural sector in B.C. Through the Canadian Agricultural Partnership, the Province and the federal government are investing in the agriculture, agri-food and agri-based sectors across the province and will continue to explore new opportunities to benefit from the growing demand for clean fuels and clean food.

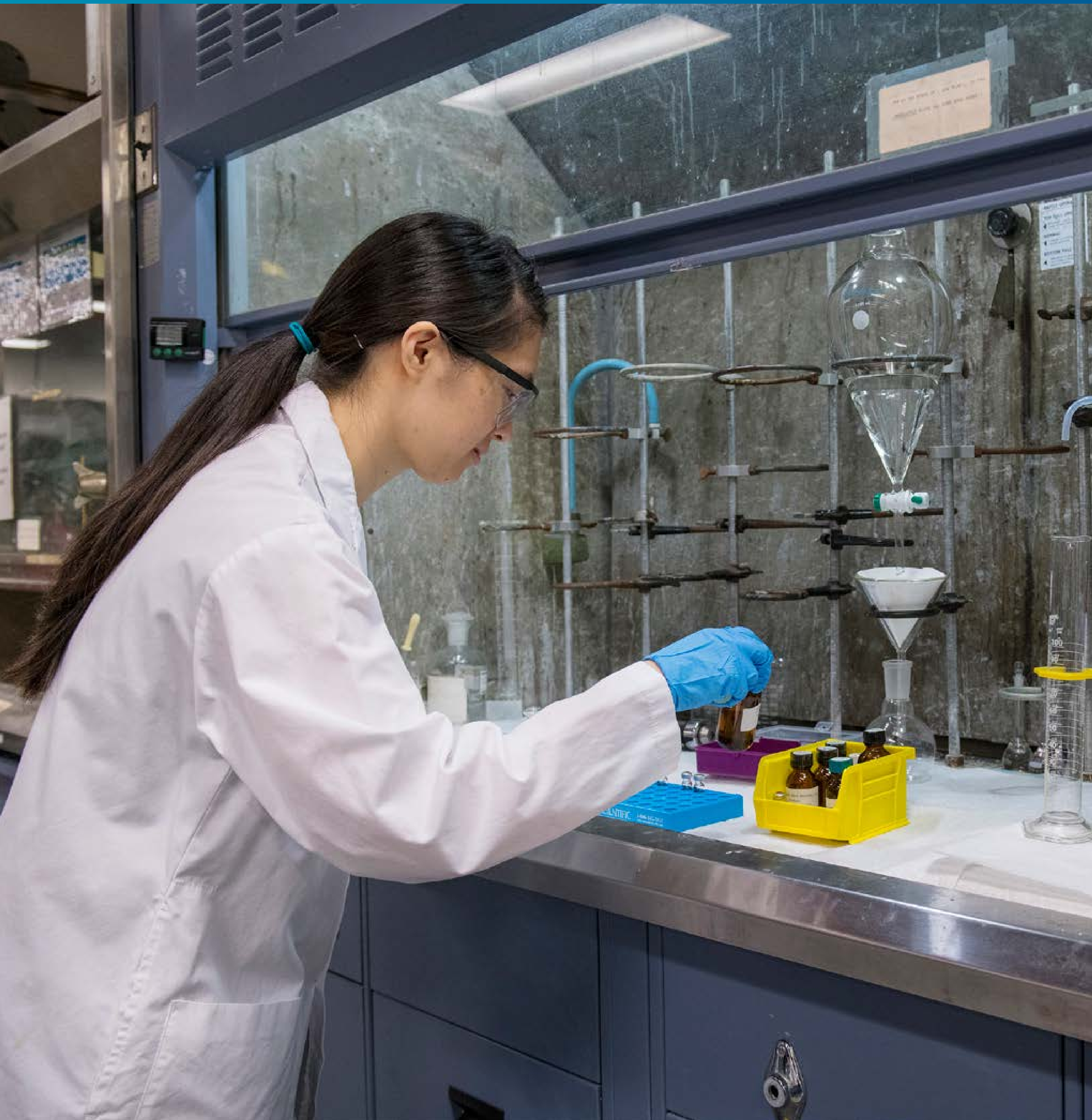
Cleaner, more efficient technology

As part of the move to cleaner industries, the Province will continue to explore technologies that have the potential to reduce emissions in sectors where there are few alternatives to fossil fuels. For example, carbon capture, utilization and storage contains carbon dioxide emissions from sources like natural gas production or manufacturing plants and either reuses it in low-carbon products, such as fuels or concrete, or stores it underground to keep it out of the atmosphere. This is just one example of the new technologies evolving to support cleaner, more sustainable industries to drive our future economy.

MineSense, a pioneer B.C. technology company, is creating digital mining solutions that provide real-time, sensor-based ore sorting for large-scale mines. They concentrate ore through superior ore-waste classification to increase revenue from higher recoveries and reduce costs spent on processing waste. MineSense was recently named to the Global Cleantech 100 and has offices and field personnel in South America, Australia and Africa and works with mining customers around the world.

Another innovative company, G4 Insights Inc., is developing and commercializing the conversion of forestry waste into pipeline grade renewable natural gas (RNG). Their process turns forestry residue such as slash piles and sawmill waste into methane, which can be used as a low carbon transportation fuel or for renewable power generation and space heating. The company is currently working on a pilot project with plans for a commercial product within three years.

APPENDIX



CleanBC initiatives by sector

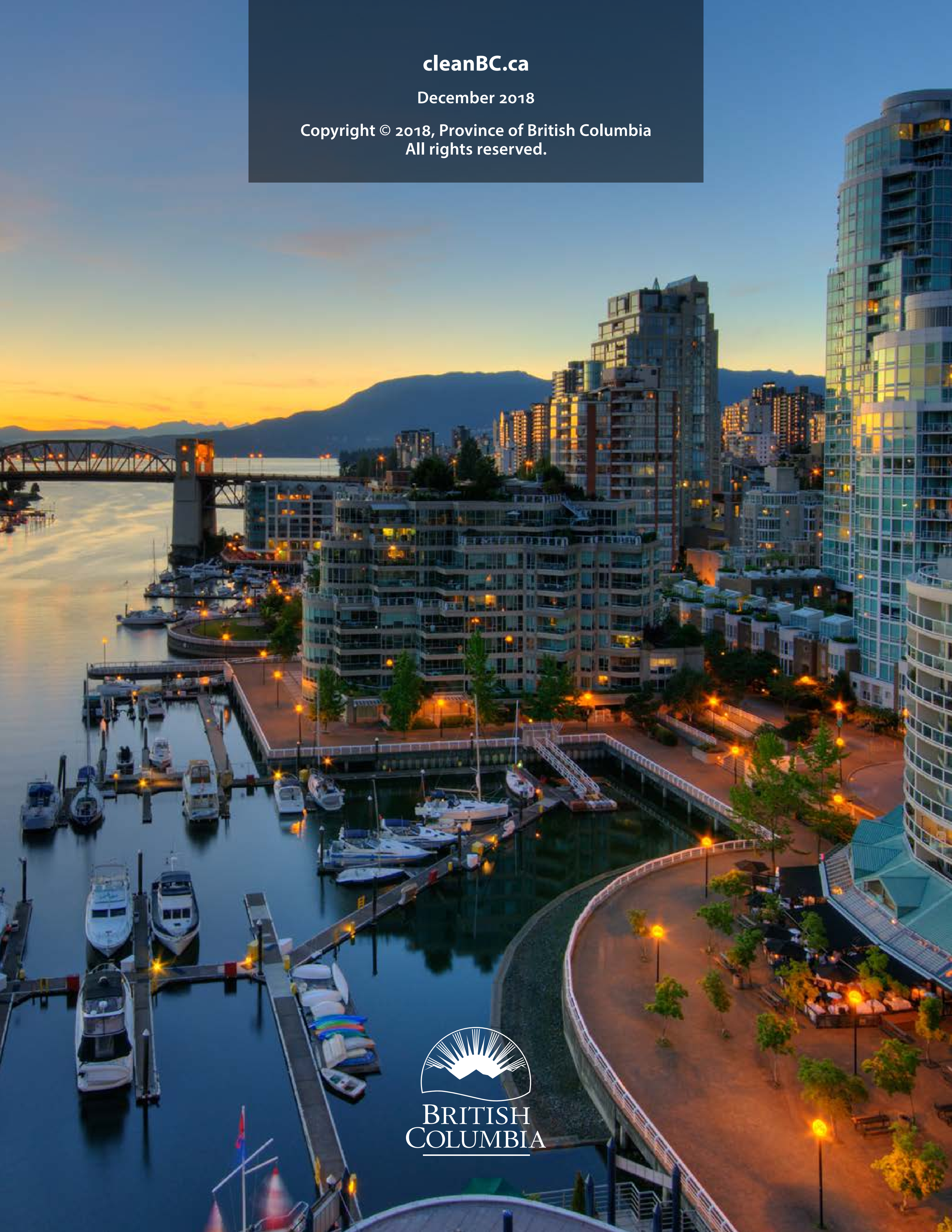
INITIATIVE	DESCRIPTION	GHG Mt in 2030
CLEANER TRANSPORTATION		
Bring down the price of clean vehicles	**Just over 20 years from now, every new car will be a zero-emission vehicle** • Mandate 100% of new cars to be zero-emission vehicles (ZEVs) by 2040; 30% ZEV by 2030 and 10% ZEV by 2025.	1.3
	Help people to afford cleaner cars and save money on gas bills with zero-emission vehicle (ZEV) incentives • Continue to provide rebates for light-duty vehicles • Expand incentives for clean buses and heavy-duty vehicles	0.3
	Make it easier to charge an electric car or fuel a hydrogen car • Expand the charging network with home, work and public fast-charging stations and additional hydrogen fueling stations • Enable private investment in charging and hydrogen fueling infrastructure to get more stations faster	
Speed up the switch to cleaner fuels	**Phase in more renewable fuels for the gas we use** • Make our fuel cleaner by increasing the low carbon fuel standard to 20% by 2030 • Increase the supply of cleaner fuels by ramping up new production in B.C. of 650 million litres of renewable gasoline and diesel by 2030	4.0
	• Make vehicles run cleaner by increasing tailpipe emissions standards for vehicles sold after 2025	0.4
Get to work on getting rid of gridlock	• Help people get around with a long-term strategy to increase active transportation and look at better commuting solutions.	
	subtotal	**6.0**
IMPROVE WHERE WE LIVE AND WORK		
Better Buildings	**Make every building more efficient** • Improve the BC Building Code in phases leading up to "net-zero energy ready" by 2032 • Adopt the model National Energy Code for existing buildings by 2024 • Increase efficiency standards for heating equipment and windows • Encourage the development of innovative and cost-effective low-carbon building solutions	0.5
Support for Better Buildings	**Focused investments in public housing to use less energy at home** • $1.1 B for Capital Renewal fund for public housing to improve living conditions, energy efficiency, and reduce emissions • Incentives to make heat pumps affordable and make homes more comfortable through building envelope upgrades • Retrofits for public buildings so they use less energy • Improve building energy information available to buyers and renters	
	• Make residential natural gas consumption cleaner by putting in place a minimum requirement of 15% to come from renewable gas	1.5
Support for Communities	• Help remote communities reduce their dependence on diesel • Support public infrastructure efficiency upgrades and fuel switching to biofuels with the CleanBC Communities Fund	
	subtotal	**2.0**

INITIATIVE	DESCRIPTION	GHG Mt in 2030
CLEANER INDUSTRY		
Ramp up the clean growth program for industry	• Direct a portion of B.C.'s carbon tax paid by industry into incentives for cleaner operations	2.5
Improve air quality by cutting air pollution	• Clean up air pollution in the lower mainland with a pilot project to test options to switch 1,700 freight trucks to natural gas and low or zero-carbon fuel by 2030 • Make heavy-duty vehicles more efficient with fuel efficiency improvements, education on best driving practices	
Reduce emissions from methane	• Reduce methane emissions from upstream oil and gas operations by 45%	0.9
Industrial electrification	• Provide clean electricity to planned natural gas production in the Peace region	2.2
	• Increase access to clean electricity for large operations with new transmission lines and interconnectivity to existing lines	1.3
Carbon capture and storage	• Ensure a regulatory framework for safe and effective underground CO_2 storage and direct air capture	0.6
Cleaner fuels for industry	• Make industrial natural gas consumption cleaner by putting in place a minimum requirement of 15% to come from renewable gas	0.9
	subtotal	**8.4**
REDUCE WASTE		
Reduce waste and turn it into a clean resource	• Help communities to achieve 95% organic waste diversion for agricultural, industrial, and municipal waste – including systems in place to capture 75% of landfill gas • Waste less and make better use of it across all sectors of our economy, like forestry, agriculture, and residential areas, including renewing the B.C. Bioenergy Strategy and building out the bioenergy and biofuels cluster	0.7
	subtotal	**0.7**
HELPING PEOPLE GET THE SKILLS THEY NEED		
Make sure British Columbians can lead the clean transition	• Develop programs like Energy Step Code training and certification, and Certified Retrofit Professional accreditation • Expand job training for electric and other zero-emission vehicles	
MEASURING OUR PROGRESS		
Establish credible targets and a strategy to meet them	• Roll-out associated programs and enabling legislation for CleanBC	
Stay accountable	• Coordinate implementation and reporting for CleanBC	
Carbon pricing	• Grow the carbon tax $5.00 per year 2018 to 2021 to encourage lower emission alternatives, with rebates for low and middle income British Columbians and support for clean investments	1.8
	subtotal	**1.8**
	2018 CleanBC TOTAL REDUCTIONS *The legislated target for 2030 is a reduction of 25.4 Mt GHG from a 2007 baseline*	**18.9**

** Policy line items represent individual reduction potential estimates. Subtotals and totals are derived from combined modeling and may be lower than the sum of policies because of policy interactions (two policies contribute to the same reduction)*

cleanBC.ca

December 2018



Appendix C

FORTISBC CLEAN GROWN PATHWAY TO 2050

Energy at work FORTIS BC™

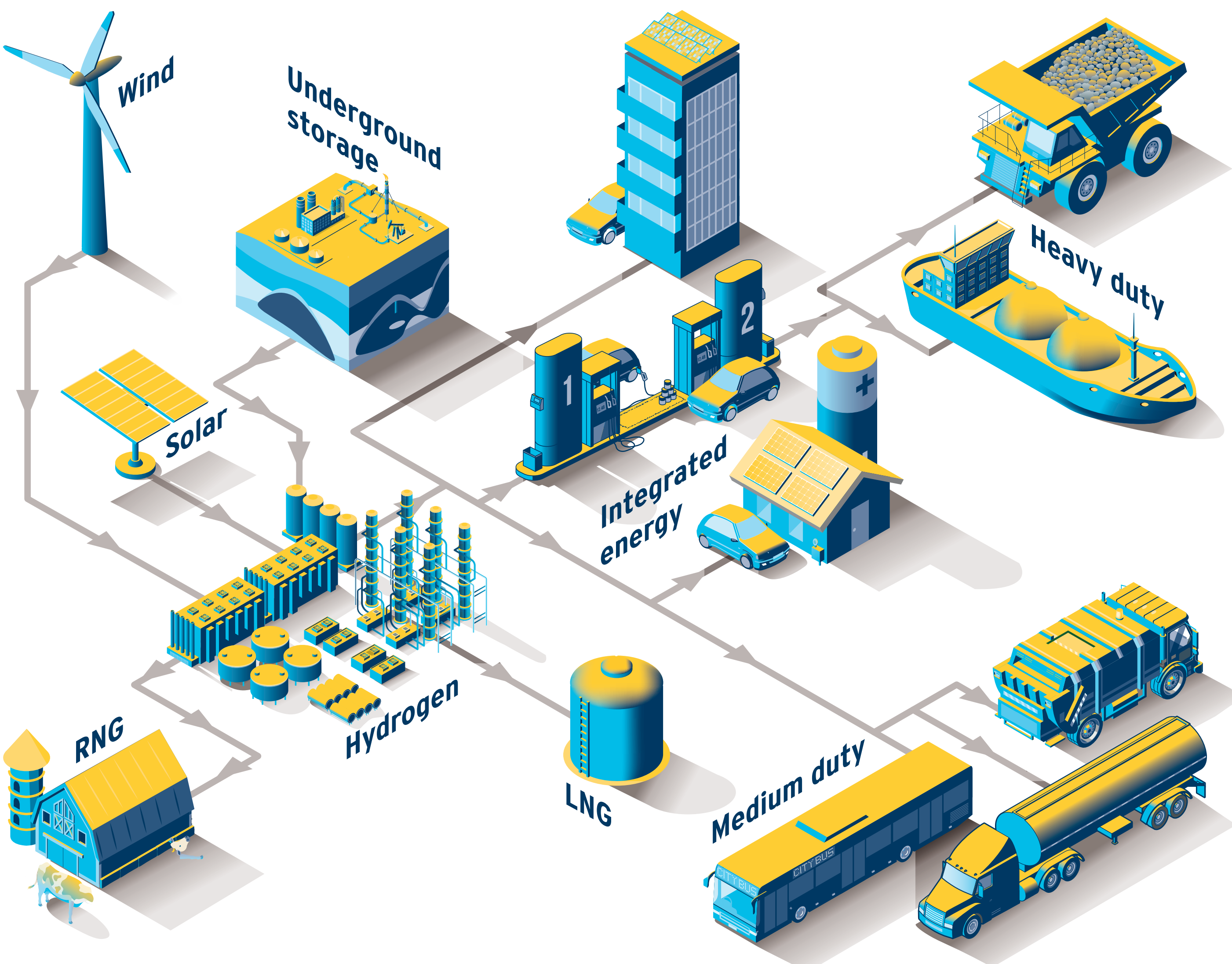
Clean growth pathway to 2050

Contents

Affordability, clean energy and efficiency: FortisBC's clean growth pathway

We believe FortisBC has an important role to play in helping British Columbia move to a low-carbon, renewable energy future. We see ourselves as an energy delivery company that has climate and economic solutions in the buildings and transportation sectors. Millions of British Columbians we serve in communities across the province look to us to deliver energy safely, reliably and affordably every day. As a subsidiary of our Canadian-based parent company, Fortis Inc., one of the largest energy companies in North America, we're committed to helping British Columbia achieve its climate goals and addressing climate change solutions in a global context. We're focused on providing practical solutions that can be implemented today by leveraging our existing infrastructure.

Figure 1: FortisBC's role in driving BC's sustainable prosperity



This paper presents FortisBC's pathway to align with the provincial government's goal to significantly reduce greenhouse gas emissions (GHG) while supporting economic growth and maintaining affordability and customer choice. Our approach combines several strategies that together outline a clear pathway to significant emissions reductions and signal a paradigm shift in the way we relate to energy.

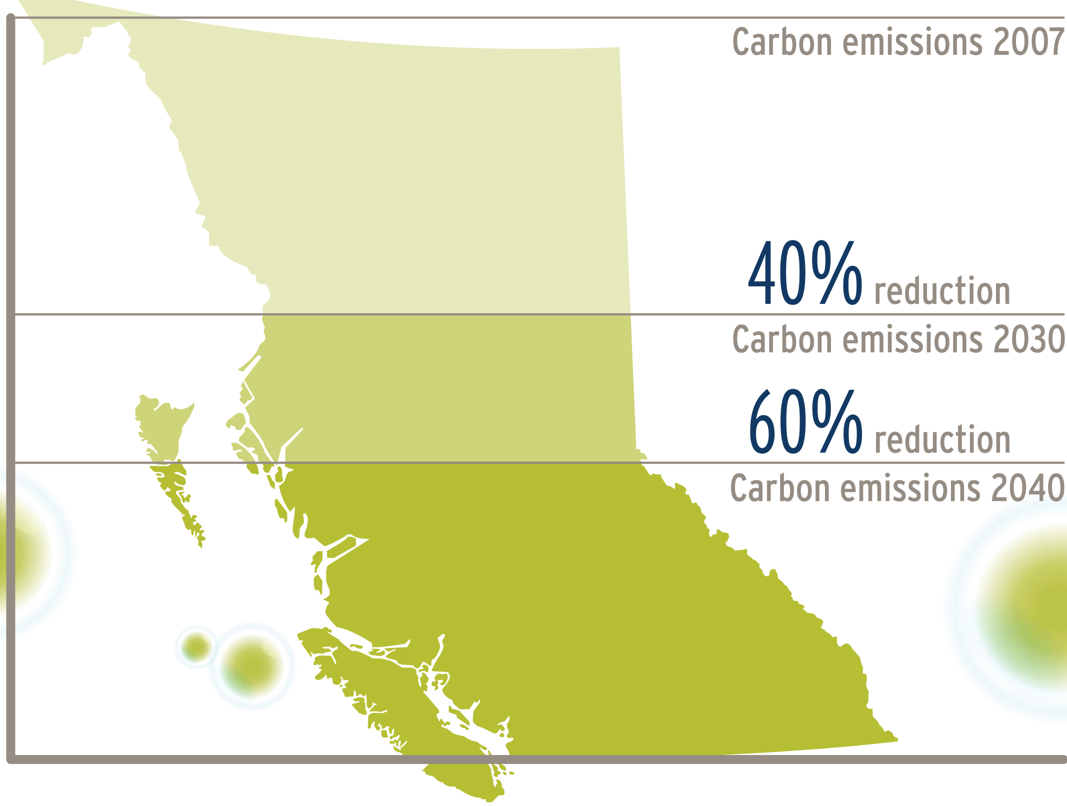
Our pathway calls for four significant shifts in our energy systems to foster market transformation:

- making significant investments in both low and zero carbon vehicles and infrastructure in the transportation sector
- transitioning from higher carbon energy sources to lower carbon sources by ramping up Renewable Natural Gas (RNG) and hydrogen deployment to achieve a ten per cent zero-carbon fuel supply by 2030 and a thirty per cent supply by 2050
- positioning BC as a vital domestic and international Liquefied Natural Gas (LNG) provider to lower global GHG emissions
- tripling our investment in energy efficiency in the built environment and developing innovative energy projects in BC's communities

Introduction

British Columbia (BC) has committed to achieving deep carbon reductions in greenhouse gas emissions by 2050. The province recently updated its climate targets to a 40 per cent reduction in carbon emissions from 2007 levels by 2030, and a 60 per cent reduction from 2007 levels by 2040. Achieving these long-term targets will require immediate and coordinated action by policy makers, regulators and industry. The province will need more than aspirations to achieve real, timely results.

Provincial Carbon Emission Goals



We believe we have a significant role to play in helping the BC Government deliver on its climate and energy goals. Our pathway is based upon our commitment to investing in projects that will make life more affordable for British Columbians, improve efficiency, reduce GHG emissions and drive innovation. By strategically managing BC's existing energy infrastructure and investing in new low-carbon energy supply, we see a long-term opportunity to continue creating sustainable, good-paying jobs across BC.

In 2015, BC's emissions were 63 million tonnes (Mt) of CO_2e. Most emissions fall into three categories: transportation, buildings and industry. We recommend any sectoral targets being considered should be proportionate to the sector's share of GHG emissions and the ability to deliver cost-effective emissions reductions using our current infrastructure.

25%
of BC's CO_2 emissions are from commercial transportation

For example, the commercial transportation sector is the largest contributor to BC's emissions at 25 per cent. The provincial government can achieve large emission reductions in transport using today's commercially-available technology. Practical and affordable solutions that can be implemented immediately should be differentiated from aspirational goals that require technology breakthroughs.

A made-in-BC pathway

As a utility serving gas, electric and alternative energy customers, FortisBC recommends developing an integrated, system-wide evaluation of achieving the province's carbon reduction objectives. Because FortisBC delivers the most energy to consumers of any entity in the province, we have a keen interest in British Columbians understanding the system-wide impacts of various pathways that meet the province's GHG emissions targets. BC's electric and gas energy systems work in tandem to provide reliable energy to British Columbians. Both systems complement one another, providing redundancy and a low-cost solution to delivering energy to British Columbians. FortisBC believes that the provincial pathway should be guided by strong analysis and pursue a strategy that utilizes 'every tool in the toolbox': all of our provincial energy resources and existing infrastructure will be needed to achieve long-term GHG emissions reductions.

Many low-carbon pathways have emphasized the importance of the electrification of end-uses. We agree that electricity will play a key role in reducing emissions but we also caution that there are significant challenges to this strategy. Notably, the direct substitution of electricity for gas to meet heating load, coupled with growth in other areas like electric vehicles, would far exceed the available electric infrastructure and add significant costs to the existing system which would be borne by all BC residents.

FortisBC supports the provincial government's commitment to undertake a review of BC Hydro and incorporate the findings into the Clean Growth Strategy. As we consider how best to transition to a sustainable and innovative economy, we believe there is a need to reflect the real cost of all energy in our long-term goals and strategies.

FortisBC believes that gas—as an energy carrier—will continue to be a critical component of a decarbonized energy system in BC. Gas infrastructure in the province is a multi-billion dollar asset that provides reliable, safe, affordable and high-quality energy services to British Columbians. This infrastructure is designed to serve difficult-to-decarbonize end-uses such as building and industrial heating and heavy-duty freight. Additionally, BC's gas infrastructure is equipped to handle decarbonization pathways that use drop-in fuels such as RNG and hydrogen, along with other key mitigation options like carbon capture and storage. The provincial government and stakeholders like FortisBC need to work to define the key role of the gas system to achieve our GHG reduction objectives and develop policies and other support mechanisms to leverage this system in a low-carbon transition.

Transportation

The transportation sector accounts for 39 per cent of BC's total emissions, making it the most important sector where we can achieve significant and immediate carbon reductions with technology that is available to us today. FortisBC is a leader in North America, providing innovative and clean technology that lowers emissions throughout the transportation sector.

BC's transportation sector accounts for

39%

of our CO_2 emissions

The decarbonization of BC's transportation sector will require the use of all tools available to us including:

- cleaner transportation systems, including increased investment in fuelling infrastructure, clean trade corridors
- displacing high-carbon fuels with cleaner fuels like natural gas, RNG, biofuels or hydrogen
- cleaner vehicles that use alternative fuels, electric power or hybrid technologies

Cleaner transportation systems

BC Ferries new Salish Orca is fuelled by natural gas—an innovative and clean solution that will provide benefits to BC Ferries' customers and the provincial economy.

Marine

The marine sector represents a massive GHG reduction and economic opportunity that should be the top priority in the province's Clean Growth Strategy. BC has had excellent early success in advancing liquefied natural gas (LNG) in the domestic marine sector that serves as a foundation to build upon for other markets.

BC Ferries launched their fourth LNG vessel this summer with a fifth expected next year and Seaspan Ferries now operates two LNG vessels in BC waters. With five LNG vessels in operation, BC Ferries, for example, expects to reduce their fuel costs by millions of dollars and CO_2 emissions by 21,500 tonnes annually, the equivalent of taking approximately 4,400 vehicles off the road per year. To put that in perspective, that's more than double the 2,200 battery electric vehicles that were purchased in all of BC in 2017.

The *Spirit of British Columbia* is the first vessel in the world to refuel LNG through delivery on a fully enclosed vehicle deck. In collaboration with BC Ferries, FortisBC developed a proprietary tanker truck technology to deliver fuel while on board the vessel. Innovative solutions like this help make it easier for transportation customers to make the switch to LNG.

The conversion of BC Ferries' two largest ships in the fleet, along with the introduction of three new natural gas-fuelled Salish Class vessels last year, improves sustainability and affordability for ferry users. FortisBC is proud to have partnered with BC Ferries to develop these innovative and clean solutions that will provide benefits to BC Ferries' customers and the provincial economy.

Clean Trade Corridors

FortisBC applauds the provincial government for initiating the Clean Transportation in BC Trade Corridors initiative. We see this multi-stakeholder collaboration as an essential forum to ensure that BC and Canada are in position to capitalize on international conventions that will reduce the use of dirtier fuels and drive the adoption of LNG in the marine sector. The group's mandate to improve competitiveness and reduce GHGs is well focused and timely—conventions set by the International Maritime Organization (IMO) will take effect by 2020 which is an incredibly short period to transition the practices of international vessels in BC's ports.

Marine vessels that regularly call at BC ports originate from ports of other countries are not included in the provincial emissions inventory, yet these vessels emit a significant amount of emissions when in transit and when berthed in our ports. GHG emissions from this segment of international marine transport are approximately 70 million Mt of CO_2e per year—greater than BC's total annual GHG emissions. These emissions should be considered as part of the province's global GHG reduction strategy by displacing high-carbon marine fuels with low-carbon LNG.

GHG emissions from international marine shipping currently represent around 2.6 per cent of total global emissions, but this share could more than triple by 2050 if measures are not taken to help speed a transition to a low-carbon environment in this sector. Following the Paris Climate Agreement, discussions began at the IMO to agree to an Initial Greenhouse Gas Strategy to stipulate significant measures to mitigate emissions. In April 2018, the IMO agreed on its first strategy to reduce GHG emissions in the international shipping sector to meet the Paris Agreement goals. The IMO strategy includes a target to reduce carbon emissions by at least 50 per cent compared with 2008 levels by 2050. This strategy presents a challenge for a sector that has traditionally faced significant barriers to innovation and an opportunity for BC to position itself as a low-carbon fuel provider in the form of LNG.

Low-carbon fuels such as LNG will be critical to achieving the IMO emission reduction targets. BC is well-positioned to assist in these efforts and become a world leader in LNG bunkering. The provincial government should consider developing policies to start addressing these emissions such as including the ability to generate compliance credits with the Renewable and Low Carbon Fuel Requirement Regulation if international marine vessels use lower carbon fuels such as LNG.

FortisBC was the first company in the world to offer onboard truck-to-ship LNG bunkering. This proprietary design was developed by collaborating with Seaspan Ferries, BC Ferries and their shipbuilders to create a customized solution to fit our customers' needs.

FortisBC has the infrastructure in place to be ready for 2020. FortisBC has completed construction of a $400-million LNG expansion project at our Tilbury facility which includes a new storage tank and additional liquefaction capacity. Plans are being developed to increase the Tilbury LNG facility's liquefaction capacity up to to three million tonnes per annum, expand LNG storage by another 92,000 cubic metres and provide ship loading facilities to serve these markets. Our Tilbury LNG facility is powered by electricity, creating safe, clean, low-GHG emitting LNG.

Expanding our natural gas liquefaction capacity by

92,000

cubic metres

Locally, other agencies such as the Port of Tacoma are also working to position themselves for success. Puget Sound Energy (PSE) is developing an LNG production facility that will enable LNG supply for marine and transportation markets in the region. This LNG facility will incorporate LNG liquefaction, storage and bunkering to the marine market. The project is scheduled to be completed in late 2019 and would compete with BC. FortisBC believes there is a limited window of time for BC to establish itself as an LNG bunkering hub before 2020. BC has an advantage as we have an ample supply of clean LNG available at globally competitive rates.

FortisBC recommends the following actions:

- Continue supporting the Clean Transportation in BC Trade Corridors initiative. Specifically, the opportunity to introduce a pilot program to convert drayage vehicles from diesel to compressed natural gas (CNG) and the advancement of the LNG bunkering in advance of 2020. The provincial and federal governments need to advance the regulation, financial tools for bunkering infrastructure and policies to establish BC as a global leader in LNG bunkering.
- Amend British Columbia's Renewable Low Carbon Fuel Reduction Regulation to generate credits for LNG bunkering that lower international shipping emissions.
- Work with the federal government to develop policies that account for the role of BC LNG in meeting global GHG reduction targets via Article Six of the Paris Agreement.

Cleaner fuels

FortisBC supports the provincial government's proposal to support the transition to cleaner fuels. We see RNG as being an essential component of this transition.

FortisBC was the first utility in North America to offer RNG to residential customers in 2011. RNG is a critical source of renewable energy that is helping the province achieve its GHG emission reduction target. Farms, landfills and other suppliers like the City of Surrey have teamed up with FortisBC to capture methane (CH_4) from organic waste, which would otherwise escape into the atmosphere. This methane, also known as biogas, is purified to make RNG.

FortisBC's RNG program is enabled by a British Columbia Ministerial Regulation, the Greenhouse Gas Reduction Regulation (GGRR). The GGRR has facilitated the development of five operational projects which are forecasted to supply over 203,000 GJ of RNG this year. These facilities capture biogas, clean and upgrade the biogas into RNG, and inject the RNG into our distribution system. Since the RNG offering launched to residential customers in June 2011 and commercial customers in March 2012, over 9,000 customers have subscribed to this offering and have helped reduce GHG emissions an equivalent amount to removing 7,200 cars from the road.

Though FortisBC has achieved important early successes in the residential and commercial sectors, further work is required to grow BC's supply of RNG for use in the transportation sector. Innovations in biogas could boost our supply of RNG to between 25 and 46 per cent of FortisBC's annual natural gas demand by 2036. Power-to-gas, the process of converting electric power into carbon-neutral hydrogen, presents a further opportunity and could account for between five and 15 per cent of annual demand by 2036.

We believe that hydrogen will be a key driver towards reducing BC's carbon emissions, not only as an alternative fuel to enable the decarbonisation of heating, but as a means of storing renewable power (hydroelectric, solar and wind) and, through this, linking together the decarbonisation of the building, industry and transport sectors. We believe in taking a system-wide perspective of hydrogen as a technology that further integrates the electric and gas systems by acting as a high capacity storage medium for carbon-free power generation and a carbon-free fuel for heat and transport.

Turning waste into fuel

Earlier this year, we joined the City of Surrey and the Government of Canada to open North America's first closed-loop waste management system. The facility will convert curbside organic waste into renewable biofuel to fuel the City's fleet of natural gas powered waste collection and service vehicles. Under this closed-loop system, waste collection trucks will literally be collecting their fuel source at curbside. Excess fuel will go to the new district energy system that heats and cools Surrey's City Centre.

The potential of a low-carbon gas system

In our 2017 Long-Term Gas Resource Plan, FortisBC outlined a preliminary analysis of initiatives that could achieve significant GHG emissions reductions by 2030. Emissions reductions opportunities for FortisBC fall into three categories: i) decarbonizing pipeline gas with RNG, hydrogen and carbon capture and storage; ii) energy efficiency and demand-side management (DSM); and iii) fuel switching from more carbon-intensive energy to pipeline gas and LNG.

Should low-carbon gases like RNG and hydrogen achieve a notable share of the total supply in the gas distribution system, FortisBC estimates that the technical potential to reduce GHG emissions would be up to 2.7 and 5.0 Mt. This would reduce emissions from natural gas consumption by between 25 per cent and 42 per cent from 2007 levels in the industrial, commercial and residential sectors.

In the transport sector, FortisBC could achieve 0.3 Mt of domestic reductions and 10.7 Mt from international shipping by 2030. This highlights the significant potential for the gas system to be a key contributor to the province's climate objectives. Ambitious provincial incentives and other policy support would be required to expand the supply of low-carbon gas to this scale. But, maintaining a role for gas within a low-carbon transition ensures that customers maintain their choice of energy supply and lowers the technology risk and costs of a narrowly defined abatement pathway. Such a pathway would also ensure that provincial energy resources and infrastructure are leveraged for a made-in-BC solution.

Growing BC's low-carbon fuel sector will require a number of actions from the province:

- identify RNG as an essential component of the province's clean growth pathway
- address regulatory barriers to expanding utility investment in RNG projects
- streamline regulations to enable RNG production from agricultural waste
- provide support to advance the commercial production of hydrogen as a form of RNG

Domestic carbon reductions from international shipping of

10.7

metric tonnes

What is Renewable Natural Gas?

Renewable Natural Gas (RNG) is a carbon-neutral energy source, because it does not contribute any net carbon dioxide into the atmosphere. RNG is produced in a different manner than conventional natural gas. It is derived from biogas, which is produced from decomposing organic waste from landfills, agricultural waste and wastewater from treatment facilities. The biogas is captured and cleaned to create carbon-neutral RNG.

Peter Schouten, Owner Operator, Fraser Valley Biogas. One of FortisBC's first RNG suppliers.

Cleaner vehicles

Displace higher carbon fuels by expanding BC's natural gas vehicle sector

Commercial transportation accounts for 25 per cent of total GHG emissions in BC and more than half of these emissions originate from road freight transport. By increasing our efforts to displace higher carbon fuels in the heavy-duty vehicle and marine transport sectors, BC can achieve substantial emissions reductions.

By converting heavy-duty truck fleets and transit vehicles to LNG or CNG, we're helping the province meet its carbon emission reduction goals while helping operators save on fuel costs.

FortisBC natural gas for transportation customers are realizing anywhere from 25 to 60 per cent reduction in fuel costs. This helps improve the competitiveness of our private and public sector partners. Since initiating our efforts to introduce cleaner vehicles in 2010, we have eliminated more than 110,000 tonnes of CO_2e and displaced more than 145 million litres of diesel.

Natural gas can reduce GHG emissions by up to 30 per cent compared to diesel and gasoline. Additionally, switching to natural gas fuel can improve air quality: natural gas vehicles emit virtually no particulate matter, and they emit up to 95 per cent less nitrogen oxides (NOx).

UPS' commitment to CNG

Earlier this year, we partnered with the world's largest package delivery company to launch a compressed natural gas fuelling station and vehicles in Vancouver, BC. Seven CNG highway tractors and 40 delivery trucks were added to the current Canadian UPS fleet of over 2,900 package cars, tractors and shifters. Presently, more than 40 per cent of the UPS fleet in Canada runs on alternative fuels. UPS Canada now joins over 800 transit buses, commercial vehicles and freight vehicles powered by natural gas here in BC.

FortisBC recommends the following actions:

- continue supporting investment in CNG transit vehicles and fuelling infrastructure to displace higher carbon fuels and reduce particulate emissions
- expand the GGRR and develop a BC Ports incentive program to convert the 1,700 trucks in BC's drayage sector to CNG or CNG/Hybrid trucks, covering the full cost of the vehicle and reducing both the particulate and GHG emissions associated with BC's ports
- expand eligibility for BC's CEV Specialty-Use Vehicle Program to include hybrid vehicles that include an alternative fuel, such as CNG or hydrogen
- undertake a review of Ministry of Transportation policy to permit low emission natural gas and hydrogen vehicles to use designated HOV lanes on key trade corridors such as Highway 99 and Highway 1

Transform the light-duty transportation sector through electrification

The light-duty transportation sector accounts for 14 per cent of BC's total GHG emissions. This includes light-duty passenger vehicles and trucks that use gasoline or diesel. Electrification of this segment provides a promising pathway to reduce emissions, as cost and performance of the underlying battery technology has seen dramatic improvements in recent years. The automotive industry is responding with many new electric vehicle models arriving in the showrooms of almost every manufacturer.

Growth in the electric vehicle segment is happening in BC but further incentives will be required to achieve government's goal of 5 per cent of all new light-duty vehicle sales. EV sales in 2017 increased by 53 per cent compared to 2016 and were accelerated by an expanding lineup of fully electric vehicles. However, while there has been an increase in the sale of EVs since 2013, at approximately 1.7 per cent of total vehicle sales in 2017 for BC, EV sales are still a small portion of the overall market. FortisBC supports the province's proposal to continue providing vehicle incentives.

Light-duty transportation accounts for

14%

of BC's total GHG emissions

Additional EV charging infrastructure will be critical to advancing the adoption of EVs in the province. Without adequate charging infrastructure deployed throughout the province to allow zero emission vehicles to travel throughout BC safely and conveniently, it is unlikely that the EV market share will progress quickly. Further collaboration between the province, local governments and FortisBC and BC Hydro can address this gap.

We recommend that the province take the following actions:

- continue providing incentives for EV vehicles and infrastructure
- support increased utility investment in EV charging infrastructure in BC
- leverage existing FortisBC CNG fuelling infrastructure to include fast-charging EV stations
- develop measures to encourage charging station installations at businesses and other buildings as part of a smart grid

accelerate Kootenays

FortisBC is a core funder of the *accelerate* Kootenays initiative, a collaborative project that will address the charging infrastructure gap across the Kootenay region in Southeast British Columbia. Earlier this year, we opened five electric vehicle Direct Current Fast Charging (DCFCs) stations in the region, connecting the West Kootenays to surrounding regions for electric vehicle travel.

All West Kootenay stations were installed by Kootenay-based electricians, creating local employment opportunities for residents.

All are part of the broader *accelerate* Kootenays initiative which will ultimately facilitate the installation of 13 fast chargers and 40 Level two chargers in communities across the Kootenays, resulting in over 1,800 kms of connected electric vehicle travel. The fast-charging stations are critical infrastructure to allow electric vehicle drivers to travel to and through the region, and to facilitate increased adoption of electric vehicles locally.

Buildings & communities

FortisBC is uniquely positioned to be a key agent of the government's strategy to reduce GHG emissions in buildings and communities in a cost-effective, market-driven manner. We provide energy in the built environment through gas, electricity and as an alternative energy provider.

In 2017, we opened the door to our new LEED-equivalent Kootenay Operations Centre outside of Castlegar, BC.

The marketplace recognizes the affordable, high-quality, reliable and safe energy services delivered by FortisBC. Over three million British Columbians use natural gas every day with over 58 per cent of households using natural gas as their primary heating source. The preference for gas is reflected by our continued customer growth. In fact, 2017 was FortisBC's best-performing year for customer growth, with many new customers converting their home heating system from high carbon fuels such as heating oil. This emphasizes the foundational role of gas infrastructure in BC's energy system. To achieve the provincial government's GHG reduction objectives, consumer preference for gas as a low-carbon and affordable energy source should be recognized and harnessed.

Even though customer additions to FortisBC's gas system were at record-levels in 2017, the amount of gas used on a per customer basis declined by 1.8 per cent in 2017 on a weather normalized basis. This speaks to the success of energy-efficiency measures in the province including FortisBC's energy conservation programs, federal and provincial policies and the gradual but concerted shift in the built environment to more energy-efficient dwellings.

The unique aspect of the gas system is that it is specifically designed to address heating demand. Seasonal changes in heat demand (referred to as "peak load" or "peak demand") can be up to 400 to 500 per cent greater than FortisBC's average demand. For comparison, peak load in the FortisBC electric system is approximately 40 per cent higher than average load. If BC used electricity as the primary source for heat, the seasonal variability of heating load would create a huge need for energy storage. Hydropower could meet the storage requirement were it not for the magnitude of heat load in BC. The approximate peak-hour heating load in 2017 in FortisBC's gas system was over 12 GW of electrical capacity equivalent (at a one-to-one unit energy conversion basis). In other words, electrifying heating could require almost a doubling of the existing hydroelectric capacity in BC even before considering the electrification of some part of the transportation fleet or other energy end uses and the additional transmission and distribution requirements. Recognizing this, decarbonizing the gas flowing through the system while maintaining the use of that system is a prudent and low-cost strategy to ensure that BC achieves its climate targets.

Stronger codes and standards over time

We support stronger codes and standards that result in increased energy efficiency. We support an approach that is aligned with the current BC Building Code and BC Energy Step Code (BC ESC) targets. The BC ESC provides an incremental and consistent approach to achieving more energy-efficient buildings in a cost-effective manner while also reducing GHG emissions.

Codes and standards should stay consistent to achieve energy-efficiency gains

The BC ESC was developed after an extensive, multi-year engagement process. As a member of the Energy Step Code Council, FortisBC provided insights into the development of the BC ESC, particularly with respect to ensuring affordability needs for British Columbians are addressed, while supporting continuing innovation in the use of energy in buildings.

In addition to supporting long-term improvements in energy efficiency in the BC Building Code, the BC ESC ensures the consistency of building regulations in the province; a key to ensuring clear regulation for builders and developers looking to build in multiple municipalities. The BC ESC provides a provincial framework that replaces the patchwork of different green building standards that have been required or encouraged by local governments in the past. This allows local governments to play a leadership role in improving energy efficiency, while providing a single standard for industry, and build capacity over time.

The BC ESC focuses first on building envelope design with a goal of taking incremental steps to make buildings net-zero energy ready by 2032. It provides for a fuel neutral approach and focuses on the efficiency of buildings and equipment. By focusing on building and equipment efficiency, both overall energy usage and GHG emissions are reduced while building comfort is increased. While costs increase at higher levels of the code, energy usage decreases help offset the increase in overall costs to consumers. The BC ESC also provides flexibility to meet the changing needs and abilities of local governments, industry and technologies. It does this by providing local governments with the tools to pursue a long-term vision for the future of energy efficiency of buildings and related climate action initiatives. As a new code structure, the BC ESC, similar to other changes in the BC Building Code, requires time to learn, implement and see results. It is common practice to make changes to the code only every five to seven years to allow the industry and consumers to become familiar with the change.

Adding additional regulations into the BC ESC, such as the proposed GHG intensity (GHGi) requirement, before results of the adoption of the existing BC ESC are understood and realized would be premature and could lead to unintended consequences: higher energy costs, impaired housing affordability and a loss of choice for consumers. The provincial approach should support consumer choice, by allowing designers and builders to continue to choose gas, electricity, or other energy sources for their project. A fuel-neutral approach provides builders with the flexibility to make energy-efficient buildings using all the available technologies along with managing their costs. It also empowers builders and developers to pursue innovative, creative, cost-effective solutions, and allows them to incorporate leading-edge technologies as they come available. We believe that committing to the current

BC ESC is a prudent measure accounting for the scale of change that the new code presents to the market and the importance of aligning the code across the province.

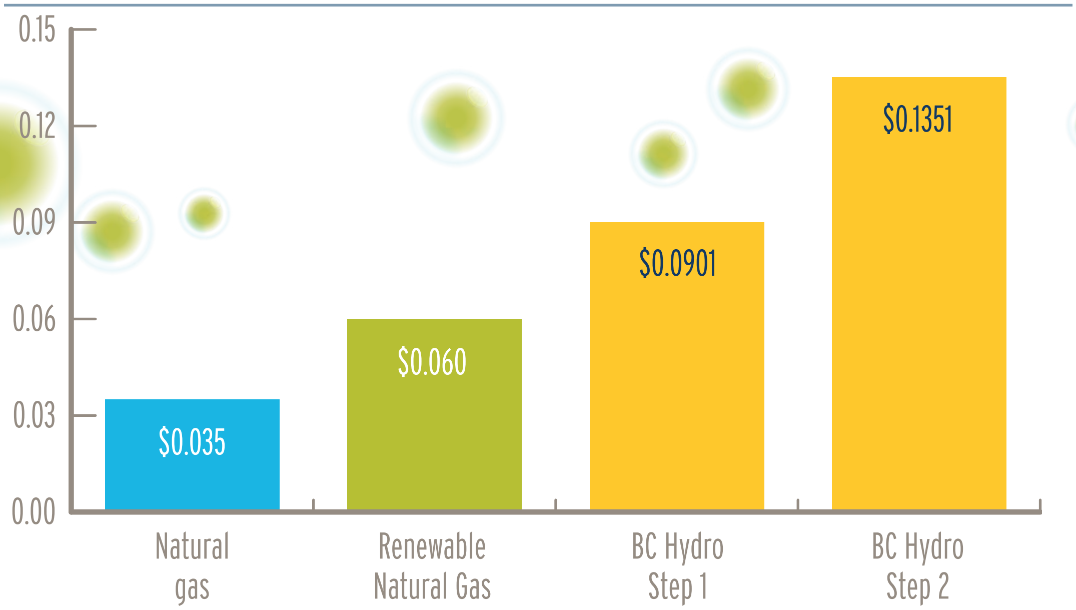
FortisBC has been, and continues to be, a strong advocate for the use of the BC ESC. For example, FortisBC and the City of Vancouver signed a Memorandum of Understanding (MoU) which ensured that the City would introduce pathways that used the BC ESC for builders to comply with the City's Zero Emissions Building Plan. Under these compliance pathways, builders can choose to follow the BC ESC without additional requirements such as a GHGi target. FortisBC also committed to developing a DSM program based on the BC ESC in the MoU. By having new pathways aligned with the BC ESC, FortisBC could provide DSM incentives to lower the costs of achieving the BC ESC to builders in Vancouver while still achieving meaningful improvements in the energy efficiency and GHG reductions of new buildings. Were the province to allow a patchwork of BC ESC along with municipally-specific GHGi requirements, FortisBC would not be able to provide DSM incentives to moderate the affordability pressures of new ambitious codes that restrict access to the gas system.

BC should seek alignment with national codes and standards to ensure consistency with other jurisdictions as it considers a new code for retrofits. The federal code for alterations to existing buildings should serve as a template for BC, as suggested. Because of the scale of the retrofit challenge, clear goals and objectives need to be identified to ensure that all players in this sector have a role. FortisBC is exploring innovative partnerships to demonstrate building energy retrofits and we believe that large GHG reductions consistent with the province's long-term GHG objectives are possible while still maintaining connection to the gas system.

Finally, we recommend that any further changes to the BC Energy Efficiency Standards Regulation should be aligned with federal standards to ensure consistency for equipment manufacturers. We agree with the Canadian Homebuilders Association that it is likely that manufacturers will focus efforts on areas with the greatest market share, national and international, and BC's initiatives may not be as lucrative to encourage the necessary research and development in comparison to federal approaches.

Maintaining affordability for BC energy consumers

Residential gas $/kWh price comparison



Affordability is the key concern among BC residents and FortisBC customers while producing energy locally is the top policy priority for government to consider. As we transition to a low-carbon economy, care must also be taken to ensure that we pursue cost-effective strategies that will not result in higher costs for energy consumers.

Consumer priorities on energy issues

In August 2018, FortisBC commissioned Innovative Research Group to conduct a survey on consumer priorities on energy issues. The survey found that:

- **For 42 per cent of respondents affordability is the top priority in their personal energy choices**, followed by the environment (24 per cent) and reliability (22 per cent).
- When it comes to government policy, the top priority is **helping the economy by producing energy locally (28 per cent)**, followed by affordability (27 per cent), with environment third (21 per cent).

The survey was conducted between August 3 and 14, 2018 among a sample of 1,328 randomly-selected British Columbians. The survey used a mixed-method online and phone methodology. Interviews in English (n=1,024) were conducted using a representative online panel and in-language interviews in Cantonese, Mandarin, and Punjabi (n=304) were conducted over the phone. Results were weighted to a sample size of n=1,200 based on age, gender, region of the province and mother tongue.

We also believe that regional differences in BC should be taken into account. For example, policies that restrict choice will disproportionately impact energy consumers outside of the Lower Mainland and Southern Vancouver Island that reside in BC's colder regions. Similarly, regions that rely on BC's natural gas industry to drive the provincial economy, should also be taken into account.

FortisBC's RNG, while more expensive than natural gas, is still approximately half the price of electricity in BC and with a lower carbon intensity. This demonstrates the potential for the gas system to achieve significant, affordable GHG reductions with low-carbon drop-in fuels such as RNG and hydrogen. To achieve this potential, supportive policies that provide incentives and opportunities to invest in low-carbon gas supply will be needed over the long-term. These investments will only happen as long as the gas system remains a viable productive asset and consumers have the choice to continue to connect to and use gas.

It is for all these reasons that we believe an approach that targets increased energy efficiency and allows for consumer choice and innovation is consistent with the broader government objectives: making life more affordable and growing the BC economy while taking action on climate change.

Incentives tied to energy efficiency and building improvements

We support increasing energy-efficiency incentives. FortisBC is seeking to significantly expand energy-efficiency investments in our DSM portfolio. Our proposal currently before the British Columbia Utilities Commission (BCUC) includes more than doubling energy efficiency spending from 2016 levels by 2019 and with further increases over the next four years. By 2022, we are committed to investing more than $96 million annually, approximately tripling our 2016 spending.

Committed to investing more than

$96 million

annually by 2022

FortisBC estimates that this increased funding would effectively double annual natural gas energy savings and GHG emissions reductions, with the majority of savings occurring in the built environment. Annual energy savings would be in the order of one million GJ of gas which will in turn lead to reductions in GHG emissions of approximately 50 thousand tonnes of CO_2e per year.

We are also seeking approval to expand our electricity DSM portfolio. In our 2019 to 2022 DSM Plan, which is currently before the BCUC for review, we are seeking a 21 per cent spending increase over what we put forward in our long-term DSM Plan. We expect to achieve 17 per cent more energy savings than set out in the long-term plan, or 130 GWh over the plan period.

Through assisting customers in moving to higher-efficiency equipment, supporting the BC ESC and advancing energy conservation in BC overall, our expanded energy efficiency programs will positively impact the province and support the achievement of BC's GHG emissions reduction goals. These measures will also support the BC government's commitment to improving affordability: individual customers will reduce their energy consumption and their energy bills.

FortisBC is supportive of the proposal to develop an incentive program to complement existing utility-led energy-efficiency programs focused on retrofits. We believe that if utility and provincial actions are well-designed, they could leverage each other and strengthen participation. We advocate for the provincial government to continue to work closely with utilities in designing this program.

Advanced Metering Infrastructure (AMI) is a valuable tool in helping our customers across BC improve energy efficiency and reduce GHG emissions in residential and commercial buildings. This technology is providing FortisBC's electric customers with more control over how they use energy. To date, we have installed over 134,000 AMI meters in our electric service territory and we seek to extend these benefits to our natural gas system. This technology is the foundation of a more modern natural gas system that improves the customer experience by empowering them to access data to make informed decisions about their energy use. With advanced meters, our natural gas customers will have the information they need to inspire mindful choices like using digital control to better manage use of heating appliances or making energy-efficiency upgrades to their homes. This technology could also help facilitate more investment in behind the meter solutions by identifying buildings well suited to energy-efficiency upgrades and integrating those solutions to the broader system to maximize energy-efficiency gains. We recommend that the provincial government provide support for wider deployment of AMI across BC's natural gas network.

Support for low-carbon innovation

FortisBC is well-positioned to identify innovation investments to reduce the carbon footprint of BC's energy system. FortisBC is interested in investing in core research focused on opportunities relevant to BC. This could include ultra high-efficiency gas-fired heat pumps, hydrogen production technologies, measures to reduce the carbon intensity of natural gas such as carbon capture and storage, and near zero GHG engines in vehicles. Without innovation funding from FortisBC or other agencies focused specifically on addressing GHG emissions within BC's unique energy system and fully integrated gas supply, transitioning the gas system to align with the provincial climate targets will be even more challenging.

We recommend that the province consider mechanisms for utility-led innovation investment aimed at reducing GHGs or directing a portion of Innovative Clean Energy (ICE) funding to utility-led projects.

FortisBC also seeks to expand BC's supply of clean energy. Wood and forest residues could significantly expand the amount of RNG supply in BC but, to unlock this potential, focused support for innovation from the public and private sectors will be needed. Of the total supply potential for RNG, wood has the largest share representing approximately 50 per cent of natural gas consumption in Canada. There are a number of other co-benefits of harnessing the potential of wood feedstocks for RNG. These include reducing GHG emissions in BC's forestry-based industries while providing them with new, meaningful financial benefits. This could increase the competitiveness and international market share of Canadian forest industries and boost employment in the sector. However, there are still important technological gaps and high costs associated with wood-based RNG production meaning that, to-date, there has been limited RNG production from wood. The provincial government should identify RNG from wood feedstocks as a key priority for its innovation and climate objectives and work with the forestry sector, FortisBC and the research community to realize this opportunity.

We are supportive of new policies that will support utility investment to broaden our supply of clean energy to include new forms of alternative energy. For example, FortisBC Alternative Energy Services (FAES) is a leader in providing cost-effective, high-performance thermal energy solutions (TES) in BC's building sector. For example, our Marine Gateway and Telus Gardens energy systems in Vancouver, both use renewable and recycled energy to improve efficiency and emissions by 50-80 per cent compared to conventional systems. To date, FAES has invested more than $62 million in high-efficiency energy systems which we own and operate on behalf of our customers.

To date, FAES has invested more than

$62 million

in high-efficiency energy systems

In order to accelerate FAES' contribution to providing highly efficient and low-carbon energy systems, we propose that government support a move to facilitate adoption of a regulated pooled cost model for TES providers. This recommendation would ultimately lead to faster market adoption of TES solutions.

Another example of low-carbon, FortisBC-led innovation is the proposed Ellison Community Solar Pilot project that could be the largest utility-owned solar project in BC. Interest in solar is on the rise and we seek to provide an easy, affordable option for our customers who want to use solar energy to meet a portion of their electricity needs. Our aim is to develop a solar program for customers who are interested in solar, but the upfront cost, placement, operation or maintenance of a rooftop system is not desirable. The province should create opportunity for future utility investment in clean energy projects where there is consumer demand for these offerings.

Energy-efficiency labelling information

FortisBC supports the province's goal to improve information for building owners and residents on the energy performance of buildings. As the province develops this program, total energy consumed, carbon footprint and overall cost should all be included in the energy labeling information. FortisBC looks forward to working with the province to further develop this proposal.

A clean growth program for industry

Industry is an important part of the Provincial economy and our customer base. Of FortisBC's million customers, less than a thousand are industrial clients, yet these firms consume approximately one-third of FortisBC's total gas demand. To these customers, gas is a low-cost, efficient, reliable and high-quality fuel source. FortisBC is proud to be the energy supplier of choice to the industries that propel BC's economy.

FortisBC agrees with the provincial government that reducing GHG emissions must happen alongside a strengthening economy. Reducing GHG emissions through investment, technology and sustainable growth must be fostered in a framework to ensure BC's businesses and industries are not put at a competitive disadvantage. The intention to develop an effective Clean Growth Program for Industry is an important objective of the provincial government. To this end, we believe that an incentive-based approach for industry is an important development.

We also believe that BC needs to be in alignment with the rest of Canada. The federal government's output-based system in the Carbon Pricing Backstop provides more relief to industry while still maintaining the same marginal incentive to reduce GHG emissions. BC should commit to reviewing and evaluating outcomes from the two systems. If the federal approach demonstrates better outcomes for emissions and the economy, then BC should adopt this system to create a level playing field for industries across Canada.

Industrial incentive

We believe that setting the performance benchmark at the level of the cleanest facilities in the world is an ambitious but achievable starting point as many industries in BC are already world-leading environmental performers. Because the Clean Growth Program for Industry aims to improve the international competitiveness of BC's industries, we support the benchmark level as the best performing international firm or facility.

Industries within BC or Canada should not be used to set the benchmark. This would force domestic firms to compete against each other and incur costs with no impact on their international competitiveness. As provincial carbon policy costs begin to align under the Pan-Canadian Framework, the incentive for domestic firms to reduce their carbon emissions is evened. In fact, BC's approach to tax all of a firm's carbon emissions up to $30 per tonne applies significantly more carbon costs than the approach used in the federal output-based allocation system which applies the carbon price only on emissions above the benchmark. This means that even with an aligned price on carbon, BC firms would be disadvantaged compared to other provinces.

A Canadian first

Climate change is a global issue, and FortisBC is committed to being part of the solution. One of the ways we're doing this is by exporting liquefied natural gas (LNG) to countries like China that are looking to significantly reduce their greenhouse gas emissions.

Late last year, FortisBC notched a milestone by delivering the first shipment of LNG from Canada to China. Since then, our shipments have continued, with the most recent one arriving in Shanghai in May.

As China's LNG imports continue to increase, analysts predict it could one day eclipse Japan as the world's biggest importer of natural gas. This presents a unique opportunity for FortisBC, which has the only two LNG storage facilities on Canada's West Coast.

FortisBC's LNG facility in Delta, BC has been operating since 1971 and in order to meet the growing demand for LNG it recently underwent a $400-million expansion.

This market shift is about more than just an economic opportunity for Canada. Underlying this trend is the fact that natural gas is a strong energy option for countries like China that are looking to transition from high-carbon fuels to cleaner and more affordable alternatives.

FortisBC offers an abundant supply of LNG that meets high environmental standards. In fact, when FortisBC's Tilbury LNG plant expansion is operational later this year it will be one of the cleanest LNG facilities in the world.

The additional GHG reduction that would be achieved by using domestic firms for the performance benchmark is marginal while simultaneously not improving the competitive position of BC firms in the international market. Because BC's firms compete for market share against international firms, ensuring that carbon costs are moderated compared to the next best international performer should be the key objective. We believe this makes both economic and environmental sense. Incentivizing firms to achieve the lowest carbon intensity than the next best global performer ensures that carbon leakage is minimized while firms in BC are allowed to grow.

The provincial government should use a consistent approach when setting the benchmark across all industries. This means that determining the benchmark for incumbent industries such as mining and pulp and paper should be the same as for nascent industries such as LNG exports. A consistent approach ensures industries of the future can compete for global markets just as today's industries can. FortisBC also supports the principle of consistency regarding the threshold to enter the program at 10,000 tonnes of annual GHG emissions. This will ensure that all large industries can access carbon tax incentives. The government should monitor this threshold and consider opportunities for smaller firms to opt-in to the program.

A threshold of
10,000
tonnes
will ensure all large industries can access carbon tax incentives

The threshold and the benchmark should also account for all emissions whether from combustion, process or fugitive. Firms that demonstrate real investments in technologies and practices that reduce process and fugitive emissions should be able to report those savings toward their emission intensity.

Clean Industry Fund

FortisBC supports the creation of the Clean Industry Fund as a way to invest carbon revenues into direct emissions reductions and innovation in low-carbon technologies. The fund should only be available to firms that are participants in the Clean Growth Program. The fund should be additional to existing government funds for innovation and technology and focused on industrial improvements. The scope for funding should be broad and include direct facility-level improvements, research and development, pilots and demonstrations and projects across the energy supply chain that will lower the carbon intensity of fuels. FortisBC anticipates that it would be a recipient of funds to develop leading technologies in, for example, efficiency, RNG and hydrogen that would improve the carbon intensity of industrial clients.

Investments from the fund should allow projects that achieve both short and long-term GHG reductions and be fuel neutral. A common and agreed framework to evaluate proposals that emphasized cost-effective short term reductions or long-term projects with high reduction potential should be negotiated with Clean Growth Program participants.

FortisBC believes that the government should target industry specific reductions along with system-wide initiatives that could reduce the carbon intensity of all industries. A priority list of actions could be developed in consultation with industry to earmark fund dollars for high-payoff strategies. We believe that one such strategy is to support clean gaseous fuels such as RNG and hydrogen. A specified and focused tranche of support from the fund could have an outsized role to improve the carbon intensity of all industries in BC.

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Energy at work

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(19-110.1 02/2019)

Appendix D

PNW ELECTRIC UTILITIES INTEGRATED RESOURCE PLANS COMPARISON TABLE

PNW Utilities IRP Comparison Table

	Idaho Power Company	Avista Utilities	PacifiCorp	Puget Sound Energy	Portland General Electric	Seattle City Light
IRP Link	https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/our-twenty-year-plan/	https://www.myavista.com/about-us/integrated-resource-planning	https://www.pacificorp.com/energy/integrated-resource-plan.html	https://pse-irp.participate.online/	https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning	http://www.seattle.gov/light/IRP/default.asp
Latest Plan	June 2019 IRP (2019-2038)	February 2020 IRP (2021-2045)	October 2019 IRP (2019-2038)	2019 IRP Progress Report (2018-2037)	March 2019 IRP (2020-2050)	2018 Progress Report (2018-2037)
Service Area(s)	Idaho and Oregon	Eastern Washington and Northern Idaho	Pacific Power: Oregon, Washington and California Rocky Mountain Power: Utah, Wyoming and Idaho	Washington	Oregon	Washington (City of Seattle & outlying communities)
Number of electric customers	557,645[1]	340,000[2]	1,900,000	1,100,000	887,000	780,000
Current Energy/ Capacity[3] Requirement	Capacity: 3,392 MW[4] Energy: 1,810 aMW[5]	Capacity: 1,726 MW[6] Energy: 1,102 aMW	Capacity: 10,880 MW[7] Energy: 60,555 GWh	Capacity: 5098 MW[8] Energy: 2,681 aMW	Capacity: 3,976 MW[9] Energy: 2,099 aMW	Capacity: 2,841 MW Energy: 10,068 GWh

[1] *https://www.idahopower.com/AboutUs/CompanyInformation/Facts/default.cfm*
2 https://www.myavista.com/about-us/our-company

[3] *8,760 hrs / year (non-leap year) * aMW - If leap year – 8,784 hrs / year*
[4] *Idaho Power Company 2019 IRP – Table 3.1 (Historical capacity, load and customer data)*
[5] *Average Megawatt (aMW)*
[6] *Avista 2020 IRP – Table 3.6 Energy and Peak Forecasts (for year 2020)*
[7] *Net-Owned Generation Capacity https://www.brkenergy.com/assets/pdf/facts_pacificorp.pdf*
[8] *Puget Sound 2017 IRP – Figure 5-4, 5-6*
[9] *2017 peak load - https://www.portlandgeneral.com/our-company/pge-at-a-glance/quick-facts*

	Idaho Power Company	Avista Utilities	PacifiCorp	Puget Sound Energy	Portland General Electric	Seattle City Light
Annual Load Growth Forecast[10]	Energy: 1.0 % Capacity: 1.2%	Energy: 0.3%	Energy: 0.87% Capacity: 0.83%	Energy: 1.3% Capacity: 1.4%	Energy: 1.0% Capacity: 1.2%	Energy: 0.4%
Current Energy Portfolio Mix	46% Hydro 17% Coal 8% Natural Gas 29% Purchased Power (20% PURPA[11] & PPA[12], 9% Market Purchases)	41% Natural Gas 26% Owned Hydro 9% Contracted Hydro 12% Coal 12% Biomass, Wind, Solar and Refuse[13]	56% Coal 24% Natural Gas 10% Hydro 10% Renewable (Wind, Solar)	36% Coal 20% Natural Gas 32% Hydro Wind 10% Nuclear 1% Biomass, Other 1% ([14]	15% Coal 28% Natural Gas 15% Hydro 9% wind 33% Market Purchases (mix of renewables, hydro and thermal resources)	86% Hydro 7%Wind 5% Nuclear 1% Biogas 1% Unspecified[15]
Planning Reserve Margin	15%	Summer: 7% Winter : 16%	13%	17.8% After 2026 : 18.3%[16]	Summer: 10% Winter : 12%	Only provide WECC Target Margins: Summer: 17.5% Winter 19.2%
DSM	Energy efficiency reduces annual energy demand by 234 aMW and peak demand by 367 MW by 2038	Energy efficiency achievable potential of 235.4 aMW by 2040	Energy Efficiency and direct load control equal to 700 MW for the planning period (2019-2038)	Energy efficiency 374 MW by 2023 and 714 MW by 2037.[17]	Energy efficiency resource supply of 547.6 aMW by 2037	New conservation reaching 128 aMW by 2025 and 205 aMW by 2035
Owned Supply Resources	17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel-powered	8 hydroelectric developments, 1 coal-fired unit, 5 natural gas-fired projects, and a	10 coal facilities, 6 natural gas facilities, 1 geothermal and other, 41 hydro systems, 13 wind facilities, 2 coal mines	Shared ownership in 4 coal-fired generation units, 6 CCCT[18], 4 SCCTs[19], 3 hydro plants, 3 wind farms	7 hydroelectric plants, 5 natural gas plants, 2 coal-fired plants, 2 wind facility, 1 solar	4 major hydroelectric projects, 3 small hydroelectric projects, Landfill gas plant, BPA

[10] *All after DSM*
[11] *Public Utility Regulatory Policies Act (PURPA)*
[12] *Power Purchase Agreement (PPA)*
[13] *Refuse is a fuel produced from various types of waste, such as municipal solid waste.*
[14] *https://www.pse.com/pages/energy-supply/electric-supply*
[15] *http://www.seattle.gov/light/FuelMix/*
[16] *Includes operating reserves. After 2026 Planning Margin increases to 18.3% after Colstrip Units 3 and 4 are removed from energy supply*
[17] *2017 PSE IRP*
[18] *Combined-cycle combustion turbine (CCCT)*
[19] *Simple-cycle combustion turbine (SCCT)*

	Idaho Power Company	Avista Utilities	PacifiCorp	Puget Sound Energy	Portland General Electric	Seattle City Light
	plant, share ownership in 3 coal-fired facilities	biomass plant.				Hydro PPA (40%)
Load- Resource Balance	Energy deficit: 2026 Capacity deficit: 2029	Energy deficit: 2026 Capacity[20] deficit: 2026	Energy Deficit: 2026 Capacity Deficit: Winter 2024 Summer 2028	Energy deficit: 2025 Capacity deficit: 2025	Energy deficit: 2021 Capacity deficit Winter: 2021 Summer: 2026	Energy deficit: 2028 Capacity deficit: 2028
Preferred Resource Strategy	220 MW of Solar PV capacity by 2022-23 and 125 MW from 2034-2038. Exit 3 coal units by 2022 and 2 other coal units by 2026[21]. B2H transmission line project on-line in 2026. Natural Gas generation of 222 MW from 2028-2030 and additional 300 MW in 2035 and 2038.	Adequate resources before 2022, 500 MW of new wind, thermal upgrades in 2026 and 2027. Additional long duration pumped hydro storage and demand response.	DSM (700 MW of energy efficiency and new direct control resources), incremental transmission investment, 3,000 MW solar and 3,500 MW wind by 2023, 600 MW of battery storage capacity	Energy efficiency and demand-response push natural-gas-fueled peaking plant to 2025. Additional 265 MW of solar by 2023, followed by another 377 MW by 2027. Removal of all coal generation by 2025.	Energy Efficiency (157 MWa[22] by 2025), renewable actions including wind resources of 227 MWa by 2025 and energy storage (batteries and pumped storage)	Acquisition of energy efficiency, renewable resources, and improvements in hydro generation efficiency. Major resource required earliest by 2028
Clean Energy and GHG Reduction Targets and Initiatives	Reduce average C02 of energy sources from 2010-2020 to 15-20% lower than 2005. Ending participation in 2 coal plants. Reduce average CO2 emissions from	Shift to clean energy reduces GHG emissions from 2018 levels by 71% in 2030 and 79% in 2045 100% carbon neutral energy by 2027 (Renewable	Energy Vision 2020 Plan: 1,150 MW of new wind and 999 MW of upgraded wind resources to come on-line by 2020. California: Planning target of 100% renewable and carbon-free by 2045. Oregon: 50% Renewable by	Washington State Energy Independence Act calls for utilities to invest in renewable generation to meet 15% of demand by 2020 and the Clean Energy Transformation Act requires at least	Reduction in GHG emissions of more than 80% by 2050. On track to serve 50% of customers with clean energy. Expanding and accelerating their “Electric Avenue”	Washington State Energy Independence Act calls for utilities to invest in renewable generation to meet 15% of demand by 2020 and the Clean Energy Transformation Act requires at least

[20] *Net of energy efficiency*

[21] *There are seven coal units are within the 3 Coal-fired facilities owned (shared) by Idaho Power Company*

[22] *Megawatt Average (MWa)*

	Idaho Power Company	Avista Utilities	PacifiCorp	Puget Sound Energy	Portland General Electric	Seattle City Light
	energy sources from 2010 to 2020 is 15-20% lower than 2005 levels. 100% Clean Energy by 2045.	resources and REC[23]) and 100% clean energy by 2045 (phase out all carbon producing generation). Developing new programs for 2020 and beyond in Transportation Electrification Plan.	2040. Washington: 100% carbon neutral by 2030 and planning target of 100% renewable by 2045. Utah: goal of 20% by 2025 (must be cost effective). Investing $26 million to support EV fast chargers, develop workplace charging programs, implement smart mobility.	80% of delivered load be met by renewable resources by 2030 and 100% by 2045. Reduce Puget Sound Energy's carbon footprint by 50% by 2040. Carbon Balance program allows customers to purchase verified carbon offsets from local projects that work to reduce GHG. emissions. Green Direct Program allows customers the ability to purchase 100% of their energy from dedicated, local, renewable energy sources. Moving away from coal generation ahead of schedule with sale of Colstrip Unit 4 and closure of Units 1 & 2 in 2020.	charging stations. Currently have 5 locations, 2 more by 2020. Distributed Flexibility to reduce 200 MW of conventional generation.	80% of delivered load be met by renewable resources by 2030 and 100% by 2045. City of Seattle has target of 30% EV adoption and fossil-fuel-free municipal fleet by 2030. Invest in EV charging infrastructure with emphasis on universal access and expanding coverage. Develop new rates for Transportation Market. [24]

[23] *Renewable Energy Credit (REC)*
24 Transportation Electrification Strategy : https://rmi.org/wp-content/uploads/2019/06/rmi-seattle-city-lights.pdf

General Themes

Regional Resource Adequacy

- Pacific Northwest utilities are forecasting the need for renewable resources, battery storage and natural gas-fired generation to meet increased demand and coal plant retirements
- Relying on short-term wholesale market purchases to meet peak demand has traditionally been a low cost and low risk strategy for many Pacific Northwest utilities. However, this may change with the significant amount of firm generation announced for retirement.
- Northwest Power Pool members are designing and implementing a regional resource adequacy program to help in providing members reliability and cost savings.

Preferred Resource Strategy

- Under current market conditions, utilities across the Pacific Northwest are planning on meeting future demand by incorporating more demand-side management programs, improvements in hydro generation efficiency, some natural gas-fired generation and additional renewable resources and energy storage (batteries and pumped storage)
- Utilities have adopted resource strategies to meet renewable and clean energy targets set by state and city governments.
- Utilities have initiated strategies to exit coal plants and add natural gas-fired generation to meet capacity requirements and support renewables and reduction of GHG emissions.

Environmental Regulations and Initiatives

- State and regional climate and environmental policies continue to impact the resource planning strategies for utilities across the Pacific Northwest
- Washington State Energy Independence Act established renewable energy target of 15% renewable energy by 2020 for electric utilities.
- Clean Energy Transformation Act (CETA) in Washington State sets specific milestones to reach the required 100% clean electricity supply by 2045. By 2022, each utility must publish a clean energy implementation plan with its own targets for energy efficiency and renewable

energy. By 2025, utilities must eliminate coal-fired electricity from their state portfolios. By 2030, utilities must meet greenhouse gas neutral standard, which means having flexibility to use limited amounts of electricity from natural gas if offset by other actions.

- Utilities are investing in EV charging infrastructure with emphasis on universal access, workplace charging programs, and expanding coverage.

Appendix E

PRICE FORECAST TABLES

Sumas Gas Price Forecast $CAD/GJ 2020 Dollars - Base

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	$5.71	$7.38	$5.59	$5.36	$5.29	$5.31	$5.43	$5.48	$5.50	$5.56	$5.99	$6.23
2022	$6.32	$5.86	$5.50	$5.28	$5.11	$5.17	$5.23	$5.32	$5.35	$5.31	$5.70	$5.94
2023	$6.00	$5.55	$5.31	$5.06	$5.11	$5.15	$5.27	$5.38	$5.49	$5.48	$5.88	$6.07
2024	$6.14	$5.89	$5.60	$5.30	$5.28	$5.33	$5.49	$5.55	$5.60	$5.66	$6.20	$6.51
2025	$6.30	$6.08	$5.58	$5.38	$5.38	$5.45	$5.50	$5.54	$5.47	$5.53	$6.03	$6.25
2026	$6.46	$6.13	$5.63	$5.38	$5.41	$5.49	$5.54	$5.56	$5.52	$5.63	$6.06	$6.39
2027	$6.55	$6.29	$5.87	$5.58	$5.45	$5.52	$5.57	$5.62	$5.58	$5.91	$6.34	$6.71
2028	$6.62	$6.26	$5.89	$5.58	$5.40	$5.47	$5.52	$5.56	$5.54	$5.89	$6.42	$6.74
2029	$6.87	$6.45	$6.10	$5.77	$5.60	$5.70	$5.75	$5.80	$5.79	$6.16	$6.58	$6.85
2030	$7.04	$6.61	$6.26	$5.90	$5.78	$5.83	$5.90	$5.95	$5.91	$6.31	$6.67	$7.08
2031	$7.03	$6.64	$6.15	$5.90	$5.66	$5.79	$5.84	$5.88	$5.82	$6.20	$6.58	$6.96
2032	$7.21	$6.65	$6.18	$5.93	$5.82	$5.87	$5.91	$5.96	$5.92	$6.30	$6.84	$7.21
2033	$7.45	$6.97	$6.48	$6.06	$5.95	$6.00	$6.05	$6.10	$6.03	$6.37	$7.05	$7.46
2034	$7.46	$6.94	$6.42	$5.95	$5.86	$5.91	$5.95	$6.00	$5.93	$6.26	$6.88	$7.23
2035	$7.37	$6.91	$6.40	$5.93	$5.90	$6.00	$6.05	$6.10	$6.03	$6.30	$6.91	$7.37
2036	$7.61	$7.07	$6.59	$6.04	$5.92	$5.97	$6.02	$6.07	$6.01	$6.27	$7.02	$7.50
2037	$7.57	$7.04	$6.50	$5.95	$5.89	$5.93	$5.98	$6.03	$5.94	$6.20	$6.91	$7.29
2038	$7.61	$7.13	$6.66	$5.99	$5.97	$6.01	$6.05	$6.10	$6.11	$6.34	$7.13	$7.48
2039	$7.59	$7.22	$6.94	$6.11	$6.11	$6.16	$6.21	$6.27	$6.36	$6.58	$7.35	$7.65
2040	$7.49	$6.93	$6.65	$6.12	$6.13	$6.18	$6.23	$6.28	$6.35	$6.59	$7.40	$7.66

Sumas Gas Price Forecast $CAD/GJ 2020 Dollars - Low

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	$4.74	$5.99	$4.65	$4.47	$4.42	$4.44	$4.53	$4.56	$4.58	$4.63	$4.95	$5.13
2022	$5.10	$4.76	$4.50	$4.34	$4.22	$4.26	$4.30	$4.37	$4.39	$4.36	$4.64	$4.82
2023	$4.79	$4.47	$4.30	$4.12	$4.16	$4.19	$4.27	$4.35	$4.43	$4.42	$4.71	$4.84
2024	$4.83	$4.65	$4.45	$4.24	$4.23	$4.26	$4.37	$4.42	$4.44	$4.49	$4.86	$5.08
2025	$4.77	$4.63	$4.30	$4.17	$4.17	$4.21	$4.25	$4.28	$4.23	$4.27	$4.59	$4.74
2026	$4.89	$4.67	$4.34	$4.17	$4.20	$4.25	$4.28	$4.29	$4.27	$4.34	$4.63	$4.84
2027	$4.96	$4.79	$4.51	$4.31	$4.23	$4.28	$4.31	$4.34	$4.31	$4.53	$4.82	$5.07
2028	$5.04	$4.80	$4.55	$4.34	$4.22	$4.27	$4.30	$4.33	$4.31	$4.55	$4.91	$5.12
2029	$5.17	$4.89	$4.66	$4.44	$4.33	$4.39	$4.43	$4.46	$4.45	$4.70	$4.98	$5.16
2030	$5.26	$4.97	$4.74	$4.51	$4.43	$4.46	$4.51	$4.54	$4.51	$4.78	$5.01	$5.28
2031	$5.31	$5.04	$4.71	$4.55	$4.39	$4.47	$4.51	$4.54	$4.49	$4.75	$5.01	$5.26
2032	$5.39	$5.02	$4.71	$4.55	$4.47	$4.50	$4.53	$4.56	$4.54	$4.79	$5.15	$5.39
2033	$5.52	$5.20	$4.88	$4.61	$4.53	$4.57	$4.60	$4.64	$4.59	$4.81	$5.26	$5.52
2034	$5.48	$5.14	$4.81	$4.50	$4.44	$4.47	$4.50	$4.53	$4.49	$4.70	$5.11	$5.33
2035	$5.37	$5.07	$4.75	$4.45	$4.43	$4.49	$4.52	$4.55	$4.51	$4.69	$5.07	$5.37
2036	$5.47	$5.12	$4.83	$4.48	$4.41	$4.44	$4.47	$4.50	$4.46	$4.62	$5.10	$5.40
2037	$5.50	$5.16	$4.82	$4.46	$4.42	$4.45	$4.48	$4.51	$4.46	$4.62	$5.08	$5.32
2038	$5.55	$5.24	$4.94	$4.50	$4.49	$4.52	$4.55	$4.58	$4.58	$4.73	$5.24	$5.46
2039	$5.56	$5.32	$5.13	$4.59	$4.60	$4.63	$4.66	$4.70	$4.76	$4.90	$5.40	$5.59
2040	$5.38	$5.03	$4.86	$4.52	$4.53	$4.56	$4.59	$4.62	$4.67	$4.82	$5.33	$5.49

Sumas Gas Price Forecast $CAD/GJ 2020 Dollars - High

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	$7.02	$9.26	$6.86	$6.55	$6.47	$6.49	$6.66	$6.71	$6.75	$6.83	$7.40	$7.72
2022	$8.43	$7.76	$7.24	$6.90	$6.65	$6.74	$6.83	$6.96	$7.01	$6.94	$7.52	$7.88
2023	$8.21	$7.52	$7.16	$6.78	$6.84	$6.91	$7.10	$7.27	$7.44	$7.41	$8.04	$8.32
2024	$8.66	$8.26	$7.79	$7.32	$7.30	$7.37	$7.63	$7.72	$7.79	$7.89	$8.74	$9.23
2025	$8.82	$8.49	$7.70	$7.38	$7.38	$7.50	$7.57	$7.64	$7.52	$7.62	$8.40	$8.75
2026	$9.36	$8.82	$8.01	$7.60	$7.66	$7.78	$7.86	$7.89	$7.83	$8.01	$8.71	$9.24
2027	$9.78	$9.33	$8.63	$8.13	$7.92	$8.04	$8.12	$8.21	$8.14	$8.69	$9.42	$10.05
2028	$10.10	$9.47	$8.83	$8.29	$7.99	$8.11	$8.19	$8.27	$8.23	$8.82	$9.75	$10.30
2029	$10.53	$9.80	$9.20	$8.62	$8.33	$8.50	$8.59	$8.67	$8.65	$9.29	$10.02	$10.48
2030	$10.82	$10.08	$9.48	$8.86	$8.65	$8.73	$8.86	$8.94	$8.87	$9.57	$10.18	$10.88
2031	$10.83	$10.15	$9.29	$8.86	$8.45	$8.67	$8.76	$8.84	$8.72	$9.39	$10.05	$10.70
2032	$10.89	$9.95	$9.17	$8.74	$8.56	$8.64	$8.70	$8.78	$8.72	$9.36	$10.27	$10.90
2033	$11.08	$10.28	$9.48	$8.79	$8.61	$8.69	$8.78	$8.86	$8.75	$9.31	$10.43	$11.09
2034	$10.95	$10.10	$9.27	$8.50	$8.36	$8.43	$8.50	$8.58	$8.47	$9.01	$10.01	$10.57
2035	$10.79	$10.04	$9.22	$8.46	$8.40	$8.57	$8.65	$8.73	$8.62	$9.06	$10.03	$10.78
2036	$11.16	$10.27	$9.51	$8.62	$8.43	$8.51	$8.59	$8.67	$8.57	$8.99	$10.20	$10.98
2037	$11.14	$10.28	$9.41	$8.50	$8.41	$8.48	$8.56	$8.64	$8.50	$8.91	$10.07	$10.68
2038	$11.19	$10.41	$9.65	$8.56	$8.53	$8.60	$8.67	$8.75	$8.76	$9.13	$10.41	$10.98
2039	$11.15	$10.55	$10.09	$8.74	$8.76	$8.83	$8.92	$9.01	$9.15	$9.52	$10.76	$11.25
2040	$10.88	$9.98	$9.54	$8.69	$8.71	$8.78	$8.86	$8.95	$9.06	$9.44	$10.74	$11.15

Mid-C Electricity Price Forecast $CAD/MWh 2020 Dollars - Base

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	$41.10	$38.67	$31.41	$29.31	$26.53	$23.94	$41.29	$48.05	$45.96	$42.75	$40.84	$43.33
2022	$37.53	$34.27	$26.53	$25.12	$18.65	$16.95	$34.63	$42.04	$41.52	$39.04	$38.97	$41.47
2023	$47.64	$34.02	$26.43	$26.10	$20.67	$15.64	$35.55	$42.66	$42.20	$40.70	$39.74	$42.62
2024	$38.72	$33.01	$27.53	$26.00	$18.28	$14.46	$36.83	$45.61	$45.43	$43.56	$42.93	$43.56
2025	$38.19	$35.51	$27.48	$24.92	$19.09	$14.38	$36.96	$46.17	$45.96	$42.01	$42.03	$44.98
2026	$40.75	$35.24	$27.28	$26.21	$18.93	$13.57	$37.04	$46.95	$46.47	$42.34	$40.06	$44.30
2027	$39.82	$33.22	$27.10	$24.14	$18.18	$14.01	$36.96	$46.89	$45.89	$42.46	$41.48	$42.80
2028	$42.86	$32.57	$26.69	$23.25	$19.14	$12.54	$36.99	$47.86	$46.59	$41.58	$41.23	$45.54
2029	$41.07	$33.32	$25.89	$25.07	$20.53	$11.90	$37.79	$49.03	$48.22	$42.05	$41.34	$45.86
2030	$43.78	$34.62	$26.79	$22.54	$18.04	$11.17	$40.43	$51.70	$49.67	$45.03	$43.34	$46.15
2031	$44.81	$36.46	$28.20	$24.46	$20.45	$17.47	$41.50	$51.92	$50.01	$45.53	$41.99	$46.37
2032	$48.59	$32.19	$25.92	$23.19	$16.55	$17.21	$41.01	$52.95	$51.00	$44.93	$41.32	$47.16
2033	$43.12	$34.68	$26.06	$20.88	$15.76	$18.09	$43.16	$54.39	$50.49	$48.15	$44.01	$50.29
2034	$41.37	$32.91	$24.46	$19.96	$13.83	$16.90	$42.14	$52.84	$50.23	$45.06	$41.89	$47.00
2035	$41.99	$34.60	$24.81	$21.30	$15.74	$16.63	$41.92	$54.01	$51.30	$44.64	$41.65	$47.38
2036	$43.40	$30.68	$23.40	$18.91	$13.84	$16.84	$43.47	$55.16	$51.99	$47.19	$43.16	$47.79
2037	$42.07	$33.42	$22.52	$17.01	$12.47	$15.74	$42.73	$54.55	$52.69	$44.56	$41.75	$48.65
2038	$43.67	$32.02	$22.21	$18.34	$13.20	$15.68	$44.96	$55.66	$54.77	$46.50	$43.00	$51.63
2039	$46.26	$34.22	$22.63	$16.37	$13.33	$18.40	$47.39	$58.69	$56.42	$50.13	$47.82	$52.47
2040	$47.04	$31.28	$25.25	$16.80	$14.62	$19.10	$45.70	$58.06	$56.29	$47.62	$45.74	$51.55

Mid-C Electricity Price Forecast $CAD/MWh 2020 Dollars - Low

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	$34.89	$32.82	$25.98	$24.48	$20.86	$20.47	$34.48	$41.94	$40.95	$36.01	$34.20	$37.38
2022	$30.85	$29.09	$22.01	$20.84	$15.36	$14.92	$28.57	$35.23	$35.29	$32.80	$32.04	$36.23
2023	$38.47	$28.57	$21.51	$21.18	$16.72	$13.24	$29.21	$34.97	$35.34	$33.20	$31.25	$35.32
2024	$31.20	$27.00	$21.81	$20.47	$14.71	$12.21	$29.06	$36.48	$37.94	$34.18	$33.97	$35.63
2025	$30.38	$28.18	$21.22	$19.68	$15.32	$11.84	$29.11	$35.33	$36.56	$32.05	$30.99	$35.31
2026	$31.99	$27.85	$21.31	$21.09	$15.07	$11.39	$28.33	$35.80	$36.63	$31.77	$30.31	$34.53
2027	$31.92	$26.49	$21.46	$19.25	$14.77	$11.50	$28.33	$36.00	$37.14	$32.78	$30.90	$32.99
2028	$32.32	$26.30	$20.72	$18.39	$15.67	$10.57	$28.40	$35.92	$36.72	$31.78	$31.44	$34.57
2029	$32.85	$26.84	$20.20	$20.18	$16.15	$10.07	$28.58	$38.03	$37.54	$32.19	$30.53	$34.92
2030	$32.69	$27.09	$20.99	$18.18	$14.57	$9.60	$30.59	$38.73	$38.00	$33.11	$31.48	$34.38
2031	$34.37	$28.33	$21.76	$19.67	$16.74	$14.27	$31.32	$38.99	$38.36	$34.67	$31.68	$34.72
2032	$37.65	$25.20	$20.12	$18.50	$13.57	$13.93	$30.52	$39.08	$38.93	$33.12	$30.51	$35.74
2033	$31.95	$27.09	$20.16	$17.00	$12.75	$14.68	$31.48	$41.69	$38.04	$36.49	$32.97	$37.73
2034	$31.26	$26.30	$19.15	$15.98	$11.41	$13.76	$31.53	$38.40	$37.26	$32.77	$29.86	$35.09
2035	$31.79	$27.07	$19.11	$16.80	$12.27	$13.19	$30.72	$40.18	$38.08	$33.33	$29.83	$34.35
2036	$31.63	$23.61	$18.16	$14.92	$11.48	$13.59	$32.73	$40.04	$39.07	$34.90	$31.03	$35.35
2037	$30.93	$26.30	$17.81	$13.87	$10.34	$12.80	$31.88	$41.03	$39.65	$33.64	$30.21	$36.28
2038	$33.99	$24.96	$17.39	$14.70	$10.81	$12.96	$34.05	$41.06	$41.53	$34.80	$31.06	$38.65
2039	$33.65	$26.56	$17.49	$13.68	$10.77	$15.13	$35.27	$43.38	$42.99	$38.73	$35.31	$39.20
2040	$34.63	$24.78	$19.76	$14.35	$12.11	$16.01	$34.48	$43.34	$43.27	$37.23	$34.26	$38.95

Mid-C Electricity Price Forecast $CAD/MWh 2020 Dollars - High

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	$51.87	$48.96	$39.45	$37.63	$34.54	$29.22	$51.97	$59.24	$55.18	$53.07	$51.08	$53.02
2022	$45.84	$42.31	$33.30	$31.43	$24.06	$21.06	$43.78	$51.72	$50.56	$49.27	$48.92	$52.58
2023	$61.88	$44.49	$34.39	$33.85	$27.04	$19.07	$45.33	$54.00	$53.03	$53.52	$50.39	$54.36
2024	$48.55	$41.98	$34.33	$33.49	$23.13	$18.05	$47.96	$59.68	$58.87	$57.45	$57.20	$57.95
2025	$47.74	$45.71	$33.15	$30.84	$22.53	$17.60	$48.21	$60.79	$59.20	$55.11	$54.97	$59.23
2026	$54.83	$46.06	$34.50	$33.36	$24.76	$17.09	$51.40	$64.00	$62.77	$58.23	$54.77	$59.86
2027	$54.22	$45.95	$35.71	$30.88	$24.22	$17.48	$52.52	$68.07	$64.18	$60.10	$57.05	$61.51
2028	$58.41	$46.23	$35.96	$29.99	$25.61	$15.82	$52.98	$69.82	$66.48	$60.08	$58.09	$66.32
2029	$59.06	$47.01	$34.31	$32.72	$27.56	$14.85	$55.54	$71.98	$70.00	$60.56	$58.09	$66.13
2030	$61.09	$49.84	$36.43	$28.70	$24.18	$13.63	$57.09	$76.73	$71.78	$64.79	$60.36	$66.46
2031	$66.75	$51.69	$38.78	$32.49	$27.31	$24.23	$62.24	$79.09	$73.12	$65.26	$62.48	$69.26
2032	$71.63	$45.08	$35.11	$29.84	$22.24	$23.07	$58.93	$78.33	$73.23	$62.49	$59.07	$70.04
2033	$59.34	$47.86	$34.30	$26.94	$20.35	$24.44	$59.94	$78.06	$73.79	$70.36	$61.13	$74.43
2034	$56.73	$44.37	$32.42	$25.88	$17.51	$22.21	$59.64	$74.08	$71.93	$62.24	$57.61	$67.69
2035	$60.76	$47.89	$32.52	$26.47	$19.43	$21.52	$58.76	$77.57	$71.91	$61.45	$56.27	$67.42
2036	$59.14	$41.51	$31.31	$23.70	$17.08	$22.40	$62.10	$79.24	$72.74	$64.84	$59.04	$68.42
2037	$57.38	$46.21	$29.63	$21.24	$15.39	$20.21	$58.88	$76.53	$76.34	$63.90	$56.63	$70.89
2038	$61.75	$43.04	$29.01	$23.22	$16.47	$20.63	$64.60	$79.23	$76.40	$63.46	$59.79	$75.62
2039	$64.54	$48.55	$28.78	$20.75	$16.87	$24.55	$68.44	$84.71	$78.61	$70.75	$67.04	$76.53
2040	$65.03	$43.44	$31.82	$20.77	$18.09	$24.90	$65.18	$83.07	$77.80	$66.42	$63.36	$74.41

PPA Tranche 1 Energy Rate Scenarios $CAD/MWh $2020 Dollars

Year	Base	Low	High
2021	$49.79	$49.79	$49.79
2022	$48.66	$48.66	$48.66
2023	$49.14	$49.14	$49.14
2024	$49.62	$49.14	$50.59
2025	$50.11	$49.14	$52.07
2026	$50.60	$49.14	$53.60
2027	$51.10	$49.14	$55.18
2028	$51.60	$49.14	$56.80
2029	$52.10	$49.14	$58.48
2030	$52.61	$49.14	$60.20
2031	$53.13	$49.14	$61.97
2032	$53.65	$49.14	$63.79
2033	$54.18	$49.14	$65.66
2034	$54.71	$49.14	$67.60
2035	$55.24	$49.14	$69.58
2036	$55.79	$49.14	$71.63
2037	$56.33	$49.14	$73.74
2038	$56.88	$49.14	$75.91
2039	$57.44	$49.14	$78.14
2040	$58.01	$49.14	$80.44

PPA Tranche 2 Energy Rate Scenarios $CAD/MWh $2020 Dollars

Year	Base	Low
2021	$95.09	$80.00
2022	$95.09	$80.00
2023	$95.09	$80.00
2024	$95.09	$80.00
2025	$95.09	$80.00
2026	$95.09	$80.00
2027	$95.09	$80.00
2028	$95.09	$80.00
2029	$95.09	$80.00
2030	$95.09	$80.00
2031	$95.09	$80.00
2032	$95.09	$80.00
2033	$95.09	$80.00
2034	$95.09	$80.00
2035	$95.09	$80.00
2036	$95.09	$80.00
2037	$95.09	$80.00
2038	$95.09	$80.00
2039	$95.09	$80.00
2040	$95.09	$80.00

PPA Capacity Rate Scenarios $CAD/kW-year $2020 Dollars

Year	Base	Low	High
2021	$101.93	$101.93	$101.93
2022	$99.63	$99.63	$99.63
2023	$100.60	$100.60	$100.60
2024	$101.59	$100.60	$103.56
2025	$102.59	$100.60	$106.61
2026	$103.59	$100.60	$109.75
2027	$104.61	$100.60	$112.97
2028	$105.63	$100.60	$116.30
2029	$106.67	$100.60	$119.72
2030	$107.72	$100.60	$123.24
2031	$108.77	$100.60	$126.86
2032	$109.84	$100.60	$130.59
2033	$110.91	$100.60	$134.43
2034	$112.00	$100.60	$138.39
2035	$113.10	$100.60	$142.46
2036	$114.21	$100.60	$146.65
2037	$115.33	$100.60	$150.96
2038	$116.46	$100.60	$155.40
2039	$117.60	$100.60	$159.97
2040	$118.75	$100.60	$164.68

RNG Price Forecasts $CAD/GJ $2020 Dollars

Year	Base	Low
2021	$22.13	$22.13
2022	$22.60	$22.60
2023	$23.07	$23.07
2024	$23.55	$22.92
2025	$24.05	$22.77
2026	$24.55	$22.62
2027	$25.07	$22.47
2028	$25.60	$22.32
2029	$26.13	$22.17
2030	$26.68	$22.02
2031	$27.24	$21.87
2032	$27.82	$21.72
2033	$28.40	$21.57
2034	$29.00	$21.42
2035	$29.60	$21.27
2036	$30.00	$21.12
2037	$30.00	$20.97
2038	$30.00	$20.82
2039	$30.00	$20.67
2040	$30.00	$20.52

BC Carbon Price Scenarios $CAD/Tonne $2020 Dollars

Year	Base	Low	Medium	High
2021	$45.00	$45.00	$45.00	$45.00
2022	$50.00	$50.00	$50.00	$50.00
2023	$50.00	$0.00	$54.24	$61.31
2024	$50.00	$0.00	$60.11	$73.98
2025	$50.00	$0.00	$65.73	$86.13
2026	$50.00	$0.00	$71.11	$97.77
2027	$50.00	$0.00	$76.25	$108.93
2028	$50.00	$0.00	$81.16	$119.61
2029	$50.00	$0.00	$85.85	$129.82
2030	$50.00	$0.00	$90.33	$139.60
2031	$50.00	$0.00	$94.59	$148.93
2032	$50.00	$0.00	$98.66	$157.85
2033	$50.00	$0.00	$102.53	$166.37
2034	$50.00	$0.00	$106.21	$174.48
2035	$50.00	$0.00	$109.70	$182.22
2036	$50.00	$0.00	$113.02	$189.58
2037	$50.00	$0.00	$116.17	$196.59
2038	$50.00	$0.00	$119.14	$203.25
2039	$50.00	$0.00	$121.96	$209.57
2040	$50.00	$0.00	$124.62	$215.56

Appendix F

LONG-TERM LOAD FORECAST

FORTISBC INC.

Appendix F

2021 Long-Term Electric Resource Plan

Long-Term Load Forecast

Table of Contents

1. INTRODUCTION

Two key elements of the LTERP are the Reference Case load forecasts for annual energy and peak demand. The annual energy forecast represents annual consumption by customer class while the peak demand forecast provides an estimate of the maximum hourly electricity demand under expected peak summer and winter conditions.

All forecast elements use actuals up to and including 2019. The 2020 actuals are not included as discussed in section 3.2.

The Reference Case load forecast is used to determine the Load-Resource Balance before incremental demand- and supply-side resources (discussed in the LTERP, Section 7).

1.1 *FORECAST TAXONOMY*

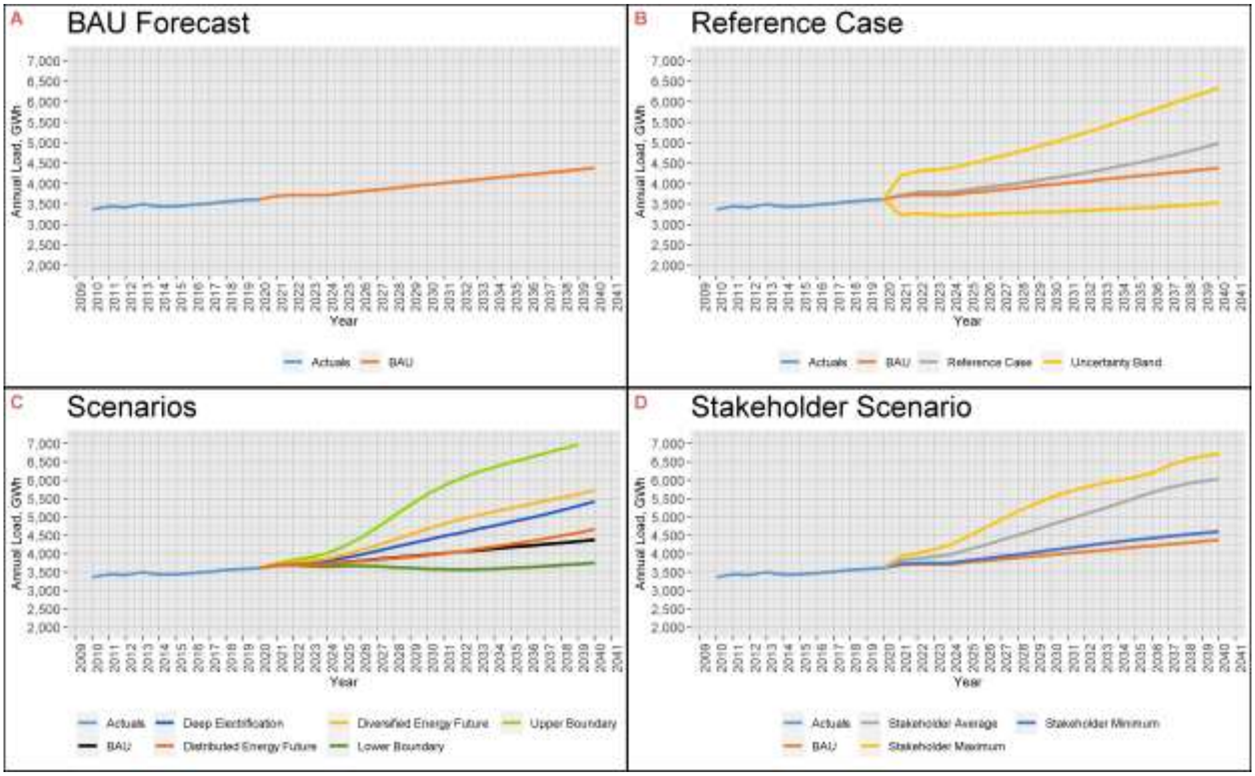
FBC has defined four forecast levels that start with a continuation of current trends in the Business as Usual (BAU) forecast and end with the stakeholder average scenario developed using stakeholder input. The four forecast levels are defined in the following table.

Table F-1: Forecast Taxonomy

Chart Reference	Forecast Name	Description	LTERP Section
A	BAU Forecast	• Time series methods • Same as Multi-Year Rate Plan update, extended 20 years • Based on 2019 actual data and external forecasts	Section 3 and Appendix F
B	Reference Case	• Starts with BAU • Adds industrial loads with high confidence, based on discussions with customers • Adds EV charging loads based on the *ZEV Act* light-duty sales to the residential load forecast • Includes uncertainty band	Section 3 and Appendix F
C	Scenarios	• Include new load driver impacts beyond BAU forecast • Upper/lower bounds set scenario range book-ends • Intermediate scenarios provide potential pathways for future electricity loads	Section 4.1
D	Stakeholder Scenario	• Scenario developed based on responses received from stakeholders as part of the crowd forecast exercise	Section 4.2

The four forecast levels are illustrated graphically in the following figure.

Figure F-1: Forecast Levels



1.2 *DEFINITIONS*

The following table summarizes the definitions used within this appendix.

Table F-2: Load Forecast Definitions

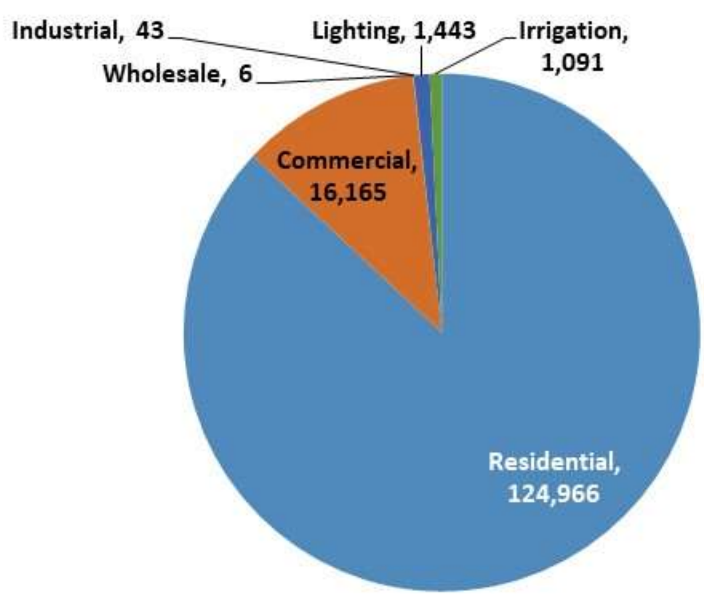
Term	Definition
Gross Energy Load	The sum of the residential, commercial, industrial, wholesale, lighting, irrigation and losses energy loads.
Losses	Loss of electric energy due to line losses, losses due to wheeling through the BC Hydro system, unaccounted for energy (meter inaccuracies and theft) and company use (electric energy used by FBC to run the utility).
Net Energy Load	Gross energy loads less losses and company use.
Direct Customer	A customer who is served directly by FBC.
Indirect Customer	A customer who receives energy from a FBC wholesale customer that owns and operates its own electrical distribution system.
UPC	Use per customer. The quantity of energy used by a customer over a fixed time period, normally one year.

2. CUSTOMER BASE

The FBC customer base is a mix of residential, commercial, industrial, wholesale, irrigation and lighting customers. Residential customers include the occupants of houses, condominiums, apartment and mobile homes. The commercial customer base is mostly small to medium size businesses, from small store-front operations and restaurants to larger operations such as hotels and ski resorts, while the industrial class[1] covers large businesses like lumber mills and institutions such as universities and hospitals. FBC's wholesale customers purchase power for distribution to individual customers via the wholesale customers' electrical system. Irrigation customers use electricity to run irrigation equipment on properties such as farms and orchards, while the lighting class is comprised of street lights in the FBC service area. At the end of December 2020, FBC had 143,714 direct customers and 38,298 indirect customers for a total customer base of 182,012 customers.

As shown in the figure below, residential customers made up 87 percent of the FBC customer base in 2020, while commercial customers accounted for 11 percent. The wholesale, industrial, lighting and irrigation rate classes make up the remaining 2 percent of the customer base.

Figure F-2: 2020 Direct Customer Counts

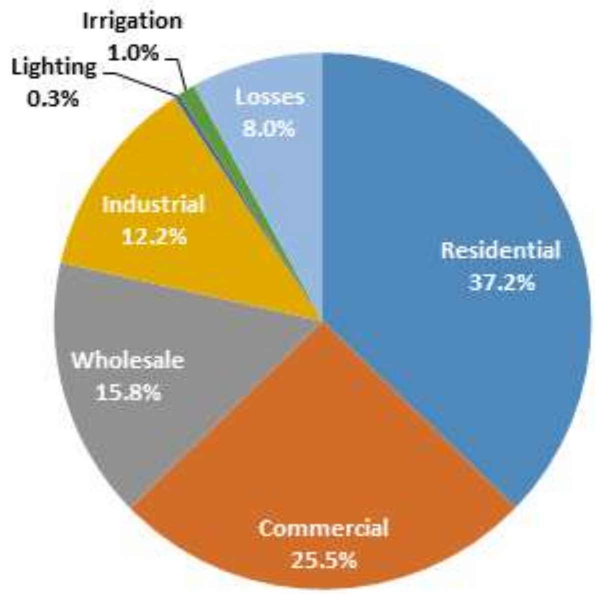


As far as energy usage is concerned, the residential class is the largest sector with 37.2 percent of the 2020 gross energy load, followed by the commercial, wholesale and industrial classes

[1] FBC uses the term 'industrial class' for those customers that are served under the large commercial rate schedule.

with 25.5 percent, 15.8 percent and 12.2 percent, respectively. Losses and the irrigation and lighting classes compromise the remaining 9.3 percent of the 2020 energy load composition[2].

Figure F-3: 2020 Gross Energy Load Composition



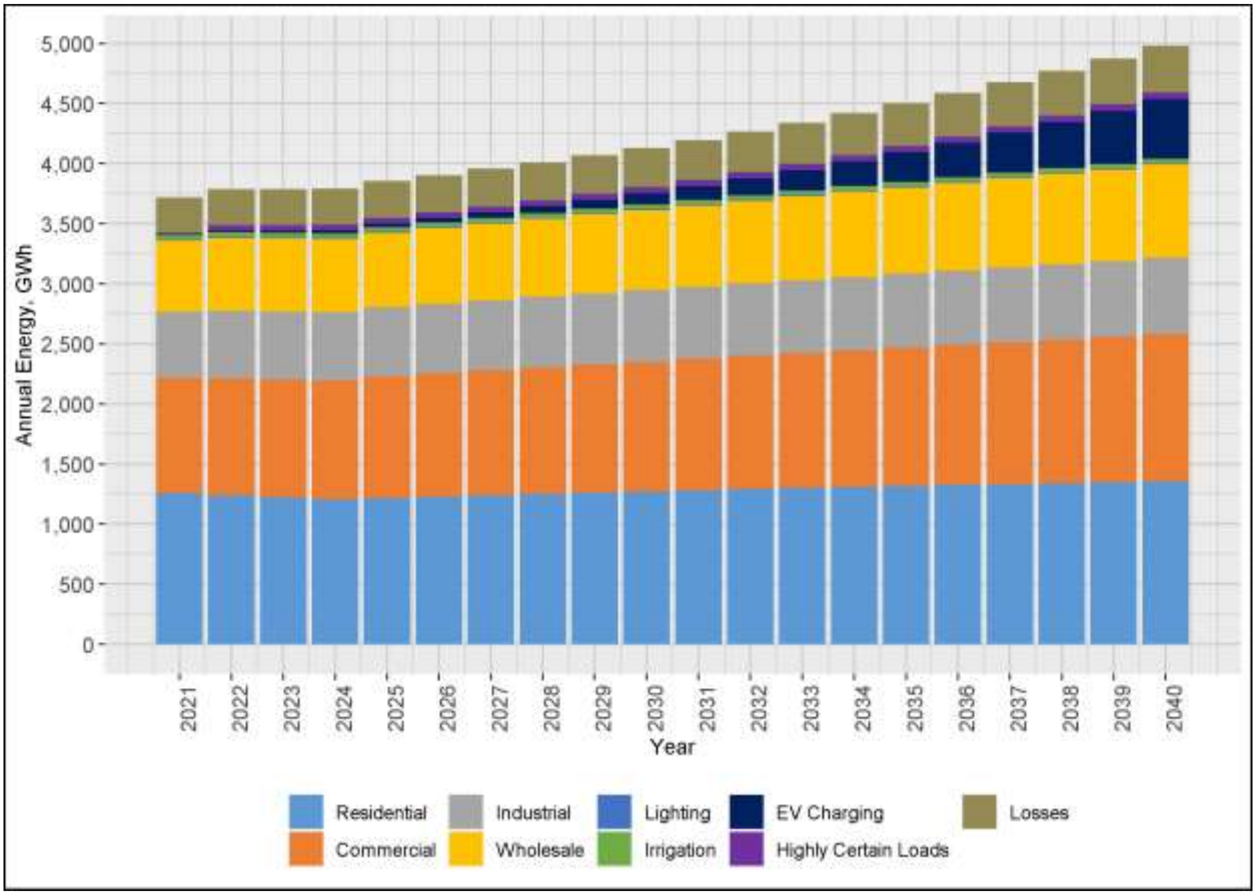
3. RATE CLASS REFERENCE CASE ENERGY LOAD FORECASTS

FBC's Reference Case energy load forecast is composed of individual forecasts for each of the residential, commercial, industrial, wholesale, lighting and irrigation classes as well as system losses. The Reference Case load forecast is presented before any DSM reductions are applied. The residential load forecast also includes electric vehicle charging while the industrial forecast includes highly certain new loads. The method is primarily econometric, while for some rate classes survey data is also employed. Forecasts of service territory population and provincial GDP by sector are primary drivers of customer sales. GDP forecasts are provided by the CBOC, while service territory population forecasts are provided by BC Stats.

The Reference Case gross system energy load by customer class is provided below for the forecast period. The EV charging and highly certain industrial loads have been separated out in the figure to show their relative contribution to annual energy over the 20-year period.

[2] Based on the FBC 2020 normalized actual energy load of 3,617 GWh.

Figure F-4: Gross Energy Load Forecast (GWh)



The EV charging contributes about 500 GWh of annual energy by 2040 while the highly certain loads add about 54 GWh by 2040.

Net load, which is comprised of all load classes except for losses, is forecast to grow at an average annual growth rate of 1.6 percent per year over the next 20 years. The BAU forecast grows at an average annual growth rate of 0.9 percent and does not include electric vehicle charging or highly certain industrial loads.

The following sections describe the Reference Case energy load forecasts for each of the FBC rate classes.

3.1 *RESIDENTIAL*

The residential BAU load growth is driven by the increase in customer count, which itself is determined econometrically as a function of population in the FBC service area. The customer forecast is then combined with the use per customer (UPC) forecast to determine the residential BAU load forecast. The residential Reference Case forecast is calculated by adding the electric vehicle charging load to the BAU forecast.

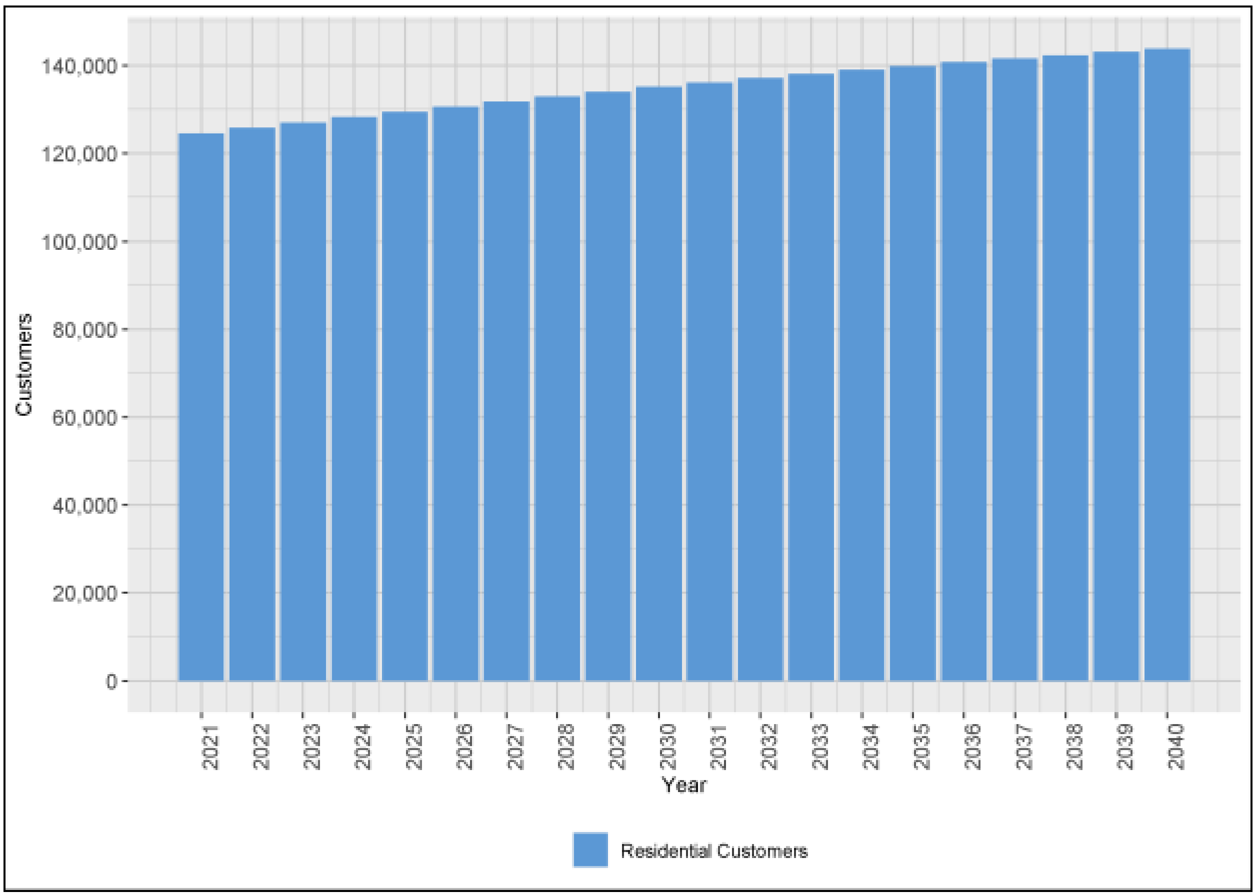
3.1.1 Customer Count

Forecast residential customer counts are determined by a regression analysis of the year-end customer accounts on population in the FBC direct service area. The population forecast for the FBC service area is provided in a custom BC Stats report produced for FBC.

The BC Stats forecast predicts the population for the FBC service area will grow, but at a declining rate over the forecast period, from 0.9 percent in 2021 to 0.5 percent in 2040.

The FBC residential customer count is forecast to grow at an average annual growth rate of 0.8 percent per year over the next 20 years.

Figure F-5: Residential Customer Count

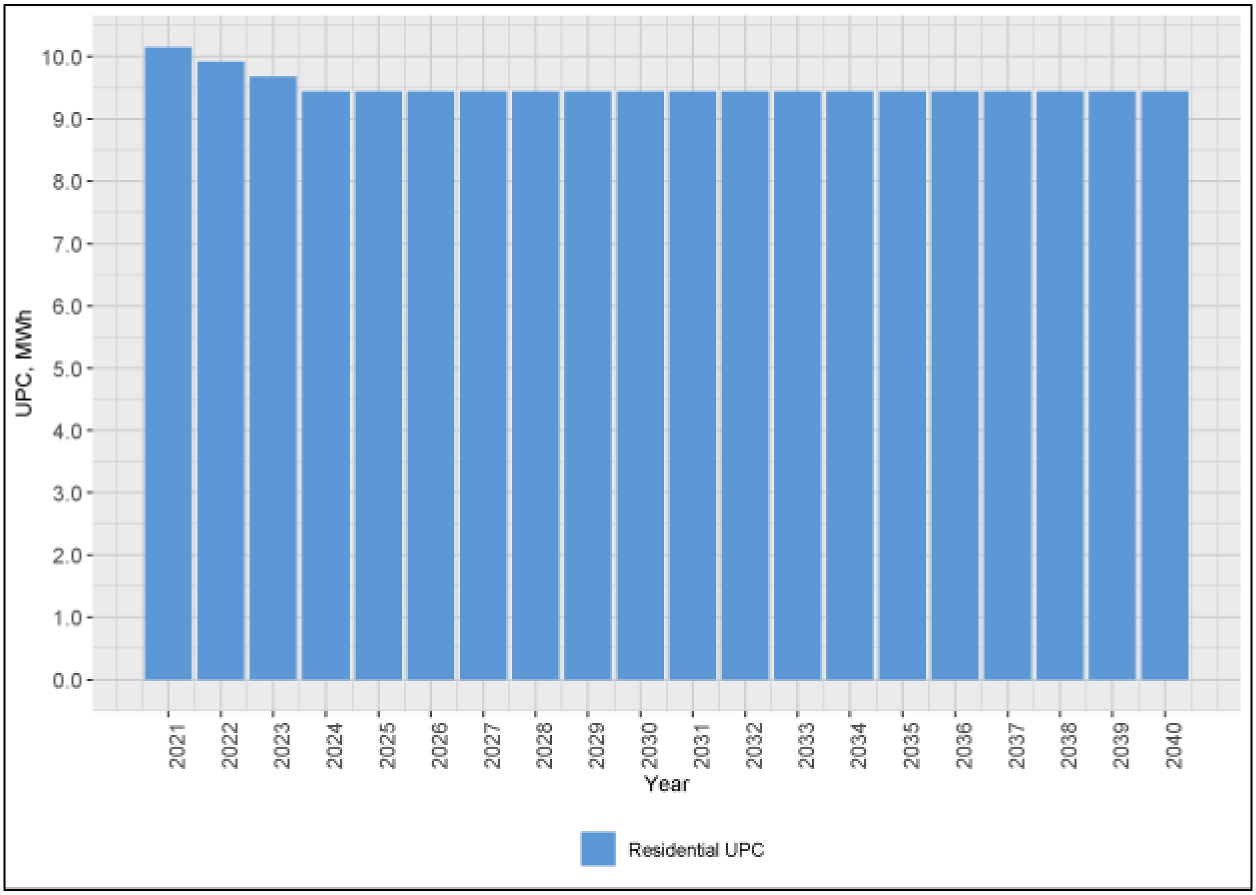


3.1.2 UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-DSM UPC is forecast by applying a ten-year trend to the normalized historical UPCs. The before-DSM UPC forecast is then multiplied by the forecast average customer count to derive the before-DSM load forecast.

The before-DSM UPC is forecast to decline from 10.15 MWh in 2021 to 9.44 MWh in 2024. With trends towards more electrification of end uses, a continuation of the current downward trend in UPC is not realistic. If the downward trend in UPC were to continue, the before savings UPC by 2041 would be approximately half of the current value, which would be further reduced by DSM. As a result, FBC has held the UPC constant for the remainder of the planning horizon.

Figure F-6: Residential UPC (MWh)

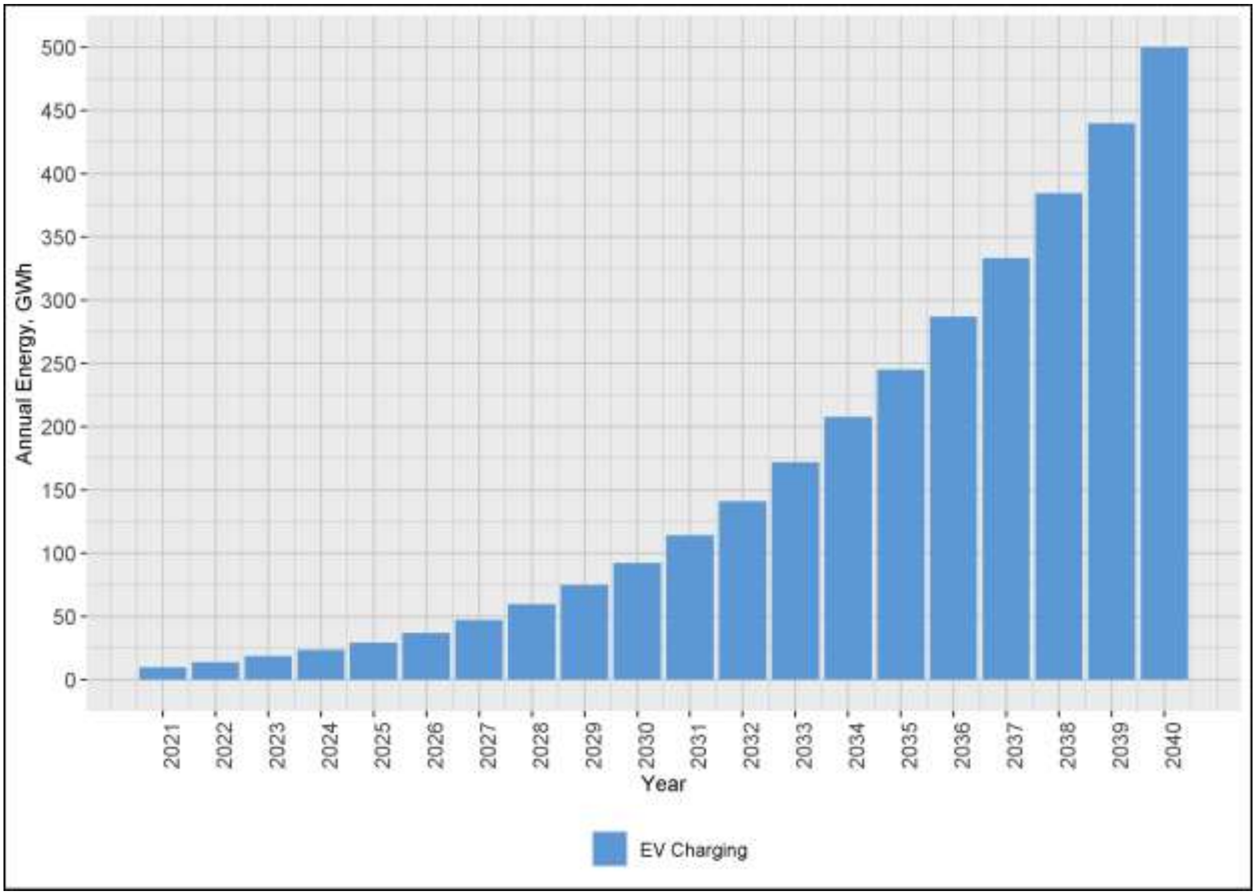


3.1.3 Electric Vehicle Charging Load

The residential Reference Case forecast is the summation of the residential BAU and the EV charging load forecast. The EV charging load forecast is based on the *ZEV Act* light-duty sales targets for EVs, discussed in LTERP Section 2.2.3.5.

The EV charging load energy is forecast to be 9.8 GWh in 2021 and then grow to 500 GWh in 2040, as shown in Figure F-7 below.

Figure F-7: EV Charging Load (GWh)

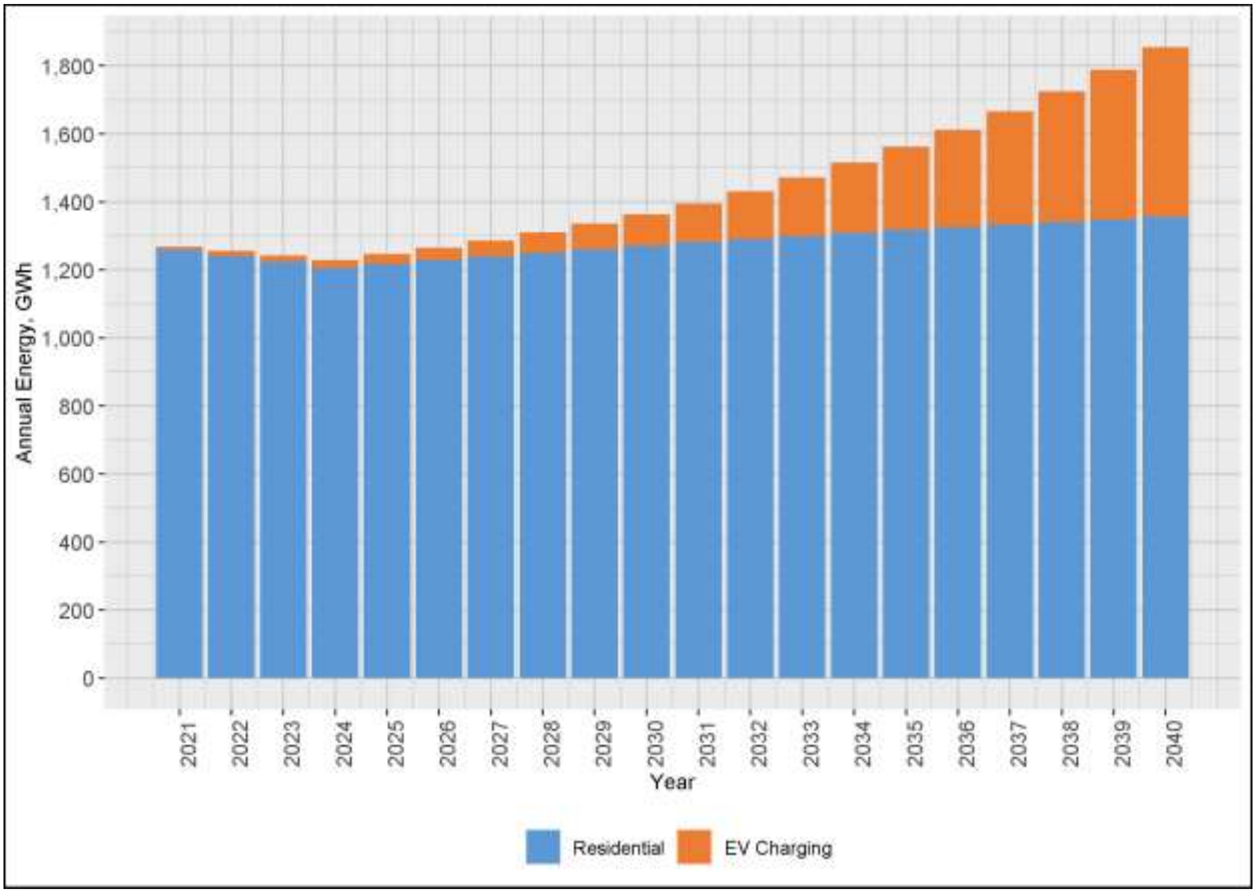


3.1.4 Residential Energy Load

Consistent with past practice, the total BAU energy load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC. The Reference Case residential load forecast is the sum of the BAU residential load and the EV charging load.

The BAU residential load is forecast to increase at an average annual growth rate of 0.4 percent over the forecast period. The growth in this class is low over the planning horizon due to a declining UPC during the early years and low annual population increases. The Reference Case residential load is forecast to grow at an average annual rate of 2.0 percent due to the addition of EV charging loads. EV charging loads have little impact in the short term, but in the medium to long term they increase load substantially as shown below.

Figure F-8: Residential Energy Load (GWh)

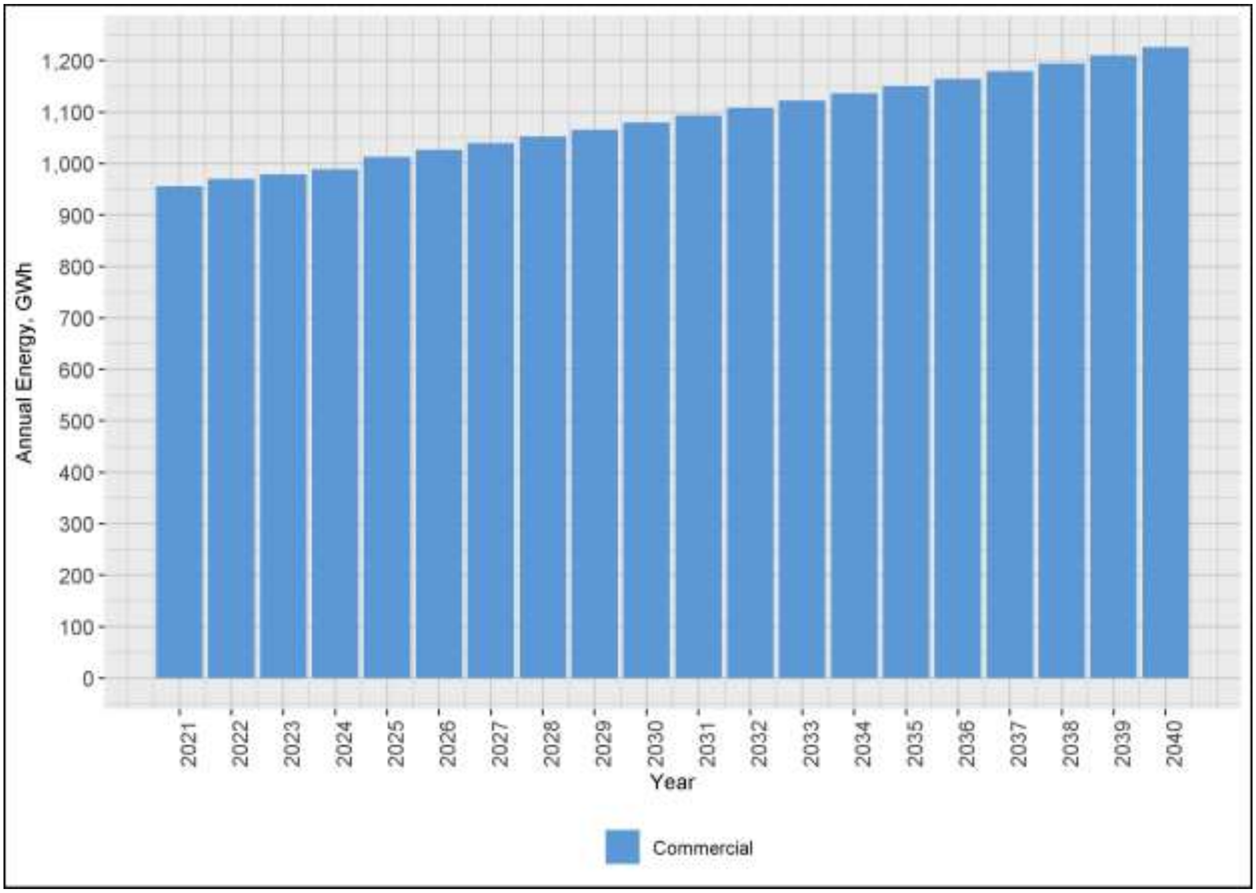


3.2 *COMMERCIAL*

The commercial load is forecast based on a regression analysis using the provincial GDP forecast from the CBOC. This class is comprised of customers from many diverse industries including agriculture, forestry, manufacturing, utilities and commercial service. As such, the energy use in this class is well correlated to the provincial real GDP and is forecast on that basis. The Reference Case forecast does not include any additional commercial loads compared to the BAU, so the BAU and reference case forecasts are identical.

The Commercial load is forecast to grow at an average annual rate of 1.3 percent per year over the next 20 years. Growth will be stronger on average in the near term and then will begin to slow due to reduced economic growth.

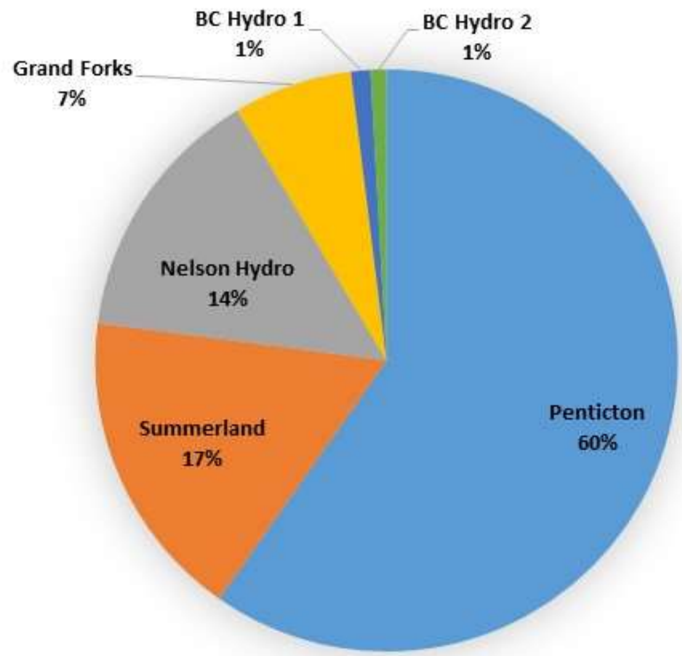
Figure F-9: Commercial Energy Load (GWh)



3.3 *WHOLESALE*

FBC sells wholesale power to municipalities within its service territory that own and operate their own electrical distribution systems. FBC has six wholesale customers that made up 15.8 percent of the total 2020 gross load. FBC's wholesale customers consist of the communities of Penticton, Grand Forks, Summerland, Nelson, and two communities in the BC Hydro service territory. These customers' loads are primarily a mix of residential and commercial in nature. The City of Penticton is the largest wholesale customer, comprising 60 percent of the wholesale load in 2020. The forecast for both the BAU and Reference Case is the same for the wholesale class.

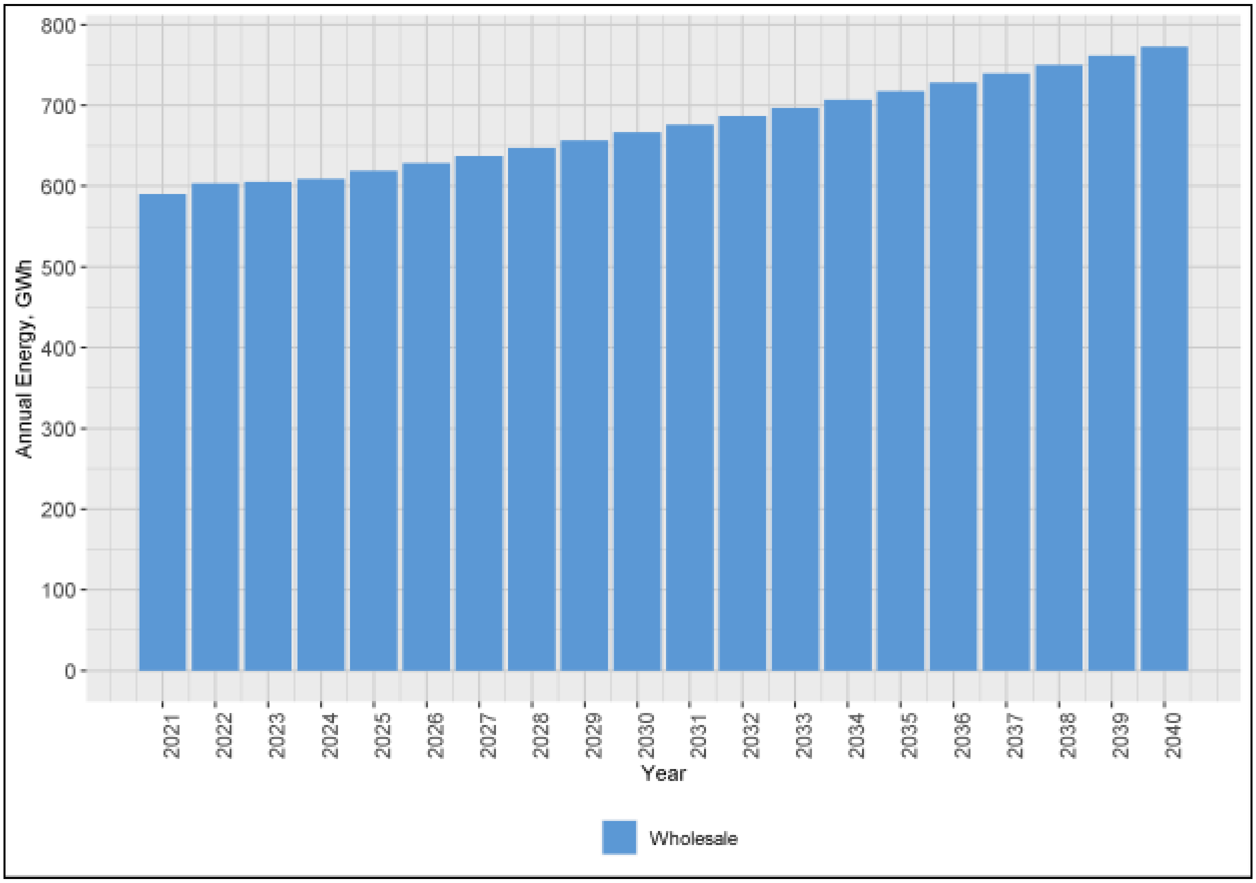
Figure F-10: 2020 Wholesale Energy Load Composition



Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers. FBC believes that individual wholesalers are best able to forecast their future load growth based on their knowledge of their customer mix, load behaviors and development projects with associated energy requirements. FBC's survey requested five years of data from wholesale customers. After that time period, an average of each individual customer's forecasted growth rate is used to project the long-term forecast.

All of the wholesale customers responded to the surveys with their forecast growth projections. The wholesale load is forecast to grow at an average annual growth rate of 1.4 percent per year over the next 20 years.

Figure F-11: Wholesale Energy Load (GWh)



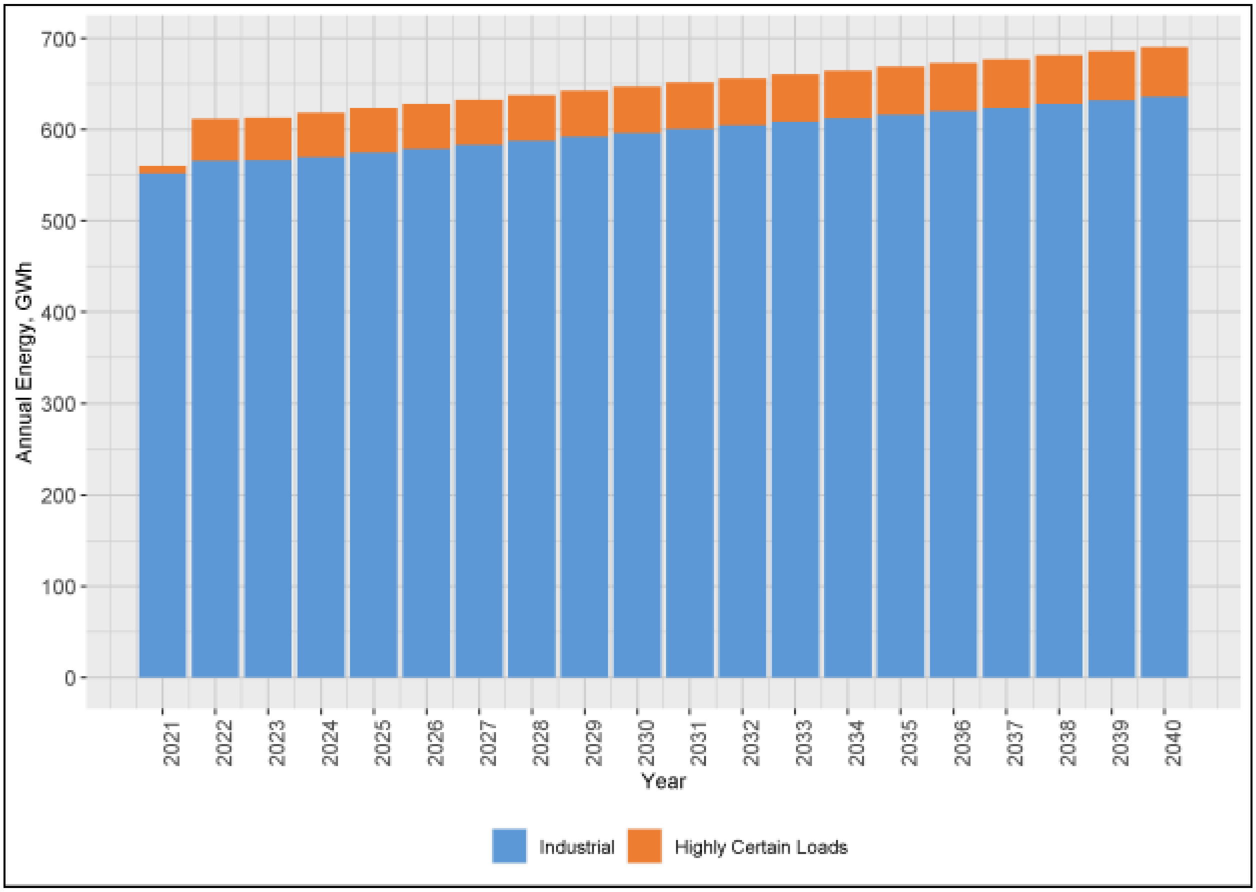
3.4 *INDUSTRIAL*

Industrial loads are forecast based on survey results provided by individual customers and, where customer information is not available, by forecast GDP growth rates in each industrial sector. In the long term, composite GDP growth rates of industrial sectors are used to escalate the entire industrial load. FBC sends all industrial customers a load survey that requests the customer's anticipated use for the next five years. A survey method is utilized because FBC believes that individual industrial customers have the best understanding of what their future energy usage will be. FBC's industrial load is mostly composed of agriculture, forestry, manufacturing, education, healthcare, commercial service and block chain technology customers. FBC received a response from 80 percent of the industrial customers. The responding customers represent approximately 92 percent of the total industrial energy load.

FBC Key Account Managers also provide load projections for potential new customers that they are in direct contact with. Not all customer inquiries result in load being added to the FBC system. FBC set a minimum probability of seventy-five percent certainty as the threshold for including potential customers' projected loads in its reference case load forecast. Three new customers were identified based on this criteria that they are expected to be added to the FBC system in the near future and are included in the Reference Case forecast. Since these customers' loads do have some uncertainty of materializing, FBC only included seventy-five percent of their projected loads to the Reference Case forecast. Most of the highly certain loads begin in 2022.

The Industrial load is forecast to grow at an average annual rate of 1.1 percent per year over the next 20 years for the Reference Case and 0.8 percent for the BAU forecast.

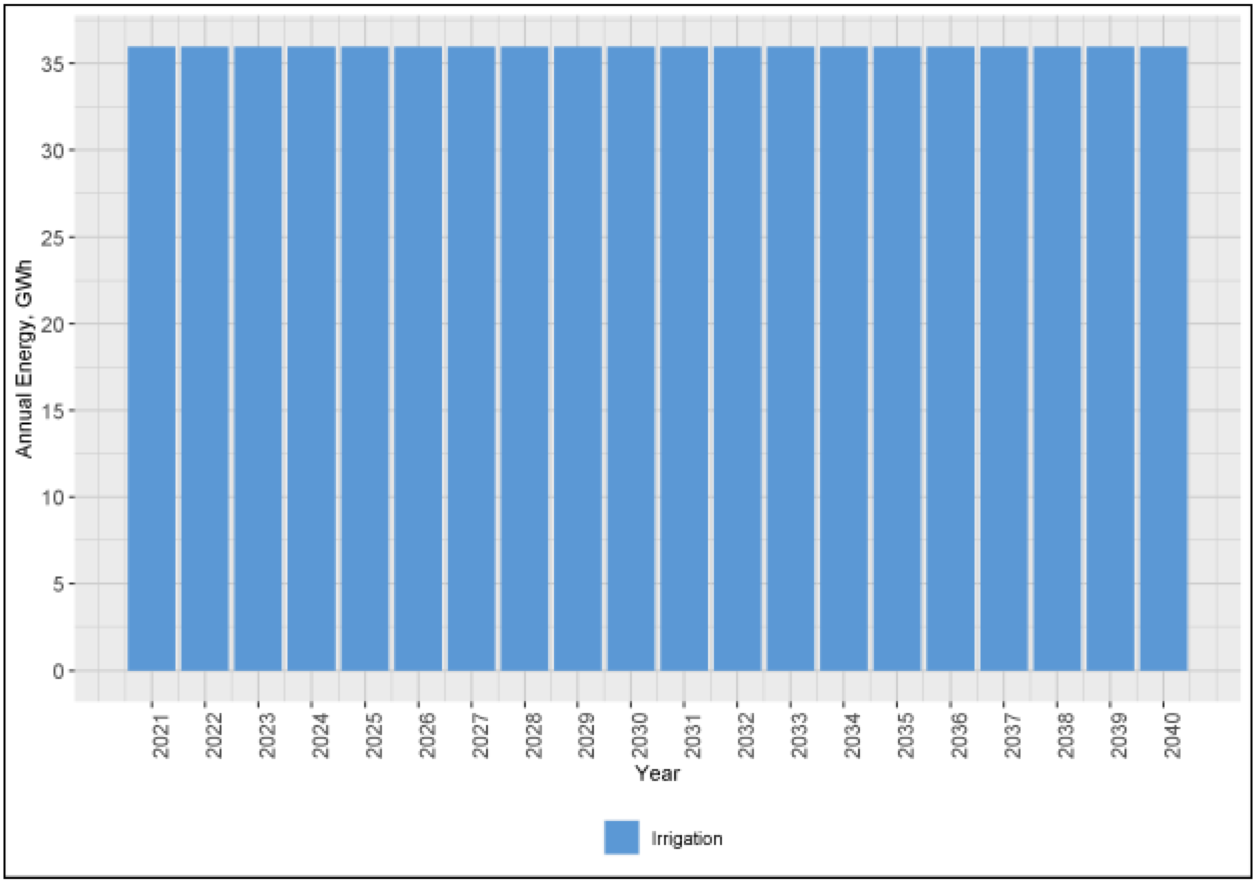
Figure F-12: Industrial Energy Load (GWh)



3.5 *IRRIGATION*

Due to the variability in the energy load in the recent historic data, FBC has chosen to use the 2019 energy load as the forecast. The forecast remains constant over the planning horizon at 36 GWh. The irrigation energy load represents approximately 0.9 percent of the overall gross energy load over the planning horizon.

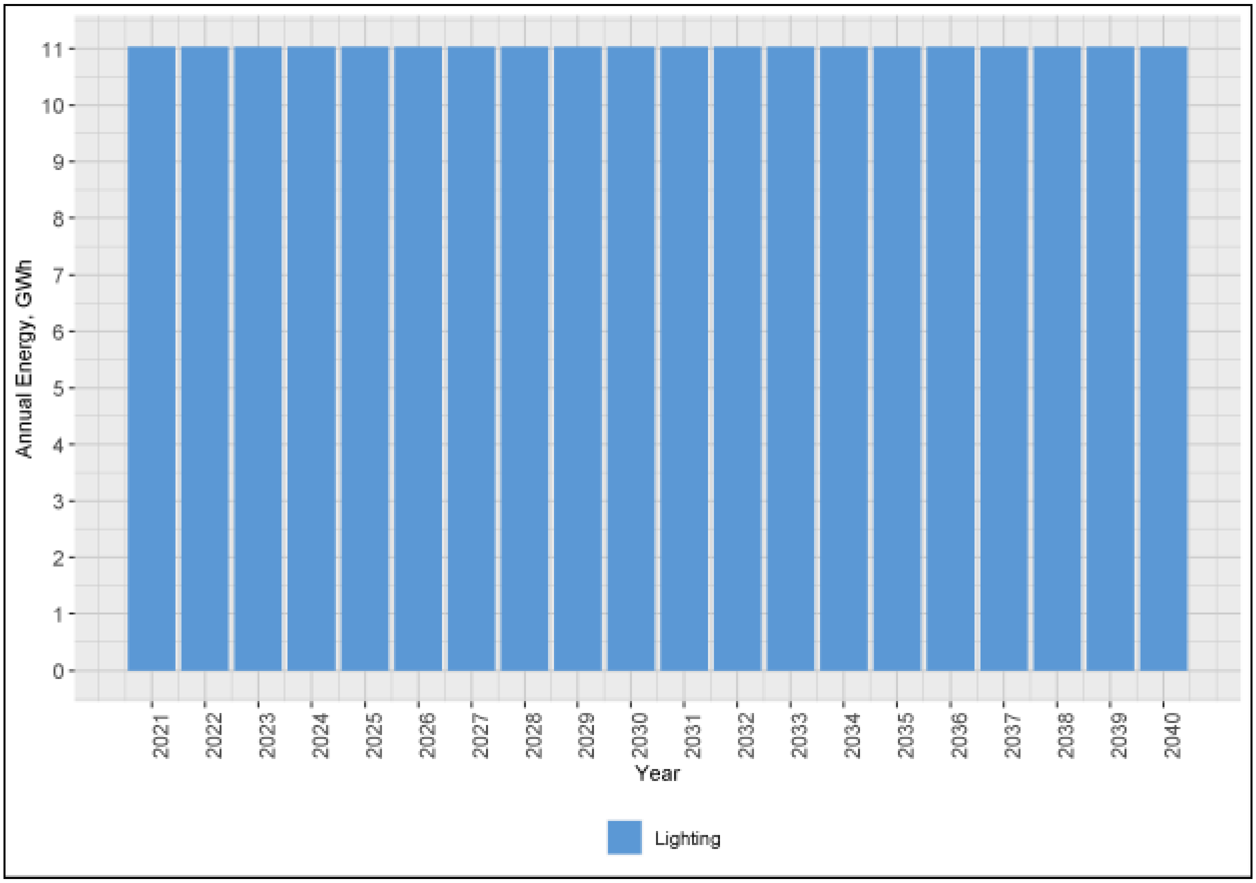
Figure F-13: Irrigation Energy Load (GWh)



3.6 *LIGHTING*

Due to the implementation of light-emitting diode (LED) street lights, the lighting energy load has been declining in recent years. As the LED programs wrap up, FBC expects the energy load trends to level off. As a result, FBC has assumed the lighting energy load is forecast to remain at the 2019 energy loads of 11 GWh for the remainder of the planning horizon. Lighting load makes up approximately 0.3 percent of gross load.

Figure F-14: Lighting Energy Load (GWh)



3.7 *LOSSES*

FBC conducted a Losses Study in 2019[3] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross energy load excluding company use. System losses consist of the following:

- Losses in the transmission and distribution system;
- Losses due to wheeling through the BC Hydro system; and
- Unaccounted-for energy load (meter inaccuracies and theft).

Additionally, FBC has forecasted company use energy at 13 GWh annually for the planning horizon which is included in the annual losses.

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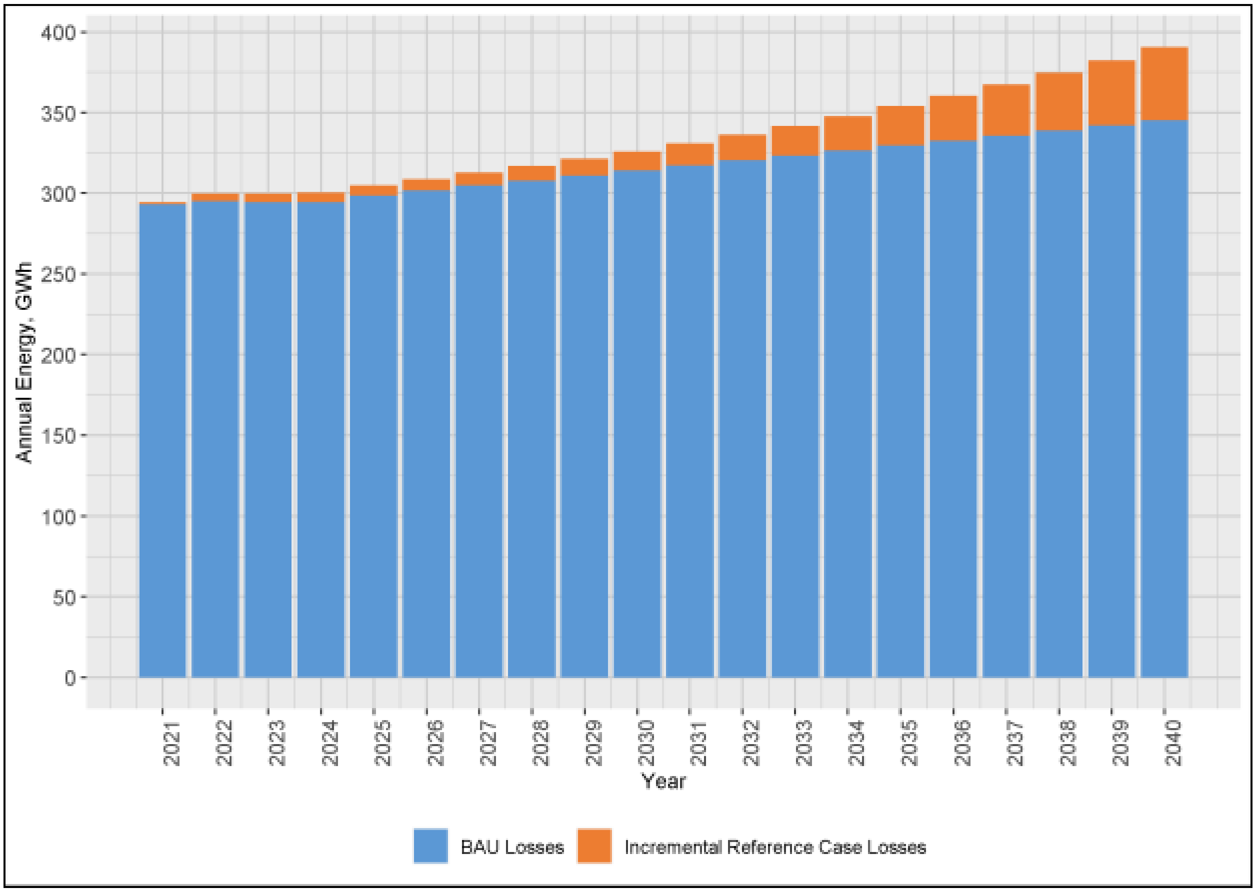
[3] FBC 2020-2024 MRP Application, Appendix B3 – FBC Losses Study, page 65. https://www.bcuc.com/Documents/Proceedings/2019/DOC_53565_B-1-1-FortisBC-2020-2024-Multi-YearRatePlan-Appendices.pdf

The Reference Case total annual losses are forecast to grow at an average annual rate of 1.5 percent per year over the next 20 years, while the BAU forecast losses grow at average rate of 0.9 percent per year. The graph below shows the projected losses for the Reference Case forecast and the BAU forecast over the planning horizon.

Figure F-15: Energy Load Losses (GWh)



4. PEAK DEMAND FORECAST

Peak demand is the largest amount of capacity needed at one point in time on the FBC system due to high customer demand, and is affected by both weather and system growth. The peak demand forecast is calculated by escalating the ten year average (2010-2019) of historic peak data by the gross energy load growth rate.

Monthly peaks were calculated and then escalated by the annual energy load growth rates for the forecast period to produce forecast monthly peaks. The winter peak is the maximum forecast between the months of November and February and is usually on one of the coldest days of the year. Similarly, the summer peak is the maximum demand expected between July and August. Peak demand in the load forecast does not include Planning Reserve Margin (PRM) requirements. PRM is discussed in the LTERP, Section 11.3.10 and Appendix M.

The winter and summer peaks for the Reference Case forecast grow at an average annual rate of 1.7 percent and 1.9 percent, respectively, over the next 20 years. Both the winter and summer peaks for the BAU forecast grow at a average annual rate of 0.9 percent over the planning horizon. The winter and summer peak forecast are provided in the following figures.

Figure F-16: Winter Peak (MW)

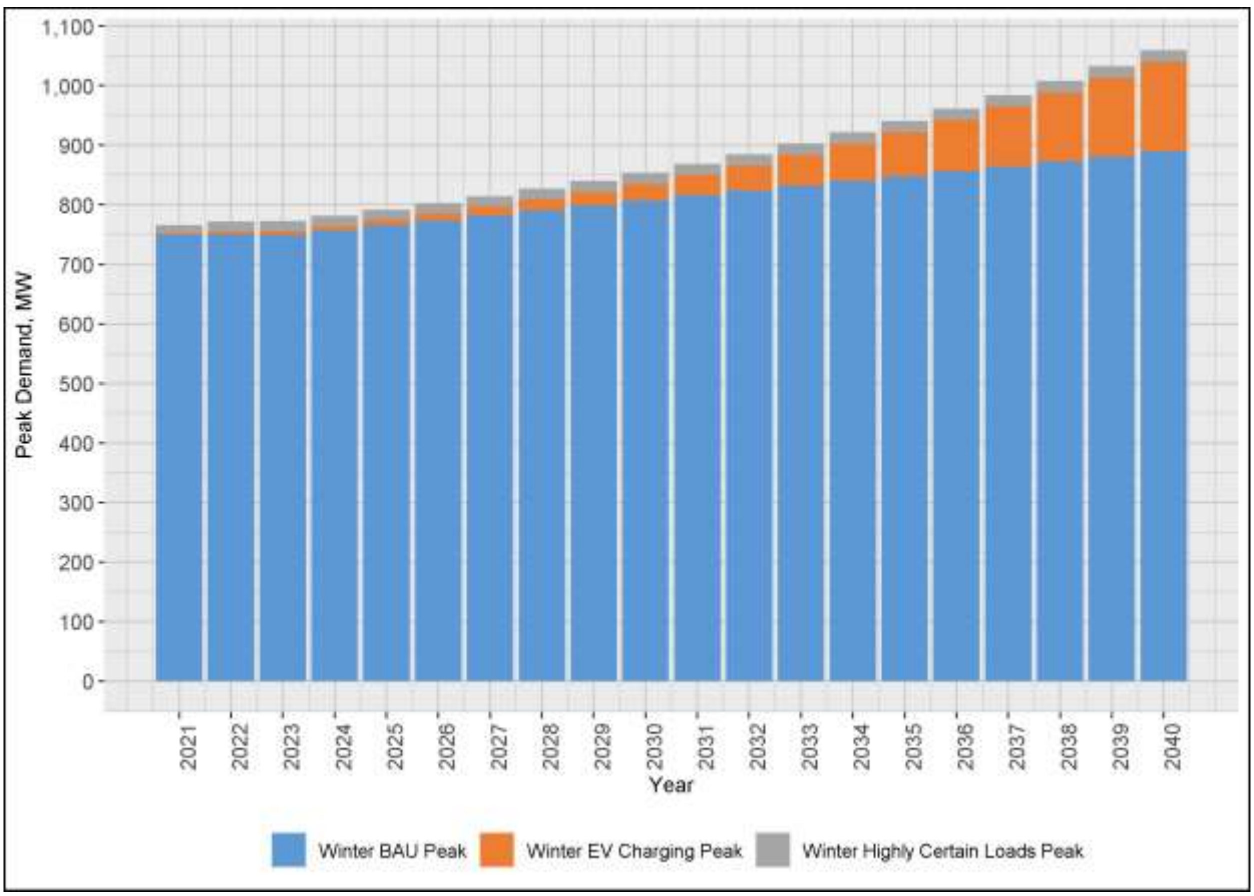
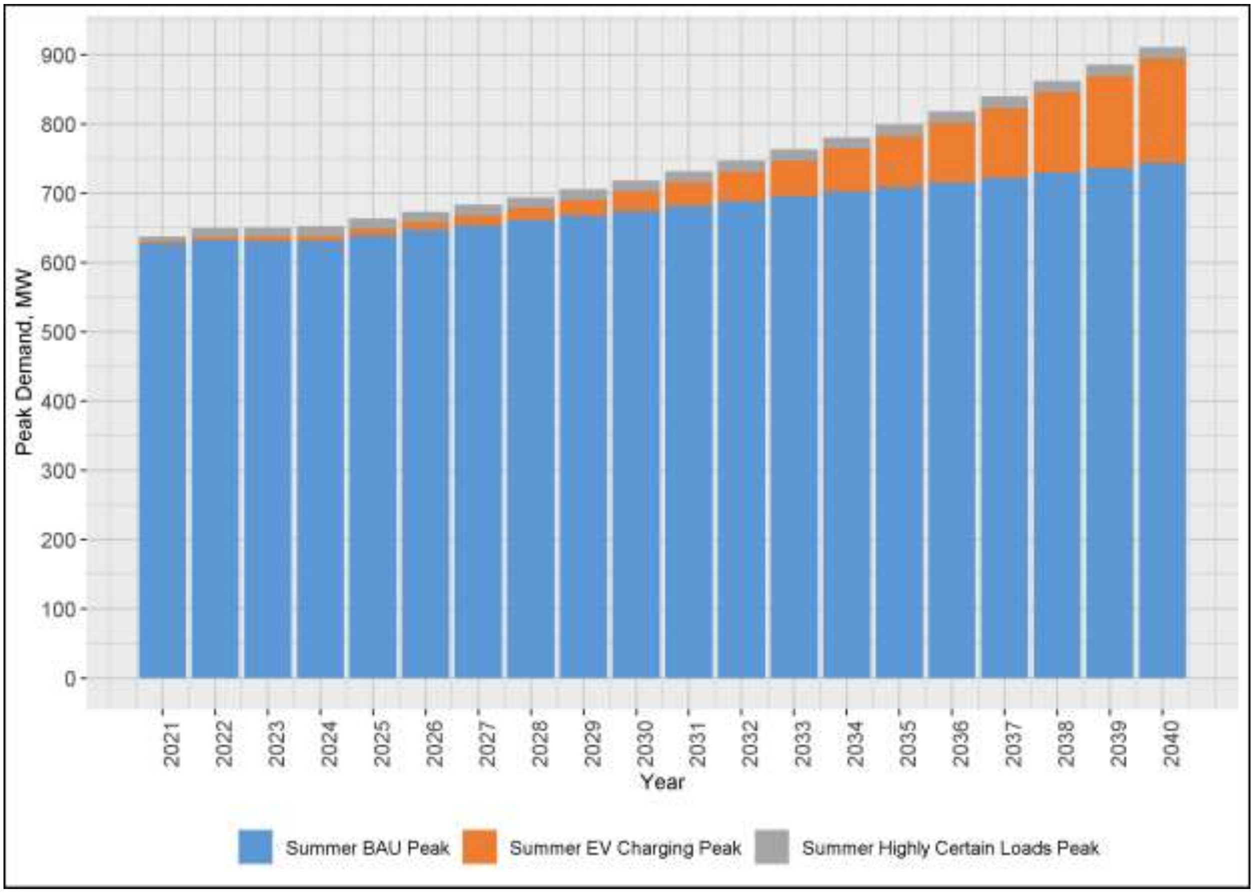


Figure F-17: Summer Peak (MW)



The EV charging load contributes 150 MW to the winter and summer peak demand by 2040. This assumes no mitigation programs or initiatives are in place to shift home EV charging off peak demand periods. Options regarding EV charging shifting are discussed in section 2.3.2.

5. LOAD FORECAST UNCERTAINTY

In order to account for future variability in the Reference Case load forecast, FBC developed uncertainty bands around the reference case forecast composed of three elements:

1. Prediction intervals computed for the BAU forecast at the 90% confidence level;
2. An upper and lower EV forecast, and
3. An upper and lower highly certain industrial energy loads forecast.

The three sources of uncertainty were then summed and applied to the Reference Case forecast to develop the range of uncertainty.

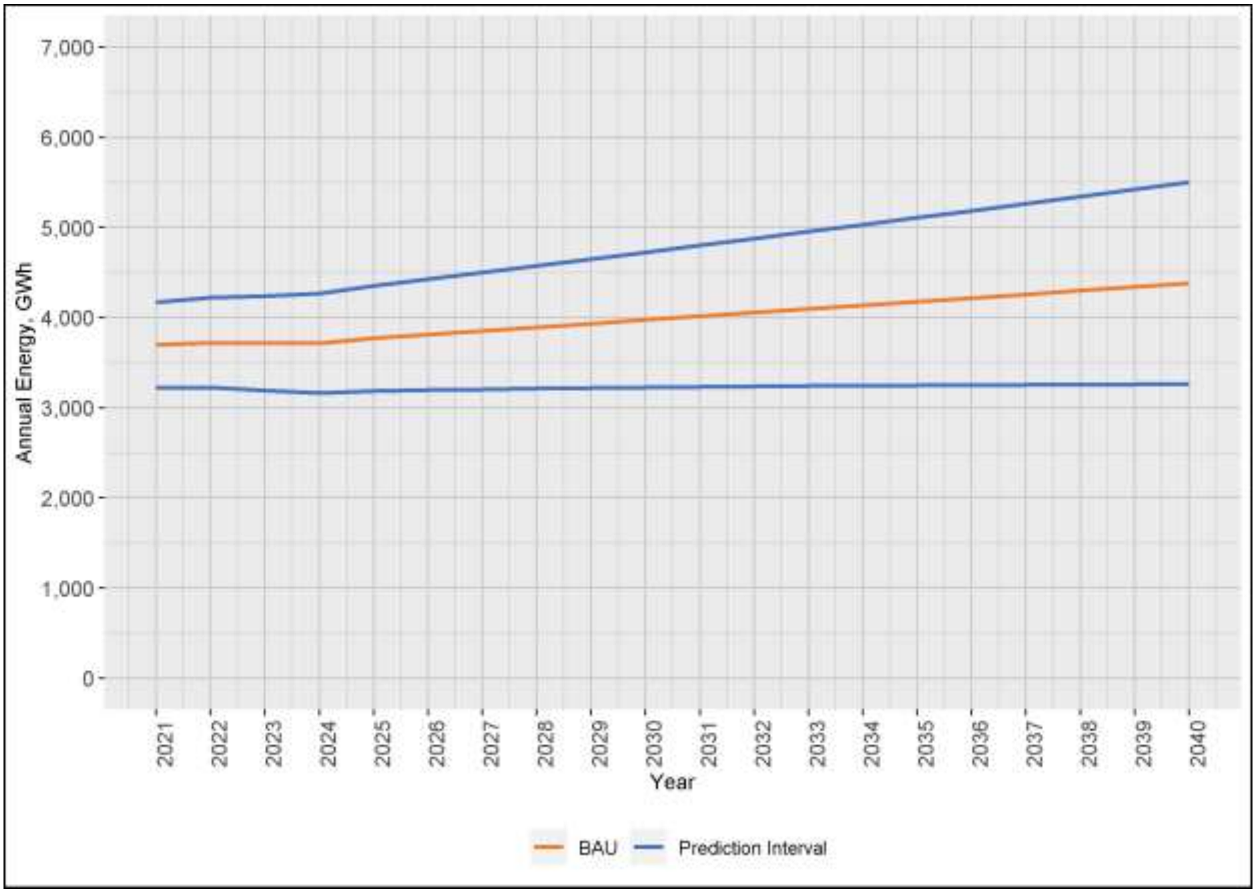
5.1 BAU FORECAST PREDICTION INTERVAL

The prediction intervals for the BAU forecast are calculated with the standard prediction interval formula[4] using ten years of historic actual data by rate class.

The prediction intervals for each rate were calculated and the results summed to create the aggregate prediction interval. The prediction interval was both added to and subtracted from the reference case forecast to produce the following plot:

[4] Sullivan, M. (2013). *Statistics: Informed decisions using data*, 4th ed.

Figure F-18: BAU Forecast Prediction Intervals (GWh)

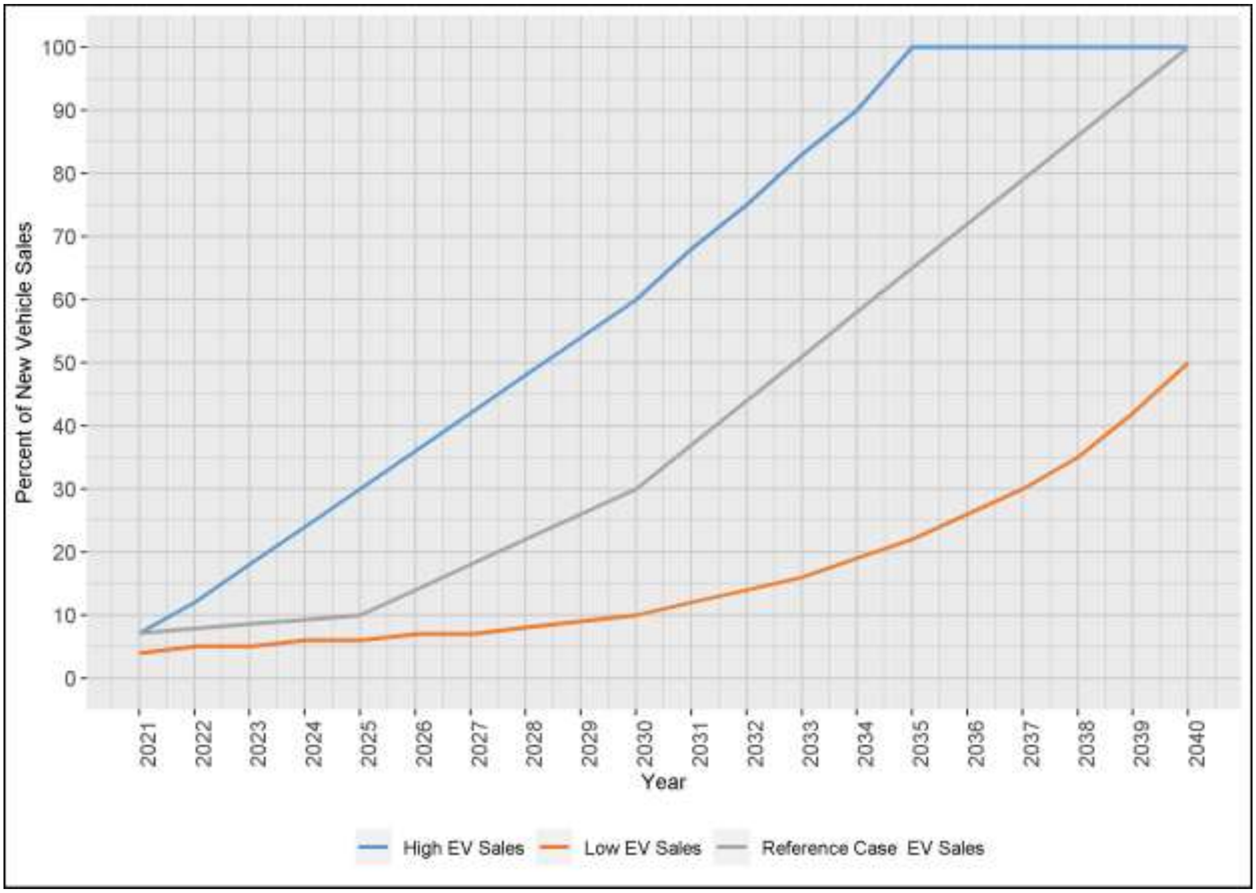


5.2 *EV CHARGING LOAD FORECAST UNCERTAINTY*

The EV charging load portion of the Reference Case load forecast line is based on the *ZEV Act* sales targets with 100 percent of new light-duty vehicle sales in 2040 being EVs. There is no historic data for this forecast so formal prediction intervals cannot be calculated directly. Instead, for the high case, FBC assumed that 100 percent of vehicles sales would be EVs by 2035 instead of 2040. For the low case, FBC assumed that by 2040 only 50 percent of new light-duty vehicle sales were EVs.

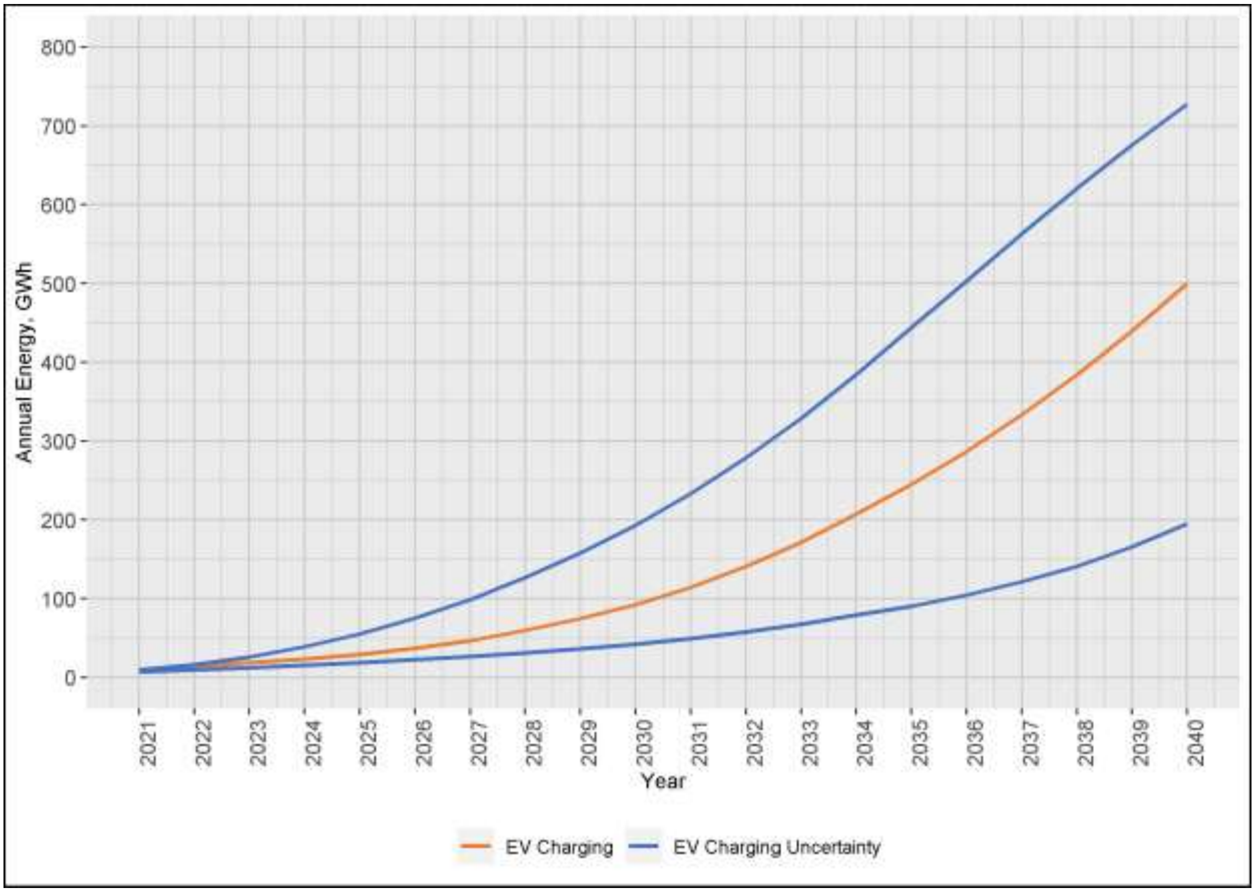
The high and low bands for the new light-duty EV sales percentages are shown in the following figure.

Figure F-19: EV Sales Bands (% of New Light-Duty Vehicle Sales)



The EV sales percentages, along with the forecast of total new light-duty vehicle sales and the assumed EV charging load, were then used to calculate the EV charging load portion of the Reference Case load forecast along with the high and low bands, as shown below.

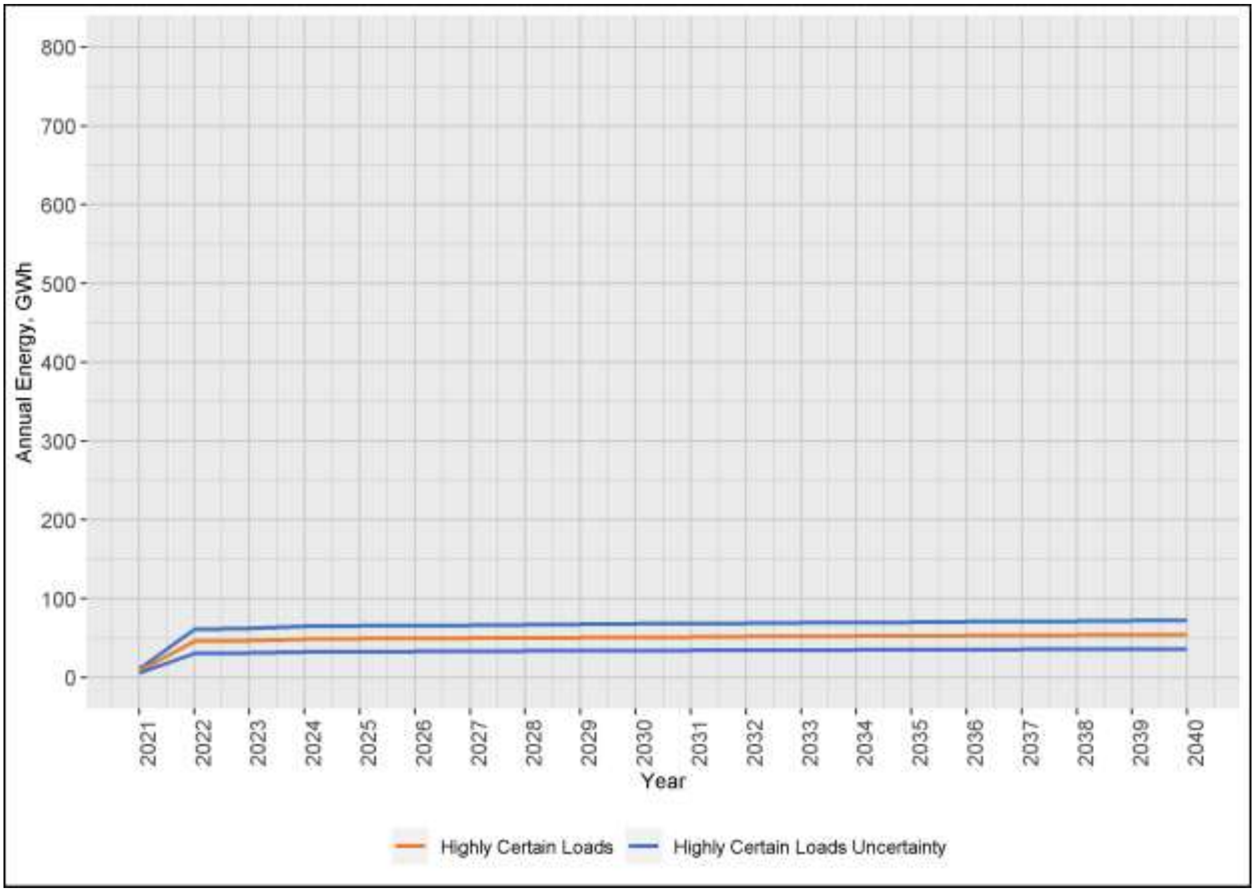
Figure F-20: EV Charging Load Uncertainty Bands (GWh)



5.3 *HIGHLY CERTAIN INDUSTRIAL LOADS FORECAST UNCERTAINTY*

The highly certain industrial energy loads forecast is shown in blue in the figure below and represents 75 percent of the known future industrial energy loads materializing. There is no historic data for this forecast component so formal prediction intervals cannot be calculated directly. Instead, FBC has assumed 50 percent probability for the low band and 100 percent probability for the high band. For ease of comparison, the scale for the EV uncertainty bands shown in Section 5.1 above and Figure F-21 are identical.

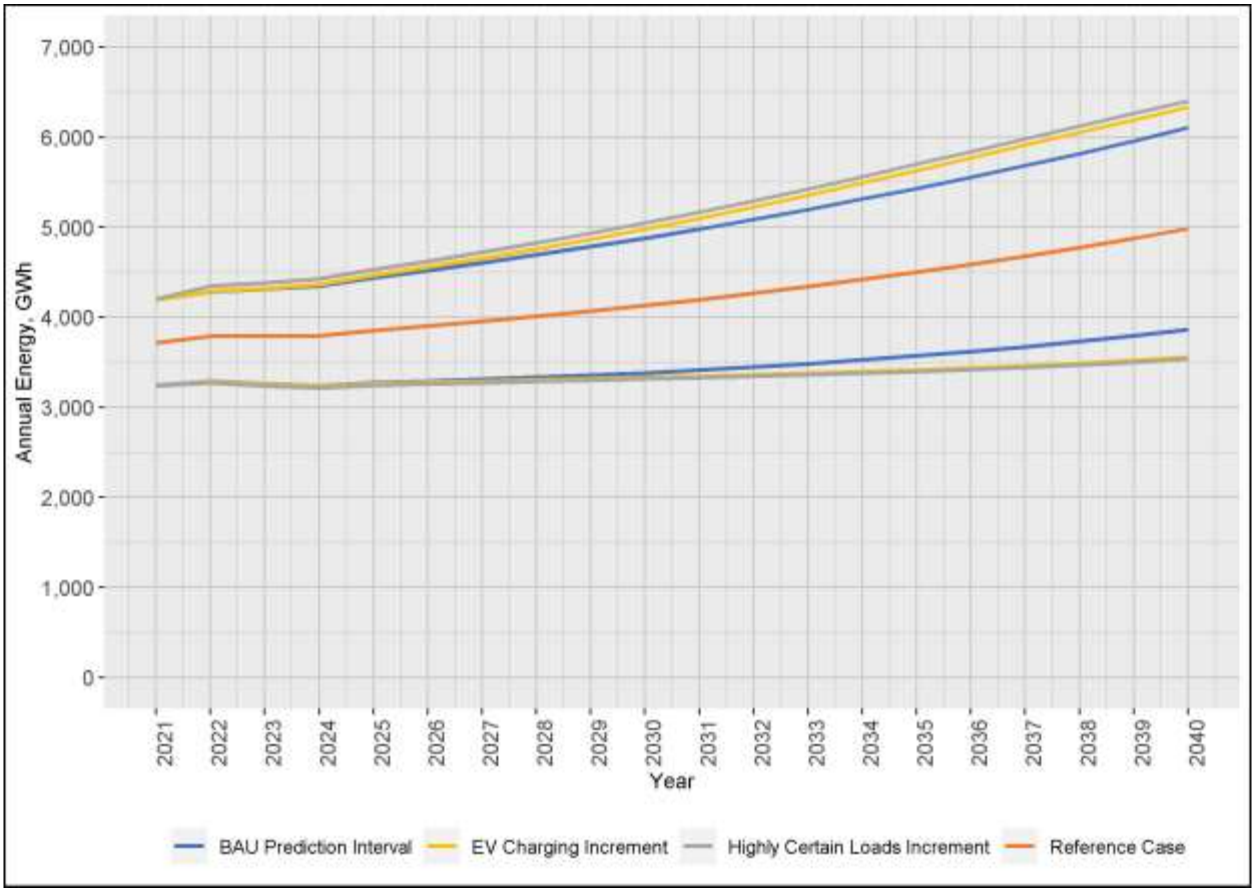
Figure F-21: Highly Certain Industrial Energy Loads Uncertainty Bands (GWh)



5.4 *REFERENCE CASE FORECAST UNCERTAINTY BANDS SUMMARY*

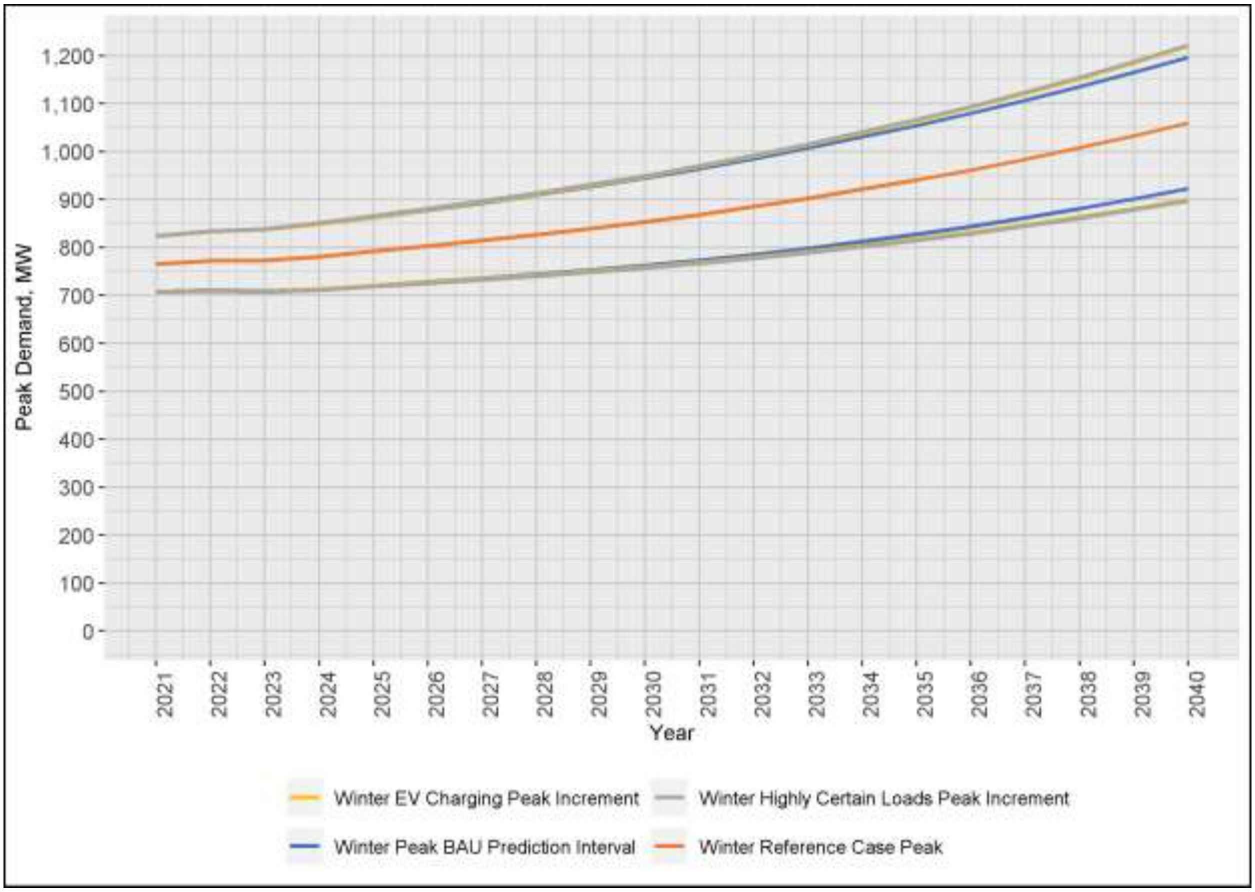
Once uncertainly bands were computed for EV charging loads, highly certain industrial loads and the BAU forecast, they were summed to produce the following uncertainty bands for the Reference Case load forecast.

Figure F-22: Reference Case Forecast Uncertainty Bands Summary (GWh)



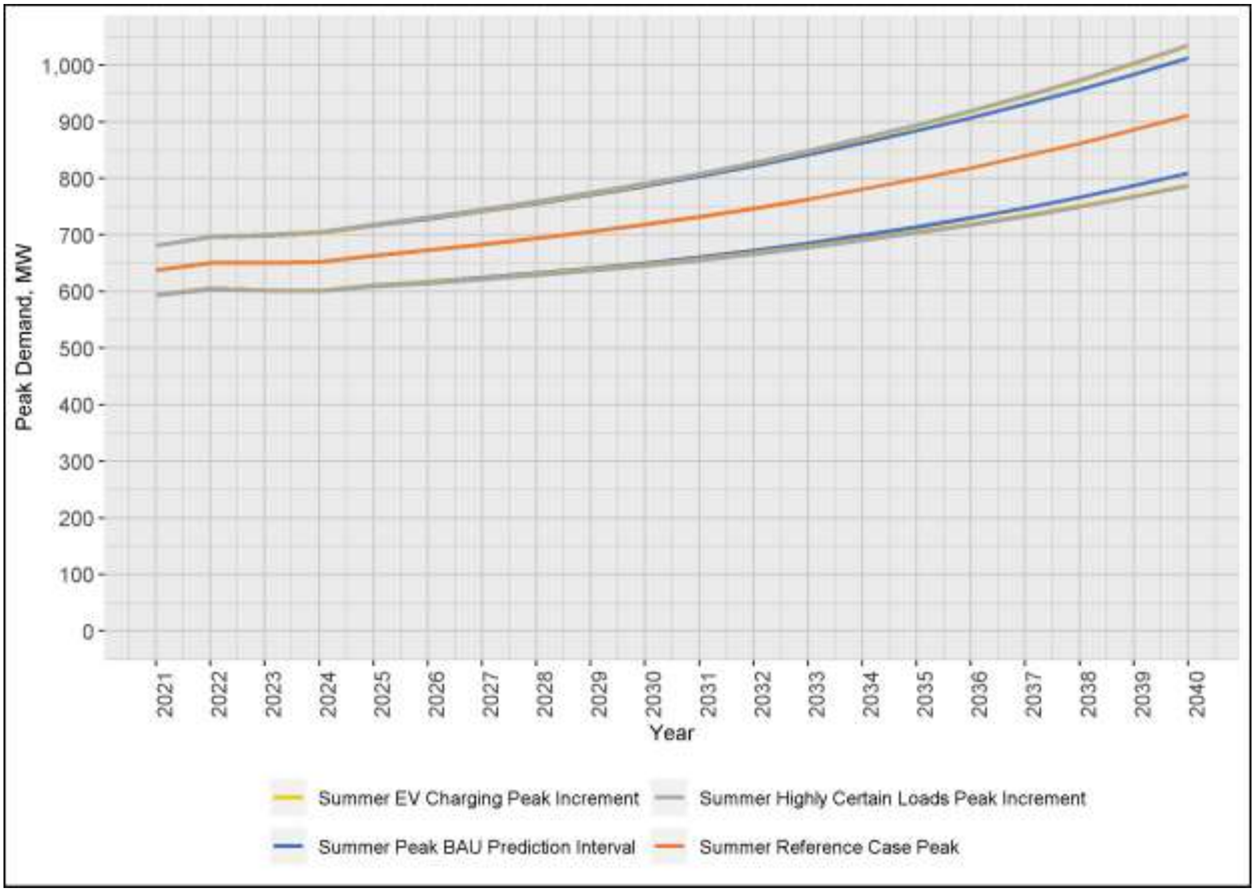
Winter and summer peak uncertainly bands for the BAU forecast were calculated using the same method. Winter and summer peak uncertainty bands for EV charging and highly certain industrial loads were calculated assuming the same ratios as were calculated above.

1 **Figure F-23: Reference Case Winter Peak Forecast Uncertainty Bands Summary (MW)**



2

Figure F-24: Reference Case Summer Peak Forecast Uncertainty Bands Summary (MW)



6. SUMMARY

FBC is forecasting long-term Reference Case energy net load growth to average about 1.6 percent per year. Growth in the residential class is forecast to increase over the medium and long term, with the largest driver relating to EV charging loads, while the commercial and wholesale classes are forecast to have steady growth over the planning horizon. The industrial sectors are forecast to see some large increases over the short term due to new loads and then have modest growth over the remainder of the planning horizon. Lighting and irrigation energy loads are forecast to remain constant.

Appendix G

LONG-TERM LOAD FORECAST TABLES

FORTISBC INC.

Appendix G

2021 Long Term Electric Resource Plan

Load Forecast Tables

Table of Contents

1. INTRODUCTION

This appendix provides the monthly historical, BAU and reference case forecast load data used in Section 3 of the LTERP Application. Tables 2.1 to 2.10 show ten years of historical data and the BAU and Reference Case load forecast, before DSM,for 2021 to 2040.

The tables in this appendix reflect the acquisition by FBC of the assets and customers of the City of Kelowna electric utility effective March 31, 2013. The acquisition resulted in an increase in direct customers to FBC and a re-distribution of load from wholesale to other rate classes in 2013 and 2014.

Gross load is calculated by adding the residential, commercial, wholesale, industrial, lighting, irrigation and losses loads together, which are provided in tables 2.3 to 2.9. Net load excludes losses and is the sum of the information in tables 2.3 to 2.8.

2. MONTHLY LOAD FORECAST

2.1 GROSS ENERGY LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2011	374,096	313,764	312,059	254,039	235,722	242,276	268,421	273,732	242,593	260,877	307,093	362,607	3,447,280
2012	354,376	315,497	304,411	253,594	237,899	233,308	272,143	275,122	236,457	262,538	313,757	362,555	3,421,657
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,947	304,540	303,886	253,159	241,999	242,933	284,643	269,971	229,496	256,060	300,844	381,603	3,433,082
2015	365,681	319,636	299,774	250,449	249,965	245,501	286,189	276,449	233,713	256,762	300,047	361,987	3,446,152
2016	363,248	311,848	292,351	268,698	248,319	242,786	289,259	280,588	234,770	266,284	332,085	350,062	3,480,297
2017	361,265	295,737	307,586	263,795	249,642	251,284	299,544	288,941	246,701	265,695	326,103	355,527	3,511,820
2018	375,664	309,496	306,028	264,140	273,621	256,591	308,227	297,251	231,377	262,531	302,555	376,342	3,563,824
2019	372,224	288,274	315,330	261,324	268,354	257,653	298,081	293,227	260,757	291,917	313,593	371,724	3,592,459
2020	382,181	332,609	303,499	246,152	239,601	248,354	309,611	303,017	260,523	282,780	333,207	374,349	3,615,884
BAU Forecast													-
2021F	379,611	307,982	319,515	273,964	275,454	264,390	311,349	306,319	257,586	290,948	329,797	380,698	3,697,614
2022F	386,037	313,141	324,520	275,574	277,120	265,307	312,359	307,301	258,322	291,679	330,438	381,209	3,723,006
2023F	384,941	312,496	323,816	275,090	276,689	265,033	311,899	307,000	258,121	291,280	329,736	380,114	3,716,215
2024F	384,474	312,390	323,654	275,061	276,704	265,190	311,939	307,204	258,370	291,389	329,578	379,606	3,715,558
2025F	390,123	317,006	328,405	279,091	280,771	269,062	316,533	311,758	262,233	295,535	334,330	385,140	3,769,987
2026F	390,884	319,076	330,932	282,807	283,511	276,734	323,524	315,432	267,050	295,212	336,275	389,105	3,810,545
2027F	395,181	322,577	334,554	285,889	286,558	279,669	326,989	318,834	269,938	298,429	339,960	393,380	3,851,957
2028F	399,455	326,065	338,162	288,960	289,593	282,596	330,438	322,222	272,815	301,635	343,632	397,636	3,893,210
2029F	403,702	329,532	341,744	292,013	292,607	285,503	333,866	325,594	275,678	304,823	347,281	401,864	3,934,207
2030F	407,941	332,991	345,320	295,058	295,616	288,400	337,290	328,965	278,536	308,003	350,919	406,081	3,975,121
2031F	412,228	336,493	348,941	298,144	298,666	291,345	340,765	332,387	281,443	311,230	354,602	410,342	4,016,586
2032F	416,499	339,989	352,553	301,224	301,711	294,284	344,234	335,808	284,345	314,452	358,277	414,590	4,057,966
2033F	420,683	343,412	356,088	304,237	304,685	297,155	347,625	339,156	287,185	317,608	361,876	418,753	4,098,465
2034F	424,806	346,782	359,565	307,203	307,613	299,975	350,963	342,449	289,976	320,712	365,420	422,854	4,138,317
2035F	428,956	350,183	363,076	310,196	310,566	302,831	354,335	345,783	292,803	323,848	368,995	426,981	4,178,554
2036F	433,061	353,547	366,546	313,157	313,487	305,650	357,671	349,083	295,599	326,951	372,532	431,065	4,218,349
2037F	437,192	356,941	370,044	316,145	316,436	308,499	361,040	352,417	298,425	330,084	376,095	435,175	4,258,493
2038F	441,419	360,421	373,632	319,214	319,468	311,439	364,502	355,849	301,339	333,308	379,751	439,376	4,299,718
2039F	445,648	363,908	377,225	322,290	322,505	314,384	367,973	359,292	304,263	336,539	383,413	443,578	4,341,018
2040F	449,966	367,474	380,902	325,440	325,620	317,410	371,532	362,826	307,268	339,853	387,156	447,871	4,383,318
Reference Case Forecast													
2021F	381,199	309,666	321,147	275,672	276,976	265,904	312,723	307,817	259,175	292,492	331,491	383,105	3,717,367
2022F	391,015	318,524	330,137	281,293	282,685	270,650	317,521	312,714	263,918	297,152	335,961	386,107	3,787,675
2023F	390,320	318,287	329,837	281,217	282,662	270,781	317,465	312,818	264,418	297,455	335,950	385,652	3,786,862
2024F	390,542	318,897	330,416	281,927	283,423	271,668	318,237	313,755	265,110	298,004	336,231	385,576	3,793,785
2025F	396,713	324,043	335,700	286,489	288,025	276,073	323,364	318,841	269,505	302,683	341,511	391,628	3,854,576
2026F	398,544	326,864	338,717	290,304	291,051	284,820	331,379	323,282	274,694	303,119	344,303	396,848	3,903,924
2027F	403,787	331,324	343,289	294,336	295,048	288,709	335,794	327,636	278,533	307,289	348,944	402,071	3,956,758
2028F	409,227	335,993	348,069	298,579	299,252	292,811	340,415	332,197	282,584	311,666	353,791	407,493	4,012,077
2029F	414,863	340,865	353,046	303,025	303,658	297,117	345,240	336,963	286,841	316,250	358,839	413,112	4,069,818
2030F	420,718	345,958	358,243	307,692	308,285	301,640	350,284	341,956	291,321	321,052	364,102	418,944	4,130,195
2031F	427,009	351,491	363,879	312,797	313,348	306,607	355,775	347,393	296,242	326,297	369,808	425,213	4,195,858
2032F	433,690	357,424	369,908	318,296	318,807	311,970	361,662	353,233	301,565	331,936	375,908	431,869	4,266,270
2033F	440,692	363,699	376,271	324,144	324,609	317,677	367,883	359,409	307,236	337,920	382,344	438,851	4,340,736
2034F	448,047	370,339	382,993	330,358	330,777	323,751	374,467	365,950	313,276	344,269	389,140	446,187	4,419,554
2035F	455,599	377,182	389,916	336,768	337,142	330,025	381,252	372,697	319,520	350,821	396,138	453,716	4,500,776
2036F	463,497	384,384	397,193	343,543	343,866	336,661	388,396	379,806	326,127	357,733	403,492	461,595	4,586,294
2037F	471,825	392,021	404,901	350,748	351,022	343,731	395,976	387,350	333,169	365,076	411,278	469,902	4,676,998
2038F	480,655	400,160	413,107	358,444	358,670	351,301	404,059	395,403	340,708	372,920	419,564	478,707	4,773,699
2039F	489,900	408,718	421,732	366,559	366,735	359,288	412,563	403,877	348,668	381,184	428,269	487,927	4,875,420
2040F	499,650	417,779	430,859	375,171	375,297	367,776	421,572	412,863	357,130	389,947	437,479	497,654	4,983,177

2.2 NET ENERGY LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2011	333,975	282,076	283,208	233,733	218,542	223,679	246,555	251,059	223,951	240,135	278,304	324,686	3,139,902
2012	321,730	286,779	279,732	235,517	222,312	217,842	252,099	254,667	220,598	243,793	286,926	328,517	3,150,511
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	330,080	277,952	279,588	235,366	226,108	226,460	263,122	250,470	214,691	238,394	276,319	344,675	3,163,224
2015	331,359	290,442	275,968	232,925	232,996	228,619	264,346	255,968	218,317	238,919	275,526	328,297	3,173,683
2016	329,697	284,239	269,871	248,933	231,743	226,433	267,219	259,761	219,415	247,393	302,834	318,710	3,206,245
2017	327,600	270,353	282,545	244,429	232,661	233,596	275,700	266,639	229,612	246,617	297,428	322,834	3,230,015
2018	340,082	282,343	281,627	245,049	253,803	238,507	283,500	274,131	216,479	244,187	277,988	340,643	3,278,339
2019	337,457	264,607	289,706	242,736	249,368	239,550	274,993	270,833	242,244	269,708	287,514	337,042	3,305,758
2020	346,177	302,227	279,953	229,763	224,464	231,690	285,178	279,540	242,297	262,136	304,435	339,684	3,327,545
BAU Forecast													
2021F	344,683	282,083	294,089	254,316	256,163	246,005	287,115	282,806	240,077	269,582	302,076	345,587	3,404,583
2022F	350,247	286,608	298,521	255,841	257,739	246,926	288,137	283,803	240,836	270,354	302,797	346,235	3,428,046
2023F	349,277	286,019	297,877	255,387	257,330	246,654	287,701	283,504	240,629	269,972	302,156	345,265	3,421,771
2024F	348,880	285,921	297,731	255,357	257,338	246,786	287,729	283,672	240,841	270,061	302,015	344,833	3,421,164
2025F	354,025	290,159	302,117	259,110	261,131	250,402	291,980	287,888	244,449	273,924	306,391	349,882	3,471,456
2026F	354,970	292,144	304,504	262,511	263,692	257,244	298,182	291,254	248,816	273,839	308,284	353,490	3,508,931
2027F	358,884	295,358	307,847	265,381	266,538	259,985	301,390	294,407	251,517	276,832	311,672	357,385	3,547,196
2028F	362,778	298,561	311,176	268,240	269,371	262,720	304,584	297,549	254,206	279,815	315,049	361,264	3,585,314
2029F	366,647	301,746	314,483	271,082	272,186	265,434	307,758	300,674	256,883	282,781	318,405	365,117	3,623,195
2030F	370,509	304,921	317,784	273,917	274,996	268,141	310,929	303,799	259,554	285,740	321,750	368,961	3,661,000
2031F	374,415	308,138	321,126	276,790	277,844	270,892	314,145	306,970	262,270	288,742	325,137	372,845	3,699,314
2032F	378,307	311,348	324,460	279,657	280,687	273,636	317,357	310,140	264,983	291,739	328,517	376,718	3,737,549
2033F	382,120	314,492	327,723	282,463	283,464	276,318	320,497	313,242	267,636	294,675	331,827	380,513	3,774,969
2034F	385,876	317,586	330,932	285,224	286,198	278,953	323,587	316,294	270,245	297,562	335,085	384,251	3,811,792
2035F	389,658	320,710	334,173	288,011	288,956	281,619	326,709	319,382	272,887	300,479	338,373	388,014	3,848,972
2036F	393,399	323,799	337,376	290,768	291,683	284,253	329,797	322,439	275,499	303,366	341,625	391,738	3,885,743
2037F	397,165	326,916	340,605	293,549	294,437	286,914	332,915	325,527	278,140	306,280	344,903	395,485	3,922,835
2038F	401,018	330,112	343,918	296,407	297,268	289,659	336,120	328,705	280,862	309,278	348,265	399,317	3,960,928
2039F	404,875	333,314	347,235	299,270	300,103	292,408	339,333	331,893	283,592	312,283	351,633	403,152	3,999,088
2040F	408,813	336,589	350,630	302,202	303,011	295,232	342,626	335,165	286,398	315,363	355,076	407,069	4,038,174
Reference Case Forecast													
2021F	346,165	283,627	295,600	255,890	257,579	247,411	288,405	284,203	241,548	271,018	303,638	347,750	3,422,835
2022F	354,904	291,545	303,695	261,097	262,874	251,858	292,922	288,802	245,992	275,407	307,880	350,823	3,487,800
2023F	354,316	291,336	303,431	261,025	262,847	251,966	292,866	288,884	246,422	275,662	307,862	350,433	3,487,048
2024F	354,551	291,890	303,963	261,670	263,539	252,766	293,563	289,723	247,053	276,168	308,140	350,420	3,493,446
2025F	360,182	296,614	308,841	265,914	267,827	256,873	298,307	294,430	251,151	280,523	313,003	355,951	3,549,617
2026F	362,089	299,290	311,702	269,444	270,679	264,690	305,439	298,506	255,882	281,142	315,672	360,678	3,595,214
2027F	366,882	303,384	315,924	273,191	274,403	268,312	309,526	302,540	259,460	285,016	319,942	365,453	3,644,033
2028F	371,858	307,671	320,337	277,131	278,319	272,131	313,803	306,765	263,233	289,082	324,403	370,413	3,695,147
2029F	377,016	312,142	324,933	281,260	282,420	276,138	318,269	311,180	267,197	293,339	329,049	375,557	3,748,500
2030F	382,377	316,818	329,733	285,592	286,727	280,344	322,937	315,803	271,367	297,797	333,893	380,899	3,804,288
2031F	388,144	321,896	334,938	290,327	291,437	284,960	328,018	320,838	275,944	302,665	339,147	386,647	3,864,961
2032F	394,272	327,342	340,507	295,427	296,513	289,943	333,465	326,244	280,891	307,897	344,763	392,754	3,930,021
2033F	400,700	333,101	346,386	300,848	301,906	295,241	339,221	331,961	286,160	313,448	350,690	399,165	3,998,828
2034F	407,455	339,195	352,596	306,607	307,637	300,879	345,313	338,015	291,769	319,336	356,949	405,904	4,071,656
2035F	414,394	345,474	358,992	312,547	313,551	306,702	351,591	344,259	297,565	325,412	363,395	412,823	4,146,705
2036F	421,654	352,084	365,716	318,823	319,798	312,858	358,200	350,838	303,697	331,820	370,169	420,067	4,225,723
2037F	429,313	359,093	372,838	325,497	326,443	319,414	365,211	357,819	310,230	338,627	377,341	427,708	4,309,534
2038F	437,438	366,561	380,422	332,623	333,543	326,432	372,689	365,270	317,223	345,898	384,976	435,810	4,398,886
2039F	445,947	374,415	388,392	340,137	341,030	333,836	380,555	373,109	324,604	353,557	392,996	444,298	4,492,876
2040F	454,924	382,730	396,827	348,110	348,978	341,702	388,888	381,422	332,448	361,677	401,483	453,255	4,592,444

2.3 RESIDENTIAL ENERGY LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2011	150,580	112,169	121,527	98,312	80,093	79,957	85,233	91,744	76,608	88,720	117,345	146,806	1,249,094
2012	134,187	105,958	112,447	88,508	81,808	82,946	97,309	91,118	73,417	89,175	117,807	154,029	1,228,709
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
2017	145,663	112,986	118,857	102,166	94,155	86,021	106,392	95,082	82,012	96,745	129,829	150,584	1,320,492
2018	154,740	121,081	119,975	97,261	100,276	86,146	109,349	100,153	70,342	89,942	112,695	150,638	1,312,598
2019	147,714	98,552	116,377	90,039	91,727	81,739	100,157	94,674	87,612	98,618	112,609	146,320	1,266,137
2020	150,634	126,164	117,219	93,211	89,289	91,128	111,958	103,644	86,533	100,913	126,958	149,181	1,346,832
BAU Forecast													
2021F	144,697	107,404	114,697	93,469	92,401	81,986	102,003	93,612	77,485	92,125	114,672	144,511	1,259,064
2022F	142,706	105,925	113,119	92,182	91,130	80,857	100,600	92,324	76,419	90,858	113,095	142,522	1,241,737
2023F	140,671	104,415	111,507	90,868	89,830	79,706	99,166	91,007	75,329	89,562	111,483	140,491	1,224,036
2024F	138,581	102,862	109,849	89,517	88,495	78,520	97,691	89,654	74,210	88,231	109,824	138,402	1,205,837
2025F	139,908	103,849	110,900	90,375	89,343	79,273	98,627	90,513	74,921	89,076	110,877	139,729	1,217,392
2026F	141,210	104,814	111,932	91,216	90,173	80,010	99,544	91,356	75,618	89,905	111,908	141,028	1,228,713
2027F	142,483	105,759	112,942	92,039	90,987	80,731	100,443	92,180	76,300	90,715	112,917	142,299	1,239,795
2028F	143,728	106,683	113,929	92,843	91,781	81,437	101,320	92,984	76,965	91,508	113,904	143,543	1,250,626
2029F	144,939	107,583	114,889	93,625	92,554	82,123	102,174	93,769	77,615	92,279	114,865	144,753	1,261,168
2030F	146,111	108,452	115,818	94,383	93,304	82,787	103,000	94,527	78,242	93,025	115,794	145,924	1,271,367
2031F	147,246	109,294	116,717	95,115	94,028	83,431	103,801	95,261	78,851	93,747	116,692	147,056	1,281,240
2032F	148,341	110,108	117,586	95,822	94,728	84,051	104,573	95,969	79,437	94,445	117,560	148,150	1,290,770
2033F	149,398	110,892	118,424	96,505	95,402	84,650	105,318	96,653	80,003	95,119	118,398	149,207	1,299,968
2034F	150,417	111,648	119,230	97,164	96,054	85,226	106,036	97,312	80,548	95,767	119,205	150,224	1,308,833
2035F	151,397	112,375	120,008	97,796	96,679	85,782	106,726	97,946	81,073	96,391	119,981	151,202	1,317,357
2036F	152,338	113,074	120,753	98,404	97,279	86,315	107,389	98,555	81,577	96,989	120,728	152,142	1,325,544
2037F	153,241	113,745	121,469	98,988	97,856	86,827	108,026	99,139	82,061	97,565	121,444	153,045	1,333,405
2038F	154,112	114,391	122,160	99,550	98,412	87,321	108,640	99,703	82,526	98,119	122,133	153,914	1,340,980
2039F	154,951	115,014	122,825	100,092	98,948	87,795	109,231	100,246	82,976	98,653	122,799	154,751	1,348,281
2040F	155,764	115,616	123,470	100,617	99,468	88,256	109,805	100,772	83,412	99,171	123,443	155,563	1,355,355
Reference Case Forecast													
2021F	145,517	108,222	115,517	94,289	93,220	82,806	102,823	94,431	78,305	92,945	115,493	145,332	1,268,901
2022F	143,869	107,089	114,282	93,346	92,293	82,021	101,764	93,488	77,583	92,021	114,258	143,686	1,255,699
2023F	142,216	105,959	113,050	92,413	91,375	81,249	100,710	92,552	76,875	91,108	113,028	142,035	1,242,571
2024F	140,545	104,827	111,813	91,481	90,458	80,484	99,656	91,618	76,174	90,194	111,789	140,366	1,229,404
2025F	142,330	106,270	113,322	92,797	91,764	81,694	101,048	92,934	77,343	91,497	113,298	142,150	1,246,448
2026F	144,281	107,885	115,004	94,288	93,244	83,082	102,616	94,427	78,690	92,976	114,980	144,099	1,265,571
2027F	146,402	109,679	116,860	95,958	94,906	84,650	104,361	96,099	80,219	94,635	116,837	146,219	1,286,824
2028F	148,696	111,653	118,898	97,812	96,751	86,406	106,289	97,954	81,936	96,477	118,874	148,511	1,310,257
2029F	151,165	113,809	121,116	99,851	98,781	88,349	108,401	99,995	83,842	98,505	121,091	150,979	1,335,883
2030F	153,807	116,149	123,514	102,078	101,000	90,483	110,696	102,223	85,939	100,721	123,489	153,620	1,363,718
2031F	156,775	118,824	126,247	104,645	103,558	92,960	113,330	104,790	88,379	103,278	126,222	156,586	1,395,595
2032F	160,077	121,844	129,322	107,558	106,463	95,788	116,309	107,705	91,172	106,181	129,297	159,886	1,431,602
2033F	163,721	125,215	132,747	110,829	109,725	98,972	119,641	110,976	94,326	109,440	132,721	163,529	1,471,842
2034F	167,712	128,944	136,527	114,460	113,349	102,523	123,332	114,608	97,845	113,062	136,501	167,520	1,516,383
2035F	171,821	132,800	140,431	118,219	117,103	106,206	127,150	118,370	101,497	116,815	140,406	171,626	1,562,443
2036F	176,255	136,992	144,671	122,321	121,197	110,232	131,307	122,473	105,495	120,908	144,645	176,060	1,612,558
2037F	181,024	141,528	149,253	126,771	125,640	114,610	135,810	126,923	109,845	125,349	149,228	180,828	1,666,810
2038F	186,138	146,418	154,185	131,575	130,438	119,347	140,666	131,729	114,553	130,145	154,159	185,939	1,725,292
2039F	191,601	151,664	159,474	136,741	135,598	124,445	145,882	136,895	119,625	135,304	159,447	191,401	1,788,077
2040F	197,423	157,277	165,129	142,278	141,128	129,917	151,465	142,431	125,071	140,831	165,103	197,224	1,855,277

2.4 COMMERCIAL ENERGY LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2011	57,742	59,980	55,524	50,675	51,759	55,477	59,401	55,911	50,918	50,637	53,116	55,779	656,918
2012	64,101	63,452	59,292	53,673	54,431	49,553	55,968	62,008	56,661	52,596	57,398	51,423	680,553
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,917	72,012	69,241	70,566	73,379	72,714	75,404	74,677	66,669	60,028	65,444	82,026	863,078
2015	81,041	74,201	68,933	64,674	71,533	72,581	71,204	71,712	68,657	62,650	66,828	79,463	853,478
2016	82,612	75,915	71,711	71,671	69,996	66,744	76,904	77,981	68,748	70,333	81,859	90,367	904,841
2017	85,017	74,211	77,360	69,012	70,513	72,529	81,817	81,344	72,335	73,835	78,070	78,916	914,960
2018	87,447	74,470	78,245	70,839	73,624	72,175	81,335	82,374	71,079	73,218	76,070	85,202	926,078
2019	86,215	75,958	80,152	69,784	72,863	72,688	80,601	81,248	73,015	75,305	77,661	86,230	931,722
2020	88,558	80,807	76,026	63,736	65,028	67,948	79,777	81,941	74,160	76,659	80,994	86,252	921,886
BAU Forecast													
2021F	89,205	77,467	81,301	72,292	74,832	74,967	84,058	84,476	74,635	76,681	79,937	86,333	956,184
2022F	90,500	78,591	82,481	73,342	75,918	76,056	85,278	85,702	75,719	77,793	81,097	87,585	970,062
2023F	91,311	79,296	83,220	74,000	76,599	76,738	86,043	86,471	76,398	78,491	81,824	88,370	978,760
2024F	92,294	80,149	84,116	74,796	77,424	77,564	86,969	87,402	77,220	79,335	82,705	89,322	989,297
2025F	94,531	82,091	86,154	76,608	79,299	79,444	89,077	89,520	79,091	81,258	84,709	91,486	1,013,270
2026F	95,758	83,158	87,273	77,604	80,329	80,475	90,233	90,682	80,118	82,313	85,808	92,674	1,026,424
2027F	97,001	84,236	88,405	78,610	81,371	81,519	91,404	91,859	81,158	83,381	86,922	93,877	1,039,745
2028F	98,227	85,302	89,524	79,604	82,401	82,550	92,560	93,020	82,184	84,435	88,021	95,064	1,052,891
2029F	99,452	86,365	90,639	80,597	83,428	83,579	93,714	94,180	83,209	85,488	89,119	96,249	1,066,019
2030F	100,732	87,477	91,807	81,634	84,502	84,655	94,921	95,393	84,280	86,589	90,266	97,488	1,079,744
2031F	102,069	88,637	93,025	82,718	85,623	85,779	96,179	96,658	85,398	87,738	91,464	98,782	1,094,069
2032F	103,423	89,814	94,259	83,815	86,760	86,917	97,456	97,941	86,531	88,902	92,678	100,092	1,108,588
2033F	104,722	90,942	95,443	84,868	87,849	88,009	98,680	99,172	87,618	90,019	93,842	101,350	1,122,514
2034F	106,002	92,052	96,608	85,904	88,922	89,083	99,885	100,382	88,688	91,118	94,988	102,587	1,136,220
2035F	107,324	93,201	97,815	86,976	90,031	90,195	101,131	101,635	89,796	92,255	96,173	103,867	1,150,401
2036F	108,641	94,345	99,015	88,044	91,136	91,302	102,373	102,883	90,898	93,388	97,354	105,143	1,164,522
2037F	109,995	95,521	100,248	89,141	92,272	92,439	103,649	104,164	92,030	94,550	98,566	106,452	1,179,028
2038F	111,427	96,765	101,553	90,301	93,473	93,642	104,998	105,520	93,228	95,782	99,850	107,838	1,194,377
2039F	112,883	98,029	102,880	91,481	94,694	94,866	106,370	106,899	94,446	97,033	101,154	109,247	1,209,982
2040F	114,418	99,361	104,279	92,725	95,982	96,156	107,816	108,353	95,731	98,352	102,529	110,733	1,226,435
Reference Case Forecast													
2021F	89,205	77,467	81,301	72,292	74,832	74,967	84,058	84,476	74,635	76,681	79,937	86,333	956,184
2022F	90,500	78,591	82,481	73,342	75,918	76,056	85,278	85,702	75,719	77,793	81,097	87,585	970,062
2023F	91,311	79,296	83,220	74,000	76,599	76,738	86,043	86,471	76,398	78,491	81,824	88,370	978,760
2024F	92,294	80,149	84,116	74,796	77,424	77,564	86,969	87,402	77,220	79,335	82,705	89,322	989,297
2025F	94,531	82,091	86,154	76,608	79,299	79,444	89,077	89,520	79,091	81,258	84,709	91,486	1,013,270
2026F	95,758	83,158	87,273	77,604	80,329	80,475	90,233	90,682	80,118	82,313	85,808	92,674	1,026,424
2027F	97,001	84,236	88,405	78,610	81,371	81,519	91,404	91,859	81,158	83,381	86,922	93,877	1,039,745
2028F	98,227	85,302	89,524	79,604	82,401	82,550	92,560	93,020	82,184	84,435	88,021	95,064	1,052,891
2029F	99,452	86,365	90,639	80,597	83,428	83,579	93,714	94,180	83,209	85,488	89,119	96,249	1,066,019
2030F	100,732	87,477	91,807	81,634	84,502	84,655	94,921	95,393	84,280	86,589	90,266	97,488	1,079,744
2031F	102,069	88,637	93,025	82,718	85,623	85,779	96,179	96,658	85,398	87,738	91,464	98,782	1,094,069
2032F	103,423	89,814	94,259	83,815	86,760	86,917	97,456	97,941	86,531	88,902	92,678	100,092	1,108,588
2033F	104,722	90,942	95,443	84,868	87,849	88,009	98,680	99,172	87,618	90,019	93,842	101,350	1,122,514
2034F	106,002	92,052	96,608	85,904	88,922	89,083	99,885	100,382	88,688	91,118	94,988	102,587	1,136,220
2035F	107,324	93,201	97,815	86,976	90,031	90,195	101,131	101,635	89,796	92,255	96,173	103,867	1,150,401
2036F	108,641	94,345	99,015	88,044	91,136	91,302	102,373	102,883	90,898	93,388	97,354	105,143	1,164,522
2037F	109,995	95,521	100,248	89,141	92,272	92,439	103,649	104,164	92,030	94,550	98,566	106,452	1,179,028
2038F	111,427	96,765	101,553	90,301	93,473	93,642	104,998	105,520	93,228	95,782	99,850	107,838	1,194,377
2039F	112,883	98,029	102,880	91,481	94,694	94,866	106,370	106,899	94,446	97,033	101,154	109,247	1,209,982
2040F	114,418	99,361	104,279	92,725	95,982	96,156	107,816	108,353	95,731	98,352	102,529	110,733	1,226,435

2.5 *WHOLESALE ENERGY LOAD (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2011	100,725	84,225	82,112	65,996	58,766	60,441	68,427	71,106	64,187	70,871	84,304	98,386	909,548
2012	96,036	85,333	81,119	66,560	58,307	59,084	69,719	70,177	60,311	72,646	82,146	97,532	898,971
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
2017	61,637	51,026	51,573	40,753	35,692	35,965	47,044	49,971	39,411	42,639	56,771	61,621	574,101
2018	65,721	51,837	50,293	43,769	41,467	33,766	45,024	47,275	36,478	47,576	54,103	67,407	584,715
2019	61,944	48,097	50,091	42,390	39,513	36,881	47,393	44,924	37,351	44,052	49,804	63,534	565,972
2020	64,233	56,219	48,768	39,333	33,066	35,088	44,642	44,913	39,548	45,075	55,660	62,943	569,488
BAU Forecast													
2021F	64,794	51,671	52,012	43,439	39,934	36,491	47,734	48,661	38,760	45,957	54,997	65,910	590,359
2022F	66,218	52,806	53,155	44,394	40,812	37,293	48,784	49,731	39,612	46,967	56,206	67,359	603,337
2023F	66,449	52,990	53,340	44,548	40,954	37,423	48,953	49,904	39,750	47,130	56,401	67,593	605,435
2024F	66,843	53,304	53,656	44,813	41,197	37,645	49,244	50,200	39,985	47,410	56,736	67,994	609,027
2025F	67,928	54,170	54,527	45,540	41,866	38,256	50,043	51,015	40,635	48,180	57,657	69,098	618,915
2026F	68,943	54,979	55,342	46,221	42,491	38,827	50,791	51,777	41,242	48,899	58,518	70,131	628,163
2027F	69,973	55,801	56,169	46,911	43,126	39,408	51,550	52,551	41,858	49,630	59,393	71,178	637,548
2028F	71,019	56,634	57,008	47,612	43,771	39,996	52,320	53,336	42,483	50,372	60,280	72,242	647,074
2029F	72,080	57,481	57,860	48,324	44,425	40,594	53,102	54,133	43,118	51,124	61,181	73,321	656,742
2030F	73,157	58,339	58,724	49,046	45,088	41,201	53,895	54,942	43,762	51,888	62,095	74,417	666,554
2031F	74,250	59,211	59,602	49,778	45,762	41,816	54,701	55,763	44,416	52,663	63,023	75,529	676,513
2032F	75,359	60,096	60,492	50,522	46,446	42,441	55,518	56,596	45,080	53,450	63,964	76,657	686,621
2033F	76,485	60,994	61,396	51,277	47,140	43,075	56,347	57,442	45,753	54,249	64,920	77,803	696,880
2034F	77,628	61,905	62,313	52,043	47,844	43,719	57,189	58,300	46,437	55,059	65,890	78,965	707,293
2035F	78,788	62,830	63,245	52,821	48,559	44,372	58,044	59,171	47,131	55,882	66,875	80,145	717,860
2036F	79,965	63,769	64,189	53,610	49,284	45,035	58,911	60,055	47,835	56,717	67,874	81,342	728,586
2037F	81,160	64,722	65,149	54,411	50,021	45,708	59,791	60,952	48,550	57,564	68,888	82,558	739,472
2038F	82,372	65,689	66,122	55,224	50,768	46,391	60,684	61,863	49,275	58,424	69,917	83,791	750,521
2039F	83,603	66,670	67,110	56,049	51,527	47,084	61,591	62,787	50,011	59,297	70,962	85,043	761,734
2040F	84,852	67,666	68,113	56,886	52,297	47,787	62,511	63,725	50,759	60,183	72,022	86,314	773,116
Reference Case Forecast													
2021F	64,794	51,671	52,012	43,439	39,934	36,491	47,734	48,661	38,760	45,957	54,997	65,910	590,359
2022F	66,218	52,806	53,155	44,394	40,812	37,293	48,784	49,731	39,612	46,967	56,206	67,359	603,337
2023F	66,449	52,990	53,340	44,548	40,954	37,423	48,953	49,904	39,750	47,130	56,401	67,593	605,435
2024F	66,843	53,304	53,656	44,813	41,197	37,645	49,244	50,200	39,985	47,410	56,736	67,994	609,027
2025F	67,928	54,170	54,527	45,540	41,866	38,256	50,043	51,015	40,635	48,180	57,657	69,098	618,915
2026F	68,943	54,979	55,342	46,221	42,491	38,827	50,791	51,777	41,242	48,899	58,518	70,131	628,163
2027F	69,973	55,801	56,169	46,911	43,126	39,408	51,550	52,551	41,858	49,630	59,393	71,178	637,548
2028F	71,019	56,634	57,008	47,612	43,771	39,996	52,320	53,336	42,483	50,372	60,280	72,242	647,074
2029F	72,080	57,481	57,860	48,324	44,425	40,594	53,102	54,133	43,118	51,124	61,181	73,321	656,742
2030F	73,157	58,339	58,724	49,046	45,088	41,201	53,895	54,942	43,762	51,888	62,095	74,417	666,554
2031F	74,250	59,211	59,602	49,778	45,762	41,816	54,701	55,763	44,416	52,663	63,023	75,529	676,513
2032F	75,359	60,096	60,492	50,522	46,446	42,441	55,518	56,596	45,080	53,450	63,964	76,657	686,621
2033F	76,485	60,994	61,396	51,277	47,140	43,075	56,347	57,442	45,753	54,249	64,920	77,803	696,880
2034F	77,628	61,905	62,313	52,043	47,844	43,719	57,189	58,300	46,437	55,059	65,890	78,965	707,293
2035F	78,788	62,830	63,245	52,821	48,559	44,372	58,044	59,171	47,131	55,882	66,875	80,145	717,860
2036F	79,965	63,769	64,189	53,610	49,284	45,035	58,911	60,055	47,835	56,717	67,874	81,342	728,586
2037F	81,160	64,722	65,149	54,411	50,021	45,708	59,791	60,952	48,550	57,564	68,888	82,558	739,472
2038F	82,372	65,689	66,122	55,224	50,768	46,391	60,684	61,863	49,275	58,424	69,917	83,791	750,521
2039F	83,603	66,670	67,110	56,049	51,527	47,084	61,591	62,787	50,011	59,297	70,962	85,043	761,734
2040F	84,852	67,666	68,113	56,886	52,297	47,787	62,511	63,725	50,759	60,183	72,022	86,314	773,116

2.6 *INDUSTRIAL ENERGY LOAD (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2011	23,160	24,129	21,555	17,261	24,902	22,812	25,671	21,690	22,374	24,978	20,262	21,971	270,764
2012	24,973	30,356	25,036	25,285	23,707	21,432	22,094	22,115	22,666	22,863	26,328	23,917	290,771
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
2017	33,109	30,227	32,593	30,117	27,928	31,621	29,477	29,518	28,665	28,831	30,770	29,734	362,590
2018	30,089	33,113	31,062	30,455	32,718	39,030	38,264	35,307	33,245	30,034	33,591	35,836	402,744
2019	40,014	40,563	41,563	37,886	39,198	40,876	38,967	41,784	39,929	49,045	45,695	39,390	494,911
2020	41,115	37,485	36,324	30,596	32,632	32,899	39,933	39,350	35,590	36,265	39,250	39,794	441,233
BAU Forecast													
2021F	44,315	44,054	44,431	42,850	44,138	45,835	44,698	47,564	44,115	51,643	50,951	47,366	551,959
2022F	49,151	47,797	48,119	43,657	45,021	45,994	44,854	47,554	44,005	51,560	50,880	47,301	565,894
2023F	49,174	47,830	48,163	43,705	45,089	46,061	44,918	47,629	44,071	51,612	50,929	47,343	566,524
2024F	49,490	48,117	48,463	43,964	45,365	46,331	45,203	47,924	44,345	51,908	51,230	47,646	569,987
2025F	49,986	48,561	48,887	44,320	45,765	46,703	45,611	48,347	44,720	52,233	51,628	48,101	574,863
2026F	47,388	47,705	48,309	45,205	45,841	51,205	48,993	48,947	46,757	49,545	50,530	48,190	578,615
2027F	47,755	48,074	48,683	45,555	46,195	51,602	49,372	49,326	47,119	49,928	50,921	48,563	583,092
2028F	48,133	48,454	49,068	45,915	46,561	52,010	49,763	49,717	47,492	50,323	51,324	48,948	587,708
2029F	48,505	48,829	49,447	46,270	46,921	52,412	50,147	50,101	47,859	50,712	51,721	49,326	592,250
2030F	48,838	49,164	49,787	46,588	47,243	52,772	50,492	50,445	48,188	51,061	52,076	49,665	596,318
2031F	49,178	49,507	50,134	46,913	47,573	53,140	50,844	50,797	48,524	51,417	52,439	50,011	600,476
2032F	49,512	49,843	50,475	47,231	47,896	53,501	51,189	51,142	48,853	51,766	52,795	50,351	604,554
2033F	49,843	50,176	50,812	47,547	48,215	53,858	51,531	51,483	49,180	52,111	53,148	50,687	608,590
2034F	50,157	50,493	51,132	47,847	48,520	54,198	51,856	51,808	49,490	52,440	53,483	51,007	612,431
2035F	50,477	50,815	51,458	48,152	48,829	54,544	52,187	52,138	49,806	52,775	53,824	51,332	616,338
2036F	50,783	51,123	51,770	48,444	49,125	54,874	52,503	52,455	50,108	53,095	54,151	51,643	620,074
2037F	51,098	51,440	52,091	48,744	49,429	55,214	52,828	52,779	50,418	53,424	54,486	51,963	623,914
2038F	51,435	51,779	52,435	49,066	49,756	55,579	53,177	53,128	50,751	53,776	54,846	52,306	628,034
2039F	51,766	52,112	52,772	49,381	50,076	55,936	53,519	53,470	51,077	54,122	55,199	52,643	632,075
2040F	52,108	52,457	53,121	49,708	50,407	56,306	53,873	53,823	51,415	54,480	55,563	52,991	636,252
Reference Case Forecast													
2021F	44,977	44,780	45,123	43,604	44,734	46,420	45,169	48,142	44,766	52,258	51,692	48,708	560,373
2022F	52,645	51,571	52,130	47,750	48,993	49,762	48,475	51,389	47,997	55,450	54,800	50,725	611,686
2023F	52,668	51,603	52,173	47,797	49,061	49,830	48,539	51,465	48,318	55,756	55,089	50,966	613,266
2024F	53,198	52,122	52,731	48,313	49,602	50,347	49,074	52,011	48,592	56,052	55,391	51,270	618,701
2025F	53,721	52,595	53,189	48,703	50,039	50,753	49,517	52,469	49,001	56,411	55,820	51,749	623,968
2026F	51,436	51,780	52,435	49,066	49,756	55,579	53,178	53,128	50,751	53,777	54,846	52,307	628,040
2027F	51,834	52,180	52,841	49,446	50,141	56,009	53,589	53,539	51,144	54,193	55,271	52,712	632,900
2028F	52,244	52,593	53,259	49,837	50,538	56,453	54,013	53,963	51,549	54,622	55,708	53,129	637,909
2029F	52,648	53,000	53,671	50,223	50,929	56,889	54,431	54,380	51,947	55,044	56,139	53,539	642,840
2030F	53,009	53,364	54,040	50,567	51,279	57,280	54,805	54,754	52,304	55,422	56,524	53,907	647,255
2031F	53,379	53,736	54,417	50,920	51,636	57,679	55,187	55,136	52,669	55,809	56,918	54,283	651,768
2032F	53,741	54,101	54,786	51,266	51,987	58,071	55,562	55,510	53,026	56,188	57,305	54,652	656,194
2033F	54,100	54,462	55,152	51,608	52,334	58,459	55,933	55,881	53,380	56,563	57,688	55,017	660,576
2034F	54,442	54,806	55,500	51,934	52,664	58,828	56,286	56,233	53,717	56,920	58,052	55,364	664,745
2035F	54,789	55,155	55,854	52,265	53,000	59,203	56,645	56,592	54,060	57,283	58,422	55,717	668,985
2036F	55,121	55,490	56,193	52,582	53,322	59,562	56,988	56,935	54,388	57,630	58,776	56,055	673,041
2037F	55,462	55,833	56,541	52,908	53,652	59,931	57,341	57,288	54,724	57,987	59,140	56,402	677,208
2038F	55,829	56,202	56,914	53,257	54,006	60,326	57,720	57,666	55,086	58,370	59,531	56,774	681,680
2039F	56,188	56,564	57,280	53,600	54,353	60,714	58,091	58,037	55,440	58,745	59,914	57,140	686,066
2040F	56,559	56,938	57,659	53,954	54,713	61,116	58,475	58,421	55,807	59,134	60,310	57,517	690,600

2.7 LIGHTING ENERGY LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2011	1,114	1,027	1,674	582	1,092	1,098	1,086	1,113	1,615	560	1,121	1,153	13,233
2012	1,618	1,031	1,232	601	1,666	601	1,661	1,137	611	1,127	1,137	1,064	13,487
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
2017	1,394	1,233	1,390	1,286	1,339	1,301	1,383	1,382	1,289	1,335	1,270	1,330	15,932
2018	1,385	1,178	1,291	1,307	1,198	1,118	1,068	998	988	952	848	894	13,225
2019	907	808	873	943	965	937	917	949	955	947	909	928	11,039
2020	929	892	955	900	914	874	932	949	878	907	863	852	10,846
BAU Forecast													
2021F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2022F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2023F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2024F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2025F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2026F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2027F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2028F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2029F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2030F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2031F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2032F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2033F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2034F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2035F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2036F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2037F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2038F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2039F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2040F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
Reference Case Forecast													
2021F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2022F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2023F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2024F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2025F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2026F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2027F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2028F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2029F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2030F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2031F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2032F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2033F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2034F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2035F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2036F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2037F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2038F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2039F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
2040F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039

2.8 IRRIGATION ENERGY LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2011	654	545	816	908	1,931	3,894	6,737	9,495	8,249	4,369	2,156	590	40,345
2012	816	650	606	890	2,393	4,226	5,348	8,113	6,933	5,385	2,109	552	38,019
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
2017	780	670	772	1,096	3,035	6,160	9,587	9,343	5,898	3,231	719	649	41,939
2018	700	662	761	1,419	4,521	6,271	8,461	8,024	4,348	2,465	681	666	38,979
2019	663	630	650	1,694	5,103	6,429	6,958	7,254	3,381	1,741	835	640	35,978
2020	708	660	662	1,987	3,535	3,752	7,936	8,743	5,588	2,317	709	662	37,260
BAU Forecast													
2021F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2022F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2023F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2024F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2025F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2026F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2027F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2028F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2029F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2030F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2031F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2032F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2033F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2034F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2035F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2036F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2037F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2038F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2039F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2040F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
Reference Case Forecast													
2021F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2022F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2023F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2024F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2025F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2026F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2027F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2028F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2029F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2030F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2031F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2032F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2033F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2034F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2035F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2036F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2037F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2038F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2039F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
2040F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978

2.9 LOSSES (MWH)

Losses are only included in the gross load and are not included in the net load calculations.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2011	40,122	31,688	28,851	20,306	17,180	18,597	21,867	22,673	18,642	20,743	28,789	37,921	307,379
2012	32,646	28,718	24,679	18,077	15,587	15,466	20,044	20,455	15,860	18,745	26,831	34,038	271,146
2013	35,211	30,278	23,630	18,045	16,788	15,397	22,316	20,034	16,160	18,898	24,845	36,509	278,110
2014	33,867	26,588	24,298	17,794	15,892	16,473	21,521	19,501	14,805	17,666	24,525	36,928	269,858
2015	34,321	29,194	23,806	17,524	16,969	16,882	21,843	20,480	15,395	17,843	24,521	33,690	272,469
2016	33,551	27,609	22,480	19,765	16,577	16,353	22,040	20,827	15,355	18,891	29,250	31,352	274,051
2017	33,665	25,384	25,042	19,366	16,980	17,687	23,843	22,302	17,089	19,078	28,675	32,693	281,805
2018	35,582	27,153	24,401	19,090	19,818	18,085	24,727	23,120	14,898	18,345	24,567	35,700	285,486
2019	34,767	23,667	25,624	18,588	18,985	18,104	23,088	22,394	18,513	22,209	26,079	34,682	286,701
2020	36,003	30,382	23,546	16,389	15,137	16,665	24,433	23,477	18,226	20,644	28,772	34,665	288,339
BAU Forecast													
2021F	34,928	25,899	25,426	19,648	19,291	18,385	24,235	23,513	17,509	21,365	27,721	35,111	293,031
2022F	35,789	26,533	25,999	19,733	19,381	18,381	24,222	23,498	17,486	21,324	27,641	34,974	294,960
2023F	35,664	26,478	25,940	19,703	19,359	18,378	24,198	23,497	17,492	21,307	27,580	34,849	294,444
2024F	35,594	26,468	25,923	19,704	19,366	18,404	24,210	23,532	17,528	21,328	27,563	34,773	294,394
2025F	36,098	26,847	26,288	19,981	19,640	18,661	24,554	23,870	17,784	21,611	27,939	35,258	298,531
2026F	35,914	26,933	26,428	20,296	19,819	19,490	25,342	24,178	18,234	21,373	27,991	35,615	301,613
2027F	36,297	27,218	26,707	20,509	20,021	19,683	25,599	24,426	18,422	21,597	28,288	35,994	304,761
2028F	36,677	27,503	26,985	20,721	20,222	19,876	25,854	24,673	18,609	21,820	28,583	36,372	307,896
2029F	37,055	27,787	27,261	20,931	20,421	20,068	26,108	24,920	18,796	22,042	28,877	36,746	311,012
2030F	37,432	28,069	27,537	21,141	20,621	20,259	26,362	25,166	18,982	22,263	29,169	37,120	314,121
2031F	37,813	28,355	27,815	21,354	20,823	20,454	26,619	25,417	19,172	22,488	29,465	37,497	317,273
2032F	38,192	28,640	28,093	21,566	21,025	20,648	26,877	25,668	19,362	22,713	29,760	37,872	320,417
2033F	38,563	28,920	28,365	21,774	21,221	20,837	27,128	25,914	19,548	22,933	30,050	38,240	323,495
2034F	38,930	29,195	28,633	21,979	21,415	21,023	27,376	26,156	19,731	23,150	30,335	38,603	326,524
2035F	39,298	29,473	28,903	22,185	21,610	21,211	27,626	26,401	19,916	23,368	30,622	38,967	329,582
2036F	39,662	29,748	29,170	22,389	21,804	21,397	27,874	26,644	20,100	23,585	30,906	39,327	332,607
2037F	40,027	30,026	29,439	22,595	21,999	21,585	28,124	26,890	20,285	23,804	31,193	39,690	335,657
2038F	40,400	30,310	29,714	22,807	22,200	21,781	28,382	27,144	20,478	24,030	31,486	40,058	338,791
2039F	40,773	30,595	29,990	23,020	22,401	21,976	28,641	27,399	20,671	24,257	31,780	40,427	341,929
2040F	41,153	30,886	30,273	23,237	22,608	22,178	28,906	27,661	20,870	24,489	32,080	40,803	345,144
Reference Case Forecast													
2021F	35,034	26,039	25,546	19,782	19,397	18,493	24,318	23,614	17,627	21,474	27,853	35,355	294,532
2022F	36,110	26,979	26,441	20,195	19,811	18,792	24,599	23,912	17,926	21,745	28,081	35,284	299,875
2023F	36,005	26,951	26,406	20,192	19,815	18,815	24,599	23,934	17,996	21,794	28,088	35,220	299,813
2024F	35,990	27,007	26,453	20,257	19,885	18,902	24,674	24,032	18,057	21,836	28,091	35,156	300,340
2025F	36,531	27,429	26,859	20,575	20,199	19,200	25,058	24,411	18,354	22,159	28,507	35,678	304,960
2026F	36,454	27,574	27,015	20,859	20,372	20,130	25,940	24,776	18,812	21,977	28,631	36,171	308,710
2027F	36,905	27,940	27,365	21,145	20,645	20,396	26,268	25,096	19,073	22,273	29,001	36,618	312,726
2028F	37,369	28,323	27,732	21,447	20,934	20,680	26,612	25,432	19,350	22,584	29,388	37,079	316,930
2029F	37,847	28,722	28,113	21,765	21,238	20,980	26,971	25,783	19,643	22,911	29,790	37,555	321,318
2030F	38,341	29,140	28,510	22,101	21,558	21,296	27,347	26,152	19,954	23,255	30,209	38,045	325,907
2031F	38,865	29,595	28,941	22,469	21,911	21,646	27,757	26,555	20,298	23,632	30,661	38,566	330,897
2032F	39,418	30,082	29,400	22,869	22,294	22,028	28,197	26,989	20,674	24,039	31,145	39,115	336,249
2033F	39,992	30,598	29,885	23,296	22,703	22,435	28,662	27,448	21,076	24,472	31,654	39,686	341,908
2034F	40,592	31,144	30,397	23,751	23,139	22,872	29,154	27,935	21,508	24,933	32,191	40,283	347,898
2035F	41,205	31,707	30,924	24,221	23,591	23,324	29,662	28,438	21,955	25,409	32,743	40,893	354,071
2036F	41,843	32,300	31,477	24,720	24,069	23,803	30,196	28,968	22,430	25,913	33,323	41,528	360,570
2037F	42,511	32,929	32,063	25,252	24,579	24,317	30,764	29,531	22,939	26,449	33,936	42,194	367,464
2038F	43,217	33,599	32,686	25,821	25,126	24,869	31,370	30,134	23,485	27,022	34,588	42,896	374,813
2039F	43,953	34,303	33,340	26,422	25,704	25,452	32,008	30,768	24,064	27,627	35,273	43,629	382,544
2040F	44,726	35,049	34,032	27,062	26,320	26,075	32,684	31,441	24,681	28,270	35,996	44,399	390,733

2.10 *SYSTEM PEAK DEMAND (MW)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2011	722	666	593	516	472	448	529	537	509	508	632	691	702	537
2012	702	675	560	523	493	418	589	540	453	501	624	723	723	589
2013	720	631	549	493	515	442	600	565	523	502	598	698	698	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	693	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	685	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	755	593
2017	755	673	595	510	597	505	600	605	561	515	594	648	714	605
2018	714	648	583	516	602	533	630	631	429	459	609	659	682	631
2019	678	682	651	514	568	502	626	639	538	562	622	701	732	639
2020	732	680	609	500	482	515	666	665	551	549	631	667	667	666
BAU Forecast														
2021F	701	656	591	495	468	531	614	620	476	515	644	691	749	628
2022F	706	660	595	498	471	534	618	624	480	519	648	696	751	632
2023F	704	659	594	497	471	533	617	623	479	518	647	695	750	631
2024F	704	659	594	497	471	533	617	623	479	518	647	695	756	631
2025F	715	668	602	504	477	541	626	632	486	526	656	705	766	640
2026F	722	676	609	510	483	547	633	639	491	531	663	713	774	647
2027F	730	683	615	515	488	553	639	645	496	537	670	720	782	654
2028F	738	690	622	521	493	559	646	652	502	543	678	728	791	661
2029F	746	698	628	526	498	564	653	659	507	548	685	736	799	668
2030F	753	705	635	532	503	570	660	666	512	554	692	743	807	675
2031F	761	712	642	537	509	576	667	673	518	560	699	751	816	682
2032F	769	719	648	543	514	582	674	680	523	566	706	759	824	689
2033F	777	727	655	548	519	588	680	687	528	571	713	766	832	696
2034F	784	734	661	554	524	594	687	693	533	577	720	774	840	703
2035F	792	741	667	559	529	600	694	700	538	583	727	781	848	709
2036F	799	748	674	564	534	605	700	707	544	588	734	789	856	716
2037F	807	755	680	570	539	611	707	714	549	594	741	796	864	723
2038F	815	762	687	575	545	617	714	720	554	599	748	804	873	730
2039F	823	770	693	581	550	623	721	727	559	605	756	812	881	737
2040F	831	777	700	586	555	629	728	734	565	611	763	820	890	744
Reference Case Forecast														
2021F	712	666	600	503	477	540	624	630	485	524	654	702	766	638
2022F	726	679	612	513	486	550	636	642	495	535	667	716	772	650
2023F	726	679	613	514	487	551	636	642	495	535	667	716	773	651
2024F	728	681	614	516	489	553	638	644	497	537	669	718	781	653
2025F	740	693	625	525	497	562	649	655	506	546	680	730	792	664
2026F	750	702	634	533	505	570	658	664	513	555	690	740	803	673
2027F	761	713	644	541	513	580	668	674	522	563	700	751	815	683
2028F	773	724	654	551	522	589	679	685	531	573	711	763	827	694
2029F	785	736	665	561	532	600	690	697	541	583	723	775	840	706
2030F	798	749	677	572	543	611	703	709	552	595	735	788	854	718
2031F	813	763	691	584	555	624	716	723	564	607	749	803	869	732
2032F	829	778	705	598	568	638	731	738	577	621	765	818	885	747
2033F	846	795	721	612	582	653	747	754	592	636	781	836	903	763
2034F	864	813	738	629	598	670	765	772	608	652	799	854	922	781
2035F	884	831	756	645	615	687	783	790	624	669	817	873	941	799
2036F	904	851	775	663	632	705	802	809	642	688	837	893	962	819
2037F	925	872	796	683	652	725	823	830	661	707	858	914	984	839
2038F	949	895	818	704	672	746	845	852	682	728	881	938	1,008	862
2039F	973	919	841	726	694	769	869	876	704	751	905	962	1,033	886
2040F	1,000	945	866	750	718	793	894	901	728	775	930	988	1,060	911

Appendix H

LOAD SCENARIOS ASSESSMENT REPORT

Load Scenario Assessment

Final Report

Prepared for:

FortisBC Inc.

Submitted by:
Guidehouse Canada
First Canadian Place | 100 King Street West
Suite 4950 | P.O. Box 64
Toronto, ON, M5X 1B1 | Canada

416.956.5050
guidehouse.com

Reference No.: 208164
November 22, 2020

Contributing Authors

Peter Steele-Mosey, Associate Director

Dixon Grant, Senior Consultant

Kristen Malik, Consultant

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Companion Documents

Load Scenario Assessment: Final Report – Spreadsheet Appendix

Filename: "Fortis LTERP Load Scenarios Outputs 2020-11-22 - monthly and annual data.xlsx"

Contents: Monthly energy and demand values by load driver and scenario.

DISCLAIMER

This report was prepared by Guidehouse Canada Ltd. ("Guidehouse" f/k/a Navigant Consulting Ltd., "Navigant"), for FortisBC Inc. ("FortisBC"). The work presented in this report represents Guidehouse's professional judgment based on the information available at the time this report was prepared. Guidehouse is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. GUIDEHOUSE MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

EXECUTIVE SUMMARY

FortisBC Inc. ("FortisBC") plans for the future energy and capacity needs of its electricity customers through the development and periodic updating of a Long Term Electric Resource Plan (LTERP). The 2021 LTERP, currently in development, is expected to be submitted to the British Columbia Utilities Commission in 2021. The planning horizon of the 2021 LTERP is 2021 to 2040.

A core component of the LTERP is FortisBC's long-term *business-as-usual* and *reference* forecast (see box at right for definitions) of peak demand and energy consumption. While the reference forecast does account for uncertainty and variability in existing load classes (via a confidence interval range) it does not capture many potential future structural changes in the way electricity is consumed. Given the rapid development of some emerging technologies, the on-going economic transformations occurring in B.C., and the current policy environment, FortisBC has deemed it prudent to explore what the potential impacts of structural changes in the drivers of electricity demand in its service territory may be.

FortisBC engaged Guidehouse Canada Ltd. (formerly known as Navigant Consulting, Ltd.) to:

- Work with FortisBC staff and obtain feedback from the stakeholders of the Resource Planning Advisory Group (RPAG) to select a group of nine load drivers to include in the study;
- Develop, in collaboration with FortisBC staff, and in consultation with RPAG stakeholders, a set of five scenarios, each of which assumes a different level of penetration by each of the load drivers;
- Estimate the unit impacts[1] of the load drivers and;
- Model the potential impacts of these drivers as part of the five load scenarios.

This report presents the outcome of these efforts.

What Forecast is What?

BUSINESS-AS-USUAL (BAU) FORECAST: A forecast of energy consumption based on an extrapolation of trends and relationships estimated using observed historical data.

REFERENCE FORECAST: An adjusted version of the BAU forecast that accounts for some structural changes in energy consumption patterns not evident in the historical record. These are changes that are anticipated with a high degree of certainty and include the anticipated effects of the Zero Emission Vehicle (ZEV) Act and the growth in load from very large non-residential customers (e.g., a renewable natural gas production facility).

Because the load scenarios in this report identify potential impacts of the ZEV Act and growth of large non-residential loads, they should be considered incremental to the BAU, and not the reference forecast.

Load Drivers

Guidehouse worked with FortisBC staff to identify and develop a set of nine load drivers to include in this study. These are shown in the table below, along with an indication of the impact each has on annual energy consumption.

[1] The "unit impact" of a load driver refers to the load impact that a single unit of that load driver has. For example, the unit impact for electric vehicles would be the average impact of a single EV.

Figure ES - 1. Load Drivers

Load Driver	Short Form	Effect on System Load (+/-)
Residential Integrated Photovoltaic Solar and Storage	**IPSS-RES**	
Commercial Integrated Photovoltaic Solar and Storage	**IPSS-COM**	
Electric Vehicles, Light Duty and Medium/Heavy Duty	**LD EVs** **MHD EVs**	
Fuel Switching – Gas to Electricity	**FS – G2E**	
Fuel Switching – Electricity to Gas	**FS – E2G**	
Climate Change	**CC**	
Large Load Sector Transformation	**LLST – Data Centres** **LLST - Cannabis**	
Hydrogen Production	**HP**	
Carbon Capture and Storage	**CCS**	

For each load driver, Guidehouse developed an estimate of the unit load impact. For example: Guidehouse estimated the impact on annual energy consumption and winter peak demand of one residential customer installing rooftop photovoltaic (PV) solar generation and energy storage (IPSS). This work involved drawing on many sources, some specific to FortisBC, others more general (e.g., Statistics Canada, Natural Resources Canada, etc.). These inputs were supported by assumptions around participant behaviour, and used to deliver an estimate of the unit impact. Chapter 2 provides a detailed description of Guidehouse's approach to estimating these unit impacts.

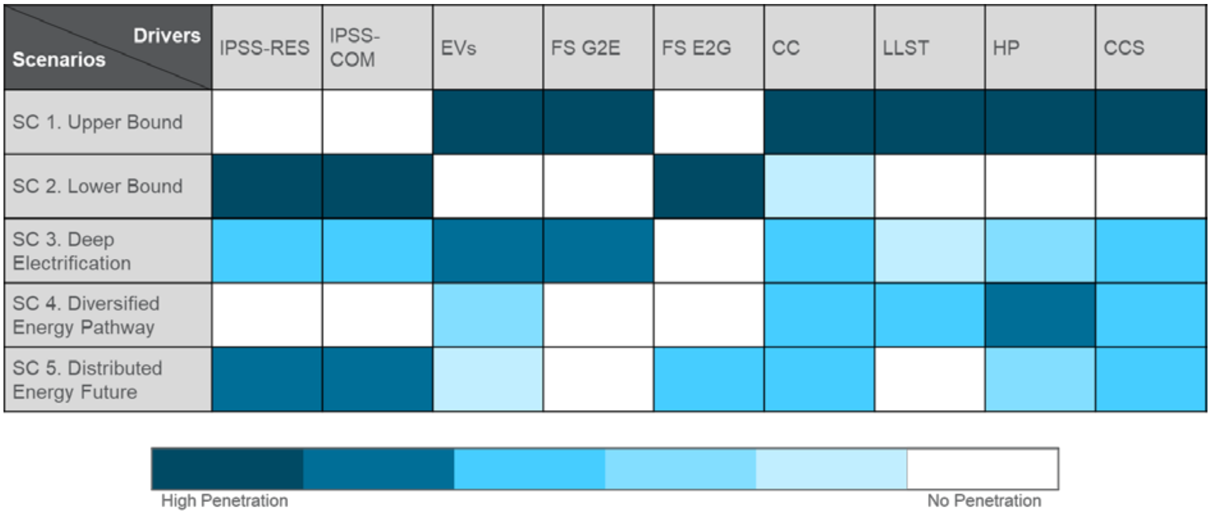
Load Scenarios

Load drivers were combined in a variety of ways to deliver five different load scenarios, or potential future worlds. Two of these, the Upper and Lower Bound (Scenario 1 and 2) were deliberately-set boundary scenarios – the first includes only drivers that increase loads, the second includes only drivers that decrease them. The three intermediate scenarios, Scenarios 3, 4, and 5, apply different combinations of the load drivers with different levels of assumed penetration.[2] The projection period for the scenarios is 20 years, from 2021 to 2040.

Figure ES - 2, below lists the five scenarios and identifies which load drivers were applied to each, and the approximate relative level of penetration assumed for each load driver in each scenario.

[2] "Penetration" is a somewhat imprecise term in this case, but broadly it refers to the amount of a driver that is assumed to exist in a given scenario. The level of penetration is directly correlated with the driver's impact.

Figure ES - 2: Qualitative Summary of Load Driver Penetrations by Scenario

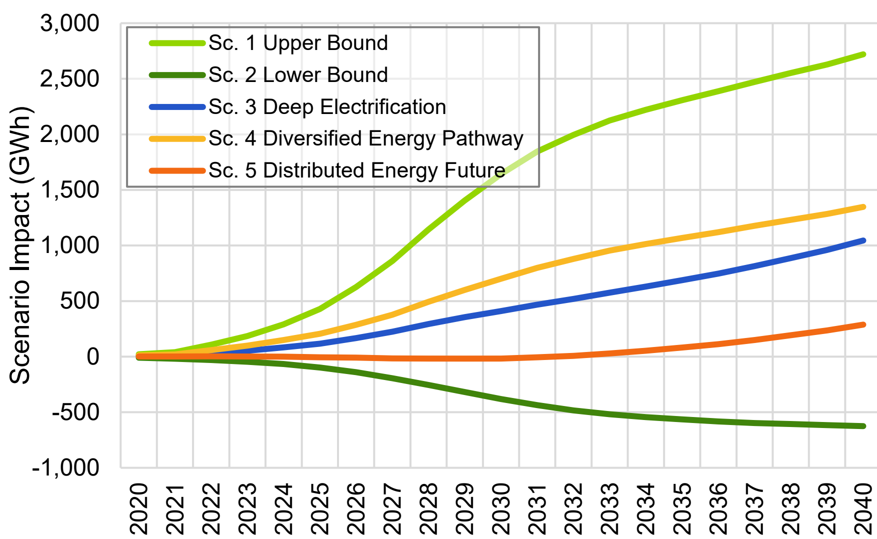


Two of the intermediate load scenarios, Scenario 3 (Deep Electrification) and Scenario 4 (Diversified Energy Pathway) were deliberately specified to align with the similarly named scenarios studied as part of the recent Pathways[3] analysis conducted for FortisBC for the entire province of British Columbia.

The detailed assumptions used to scale each of the load drivers for each of the scenarios are described in detail in Chapter 3.

The modeling of these load scenarios yielded a set of annual impacts for annual energy and peak winter demand[4]. These are illustrated below. All impacts modeled in this study should be understood to be **incremental** to the FortisBC business-as-usual forecast.

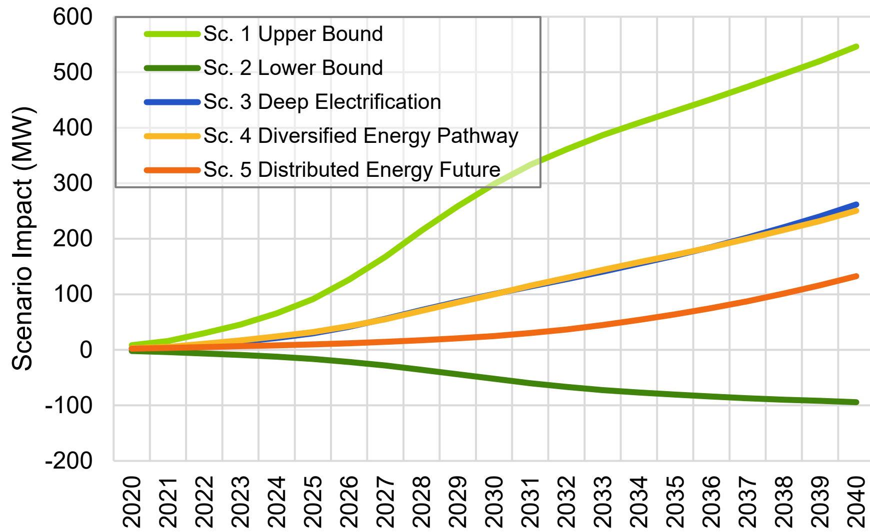
Figure ES - 3. Summary of Energy Impacts by Scenario



[3] Guidehouse Canada on behalf of FortisBC, *Pathways for British Columbia to Achieve its Greenhouse Gas Reduction Goals*, 2020 Publication forthcoming.

[4] The average demand on non-holiday January weekdays between 5pm and 6pm PST.

Figure ES - 4. Summary of Winter Demand Impacts by Scenario



Note that there is a difference in the order of the scenarios in these two plots – the energy impacts of Scenario 4 (Diversified Energy Pathway) are higher than those of Scenario 3 (Deep Electrification), whereas the two scenarios are roughly the same when considering winter peak demand.

This is for the following reasons: 1) IPSS-RES does not deliver any peak demand reductions in winter – it gets dark too early and storage is insufficient (under the behaviours assumed) to shift PV output that late in the day; 2) Scenario 4 (Diversified Energy Pathway) includes very high penetration for a number of load drivers that, though they consume a great deal of electricity (HP, LLST) also have very flat (or highly non-coincident) loads. This is in contrast with Scenario 3 (Deep Electrification) in which loads (in particular the electrification of transportation and space-heating) are highly peak-coincident.

Findings and Recommendations

Guidehouse has identified three key findings as part of its analysis. Each finding is accompanied by one or more recommendations.

#	FINDING	RECOMMENDATION
1	Electrification will require additional capital investment in order to address growth in "peaky" loads. Prudent management of such a transition could reduce the required capital investments and impacts on customer rates.	1.1. FortisBC should consider studying a TOU rate designed for EV drivers and encourage electric vehicle supply equipment (EVSE) distributors to promote enabling technologies (such as timers) that could allow customers to take advantage of such rates. FortisBC should additionally consider other programmatic options for reducing the impact of potential future EV growth. 1.2. If FortisBC expects a large-scale electrification of residential water-heating, it should consider developing a water heater demand response (DR) program. Such direct load control is unobtrusive, tends not to inconvenience customers, has a long history of reliable performance in jurisdictions with high levels of electric water heater penetration (e.g., Florida, western North Carolina, etc.), and can substantially reduce peak contributions from this end-use. Additionally, FortisBC may wish to consider energy efficiency as well as DR as an option here, and encourage the adoption of heat pump water heaters. 1.3. If FortisBC expects large-scale electrification of space heating, it should consider studying whether peak demand impacts could be mitigated by encouraging "hybrid" electrification, in which residents maintain existing gas heating equipment to supplement new electric equipment on the coldest days. FortisBC may also wish to consider exploring the possibilities offered by electric thermal storage heating systems.[5]
2	Distributed generation installed in residential households – with current incentives in place – is unlikely to make any meaningful contribution to peak demand reductions, even when enabled with energy storage.	2.1 FortisBC should continue to monitor developments in distributed energy storage, including the use of EV batteries as distributed energy resources (DERs) and consider formalizing an approach to leveraging such resources for system benefit. 2.2 FortisBC should consider the value of energy storage in relieving localized distribution constrains and, if justified, identify how best to unlock that value through incentives or program intervention. FortisBC should also consider whether revisions to the existing net metering tariff to encourage the adoption of energy storage to support rooftop solar generation may be appropriate

[5] Electric thermal storage is a form of electric resistance heating that aims to shift demand. During off-peak periods electricity is used to heat a high-density ceramic brick. During on-peak periods, heat released from the brick is used to meet thermal requirements. Nova Scotia Power currently offers time of day (TOD) rates to customers that have such equipment and offers on-bill financing to encourage their adoption. See:
Nova Scotia Power, *Electric Thermal Storage*, accessed August 2020
https://www.nspower.ca/your-home/energy-products/electric-thermal-storage

3	There is potential for substantial growth in non-traditional high load-factor customer loads. If properly managed such loads may deliver substantial benefits to rate-payers.	3.1	The energy impacts of the growth of hydrogen production and data centres in FortisBC could be considerable. Given the very favourable load profiles of these two drivers and the potential growth of these industries (to support the decarbonization of the natural gas supply, and the ongoing growth in global data storage and processing requirements) FortisBC may wish to consider what ratepayer benefits could exist in developing (or refining any existing) economic development rates that target such industries conditional on where on the system these customers connect.

1. INTRODUCTION

FortisBC plans for the future energy and capacity needs of its electricity customers through the development and periodic updating of a Long Term Electric Resource Plan (LTERP). The LTERP, currently in development, is expected to be submitted to the British Columbia Utilities Commission in 2021.

A core component of the LTERP is FortisBC's long-term *business-as-usual* and *reference* forecast of peak demand and energy consumption. While this reference forecast does account for uncertainty and variability in existing load drivers (via a confidence interval range) it does not capture many potential future structural changes in the way electricity is consumed. Given the rapid development of some emerging technologies, the on-going economic transformations occurring in B.C., and the current policy environment, FortisBC has deemed it prudent to explore what the potential impacts of structural changes in the drivers of electricity demand in its service territory may be.

FortisBC engaged Navigant Consulting Ltd. (now known as Guidehouse Canada Ltd.) to:

- Work with FortisBC staff and obtain feedback from the stakeholders of the Resource Planning Advisory Group (RPAG) to select a group of nine load drivers to include in the study;
- Develop, in collaboration with FortisBC staff, and in consultation with RPAG stakeholders, a set of five scenarios, each of which assumes a different level penetration by each of the load drivers;
- Estimate the unit impacts[6] of the load drivers and;
- Model the potential impacts of these drivers as part of the five load scenarios.

What Forecast is What?

BUSINESS-AS-USUAL (BAU) FORECAST: A forecast of energy consumption based on an extrapolation of trends and relationships estimated using observed historical data.

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Because the load scenarios in this report identify potential impacts of the ZEV Act and growth of large non-residential loads, they should be considered incremental to the BAU, and not the reference forecast

This report presents the outcome of these efforts.

The purpose of this report is to provide a quantitatively robust answer to the question: "*what would be the impact on FortisBC demand and energy if one of five given sets of circumstances were to arise?*"

The reader should therefore bear in mind that:

- **The scenarios presented are cause-agnostic.** For example, this report quantifies what the impact might be of a substantial increase in the penetration of roof-top solar photovoltaic (PV) distributed generation and energy storage. Determining what might drive such increased uptake in PV and storage is beyond the scope of this study, though in each scenario a narrative is presented illustrating how such a scenario could arise.

[6] The "unit impact" of a load driver refers to the load impact that a single unit of that load driver has. For example, the unit impact for electric vehicles would be the average impact of a single EV.

- **No probabilities have been be assigned to these scenarios.** The future development of the load drivers included in these scenarios is sufficiently uncertain that no objective probabilities have been assigned to the scenarios – it is for this reason that these load drivers are included in this exercise, as opposed to a more formal empirical forecast.
- **The purpose of this report helps inform FortisBC's need for flexibility in planning to manage potential changes in future loads.** FortisBC's purpose in engaging Guidehouse is to help understand the potential impacts of the load drivers and scenarios. FortisBC will explore the impacts of the load scenarios on its resource portfolios as part of its contingency analysis and the need for flexibility in resources to manage potential changes in future load requirements.

Nine load drivers are considered in this report. These were selected by FortisBC staff (with feedback from RPAG stakeholders) from a broader list developed by Guidehouse. The nine load drivers are:

1. **Residential Integrated Photovoltaic Solar and Storage (IPSS-RES).** Behind-the-meter rooftop solar photovoltaic (PV) generation acquired by residential customers. Some proportion of customers are assumed to support their PV with battery storage, referred to in this report as Integrated Photovoltaic Storage Systems (IPSS).[7]
2. **Commercial Integrated Photovoltaic Solar and Storage (IPSS-COM).** Behind-the-meter solar PV generation installed by large commercial (Rate Schedule 21) customers. This load driver includes some instances of customers supporting their PV with battery storage.
3. **Electric Vehicles (LD EVs and MHD EVs).** Light duty electric vehicles (LD EVs) and medium and heavy-duty (MHD EVs). LD EVs were assumed to charge from a mix of Level 1, Level 2, and DC Fast Charging (DCFC) stations, located at the driver's residence, workplace, or some other public location (no DCFC was assumed for residence-located charging). MHD EVs include three types of vehicles: buses, return-to-base fleet vehicles, and combination tractors (sometimes referred to as tractor-trailers)
4. **Fuel Switching – Gas to Electricity (FS – G2E).** Residential fuel switching from gas-fired to electric space- and water-heating.
5. **Fuel Switching – Electricity to Gas (FS – E2G).** Residential fuel switching from electric to gas-fired space- and water-heating, applicable only to residential customers within 50 metres of a gas main.
6. **Climate Change (CC).** Increasing average annual temperatures, increases in average temperatures during the 10 hottest days of the year, and decreases in average temperatures during the 10 coldest days of the year.
7. **Large Load Sector Transformation (LLST).** Substantial growth in the data centre and cannabis cultivation floorspace in FortisBC's service territory.
8. **Hydrogen Production (HP)**. The production of "green" hydrogen[8] for injection into the natural gas distribution system to help with decarbonization.
9. **Carbon Capture and Storage (CCS).** The capture and storage of carbon emissions from large industrial processes.

[7] This usage was coined by the Australian Energy Market Operator. See for example:
Australian Energy Market Operator, *Emerging Technologies Information Paper; National Electricity Forecasting Report*, June 2015 https://www.aemo.com.au/-/media/Files/PDF/Emerging-Technologies-Information-Paper.pdf

[8] "Green" hydrogen is hydrogen obtained from water via electrolysis, whereas "blue" hydrogen is made from natural gas through a process of steam methane reforming (SMR). The SMR process releases considerable amounts of carbon dioxide into the atmosphere.

These load drivers are the building blocks for five scenarios modeled by Guidehouse. The assumed penetration[9] of each load driver varies from scenario to scenario, from zero in some scenarios to a very aggressive level in others. All load driver uptake assumed in any given scenario must be understood to be incremental to that which is already embedded in the business-as-usual load forecast.

The remainder of this report is comprised of three chapters:

1. **Load Driver Unit Impacts.** This chapter provides a detailed description of how the unit load impact of each load driver was estimated, and a more precise definition of the load driver itself.
2. **Load Scenarios.** This chapter describes the five scenarios modeled, outlines the input assumptions driving each scenario, and describes the estimated impacts of each scenario relative to the business-as-usual forecast.
3. **Findings and Recommendations.** This chapter summarizes Guidehouse's findings from the analysis and makes some recommendations to FortisBC.

[9] "Penetration" is a somewhat imprecise term in this case, but broadly it refers to the amount of a driver that is assumed to exist in a given scenario. The level of penetration is directly correlated with the driver's impact.

2. LOAD DRIVER UNIT IMPACTS

This chapter of the report describes each of the nine load drivers considered in this analysis and outlines the assumptions and calculations employed to estimate unit load impacts for each driver. The nine load drivers described below include:

1. Integrated Photovoltaic Solar and Storage – Residential (IPSS-RES)
2. Integrated Photovoltaic Solar and Storage – Commercial (IPSS-COM)
3. Electric Vehicles (EV)
    - Light-Duty EVs (LD EVs)
    - Medium and Heavy-Duty EVs (MHD EVs)
4. Fuel Switching: Gas to Electric (FS – G2E)
5. Fuel Switching: Electric to Gas (FS – E2G)
6. Climate Change (CC)
7. Large Load Sector Transformation (LLST)
    - Data Centres
    - Cannabis Production
8. Hydrogen Production (HP)
9. Carbon Capture and Storage (CCS)

Guidehouse's focus for this part of the analysis is the development of "unit" estimated annual energy and winter peak demand impacts.[10] "Unit impacts" is a terminology of convenience in this case and refers to the definition of the variable, or in the case of some load drivers, the variables that are scaled to deliver the scenario impacts.

In some cases the "unit" is defined relatively intuitively, e.g. for EVs, it is per vehicle. For that load driver there are two "units" (variables) that are scaled to deliver scenario impacts: light duty EVs and medium and heavy-duty EVs. In other cases, the unit is defined in a less obvious manner, one dictated by the available data. For example, for FS – G2E, the "unit" is the 2035 electrification technical potential estimated by the most recent electrification Conservation Potential Study[11] and the volume of units for each scenario is expressed as a percentage of that "unit" value. For Climate Change, the "unit" is threefold: the average number of degrees of warming by 2040, the average number of degrees of cooling on the ten coldest days by 2040, and the average number of degrees of warming on the ten hottest days by 2040.

Guidehouse has also developed monthly energy and demand[12] values for FortisBC. These are not addressed in this report but are included in the "Fortis LTERP Load Scenarios Outputs 2020-11-22 - monthly and annual data.xlsx" spreadsheet that accompanies this report.

This chapter is divided into sub-sections, one for each load driver.

[10] Defined as the average impact of a load driver between 5pm and 6pm PST on non-holiday January weekdays.

[11] Navigant (n/k/a Guidehouse Canada) prepared for FortisBC Energy Inc. and FortisBC Inc., *British Columbia Conservation Potential Review: Total Thermal Demand, Fuel Switching Potential, and Vehicle Electrification Potential*, June 2019.

[12] Average impact of a load driver between 5pm and 6pm local prevailing time on non-holiday weekdays of the given month.

2.1 Integrated Photovoltaic Solar and Storage (IPSS) – Residential

Battery-supported solar PV is sometimes referred to as integrated photovoltaic solar storage (IPSS).[13] The impact of this load driver is derived from:

1. Displaced residential load due to PV output;
2. Displaced residential load due to the use of storage to capture excess PV output during sunny periods and to use it when solar output falls beneath household requirement; and,
3. PV output in excess of consumer requirements, delivered to the grid.

Guidehouse has assumed that this load driver applies only to single family homes. The impacts for this load driver are estimated in two steps: first the unit impact of only PV, next the unit impact when PV is combined with storage.

2.1.1 *PV Impact – Residential*

The average estimated monthly impact per single-family household equipped with the assumed rooftop solar photovoltaic (PV) installation (assumed nameplate capacity of 8 kW per installation) is presented in Table 1 below. This table presents the average monthly energy impact, demand impact between 5pm and 6pm (the final reported demand impact) and between 9am and 10am (for illustrative purposes).[14] The impacts outlined below should be understood as reductions (hence the sign of the values) in load due to a solar installation. The impacts presented below do not yet account for any storage charging or discharging; these are purely the output of the solar installation. The underlying assumptions and approach to generating these unit impacts are presented below Table 1.

Table 1 Residential PV Unit Impacts

Month	Monthly kWh	kW (9am – 10am)	kW (5pm – 6pm)
January	-320	-1.2	0
February	-466	-1.8	0
March	-764	-2.8	-0.2
April	-816	-2.8	-0.5
May	-853	-2.8	-0.7
June	-843	-3.0	-0.9
July	-928	-3.0	-0.9
August	-932	-3.1	-0.6
September	-896	-3.2	-0.3
October	-711	-3.1	0
November	-391	-1.6	0
December	-275	-1.2	0

[13] See, for example:

Jacobs, prepared for the Australian Energy Market Operator, *Projections of uptake of small-scale systems*, June 2017

https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2017/2017-WEM-ESOO-Methodology-Report---Projections-of-Uptake-of-Small-scale-Systems.pdf

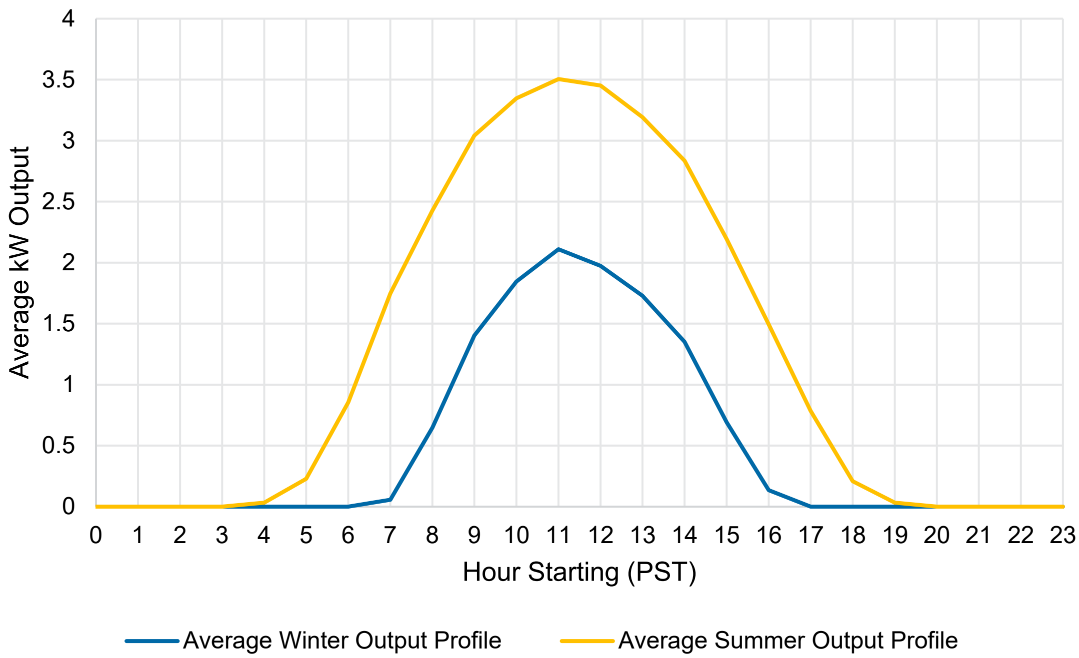
[14] Unless otherwise explicitly stated, all times provided in this memo are in Pacific Standard Time, and do not reflect any daylight savings adjustment.

Guidehouse has estimated the unit load impacts of residential rooftop PV based on the following:

- Average installed capacity of grid-connected residential sector rooftop PV installations: 8 kW[15]
- A region-specific (Penticton, BC) historical average solar PV capacity factor, by month of year[16]
- A region-specific (Penticton, BC) average hourly distribution of solar output, by month of year[17]

The single day hourly profile of PV output, estimated based on factors detailed above, is presented in Figure 1. “Winter” is defined as December, January and February, and “summer” is defined as June, July and August.

Figure 1 Seasonal Residential Solar Profile (8 kW Unit)[18]



2.1.2 *Impact with Storage – IPSS Residential*

In the system above, impacts are a function of solar output alone. Once storage is available, and residential customers can use that storage to extend the effective output of their rooftop PV system into non-daylight hours, impacts then become a function of the estimated solar output, the average residential electricity requirements, and the capacity of the energy storage.

[15] Average residential solar capacity in Fortis service territory is 7.9 kW per installation. Provided by FortisBC to Guidehouse on January 15th, 2020.

[16] Natural Resources Canada, *Photovoltaic and Solar Resource Maps*, March 2017.
Available at: https://www.nrcan.gc.ca/18366

[17] National Renewable Energy Laboratory, *PVWatts Calculator*. Accessed January 2020.
Available at: https://pvwatts.nrel.gov/index.php

[18] The x-axis of this graphic uses the “hour starting” convention for displaying output. So summer peak output occurs in hour starting 11, the period between 11am and noon, standard time. In the summer months, the prevailing time is daylight time. Under daylight (summer prevailing) time, peak output occurs between noon and 1pm.

The storage algorithm adopted for this analysis assumes that, in any given hour of each day:

- As much of the given home's electricity consumption as possible is satisfied by PV output.
- Electricity needs exceeding solar output are satisfied by storage output (subject to quantity of energy stored).
- Solar output in excess of the home's electricity needs is stored, subject to the storage charge capacities and efficiency of the storage device.
- Solar output in excess of the home's electricity needs that exceeds either the storage device's storage or charge capacities is returned to the grid.

The algorithm implicitly assumes a residential preference for self-generated electricity over grid electricity.

Guidehouse has estimated the unit load impacts of IPSS by combining the inputs used for estimating the solar PV impact with the following assumptions, all required by the algorithm described above:

- Average residential hourly load profile by month[19]
- Average single-family home residential electricity use by customer by month (averaged from 2017-2019)[20]
- Total capacity, charge efficiency and charge capacity for the energy storage device (assumed to be a Tesla Powerwall):[21]
  - Storage capacity: 13.5 kWh
  - Charge efficiency: 90%
  - Charge capacity: 5 kW

Figure 2 below presents the average daily (all-season) single family home residential load profile and solar output profile. Solar output from approximately hour starting 6 through to approximately hour starting 15 (6am – 4pm) completely satisfies the average home's electricity requirements. Under the storage algorithm assumed by Guidehouse, storage output would occur in the hours following hour starting 15, when solar output is less than the given home's demand.

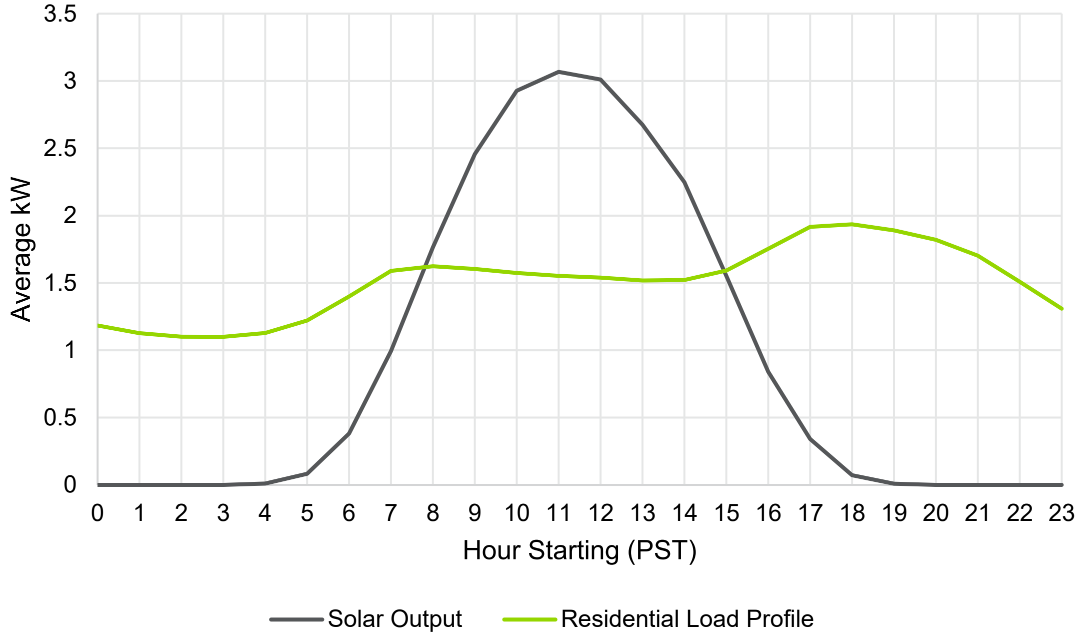
[19] Provided by FortisBC on January 29th, 2020, based on a sample of residential customer data within FortisBC's electric service territory

[20] Derived from FortisBC total monthly residential consumption in 2017 and 2018, the corresponding monthly residential customer count (both provided by FortisBC on January 15th, 2020), and the relative annual loads and number of residential households that are single family homes drawn from:

NRCan, *Comprehensive Energy Use Database – Residential Sector – British Columbia*, Tables 14, 34, 36, 38. Available at: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_res_bc.cfm

[21] Tesla, *Meet Powerwall, your home battery - Technical Specs*. Available at: https://www.tesla.com/powerwall

Figure 2 Residential Solar Output and Load Profile



The ultimate impact on FortisBC system load of the algorithm assumed above, with combined PV and storage in the summer months (when impacts are highest), is shown in Table 2 below. Due to the storage efficiency losses, energy reductions will be lower when PV is enabled with storage than without it. The impact for summer months is shown in Figure 3 below. Although the scale of this chart is positive, these should be understood to be the unit *reductions* in load imposed by residential IPSS. Solar output is occasionally pushed to the grid because it is exceeds residential requirements or storage (or charge) capacity. This only occurs in August through September between 1 - 4pm. In this period, net modelled output is on average 0.83 kW per system.

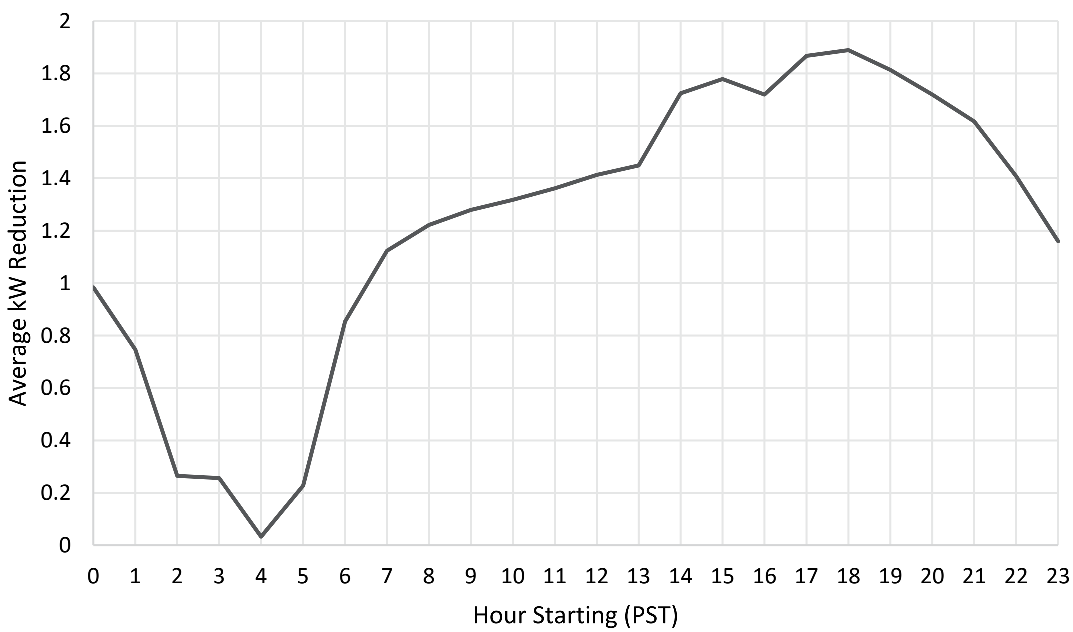
In comparing Table 2 to Table 1, the effects of storage are clear: a reduction in the absolute value of the impact from 9am to 10am (PV output in excess of the residential consumer’s needs is stored), and an increase in the absolute value of the impact from 5pm to 6pm (storage is discharged to supplement any PV output).

Table 2 Residential IPSS Unit Impacts

Month	kW (9am – 10am)	kW (5pm – 6pm)
January	-1.2	0
February	-1.8	0
March	-1.9	-1.9
April	-1.5	-1.47
May	-1.4	-1.65
June	-1.2	-1.64
July	-1.3	-2.01
August	-1.3	-1.95
September[22]	-1.0	-1.28
October	-1.5	-1.64
November	-1.6	0
December	-1.6	0

Figure 3, below, shows the average hourly profile of residential IPSS impacts in the summer months of June, July, and August. Note how solar output and storage capacity allow the consumer to almost completely avoid using any grid delivered electricity during this period.

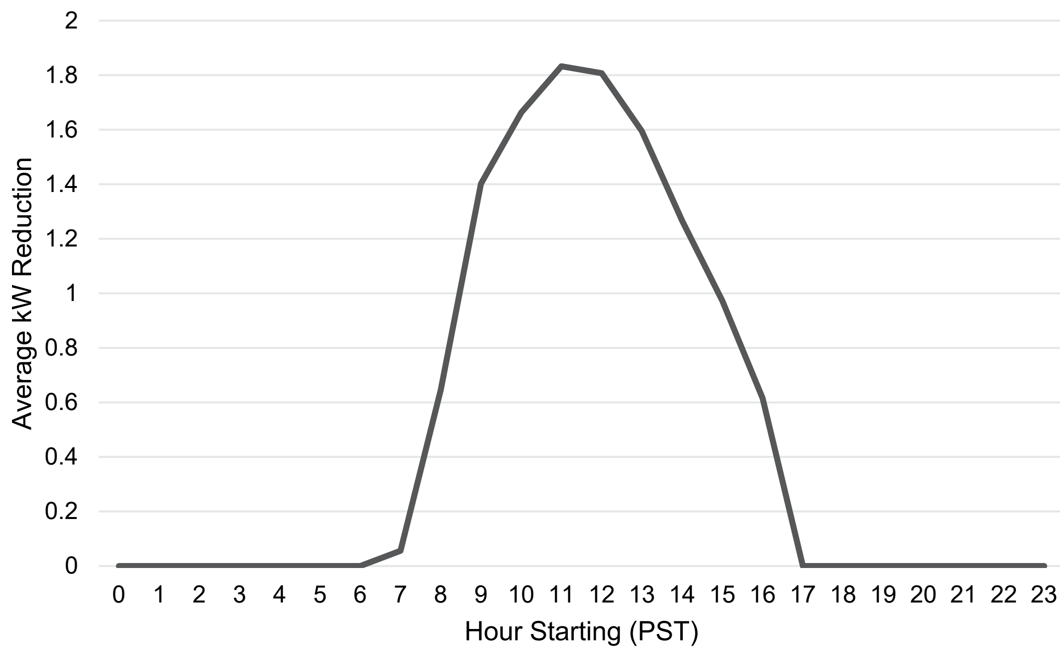
Figure 3 Summer Residential IPSS Impact Profile



[22] September impacts are lower than both August's and October's as a result of residential customer loads, which are, per the data provided by FortisBC, lowest in September. The kW impact in each given hour is the residential load displaced by storage (when loads exceed solar output) or the sum of the residential load displaced and any solar output that exceeds the needs of the home and the capacity (storage or charge) of the battery being used.

Figure 4 shows the average hourly profile of residential IPSS impacts in the winter months of December, January, and February. Note how the reduced hours of sunlight and irradiance available as well as the higher household loads during the day mean that there is no excess energy stored that can be used for overnight household consumption. In fact, storage output is completely exhausted by 5pm, meaning that this load driver will not impact winter peak demand at all.

Figure 4 Winter Residential IPSS Impact Profile



Under FortisBC's current net metering tariff, there is no economic incentive (in fact, due to efficiency losses, a disincentive) to install a storage unit. Customers currently get a storage account from FortisBC and can use this to "store" (as a credit) the additional output from their solar units, then consume from this account once their solar output falls below their use. This is similar to the storage use-case presented above, but without requiring participants acquire any additional equipment or subject them to any efficiency loss during charging.

2.2 Integrated Photovoltaic Solar and Storage (IPSS) – Commercial

The commercial IPSS use-case differs substantially from the residential due to (among other things) the assumed size of the consumer and their billing determinants.

Guidehouse has assumed that this load driver applies only to consumers that would qualify as part of FortisBC's Commercial Service Rate Schedule 21 ("GS21")[23]. The impacts for this load driver are

[23] Commercial customers with a noncoincident peak demand of between 40 and 500 kW that can be supplied through a single meter. For more details please consult:

FortisBC Inc., *Electric Tariff For Service in the West Kootenay and Okanagan Areas – General Terms and Conditions and Rate Schedules*, Accepted for Filing June 26, 2019, Order Number: G-40-19

https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/fortisbcelectrictariff.pdf estimated in two steps: first the unit impact of only PV, next the unit impact when PV is combined with storage.

2.2.1 *PV Impact – Commercial*

The average estimated monthly impact per building equipped with the assumed rooftop solar photovoltaic (PV) installation is presented in Table 3 below. This table presents the average monthly energy impact, demand impact between 5pm and 6pm (the final reported demand impact) and between 9am and 10am (for illustrative purposes). The impacts outlined below should be understood as reductions (hence the sign of the values) in load due to a solar installation. The underlying assumptions and approach to generating these unit impacts are presented below Table 3.

Table 3 Commercial PV Unit Impacts (20 kW Unit)

Month	Monthly kWh	kW (9am – 10am)	kW (5pm – 6pm)
January	-798	-3.0	0
February	-1,162	-4.5	0
March	-1,906	-6.9	-0.6
April	-2,034	-6.9	-1.3
May	-2,128	-6.9	-1.7
June	-2,103	-7.5	-2.2
July	-2,315	-7.5	-2.2
August	-2,325	-7.8	-1.4
September	-2,236	-7.9	-0.6
October	-1,773	-7.6	0
November	-975	-4	0
December	-685	-2.9	0

Guidehouse has estimated the unit load impacts of commercial PV based on the following factors:

- Average installed capacity of grid-connected commercial sector rooftop PV installations: 20 kW[24]
- A region-specific (Penticton, BC) historical average capacity factor by month of year[25]
- A region-specific (Penticton, BC) average hourly distribution of solar output by month[26]

The single day hourly profile of PV output, estimated based on factors detailed above, is presented in Figure 5, where "winter" is defined as December, January and February, and "summer" is defined as June, July and August.

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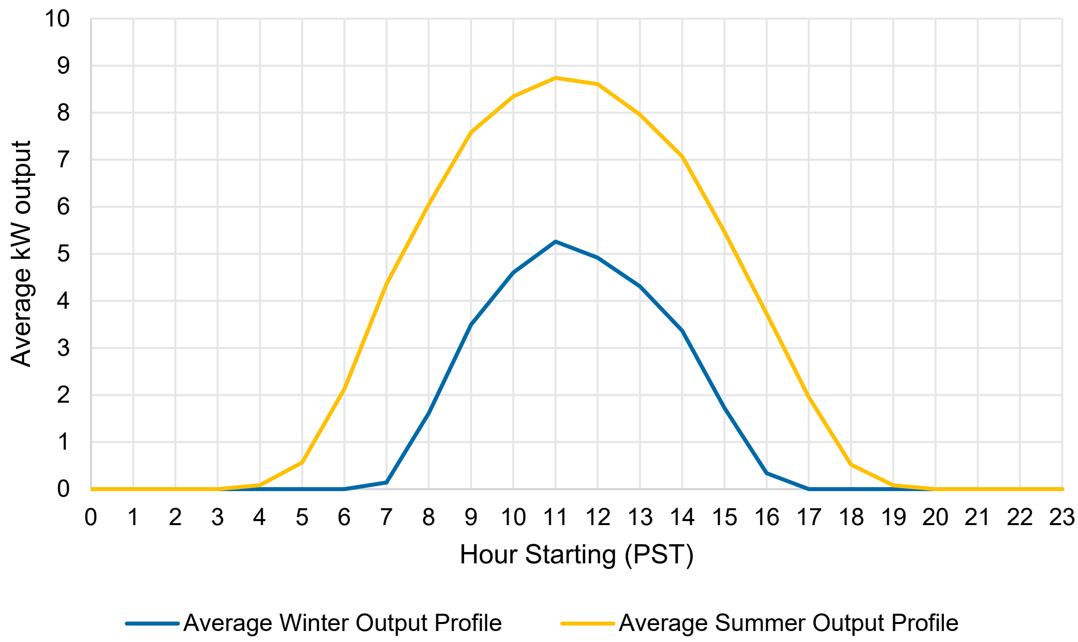
[24] Average commercial customer solar PV capacity within FortisBC electric service territory, provided by FortisBC on January 15th, 2020. The maximum allowable installed capacity under FortisBC's current net metering program is 50 kW.

[25] Natural Resources Canada, *Photovoltaic and Solar Resource Maps*, March 2017
Available at: https://www.nrcan.gc.ca/18366

[26] National Renewable Energy Laboratory, *PVWatts Calculator*, accessed January 2020
Available at: https://pvwatts.nrel.gov/index.php

Figure 5 Seasonal Commercial Solar Profile (20 kW Unit)



2.2.2 *Impact with Storage – IPSS Commercial*

In the system above, impacts are a function of solar output alone. Once storage is available, and medium or large commercial customers can use that to supplement storage in flattening their load and so minimize their exposure to their demand charge ($/kW) without needing to change any business processes or consumption patterns.

The storage algorithm adopted for this analysis assumes that this system is adopted only by medium and commercial customers (GS21 rate class) and that, in any given hour of the day:

- As much of the given building's electricity consumption as possible is satisfied by PV output.
- Commercial customers will attempt to flatten their load profile as much as possible in order to reduce their peak billing demand. Average commercial customers equipped with storage do this by using storage to shift demand from day-time to overnight periods.
- Solar output in excess of the building's electricity needs is stored, subject to the storage charge capacities, efficiency of the storage device, and the goal of flattening load to avoid demand charges.
- Solar output in excess of the building's electricity needs that exceeds either the storage device's storage or charge capacities is returned to the grid.

Guidehouse has estimated the unit load impacts of IPSS by combining the inputs used for estimating the solar PV impact with the following assumptions, all required by the algorithm described above:

- Average commercial hourly load profile by month[27]

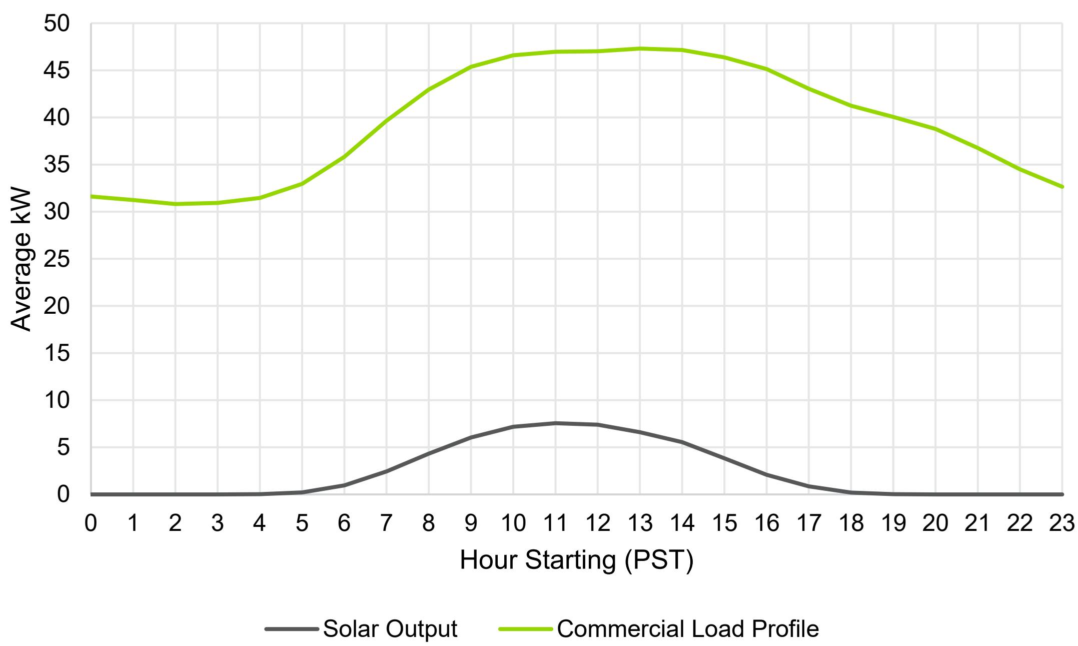
[27] Provided by FortisBC on January 29th, 2020

- Average commercial electricity consumption by customers in the GS21 rate class[28] - GS21 customers represent approximately 11% of commercial customers and account for approximately 64% of total commercial load[29]
- Total capacity, energy efficiency and charge capacity for storage unit (chosen to be the Tesla Powerpack):[30]
  - Storage capacity: 210 kWh
  - Charge efficiency: 88%
  - Charge capacity: 50 kW

Commercial and residential customers are assumed to use storage differently based on differences in the incentives they face under the current rate tariffs. Residential customers are billed based on energy and are therefore assumed to use stored energy to extend the benefits of their PV production later into the evening. Commercial customers, specifically those in the GS21 rate class, are billed based on monthly non-coincident peak demand, so they are assumed to use their storage to ensure their peak load is as close as possible to their average load.

Figure 6 below presents the average commercial load profile and solar output profiles. The commercial assumed installation differs from that of the residential assumed installation in that PV output never exceeds participant demand. For this reason, as well as in response to the GS21 demand-based billing determinant, the commercial storage use-case relies on shifting demand during the peak day-time period to low-demand overnight periods, with the goal of flattening the commercial load profile as much as possible. This is accomplished by charging the storage device with grid-delivered power over night, and discharging during peak periods.

Figure 6 Commercial Solar Output and Load Profile



The ultimate impact on FortisBC system load of the algorithm assumed above is shown in Table 4 below.

[28] Provided by FortisBC on January 15th, 2020
[29] Provided by FortisBC on February 6th, 2020.
[30] Tesla, *Powerpack Technical Specs*. Available at: https://www.tesla.com/powerpack

Table 4 Commercial IPSS Unit Impacts

Month	kW (9am – 10am)	kW (5pm – 6pm)
January	-7.50	-4.27
February	-8.75	-4.49
March	-9.93	-3.51
April	-9.34	-4.22
May	-7.95	-6.95
June	-8.68	-8.15
July	-7.81	-10.24
August	-7.29	-9.53
September	-8.90	-7.47
October	-9.27	-4.30
November	-7.12	-4.19
December	-6.71	-4.06

The average impact for summer months (June, July, August) is shown in Figure 7 below. Note that this chart displays unit *reductions* in load imposed by commercial IPSS. This means that when the series shown on the chart is negative, commercial customers are storing grid-delivered power which they are discharging during the day (when the series on the chart is positive). Note, when considering this impact, the final result of this is that the commercial customer's load profile (not shown) becomes entirely flat – storage allows them to minimize demand charges without impacting overall consumption, and achieving a load factor of 1.

Figure 7 Summer Commercial IPSS Unit Impact

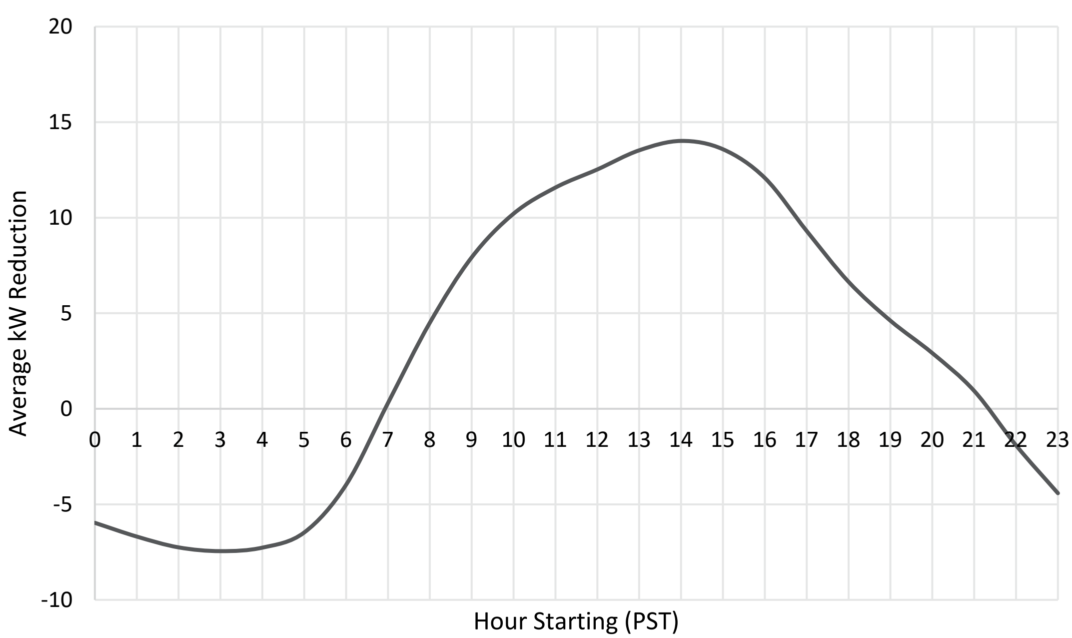
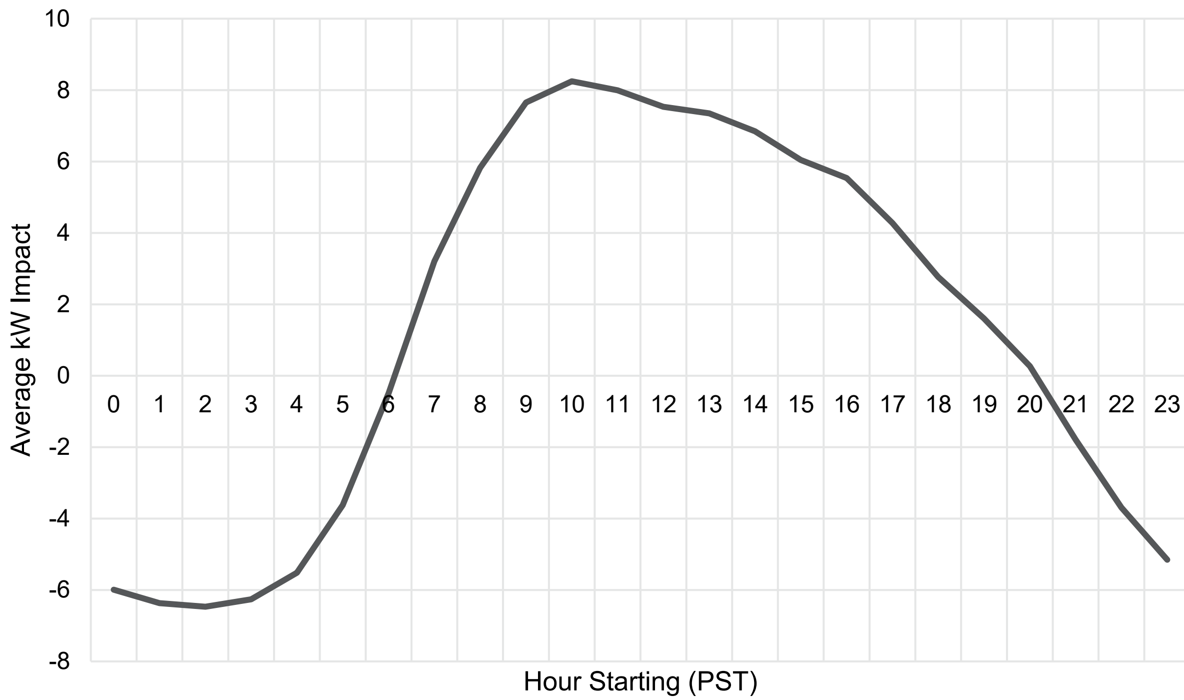


Figure 8 shows the profile of the impact from this load driver in the winter months of December, January, and February. The principal difference between the unit load driver impacts in winter and in summer is that load reductions during the day are lower in the winter than in the summer as a consequence of reduced solar output in that season.

Figure 8 Winter Commercial IPSS Unit Impact



2.3 Electric Vehicles (EV)

The average estimated unit impact per electric vehicle, by vehicle type is presented in Table 5 below.[31] The underlying assumptions and approach to generating these unit impacts are presented below that. The four types of vehicles (in two categories) for which impacts are presented are:

- Light Duty Vehicle (LDV) – Vehicles under approximately 4,000 kg (sedans, SUVs etc.)
- Medium and Heavy-Duty Vehicles (MHDV)
    - Combination Tractor (CT) – The combination of a tractor unit and one or more trailers (otherwise known as a semi-truck)
    - Return to Base Fleet Vehicle (RtB) – Vans and trucks that are used in commercial fleet applications, school buses, waste haulers, and any medium or heavy duty vehicle that return to a central location for charging
    - Bus – City buses used for public transportation

Table 5 Electric Vehicle Unit Impacts

Vehicle Type	Monthly kWh	kW (9am – 10am)	kW (5pm – 6pm)
LDV	273	0.1	1.0
CT	3,047	0.8	4.7
RtB	838	0.2	1.1

[31] Note that the scenario impacts derived from the light duty EV unit impacts that are applied in Scenarios 1 and 3 (which match adoption mandated by the ZEV Act) are present in the reference forecast, but *not* the business-as-usual forecast, which implicitly carries forward the (very small) historical impacts of EV adoption.

Vehicle Type	Monthly kWh	kW (9am – 10am)	kW (5pm – 6pm)
Bus	6,191	6.8	8.2

An important distinction must be made about the kW impacts reported above. These are not strictly speaking unit impacts (i.e., the impact of a single vehicle charging at that time), but rather the average impact per vehicle. The impacts above reflect the diversity of times across the day at which individuals (unconstrained by a time-differentiated electricity rate) typically charge their vehicles.

Due to differences in the quality and availability of data, Guidehouse did not use the same approach for quantifying the profile of the impacts of LDV EVs as for quantifying the profile of the impacts of MHDV EVs. The LDV approach is “bottom-up”, and depends on assumptions about the distribution of charger types, and charging times, whereas the MHDV approach is more “top-down”, relying on empirically-derived charging profiles.

In both cases, the profiles thus derived are applied to an average daily consumption value for each vehicle type calculated based on the average number of kilometers driven by vehicles in BC (LDVs, RtB CT[32], Bus[33]) and the average consumption per kilometer of the electric vehicle (LDVs[34], RtB[35], CT[36], Bus[37]). These values can be seen in Table 6.

Table 6 Kilometer Assumptions by Vehicle Type

Vehicle Type	Average Kilometers Driven per Day (km)	Average Consumption per Kilometer (kWh/km)
LDV	36	0.25
RtB	53	0.52
CT	91	1.10
Bus	135	1.50

2.3.1 *Light-Duty Vehicle Profiles*

[32] Natural Resources Canada, *Canadian Vehicle Survey 2008*, Figure 6 (LDVs), Figure 7 (RtB), Figure 8 (CT). Available at: http://oee.rncan.gc.ca/Publications/statistics/cvs08/chapter2.cfm?attr=1

[33] US Department of Transportation, *Vehicle Travel by Selected Country*. Available at: https://www.fhwa.dot.gov/policyinformation/statistics/2008/pdf/in5.pdf

[34] Guidehouse initially used an efficiency of 0.19 kWh/km for light duty vehicles, reflective of the efficiency performance of a Tesla Model 3 (see citation below). In consultation with FortisBC’s EV expert, however, Guidehouse has increased this value somewhat to 0.25 kWh/km to reflect an anticipated mix of vehicles less efficient than the Tesla and non-driving activities (warming up the car, etc.) to better reflect assumptions about “actual-use” of vehicle.
Original estimate of 0.19 kWh/km from: Electric Vehicle database, *Tesla Model 3 Long Range Dual Motor*. Average of cold weather efficiencies on highway, city, and combined. Available at: https://ev-database.org/car/1138/Tesla-Model-3-Long-Range-Dual-Motor

[35] US Department of Energy, *Navistar eStar Vehicle Performance Evaluation*. Available at: https://www.nrel.gov/docs/fy14osti/61899.pdf

[36] US Department of Energy, *Smith Newton Vehicle Performance Evaluation*. Available at: https://www.nrel.gov/docs/fy14osti/61850.pdf

[37] City of Edmonton, *Electric Bus Feasibility Study*. Available at: https://www.edmonton.ca/documents/transit/ETS_Electric_Feasibility_Study.pdf. Note that although this source related to the city of Edmonton, it is not expected to vary much for FortisBC territory.

For LDV EV profiles, Guidehouse used a bottom-up approach, developing a different profile for each charger level and blending them to create a composite profile of LDV charging.

The three types of charging considered for LDVs are:

- Level 1: 120V AC charging station with a 1.4 kW charging capacity
- Level 2: 240V AC charging station with a 6.9 kW charging capacity
- DC Fast Charging (DCFC): DC charging station with a 50[38] kW or greater charging capacity[39]

Level 1 and level 2 charging stations are typically mutually exclusive – a home or workplace charging station will generally be equipped with one or the other. DCFC stations are, in effect, "gas stations" for fully electric vehicles. They are designed to extend the practical range of EVs.

For LDVs, Guidehouse used the following inputs:

- Charger capacities for Level 1 and Level 2 chargers[40]
- Charging profiles for:
    - Home (Level 1 and Level 2) [41]
    - Public (Level 1, Level 2, and direct-current fast chargers (DCFC)) [42]
    - Work (Level 1, Level 2, and DCFC) [43]
- Distribution of charger type (Level 1, Level 2, DCFC) used by LDVs by charging location (home[44], public[45], work[46])
- Distribution LDV charging locations[47]

Charging profiles for LDVs using Level 1 and Level 2 chargers at home were estimated based on driving diary data, which included home arrival times for 528 vehicles in BC. The daily energy requirements and charging capacities for the technologies in use were also used. The embedded assumptions for these two charging profiles is that vehicle charging begins in the same hour at which vehicle owners arrive home.

The average home charging profiles for LDVs using either Level 1 or Level 2 chargers are shown in Figure 9, below.

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[38] Assumption recommended by FortisBC staff.

[39] Increasing the assumed charger capacity will have no effect on outputs of this study. Even with only a 50kW capacity charger, LDVs always complete charging within an hour. Increasing charger capacity will increase the speed at which vehicles charge and will impact instantaneous demand but will not affect the average hourly demand, the value of concern in this study.

[40] Chargepoint, *Level Up Your EV Charging Knowledge*. Available at: https://www.chargepoint.com/blog/level-your-ev-charging-knowledge/

[41] Simon Fraser University, *Electrifying Vehicles*, Figure 27. Available at: http://rem-main.rem.sfu.ca/papers/jaxsen/Electrifying_Vehicle_(Early_Release)-The_2015_Canadian_Plug-in_Electric_Vehicle_Study.pdf

[42] Provided by FortisBC on January 22, 2020, based on charger data within FortisBC's electric service territory

[43] Provided by FortisBC on January 22, 2020, based on charger data within FortisBC's electric service territory

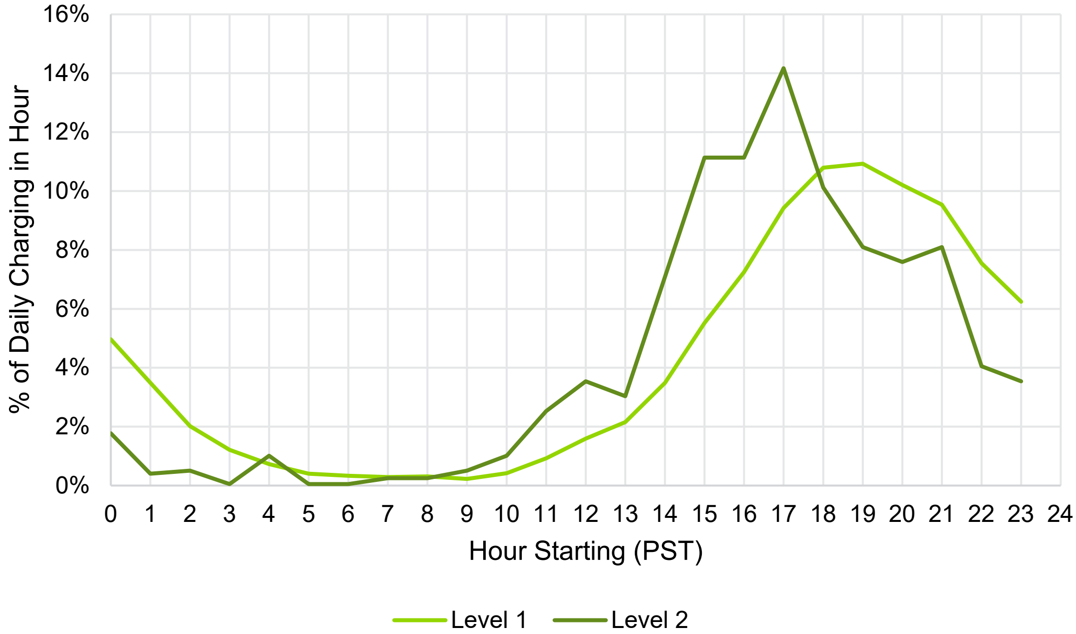
[44] The International Council on Clean Transportation, *Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets*, Figure 4. Available at: https://theicct.org/sites/default/files/publications/US_charging_Gap_20190124.pdf

[45] This distribution was calculated based on data scraped from the Natural Resources Canada Electric Charging and Alternative Fueling Stations Locator in BC. Available at: https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-transportation-and-alternative-fuels/electric-charging-alternative-fuelling-stationslocator-map/20487#/analyze?region=CA-BC&country=CA&fuel=ELEC&ev_levels=all&show_map=true

[46] California Plug-In Electric Vehicle Collaborative, *20 Case Studies on Plug-In Electric Vehicle Charging at Work*. Available at: http://www.ct.gov/deep/lib/deep/air/electric_vehicle/CAPEV_-_Amping_Up_California_Workplaces.pdf

[47] National Renewable Energy Laboratory, *Electric Vehicle Charging Implications for Utility Ratemaking in Colorado*, Page 10. Available at: https://www.nrel.gov/docs/fy19osti/73303.pdf

Figure 9 Home Charging Profiles



The charging profiles for LDVs charging at work and in public using either Level 1, Level 2, or DCFC chargers were estimated using installed charger data provided by FortisBC. The profiles use an average of charging stations within the FortisBC electric service territory.[48] The profiles can be seen in Figure 10 below.

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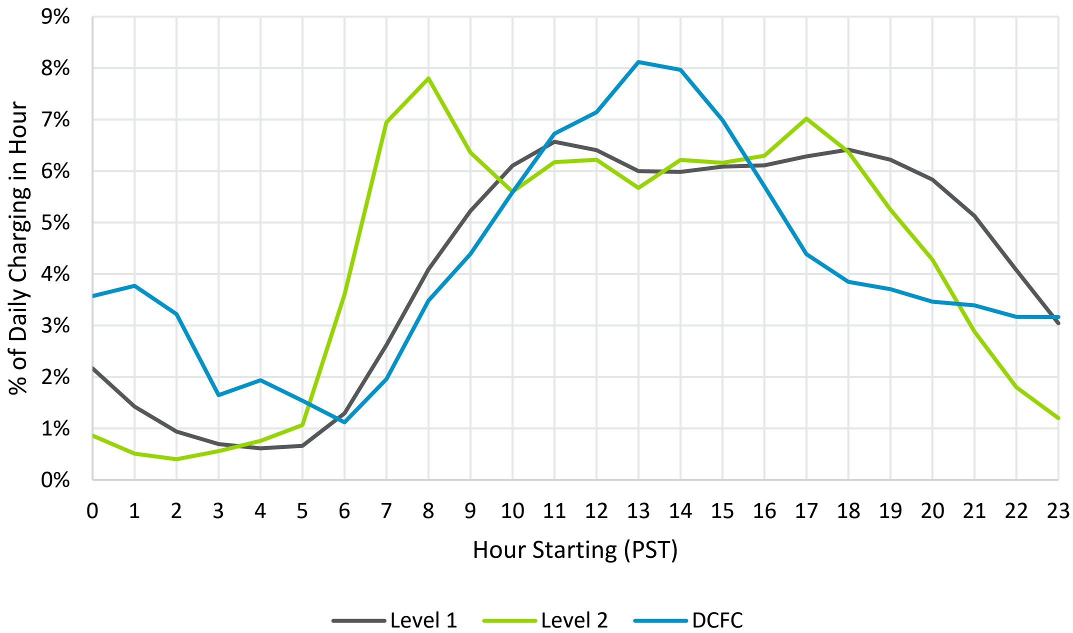
[48] The charging profiles are based on an estimate from 16 DCFC and 3 Level 1 and Level 2 chargers over a year.

Figure 10 Work and Public Charging Profiles



2.3.2 *Medium and Heavy-Duty Electric Vehicles*

For MHDVs, Guidehouse used a top-down approach to develop load profiles, depending on empirically-derived charging profiles, rather than building profiles based on charger type and driving pattern assumptions.

For MHDV profiles, Guidehouse used existing charging profiles for: Combination Tractors [49], RtB [50], and Buses. [51]

The resultant charging profiles are shown in Figure 11, below. These profiles assume CT charge only at public stations and RtB fleet vehicles and Buses charge only at their idle time storage location.

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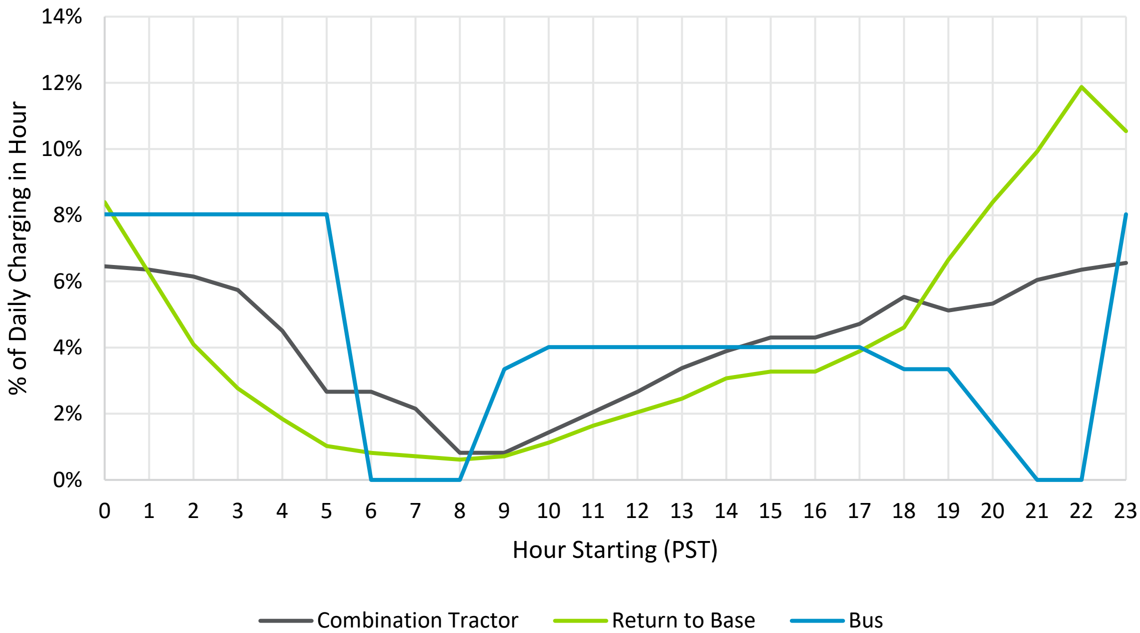
[49] National Renewable Energy Laboratory, *Characterization of In-Use Medium Duty Electric Vehicle Driving and Charging Behavior*, Figure 11. Available at: https://www.nrel.gov/docs/fy15osti/63208.pdf

[50] Ibid

[51] Cheng Shiu University, *Optimal Charging Schedule Planning and Economic Analysis for Electric Bus Charging Stations*, Figure 10. Available at: https://pdfs.semanticscholar.org/c2f6/fa737027b93a85c9de69bc45c7a4531a4f53.pdf

Figure 11 Medium and Heavy-Duty Charging Profiles



2.4 Fuel Switching: Gas to Electric (G2E)

G2E fuel switching is characterized differently than other load drivers. Rather than building up impacts from a new set of assumptions, the estimation of these unit impacts take advantage of the extensive fuel switching modeling developed for the 2019 British Columbia Conservation Potential Review (CPR).[52] As such, impacts in each scenario are presented as a percentage of the technical potential of residential space and water-heating electrification in the FortisBC service territory (the technical potential being the "unit" in this case).

"Technical potential" is defined as the scenario in which every piece of residential gas-fired water or space-heating equipment is replaced by the most efficient (highest savings) available type of electric-powered space- or water-heating equipment, where it is technically feasible to do so. The improved efficiency of modeled replacement equipment results in an overall efficiency gain, delivering an estimated energy savings of 16%.

These impacts, the technical potential estimates from the CPR, are presented in Table 7 below. The underlying assumptions and approach to generating these unit impacts are presented below that.

Table 7 Impacts of Fuel Switching – Gas to Electric

Energy Type	Total Impact (for 2035)
Electric Energy	1,032 GWh/year
Electric Demand	276 MW
Gas Energy	-4,406 TJ/year*

*reduced natural gas demand

[52] Navigant (n/k/a Guidehouse Canada) prepared for FortisBC Energy Inc. and FortisBC Inc., *British Columbia Conservation Potential Review: Total Thermal Demand, Fuel Switching Potential, and Vehicle Electrification Potential*, June 2019.

Guidehouse has estimated the energy impact of fuel-switching based on the technical potential estimated in the CPR. The impacts of this driver will be modelled in each scenario as a fraction of technical potential, a fraction which will change based on which LTERP scenario is modeled. e.g. a higher fraction of technical potential will be used in the Deep Electrification scenario than the Distributed Energy Future scenario. Note that the technical potential value considers a number of different technologies, so the values above should be considered as a blend across different combinations of base and efficient technologies. Although heat pumps contribute substantially to fuel switching, Guidehouse has not applied any assumptions regarding changes in summer air conditioning (A/C) use.

Guidehouse selected the 2035 technical potential because it is the last available year of the CPR forecast. In the years following 2035, technical potential will be held constant at 2035 levels. This may slightly understate true technical potential for the terminal year of the projection period (given projected customer growth over those four years), although given the uncertainties attendant to a twenty-year projection period, these differences are unlikely to make a material difference to the conclusions of the analysis. Using the forecast residential load for FBC[53] for 2035 before accounting for DSM (approximately 1.6 TWh), G2E fuel switching would increase FortisBC forecast residential load (before DSM) by approximately 64% in 2035.

The CPR modelled the impact of G2E fuel switching on peak demand[54] which is represented by the Electric Demand row in Table 7. This demand value will be incorporated into each scenario using the same approach as described above for annual energy.

2.5 Fuel Switching: Electric to Gas (E2G)

The average estimated unit impact of a switch from electric to natural gas space- and water-heating is presented in Table 8 below. The underlying assumptions and approach to generating these unit impacts are presented below that. In comparing this section to the one that precedes it (Fuel Switching, Gas to Electric), it is important to note that due to the difference in approach in estimating unit impacts, the unit in this case is *per customer*, whereas for Gas to Electric fuel switching the unit is (because the value is derived from the Conservation Potential Review, rather than a bottom-up analysis) the system as a whole.

Table 8 Unit Impacts of Fuel Switching – Electric to Gas

System Type	Month	Monthly kWh	kW (9am – 10am)	kW (5pm – 6pm)
Water-Heating	January	-286	-0.52	-0.52
	February	-259	-0.52	-0.52
	March	-288	-0.52	-0.52
	April	-234	-0.37	-0.37
	May	-244	-0.37	-0.37
	June	-197	-0.35	-0.35
	July	-202	-0.35	-0.35
	August	-204	-0.35	-0.35
	September	-196	-0.35	-0.35

53 Provided by FortisBC on January 21st, 2020.

54 Note that the CPR's definition of peak demand may not exactly match that of this engagement. In this engagement, peak annual demand is assumed to be the average demand observed between 5pm and 6pm on January weekdays. The definitions are sufficiently close (and the uncertainty associated with 20-year forecasts sufficiently large) that the CPR value will be used unmodified for this analysis.

System Type	Month	Monthly kWh	kW (9am – 10am)	kW (5pm – 6pm)
	October	-243	-0.37	-0.37
	November	-236	-0.37	-0.37
	December	-285	-0.52	-0.52
Space-Heating	January	-1070	-2.0	-1.5
	February	-842	-2.0	-1.2
	March	-544	-1.2	-0.6
	April	-276	-0.7	-0.2
	May	-116	-0.3	-0.1
	June	-45	-0.1	0.0
	July	-6	0.0	0.0
	August	-10	0.0	0.0
	September	-120	-0.3	-0.1
	October	-365	-0.8	-0.4
	November	-694	-1.6	-1.0
	December	-908	-1.8	-1.3

Guidehouse estimated the unit load impact of fuel-switching based on the following factors:

- It was assumed that only those electric space-heating customers without heat pumps would switch over to gas.[55]
- The estimated yearly unit energy consumption (UEC) of electric space-heating equipment and of electric water-heating equipment, for FortisBC territory from the 2017 FortisBC Residential End Use Study (REUS)[56]:
    - Water-heating: 2,684 kWh
    - Space-heating: 4,749 kWh. This value,which is the average annual space-heating consumption for all primary space-heating systems, is then scaled (using the factors outlined immediately below) to 4,995 kWh per year to account for the fact that only non-heat pump systems are considered for switching.
- The distribution of heat-pump (3.5% of total heating systems, 10% of electric heating systems) and non-heat pump equipment electric heating systems (30% of total heating systems, 90% of electric heating systems) in FortisBC territory[57]:
- The average efficiency of space-heating equipment in British Columbia[58]
- The space-heating load profile from the Conservation Potential Review[59]
- The water-heating load profile from the Independent Electricity System Operator (IESO)[60]

[55] This may slightly understate the potential effect of the driver as it embeds the assumption that owners of electric heat pumps will, at the end of that equipment's life, replace it with another electric heat pump.

[56] Sampson Research, prepared for FortisBC Inc., *FBC 2017 Residential End Use Study*, May 2019, see Table 234.

[57] Natural Resources Canada, *Comprehensive Energy Use Database*, Table 21: Heating System Stock by Building Type and Heating System Type for British Columbia. Available at: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=bc&rn=26&page=0

Note that although the REUS is generally much more locally specific (and may be more accurate) than NRCan's CEUD, it does not provide a sufficiently granular cross-tabulation of heating system types to clearly distinguish non-heat pump electric heating systems from electric heat pump systems – e.g., Table 81 (Main Space Heating Method) does not distinguish between electric boilers and natural gas boilers.

[58] Natural Resources Canada, *Comprehensive Energy Use Database*, Table 26: Heating System Stock Efficiencies for British Columbia. Available at: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=bc&rn=26&page=0

[59] Navigant (n/k/a Guidehouse Canada), *British Columbia Conservation Potential Review*, January 2018

[60] CDM Energy Efficiency Cost Effectiveness Tool, Independent Electricity System Operator. Available at: http://www.ieso.ca/sector-participants/conservation-delivery-and-tools/ldc-toolkit

The load profiles used for water-heating and space-heating are shown Figure 12 and Figure 13 respectively below.

Figure 12 Average Water-Heating Load Profile

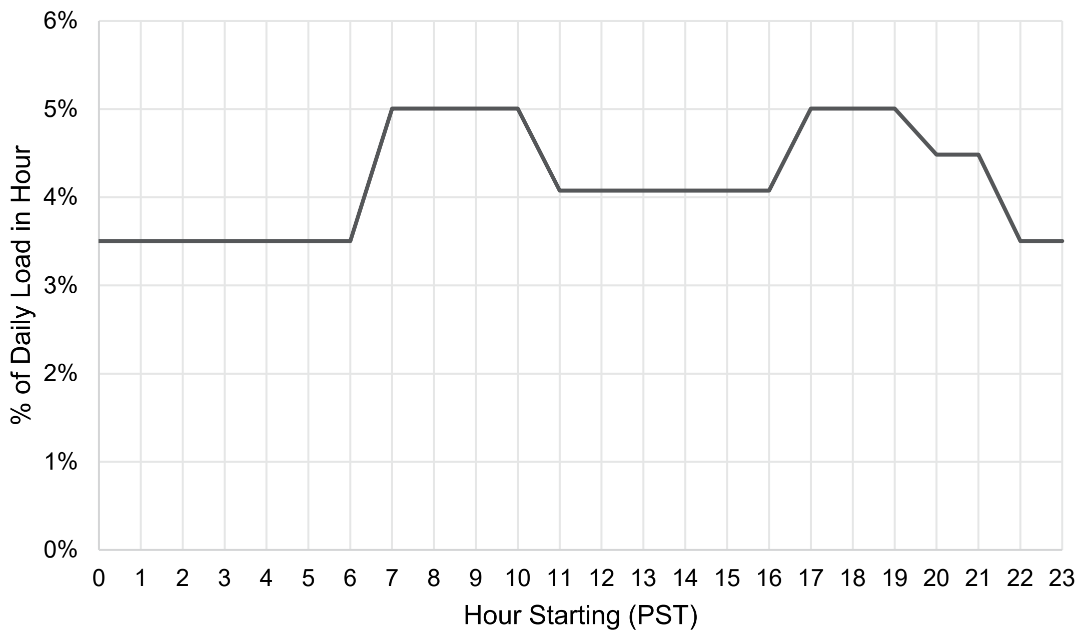
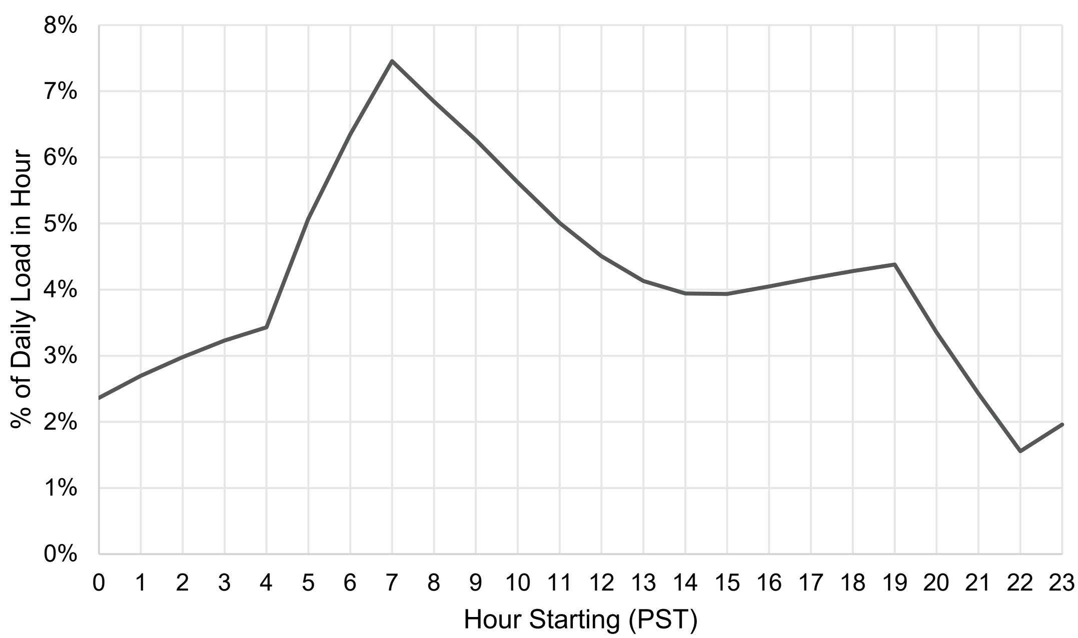


Figure 13 Average Winter Space-Heating Load Profile



2.6 Climate Change (CC)

For estimating the impacts of climate change, Guidehouse worked collaboratively with FortisBC staff, who have directly contributed some of the text below.

The climate change driver reflects average changes in demand relating to temperature over time. To determine the potential impacts on both average annual energy as well as summer and winter peak capacity, Guidehouse explored scenarios which included:

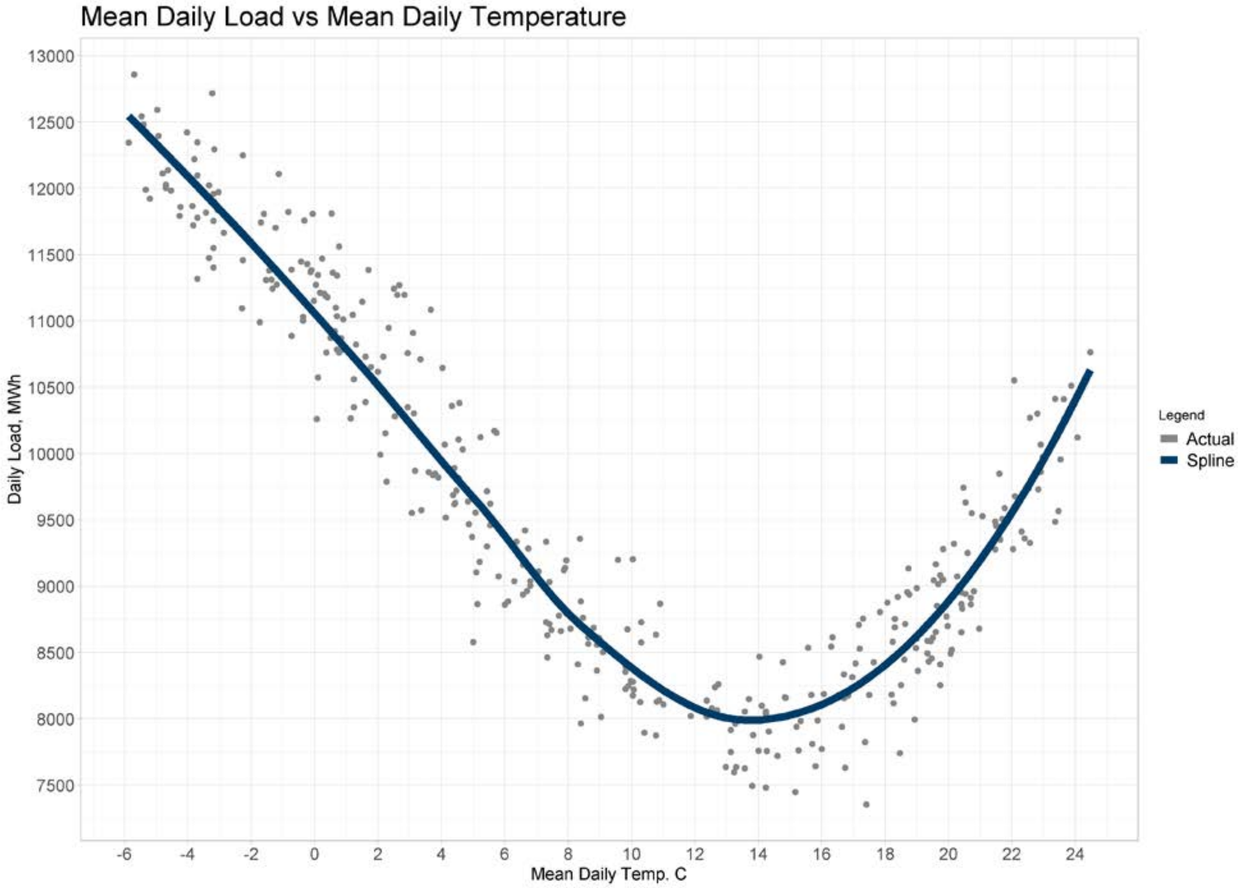
- A decrease in the average daily temperature on the ten coldest days of the year;
- An increase in the average daily temperature on the ten hottest days of the year; and,
- An additional increase in the average daily temperature in all days of the year.

More explicitly, scenario impacts are estimated as a function of these variables which collectively define the “unit” impact of the load driver.

2.6.1 *Load Response to Temperature*

Climate change impacts themselves were derived from an estimate of the temperature/energy consumption relationship. This relationship was estimated by fitting the average daily energy consumption in the FortisBC service territory to the average daily temperature for the five most complete recent calendar years using a cubic spline function. This spline provides the parameters that approximately predict changes in demand resulting from changes in daily average temperature. This estimated relationship is illustrated in Figure 14, below.

Figure 14: Actal and Fitted Average Daily Loads Compared to Daily Temperatures



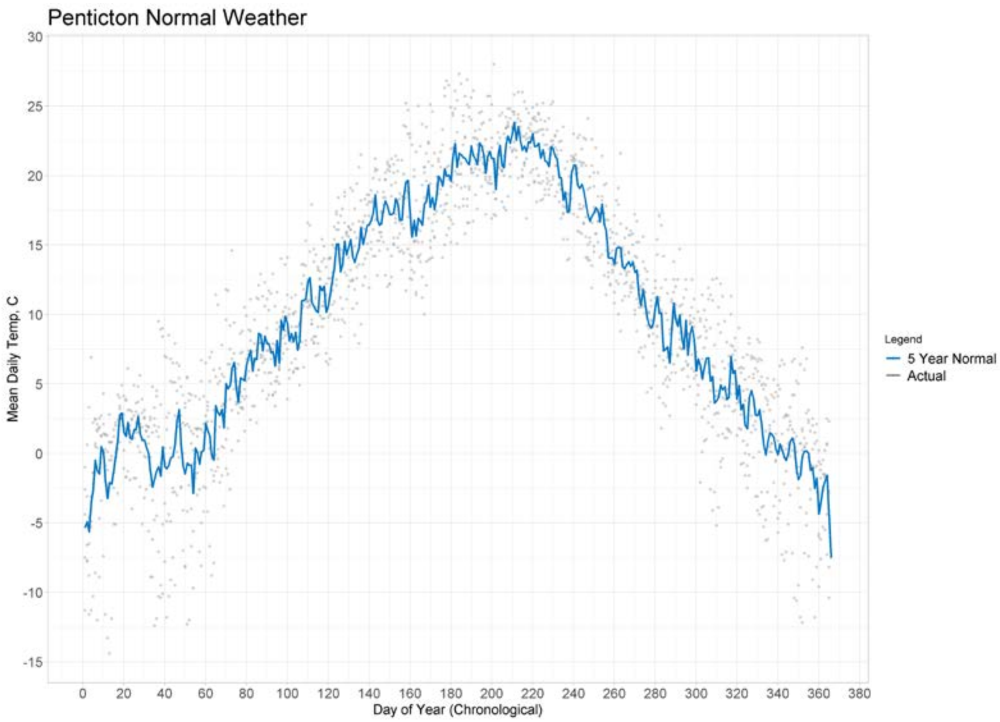
The spline function can be used to develop a load duration curve[61] by applying an annual weather model. If two different weather models are used then the demand impact from changing weather can be estimated by subtracting one load duration curve from the other.

2.6.2 *Normal Weather*

The first weather model to develop for the spline function is the five-year normal weather. For this driver the most recent weather data from the Penticton airport was used as a proxy for the FortisBC service area. The daily temperature values and the mean of those values is plotted in Figure 15, below.

[61] A Load Duration Curve plots daily load vs day of the year in descending order of load. The area under the load duration curve is the annual load. The first point on the load duration curve is the peak daily demand.

Figure 15: Penticton Average Daily Temperatures



2.6.3 *Scenario Weather*

The Scenario Weather starts off as the Normal Weather and then is adjusted using five parameters:

1. Daily mean temperature change applied to all days
2. Number of coldest winter days to assumed to become colder (days)
3. Average temperature decrease on coldest days, degrees Celsius (C)
4. Number of hottest summer days assumed to become hotter (days)
5. Average temperature increase on hottest days, C

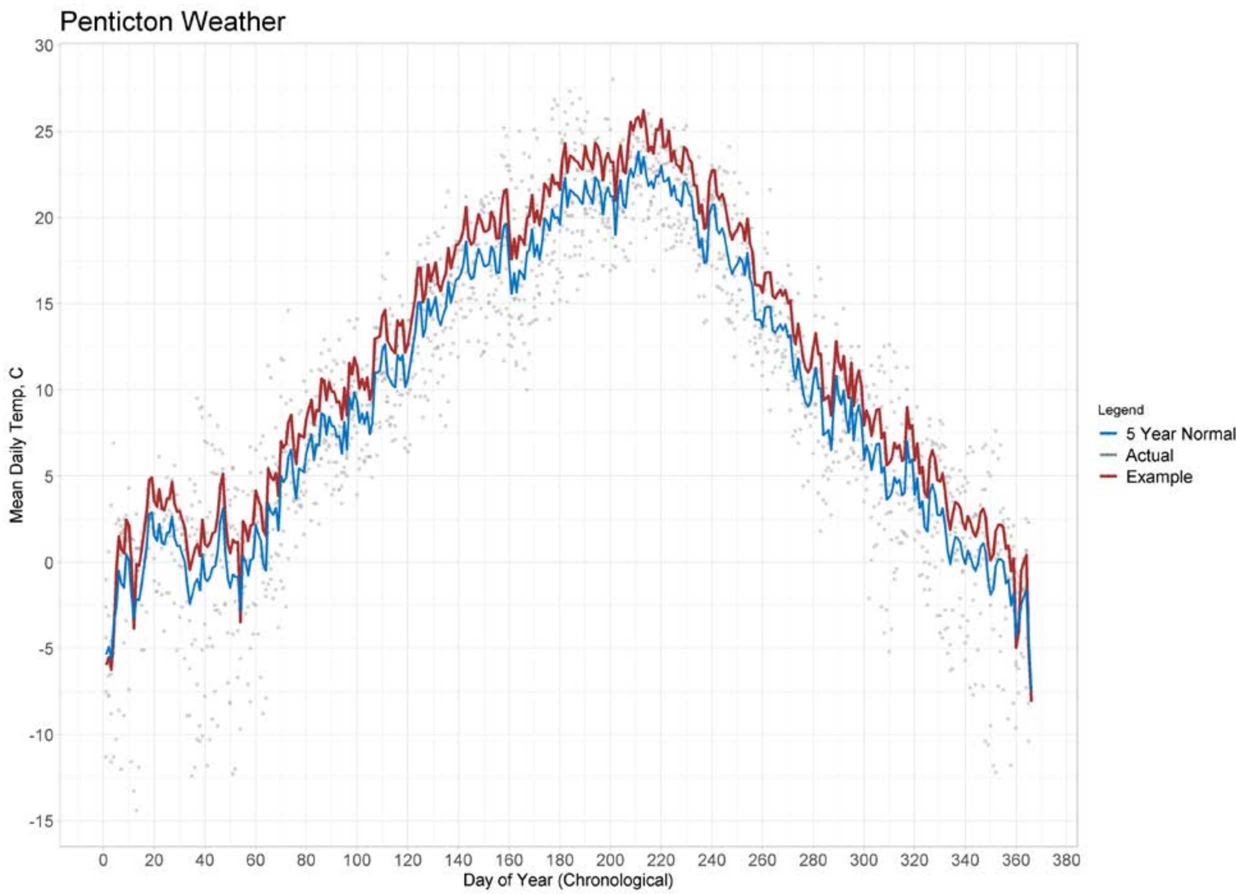
2.6.4 *Scenario Settings*

The following table shows the settings applied to each of the Guidehouse scenarios.

Scenario	Number of Coldest Days Adjusted	Temperature Decrease on Coldest Days, C	Number of Hottest Days Adjusted	Temperature Increase on Hottest Days, C	Average Daily Change, C
Upper Bound	10	-6.2	10	+2.1	n/a
Lower Bound	n/a	n/a	n/a	n/a	+2
All other scenarios	10	-2.6	10	+0.7	+2

The temperature reductions and increases applied to the coldest and hottest days were derived from daily Penticton weather records recorded since 1945. For each year the warmest and coldest ten contiguous daily mean temperature were determined. From this distribution the 95th percentile value was used for the Upper scenario. For all other scenarios the 75th percentile value was used. A value for average annual warming of 2 C was selected as this value seems to be commonly used as a temperature change limitation target globally (such as through the most recent Paris Agreement), although the target is typically applied further out in time than the LTERP planning horizon end year of 2040.

For the purposes of developing an example the values for “All other scenarios” from the preceeding table were used and result in the following weather model.



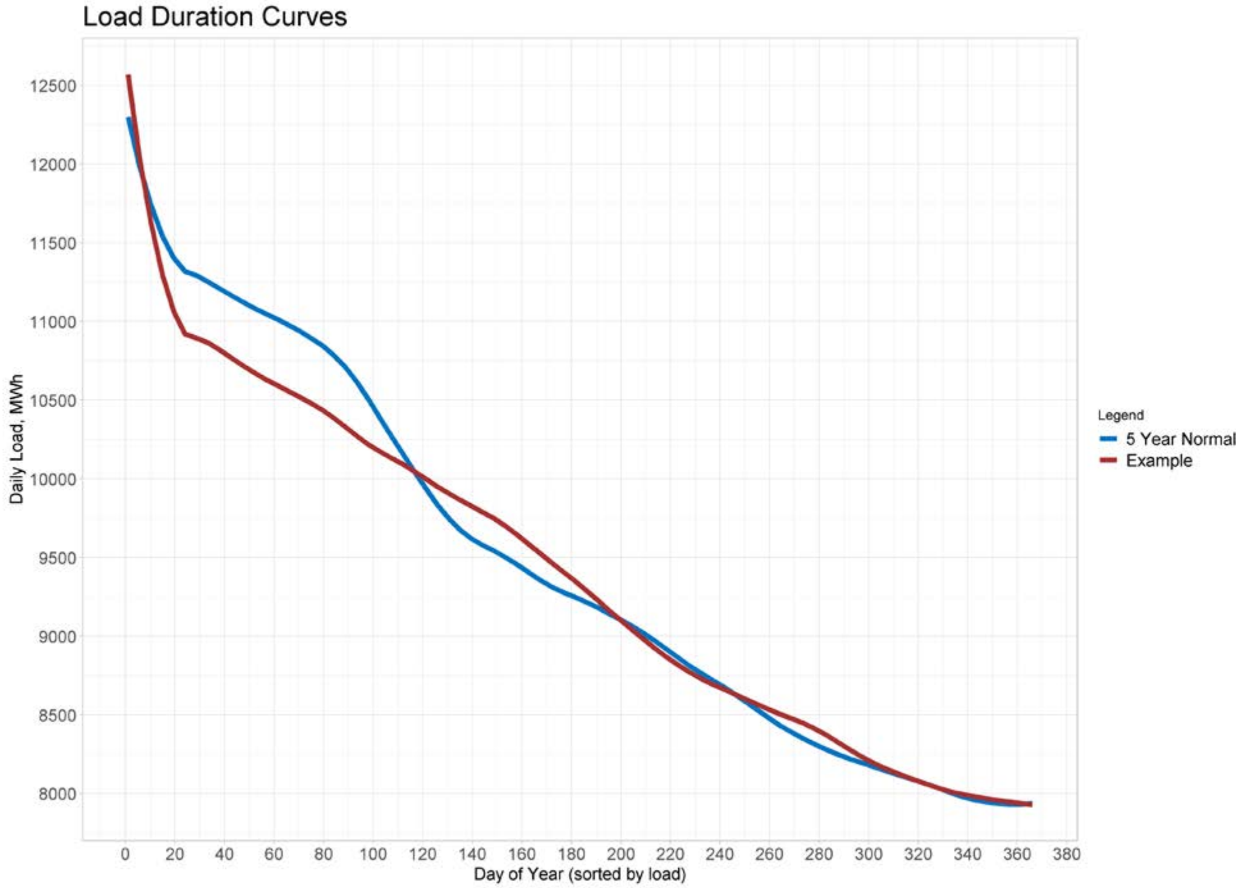
Key observations from the figure above include:

- The decreases in temperature on the coldest days are visible in January and December (red line below the blue line)
- The increases in temperature on the hottest days are visible in the center of the plot (red line above blue line)
- The average daily warming is visible on every day except for the coldest winter days (red line above blue line)

2.6.5 *Load Duration Curves*

With the spline function, Normal weather model and Example weather model two load duration curves can be created as follows:

Figure 16: "Normal" and Example Load Duration Curves



Comparing the two curves:

- The peak at Day 1 is higher for the example (red line) than the 5-year "normal" weather, due to the assumed temperature decreases on the coldest days.
- The lines weave back in forth because the demand is reduced as a result of the mean daily temperature increase (red line below blue) and because of the increased load during the colder and warmer periods (red line above blue)

2.6.6 *Peak Demand Impacts*

FBC examined peak hour data from the ten coldest and ten warmest days from 1997 forward. The peak hour as a percentage of peak day was determined to be approximately 5.4% of the peak day. The peak hour factor can be applied to the peak day from both the Normal or Scenario load duration curves to determine the peak impact from the scenario.

2.7 Large Load Sector Transformation (LLST)

Large load sector transformation captures the growth of large loads in FortisBC's electric service territory unrelated to traditional large load customer industries (e.g., pulp and paper, manufacturing, etc.). These non-traditional customer industries were selected by FortisBC staff in collaboration with Guidehouse staff, based on trends anticipated in FortisBC's electric service territory:

- Data Centres (including bitcoin/cryptocurrency facilities)
- Cannabis Greenhouses

The average unit impacts for large load sector transformation are shown for data centres and cannabis greenhouses in Table 9 and Table 10 respectively below. These impacts are shown per 10,000 square feet (sq. ft.) of a data centre or cannabis greenhouse, per month. The underlying assumptions and approach to generating these impacts are outlined below that.

Table 9 Unit Impacts for Data Centres (per 10,000 sq. ft.)

Month	Monthly kWh	kW (9am – 10am)	kW (5pm – 6pm)
January	403,872	543	545
February	482,331	719	721
March	484,938	653	655
April	499,877	695	698
May	501,135	674	677
June	483,670	673	675
July	470,602	633	636
August	475,305	640	642
September	497,935	692	695
October	479,085	645	647
November	470,385	654	656
December	376,663	507	509

Table 10 Unit Impacts for Cannabis Greenhouses (per 10,000 sq. ft.)

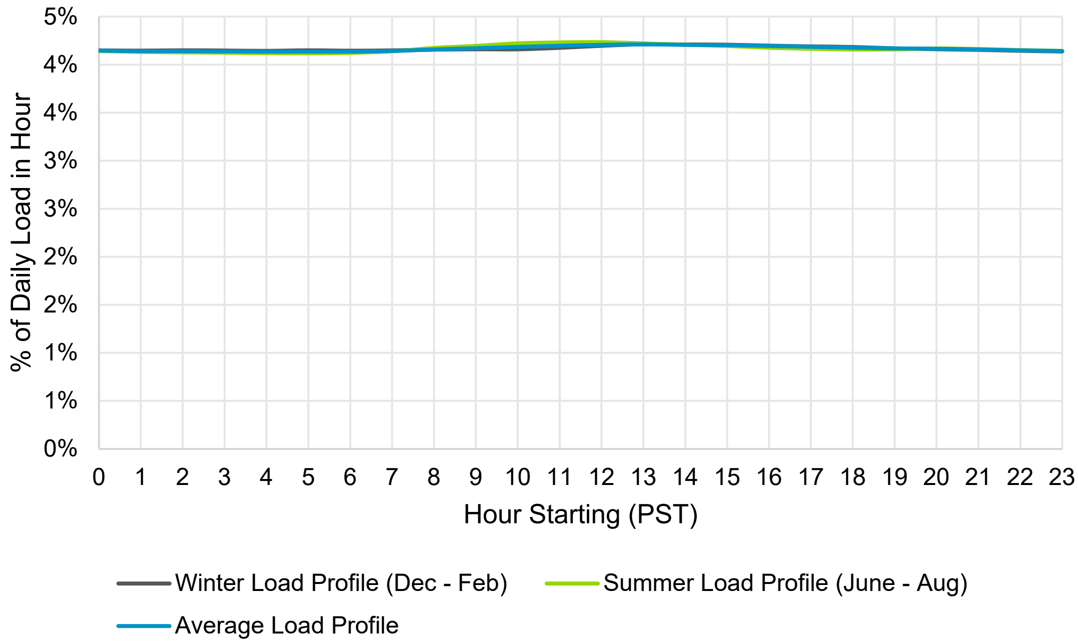
Month	Monthly kWh	kW (9am – 10am)	kW (5pm – 6pm)
January	93,604	132	133
February	72,270	113	114
March	70,844	100	101
April	60,762	89	89
May	63,994	90	91
June	61,706	90	91
July	66,807	94	95
August	71,232	101	101
September	54,059	79	79
October	57,793	82	82
November	68,311	100	100
December	83,909	118	119

Unit load impacts for this driver are based on the average loads of existing customers in FortisBC territory as well as data centre intensity per square foot from EnergyStar.[62] The average seasonal load profiles for data centres in FortisBC territory[63] are shown in Figure 17 below. The load remains relatively constant across all hours of the day, regardless of season.

[62] Data Center Esimated in the United States and Canada, Energy Star. Available at: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/benchmarking-rendement/DataCenter-US-and-Canada-EN-Feb2018.pdf

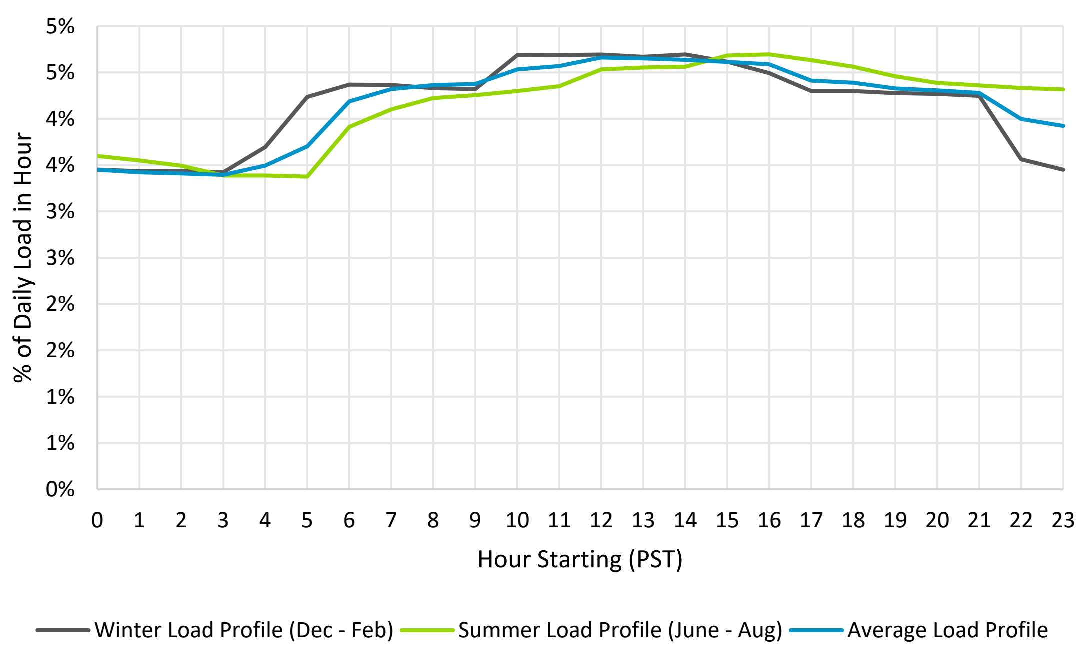
[63] Provided by FortisBC on January 21st, 2020

Figure 17 Data Centre Load Profiles



Cannabis greenhouse[64] loads show considerably greater variation hour-by-hour than data centres, but are (relative to other commercial enterprises or residential loads) still quite flat, as shown in Figure 18 below. Note that this profile assumes an indoor operation with similar equipment and processes to existing customers in this sector.

Figure 18 Cannabis Greenhouse Load Profiles



64 Provided by FortisBC on January 21st, 2020

2.8 Hydrogen Production (HP)

This load driver quantifies the electricity consumption driven by the production of "green" hydrogen, a key renewable gas[65]. The unit impacts for HP are shown in Table 11 below, these are presented in terms of electricity consumption per gigajoule (GJ) of fuel produced per day[66]. The underlying assumptions and approach to generating these impacts are outlined below the table.

Table 11 Unit Impacts for Hydrogen Production per GJ of Fuel Produced per Day

Month	Monthly kWh	kW (9am – 10am)	kW (5pm – 6pm)
January	12,400	25.9	11.2
February	11,200	25.3	11.2
March	12,400	22.8	14.1
April	12,000	23.8	17.0
May	12,400	24.3	16.2
June	12,000	18.2	13.0
July	12,400	22.6	14.1
August	12,400	22.0	14.0
September	12,000	26.9	12.0
October	12,400	23.0	11.8
November	12,000	23.8	10.6
December	12,400	23.4	12.4

The electric intensity for hydrogen production is assumed to begin at 378 kWh/GJ[67], or approximately 73%. Over time, the efficiency of hydrogen production is assumed to grow to 95% (by 2040). The unit impacts calculated assume 1 GJ is produced per day of the month, and assume the starting production efficiency of 378 kWh/GJ. This production efficiency is based on data from FortisBC and is comparable to benchmark data from public sources.[68]

The average load profile for hydrogen production[69] for all months of the year is presented in Figure 19 below. This profile is derived under the assumprion that hydrogen production will be aligned with renewable distributed generation (wind and solar) output. Accordingly, the profile reflects a weighted average (30% solar, 70% wind) output profile for solar and wind generation in the Pacific Northwest developed by Navigant's Capital Markets team based on historical observed production values.

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[65] Green hydrogen is produced via an electrolysis reaction with renewable electricity and water. It is distinct from "blue" hydrogen, hydrogen chemically converted from natural gas. Although synthetic methane is also often considered as a renewable natural gas, the processes for the production of synthetic methane remain in the very early stages of technical development, and appears unlikely to play a major role in the decarbonization of the natural gas system until after 2040, the terminal year of this projection.

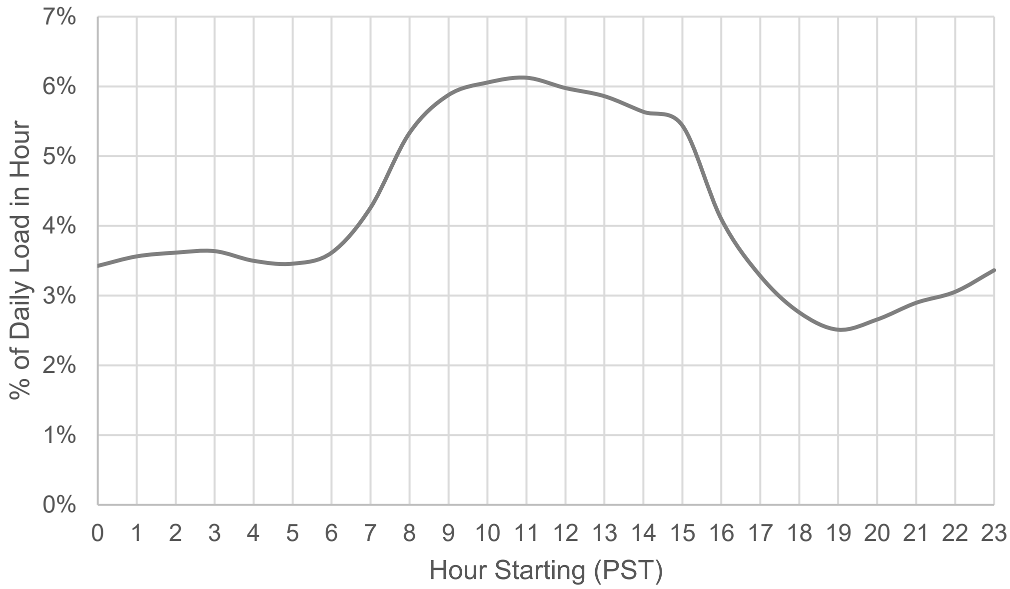
[66] For clarity: the sum of the Monthly kWh column in the table below shows the electric energy required to produce 365 GJ of hydrogen in one year, one GJ on each day of the year.

[67] Provided by FortisBC on January 29th, 2020 based on data from hydrogen pilot programs.

[68] IRENA, *Comprehensive Hydrogen from Renewable Power, Technology Outlook for the Energy Transition*, Available at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Sep/IRENA_Hydrogen_from_renewable_power_2018.pdf

[69] Provided by Guidehouse's energy market modeling group based on renewable generator output in the Pacific Northwest.

Figure 19 Hydrogen Load Profile



2.9 Carbon Capture and Storage (CCS)

This load driver quantifies the electricity consumption driven by the power requirements of CCS technologies used to capture carbon emissions from industrial processes. Capturing and storing one kg of CO_2 per day requires an additional load of approximately 9 kWh per month and imposes an increased demand on the system of approximately 0.01 kW between both 9am and 10am, and between 5pm and 6pm. The underlying assumptions and approach to generating these impacts are outlined below.

Guidehouse's unit impact estimate is based on the findings of an International Energy Agency study which estimated the intensity of CCS to be approximately 0.3 kWh per kg of CO_2 captured from industrial applications and stored.[70]

The distribution of demand from CCS across the year is determined by the distribution of industrial CO_2 emissions across the year. Guidehouse, lacking a profile of emissions output, has assumed a flat profile for emissions and thus for the demand associated with the capture of those emissions.

[70] International Energy Agency, *CO_2 Capture and Storage*. Available at: https://iea-etsap.org/E-TechDS/PDF/E14_CCS_oct2010_GS_gc_AD_gs.pdf

3. LOAD SCENARIOS

This chapter describes the five scenarios modeled as part of this analysis, outlines the load scenario assumptions (e.g., load driver penetration level, turnover, etc.) underlying each scenario, and presents the estimated potential impact of each scenario, relative to the business-as-usual forecast.

This chapter is divided into three sections:

- **Scenario Descriptions.** This section describes the five scenarios modeled and outlines the motivation driving the combinations of load drivers included in each scenario.
- **Scenario Assumptions.** This section describes the assumptions applied to each scenario, including both "global" assumptions (e.g., stock turn-over rate) and scenario-specific assumptions (penetration).
- **Scenario Results.** This section provides the estimated impact of the five scenarios. Additional contextual supporting details (e.g., number of EVs vs number of combustion vehicles) are provided for the two "boundary" scenarios (for more details see below).

3.1 Scenario Descriptions

Each of the five scenarios modeled for this analysis is comprised of a different combination of load drivers. The five combinations of load drivers (the scenarios) defined for this analysis were chosen based on two guiding principles:

1. **The analysis should include "boundary" scenarios.** Boundary scenarios are those scenarios that define major deviations from existing empirical forecasts driven by the cumulative effects of emerging technologies and structural shifts that overwhelmingly affect system load in one direction or the other. These scenarios, Scenario 1, the "Upper Bound", and Scenario 2, the "Lower Bound" each only consider driver impacts that push load in one direction – the Upper Bound considers only drivers that increase load, the Lower Bound considers only drivers that reduce load.
2. **The analysis should include scenarios consistent with the Pathways analysis.** FortisBC recently undertook a province-wide scenario analysis seeking to identify different decarbonization strategies.[71] Two of the scenarios in this analysis were specified to be aligned with those of the Pathways report: Scenarios 3 ("Deep Electrification") and 4 ("Diversified Energy Pathway"). The fifth scenario is an amalgam of assumptions in Scenarios 3 and 4. The detailed assumptions of all scenarios are described below.

To better understand how load driver combinations were selected for each scenario, the principles above should be compared to the directional impacts characterized for each load driver, as presented in Figure 20 below. This figure also includes the short-form description of each load driver used further below in the graphical representations of each scenario.

Note that the direction of the impact shown in the figure below identifies the impact on annual energy consumed within the FortisBC electric service territory. The text below this figure identifies cases in which the effect of the driver on demand differs in some way from the effect on energy. Of all the drivers, only Climate Change's energy impacts are ambiguous – these vary by scenario, according to the climate

[71] Guidehouse Canada on behalf of FortisBC, *Pathways for British Columbia to Achieve its Greenhouse Gas Reduction Goals*, 2020 Publication forthcoming.

change assumptions adopted for each scenario. These assumptions are described in greater detail in Section 3.2, below.

Figure 20: Load Driver Directional Impacts

Load Driver	Short Form	Effect on System Load (+/-)
Residential Integrated Photovoltaic Solar and Storage	**IPSS-RES**	▼
Commercial Integrated Photovoltaic Solar and Storage	**IPSS-COM**	▼
Electric Vehicles, Light Duty and Medium/Heavy Duty	**LD EVs** **MHD EVs**	▲
Fuel Switching – Gas to Electricity	**FS – G2E**	▲
Fuel Switching – Electricity to Gas	**FS – E2G**	▼
Climate Change	**CC**	▼ ▲
Large Load Sector Transformation	**LLST – Data Centres** **LLST - Cannabis**	▲
Hydrogen Production	**HP**	▲
Carbon Capture and Storage	**CCS**	▲

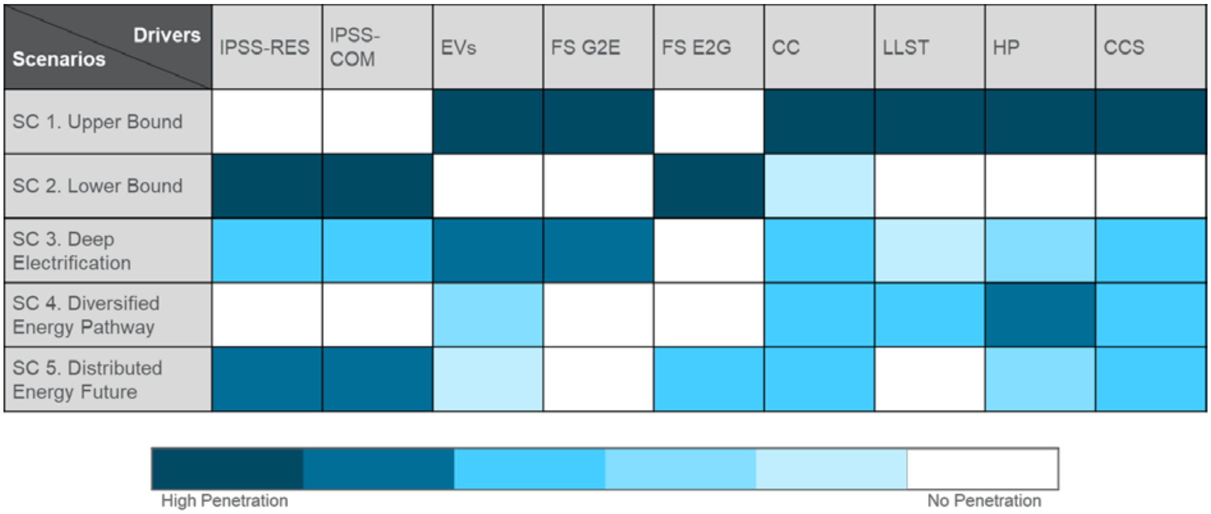
As with energy, the winter peak demand impacts for the Climate Change driver vary by scenario. In most other cases, the winter peak demand savings conform with the energy peak demands. The only exception to this is the case of the IPSS-RES driver. Given the assumed installed capacity of the PV and storage systems, and the assumed pattern of behaviour by customers (use up stored energy as soon as it is required), the IPSS-RES driver has no impact on average demand between 5pm and 6pm on non-holiday January weekdays.

The impacts in each scenario are driven by the assumed "penetration" of each driver by the terminal year of the projection (2040) and the driver-specific assumptions detailed in Section 3.2 below. In the case of this study, "penetration" takes on a very specific definition: it refers to the value taken in the terminal year (2040) of the load-motivating parameter of the load driver. Put simply, the terminal year penetration value is the metric (or that delivers, via some transformation) that is multiplied by the unit impact (described in Section 2, above) to deliver the energy and demand impacts in 2040.

In some cases this is simply the penetration of a technology – in the case of IPSS-RES, it captures the proportion of single-family residential consumers living in the FortisBC service territory that have acquired PV and storage by 2040. In other cases it is a less discrete quantity, as in the case of Climate Change where the "penetration" really refers to the change in assumed temperature values by the terminal year.

The coloured squares in Figure 21 below provide a qualitative indication of how high the penetration of each driver is in each scenario, relative to the other scenarios. Additional detail and more specific metrics are described in each of the sub-sections in Section 3.2.

Figure 21. Penetration Summary by Load Scenario and Load Driver



Guidehouse did not model any secondary or tertiary effects of load drivers due to interactions between them. This was a deliberate decision and consistent with the approach applied in modeling the load scenarios in support of the 2016 LTERP.[72] The modeling of each driver independently within scenarios where some interactions would naturally be expected (e.g., Climate Change and Fuel Switching) would provide some incremental accuracy (conditional on the accuracy of the underlying assumptions) but would reduce the flexibility of the outputs and thus the transparency to stakeholders, internal and external.

3.2 Scenario Assumptions

This section of the Scenarios chapter outlines the major assumptions driving the scenario impacts. This section is sub-divided into nine sub-sections, one for each load driver. Each sub-section outlines the "global" assumptions for the given load driver, followed by the scenario-specific penetrations/uptake assumptions for that load driver.

The assumed penetration/uptake rates for each load driver in each scenario were selected by Guidehouse in close collaboration with FortisBC staff over a period of several months. The assumed penetration values used for this analysis are not a forecast or a projection, but instead are based on a "reasonable extreme" value assumption (Upper and Lower Bound scenarios) or such that they approximately align with the assumptions in the Pathways analysis described elsewhere in this report.

3.2.1 *Integrated Photovoltaic Solar and Storage (IPSS) – Residential*

The principal global assumptions used to model this load driver are:

[72] Navigant (n/k/a Guidehouse) prepared for FortisBC, *Load Scenario Assessment: Exploring Structural Change in Electricity Consumption Drivers*, July 2016

- **Suitability.** Guidehouse assumed that PV (and storage) could be installed only on the rooftops of single-family homes (SFH). The total number of single-family homes in each year is derived from:
    - FortisBC's forecast of residential customer counts in its service territory. This grows from approximately 123,000 customers in December of 2019 to approximately 160,000 customers in December 2040.
    - The number of residential consumers that are customers of FortisBC's wholesale customers in 2019, escalated at the same rate of growth as the FortisBC's residential customers. In 2019, there were approximately 23,000 residential consumers served by FortisBC's wholesale customers, or approximately 16% of all residential consumers considered in this study, in that year.
    - The provincial proportion of permanent dwellings that are single-family homes. Once mobile homes are excluded, single family homes account for approximately 65% of residential dwellings in British Columbia.[73]
- **Storage.** Guidehouse assumed in every scenario that, by the terminal year of the analysis, half of all residential customers that had acquired rooftop PV by 2040 (incremental to those in 2019) would *also* have acquired storage with the capabilities and use patterns described in Section 1.1, above.

The assumed proportion of homes with rooftop solar PV varies by scenario. For Scenarios 1 (Upper Bound) and 4 (Diversified Energy Pathway), no incremental (to the business-as-usual case demand projection) residential rooftop solar is assumed to be deployed. In the remaining scenarios:

- For Scenario 2, Lower Bound, it is assumed that one third (33%) of all SFH have installed rooftop PV by 2040.
- For Scenario 3, Deep Electrification, it is assumed that 15% of all SFH have installed rooftop PV by 2040.
- For Scenario 5, Distributed Energy Future, it is assumed that 25% of all SFH have installed rooftop PV by 2040.

3.2.2 *Integrated Photovoltaic Solar and Storage (IPSS) – Commercial*

The principal global assumptions used to model this load driver are:

- **Suitability.** Guidehouse assumed that PV (and storage) would be installed only on the rooftops of large commercial customers, those general service customers subject to Schedule 21 (GS21), with a metered demand of between 40 and 500 kW (or the equivalent indirect customers).
    - FortisBC's forecast of commercial customer counts in its service territory. This grows from approximately 16,200 customers in December of 2019 to approximately 22,800 customers in December 2040.
    - The number of commercial consumers that are customers of FortisBC's wholesale customers in 2019, escalated at the same rate of growth as the FortisBC's commercial customers. In 2019, there were approximately 15,000 commercial consumers served by

[73] NRCan, *Comprehensive Energy Use Database – Residential Sector – British Columbia*, Table 14, Year: 2017 Available at: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_res_bc.cfm

FortisBC's wholesale customers, or approximately 48% of all commercial consumers considered in this study.

- o The proportion of FortisBC's commercial customers that are GS21 customers, in 2019. Approximately 11% of FortisBC's commercial customers in 2019 were GS21 customers, though these customers accounted for approximately 64% of FortisBC's commercial load in that year.

- **Storage.** Guidehouse assumed in every scenario that, by the terminal year of the analysis, half of all commercial GS21 customers with rooftop PV by 2040 (incremental to those in 2019) would also have acquired storage with the capabilities and use patterns described in Section 1.2, above.

The assumed proportion of large businesses with rooftop solar PV varies by scenario. For Scenarios 1 (Upper Bound) and 4 (Diversified Energy Pathway), no incremental (to the business-as-usual case demand projection) commercial rooftop solar is assumed to be deployed. In the remaining scenarios:

- For Scenario 2, Lower Bound, it is assumed that 50% of applicable businesses have installed rooftop PV by 2040.
- For Scenario 3, Deep Electrification, it is assumed that 25% of applicable businesses have installed rooftop PV by 2040.
- For Scenario 5, Distributed Energy Future, it is assumed that one third (33%) of applicable businesses have installed rooftop PV by 2040.

3.2.3 *Electric Vehicles*

This load driver includes two main components: LD EVs, and MHD EVs.

3.2.3.1 Light Duty EVs

The principal global assumptions used to model LD EVs are:

- **Turnover.** Guidehouse assumed that approximately 7.3% of light-duty vehicles turn over each year. This implies an expected useful life (EUL) for a light duty vehicle of approximately 13.5 years, and is derived from the total of new light duty vehicle sales in British Columbia in 2018[74] as a fraction of total light duty vehicle registrations in 2018.[75]

- **Vehicle Growth.** Guidehouse assumed an average of 1.43 light duty vehicles per household[76], held constant across the projection period, and further assumed a 1:1 ratio of residential consumers to households (FortisBC customers and the residential customers of wholesale customers).

- **Sales Scaling.** Each scenario defines a terminal year penetration value as the percentage of all LDV sales that are EVs. Annual sales numbers are set as some percentage of this value in each

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[74] Statistics Canada, *New motor vehicle sales*, Table 20-10-0001-01 (formerly CANSIM 079—003), Geography: British Columbia and Territories, Reference Period: January 2018 through December 2018
https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=2010000101#timeframe

[75] Statistics Canada, *Vehicle registrations, by type of vehicle*, 23-10-0067-01 (formerly CANSIM 405-0004), Geography: British Columbia and Territories, Year: 2018, Vehicles weighing less than 4,500 kilograms.
https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310006701&pickMembers%5B0%5D=1.11

[76] Natural Resources Canada, *Canadian Vehicle Survey 2009 Summary Report*, Figure 10
https://oee.nrcan.gc.ca/publications/statistics/cvs09/pdf/cvs09.pdf

year to capture escalation. In every scenario, it is assumed that by: 2025, 10% of the final penetration sales rate is achieved; 2030, 30% of the final penetration sales rate is achieved; and, 2040, 100% of the final penetration sales rate is achieved. So, for example this means that in Scenario 5 (Distributed Energy Future) where the final penetration is assumed to be 90% of LDV sales in 2040 are EVs: in 2025, 9% of LDV sales are EVs, in 2030, 27% of LDV sales are EVs etc.

The assumed percentage of LDV sales in 2040 that are EVs varies by scenario. Several scenarios are aligned with British Columbia's Zero Emission Vehicle (ZEV) Act, that mandates a transformation of LDV sales to match the pattern referenced above (2025 – 10%, 2030 – 30%, and 2040 – 100%). No incremental EV sales (beyond those embedded in the business-as-usual forecast) are assumed for Scenario 2 (Lower Bound). In the remaining scenarios:

- For Scenario 1 (Upper Bound), it is assumed that 100% of new light-duty vehicle sales in 2040 will be EVs.
- For Scenario 3 (Deep Electrification), it is also assumed that 100% of new light-duty vehicle sales in 2040 will be EVs.
- For Scenario 4 (Diversified Energy Pathway), it is assumed that 95% of new light-duty vehicle sales in 2040 will be EVs.
- For Scenario 5 (Distributed Energy Future), it is assumed that 90% of new light-duty vehicle sales in 2040 will be EVs.

3.2.3.2 Medium/Heavy Duty EVs

The principal global assumptions used to model MHD EVs are:

- **British Columbia Stock.** Guidehouse derived the annual sales of RtB vehicles, combination tractors and buses directly from the Pathway Analysis previously conducted by Guidehouse for FortisBC.[77] Using the projected EV sales and the annual market share of EVs in that work, the total sales value for all (electric and internal combustion engine) MHD vehicles (in the three categories addressed in this study) was derived for each year of the projection period.
- **Scaling to FortisBC.** The total sales in British Columbia were scaled to the FortisBC electric service territory using the ratio of commercial floorspace in the FortisBC service territory to the total commercial floorspace in British Columbia[78] – approximately 10%.

The assumed percentage of MHDV sales varies by scenario. Note that the ZEV Act does not mandate sales of MHD EVs. No incremental EV sales (beyond those embedded in the business-as-usual forecast) are assumed for Scenario 2 (Lower Bound). In the remaining scenarios:

- For Scenario 1 (Upper Bound), it is assumed that 85% of new medium/heavy duty sales in 2040 will be EVs.

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[77] Guidehouse Canada on behalf of FortisBC, *Pathways for British Columbia to Achieve its Greenhouse Gas Reduction Goals*, 2020 Publication forthcoming.

[78] Navigant (n/k/a Guidehouse Canada), *British Columbia Conservation Potential Review*, January 2018
Part of this document may be found here: https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/180802_fbc_2019-2022_dsm_expenditures_application_ff.pdf

- For Scenario 3 (Deep Electrification), it is assumed that 60% of new medium/heavy-duty vehicle sales in 2040 will be EVs.

- For Scenario 4 (Diversified Energy Pathway), it is assumed that 20% of new medium/heavy-duty vehicle sales in 2040 will be EVs.

- For Scenario 5 (Distributed Energy Future), it is assumed that 10% of new medium/heavy-duty vehicle sales in 2040 will be EVs.

3.2.4 *Fuel Switching – Gas to Electricity*

As noted above in Section 1.4, this load driver takes advantage of the sophisticated modeling deployed in the June 2019 update of the Conservation Potential Review intended to address electrification potential.[79] That work estimated that the technical potential for residential electrification was a reduction (by 2035) in annual natural gas consumption (for the FortisBC electric service territory) of approximately 4.4 PJ and a corresponding increase in electricity consumption of just over 1 TWh per year.[80] The technical potential is the potential impact of converting all residential natural gas technologies and end-uses considered to electricity, where it is technically feasible to do so.

For modeling this load driver, Guidehouse has, for each scenario, assumed a different percent achievement of the 2035 technical potential, and then held that constant for the remaining four years of the projection period. No FS – G2E penetration was assumed for Scenario 2 (Lower Bound), Scenario 4 (Diversified Energy Pathway) or Scenario 5 (Distributed Energy Future). In the remaining scenarios:

- For Scenario 1 (Upper Bound), it is assumed that FortisBC will achieve 30% of the 2035 technical potential and maintain that level of achievement through 2040.

- For Scenario 3 (Deep Electrification), it is assumed that FortisBC will achieve 15% of the 2035 technical potential and maintain that level of achievement through 2040.

3.2.5 *Fuel Switching – Electricity to Gas*

The principal global assumptions used to model FS – E2G are:

- **Existing Electric Heat.**
    - *Space Heating.* The FortisBC residential end-use study[81] (REUS) indicates that approximately 36% of customers currently use electricity as their primary space-heating fuel. Guidehouse assumed that indirect customers (the residential customers of FortisBC's wholesale customers) were distributed by heating fuel in the same way, delivering approximately 53,000 residential consumers using electricity as their primary space-heating fuel in 2020, and nearly 68,000 residential consumers in 2040.
    - *Water Heating.* The same study as cited above indicates that approximately 49% of customers currently use electricity as their primary water-heating fuel. As with space-

[79] Navigant (n/k/a Guidehouse Canada) prepared for FortisBC Energy Inc. and FortisBC Inc., *British Columbia Conservation Potential Review: Total Thermal Demand, Fuel Switching Potential, and Vehicle Electrification Potential*, June 2019

[80] The CPR assumes that customers will adopt highly efficient technologies so that in addition to a conversion of end-uses from gas to electricity, some energy efficiency savings are realized.

[81] Sampson Research, prepared for FortisBC Inc., *FBC 2017 Residential End Use Study*, May 2019, see Table 234.

heating, Guidehouse, as with space-heating, assumed this proportion would be constant across the projection period.

- **Access to Gas.** Guidehouse assumed that one-fifth of those customers with electric space-or water heat cannot switch to natural gas as a result of a lack of proximity to the required infrastructure. This is an assumption carried over from the 2016 scenario analysis[82], and is based on data provided by FortisBC in support of that analysis that found that 24% of residential customer premises are more than 50 metres from a gas main. Guidehouse scaled this down to 20% on the assumption that population growth will be more concentrated in denser or urban regions where residences are near to gas mains.

The assumed final percentage of residential customers that convert their primary space- or water-heating equipment from electricity to natural gas varies by scenario. In Scenario 1 (Upper Bound), Scenario 3 (Deep Electrification), and Scenario 4 (Diversified Energy Pathway) no electric to gas fuel-switching was assumed. In the remaining scenarios:

- For Scenario 2 (Lower Bound), it is assumed that 50% of all residential customers that can convert from electric space- and water-heat to natural gas, will have done so by 2040.

- For Scenario 5 (Distributed Energy future), it is also assumed that 35% of all residential customers that can convert from electric space- and water-heat to natural gas, will have done so by 2040.

3.2.6 *Climate Change*

Most of the key assumptions for the Climate Change load driver are either embedded in the unit impact calculation (see Section 1.6) or else specific to the scenario. The principal global assumption applied here is that growth in temperature changes toward the temperature change assumed for the terminal year (2040) of the projection is assumed to be linear.

For each scenario, five parameters for the load driver may vary:

- The average change in temperature on all days of the year.
- The average change in temperature on the X coldest days of the year.
- The number, X, of coldest days to which the assumption immediately above is applied.
- The average change in temperature on the Z hottest days of the year.
- The number, Z, of hottest days to which the assumption immediately above is applied.

The Climate Change load driver is unique in that it was applied (with varying parameter assumptions) across all five load scenarios. The key assumptions applied to each scenario are:

- Scenario 1 (Upper Bound): The temperature on the ten average hottest days of the year increases by 2.1 degrees Celsius and the temperature on the ten average coldest days of the year decreases by 6.2 degrees Celsius. In this scenario, this driver increases both energy and peak winter demand.

[82] Navigant (n/k/a Guidehouse) prepared for FortisBC, *Load Scenario Assessment: Exploring Structural Change in Electricity Consumption Drivers*, July 2016

- Scenario 2 (Lower Bound): The average temperature on all days of the year increases by 2 degrees Celsius. In this scenario, this driver decreases both energy and peak winter demand.

- All other scenarios: The average temperature on all days of the year increases by 2 degrees Celsius. In these scenarios, this driver decreases both energy and peak winter demand. The temperature on the ten average hottest days of the year increases by 0.7 degrees Celsius, and the temperature on the ten average coldest days of the year decreases by 2.6 degrees Celsius. In these scenarios, this driver increases both energy and peak winter demand.[83]

3.2.7 *Large Load Sector Transformation*

For the two types of customer considered for this load driver, the unit load impacts were estimated as a kWh/per square foot of floorspace intensity unit. This requires the scenario-specific assumptions to define the assumed growth in floorspace for these two sectors. The scenario-specific assumptions were informed by Guidehouse's estimates of current existing, or 100% confidence connection request-driven, floorspace in these two sub-sectors. These estimates of floorspace were derived by Guidehouse by applying the estimated intensity (see Section 1.7) to existing demand and 100% confidence connection requests for these types of customers, provided by FortisBC.

Assuming the accuracy of the energy intensities and load profiles derived in the unit impact estimation, Guidehouse estimates that there are currently approximately 200,000 square feet of data centre floorspace, and (based on existing and 100% confidence connection requests) that by 2021 there will be approximately one million square feet of commercial floorspace dedicated to cannabis production. Note that the impacts presented below are derived only from the *incremental* floorspace assumed for the modeling (i.e., the results do not include the impacts of the 100% confidence connection requests that have not yet connected).

No incremental LLST was assumed for Scenario 2 (Lower Bound) or Scenario 5 (Distributed Energy Future). The key assumptions applied to the remaining three scenarios are:

- Scenario 1 (Upper Bound):
    - *Data Centres.* An additional 700,000 square feet of data centre floorspace by 2040.
    - *Cannabis.* An additional 3 million square feet of cannabis production floorspace by 2040.
- Scenario 3 (Deep Electrification)
    - *Data Centres.* An additional 150,000 square feet of data centre floorspace by 2040
    - *Cannabis.* An additional 250,000 square feet of cannabis production floorspace by 2040.
- Scenario 4 (Diversified Energy Pathway)
    - *Data Centres.* An additional 380,000 square feet of data centre floorspace by 2040.
    - *Cannabis.* An additional 370,000 square feet of cannabis production floorspace by 2040

3.2.8 *Hydrogen Production*

The key global assumption for modeling this load driver is that Guidehouse has assumed (as identified previously in Section 1.8) a substantial improvement in the production efficiency of green hydrogen over

[83] Note that the average two degree change is added to all days, even extreme days. This yields a net average increase of 2.7 degrees on the hottest days, and a net average decrease in temperature of 0.6 degrees on the coldest days.

time. Growing from a production efficiency of 73% (as per a FortisBC hydrogen pilot) to a production efficiency of 95% in 2040.

In establishing the assumed final penetration values for this load driver, Guidehouse determined that the upper bound amount of hydrogen produced should not exceed approximately 5% of the natural gas energy consumption forecast for the FortisBC electric service territory (sometimes referred to as the shared service territory). To obtain an approximate estimate of total gas consumption in the shared service territory by the end of 2040, Guidehouse identified that:

- The total estimated natural gas use in the shared service territory in 2018 was approximately 40 PJ[84] per year;
- The 2017 long-term gas resource plan (LTGRP) produced by FortisBC Energy Inc. forecast growth in gas consumption of approximately 43% between 2018 and 2036.[85]

Taken together, these suggest natural gas consumption in the shared service territory of approximately 57 PJ per year by 2036. It is based on this value and the upper limit identified above that Guidehouse and FortisBC determined that scenario specific penetration assumptions.

No hydrogen production was assumed in Scenario 2 (Lower Bound). In the remaining scenarios:

- Scenario 1 (Upper Bound), it was assumed that 3 PJ of hydrogen would be produced per year by the end of 2040.
- Scenario 3 (Deep Electrification), it was assumed that 0.7 PJ of hydrogen would be produced per year by the end of 2040.
- Scenario 4 (Diversified Energy Pathway), it was assumed that 1.8 PJ of hydrogen would be produced per year by the end of 2040
- Scenario 5 (Distributed Energy Future), it was assumed, as with Scenario 3, that 0.7 PJ of hydrogen would be produced per year by the end of 2040.

3.2.9 *Carbon Capture and Storage*

The assumed penetration rates for the CCS driver are derived, and intended to be consistent with, the Pathways[86] analysis previously conducted by Guidehouse for FortisBC at the provincial level. In this previous analysis, for the "Diversified Pathway" (with which this study's Scenario 4, the Diversified Energy Pathway is intended to align), Guidehouse assumed that by 2050 provincial CCS capacity deliver reductions of 2.4 MT of provincial industrial carbon emissions per year. This assumption in the Pathways report builds on the CleanBC[87] report and assumes a quadrupling in capacity over a 20 year period (from 2030 to 2050).

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[84] FortisBC, *FortisBC Community Engagement Workshop: Natural gas & electric long term resource*

[85] Correspondence with FortisBC staff, February, 2020.

[86] Guidehouse Canada on behalf of FortisBC, *Pathways for British Columbia to Achieve its Greenhouse Gas Reduction Goals*, 2020 Publication forthcoming.

[87] Government of British Columbia, *CleanBC: Our Nature, Our Power, Our Future*, 2019 https://blog.gov.bc.ca/app/uploads/sites/436/2019/02/CleanBC_Full_Report_Updated_Mar2019.pdf

Guidehouse selected its assumptions for CCS in the FortisBC service area to align with these Pathways assumptions. Specifically, it assumed that FortisBC's electric service territory would account for approximately 10% of all provincial CCS deployment.[88]

No CCS was assumed to be deployed in the FortisBC electric service territory in Scenario 2 (Lower Bound). In the other scenarios:

- Scenario 1 (Upper Bound): it was assumed that CCS would deliver GHG emissions reductions of approximately 240 kT per year by 2040. This is one and a half times the ultimate penetration assumed for Scenario 4 (Diversified Energy Pathway), a value selected to be aligned with the Pathways analysis.

- For all other scenarios (3, 4, and 5): it was assumed that CCS would deliver GHG emissions reductions of approximately 180 kT per year by 2040. This is the mid-point between the assumed GHG reductions implied for the FortisBC electric service territory by 2050 in the Pathways analysis for the Electrification and Diversified pathways and the assumed 600 kT implied achievement implied for the FortisBC electric service territory by 2030 in the CleanBC report.

3.3 Scenario Results

This section of Chapter 3 presents the impacts of each scenario. All values presented below should be understood to be impacts relative to the business-as-usual (and not the reference[89]) forecast developed by FortisBC's planning group. That is, all values presented here are incremental to the energy consumption and peak demand (January weekdays, 5pm to 6pm) projected under the business-as-usual projection.

This section is divided into six sub-sections:

1. **Summary Impacts – Across Scenarios.** Presents a high-level comparative summary of the scenario impacts across scenarios for both energy and winter demand.

2. **Scenario 1 – Upper Bound Impacts.** Presents annual impacts, energy and demand, by driver and year for this scenario as well as some of the interim impacts (e.g., assumed proportion of LDV stock that converts to electricity).

3. **Scenario 2 – Lower Bound Impacts.** Presents annual impacts, energy and demand, by driver and year for this scenario, as well as some of the interim impacts (e.g., assumed proportion of residential households that acquire PV and storage).

4. **Scenario 3 – Deep Electrification Impacts.** Presents annual impacts, energy and demand, by driver and year for this scenario.

5. **Scenario 4 – Diversified Energy Pathway Impacts.** Presents annual impacts, energy and demand, by driver and year for this scenario.

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[88] This assumption is derived from the observation that FortisBC's shared service territory consumed approximately 40 PJ of natural gas in 2018, while the province as a whole, per the Canadian Energy Regulator's Canada's Energy Futures 2019 database, consumed approximately 396 PJ of natural gas in the same year.

[89] For this iteration of the LTERP, the reference forecast developed by FortisBC includes some assumed impacts of growth in EV penetration as a result of the Zero Emissions Vehicle Act. Load scenarios are therefore compared to the business as usual forecast to avoid any double-counting of effects.

6. **Scenario 5 – Distributed Energy Future Impacts.** Presents annual impacts, energy and demand, by driver and year for this scenario.

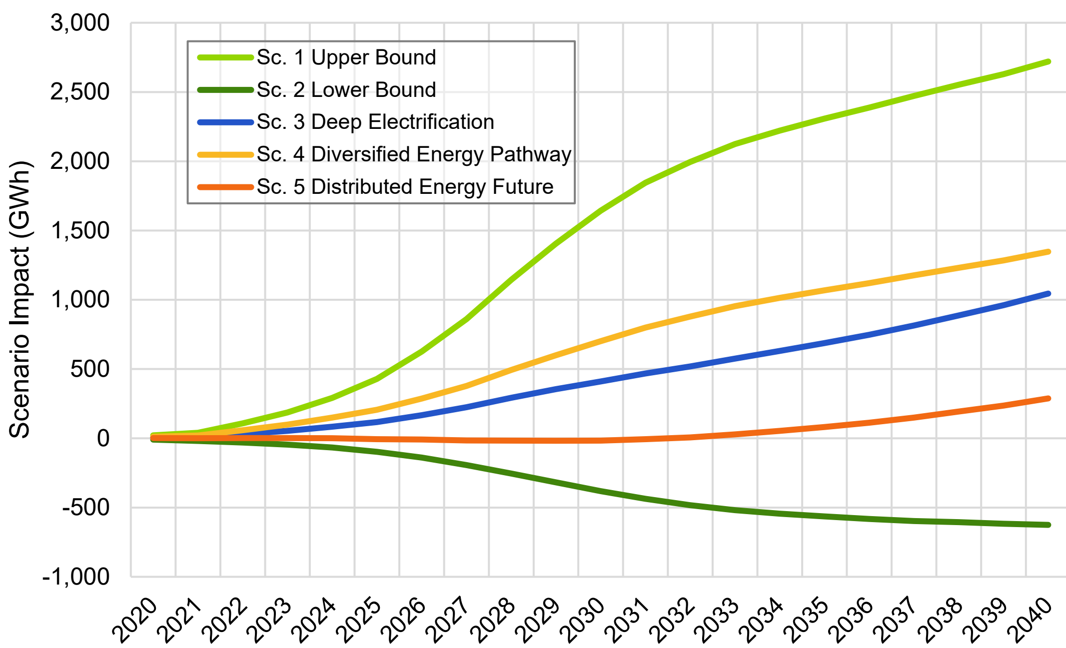
3.3.1 *Summary Impacts – Across Scenarios*

Figure 22, below provides a graphical summary of the impacts of each of the five scenarios across the entire projection period. As may be seen below the combined incremental impact of the Scenario 1 (Upper Bound) load drivers is considerable, with 2040 annual energy consumption projected to increase by more than 2,700 GWh, an increase of approximately 62% when compared to the business-as-usual forecast (4,389 GWh) for that year[90].

The S-shaped profile of the increase in energy consumption in Scenario 1 (Upper Bound) is largely driven by uptake of the HP and FS G2E load drivers, which are assumed to follow a standard new technology diffusion curve.[91] Other scenarios, reflecting less extreme sets of assumptions tend to follow either a flatter S-shape or else a curve that is more approximately linear, depending on the mix of assumed penetrations.

One thing that is immediately clear in examining this plot is that the two extreme scenarios – the Upper Bound and Lower Bound – do not deliver a symmetrical set of impacts. This is due to the load drivers assumed for each one: not only are five of the nine load drivers ones that increase load, but they also tend to be drivers with (relatively) high unit impacts and assumed levels of penetration; in particular EVs, HP, and LLST.

Figure 22: Summary of Annual Energy Impacts Across Scenarios



[90] Per FortisBC Business As Usual Forecast developed in May 2020.

[91] Where not specifically mentioned in Section 3.2, load drivers are typically assumed to ramp up to their final penetration level along an S-shaped trajectory that captures the gradual increase in penetration during the early stages of the technology adoption cycle, followed by adoption growing at an increasing rate (reflecting changes in costs as economies of scale are realized and the inertial effects of word-of-mouth and normalization) and finishing with a flattening off as the technology begins to reach the point of market saturation.

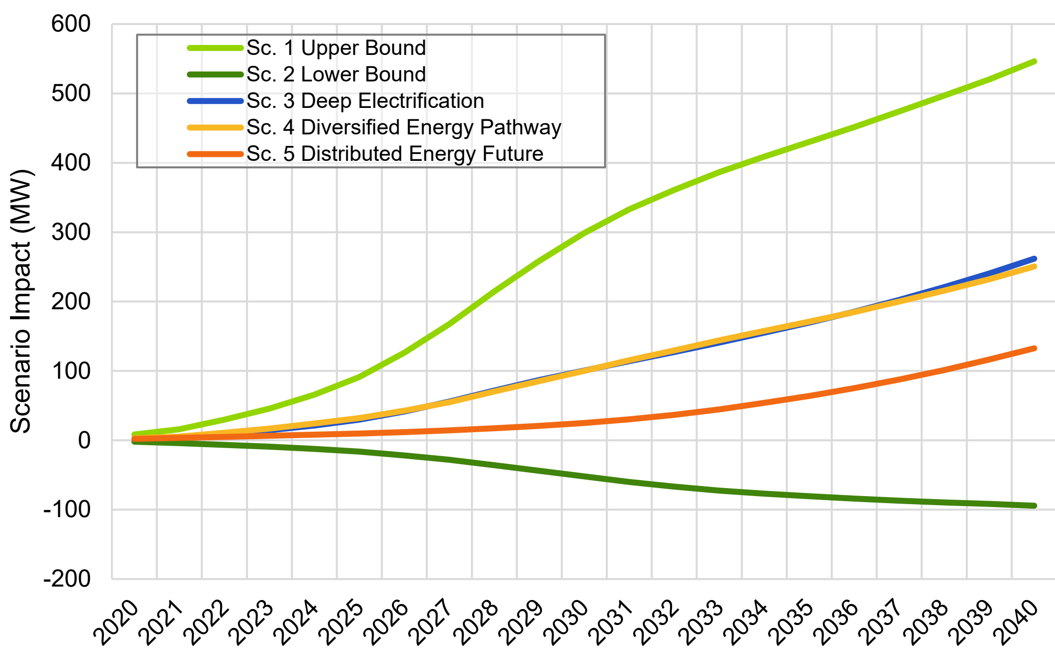
Table 12, below provides a numerical summary of the impacts of each of the five scenarios in the terminal year of the projection period and compares these against the business-as-usual (BAU) forecast energy consumption in that year (4,389 GWh). For example, as noted above Scenario 1 results in an increase in annual energy consumption of 62%, whereas Scenario 2 results in a decrease of 14%. It is only the lower bound scenario that delivers a decrease relative to the business-as-usual forecast. This is in large part due to the load drivers selected, which tend to focus on technologies and factors intended to support electrification (EVs, FS), other forms of decarbonization (HP, CCS).

Table 12. Summary of 2040 Energy Impacts by Scenario

	Sc. 1 Upper Bound	Sc. 2 Lower Bound	Sc. 3 Deep Electrification	Sc. 4 Diversified Energy Pathway	Sc. 5 Distributed Energy Future
GWh	2,720	-625	1,045	1,347	288
%Δ From BAU	62%	-14%	24%	31%	7%

Figure 23, below shows the winter peak demand impacts by year for each scenario. Note that there is a difference in the order of the scenarios in these two plots – the energy impacts of Scenario 4 (Diversified Energy Pathway) are higher than those of Scenario 3 (Deep Electrification), whereas the two scenarios deliver approximately the same winter peak demand impact.

Figure 23. Summary of January Peak Demand Impacts by Scenario



This difference in relative impacts is a function of the load drivers included in these scenarios and of their load shaped. Most importantly, Scenario 3 (Deep Electrification) includes substantial deployment of EVs, IPSS and fuel switching, whereas Scenario 4 (Diversified Energy Pathway),while it also includes many of these drivers, does *not* include residential or commercial IPSS (which reduce energy increases). Scenario 4 also includes considerably more HP than Scenario 3, but no G2E fuel-switching.

The dynamics unfolding are these: in Scenario 3 (Deep Electrification) energy impacts from electrification load drivers (EVs, FS G2E) are partially offset by the IPSS distributed generation, whereas the peak demand impacts are offset only by IPSS-COM, and not IPSS-RES. Recall that the assumed residential use pattern for IPSS (using up all storage as soon as possible to offset household requirements as PV output falls) results in that load driver making *no* contribution to peak demand reduction in January. Likewise, FS – G2E is a highly peak-coincident load driver – its contribution to demand increases is concentrated in the coldest parts of the year – just when the FortisBC system currently experiences its system peak.

Table 13, below provides a numerical comparison of the January peak demand impacts across the five scenarios in the terminal year of the forecast and shows each scenario's impact relative to the business-as-usual forecast of January peak demand (891 MW) in that year. The most significant differences in the relative change to the business-as-usual forecast (when compared with the energy impacts) are for Scenario 3 (Deep Electrification) and Scenario 5 (Distributed Energy Future). These differences are principally due to difference in impact for IPSS across the two metrics, as well as the EV and FS – G2E drivers (Scenario 3 only).

Table 13. Summary of 2040 Peak Demand Impacts by Scenario

	Sc. 1 Upper Bound	Sc. 2 Lower Bound	Sc. 3 Deep Electrification	Sc. 4 Diversified Energy Pathway	Sc. 5 Distributed Energy Future
MW	546	-94	262	251	133
%Δ From BAU	61%	-11%	29%	28%	15%

3.3.2 *Scenario 1 – Upper Bound Impacts*

The Upper Bound scenario is not really intended to reflect a single coherent narrative of a future possible world, but rather to understand the notional upper limit of increases that could be expected under the (highly improbable) confluence of load drivers that only increase load.

As seen in Figure 24 below, the largest contributor to the impacts in this scenario is the HP driver. In this scenario, the HP load driver is required to deliver 3 PJ of hydrogen per year by 2040.[92] Even given the high conversion efficiency[93] assumed to be achieved by 2040 this is still a considerable increase in overall service area energy requirements. In 2040, the impact from this load driver is approximately 880 GWh, a 20% increase in overall electric energy consumption compared to the business-as-usual scenario. This 3 PJ of hydrogen will offset approximately 5% of the projected FortisBC shared service territory natural gas needs by 2040.

[92] For context, the business-as-usual forecast of 4,389 GWh of consumption in 2040 is slightly less than 16 PJ.

[93] The distinctive shape here, where energy impacts decline slightly in later years, is due to the assumption of increasing efficiency in production which, in the final years of the projection periods, more than offsets the incremental hydrogen production requirements imposed by the scenario assumptions.

Figure 24. Scenario 1 (Upper Bound) Energy Impact

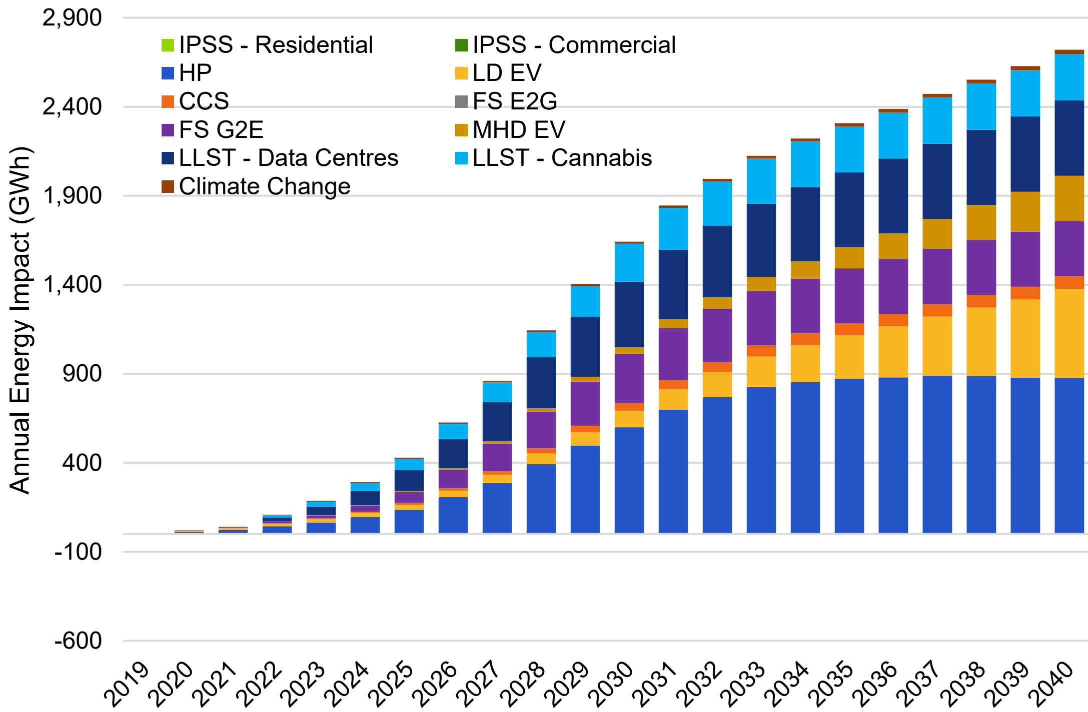


Figure 25, below, shows the distribution of energy impacts by month of year in the terminal projection year, 2040. The net total energy impact in each month is shown as a data label above each set of stacked columns.

Figure 25. Scenario 1 Energy Impact by Month (2040)

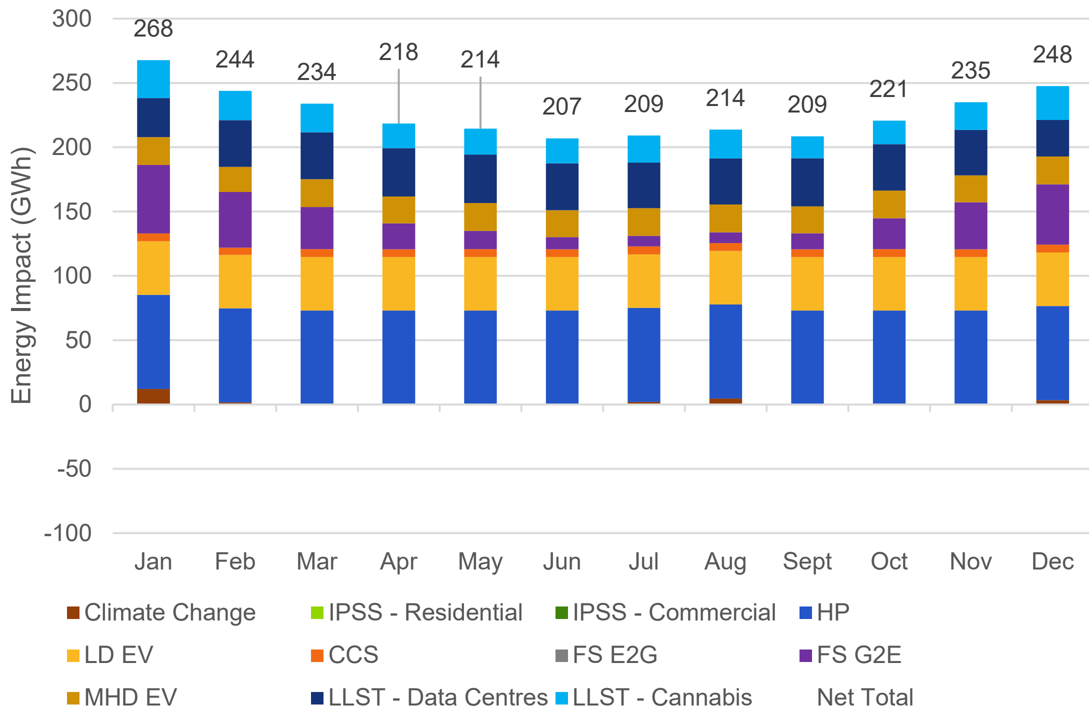


Table 14, below, shows the absolute and relative contribution to 2040 energy impacts of each of the load drivers (e.g., HP impacts in 2040 are 877 GWh, or 32% of the total impact). The greatest impacts on energy requirements are the production of hydrogen, the combined impacts of LD and MHD EVs, and the combined impacts of substantial data centre and cannabis production expansion.

Table 14: Relative Contribution of Load Drivers to Annual Energy

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
GWh	0	0	877	500	72	0	310	254	424	260	24
%	0%	0%	32%	18%	3%	0%	11%	9%	16%	10%	1%

Figure 26, below shows the contribution to scenario winter demand impacts of each of the scenario load drivers. As may clearly be seen in contrasting this with Figure 24 (and in the contrast between Table 15 below with Table 14, above) the relative contributions by the load drivers shift considerably when considering this different metric. Where in the case of energy HP and LLST were some of the most significant contributors, the flat (or non-coincident) load profiles of those drivers results in peak demand impacts being most strongly affected by EVs (in particular LD EVs). Naturally the relative contribution of drivers that are more winter-peak coincident (CC, FS G2E) is also more significant for demand than for energy.

Figure 26. Scenario 1 (Upper Bound) Winter Demand Impact

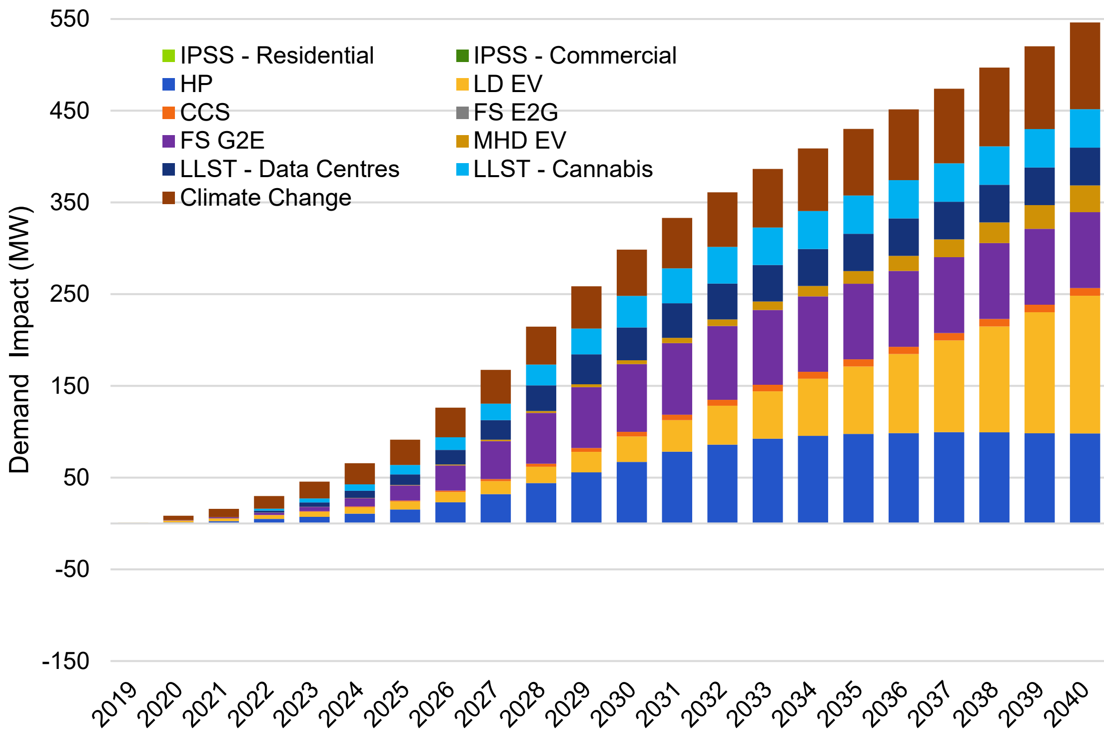


Figure 27, below, shows the average demand[94] impact by month of year in the terminal projection year, 2040. The net demand impact in each month is shown as a data label above each set of stacked columns.

[94] The average impact on demand on non-holiday weekdays between 5pm and 6pm PST.

Figure 27. Scenario 1 Demand Impact by Month (2040)

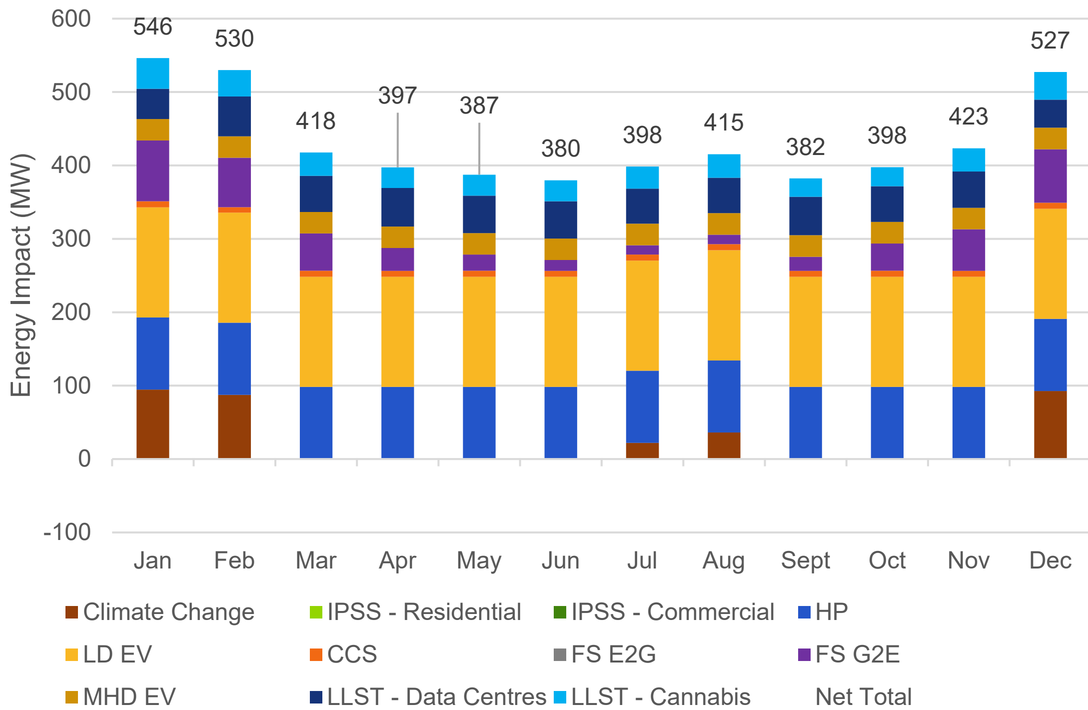


Table 15, below shows the absolute and relative contribution of each load driver to winter peak demand in Scenario 1.

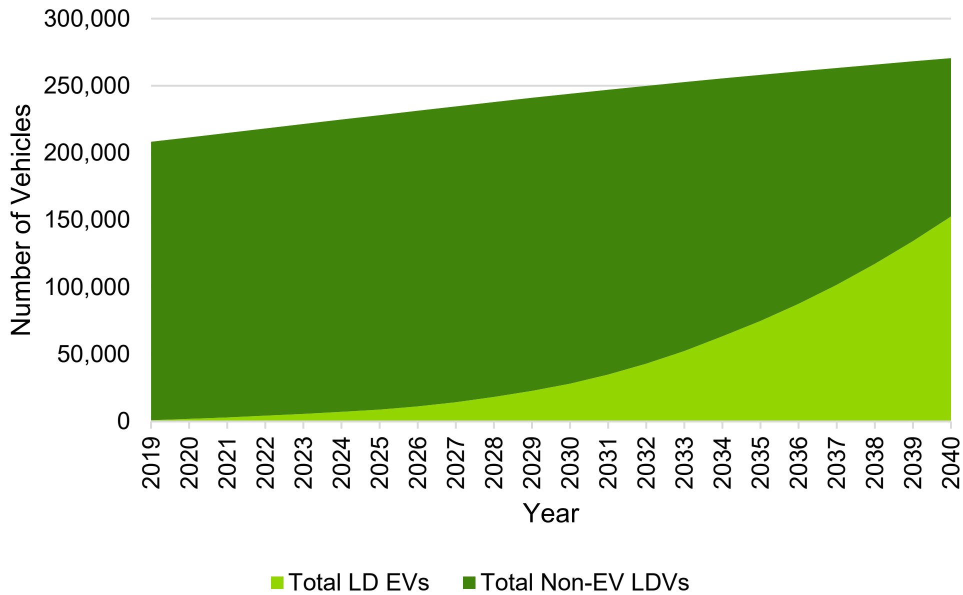
Table 15: Relative Contribution of Load Drivers to Winter Demand

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	0	98	150	8	0	83	29	41	42	95
%	0%	0%	18%	27%	2%	0%	15%	5%	8%	8%	17%

To help understand the factors driving the magnitude of some of these impacts, it may be helpful to observe the penetration of most significant driver of Scenario 1 peak demand over time - EVs. EVs – LD EVs and MHD EVs – together account for approximately one-third (32%) of the Scenario 1 peak demand impact.

Figure 28 shows how the stock of LDVs in the FortisBC service territory (driven by direct and indirect customers) changes over time. The dark green area represents non-EV LDVs, and the light green area represents EVs. Even though all LDVs *sold* in 2040 are EVs, only approximately 60% of LDVs on the road in that year are EVs. This underlines the point that the distribution of total vehicle stock lags the distribution of total vehicle sales. How far of a lag depends on the expected useful life (EUL) assumed for vehicles – the rate at which old vehicles turn over. For this analysis, Guidehouse has, based on StatCan new vehicle sales and registration data, assumed an EUL of approximately 13 for LDVs – the reality may be that this understates turnover, particularly if incentives or subsidies are put in place intended to accelerate that turnover.

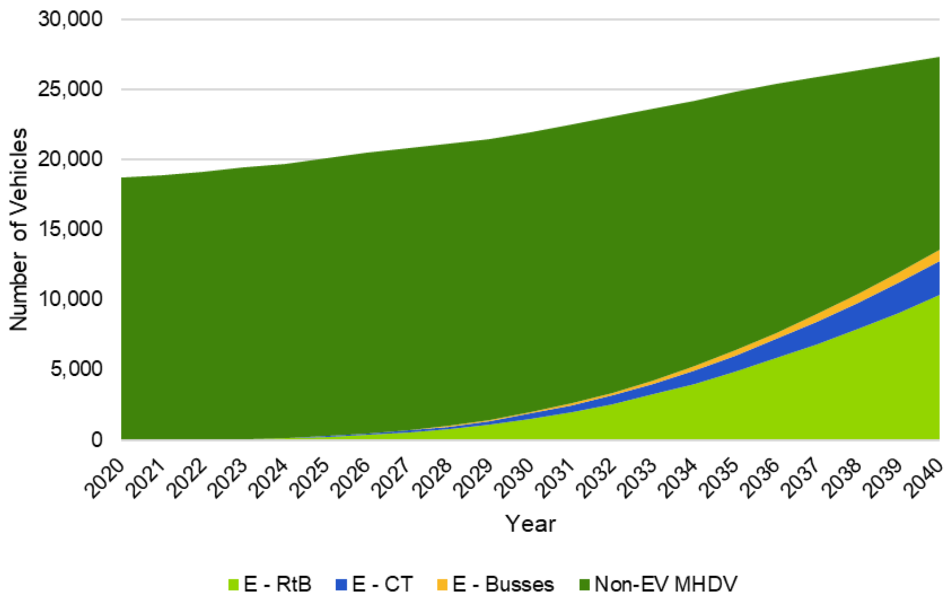
Figure 28. Scenario 1 LDV Stock Over Time



It may be seen however, from the figures above, that even the relatively conservative turnover assumption used for this analysis yields – when applied to the assumed distribution of sales – substantial peak demand impacts. The 2040 estimated peak demand impact of LD EVs in 2040 is an increase in total winter peak demand of 150 MW, or approximately 17% of the business-as-usual forecast. It is clear from this that FortisBC would be prudent to consider some mitigating action – perhaps in the form of targeted time-of-use rates or demand response – to shape charging behaviour and move it away from peak.

Figure 29, below shows an analogous plot, but of MHDV stock over time, split by type. As most MHDVs are return-to-base vehicles (RtB) it is these that dominate the uptake of MHD EVs. Given the assumptions applied in the model, in Scenario 1, approximately 50% of MHDV stock is made up of EVs by 2040. The order of magnitude difference in the number of these vehicles (in comparison with LDVs) however, and the charging profile that is less peak-coincident, meaning the impact on peak demand is much more modest for this vehicle type than for LD EVs.

Figure 29. Scenario 1 MHDV Stock Over Time



3.3.3 *Scenario 2 – Lower Bound Impacts*

As in the case of Scenario 1 (the Upper Bound), the Lower Bound scenario is not really intended to reflect a single coherent narrative of a future possible world, but rather to understand the notional upper limit of *decreases* that could be expected under the (highly improbable) confluence of load drivers that only decrease load.

As may be seen in Figure 30 below, although two load drivers dominate the Scenario 2 impacts (IPSS-RES and FS-E2G) the overall downward impact on energy consumption is relatively low (compared to the increase in energy observed in Scenario 1).

Figure 30. Scenario 2 (Lower Bound) Energy Impact

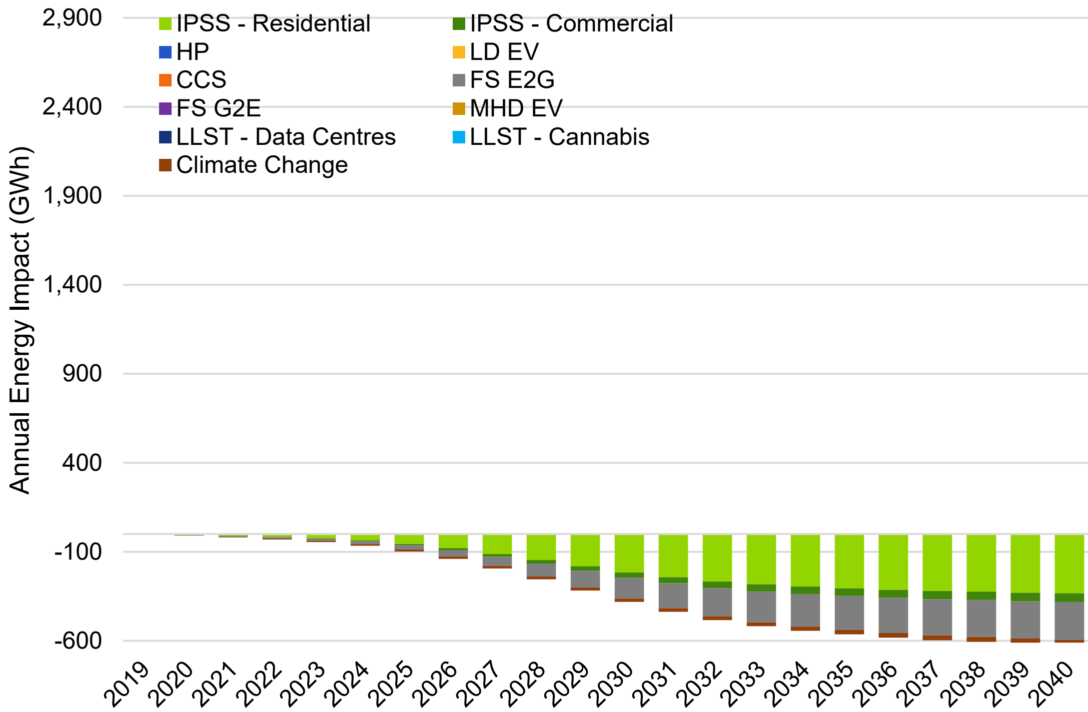


Figure 31, below, shows the distribution of energy impacts by month of year in the terminal projection year, 2040. The net total energy impact in each month is shown as a data label above each set of stacked columns.

Figure 31. Scenario 2 Energy Impact by Month (2040)

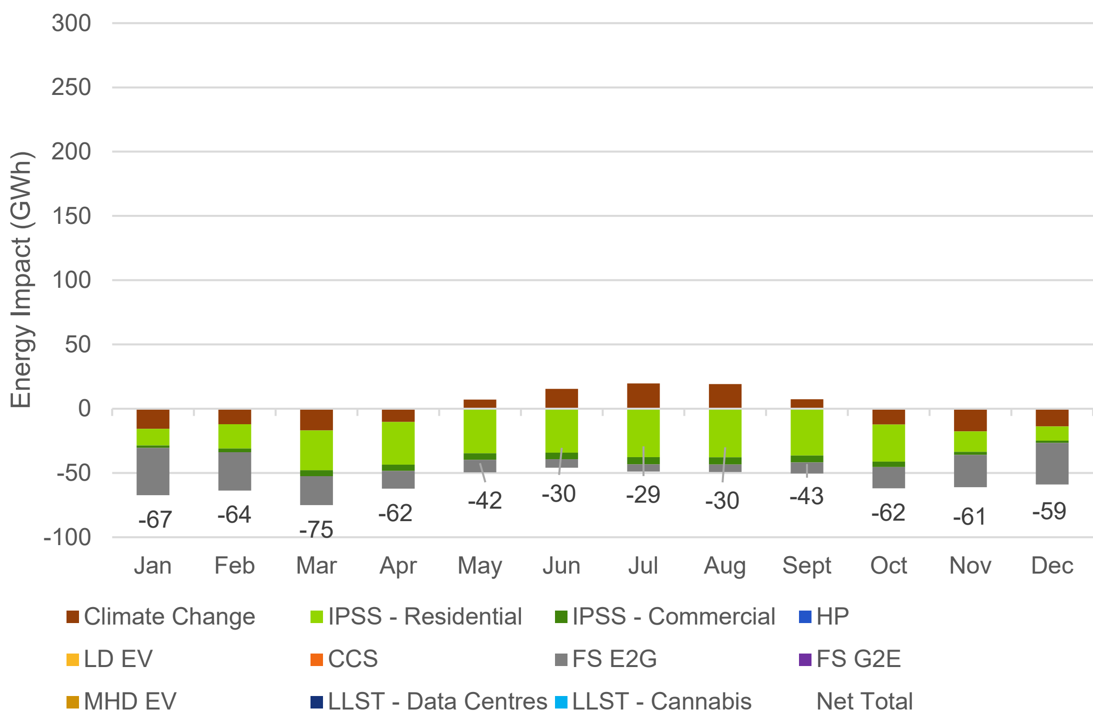


Table 16, below, shows the absolute and relative contribution to 2040 energy impacts of each of the load drivers. As noted previously, one important reason why Scenario 2 load decreases are so much lower than Scenario 1's increases (in absolute terms) is that far more of the nine load drivers examined in this study increase, rather than decrease, load. Another reason is that the two most significant contributors to load decreases have relatively limited applicability. Under the assumptions outlined in Chapter 2, only single family homes are considered as potential rooftop PV installations, and only those residential customers with both electric heat *and* in close proximity to a gas main are eligible to switch from electric to natural gas space- and water-heat.

Table 16: Relative Contribution of Load Drivers to Annual Energy

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
GWh	-333	-49	0	0	0	-213	0	0	0	0	-30
%	53%	8%	0%	0%	0%	34%	0%	0%	0%	0%	5%

As in Scenario 1, the relative contribution to terminal year impacts shifts considerably when peak demand, rather than energy, is considered. Whereas more than half of the energy impact in Scenario 2 is derived from IPSS-RES, it contributes nothing to the total peak demand impact. This is because, as noted in Chapter 2, stored energy is exhausted serving household energy requirements in the hours preceding the system peak. As would be expected, given the peak coincident nature of the load, FS – G2E dominates the load drivers impacting winter peak demand, being responsible – as may be seen in Table 17 below, nearly 60% of the scenario impact on winter demand in 2040.

Figure 32. Scenario 2 (Lower Bound) Winter Demand Impact

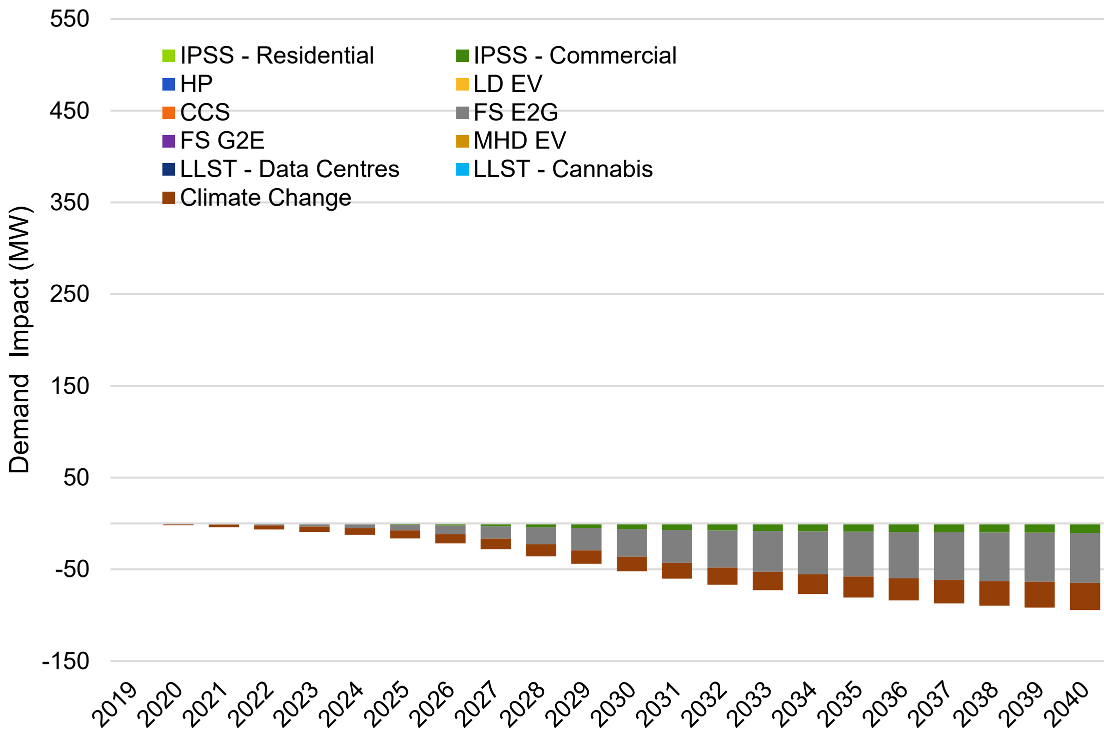


Figure 33, below, shows the average demand[95] impact by month of year in the terminal projection year, 2040. The net demand impact in each month is shown as a data label above each set of stacked columns.

[95] The average impact on demand on non-holiday weekdays between 5pm and 6pm PST.

Figure 33. Scenario 2 Demand Impact by Month (2040)

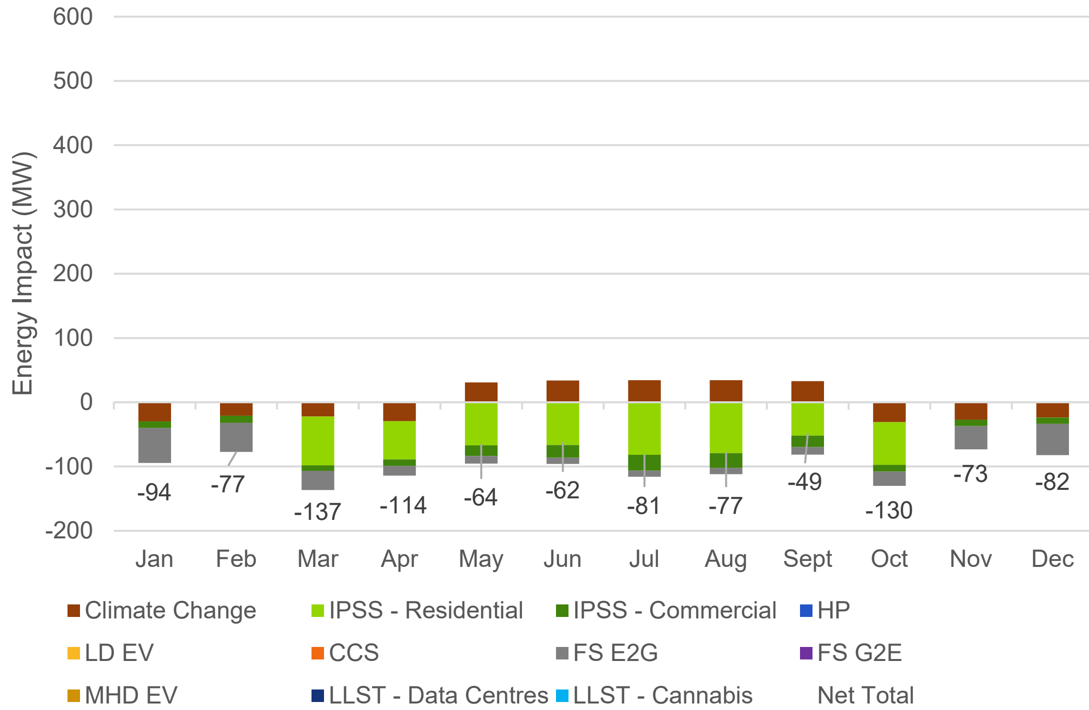


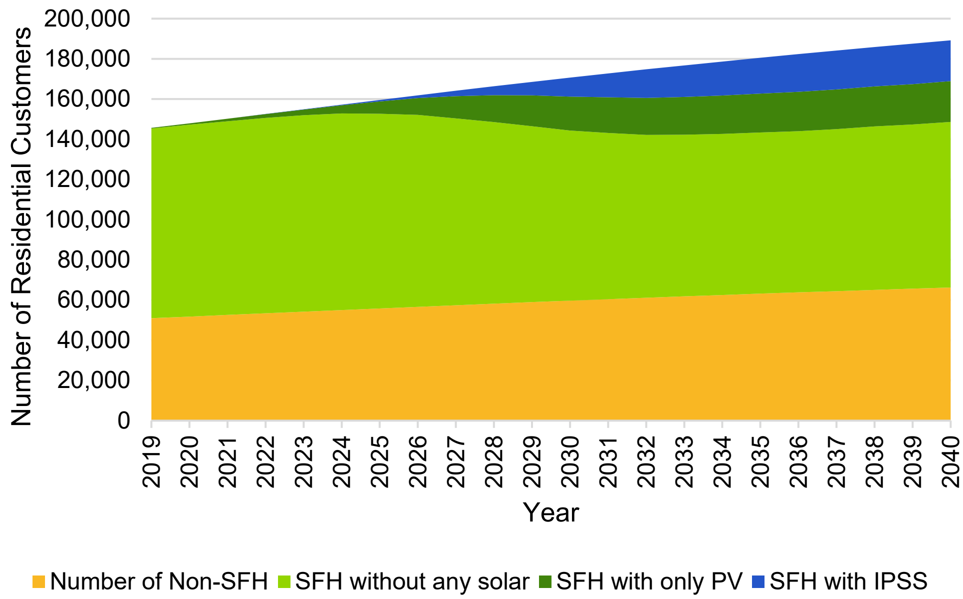
Table 19, below, shows the absolute and relative contribution to 2040 winter peak demand impacts of each of the load drivers.

Table 17: Relative Contribution of Load Drivers to Winter Demand

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	-10	0	0	0	-54	0	0	0	0	-30
%	0%	11%	0%	0%	0%	58%	0%	0%	0%	0%	31%

In considering these impacts, it is helpful to have a more concrete sense of the impact of some of these load drivers on the composition of FortisBC customers (both direct and indirect). Figure 34, below shows the count of residential consumers located within FortisBC's electric territory, distributed across four categories: non-single-family home residential consumers; single-family home residential consumers; single-family home consumers with PV; and single-family home residential consumers with PV and storage.

Figure 34. Scenario 2 IPSS-RES Customer Count Over Time



A similar distribution is shown in Figure 35, below, but for GS21 customers (and the indirect equivalent customers served by FortisBC's wholesale customers). Although (by construction) a higher proportion of GS21 customers are assumed to have acquired PV and storage than residential customers, it must be remembered that GS21 customers – despite accounting for 64% of commercial consumption – make up only 11% of FortisBC's commercial customers.

Figure 35. Scenario 2 IPSS-COM Customer Count Over Time

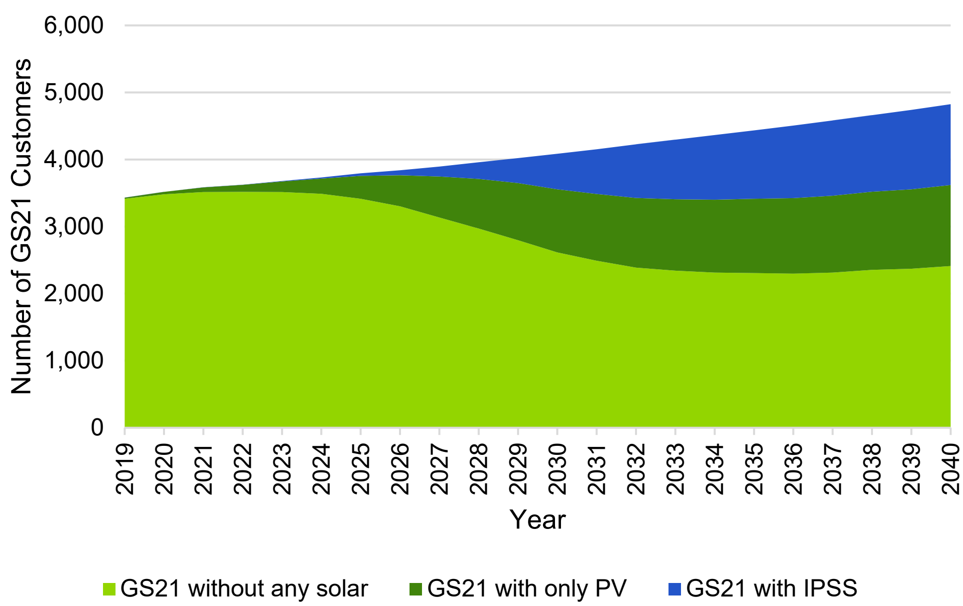


Figure 36, below displays a distribution like those above, but in this case shows the distribution of residential consumers by space-heating fuel, over time. Even with relatively aggressive assumptions regarding the proportion of the eligible population that does switch from electricity to gas (Scenario 2 assumes half of all customers that can switch, will switch), the fact is that the eligible population is constrained. The proportion of existing customers both with electric heat *and* that are reasonably close to natural gas distribution infrastructure is relatively small. Given the (currently) higher retail rate for electricity it should be expected that many of those customers that could switch may already have done so.

Figure 36. Scenario 2 Residential Customers by Space-Heating Fuel

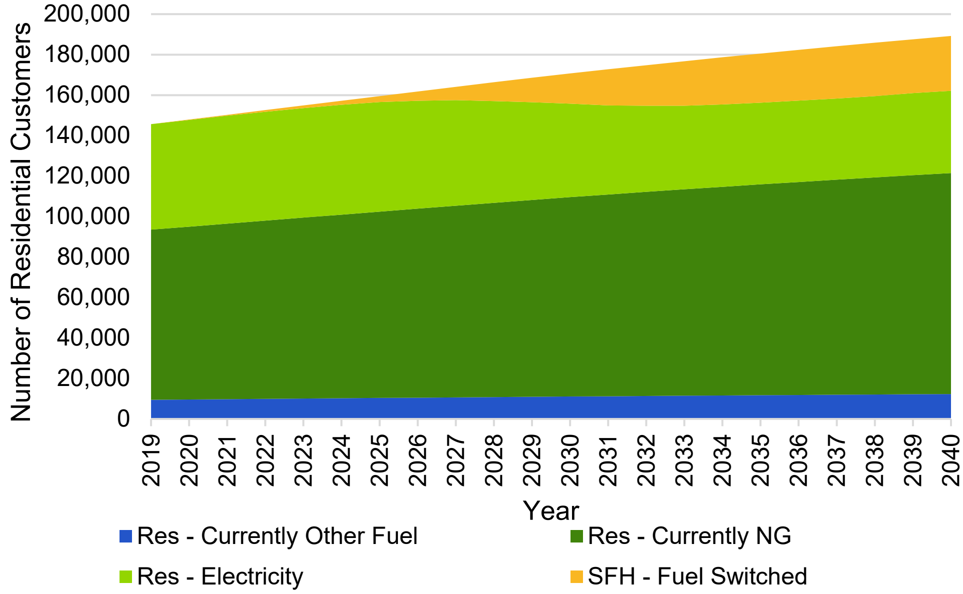
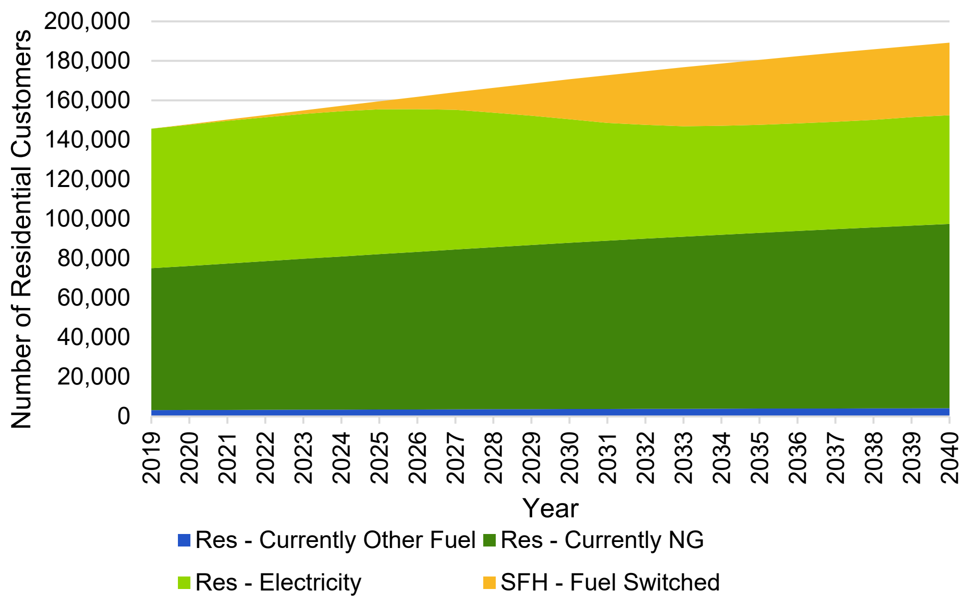


Figure 37, below, shows a similar distribution as above, but for water-heating.

Figure 37. Scenario 2 Residential Customers by Water-Heating Fuel



3.3.4 *Scenario 3 – Deep Electrification Impacts*

Scenario 3 imagines a future world with a focus on decarbonization via electrification, partially supported by an increase in distributed generation. With a focus on the electrification of space and water-heating, the societal requirements for HP and CCS are relatively lower than in some other scenarios. Although demand and energy consumption have both grown considerably, there is an incentive to improve the overall system load factor and so a modest increase in large loads (data centres, cannabis production) is observed, perhaps as a result of economic development rates.

Figure 38, below shows the energy impacts by driver and year. EVs deliver the largest impacts, though these are somewhat offset by IPSS, residential and commercial. Hydrogen production is quite significant, having the second largest impact on energy consumption after EVs.

Figure 38. Scenario 3 (Deep Electrification) Energy Impact

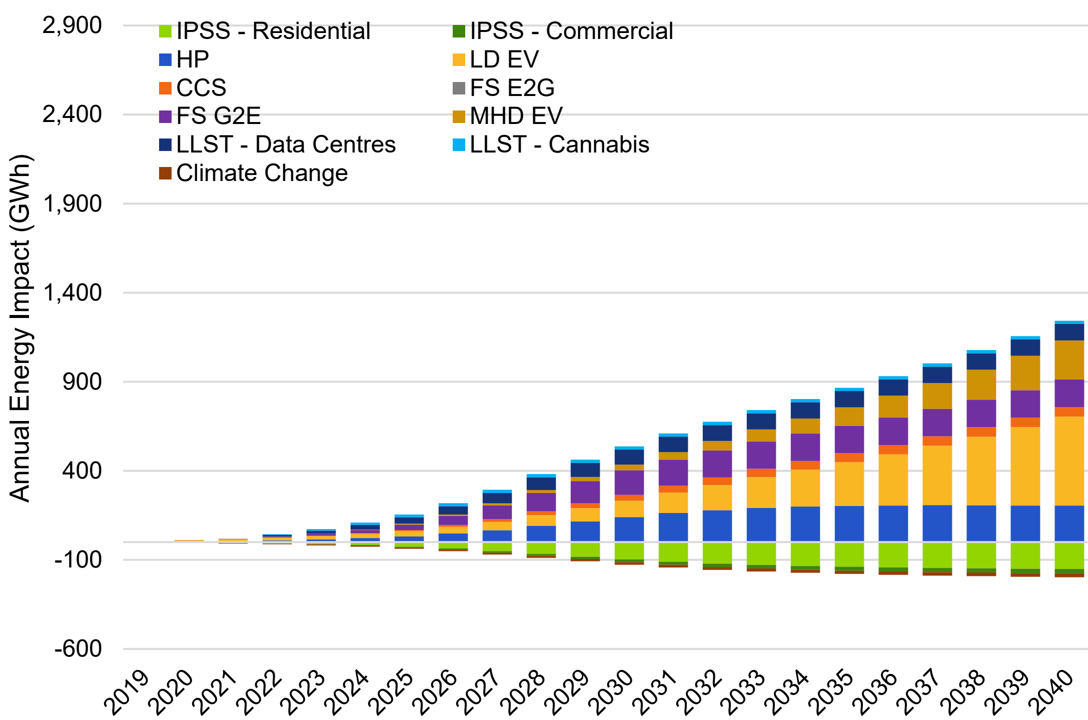


Figure 31, below, shows the distribution of energy impacts by month of year in the terminal projection year, 2040. The net total energy impact in each month is shown as a data label above each set of stacked columns.

Figure 39. Scenario 3 Energy Impact by Month (2040)

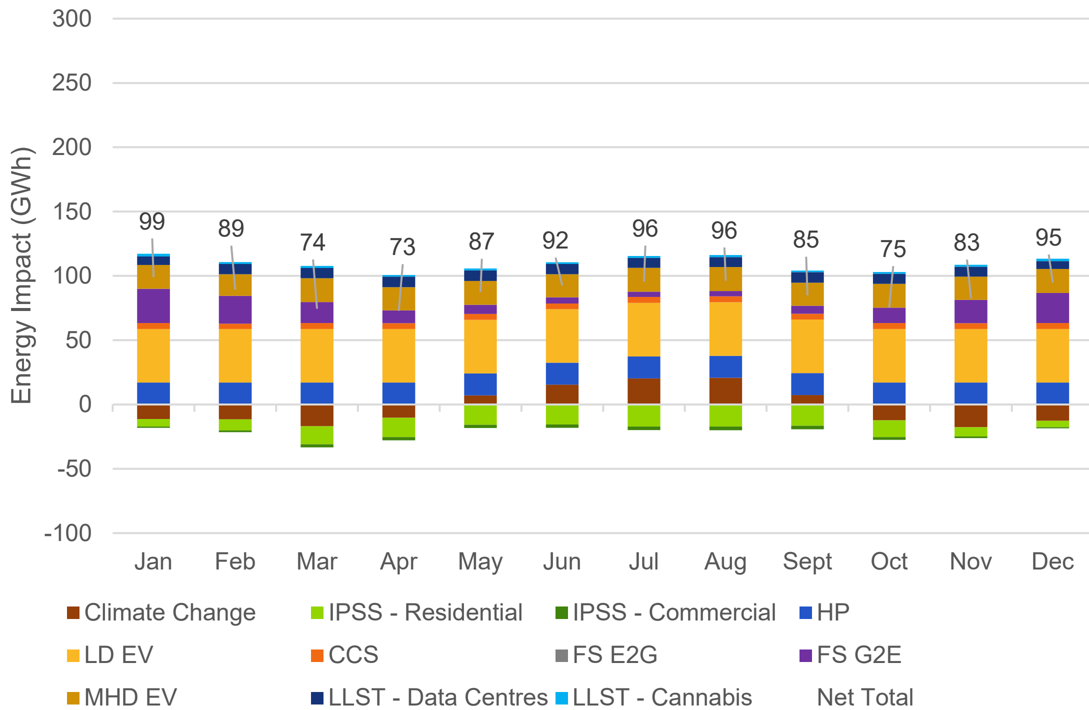


Table 18, below, presents the numerical impacts in 2040, as well as a relative comparison of the absolute impacts. Put another way, the bottom row of the table below shows what percentage of the total scenario impact each driver accounts for, if that percentage is calculated with the absolute values of the estimated impacts.

Table 18: Relative Contribution of Load Drivers to Annual Energy

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
GWh	-151	-25	205	500	54	0	155	219	92	18	-22
%	11%	2%	14%	35%	4%	0%	11%	15%	6%	1%	2%

Figure 40, below shows the distribution of winter demand impacts by year and load driver. The same phenomenon may be observed here as in Scenario 2 (Lower Bound) – while IPSS-RES somewhat mitigates energy consumption growth, it has no such effect on winter peak demand.

Figure 40. Scenario 3 (Deep Electrification) Winter Demand Impact

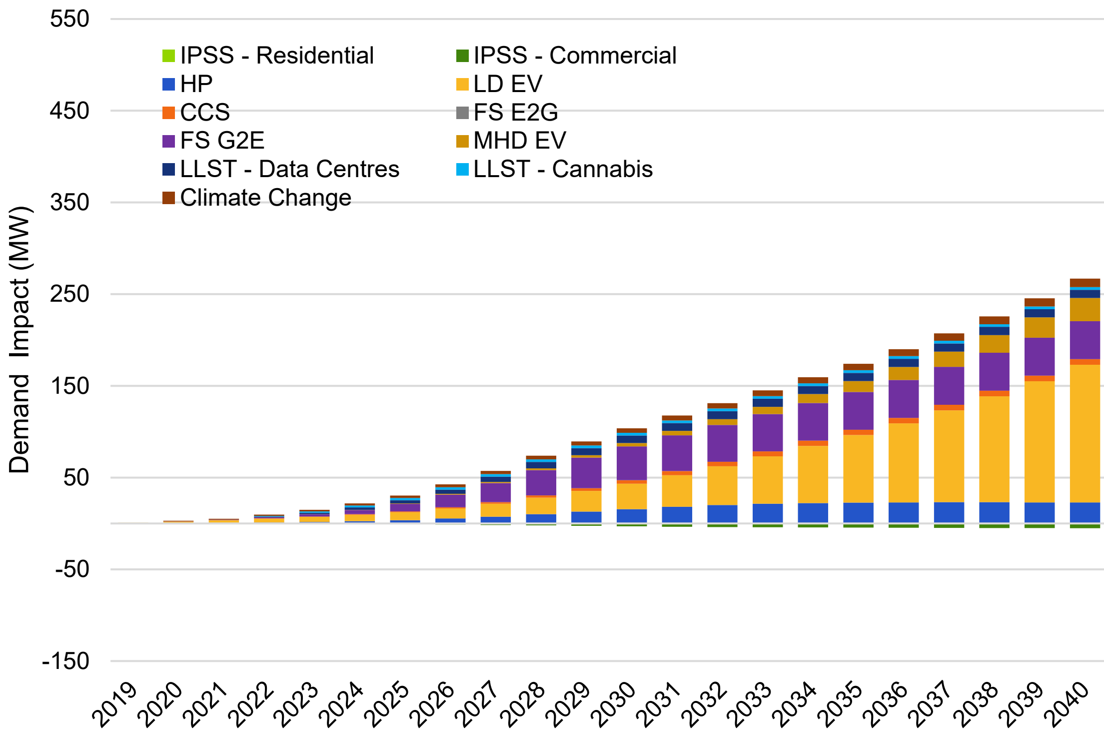


Figure 41, below, shows the average demand[96] impact by month of year in the terminal projection year, 2040. The net demand impact in each month is shown as a data label above each set of stacked columns.

[96] The average impact on demand on non-holiday weekdays between 5pm and 6pm PST.

Figure 41. Scenario 3 Demand Impact by Month (2040)

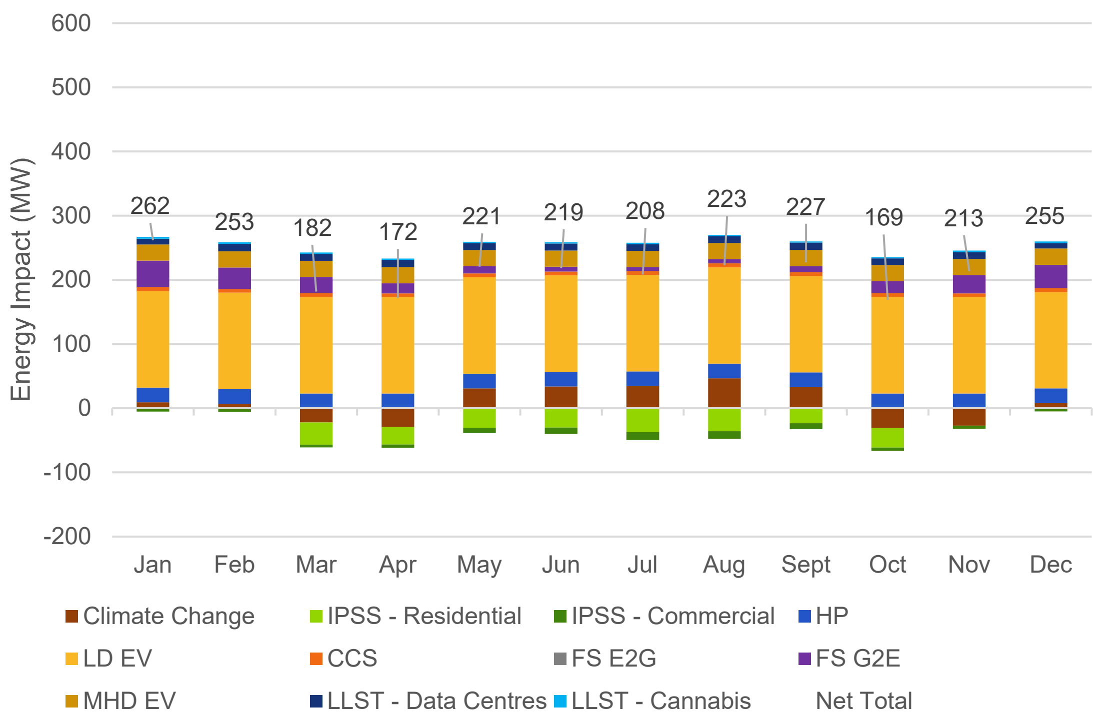


Table 19, below, presents the numerical impacts in 2040, as well as a relative comparison of the absolute impacts. Put another way, the bottom row of the table below shows what percentage of the total scenario impact each driver accounts for, if that percentage is calculated with the absolute values of the estimated impacts.

Table 19: Relative Contribution of Load Drivers to Winter Demand

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	-5	23	150	6	0	41	25	9	3	9
%	0%	2%	8%	55%	2%	0%	15%	9%	3%	1%	3%

3.3.5 *Scenario 4 – Diversified Energy Pathway Impacts*

Scenario 4 imagines a future world in which decarbonization is pursued in large part through renewable natural gas. Growth in EVs, though less than Scenario 3 (Deep Electrification) is considerable – 95% of LDV, and 20% of MHDV sales are EVs by 2040. The addition of this large, peaky EV load results in electricity prices rising, and a concerted effort through more generous economic development rates to attract large loads (data centres and cannabis production) to help flatten the utility's load profile and potentially reduce rates for all ratepayers.

Figure 42, below, shows the distribution of load driver energy impacts across the years in Scenario 4.

Figure 42. Scenario 4 (Diversified Energy Pathway) Energy Impact

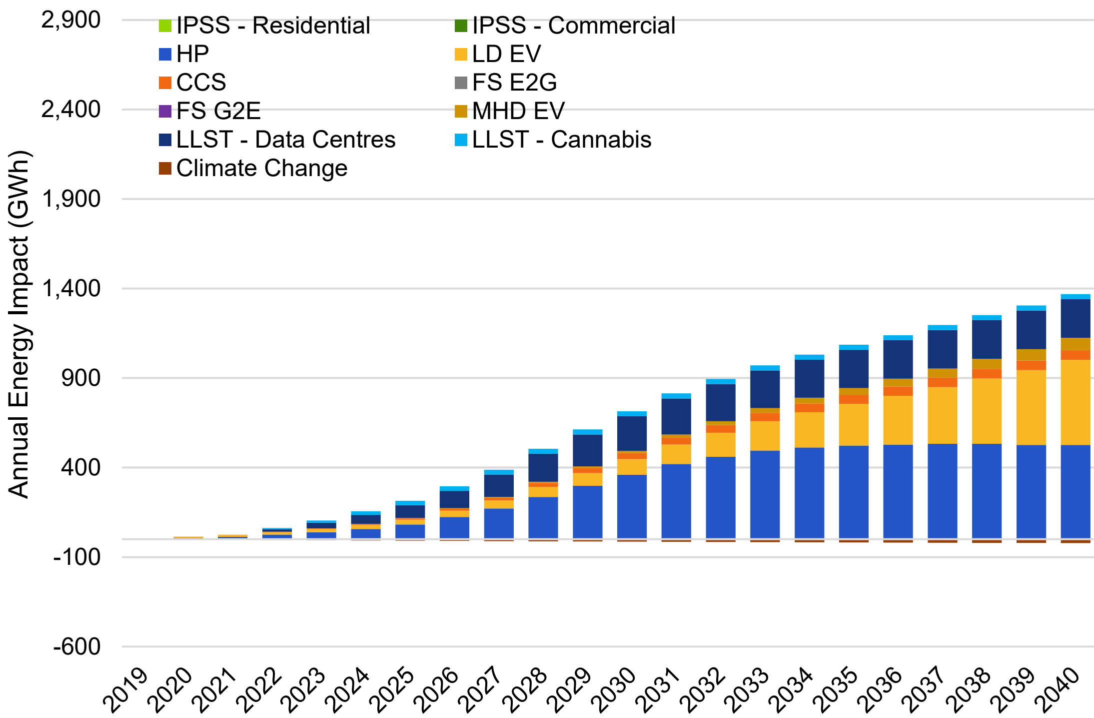


Figure 43, below, shows the distribution of energy impacts by month of year in the terminal projection year, 2040. The net total energy impact in each month is shown as a data label above each set of stacked columns.

Figure 43. Scenario 4 Energy Impact by Month (2040)

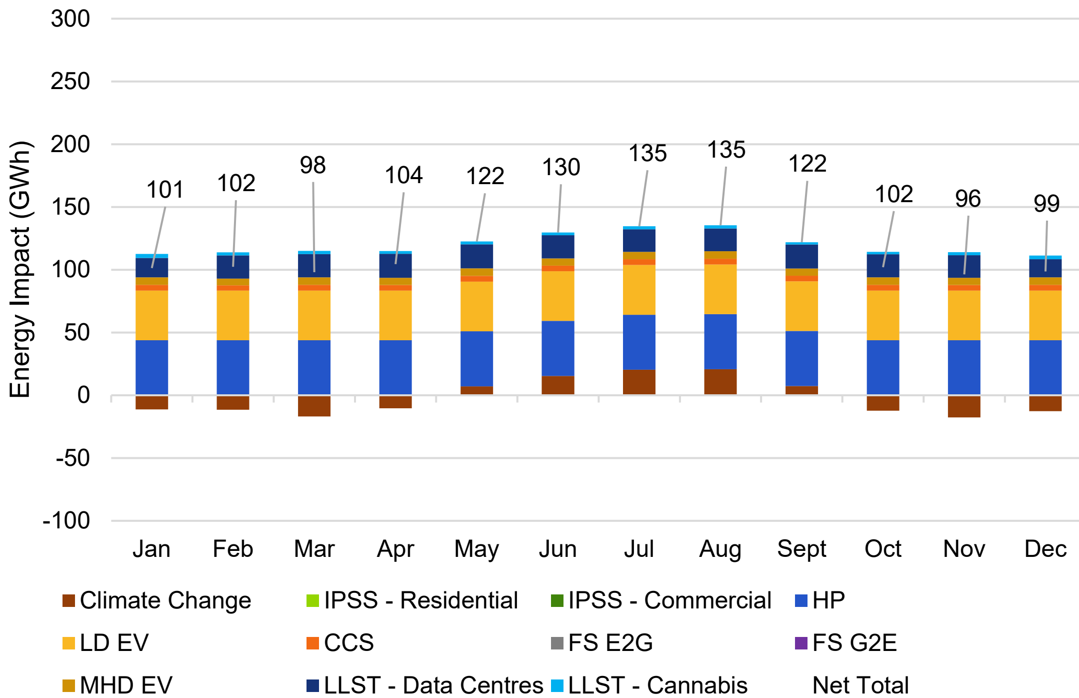


Table 20, below, presents the numerical impacts in 2040, as well as a relative comparison of the absolute impacts. Put another way, the bottom row of the table below shows what percentage of the total scenario impact each driver accounts for, if that percentage is calculated with the absolute values of the estimated impacts.

Table 20: Relative Contribution of Load Drivers to Annual Energy

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
GWh	0	0	526	475	54	0	0	70	215	29	-22
%	0%	0%	38%	34%	4%	0%	0%	5%	15%	2%	2%

Figure 44 below shows the distribution of winter demand impacts by year and load driver. This repeats the pattern observed in the Upper Bound scenario; hydrogen production contributes considerably less to the overall winter peak demand impact than it does to the annual energy impact with the opposite effect being true for EVs.

Figure 44. Scenario 4 (Diversified Energy Pathway) Winter Demand Impact

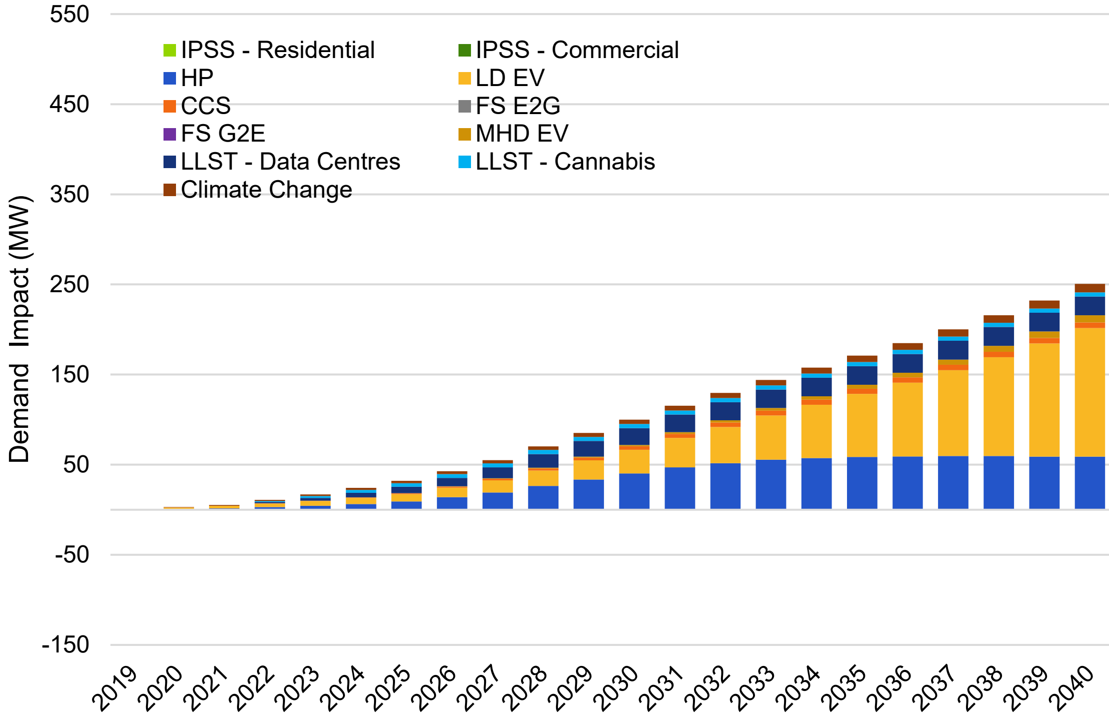


Figure 45, below, shows the average demand[97] impact by month of year in the terminal projection year, 2040. The net demand impact in each month is shown as a data label above each set of stacked columns.

[97] The average impact on demand on non-holiday weekdays between 5pm and 6pm PST.

Figure 45. Scenario 4 Demand Impact by Month (2040)

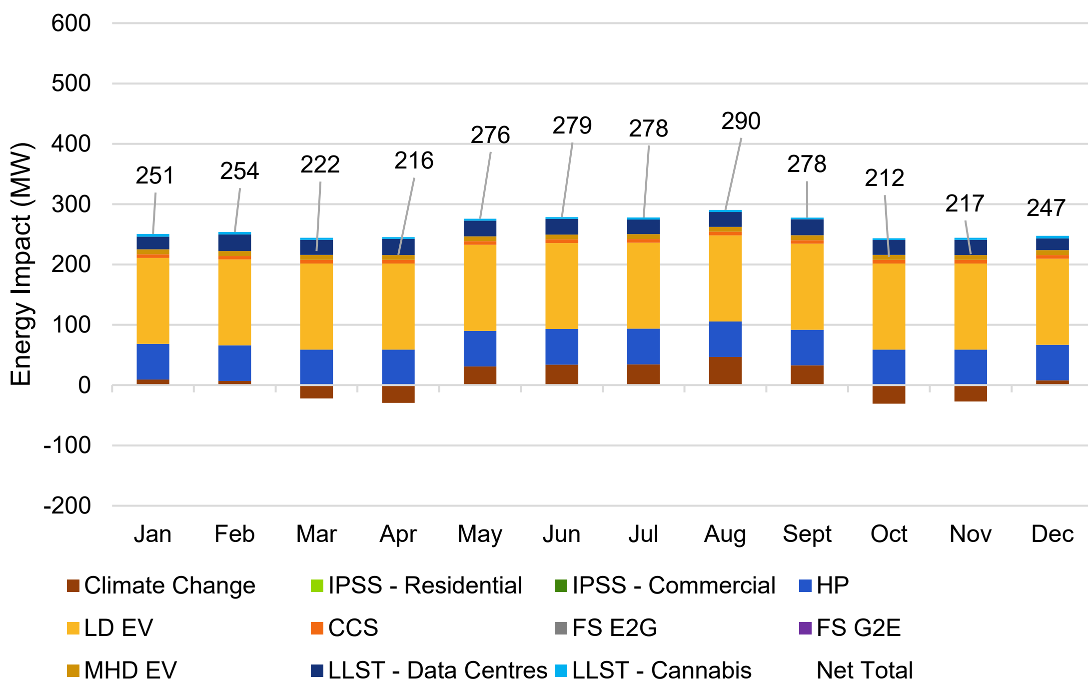


Table 21, below, presents the numerical impacts in 2040, as well as a relative comparison of the absolute impacts. Put another way, the bottom row of the table below shows what percentage of the total scenario impact each driver accounts for, if that percentage is calculated with the absolute values of the estimated impacts.

Table 21: Relative Contribution of Load Drivers to Winter Demand

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	0	59	143	6	0	0	8	21	5	9
%	0%	0%	24%	57%	2%	0%	0%	3%	8%	2%	4%

3.3.6 *Scenario 5 – Distributed Energy Future Impacts*

Scenario 5 imagines a future world in which highly favourable contracts with distributed energy (PV) producers (i.e., the consumers and businesses associated with the residential and commercial IPSS load drivers) result in a steep increase in the price of electricity. As a consequence, the adoption of EVs falls below the required levels of the ZEV mandate and residential customers convert from electric to gas-fired heat. The cost of power discourages growth in data centres and cannabis production.

In this scenario IPSS-RES offsets a considerable amount EV energy consumption, though the scenario still results in a modest increase in energy consumption, above that projected by the business-as-usual forecast.

Figure 46. Scenario 5 (Distributed Energy Future) Energy Impact

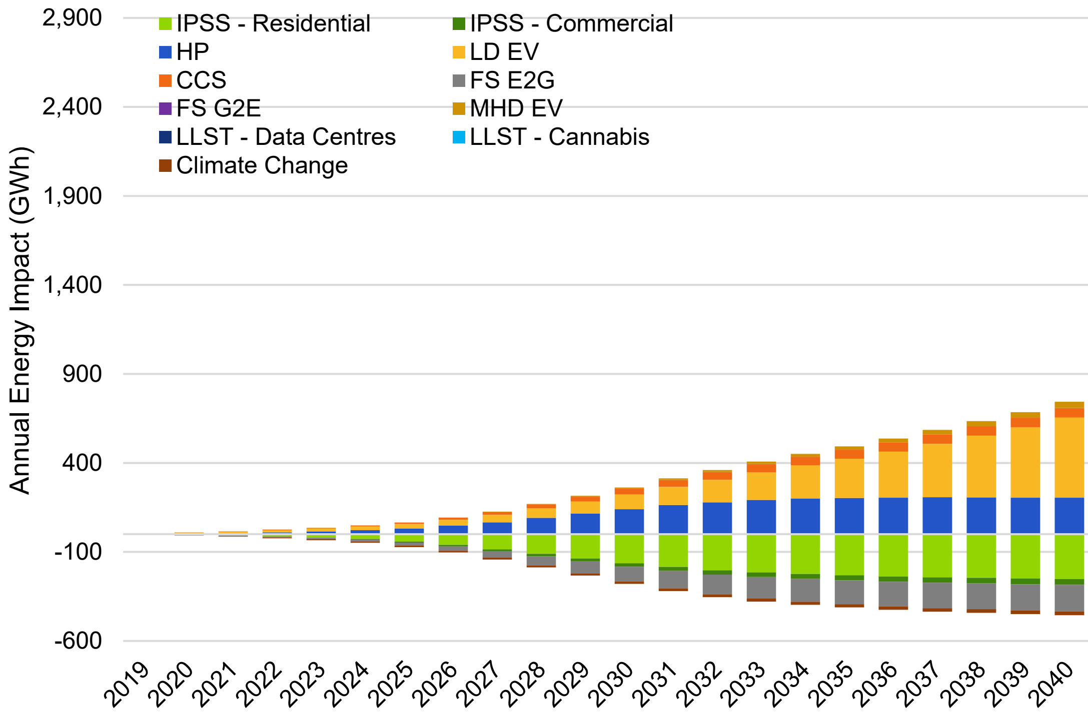


Figure 47, below, shows the distribution of energy impacts by month of year in the terminal projection year, 2040. The net total energy impact in each month is shown as a data label above each set of stacked columns.

Figure 47. Scenario 5 Energy Impact by Month (2040)

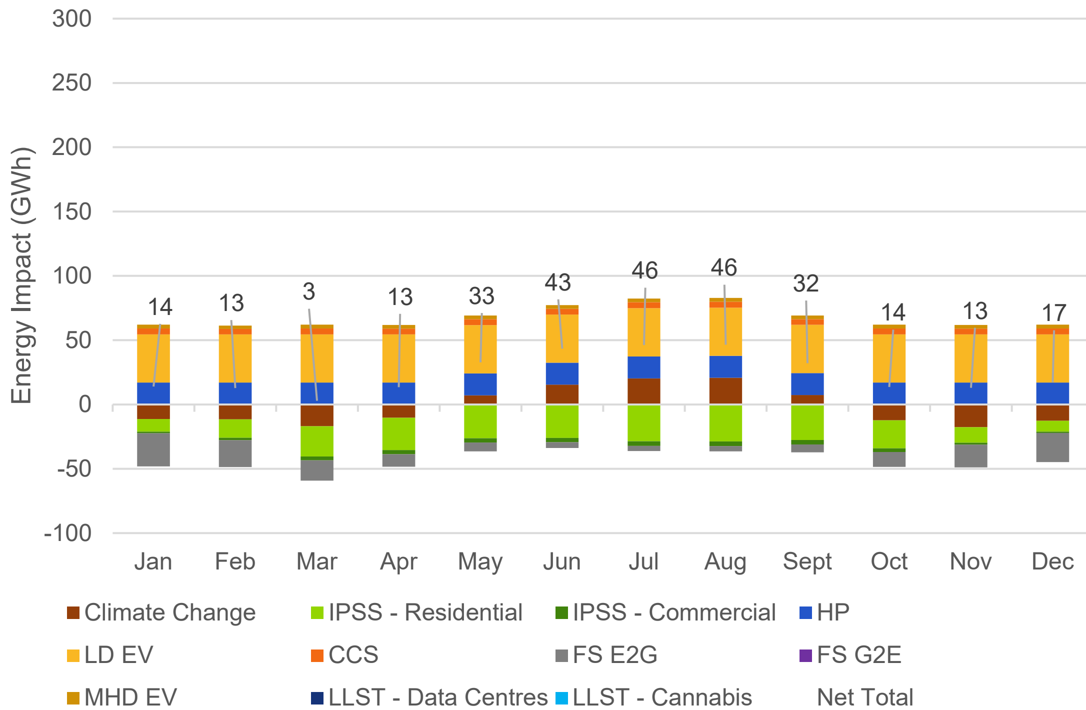


Table 22, below, presents the numerical impacts in 2040, as well as a relative comparison of the absolute impacts. Put another way, the bottom row of the table below shows what percentage of the total scenario impact each driver accounts for, if that percentage is calculated with the absolute values of the estimated impacts.

Table 22: Relative Contribution of Load Drivers to Annual Energy

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
GWh	-252	-33	205	450	54	-149	0	35	0	0	-22
%	21%	3%	17%	38%	5%	12%	0%	3%	0%	0%	2%

Figure 48 below shows the distribution of winter peak demand impacts by load driver and year. As in the previous intermediate scenarios the same underlying dynamics found in the Upper Bound and Lower Bound scenarios are evident here: IPSS-RES delivers no peak demand savings, and the LD EVs result in a considerable increase in winter peak demand. This scenario delivers the impacts with the lowest load factor of all scenarios, approximately one-third that of Scenario 2 (Lower Bound) and less than half that of either Scenario 3 (Deep Electrification) or Scenario 4 (Diversified Energy Pathway). Put another way it is this scenario that most increases peak demand relative to average demand (i.e., annual consumption).

Figure 48. Scenario 5 (Distributed Energy Future) Winter Demand Impact

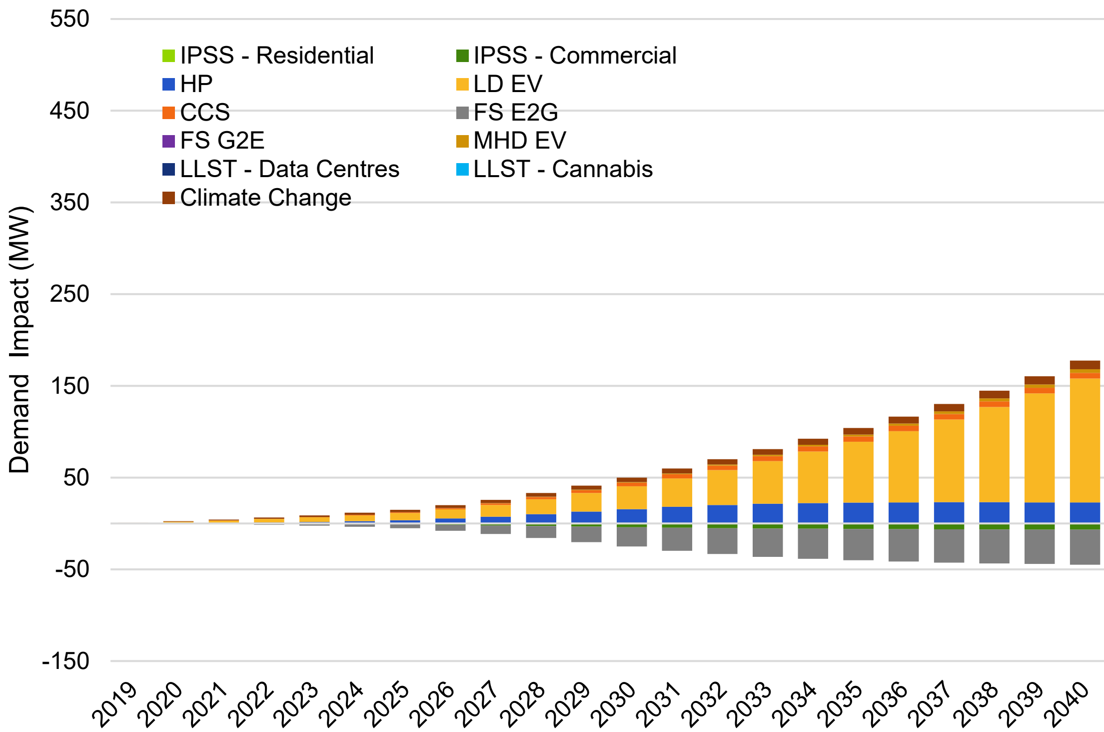


Figure 49, below, shows the average demand[98] impact by month of year in the terminal projection year, 2040. The net demand impact in each month is shown as a data label above each set of stacked columns.

[98] The average impact on demand on non-holiday weekdays between 5pm and 6pm PST.

Figure 49. Scenario 5 Demand Impact by Month (2040)

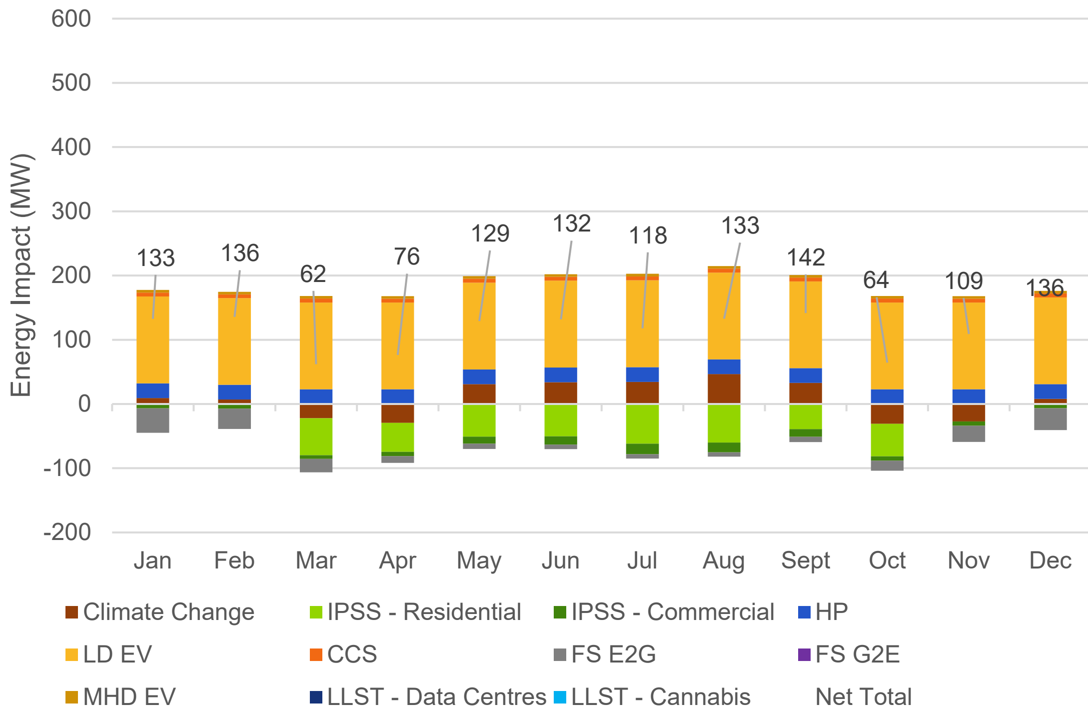


Table 23, below, presents the numerical impacts in 2040, as well as a relative comparison of the absolute impacts. Put another way, the bottom row of the table below shows what percentage of the total scenario impact each driver accounts for, if that percentage is calculated with the absolute values of the estimated impacts.

Table 23: Relative Contribution of Load Drivers to Winter Demand

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	-7	23	135	6	-38	0	4	0	0	9
%	0%	3%	10%	61%	3%	17%	0%	2%	0%	0%	4%

4. FINDINGS AND RECOMMENDATIONS

Guidehouse's analysis suggests three key findings. Each finding is described in its own section below, and accompanied by a, or a set of, recommendations.

4.1 Key Finding 1: Coping with Electrification

Electrification will requireadditional capital investment in order to address growth in "peaky" loads. Prudent management of such a transition could reduce the required capital investments and impacts on customer rates.

In Scenario 1 (Upper Bound), the electrification of both transportation and space- and water-heating account for 38% of modeled energy increases, but 47% of the impact on peak demand. In Scenario 3 (Deep Electrification) these load drivers account for 61% of the modeled energy increases, but *80%* of peak demand increases.

Without some mitigating action, significant growth in EV use and electric space-heating is likely to cause the overall load factor of FortisBC's customers to fall. If load factor falls and additional capacity is required to serve these new loads overall system costs may increase at a faster rate than the energy use over which such costs are recovered, leading to customers facing increased electricity rates.

This erosion of the load factor of FortisBC's customers is not, of course, an inevitability even if these load drivers do grow as they have been modeled in Scenario 1. Effective mitigating action may help significantly flatten the system load profile, even as energy requirements grow.

Recommendation 1.1 – Explore Approaches to Shifting EV Charging to Off-Peak Periods.

Numerous pilots[99] have demonstrated that EV drivers are responsive to rates that incent charging behaviour. A well-designed rate, particularly if paired with some enabling technology, could vastly reduce the peak demand impact of EVs. Most EV drivers plug their vehicles in when they return home from work even though in most cases a reasonable amount of charge remains in the battery (i.e., most drivers could wait to connect their vehicles until after the peak period without limiting their driving range).

Encouraging electric vehicle supply equipment (EVSE) manufacturers and distributors to market and sell equipment with a timer or direct load control functionality to help support driver response to TOU rates could also substantially reduce any potential increases in peak demand as a result of this load driver.

FortisBC may also wish to consider exploring programmatic options for reducing the impact of potential future EV growth on peak demand, including the use of demand response via direct load control of EVSE (simple curtailment or "smart charging" style selective throttling), or of rebate programs that reward drivers that charge during off-peak times.

As FortisBC explores its options for mitigating the demand impacts of EV charging, it should, when conducting benefit/cost analyses, make use (where possible) of *vehicle* and not just charging location data (i.e., residential AMI data). Given the likelihood that EV drivers will increasingly shift to workplace or public charging as this infrastructure becomes more available, analyses of policy options that ignore overall vehicle charging patterns and consider only charging behaviour observable at home charger locations risk delivering flawed conclusions.

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[99] For example, Alectra Utilities RPP Pilot Overnight rate, targeted to EV users, resulted in customer overnight demand increasing by nearly 30%, likely due to a shift from day-time workplace and early evening home charging to overnight home charging.
Alectra Utilities with its partner BEWorks, *Regulated Price Plan Pilot – Interim Report*, January 2019 – See table 1
https://www.oeb.ca/sites/default/files/rpp-alectra-interim-report-20190409.pdf

Recommendation 1.2 – Water Heater Demand Response

Electric water heaters typically exhibit bi-modal peaks – in the morning, to support shower needs, and in the evening to support food preparation and clean-up needs, and so tend to be exhibit highly peak coincident demand. Storage water tanks are famously good candidates for demand response, as in most cases cutting power to the appliance even for a few hours only moderately reduces the tank temperature, meaning that customers can still access hot water even when curtailed. Participants in water heater demand response programs are often unaware that events have even been called.

Water heater demand response is a very mature and well-established policy response to issues related to morning and evening peak demand in jurisdictions with a reasonably high penetration of electric water heaters, and has a long successful operational history in (for example) Duke Energy's Florida and North Carolina (West Region) jurisdictions.

Recommendation 1.3 – Hybrid Space-Heat Electrification and Electric Thermal Storage

Most planning for space-heat electrification centres on heat pump uptake. Although heat pumps are very efficient in most weather, their coefficient of performance (COP) decays substantially in very cold weather. Even cold-climate heat pumps will, as temperatures fall low enough, require supplementary resistance heat strips to deliver the required home set-point temperature.

If FortisBC anticipates substantial electrification of space-heat in the future, it may wish to consider the marketing of heat pump systems as add-ons to existing natural gas systems. A hybrid system that uses gas only on the coldest days, and the electric heat pump the rest of the time could yield most of the decarbonization benefits of electrification without the penalty of spiking peak demand. FortisBC may also wish to consider whether the electrification of space-heating via electric thermal storage (ETS) systems may (in some cases) be prudent.

4.2 Key Finding 2: Incentives for Residential Solar Producers are Insufficiently Aligned with System Needs

Distributed generation installed in residential households – with current incentives in place – is unlikely to make any meaningful contribution to peak demand reductions, even when enabled with energy storage.

Guidehouse assumed that residential customers generating their own electricity from rooftop PV and equipped with storage would use storage to satisfy their household requirements as soon as PV output was insufficient to do so. This is a reasonable assumption where rates are effectively flat (or have an inclining block structure) for residential consumers. The issue is that in the winter months, PV generates no power at the time of system peak (the sun has long since gone down), and that what little excess generation is produced earlier in the day (over and above the household's requirements) and stored has been used up before the time of system peak.

It is unclear how realistic it is to assume any kind of widespread growth in residential energy storage, or even widespread growth in residential rooftop PV. Although costs are falling, the capital investment required is still considerable. PV and storage are both, relative to the standard network electricity connection, infant technologies, likely to require time and trouble on the part of the homeowner. Uptake could be encouraged, and peak demand reductions delivered, either by offering storage-owning customers a TOU rate, or even better, a critical peak price net metering rate. That is, a rate which would provide capacity payments to residential customers for maintaining some minimum level of energy in storage that could be dispatched as required to meet peak system demand.

Recommendation 2.1 – Monitor Industry Developments in Energy Storage.

It is likely that the need for this is some distance in the future, but FortisBC should carefully observe to what degree Tesla (by far the best known provider for this technology) is successful in "normalizing" its energy storage solution. As energy storage (with, or without PV) becomes a more common feature in FortisBC customers' homes, FortisBC should consider formalizing an approach to leverage this available capacity for system benefit. Likewise, FortisBC should monitor the development of the use of EV batteries as distributed energy resources. Given the anticipated growth (motivated by the ZEV Act) of light-duty EVs over the projection period, some opportunity may exist to use these resources to improve the overall load factor of residential consumers.

Recommendation 2.2 – Consider the Value of Encouraging Distributed Storage.

Alternatively, if there are already localized distribution constraints, FortisBC may wish to consider whether there is any value in helping to encourage the adoption of residential energy storage technologies in certain geographies, and how best to unlock that value through incentives or direct program interventions.[100]

Furthermore, Guidehouse understands from FortisBC staff that the current net metering tariff provides customers with an annual storage account that has terms more favourable than the functionality which a standard residential battery could actually provide. FBC may wish to consider, in light of the findings above, whether it is appropriate to make revisions to the tariff to align the incentives of customers that may choose to invest in energy storage to better reflect the potential benefit these may offer the FBC system.

4.3 Key Finding 3: Opportunities Offered by New Types of Loads

There is potential for substantial growth in non-traditional customer loads whose load shapes could help improve system load factor. If properly managed such loads may deliver substantial benefits to ratepayers.

As British Columbia works to decarbonize its energy over the planning horizon, it is possible that some component of its strategy to do so will involve injecting hydrogen to its natural gas system. At present the production of green hydrogen via electrolysis is (given the makeup of British Columbia's generation fleet) the cleanest way to do so. While the Upper Bound assumptions for the HP load driver may be extreme, there is no question that increasing hydrogen production could substantially increase energy requirements in FortisBC's territory.

Likewise, there may be some question regarding how much growth really may be expected of the cannabis industry.[101] It is undoubtedly true that the exponential worldwide growth of data centres to serve individuals' and companies data storage and processing needs will continue. Should more of these facilities migrate to FortisBC territory, the impact on consumption could be considerable – even the (relatively) modest growth in floorspace assumed for Scenario 4, the Distributed Energy Pathway (nearly tripling floorspace in 20 years) results in an incremental energy requirement of 215 GWh, an increase of 5% in system energy compared to the business-as-usual forecast.

Both loads present an opportunity to FortisBC to deliver greater value to its ratepayers, conditional on where such loads are located.

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[100] Liberty Utilities in New Hampshire is currently deploying a residential energy storage pilot for just this purpose, and may be a source of useful intelligence on this.

Liberty Utilities, *Introducing Liberty's NEW Battery Storage Program*, accessed July, 2020
https://new-hampshire.libertyutilities.com/grafton/residential/smart-energy-use/electric/battery-storage.html#:~:text=The%20battery%20storage%20program%20is,called%20the%20Tesla%20Powerwall%202.

[101] Many argue that new cannabis production facilities should not be counted as "net new" production, but simply the migration of facilities from the black market to the stock market, though of course this would be difficult to prove or disprove.

Recommendation 3.1 – Explore the Possibility of Economic Development Rates that may Benefit all Ratepayers.

Very large consumers with flat or non-peak coincident load profiles, particularly ones that may have some flexibility in their loads (i.e., and ability to curtail at times of system peak) may, in systems like FortisBC's where the short-term variable commodity cost is low, offer an opportunity to reduce the share of fixed system costs paid by all ratepayers. Doing so would put downward pressure on electricity rates. Hydrogen production – which is possibly more interruptible than data centres – is likely most desirable, but both types of loads may be potentially beneficial to FortisBC and FortisBC may wish to consider whether there is some merit in exploring or developing economic development rates suitable for attracting such customers.

Appendix I

LOAD SCENARIOS STAKEHOLDER PRESENTATION

FORTISBC LOAD SCENARIO DEVELOPMENT

STAKEHOLDER WORKSHOP: SCENARIO IMPACTS

2020-06-25

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1. LOAD SCENARIO STUDY PURPOSE AND FOCUS

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LOAD SCENARIO STUDY PURPOSE AND FOCUS

Navigant (a Guidehouse Company) is supporting FortisBC in the development of a set of potential future load scenarios to explore the potential impact of structural changes in future utility loads.

STUDY PURPOSE:	Quantify the potential impact of major structural changes in FortisBC's electricity load drivers through a scenario analysis.
STUDY FOCUS:	Intermediate scenarios that align with the scenarios previously modeled for FortisBC's EnergyVision 2050 report. *(The 2015/2016 load scenarios focused on the two "boundary" scenarios. These continue to be presented here for context, but planning efforts will be informed primarily by the intermediate scenarios).*

NB: this is *not* a forecast but an exercise in understanding the consequence of a variety of potential future pathways.

The primary goals of this meeting are to:

- Present stakeholders with Navigant's estimated impacts for each of the five load scenarios developed
- Solicit feedback on Navigant's findings and in particular the scenario assumptions that drive those findings.

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2. SCENARIO LOAD DRIVERS

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SCENARIO LOAD DRIVERS

1. Integrated Photovoltaic Solar and Storage (IPSS) – Residential

Residential rooftop solar photovoltaic (PV) installations, in some cases supported by energy storage.

2. Integrated Photovoltaic Solar and Storage (IPSS) – Commercial

Commercial building solar photovoltaic (PV) installations, in some cases supported by energy storage.

3. Electric Vehicles (EV)

- Light duty vehicles (LDV) including: plug-in hybrids (PHEV) and battery electric vehicles (BEV)
- Medium and heavy duty vehicles (MHDV) including: return-to-base fleet vehicles, busses, combination tractors

4. Fuel Switching: Gas to Electric (FS G2E)

- Electrification of residential space- and water-heating
- Equipment to reflect the mix of equipment projected in the Technical Potential estimated as part of the Conservation Potential Review (June 2019)

5. Fuel Switching: Electric to Gas (FS E2G)

Replacement of non-heat pump electric residential space- and water- heating with standard efficiency (code-compliant) natural gas fired equipment.

Decrease in load

Increase in load

SCENARIO LOAD DRIVERS

6. Climate Change (CC)

Increasing average annual temperatures reduce heating loads in the winter and increase cooling loads in the summer. Assumed “new normal” includes annual winter cold snaps and summer heat waves. Net effect is reduction in energy consumption in all scenarios but increases in peak demand in some scenarios.

7. Large Load Sector Transformation (LLST)

Transformation of the large commercial and industrial (C&I) sector. Specifically: significant growth in the number of data centres and cannabis greenhouses in FortisBC territory.

8. Hydrogen Production (HP)

Electricity consumption driven by the production of “green” hydrogen to be injected into natural gas distribution system to partially decarbonize that fuel source.

9. Carbon Capture and Storage (CCS)

Electricity consumption driven by power requirements of CCS technologies used to capture carbon emissions *in situ* from industrial processes

Direction of energy and demand impacts may differ.

Decrease in load

Increase in load

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3. LOAD SCENARIOS - SUMMARY

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LOAD SCENARIOS

1. Upper Bound

Includes (aside from Climate Change) only load drivers that <u>increase</u> load. Ultimate penetration of all included load drivers set to reasonable extreme.

2. Lower Bound

Includes only load drivers that <u>decrease</u> load. Ultimate penetration of all included load drivers set to reasonable extreme.

3. Deep Electrification

Electrification of transportation, residential and commercial space and water heating and industrial process heating. Growth in IPSS (commercial and residential) to support electrification.

4. Diversified Energy Pathway

Emissions reductions characterized more by decarbonization of fuels than electrification. Includes significant increases in HP, supported by CCS. Surplus generation helps motivate LLST and adoption of EVs.

5. Distributed Energy Future

The falling costs of renewable generation and storage drives growth in residential and commercial IPSS. Increased self-generation reduces utility revenue, increasing retail rates and provoking some E2G fuel switching. Growth in HP and CCS to support growth in NG requirements.

Net decrease in load

Net increase in load

Direction of impact depends on load driver penetration assumptions.

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LOAD SCENARIOS AND DRIVERS

Scenarios / **Drivers**	IPSS (Res)	IPSS (Com)	EVs	FS G2E	FS E2G	CC	LLST	HP	CCS
Upper Bound									
Lower Bound									
Deep Electrification									
Diversified Energy Pathway									
Distributed Energy Future									

High Penetration Medium Penetration Low Penetration No Penetration

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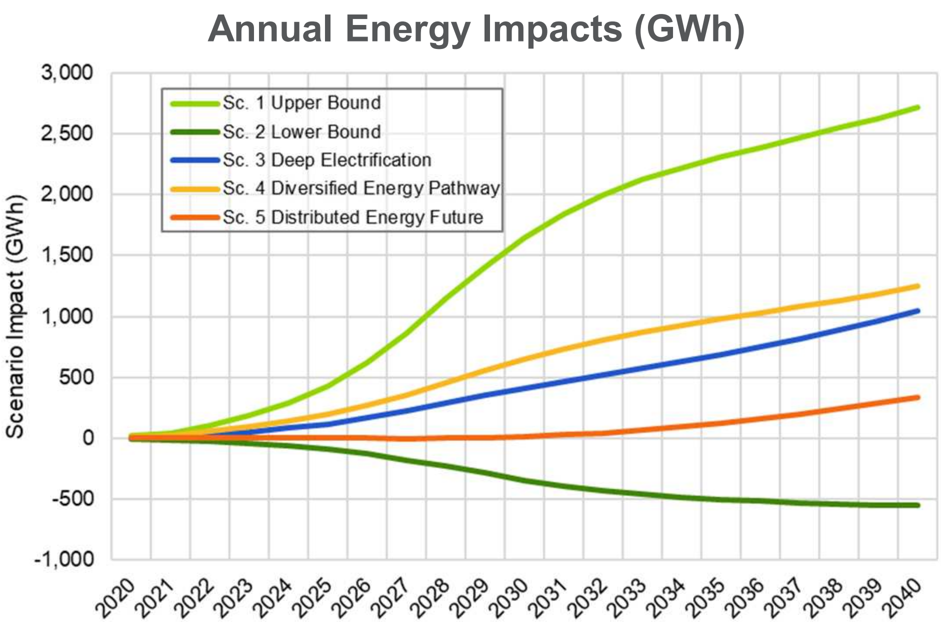
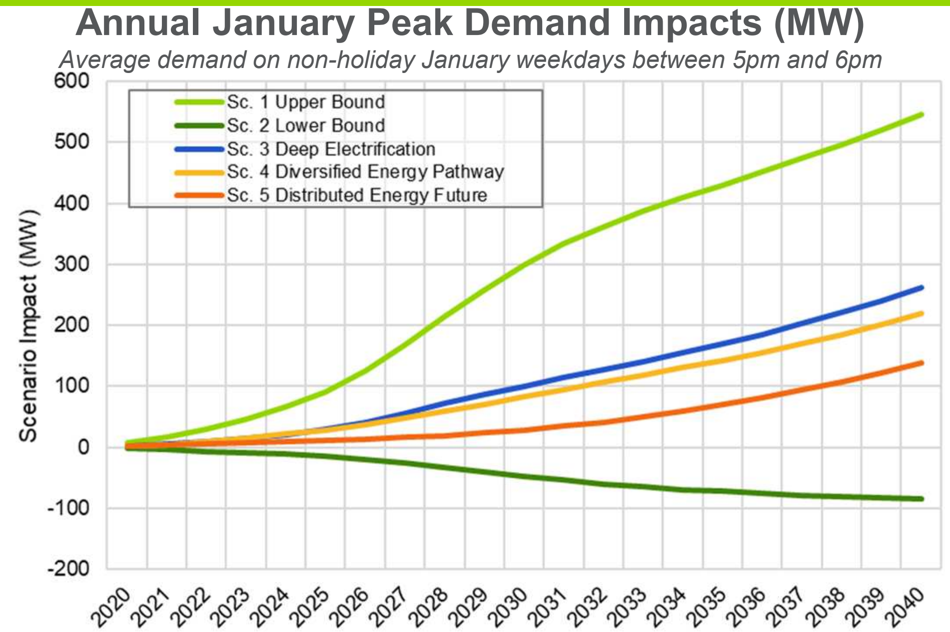
LOAD SCENARIOS IMPACTS





Scenario Impacts in 2040, and % Change from BAU Projection for 2040

	Sc. 1 Upper Bound	Sc. 2 Lower Bound	Sc. 3 Deep Electrification	Sc. 4 Diversified Energy Pathway	Sc. 5 Distributed Energy Future
GWh	2,720	-554	1,045	1,248	338
%Δ From BAU	62%	-13%	24%	28%	8%

	Sc. 1 Upper Bound	Sc. 2 Lower Bound	Sc. 3 Deep Electrification	Sc. 4 Diversified Energy Pathway	Sc. 5 Distributed Energy Future
GWh	546	-85	262	219	139
%Δ From BAU	61%	-10%	29%	25%	16%

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4. SCENARIO 1: UPPER BOUND

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SCENARIO 1 – UPPER BOUND: KEY ASSUMPTIONS

Description

The Upper Bound scenario exists to help FortisBC understand the upper limit of the potential impacts on energy consumption of structural changes in the drivers of electric load. This scenario only includes load drivers that increase load. All load drivers' ultimate penetration (where appropriate) assumed at highest levels ("reasonable extremes"). This scenario has a net **increase** in load.

Key Assumptions in Load Driver Ultimate Penetration

Driver	Key Assumptions (Ultimate Penetration of Load Driver)	
EVs	**Light-Duty EVs.**	Penetration aligns with Zero Emission Vehicle (ZEV) mandate assumptions: by 2025 10% of new vehicle sales are EVs, by 2030 30% of new vehicle sales are EVs, and by 2040 100% of new vehicle sales are EVs.
	Medium/Heavy-Duty EVs.	Assumes that by 2040, 80% of return-to-base vehicle, combination tractor, and bus sales are EVs
FS G2E	Assumes that by 2040, FortisBC will achieve 30% of the residential electrification Technical potential identified by the 2019 Conservation Potential Review electrification potential study for the terminal year of that study.	
LLST	**Data Centres**	Assumed growth (by 2040) of approximately 700,000 ft^2 of floor space from the estimated existing 200,000 ft^2.
	Cannabis Production	Assumed growth (by 2040) of approximately 3 milion ft^2 of floor space from the estimated existing and 100% confidence projected (via connection requests) 1 million ft^2 in 2021.
HP	Assumes an annual production of 3 PJ of hydrogen by 2040. This is approximately 5% of the projected NG consumption in the shared service territory by 2036 projected in the last LTGRP. Further assumes that conversion efficiency increases over time, from 73% (existing, based on FortisBC pilot data) to 95%.	
CCS	Assumes an annual capture of 240 kT per year of industrial-sector GHG by 2040. This is approximately 1.3 x the volume of industrial emissions assumed to be captured by CCS in the "Diversified Pathway" scenario in the Energy Vision 2050 report.	
CC	Assumes an average decrease in daily temperature of 6.2 C^O on the ten coldest days, and an average increase in daily temperature of 2.1 C^O on the ten hottest days.	

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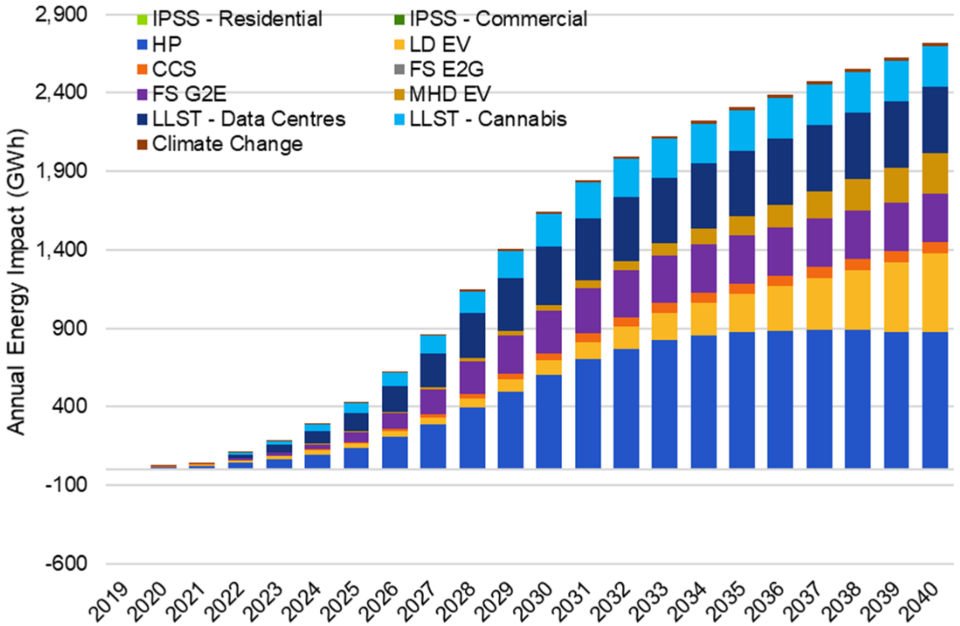
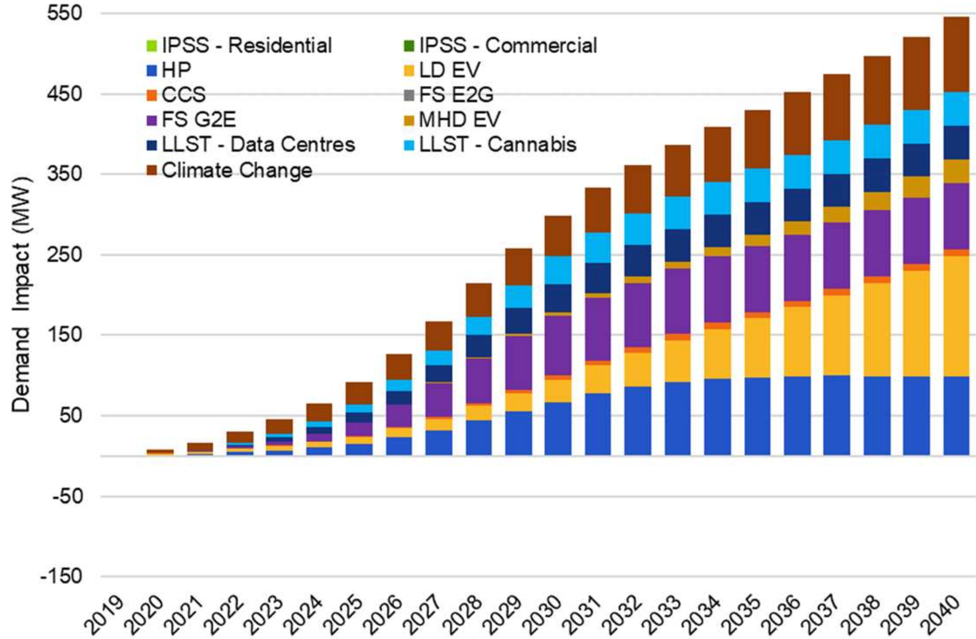
SCENARIO 1 – UPPER BOUND: IMPACTS BY LOAD DRIVER





Absolute and Relative Contribution to Total Impacts in 2040

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
GWh	0	0	877	500	72	0	310	254	424	260	24
%	0%	0%	32%	18%	3%	0%	11%	9%	16%	10%	1%

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	0	98	150	8	0	83	29	41	42	95
%	0%	0%	18%	27%	2%	0%	15%	5%	8%	8%	17%

NB: the % contribution here is calculated as the absolute value of the level impact for the given driver, divided by the sum of the absolute impacts of all drivers

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SCENARIO 1 – UPPER BOUND: NOTEWORTHY OBSERVATIONS

Under the Upper Bound scenario (Scenario 1), by 2040, both energy consumed and January weekday demand between 5pm and 6pm increase to approximately 60% more than that projected in the Business As Usual forecast.

Key Observations

- **Energy vs. Demand.** The distribution of impacts by driver differs considerably when considering energy compared to demand:
    - Energy: 32% of impact from hydrogen production, 18% from LD EVs, and 11% from G2E fuel-switching.
    - Demand: 27% of impact from LD EVs, 15% from G2E fuel-switching, 18% from hydrogen production, and 17% from assumed cold snap (CC).
- **Light-Duty EVs.** Without some mitigating action to shift loads (e.g., TOU rates, automated DR charging infrastructure, etc.) large-scale LD EV penetration in line with ZEV mandate requirements could push 2040 winter peak demand ~17% higher than BAU.
- **Hydrogen Production.** Replacing conventional natural gas with hydrogen will require substantial incremental electric energy, even with very aggressive efficiency assumptions. Replacing just 5% of the shared service territory NG energy with hydrogen increases 2040 energy consumption ~18% above BAU.
- **Data Centres.** Year-round high energy intensity of this business type means that tech-sector-style growth could result in substantial load increases.

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5. SCENARIO 2: LOWER BOUND

SCENARIO 2 – LOWER BOUND: KEY ASSUMPTIONS

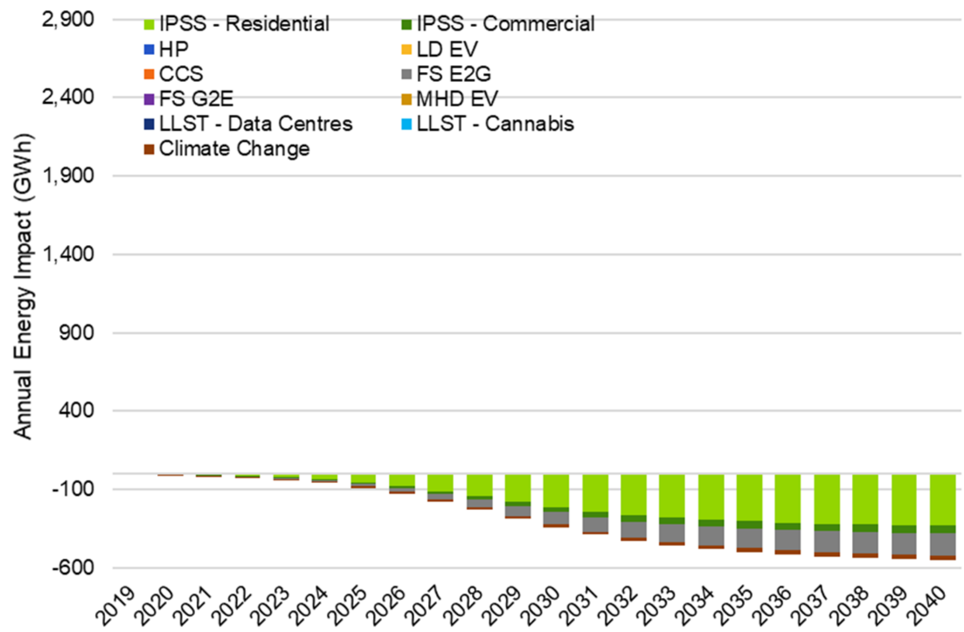
Description

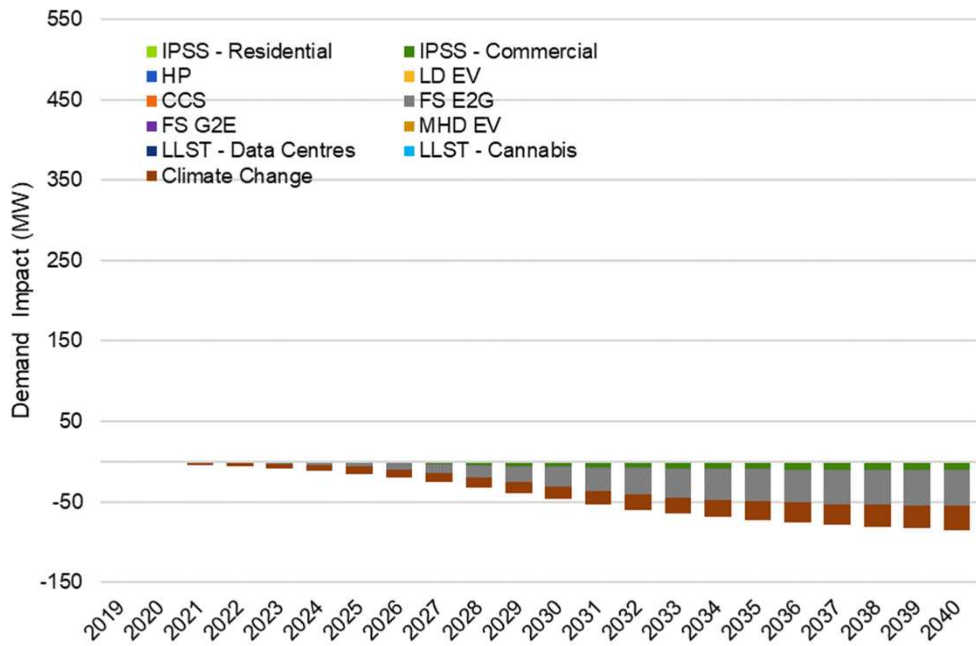
The Lower Bound scenario exists to help FortisBC understand the upper limit of the potential *negative* impacts on energy consumption of structural changes in the drivers of electric load. This scenario only includes load drivers that decrease energy consumption. All load drivers' ultimate penetration (where appropriate) assumed at highest levels ("reasonable extremes"). This scenario has a net **decrease** in load.

Key Assumptions in Load Driver Ultimate Penetration

Driver	Key Assumptions (Ultimate Penetration of Load Driver)
IPSS - Residential	Assumes that by 2040 one third of all residential consumers dwelling in single family homes (65% of all residential customers) in the FortisBC service territory (incl. those that are customers of FortisBC wholesale customers) will have installed 8 kW of rooftop solar PV, each. Further assumes that half of those that install rooftop PV will also (by 2040) install a 5 kW/13.5 kWh energy storage system. Storage is assumed to be charged with excess solar generation, and discharged as required to cover household loads.
IPSS - Commercial	Assumes that by 2040 half of all GS21 commercial customers (~12% of commercial customers and ~65% of commercial loads) in FortisBC service territory (incl. those that are customers of FortisBC wholesale customers) will have installed 20 kW of rooftop solar each. Further assumes that half of those that install rooftop PV will also (by 2040) install a 50 kW/210 kWh energy storage system. Storage is assumed to be charged so as to flatten the average GS21 customer load profile and minimize exposure to demand charges (i.e., charge overnight, discharge during day).
FS E2G	Assumes that by 2040, 50% of residential consumers dwelling in single family homes in the FortisBC service territory, that use electricity as their primary space- or water-heating fuel and that live within 50 m of a natural gas line will have converted from electric to natural gas space- and water-heating.
CC	Assumes an average daily increase in temperature of 2^{O} C.

SCENARIO 2 – LOWER BOUND: IMPACTS BY LOAD DRIVER





Absolute and Relative Contribution to Total Impacts in 2040

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
GWh	-333	-49	0	0	0	-142	0	0	0	0	-30
%	60%	9%	0%	0%	0%	26%	0%	0%	0%	0%	5%

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	-10	0	0	0	-45	0	0	0	0	-30
%	0%	12%	0%	0%	0%	53%	0%	0%	0%	0%	35%

NB: the % contribution here is calculated as the absolute value of the level impact for the given driver, divided by the sum of the absolute impacts of all drivers

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SCENARIO 2 – LOWER BOUND: NOTEWORTHY OBSERVATIONS

Under the Lower Bound scenario (Scenario 2), by 2040, both energy consumed and January weekday demand between 5pm and 6pm decrease by approximately 13% and 10% (respectively) that projected in the Business As Usual forecast.

Key Observations

- **Overall Impact.** Most load drivers considered for this analysis *increase* rather than decrease load. There are fewer load drivers in Scenario 2, and the average magnitude of effect is much smaller than for Scenario 1.
- **IPSS - Residential.** Given the assumed use parameters (charge storage with PV output, self-supply from storage as production declines through the day), residential storage is, on average, exhausted by the time of system peak 5pm – 6pm in January, resulting in no demand impact from this driver, despite accounting for ~60% of the scenario's energy impact. In sunniest summer months PV and storage completely offset customer loads in this period.
- **Fuel Switching E2G.** Although a significant share of the scenario's energy impact (26%) this load driver is overwhelmingly driving winter peak demand impacts (53%) due to the seasonal shape of the load.
- **Climate Change.** The assumed 2^{O}C increase in temperatures contributes a much larger share of the peak demand impact (35%) than of energy (5%)

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6. SCENARIO 3: DEEP ELECTRIFICATION

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SCENARIO 3 – DEEP ELECTRIFICATION: KEY ASSUMPTIONS

Description

The Deep Electrification scenario exists to help FortisBC understand the potential impacts to demand in a world where solar and storage costs have fallen, the ZEV mandate LD EV targets are met and the associated new charging infrastructure (and falling costs of storage) encourage electrification of medium and heavy duty vehicles. This scenario also assumes a concerted effort to migrate homes from natural gas to electric space- and water-heating. This scenario was designed to align with the Electrification Pathway in FortisBC's EnergyVision 2050 report. This scenario has a net **increase** in load.

Key Assumptions in Load Driver Ultimate Penetration

Driver	Key Assumptions (Ultimate Penetration of Load Driver)	
IPSS - Residential	Assumes that by 2040 15% of all residential consumers dwelling in single family homes in the FortisBC service territory will have installed 8 kW of rooftop solar PV, each. Further assumes that half of those that install rooftop PV will also (by 2040) install a 5 kW/13.5 kWh energy storage system.	
IPSS - Commercial	Assumes that by 2040 25% of all GS21 commercial customers in FortisBC service territory will have installed 20 kW of rooftop solar each. Further assumes that half of those that install rooftop PV will also (by 2040) install a 50 kW/210 kWh energy storage system.	
EVs	**Light-Duty EVs.** **Medium/Heavy-Duty EVs.**	Penetration aligns with ZEV mandate assumptions (same as Scenario 1: Upper Bound). Assumes that by 2040, 60% of return-to-base vehicle, combination tractor, and bus sales are EVs
FS G2E	Assumes that by 2040, FortisBC will achieve 15% of the residential electrification Technical potential identified by the 2019 Conservation Potential Review electrification potential study for the terminal year of that study.	
LLST	**Data Centres** **Cannabis Production**	Assumed growth (by 2040) of approximately 150,000 ft^2 of floor space from the estimated existing 200,000 ft^2. Assumed growth (by 2040) of approximately 250,000 ft^2 of floor space from the estimated existing and 100% confidence projected (via connection requests) 1 million ft^2 in 2021.
HP	Assumes an annual production of 0.7 PJ of hydrogen by 2040.	
CCS	Assumes an annual capture of 180 kT per year of industrial-sector GHG by 2040.	
CC	Assumes an average daily increase in temperature of 2^{O} C, annual 10-day cold snaps with temperatures 2.6^{O}C below average, and 10-day heat waves with temperatures 0.7 C^{O} above average	

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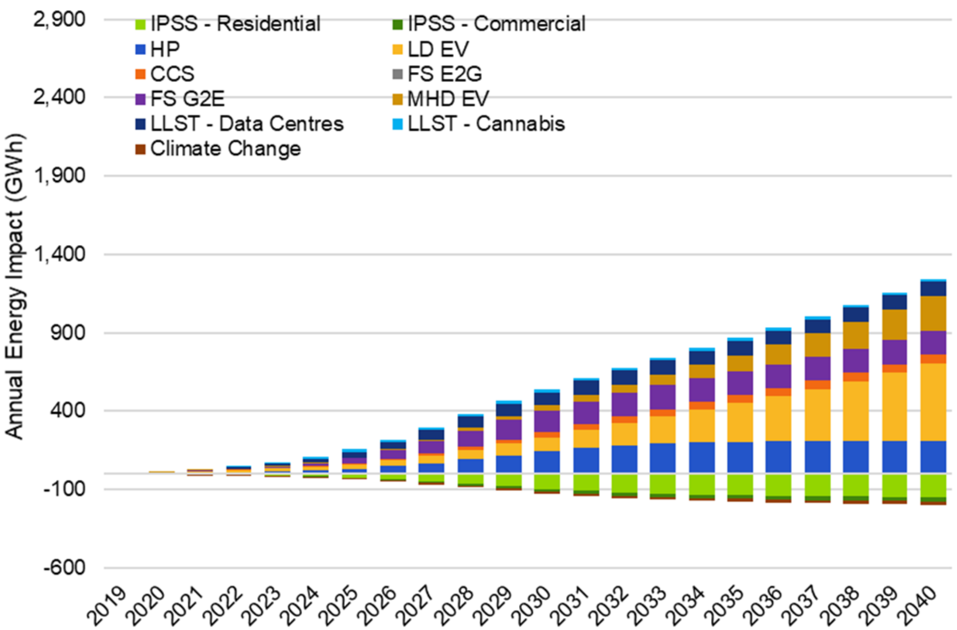
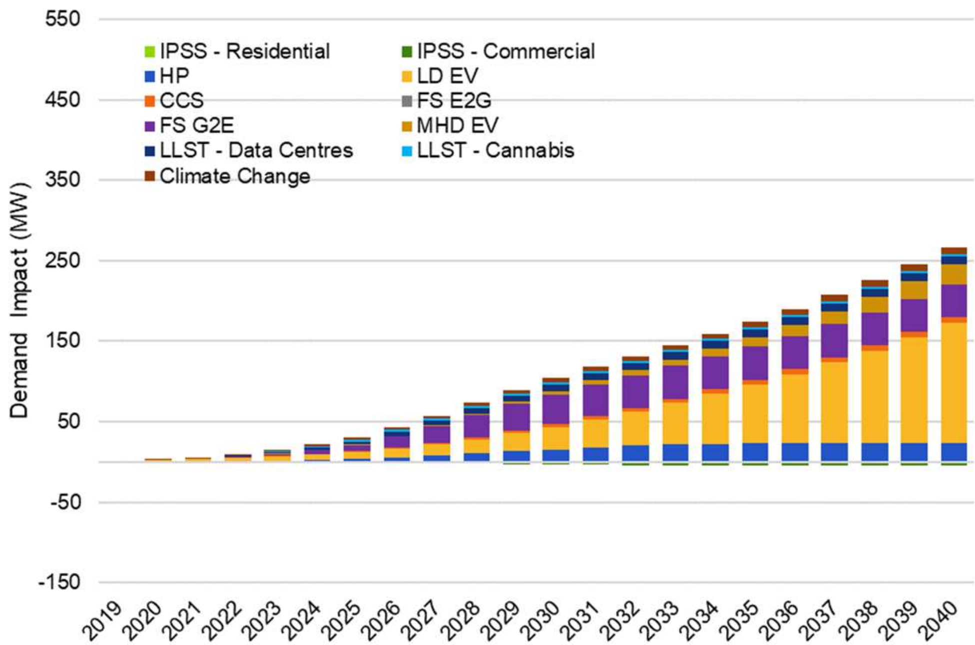
SCENARIO 3 – DEEP ELECTRIFICATION: IMPACTS BY LOAD DRIVER





Absolute and Relative Contribution to Total Impacts in 2040

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
GWh	-151	-25	205	500	54	0	155	219	92	18	-22
%	11%	2%	14%	35%	4%	0%	11%	15%	6%	1%	2%

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	-5	23	150	6	0	41	25	9	3	9
%	0%	2%	8%	55%	2%	0%	15%	9%	3%	1%	3%

NB: the % contribution here is calculated as the absolute value of the level impact for the given driver, divided by the sum of the absolute impacts of all drivers

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SCENARIO 3 – DEEP ELECTRIFICATION: NOTEWORTHY OBSERVATIONS

Under the Deep Electrification scenario (Scenario 3), by 2040, both energy consumed and January weekday demand between 5pm and 6pm increase by approximately 24% and 29% (respectively) that projected in the Business As Usual forecast.

Key Observations

- **Overall Impact.** In this scenario, the offsetting impacts of the residential IPSS driver mean that peak demand increases more (in relative terms) than energy consumption. Scenarios in which distributed generation offset energy consumption, but not peak demand growth, could result in higher electricity rates.
- **Light-Duty EVs.** The ultimate penetration of LD EVs in this scenario is the same as in the Upper Bound scenarios, approximately aligned with the Zero Emission Vehicle (ZEV) mandate. This driver therefore dominates this scenario, contributing approximately 1/3 of the sum of absolute value of energy impacts, and over half of the sum of the absolute value of demand impacts.

  This observation, along with the demonstrated effectiveness at time-varying rates (and enabling technologies) at shifting EV charging, suggests that – if growth in EV sales is expected to meet the ZEV mandate – FortisBC should consider mitigating measures.

7. SCENARIO 4: DIVERSIFIED ENERGY PATHWAY

SCENARIO 4 – DIVERSIFIED ENERGY PATHWAY: KEY ASSUMPTIONS

Description

The Diversified Energy Pathway scenario exists to help FortisBC understand the potential impact of a world featuring aggressive decarbonization of transportation (as in other scenarios) where policy attempts to meet increased demand with minimal incremental capacity procurement by converting some residential electric heating to gas. To mitigate increased emissions due this conversion, some hydrogen is injected into the NG distribution system, and some CCS procured. This scenario was designed to align with the Diversified Pathway in FortisBC's EnergyVision 2050 report. This scenario has a net **increase** in load.

Key Assumptions in Load Driver Ultimate Penetration

Driver	Key Assumptions (Ultimate Penetration of Load Driver)	
EVs	**Light-Duty EVs.** **Medium/Heavy-Duty EVs.**	By 2040, 95% of LDV sales are EVs (slightly less than Upper Bound or Deep Electrification). Assumes that by 2040, 20% of return-to-base vehicle, combination tractor, and bus sales are EVs
FS E2G	Assumes that by 2040, 35% of residential consumers dwelling in single family homes in the FortisBC service territory, that use electricity as their primary space- or water-heating fuel and that live within 50 m of a natural gas line will have converted from electric to natural gas space- and water-heating.	
LLST	**Data Centres** **Cannabis Production**	Assumed growth (by 2040) of approximately 380,000 ft^2 of floor space from the estimated existing 200,000 ft^2. Assumed growth (by 2040) of approximately 370,000 ft^2 of floor space from the estimated existing and 100% confidence projected (via connection requests) 1 million ft^2 in 2021.
HP	Assumes an annual production of 1.8 PJ of hydrogen by 2040.	
CCS	Assumes an annual capture of 180 kT per year of industrial-sector GHG by 2040.	
CC	Assumes an average daily increase in temperature of 2^{O} C, annual 10-day cold snaps with temperatures 2.6^{O}C below average, and 10-day heat waves with temperatures 0.7 C^{O} above average	

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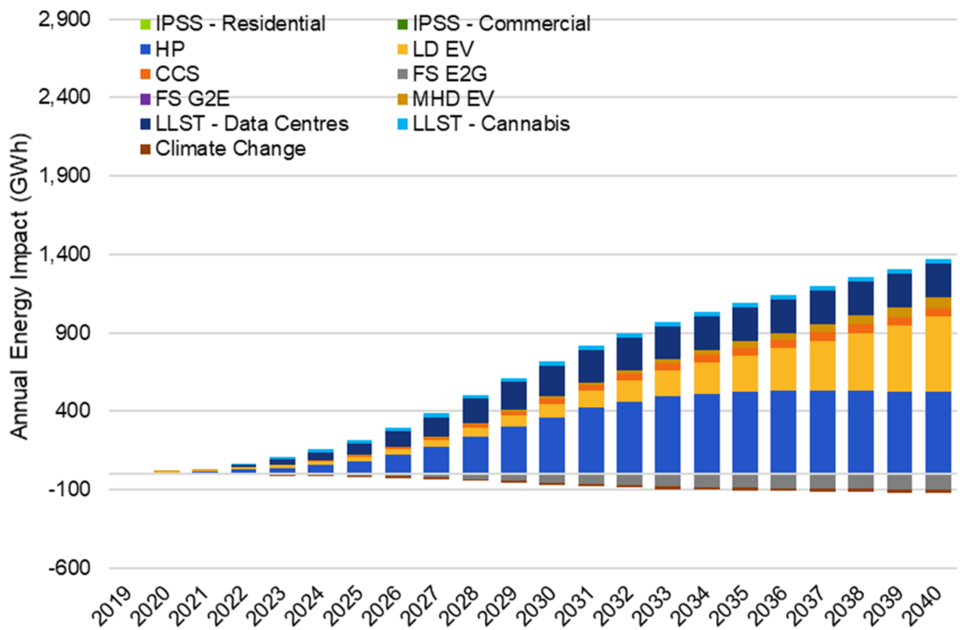
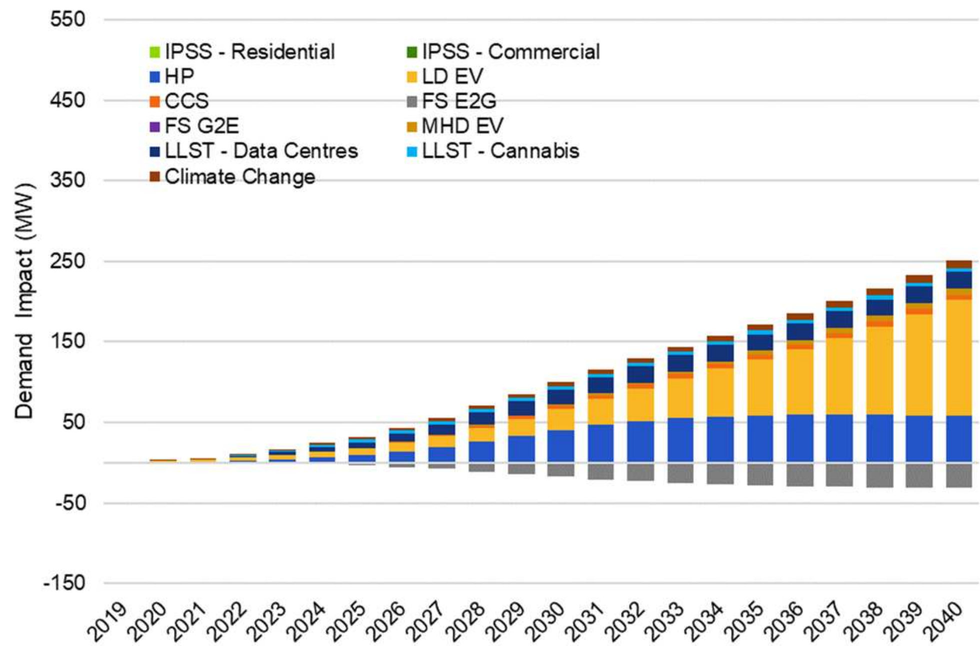
SCENARIO 4 – DIVERSIFIED ENERGY PATHWAY: IMPACTS BY LOAD DRIVER





Absolute and Relative Contribution to Total Impacts in 2040

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
GWh	0	0	526	475	54	-99	0	70	215	29	-22
%	0%	0%	35%	32%	4%	7%	0%	5%	14%	2%	1%

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	0	59	143	6	-32	0	8	21	5	9
%	0%	0%	21%	51%	2%	11%	0%	3%	7%	2%	3%

NB: the % contribution here is calculated as the absolute value of the level impact for the given driver, divided by the sum of the absolute impacts of all drivers

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SCENARIO 4 – DIVERSIFIED ENERGY PATHWAY: NOTEWORTHY OBSERVATIONS

Under the Diversified Energy Pathway scenario (Scenario 4), by 2040, both energy consumed and January weekday demand between 5pm and 6pm increase by approximately 28% and 25% (respectively) that projected in the Business As Usual forecast.

Key Observations

- **Overall Impact.** This scenario is in some ways the obverse of the Deep Electrification scenario, with energy consumption rising slightly more than peak demand (suggesting that rates could decline, or stay steady in real terms, in this scenario). This is due to the peak off-setting impact of the E2G fuel-switching reducing the peak-coincident demand increase from light-duty EVs.
- **Light-Duty EVs.** As in other scenarios, the relative contribution of this load-driver to peak demand is much greater than to energy consumption, suggesting that need for mitigating incentives or tools to shift demand off-peak.
- **Hydrogen Production**. Extensive hydrogen production (1.8 PJ, or approximately 3% of 2016 LTGRP projected 2036 gas consumption for the shared service territory) is the single largest contributor to increased energy consumption in this scenario.

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8. SCENARIO 5: DISTRIBUTED ENERGY FUTURE

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SCENARIO 5 – DISTRIBUTED ENERGY FUTURE: KEY ASSUMPTIONS

Description

The Distributed Energy Future scenario exists to help FortisBC understand the potential impact of a world where incremental energy requirements from transportation electrification are delivered via E2G fuel switching as well as growth in distributed generation. This scenario has a net **increase** in load.

Key Assumptions in Load Driver Ultimate Penetration

Driver	Key Assumptions (Ultimate Penetration of Load Driver)	
IPSS - Residential	Assumes that by 2040 25% of all residential consumers dwelling in single family homes in the FortisBC service territory will have installed 8 kW of rooftop solar PV, each. Further assumes that half of those that install rooftop PV will also (by 2040) install a 5 kW/13.5 kWh energy storage system.	
IPSS - Commercial	Assumes that by 2040 33% of all GS21 commercial customers in FortisBC service territory will have installed 20 kW of rooftop solar each. Further assumes that half of those that install rooftop PV will also (by 2040) install a 50 kW/210 kWh energy storage system.	
EVs	**Light-Duty EVs.**	By 2040, 90% of LDV sales are EVs (slightly less than Diversified Energy Pathway).
	Medium/Heavy-Duty EVs.	Assumes that by 2040, 10% of return-to-base vehicle, combination tractor, and bus sales are EVs
FS E2G	Assumes that by 2040, 35% of residential consumers dwelling in single family homes in the FortisBC service territory, that use electricity as their primary space- or water-heating fuel and that live within 50 m of a natural gas line will have converted from electric to natural gas space- and water-heating.	
HP	Assumes an annual production of 0.7 PJ of hydrogen by 2040.	
CCS	Assumes an annual capture of 180 kT per year of industrial-sector GHG by 2040.	
CC	Assumes an average daily increase in temperature of 2^{O} C, annual 10-day cold snaps with temperatures 2.6^{O}C below average, and 10-day heat waves with temperatures 0.7 C^{O} above average	

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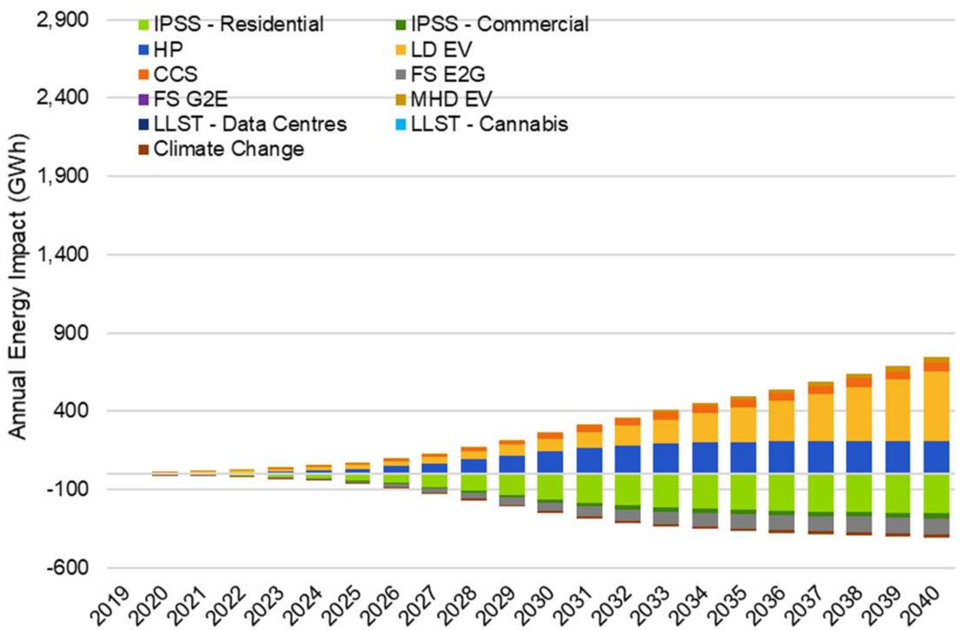
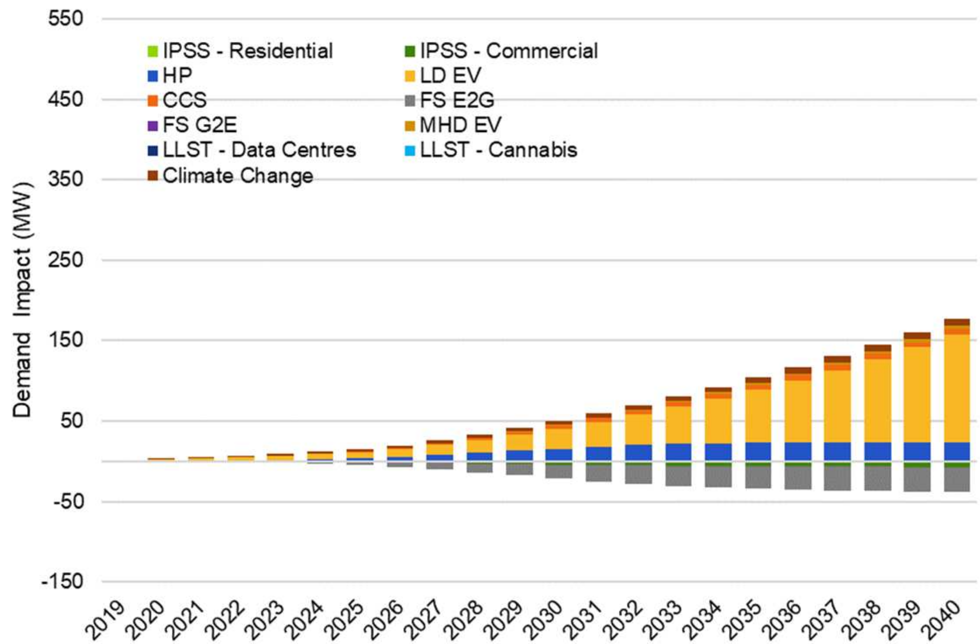
SCENARIO 5 – DISTRIBUTED ENERGY FUTURE: IMPACTS BY LOAD DRIVER





Absolute and Relative Contribution to Total Impacts in 2040

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
GWh	-252	-33	205	450	54	-99	0	35	0	0	-22
%	22%	3%	18%	39%	5%	9%	0%	3%	0%	0%	2%

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	-7	23	135	6	-32	0	4	0	0	9
%	0%	3%	11%	63%	3%	15%	0%	2%	0%	0%	4%

NB: the % contribution here is calculated as the absolute value of the level impact for the given driver, divided by the sum of the absolute impacts of all drivers

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SCENARIO 5 – DISTRIBUTED ENERGY FUTURE: NOTEWORTHY OBSERVATIONS

Under the Distributed Energy Pathway scenario (Scenario 5), by 2040, both energy consumed and January weekday demand between 5pm and 6pm increase by approximately 8% and 16% (respectively) that projected in the Business As Usual forecast.

Key Observations

- **Overall Impact.** The off-setting effects of the load drivers yield a net impact that is very small, likely well-within the uncertainty bounds of the Business-As-Usual forecast. The fact that residential IPSS delivers no peak demand reduction means, like the Deep Electrification scenario, that there is less of an increase in consumption than in peak demand.
- **Light-Duty EVs.** As in other scenarios, the relative contribution of this load-driver to peak demand is much greater than to energy consumption, suggesting that need for mitigating incentives or tools to shift demand off-peak.
- **Hydrogen Production**. Even relatively modest hydrogen production (0.7 PJ by 2040) substantially increases forecast consumption, though this driver is off-set by energy produced by residential IPSS.

NAVIGANT CONTACTS

CRAIG SABINE
Director
647-288-5227
craig.sabine@navigant.com

PETER STEELE-MOSEY
Associate Director
416-956-5050
peter.steele-mosey@navigant.com

DIXON GRANT
Senior Consultant
647-288-5211
dixon.grant@navigant.com

KRISTEN MALIK
Consultant
416-777-2449
kristen.malik@navigant.com

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APPENDIX A: JULY PEAK DEMAND IMPACTS

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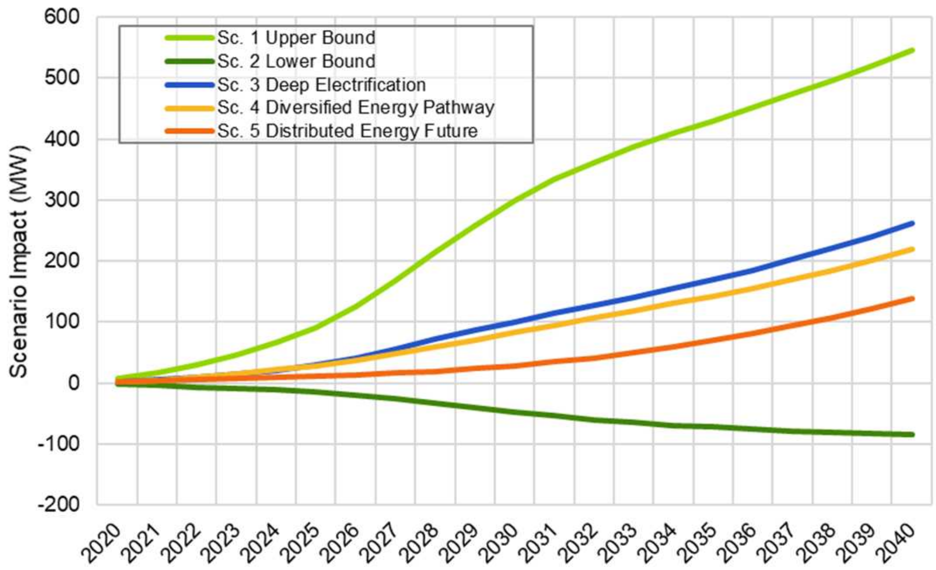
JULY DEMAND IMPACTS – COMPARED WITH JANUARY DEMAND IMPACTS

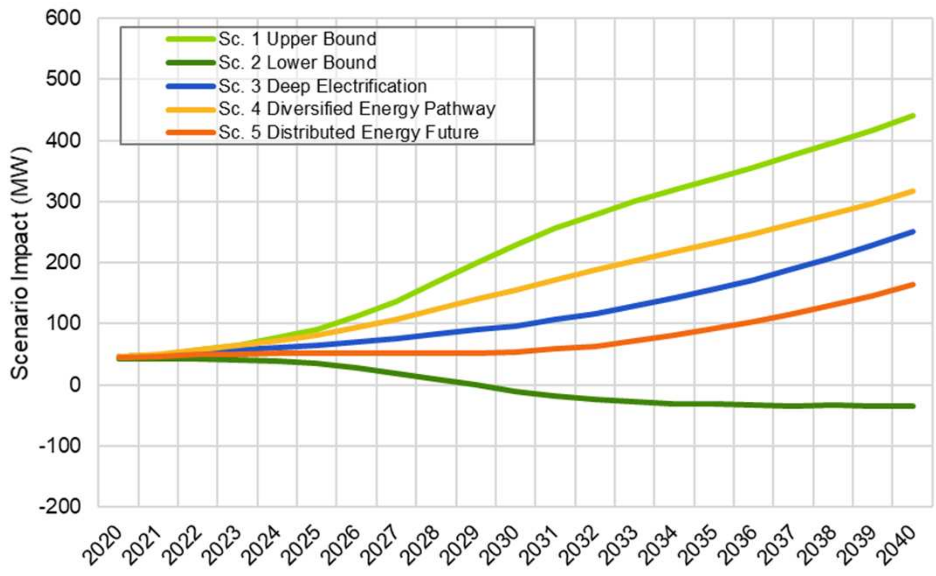
Annual January Peak Demand Impacts (MW)

Average demand on non-holiday January weekdays between 5pm and 6pm



Annual July Peak Demand Impacts (MW)

Average demand on non-holiday July weekdays between 5pm and 6pm



(MW, 2040)	Sc. 1 Upper Bound	Sc. 2 Lower Bound	Sc. 3 Deep Electrification	Sc. 4 Diversified Energy Pathway	Sc. 5 Distributed Energy Future
January	546	-85	262	219	139
July	440	-34	251	317	164

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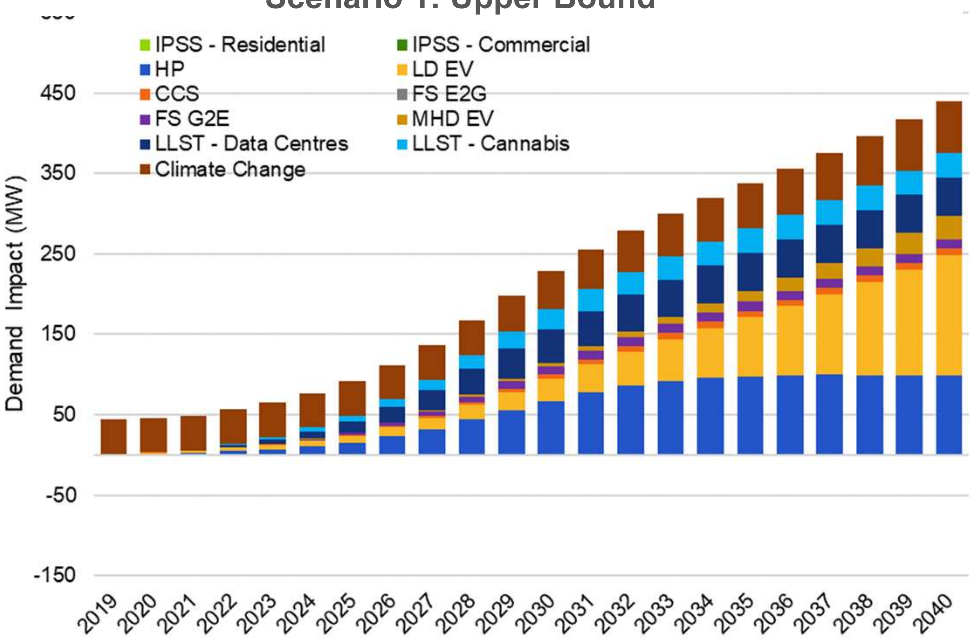
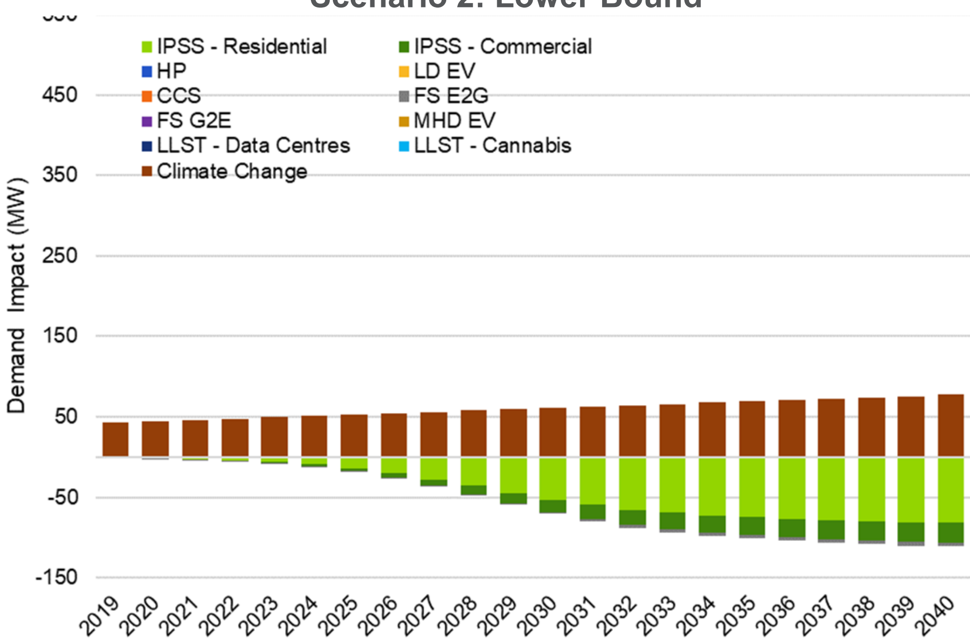
JULY PEAK DEMAND IMPACTS – UPPER AND LOWER BOUND SCENARIOS

Scenario 1: Upper Bound



Scenario 2: Lower Bound



Absolute and Relative Contribution to Total Impacts in 2040

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	0	98	150	8	0	11	29	48	30	65
%	0%	0%	22%	34%	2%	0%	3%	7%	11%	7%	15%

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	-82	-25	0	0	0	-5	0	0	0	0	77
%	43%	13%	0%	0%	0%	3%	0%	0%	0%	0%	41%

NB: the % contribution here is calculated as the absolute value of the level impact for the given driver, divided by the sum of the absolute impacts of all drivers

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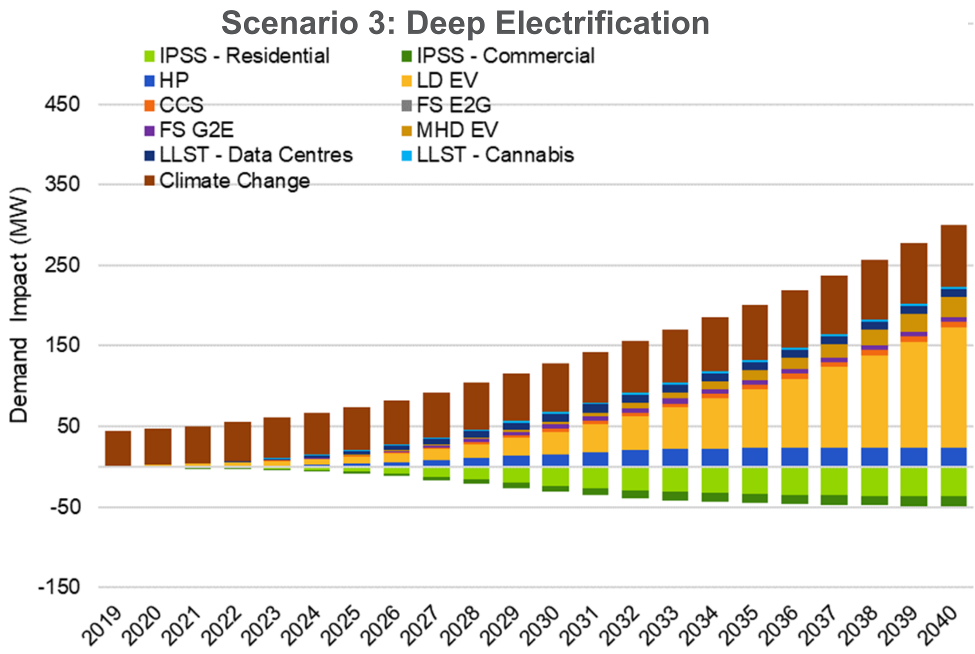
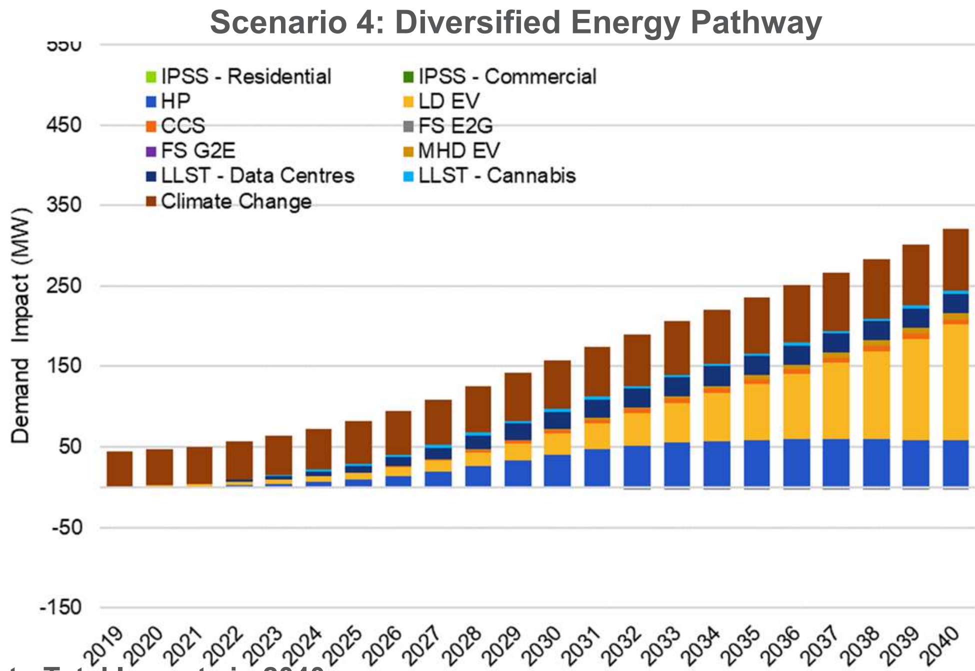
JULY PEAK DEMAND IMPACTS – DEEP ELECTRIFICATION AND DIVERSIFIED ENERGY PATHWAY SCENARIOS





Absolute and Relative Contribution to Total Impacts in 2040

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	-37	-12	23	150	6	0	6	25	10	2	77
%	11%	4%	7%	43%	2%	0%	2%	7%	3%	1%	22%

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	0	0	59	143	6	-3	0	8	24	3	77
%	0%	0%	18%	44%	2%	1%	0%	2%	8%	1%	24%

NB: the % contribution here is calculated as the absolute value of the level impact for the given driver, divided by the sum of the absolute impacts of all drivers

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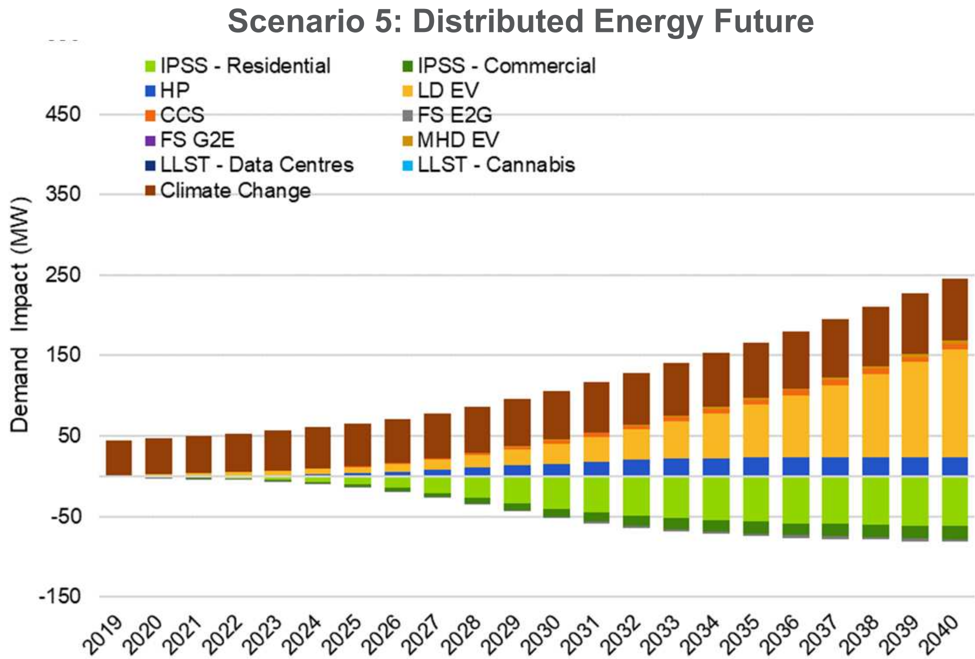
JULY PEAK DEMAND IMPACTS – DEEP ELECTRIFICATION AND DIVERSIFIED ENERGY PATHWAY SCENARIOS



Absolute and Relative Contribution to Total Impacts in 2040

2040 Impact:	IPSS - RES	IPSS - COM	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	LLST - Data Centres	LLST - Cannabis	Climate Change
MW	-62	-16	23	135	6	-3	0	4	0	0	77
%	19%	5%	7%	41%	2%	1%	0%	1%	0%	0%	24%

NB: the % contribution here is calculated as the absolute value of the level impact for the given driver, divided by the sum of the absolute impacts of all drivers

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Appendix J

LOAD SCENARIOS DATA TABLES

GUIDEHOUSE AND STAKEHOLDER AVERAGE LOAD SCENARIOS DATA TABLES

Guidehouse and Stakeholder load drivers and corresponding scenario data are stated at the point of consumption.

Scenario 1 (Upper Bound) Energy Impacts (GWh/year)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Data Centres	Cannabis	Climate Change	Total
2020	0	0	11	6	1	0	2	0	0	0	1	21
2021	0	0	22	10	1	0	5	0	0	0	2	40
2022	0	0	44	14	3	0	9	1	22	13	3	108
2023	0	0	64	19	4	0	18	2	48	27	4	186
2024	0	0	95	24	6	0	34	3	80	44	5	291
2025	0	0	136	29	9	0	61	5	118	63	6	429
2026	0	0	207	37	14	0	103	9	164	86	8	627
2027	0	0	286	47	20	0	155	13	220	111	9	861
2028	0	0	393	60	28	0	207	19	287	140	10	1,144
2029	0	0	498	75	36	0	248	27	336	174	11	1,405
2030	0	0	600	92	44	0	276	37	369	213	12	1,643
2031	0	0	699	114	52	0	292	49	390	235	13	1,845
2032	0	0	768	141	58	0	301	63	403	247	14	1,995
2033	0	0	825	172	63	0	305	79	411	253	16	2,125
2034	0	0	853	208	66	0	307	98	416	257	17	2,222
2035	0	0	872	245	68	0	308	119	419	258	18	2,308
2036	0	0	880	287	69	0	309	143	421	259	19	2,388
2037	0	0	888	333	71	0	309	168	422	259	20	2,472
2038	0	0	888	384	71	0	309	195	423	260	21	2,552
2039	0	0	878	440	71	0	310	224	423	260	23	2,628
2040	0	0	877	500	72	0	310	254	424	260	24	2,720

Scenario 1 (Upper Bound) Winter Peak Demand Impacts (MW)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Data Centres	Cannabis	Climate Change	Total
2020	0	0	1	2	0	0	1	0	0	0	5	8
2021	0	0	2	3	0	0	1	0	0	0	9	16
2022	0	0	5	4	0	0	2	0	2	2	14	30
2023	0	0	7	6	0	0	5	0	5	4	18	46
2024	0	0	11	7	1	0	9	0	8	7	23	66
2025	0	0	15	9	1	0	16	1	11	10	28	91
2026	0	0	23	11	2	0	27	1	16	14	32	126
2027	0	0	32	14	2	0	41	2	21	18	37	167
2028	0	0	44	18	3	0	55	2	28	23	41	215
2029	0	0	56	22	4	0	66	3	33	28	46	259
2030	0	0	67	28	5	0	74	4	36	34	51	299
2031	0	0	78	34	6	0	78	6	38	38	55	333
2032	0	0	86	42	7	0	80	7	39	40	59	361
2033	0	0	92	52	7	0	82	9	40	41	64	387
2034	0	0	96	62	7	0	82	11	40	41	68	409
2035	0	0	98	74	8	0	82	14	41	42	73	430
2036	0	0	99	86	8	0	83	16	41	42	77	451
2037	0	0	100	100	8	0	83	19	41	42	81	474
2038	0	0	99	115	8	0	83	22	41	42	86	497
2039	0	0	98	132	8	0	83	26	41	42	90	520
2040	0	0	98	150	8	0	83	29	41	42	95	546

Scenario 2 (Lower Bound) Energy Impacts (GWh/year)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Data Centres	Cannabis	Climate Change	Total
2020	-5	-1	0	0	0	-2	0	0	0	0	-2	(10)
2021	-11	-1	0	0	0	-3	0	0	0	0	-4	(19)
2022	-16	-2	0	0	0	-7	0	0	0	0	-6	(31)
2023	-25	-3	0	0	0	-10	0	0	0	0	-7	(46)
2024	-36	-5	0	0	0	-16	0	0	0	0	-9	(66)
2025	-56	-8	0	0	0	-23	0	0	0	0	-11	(98)
2026	-80	-11	0	0	0	-36	0	0	0	0	-12	(139)
2027	-113	-16	0	0	0	-52	0	0	0	0	-14	(194)
2028	-146	-20	0	0	0	-73	0	0	0	0	-15	(255)
2029	-181	-25	0	0	0	-95	0	0	0	0	-17	(318)
2030	-216	-30	0	0	0	-117	0	0	0	0	-18	(382)
2031	-243	-34	0	0	0	-140	0	0	0	0	-20	(437)
2032	-267	-38	0	0	0	-158	0	0	0	0	-21	(483)
2033	-283	-40	0	0	0	-173	0	0	0	0	-22	(518)
2034	-295	-42	0	0	0	-183	0	0	0	0	-23	(544)
2035	-305	-44	0	0	0	-191	0	0	0	0	-25	(564)
2036	-314	-45	0	0	0	-197	0	0	0	0	-26	(582)
2037	-320	-46	0	0	0	-203	0	0	0	0	-27	(597)
2038	-323	-47	0	0	0	-207	0	0	0	0	-28	(606)
2039	-330	-48	0	0	0	-209	0	0	0	0	-29	(616)
2040	-333	-49	0	0	0	-213	0	0	0	0	-30	(625)

Scenario 2 (Lower Bound) Winter Peak Demand Impacts (MW)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Data Centres	Cannabis	Climate Change	Total
2020	0	0	0	0	0	0	0	0	0	0	-1	(2)
2021	0	0	0	0	0	-1	0	0	0	0	-3	(4)
2022	0	0	0	0	0	-2	0	0	0	0	-4	(7)
2023	0	-1	0	0	0	-3	0	0	0	0	-6	(9)
2024	0	-1	0	0	0	-4	0	0	0	0	-7	(12)
2025	0	-2	0	0	0	-6	0	0	0	0	-9	(16)
2026	0	-2	0	0	0	-9	0	0	0	0	-10	(22)
2027	0	-3	0	0	0	-13	0	0	0	0	-12	(28)
2028	0	-4	0	0	0	-19	0	0	0	0	-13	(36)
2029	0	-5	0	0	0	-24	0	0	0	0	-14	(44)
2030	0	-6	0	0	0	-30	0	0	0	0	-16	(52)
2031	0	-7	0	0	0	-36	0	0	0	0	-17	(60)
2032	0	-8	0	0	0	-40	0	0	0	0	-19	(67)
2033	0	-8	0	0	0	-44	0	0	0	0	-20	(73)
2034	0	-9	0	0	0	-47	0	0	0	0	-21	(77)
2035	0	-9	0	0	0	-49	0	0	0	0	-23	(81)
2036	0	-9	0	0	0	-50	0	0	0	0	-24	(84)
2037	0	-10	0	0	0	-52	0	0	0	0	-26	(87)
2038	0	-10	0	0	0	-53	0	0	0	0	-27	(90)
2039	0	-10	0	0	0	-53	0	0	0	0	-28	(92)
2040	0	-10	0	0	0	-54	0	0	0	0	-30	(94)

Scenario 3 (Deep Electrification) Energy Impacts (GWh/year)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Data Centres	Cannabis	Climate Change	Total
2020	-2	0	3	6	1	0	1	0	0	0	-2	6
2021	-5	-1	5	10	1	0	2	0	0	0	-3	10
2022	-7	-1	10	14	2	0	5	1	8	4	-4	31
2023	-11	-2	15	19	3	0	9	1	17	9	-6	54
2024	-16	-2	22	24	5	0	17	3	26	13	-7	84
2025	-25	-4	32	29	7	0	31	5	36	16	-8	117
2026	-36	-5	48	37	11	0	51	7	47	17	-10	167
2027	-51	-8	67	47	15	0	77	11	59	18	-11	224
2028	-66	-10	92	60	21	0	103	17	71	18	-12	293
2029	-82	-13	116	75	27	0	124	23	79	18	-13	355
2030	-98	-15	140	92	33	0	138	32	84	18	-14	410
2031	-110	-17	163	114	39	0	146	42	87	18	-15	468
2032	-122	-19	179	141	43	0	150	54	89	18	-16	519
2033	-129	-20	193	172	47	0	153	68	90	18	-17	576
2034	-134	-21	199	208	49	0	154	84	91	18	-18	631
2035	-138	-22	203	245	51	0	154	103	92	18	-18	687
2036	-143	-23	205	287	52	0	155	123	92	18	-19	747
2037	-146	-23	207	333	53	0	155	145	92	18	-20	815
2038	-147	-24	207	384	53	0	155	168	92	18	-20	887
2039	-150	-24	205	440	53	0	155	193	92	18	-21	961
2040	-151	-25	205	500	54	0	155	219	92	18	-22	1,045

Scenario 3 (Deep Electrification) Winter Peak Demand Impacts (MW)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Data Centres	Cannabis	Climate Change	Total
2020	0	0	0	2	0	0	0	0	0	0	0	3
2021	0	0	1	3	0	0	1	0	0	0	1	5
2022	0	0	1	4	0	0	1	0	1	1	1	9
2023	0	0	2	6	0	0	2	0	2	1	2	15
2024	0	-1	2	7	1	0	5	0	3	2	2	21
2025	0	-1	4	9	1	0	8	1	3	3	3	30
2026	0	-1	5	11	1	0	14	1	5	3	3	42
2027	0	-2	7	14	2	0	21	1	6	3	4	56
2028	0	-2	10	18	2	0	28	2	7	3	4	72
2029	0	-3	13	22	3	0	33	3	8	3	4	87
2030	0	-3	16	28	4	0	37	4	8	3	5	101
2031	0	-4	18	34	4	0	39	5	8	3	5	114
2032	0	-4	20	42	5	0	40	6	9	3	6	127
2033	0	-4	22	52	5	0	41	8	9	3	6	141
2034	0	-4	22	62	6	0	41	10	9	3	7	155
2035	0	-5	23	74	6	0	41	12	9	3	7	170
2036	0	-5	23	86	6	0	41	14	9	3	8	185
2037	0	-5	23	100	6	0	41	17	9	3	8	202
2038	0	-5	23	115	6	0	41	19	9	3	8	221
2039	0	-5	23	132	6	0	41	22	9	3	9	240
2040	0	-5	23	150	6	0	41	25	9	3	9	262

Scenario 4 (Diversified Energy Pathway) Energy Impacts (GWh/year)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Data Centres	Cannabis	Climate Change	Total
2020	0	0	7	6	1	0	0	0	0	0	-2	12
2021	0	0	13	9	1	0	0	0	0	0	-3	21
2022	0	0	26	13	2	0	0	0	15	6	-4	58
2023	0	0	39	18	3	0	0	1	31	13	-6	99
2024	0	0	57	22	5	0	0	1	50	20	-7	149
2025	0	0	82	28	7	0	0	2	72	24	-8	206
2026	0	0	124	35	11	0	0	3	97	26	-10	287
2027	0	0	171	45	15	0	0	5	125	28	-11	377
2028	0	0	236	57	21	0	0	7	157	28	-12	493
2029	0	0	299	71	27	0	0	10	178	28	-13	600
2030	0	0	360	88	33	0	0	13	193	28	-14	701
2031	0	0	420	109	39	0	0	17	201	29	-15	799
2032	0	0	461	134	43	0	0	21	207	29	-16	879
2033	0	0	495	163	47	0	0	26	210	29	-17	954
2034	0	0	512	197	49	0	0	32	212	29	-18	1,014
2035	0	0	523	233	51	0	0	38	214	29	-18	1,068
2036	0	0	528	273	52	0	0	44	214	29	-19	1,120
2037	0	0	533	317	53	0	0	50	215	29	-20	1,177
2038	0	0	533	365	53	0	0	57	215	29	-20	1,231
2039	0	0	527	418	53	0	0	63	215	29	-21	1,284
2040	0	0	526	475	54	0	0	70	215	29	-22	1,347

Scenario 4 (Diversified Energy Pathway) Winter Peak Demand Impacts (MW)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Data Centres	Cannabis	Climate Change	Total
2020	0	0	1	2	0	0	0	0	0	0	0	3
2021	0	0	1	3	0	0	0	0	0	0	1	5
2022	0	0	3	4	0	0	0	0	1	1	1	11
2023	0	0	4	5	0	0	0	0	3	2	2	17
2024	0	0	6	7	1	0	0	0	5	3	2	24
2025	0	0	9	8	1	0	0	0	7	4	3	32
2026	0	0	14	11	1	0	0	0	9	4	3	43
2027	0	0	19	13	2	0	0	1	12	4	4	55
2028	0	0	26	17	2	0	0	1	15	5	4	70
2029	0	0	33	21	3	0	0	1	17	5	4	85
2030	0	0	40	26	4	0	0	2	19	5	5	100
2031	0	0	47	33	4	0	0	2	20	5	5	115
2032	0	0	52	40	5	0	0	2	20	5	6	130
2033	0	0	55	49	5	0	0	3	20	5	6	144
2034	0	0	57	59	6	0	0	4	21	5	7	158
2035	0	0	59	70	6	0	0	4	21	5	7	171
2036	0	0	59	82	6	0	0	5	21	5	8	185
2037	0	0	60	95	6	0	0	6	21	5	8	200
2038	0	0	60	110	6	0	0	7	21	5	8	216
2039	0	0	59	125	6	0	0	7	21	5	9	232
2040	0	0	59	143	6	0	0	8	21	5	9	251

Scenario 5 (Distributed Energy Future) Energy Impacts (GWh/year)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Data Centres	Cannabis	Climate Change	Total
2020	-4	0	3	6	1	-1	0	0	0	0	-2	2
2021	-8	-1	5	9	1	-2	0	0	0	0	-3	1
2022	-12	-1	10	13	2	-5	0	0	0	0	-4	2
2023	-19	-2	15	17	3	-7	0	0	0	0	-6	1
2024	-27	-3	22	21	5	-11	0	1	0	0	-7	0
2025	-42	-5	32	26	7	-16	0	1	0	0	-8	(6)
2026	-60	-7	48	33	11	-26	0	2	0	0	-10	(9)
2027	-85	-10	67	42	15	-36	0	2	0	0	-11	(16)
2028	-111	-13	92	54	21	-51	0	4	0	0	-12	(17)
2029	-137	-17	116	67	27	-66	0	5	0	0	-13	(18)
2030	-164	-20	140	83	33	-82	0	7	0	0	-14	(17)
2031	-184	-22	163	103	39	-98	0	9	0	0	-15	(6)
2032	-203	-25	179	127	43	-110	0	11	0	0	-16	6
2033	-214	-26	193	155	47	-121	0	13	0	0	-17	29
2034	-224	-28	199	187	49	-128	0	16	0	0	-18	54
2035	-231	-29	203	221	51	-134	0	19	0	0	-18	82
2036	-238	-30	205	258	52	-138	0	22	0	0	-19	113
2037	-243	-31	207	300	53	-142	0	25	0	0	-20	150
2038	-245	-31	207	346	53	-145	0	28	0	0	-20	193
2039	-250	-32	205	396	53	-146	0	32	0	0	-21	236
2040	-252	-33	205	450	54	-149	0	35	0	0	-22	288

Scenario 5 (Distributed Energy Future) Winter Peak Demand Impacts (MW)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Data Centres	Cannabis	Climate Change	Total
2020	0	0	0	2	0	0	0	0	0	0	0	2
2021	0	0	1	3	0	-1	0	0	0	0	1	3
2022	0	0	1	4	0	-1	0	0	0	0	1	5
2023	0	0	2	5	0	-2	0	0	0	0	2	7
2024	0	-1	2	6	1	-3	0	0	0	0	2	8
2025	0	-1	4	8	1	-4	0	0	0	0	3	10
2026	0	-2	5	10	1	-7	0	0	0	0	3	12
2027	0	-2	7	13	2	-9	0	0	0	0	4	14
2028	0	-3	10	16	2	-13	0	0	0	0	4	17
2029	0	-3	13	20	3	-17	0	1	0	0	4	21
2030	0	-4	16	25	4	-21	0	1	0	0	5	25
2031	0	-5	18	31	4	-25	0	1	0	0	5	30
2032	0	-5	20	38	5	-28	0	1	0	0	6	37
2033	0	-6	22	46	5	-31	0	2	0	0	6	45
2034	0	-6	22	56	6	-33	0	2	0	0	7	54
2035	0	-6	23	66	6	-34	0	2	0	0	7	64
2036	0	-6	23	78	6	-35	0	3	0	0	8	75
2037	0	-6	23	90	6	-36	0	3	0	0	8	88
2038	0	-7	23	104	6	-37	0	3	0	0	8	101
2039	0	-7	23	119	6	-37	0	4	0	0	9	116
2040	0	-7	23	135	6	-38	0	4	0	0	9	133

Stakeholder Average Scenario - Energy Impacts (GWh/year)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Large Loads	Climate Change	Total
2020	0	0	0	0	0	0	0	0	0	0	-
2021	-20	-3	30	46	2	-4	20	17	35	0	122
2022	-26	-4	38	61	2	-6	25	22	46	0	159
2023	-33	-6	48	81	3	-7	32	30	60	0	207
2024	-43	-7	61	107	4	-10	40	38	77	0	267
2025	-54	-9	76	137	5	-12	50	49	97	1	339
2026	-68	-12	94	172	6	-15	62	62	121	1	423
2027	-83	-14	116	209	7	-19	76	75	148	1	517
2028	-99	-17	141	248	9	-22	92	90	176	1	618
2029	-115	-19	170	284	10	-26	109	103	205	1	723
2030	-131	-22	202	317	12	-29	128	117	233	1	828
2031	-146	-24	237	348	13	-33	148	129	260	2	934
2032	-161	-26	276	375	15	-36	168	142	284	2	1,039
2033	-174	-28	320	399	16	-39	189	154	306	2	1,145
2034	-187	-29	369	422	18	-42	209	166	325	2	1,252
2035	-199	-30	421	443	20	-45	229	178	340	2	1,359
2036	-209	-31	472	462	21	-47	247	189	352	2	1,457
2037	-218	-32	513	477	22	-49	262	198	362	2	1,538
2038	-224	-33	542	488	23	-50	272	205	369	2	1,594
2039	-227	-33	558	494	24	-51	279	208	374	2	1,628
2040	-230	-33	567	498	24	-52	283	210	378	2	1,648

Stakeholder Average Scenario - Winter Peak Demand Impacts (MW)

Year	IPSS - Res	IPSS - Com	HP	LD EV	CCS	FS E2G	FS G2E	MHD EV	Large Loads	Climate Change	Total
2020	0	0	0	0	0	0	0	0	0	0	-
2021	0	-1	3	14	0	-1	5	2	4	1	28
2022	0	-1	4	18	0	-1	7	3	6	1	36
2023	0	-1	5	24	0	-2	8	3	7	1	48
2024	0	-2	7	32	0	-2	11	4	9	2	61
2025	0	-2	8	41	1	-3	13	6	12	2	78
2026	0	-2	11	52	1	-4	17	7	15	3	98
2027	0	-3	13	63	1	-5	20	9	18	3	119
2028	0	-3	16	74	1	-6	25	10	21	4	142
2029	0	-4	19	85	1	-7	29	12	25	5	166
2030	0	-5	23	95	1	-7	34	13	28	6	189
2031	0	-5	27	104	2	-8	40	15	32	6	211
2032	0	-5	31	112	2	-9	45	16	35	7	233
2033	0	-6	36	120	2	-10	50	18	37	7	255
2034	0	-6	41	127	2	-11	56	19	39	8	276
2035	0	-6	47	133	2	-11	61	20	41	8	296
2036	0	-7	53	139	2	-12	66	22	43	9	315
2037	0	-7	58	143	3	-12	70	23	44	9	330
2038	0	-7	61	146	3	-13	73	24	45	9	341
2039	0	-7	63	148	3	-13	75	24	45	10	347
2040	0	-7	63	150	3	-13	76	24	46	10	351

Appendix K

SUPPLY-SIDE RESOURCE OPTIONS REPORT

FORTISBC INC.

Appendix K

2021 Long-Term Electric Resource Plan

Supply-Side

Resource Options Report

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List of Tables and Figures

1. INTRODUCTION

This Supply-Side Resource Options Report (ROR) provides information related to the various supply-side energy and capacity resources that are available to FBC to meet any forecast load-resource balance gaps over the 20-year resource planning horizon. These options include resources that could potentially be available either within or outside of FBC's service area. Resources from outside of FBC's service area would require external transmission arrangements to serve FBC load. The resource options include market purchases as well as the PPA with BC Hydro. The information in this ROR enables FBC to determine the energy and capacity attributes and high-level unit costs for each resource, and is summarized in Section 10.3 of the LTERP. This enables the development of resource options portfolios so that alternative portfolios can be compared and a preferred portfolio can be selected. The portfolio analysis is provided in Section 11 of the LTERP.

The resource options information is provided at a level appropriate for long-term resource planning. If and when particular resources are required in the future, BCUC approval will be obtained by way of applications for approval of CPCNs or energy supply contracts, as appropriate.

The supply-side resource options costs were developed in collaboration with BC Hydro as it updated its Resource Options Inventory in preparation for its 2021 Integrated Resource Plan (IRP). As part of this process, consultants and industry experts helped update the potential energy and capacity available from various resource options in BC, as well as to update resource cost information. By collaborating on updating the resource options, FBC and BC Hydro achieved efficiencies in both time and costs and developed a consistent set of resource options as opposed to assessing resource options in BC through separate processes. FBC then selected a representative portfolio of projects to include in its resource options inventory for the purpose of its portfolio analysis. The cost of the projects in the resource options inventory were adjusted, where appropriate, to reflect FBC costs and assumptions regarding markets and rate forecasts.

Demand-side resource options were not included in the resource option collaboration with BC Hydro as FBC and BC Hydro each have distinct demand-side management programs tailored to their specific customer groups. FBC's DSM is discussed further in Section 8 and the LT DSM Plan.

Numerous supply-side resource options are identified and/or evaluated within this ROR, reflecting the variety and abundance of potential electricity generating resources in the FBC service area or within BC While some options are commonly used amongst electrical utilities, such as run-of-river or gas-fired generation, others are considered less mainstream and/or are based on emerging technologies, such as geothermal generation. FBC has pre-screened the resource options for any emerging resource technologies that are not yet viable or cost effective as well as those that are not consistent with the *CEA*. This does not mean that these resource options could not be considered in the future; however, these resources have not been evaluated for the purposes of this ROR. Resources that have not be evaluated for these reasons are identified in the Resource Options Summary Table J3-1. These are discussed in Section 3.9 of this ROR.

Recent declines in costs relating to some renewable resource options, such as solar and wind power, mean that these resource options may be more cost-effective than in the past. However, it is important to remember that these types of resources are intermittent and cannot reliably provide dependable capacity on their own. This must be taken into consideration when evaluating these resource options.

FBC has also given consideration to the geographical diversity of its resource base, given that the generation resources owned by FBC are all located in the Kootenay region while most of its load requirements are in the Okanagan region.

2. RESOURCE VALUATION METHODOLOGY

In addition to financial attributes, FBC considers a number of factors when evaluating its resource options. These include consistency with BC energy policy as well as resource attributes, such as operational characteristics, environmental impacts and plant footprint. Geographic diversity of resources is also a consideration given that all of the generation plants FBC owns are located in the Kootenay region whereas most of the load and recent load growth is in the Okanagan region. Locating new generation resources closer to the primary load centres would help mitigate risks relating to transmission disruptions and reliability in the future, and could reduce or delay the need for transmission upgrades in the future. Furthermore, a number of financial assumptions must be made in order to cost the resource options, such as gas and electricity market prices, BC Hydro electricity rates and the cost for carbon emissions. These are discussed in the following sections.

2.1 *ENERGY POLICY ENVIRONMENT*

2.1.1 The BC Clean Energy Act

As discussed in Section 2.2 of the LTERP, the *Clean Energy Act* (*CEA)* contains the specific energy objectives for the Province of BC These energy objectives are an important factor in resource planning and assessing resources options for FBC.

The *CEA* includes a requirement that BC Hydro achieve electricity self-sufficiency by 2016 and each year after that, and section 6(4) states that a public utility, in planning in accordance with section 44.1 of the *UCA*, must consider BC's energy objective to achieve electricity self-sufficiency.

In June 2020, the NDP government proposed Bill 17 to amend the *CEA*. One of the key proposed amendments include repealing the self-sufficiency planning requirement that BC Hydro's new generation resources must be located within BC. The other key proposed amendment includes introducing a new objective for the province to serve grid-connected customers with clean electricity, effectively enabling the implementation of a 100 percent clean energy standard for BC.

On July 15, 2020, independent MLA Andrew Weaver proposed that Bill 17 be amended to maintain the province's energy objective of electricity self-sufficiency. Clean energy producers and Indigenous groups also opposed the removal of the self-sufficiency requirement on the basis that it would reduce opportunities for development of clean energy projects within BC. At this time, the proposed *CEA* amendments have not been enacted into legislation.

Therefore, FBC must still consider this objective when assessing its resource options and, in particular, the inclusion of market purchases in its resource portfolio. Market purchases are discussed in Section 3.5 of this ROR.

Section 2 of the *CEA* also includes the objective of generating at least 93 percent of the electricity in BC from clean or renewable resources. The *CEA* defines “clean or renewable resource” as meaning biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. The Clean or Renewable Resource Regulation, BC Reg. 291/2010 (as amended) adds biogenic waste, waste heat and waste hydrogen to this list. Natural gas-fired generation is not a prescribed clean or renewable resource, however for the purpose of this ROR, FBC has included gas-fired generation fueled by RNG as a clean and renewable resource option. Section 19 of the *CEA* states that the objectives relating to clean or renewable resources apply to BC Hydro and any prescribed public utility. While FBC does not fall into these categories, it takes this energy objective (as well as other relevant objectives) into consideration in its resource planning and resource assessment.

2.1.2 BC Carbon Tax

As of April 1, 2021, BC's carbon tax rate was $45 per tonne. The rate is scheduled to increase to $50 per tonne on April 1, 2022. In December 2020, the Canadian federal government announced that it planned to increase the price on carbon as part of a push to meet and surpass Canada's goal of reducing greenhouse gas emissions by 30 percent below 2005 levels by 2030. In 2022 the federal carbon tax is to reach $50 per tonne. The announcement was that the federal carbon tax would then rise by 15 per tonne per year for the next eight years beginning in 2023 to reach $170 per tonne in 2030.[1] It is unclear how the price would be implemented in each province and territory, however based on this announcement it is likely that BC’s carbon tax will increase above its current level after 2022. Any increase in carbon tax would affect the cost of natural gas generation fueled by conventional natural gas, one of FBC’s resource options.

2.1.3 BC Provincial Climate Targets and the CleanBC Plan

The provincial government’s emission targets require that GHGs in BC be 16 percent below 2007 levels by 2025, 40 percent by 2030, 60 percent by 2040 and 80 percent by 2050. The sectoral targets were released in March of 2021 and the provincial government specified the reduction percentage ranges for each sector. The reductions are 27 to 32 percent for transportation, 38 to 43 percent for industry, 33 to 38 percent for the oil and gas sector, and 59 to 64 percent for buildings and communities[2]. The government also made funding available to help these sectors achieve the required reduction percentages.

The BC Government released its CleanBC provincial climate plan in December 2018. The CleanBC plan is aimed at reducing climate pollution while creating jobs and economic opportunities. This plan enables BC to reach 75 percent of the 2030 GHG reduction targets,

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[1] https://www.cbc.ca/news/politics/carbon-tax-hike-new-climate-plan-1.5837709
[2] https://news.gov.bc.ca/releases/2021ENV0022-000561?utm_source=All+Media&utm_campaign=cc65214715-EMAIL_CAMPAIGN_2019_04_17_05_48_COPY_01&utm_medium=email&utm_term=0_135bfb50a9-cc65214715-347685745

with the means to achieving the remaining 25 percent still to be determined. Since the CleanBC plan was released, the Climate Change Accountability Act was updated in 2020 to strengthen transparency and accountability relating to the CleanBC plan, including establishing a requirement to set an interim province-wide target and sectoral targets for emission reductions. This may impact FBC's ability to consider natural gas fired generation in the future. As mentioned above, as a carbon-neutral alternative, FBC has included gas-fired generation using RNG as a fuel as a resource option in this LTERP.

2.2 RESOURCE ATTRIBUTES

FBC considers a number of attributes of the various resource options it evaluates. These attributes include technical, financial, environmental and socio-economic development.

2.2.1 Technical Attributes

Technical attributes describe the energy and capacity characteristics of the resource options. Capacity refers to a resource's ability to meet customers' peak load requirements at a particular point in time and is typically measured in MW. Installed capacity, sometimes called nameplate capacity, is the maximum designed output of a power generation plant. Dependable capacity is defined as the generation capacity available for the peak hours during the each month of the year. For FBC, system peak electrical demand typically occurs in December or January sometime between the hours of 4 pm and 9 pm. Energy, on the other hand, is the amount of electricity generated over a period of time and is usually expressed in GWh per year. Annual energy is defined as the total energy that can be generated annually on average for the entire expected service life of a particular resource.

Depending on the type of energy conversion technology and fuel source, resources can be grouped into three distinct dispatch categories: base load resources, peaking resources and variable/intermittent resources.

Base load resources operate at a high capacity utilization factor[3], generating significant amounts of electrical energy over the entire year. Such resources can be evaluated for both energy and capacity attributes. Examples include:

- Hydro generation with some storage reservoir;
- Combined cycle gas turbine (CCGT) plants;
- Biomass wood-waste thermal generation; and
- Geothermal generation.

[3] Capacity utilization factor is the ratio of the actual output from a plant over the year to the maximum possible output from it for a year under ideal conditions.

Peaking resources can be dispatched to provide capacity but are expected to operate at a low capacity utilization factor, generating electricity when it is needed. Peaking resources typically have a low cost to construct per unit of capacity, but high per unit energy costs. These resources can also act as planning reserve margin assets which can be brought into service quickly following a contingency event (e.g. loss of a base load facility), meet sudden changes in customer load requirements or help firm up intermittent resources. Although these resources produce energy when generating, they are primarily evaluated for their capacity attributes. Examples include:

- Simple cycle gas turbine (SCGT) plants;
- Pumped storage hydro; and
- Batteries.

Variable/intermittent resources provide little dependable capacity and typically operate at lower capacity utilization rates than base load resources. Variable/intermittent resources are often renewable resources and generate electricity when their fuel source is available; therefore, generation from these resources cannot be increased on demand in response to changes in customer load. For example, generation from intermittent resources like wind or solar is determined by external environmental factors such as wind speeds and amount of sunshine. Generation from variable resources, like run-of-river, is determined by seasonal flows in rivers, such as the spring freshet. Their generation may not coincide with high system load or high market prices. Variable/intermittent resource generation is more consistent and predictable when averaged over a long period of time or when bundled into a portfolio of geographically diverse intermittent resources. Although some variable/intermittent resources can provide at least a small quantity of dependable capacity, they are not considered dispatchable and therefore are primarily valued for their energy attributes. Examples include:

- Onshore wind turbine generation;
- Run-of-river hydro generation;
- Utility-scale PV solar; and
- Distributed Solar.

A balanced resource portfolio could include a combination of these supply-side resource types along with demand-side resources to provide a cost effective, diversified, reliable and environmentally-sound portfolio to meet daily and seasonal variations in system load. The analysis of resource options portfolios is discussed in Section 11 of the LTERP.

2.2.2 Financial Attributes

To enable comparisons of the costs of resources that represent a wide range of technologies and fuel sources, capital and operating costs and project lifespans, the financial characteristics of the different resource options are described by two simplified cost metrics: Unit Capacity Cost (UCC) and Unit Energy Cost (UEC). These unit cost comparisons enable an initial ranking of various resources based on cost alone. It should be noted, however, that other resource attributes, such as a resource's ability to respond to changes in demand (i.e. dispatchability), annual energy and dependable capacity and environmental factors, should be considered to fully describe and assess the various resources. The financial as well as other resource attributes, such as the technical, environmental and socio-economic characteristics, are considered in the portfolio analysis in Section 11.

UCC is the annualized cost of providing dependable capacity for each resource option, expressed in $ per kW-year. UEC is the annualized cost of generating a unit of electrical energy using a specific resource option, expressed in $ per MWh. The unit costs include capital, fixed operating and variable operating, including any fuel, costs.

The UCC and UEC values are presented in this ROR on a levelized annual cost basis in order to enable comparison between different resources with different cost structures and energy and capacity values. This means that the UCCs and UECs are calculated by taking the present value of the total annual cost in real dollars of a capacity or energy resource and dividing it by the present value of the resource's dependable capacity or annual energy, respectively. The UECs and UCCs within this ROR are presented in real 2020 dollars.

FBC has made some adjustments to the base unit costs that were developed from the resource option collaboration process with BC Hydro. The base UECs and UCCs include the capital and operating costs for each resource option. The adjusted unit costs include items other than the base costs such as transmission interconnection costs, wheeling charges, an Indigenous communities participation cost for the costs of impact benefit or parnership agreements for projects on traditional territories, and carbon costs for resources that are not clean or renewable.

It should be noted that while the base cost information, such as capital and operating costs, for the various supply-side resources is the same for FBC and BC Hydro, the base unit costs (i.e. UECs and UCCs) will differ slightly between FBC and BC Hydro. This is because some of the financial assumptions used by FBC are different than those used by BC Hydro. FBC uses different Weighted Average Cost of Capital (WACC) discount rate (DR) assumptions than BC Hydro. This is because FBC's WACC has a different debt and equity ratio and return on equity than BC Hydro's WACC. Furthermore, the adjusted unit costs may also differ due to the differences in the adders to the base unit costs. For example, BC Hydro may have different interconnection or wheeling costs than FBC may incur.

2.2.2.1 Financial Assumptions

A number of assumptions are made in order to determine the base and adjusted UCCs and UECs for the various resource options. These include the WACC discount rate, inflation rate, wheeling, Indigenous communities participation, intermittent resource integration, carbon and system interconnection costs. These are discussed in the sections below. Also required to determine resource option costs are electricity, gas and carbon price forecasts, PPA rates and the Canada-US exchange rate forecast. These forecasts are discussed in Section 2.5 of the LTERP regarding FBC's Planning Environment. Within this ROR, base electricity and gas market prices, carbon cost and BC Hydro PPA rate scenario assumptions have been used. In Section 9, the portfolio analysis examines the costs for the various resource portfolios based on different assumptions, including various market prices and PPA rate scenarios.

Weighted Average Cost of Capital

The WACC is the expected cost to finance a resource acquisition and includes both debt and equity components. For this ROR, FBC has used 3.69% percent (in real terms) based on FBC's AFUDC rate for 2020 and 2021 which is equal to the FBC after-tax WACC, converted to a constant dollars WACC[4], from the FBC Annual Review for 2020 and 2021 Delivery Rates Application (Section 8.3.5), filed August 12, 2020.

Inflation Rate

An inflation rate assumption is required when converting between nominal dollars and real, or inflation-adjusted, dollars. FBC has assumed an annual inflation rate of about 2 percent. The projected inflation factors by year are provided in Section 2.5.6.2 of the LTERP.

Wheeling Costs

Wheeling costs include the costs for the transportation of electric power from the generation source or plant to the FBC service area where it can be provided to customers and related losses. These costs can be for transporting electricity from BC Hydro's system to the FBC system or from sources in the U.S., such as the Mid-C electricity market hub, to the FBC system.

Wheeling costs within BC are based on the BC Hydro Open Access Transmission Tariff (OATT), Point to Point service effective April 1, 2021. FBC believes that the BC Hydro point to point rate is an appropriate proxy for wheeling rates for projects located in the BC Hydro service territory. This equates to $9.00 per MWh for wheeling costs and 6.28 percent for line losses, assuming hourly rates. Note that the wheeling rate assumptions can have a significant impact on the UEC.

In order to move market electricity purchases from the Mid-C market hub to the FBC service area, FBC incurs additional wheeling costs under the CEPSA with Powerex and 71 L Letter Agreement with Teck. As the CEPSA is assumed to continue indefinitely, and comparable market access to Teck's 71 L is assumed as well, these wheeling costs are continued for the planning period.

[4] Real WACC = [(1+ Nominal WACC)/ (1 + Average Forecasted Inflation)] -1 = (1.0576/1.02) = 0.0369.

Indigenous Communities Participation Cost

Implementing projects within Indigenous communities' traditional territories has a cost, whether it be accommodation in the form of an impact benefit agreement or in the form of partnership with equity participation. FBC has included a 2.5 percent adder as a proxy for Indigenous Communities Participation Cost related to new generation projects. The cost used in FBC's portfolio analysis is a 2.5 percent adder to the UEC values for energy projects, or an adder of 2.5 percent to the UCC values for capacity projects.

Intermittent Resource Options' Integration Costs

Integration costs are those related to integrating an intermittent resource, such as wind or solar, into the FBC transmission system. Because wind or solar power generation is highly variable and unpredictable, highly responsive and flexible generation capacity reserves are required to maintain system reliability and security. The incremental costs for this are captured by adding integration costs to these variable resources.

FBC utilizes a portfolio approach which accounts for the sale of surplus energy, so no integration cost was included.

Carbon Costs

For the purposes of this ROR, FBC's base assumption is that carbon costs are based on the base forecast for carbon prices in BC per Section 2.5.4 of the LTERP. As the base case FBC has assumed the 2021 carbon tax of $45 per tonne (in nominal terms), $50 per tonne (in nominal terms) in 2022. After this time, the base case holds the carbon price constant in real terms, assuming that the carbon tax is increased to keep up with inflation over time. These carbon costs are applied to the cost of natural gas-fired generation and market purchases in the portfolio analysis in Section 11.

System Interconnection Costs

Interconnection costs are related to connecting any new generating resources to the FBC or BC Hydro transmission systems. These include the cost of power lines, substation costs and any transmission system upgrades. Power lines costs are determined by the transmission voltage level, which is based on the generating plant output and its distance from the nearest FBC or BC Hydro transmission line. For resource options outside FBC's service area, the interconnection costs to the BC Hydro system have been included. For resource options within the FBC service area, the interconnection costs to the FBC system have been included. The interconnection costs can vary according to the distance from the main transmission system and the size of the resource option.

2.2.3 Environmental Attributes

Environmental considerations are an important aspect of the *CEA* and energy policy in BC. Environmental attributes describe the estimated environmental impact of the various resource options. While DSM resources are assumed to have no negative environmental impacts, some supply-side resources can have impacts on the atmosphere, land and/or water. For the purposes of this ROR and the portfolio analysis in Section 11, FBC has characterized resource options as either clean or renewable or not according to the *CEA* definition, and also looks at the plant footprint including the land associated with the interconnection.

The *CEA* defines clean or renewable resources as including biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. FBC assumes SCGT powered by RNG to be clean and renewable although not specifically mentioned in the *CEA*, as it is analogous to a biogas plant. Based on the regional electricity generation source mix as discussed in Section 2.4 of the LTERP, market purchases would include a mix of clean or renewable and non-clean or renewable resources.

FBC also considers energy and capacity under the PPA to be clean and renewable, although there is a carbon footprint associated with the PPA as the resource is 98 percent clean[5]. For non-renewable resources FBC has considered both direct GHG emissions from burning fossil fuels and indirect GHG emissions associated with the production of the fossil fuel. Based on the regional electricity generation source mix, market purchases could include a mix of clean or renewable and non-clean or renewable resources. FBC has applied a clean adder to its market purchase prices to serve as a proxy for the purchase of only clean and renewable power from the market.

Other environmental attributes, such as plant land or water footprint, have also been considered in the LTERP.

2.2.4 New Resource Lead Time

The development lead time for new generation resource projects will vary with the technology utilized as well as the scale of the project. Development and permitting lead times are an important consideration in the planning process because for more complex projects, the lead time could be 5 years or more. Given that FBC's load-resource balance (presented in section 9) indicates that no new generation resources are required before 2030, FBC expects, at this time based on current market conditions, that it will submit its next LTERP about 2026 to account for, among other things, the lead time required for new resources.

2.2.5 Socio-Economic Development Attributes

Social and economic development and job creation are included among BC's energy objectives as set out in the *CEA*. These objectives could include contributions to provincial gross domestic

[5] BC Hydro 2019 Carbon Neutral Action Report, May 2020, Page 8. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/environment-sustainability/environmental-reports/2019-carbon-neutral-action-report.pdf

product (GDP), employment and government revenue and supporting community and Indigenous commuity development. FBC has categorized the economic development attributes for each resource option into low, medium and high impact categories based on employment contributions (job person years or full-time equivalent (FTE))[6] per MW of installed capacity for each resource option. A high impact rating means that a particular resource option contributes more to provincial job creation on a per MW basis than a resource option categorized as low impact. Generally speaking, resource options with higher employment contributions per MW will also contribute more to provincial GDP as well as support community and Indigenous community development. Employment impacts were obtained from the recent updated Resource options Inventory data provided by BC Hydro to FBC.

Typically, larger-sized plants that take many years to build and require on-going operations will provide higher socio-economic benefits than smaller plants that can be built relatively quickly with minimal operating requirements.

The following table shows the environmental, job creation and lead time attributes of each resource option.

Table K2-1: Environmental and Socio-Economic Attributes Summary

Resource Option	Clean/ Renewable	GHG[7]	Plant Footprint[8]	Job Creation[9]	Lead Time (Years)[10]
PPA Tranche 1 Energy[11]	Yes	Low	N/A	N/A	N/A
PPA Tranche 2 Energy[12]	Yes	Low	N/A	N/A	N/A
PPA Capacity[13]	Yes	Low	N/A	N/A	N/A
Market Purchases[14]	Yes	Low	N/A	N/A	N/A

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6 One person-year is equivalent to one FTE for the period of one year. For example, construction jobs that occur only during the construction phase, 40 person-years may be equivalent to 20 FTEs over a 2-year construction period. For a single full-time operator of a power plant with a life of 30 years, that one FTE has an equivalent of 30 person-years of employment.
7 Assumes direct emissions except in the case of RNG, which we include indirect emissions created in the production of RNG.
8 Calculated as nameplate capacity/hectare.
9 Calculated as person-years. Based on both construction and operating jobs.
10 Based on permitting and construction time.
11 BC Hydro purchases are 98% clean.
12 BC Hydro purchases are 98% clean.
13 BC Hydro purchases are 98% clean.
14 FBC assumes it will only acquire clean energy from the market, and has included a clean adder in the market price to reflect the premium price for clean market energy. There are two components to the clean adder: how much FBC pays for the clean adder; and an assumption that FBC will receive a credit in environmental and regulatory reporting.

Resource Option	Clean/ Renewable	GHG[7]	Plant Footprint[8]	Job Creation[9]	Lead Time (Years)[10]
Wood-Based Biomass	Yes	Low	Medium	High	4
Geothermal	Yes	Low	Medium	High	5 - 8
Gas-Fired Generation (CCGT)	No	High	Low	Medium	5
Small Hydro with Storage	Yes	Low	High	High	6
Gas-Fired Generation (SCGT) - NG	No	High	Low	Low	4
Gas-Fired Generation (SCGT) - RNG[15]	Yes	Low	Low	Low	4
Pumped Hydro Storage	Yes	Low	Medium	Low	7 - 8
Onshore Wind	Yes	Low	Medium	Medium	5
Run-of-River Hydro	Yes	Low	High	Medium	5 - 6
Utility Scale Solar	Yes	Low	High	Low	5
Distributed Solar[16]	Yes	Low	High	Low	5
Battery Storage	Yes	Low	Low	Low	2
Distributed Battery Storage	Yes	Low	Low	Low	2

2.2.6 Indigenous and Community Development

FBC's portfolio analysis, discussed in Section 11 of the LTERP, determines the different bundles of resource options required to meet future energy and capacity gaps when they occur. The LRB provided in LTERP Section 9 indicates that, after incremental DSM, FBC does not have significant resource needs in the short to medium term and that new resources are not expected to be required until at least 2030. As FBC moves closer to the period when new resource options are required, further portfolio analysis can be done to determine the resource

[15] Although not specifically listed as a clean resource under the CEA, FBC assumes a SCGT powered by RNG would be considered a clean resource as it is synonymous to a biogas plant which is explicitly listed.
[16] Distribution connected utility scale solar (up to 10 MW).

requirements and optimal mix of incremental DSM and/or generation. FBC will consider partnering with Indigenous groups and local communities on power generation projects in the future when new resources are needed.

3. SUPPLY-SIDE RESOURCE OPTIONS

There is the potential for many types of resource options within the FBC service area and within BC over the planning horizon. The summary table below identifies the resource options that were evaluated in this ROR as well as those that were not evaluated due to high cost (e.g. not commercially viable at this time) or due to restrictions on their use arising from the *CEA*. More discussion of the resources options that were not evaluated is provided in Section 3.9 of this ROR.

Table K3-1: Supply-Side Resources Evaluated vs. Not Evaluated

Resource	Status
PPA energy and capacity	Evaluated
Market Purchases	Evaluated
Wood-Based Biomass	Evaluated
Geothermal	Evaluated
Gas-Fired Generation (CCGT)	Evaluated
Small Hydro with Storage	Evaluated
Gas-Fired Generation (SCGT)	Evaluated
Pumped Hydro Storage	Evaluated
Onshore Wind	Evaluated
Run-of-River Hydro	Evaluated
Utility Solar	Evaluated
Distributed Solar	Evaluated
Battery Storage	Evaluated
Distributed Battery Storage	Evaluated
Biogas	Not Evaluated
Municipal Solid Waste (MSW)	Not Evaluated
Coal	Not Evaluated
Nuclear	Not Evaluated
Offshore Wind	Not Evaluated
Tidal	Not Evaluated
Wave	Not Evaluated

The following table provides a summary of the resource options that were evaluated including their resource type, dependable capacity, annual energy as well as environmental and socio-economic attributes. For those resource options showing a range of capacity and energy, a number of different-sized plants were considered for that particular resource option. For gas-fired generation, FBC has included both Combined Cycle Gas Turbine (CCGT) plants as well as Simple Cycle Gas Turbine (SCGT) plants. The resources are sorted in the table by type with the PPA energy and capacity in green, market purchases in orange and generation resources in blue.

1 **Table K3-2: Resource Options Type and Size**

Resource Option[17]	Type	Number of Plants in FBC Portfolio Analysis	Dependable Capacity (MW)	Annual Energy (GWh)
PPA Tranche 1 Energy	Baseload	N/A	N/A	Up to 1,041
PPA Tranche 2 Energy	Baseload	N/A	N/A	Up to 711
PPA Capacity	Baseload	N/A	Up to 200	N/A
Market Purchases	Baseload	N/A	Up to 75	Up to 3,241
Wood-Based Biomass	Baseload	3	9 – 30	73 - 237
Geothermal	Baseload	4	15 – 75	130 - 657
Gas-Fired Generation (CCGT)	Baseload	3	67 – 279	528 – 2,201
Small Hydro with Storage	Baseload	4	8 - 50	77 - 443
Gas-Fired Generation (SCGT) - NG	Peaking	3	48 – 100	75 – 158
Gas-Fired Generation (SCGT) - RNG	Peaking	3	48 - 100	75 - 158
Pumped Hydro Storage	Peaking	2	100 - 1000	0
Onshore Wind[18]	Intermittent	13	21 – 127	196 – 1239
Run-of-River Hydro	Intermittent	3	2 – 6	16 - 52
Utility Scale Solar	Intermittent	11	4 - 107	28 - 754

[17] The FBC Resource Option Report and the portfolio analysis include projects outside the FBC service territory and assume there will be BC Hydro long-term transmission available to deliver the power from these projects to the FBC grid.

[18] On-shore wind options include in the FBC Resource Option Report include projects greater than 100 MW. FBC's Scheduling Agreement with BC Hydro currently only allows wind projects up to 100 MW. Section 5 of the Scheduling Agreement also requires 100% back-up of wind resources which has not been included in the analysis as FBC does not believe that reflects the current operating environment in North America, and FBC would seek to renegotiate that requirement if it were to add a wind resource to its resource stack.

Resource Option[17]	Type	Number of Plants in FBC Portfolio Analysis	Dependable Capacity (MW)	Annual Energy (GWh)
Distributed Solar[19]	Intermittent	**3**	0 - 2	2 - 15
Battery Storage[20]	Peaking	1	50	0
Distributed [21]Battery Storage	Peaking	1	25	0

The following table show the range of unit costs for the resource options that were considered. The resource options show projects of various sizes and economies of scale, so a minimum and maximum are shown as well as the average. Resources are sorted from lowest to highest unit costs.

Table K3-3: Supply-Side Resource Options Unit Cost Summary

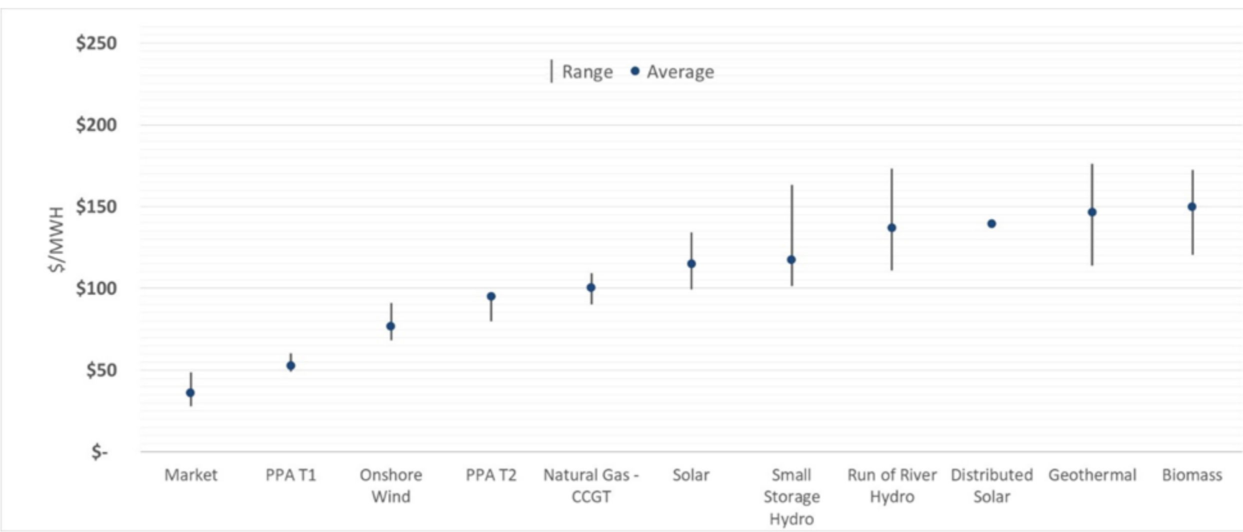
Resource Option	UEC ($/MWh)	UCC ($kW-year)
PPA Tranche 1 Energy	$49 - $60	N/A
PPA Tranche 2 Energy	$80 - $95	N/A
PPA Capacity	N/A	$101 - $123
Market Purchases	$28 - $49	N/A
Wood-Based Biomass	$121 - $173	$682 - $719
Geothermal	$114 - $176	$863 - $1,377
Gas-Fired Generation (CCGT) - NG	$90 - $109	$150 - $287
Gas Fired Generation (SCGT) - NG	N/A	$131 - $148
Gas Fired Generation (SCGT) - RNG	N/A	$131 - $148
Small Hydro with Storage	$101 - $163	$687 - $1,271
Pumped Hydro Storage	N/A	$102 - $540
Onshore Wind	$68 - $91	$509 - $734
Run-of-River Hydro	$111 - $173	$817 - $1,330
Utility Scale Solar	$99 - $134	$686 - $863
Distributed Solar	$137 - $141	$829 - $882
Battery Storage	N/A	$267
Distributed Battery Storage	N/A	$226

[19] For modelling purposes, distributed solar is defined as less than 10 MW of installed capacity and connected to the distribution system.
[20] For modelling purposes, a Battery Storage is defined as 50 MW and connected to the transmission system. One 50 MW battery was used in the portfolio modelling.
[21] For modelling purposes, a distributed battery is defined as 25 MW and connected to the distribution system. One 25 MW battery was used in the portfolio modelling.

When looking at the unit costs in Table K3-3 above, it is important to remember that a resource option with the lowest unit cost may not be the best fit in terms of meeting customers' load requirements. For example, project size is also important, and because of economies of scale the lowest cost resource may be an impractical option for FBC's requirements. The portfolio analysis in Section 11 of the LTERP helps determine the optimal mix of resources based on cost and FBC's monthly energy and capacity requirements. It should also be noted that the UCCs for intermittent renewable energy resources and the UECs for strictly capacity resources can be misleading. This is because, in the former, there is very little capacity associated with the production of energy, producing a high UCC result, and, for the latter, there is little incremental energy produced (or negative net energy in the case of pumped storage hydro or battery storage), creating a high UEC.

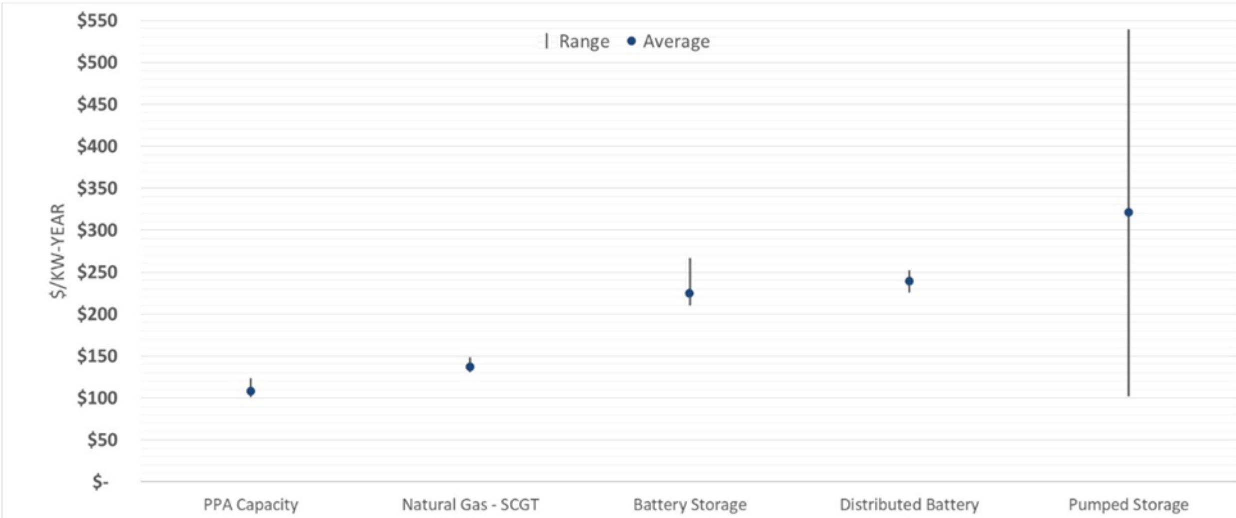
The following figures graphically show the range of unit costs (in real $2020) for the resource options that were considered. These figures help illustrate the costs of the various resource options relative to each other. The resource options show projects of various sizes and economies of scale, so a range of unit costs are shown as well as the average. Resources are sorted from lowest to highest average unit costs. The unit energy costs (in real $2020) are provided in Figure K3-1.

Figure K3-1: Resource Options Unit Energy Costs



The unit capacity costs (in real $2020) are provided in Figure K3-2.

Figure K3-2: Resource Options Unit Capacity Costs



Detailed information for each resource FBC considered is provided in the following sections, organized by resource type. This includes supply curves (which show available supply and associated unit cost), as well as details regarding energy and capacity available from the resources and their environmental and socio-economic attributes.

3.1 *BASE LOAD RESOURCES*

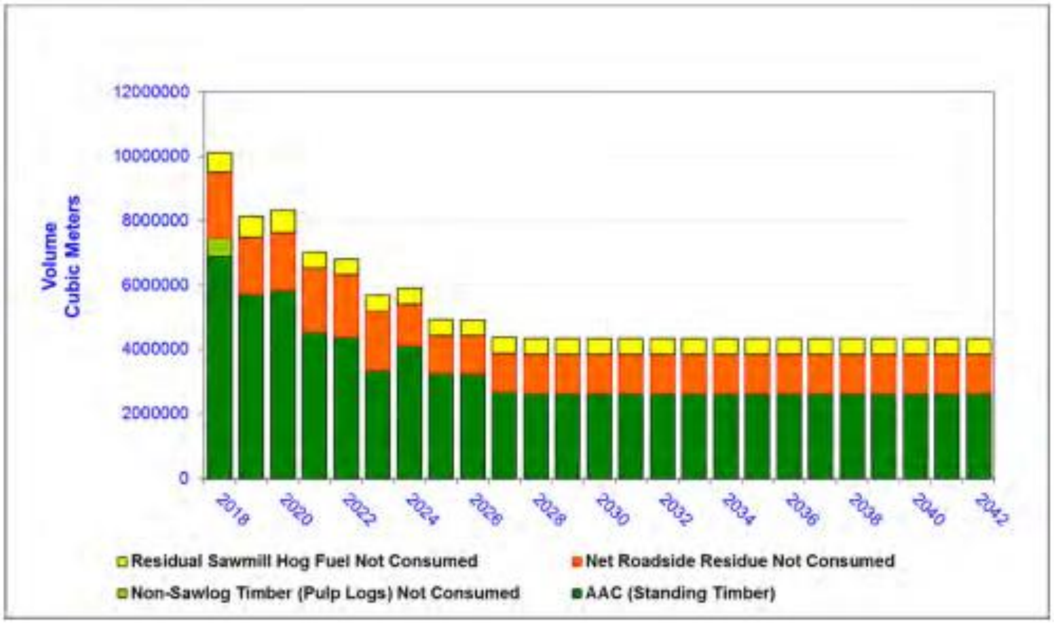
3.1.1 Wood-Based Biomass

Biomass is different from some other renewable energy sources, such as wind and solar, as it is dispatchable. Biomass also produces carbon neutral air emissions from combustion[22]. It requires that a constant supply of fuel be collected and concentrated at a specific location. Therefore, a key factor affecting the sustainability of generation from this resource is biomass availability and transportation to, and storage or management at site.

Wood-based biomass energy is electricity generated from the combustion or gasification of organic materials. The four main fibre categories of wood-based biomass are sawmill wood waste (often called "hog fuel"), roadside wood waste from normal tree harvesting operations, standing timber and standing pulp logs from the mountain pine beetle epidemic. The most critical requirement for operating a biomass plant is the availability of a stable fuel supply. As long as adequate fuel supply is available, biomass-fired steam-cycle plants can be operated as base load systems. Wood-based biomass project costs are largely dependent on capital plant and operation costs as well as the costs to deliver the fuel to the plant. In general, forecasts indicate a declining supply of available biomass in BC over the long term.

[22] BC Hydro 2013 IRP, Appendix 3A, page 53.

Figure K3-3: Forecast of Annual Available BC Wood-Based Biomass[23]

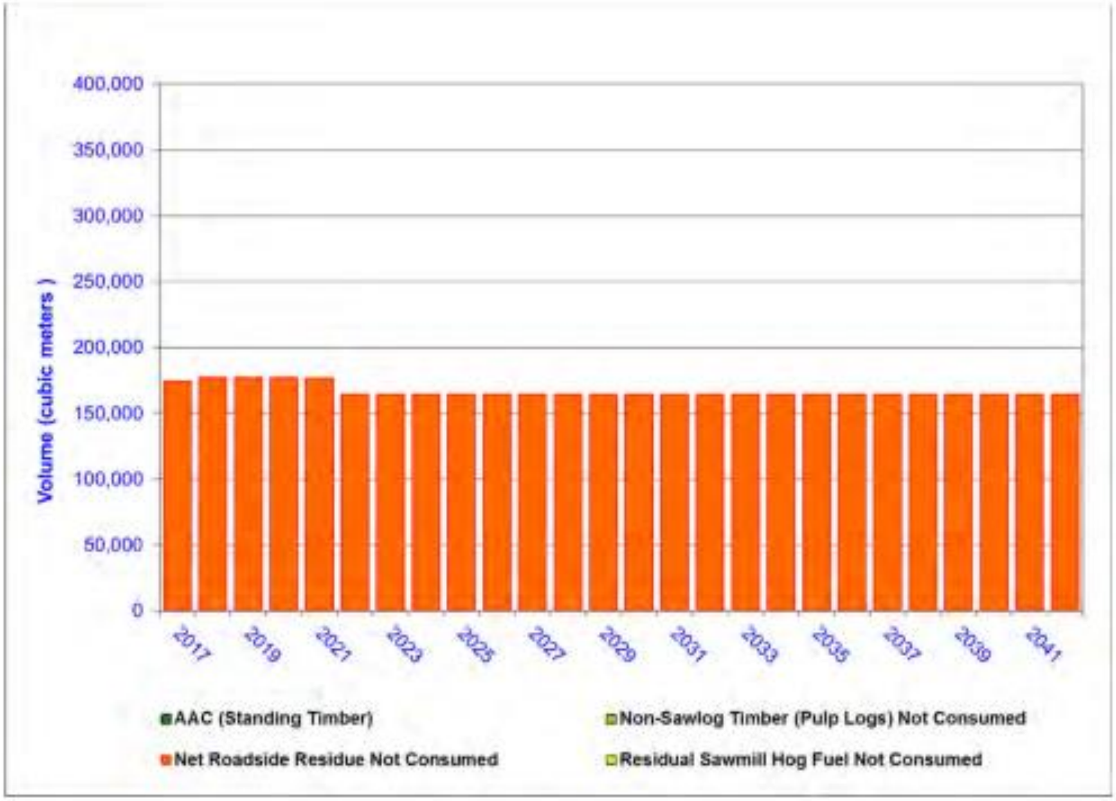


This projected decrease is due to several factors including fewer sawmills, less standing dead biomass as a result of harvesting, fires and trees falling down, reductions in regional Annual Allowable Cuts (AAC) and higher pulp log costs.

The forecasts for annual available wood based biomass within the regions in FBC's service area are provided in the following figures.

[23] MDT Management Decision and Technology Ltd. And Industrial Forestry Service Ltd., Wood Based Biomass in British Columbia and its Potential for New Electricity Generation, March 2018, page ii.

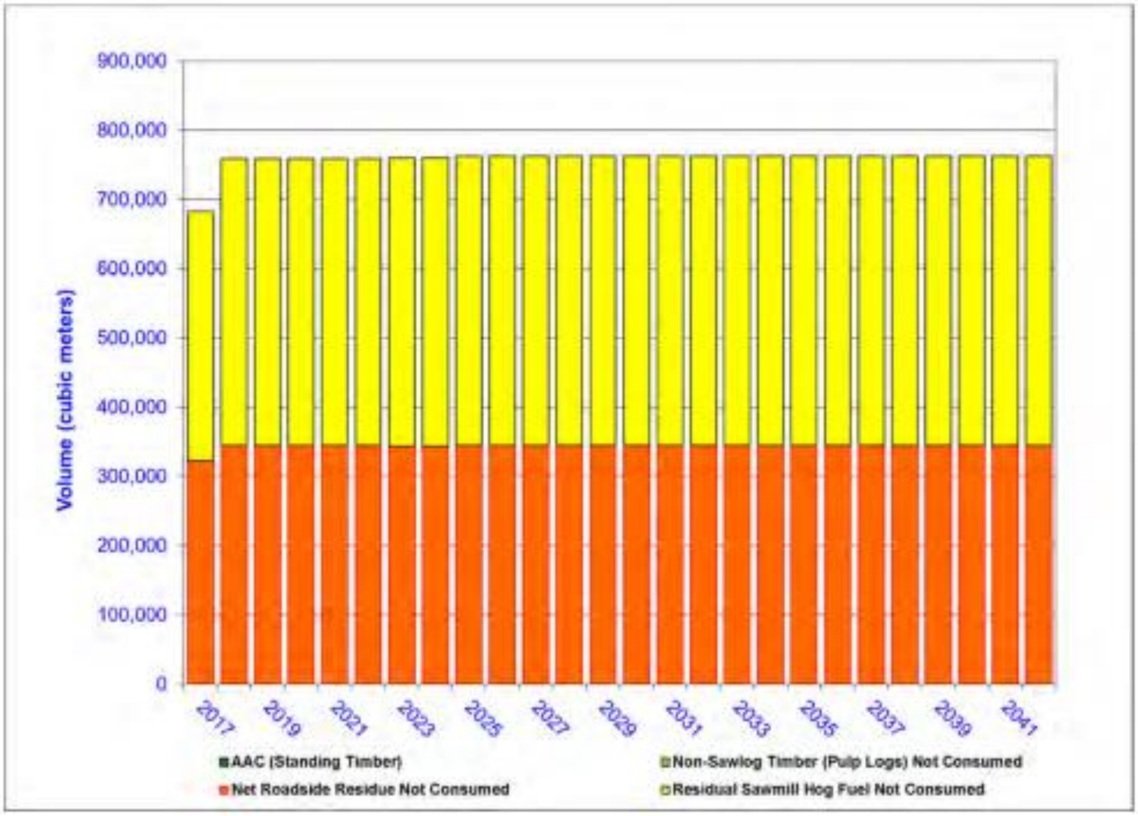
1 **Figure K3-4: Forecast of Annual Available Wood-Based Biomass in the East Kootenay Region[24]**



2

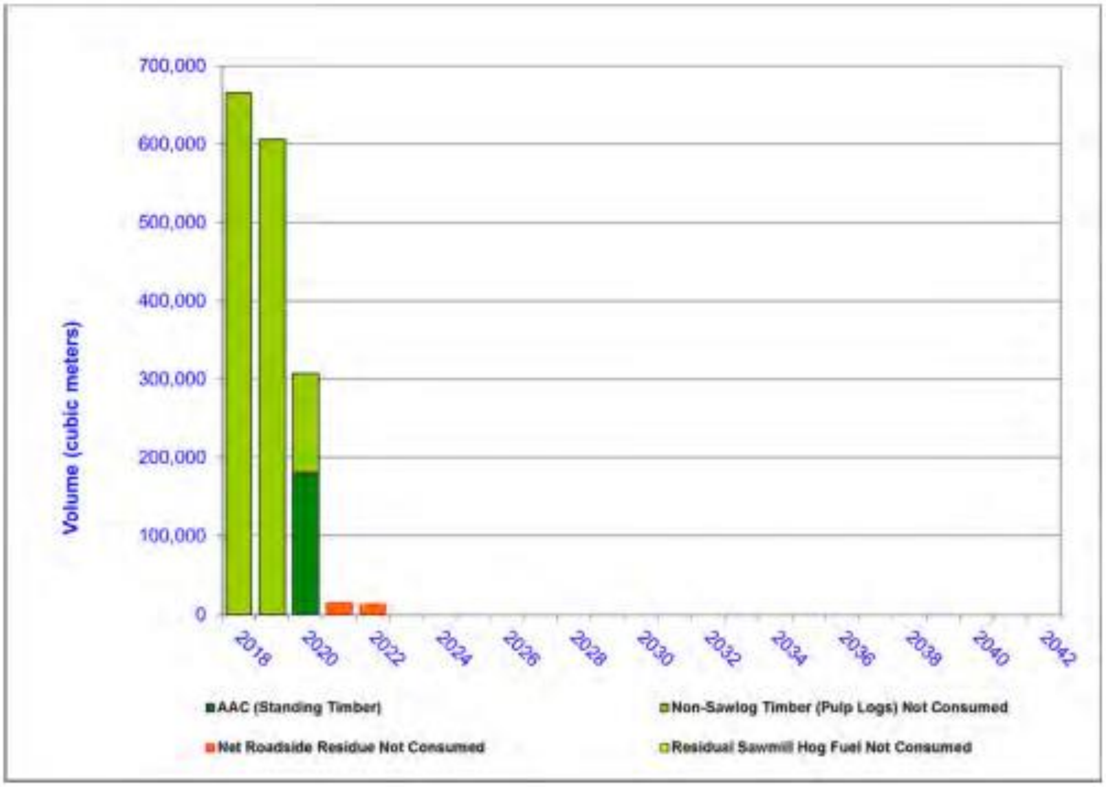
[24] MDT Management Decision and Technology Ltd. And Industrial Forestry Service Ltd., Wood Based Biomass in British Columbia and its Potential for New Electricity Generation, March 2018, page 28.

1 **Figure K3-5: Forecast of Annual Available Wood-Based Biomass in the West Kootenay Region[25]**

2 

[25] MDT Management Decision and Technology Ltd. And Industrial Forestry Service Ltd., Wood Based Biomass in British Columbia and its Potential for New Electricity Generation, March 2018, page 31.

Figure K3-6: Forecast of Annual Available Wood-Based Biomass in the Kamloops/Okanagan Region[26]

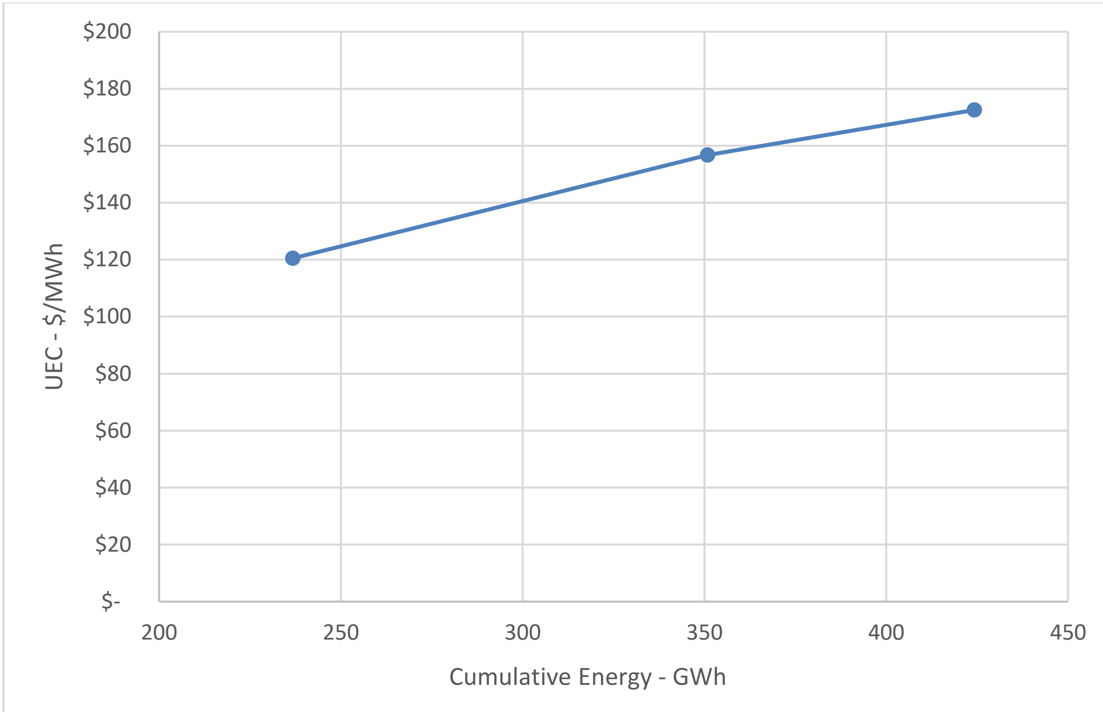


As the figures above show, there is more potential for wood-based biomass in the Kootenay regions than in the Kamloops/Okanagan region of BC.

Based on this information and the cost projections from FBC's collaboration with BC Hydro, the wood based biomass supply curve is presented in the following figure.

[26] MDT Management Decision and Technology Ltd. And Industrial Forestry Service Ltd., Wood Based Biomass in British Columbia and its Potential for New Electricity Generation, March 2018, page 34.

Figure K3-7: Wood Based Biomass Supply Curve

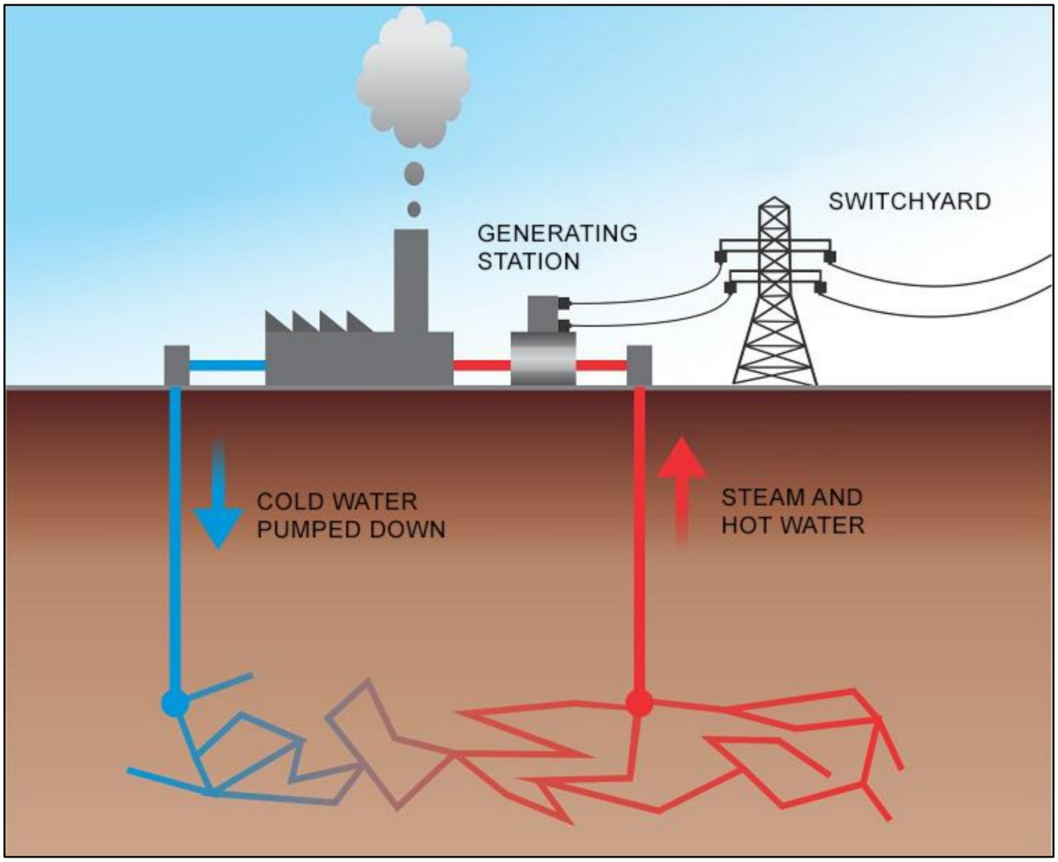


For the environmental attribute, wood-based biomass is a clean and renewable resource per the *CEA*. FBC ranks it as 'high' in terms of socio-economic attributes given the plant construction requirements, on-going plant operations and jobs related to transporting the biomass fuel.

3.1.2 Geothermal

Geothermal energy involves using the earth's naturally occurring and regenerating heat to generate electricity. Drill holes, up to several kilometers deep, are used to access hot fluid and steam below the surface. Turbines then convert the extracted steam to electricity.

Figure K3-8: Geothermal Energy Generation

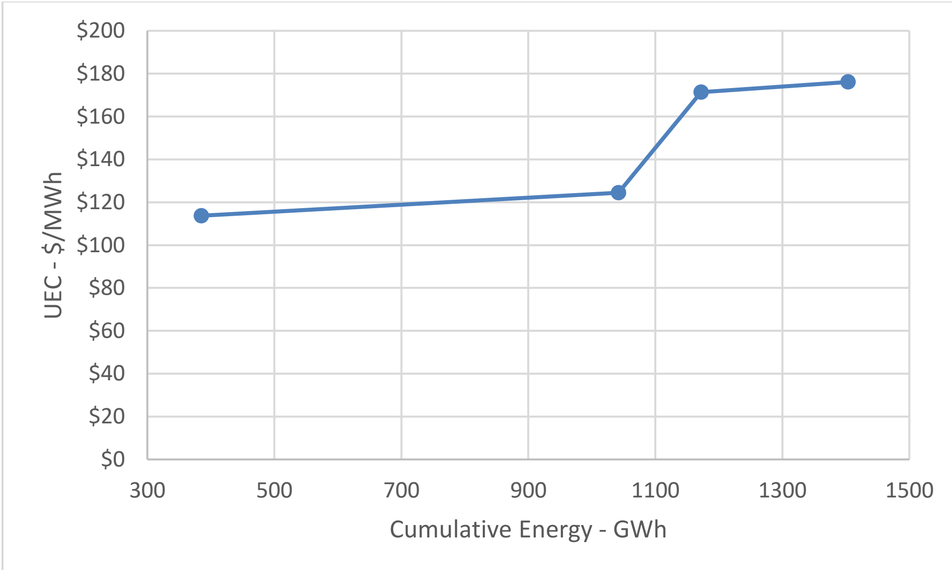


Geothermal energy generation is a mature technology and has been used for over a hundred years, primarily in areas of high volcanic potential, such as Iceland. The existence of hot springs within the FBC service area indicates that there is the potential for geothermal energy.

Geothermal resources provide year-round constant energy supply and so are different than some other renewable resources which are intermittent, like wind and solar power.

The feasibility and deployment of geothermal technology is largely dependent on potential improvements in drilling technologies and enhancements in the identification of geothermal resources. The capital costs for geothermal development can be significant due to the high costs related to drilling and well completion. FBC has included four of the lowest cost options for consideration in its portfolio analysis. The following figure shows the supply curve for these potential projects.

Figure K3-9: Geothermal Supply Curve



In terms of environmental attributes, geothermal generation is considered a clean and renewable resource pursuant to the *CEA*. Geothermal has a significant number of direct and indirect construction and operating jobs associated with the plant. FBC ranks it as 'high' in terms of socio-economic attributes.

3.1.3 Natural Gas-Fired Generation - CCGTs

Natural gas-fired generation can include combined cycle gas turbines (CCGTs) and simple cycle gas turbines (SCGTs). CCGTs can be used for both firm base load energy and dependable capacity while SCGTs are a peaking resource. Natural gas-fired generation is dispatchable and plants can respond quickly to changes in demand.

CCGTs couple a combustion turbine with a steam cycle plant. The exhaust gases from the combustion turbine become the heat source for raising water to steam in a steam cycle system. This maximizes the thermal efficiency of the power plant by using the available energy in the combustion turbine's high temperature exhaust gases. CCGTs are available in a variety of sizes. BC Hydro and FBC have considered different sized plants as a result. While CCGTs typically have higher capital costs than SCGT plants, their unit costs can be competitive with other resources due to their high capacity factors.

Combustion turbine technology is well-established and widely used. Because of this there is typically low construction risk and high operational reliability. Furthermore, generation units are available in a range of sizes and can be fit to meet specific load requirements. Plants can be installed with a minimum of site renovation and preparation because they are compact and do not require additional equipment such as cooling towers or elaborate fuel processing subsystems. This enables them to be sited close to system load centres. Furthermore, the natural gas required to fuel the plants is abundant in the Pacific Northwest (PNW) region, with plentiful supply from diverse sources and robust gas infrastructure in place. FBC has access to gas supply for its electricity service area via the Spectra T-South system for northern BC gas production or via the FEI Southern Crossing Pipeline (SCP) system and Alberta Nova Gas Transmission Limited (NGTL) system and Foothills system for Alberta gas production.

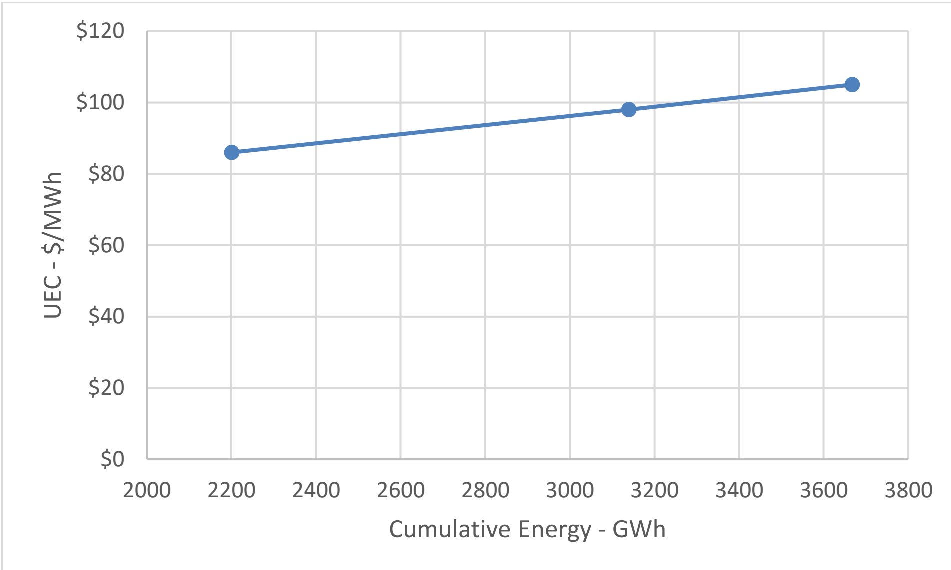
A major consideration for natural gas-fired generation is the fuel cost. While natural gas supply is abundant in North America and available within FBC's service area, natural gas prices can be highly volatile and uncertain. Natural gas prices are currently low relative to recent historical values as strong growth in natural gas production in North America has outweighed demand growth. However, there is no guarantee that this over-supplied situation will continue indefinitely into the future and market price volatility can occur in response to sudden changes in the supply/demand balance, such as during a cold spell in the winter. Market gas price forecast ranges are provided in Section 2.5.

There is also uncertainty regarding future carbon costs. As discussed in Section 2.5, the BC carbon tax will likely increase until it reaches $50 per tonne by 2022, and the federal carbon tax is expected to rise to $170 per tonne by 2030. However, it is unknown what future BC carbon tax increases may be, and the base case assumes that after 2022 it remains constant in real dollars, with sensitivities to other higher cost scenarios.

Gas-fired generation can complement the use of intermittent renewable resources, providing quick, reliable and cost-effective back-up power when needed.

The collaboration process updated the costs for several sizes of CCGT plants, including 67 MW, 119 MW and 279 MW (installed capacity). The unit costs included in this ROR include the cost of fuel gas (based on the base case gas price forecast plus adders provided in Section 2.5) as well as the base case for carbon pricing (provided in Section 2.5). The following figure shows the supply curve for these three plant sizes.

Figure K3-10: CCGT Supply Curve



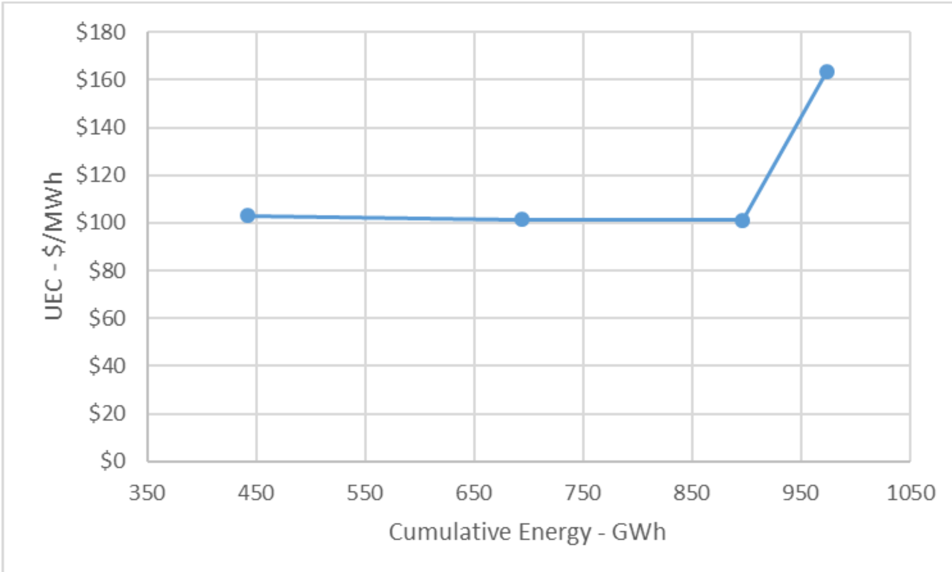
Gas-fired generating plants emit greenhouse gases, such as carbon dioxide, and other air pollutants. Therefore, gas-fired generation requires environmental permitting and can raise social licensing issues. Section 2 of the *CEA* outlines BC's GHG emission reduction targets and provides that it is a provincial energy objective to generate at least 93 percent of the electricity in BC from clean or renewable resources. The *CEA* definition of "clean or renewable resource" does not include natural gas-fired generation. RNG could be used as an alternate fuel to address the GHG issue, but the cost of doing that for a baseload plant would be prohibitive compaired to other options so that case was not included as a resource option considered for the portfolio analysis. Alternatively, while carbon capture technology does exist, it is not yet commercially viable.

In terms of socio-economic attributes, a CCGT would provide significant construction and operating jobs and revenue for the province of BC and so FBC ranks CCGTs as 'medium' in terms of socio-economic attributes.

3.1.4 Small Hydro with Storage

Small hydro with storage includes a dam or reservoir with a hydroelectric generating station. The dam or reservoir provides the ability to store water which can be released when required to meet system load. This storage ability provides capacity whereas run-of-river hydro without storage only provides energy. The following figure shows the supply curve for four plants. The plant with the higher UEC value has lower dependable capacity and reliable energy which contributes to its higher UEC value.

Figure K3-11: Small Hydro with Storage Supply Curve



3.2 *PEAKING RESOURCES*

3.2.1 Gas-Fired Generation - SCGT

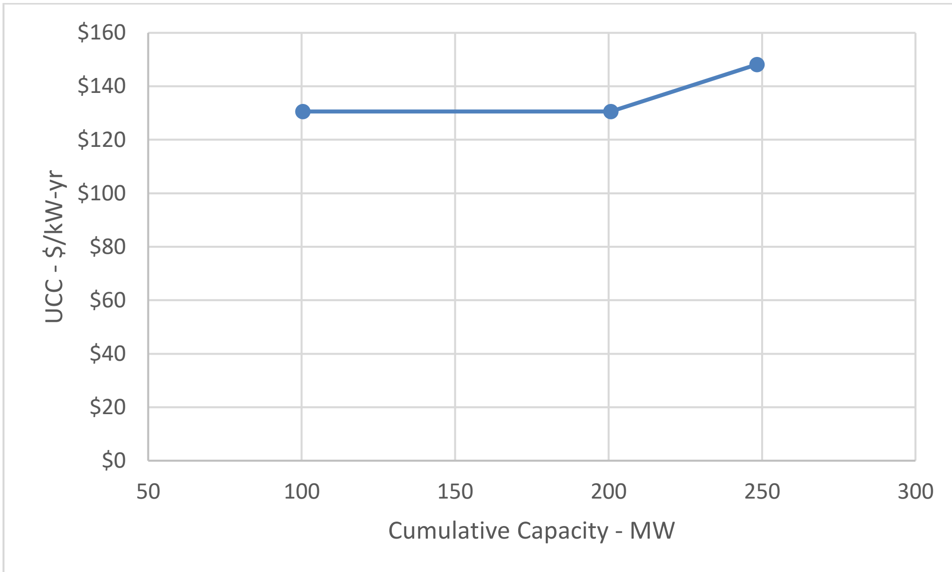
SCGTs can be used for dependable capacity generation and flexibility purposes. Unlike CCGTs, which operate as baseload plants for energy and capacity, SCGTs operate at a much lower utilization rate than CCGTs, providing peaking supply only when it is required to meet the highest loads.

SCGTs operate by propelling hot gas through a turbine in order to generate electricity. They differ from CCGTs because their waste heat is not supplied to another external heat engine, so they are only used to meet peaking power needs on the electrical grid. SCGTs are typically smaller units than CCGTs, with lower capital costs and shorter construction lead times. SCGTs can ramp up to meet increases in demand faster than CCGT plants and can handle frequent starts and stops to respond to changing system load requirements.

Peaking gas plants have increased their presence in the PNW region in recent years. This is due to the abundant and low-cost natural gas supplies in the region as well as their ability to provide valuable integration (i.e. back-up capability) for intermittent energy resources, such as wind and solar. Given their low utilization rate, SSGT gas plants can use RNG rather than conventional natural gas as fuel to offset their carbon footprint.

As part of the resource options collaboration with BC Hydro, FBC considered three separate SCGT installations utilizing 48 MW and 100 MW (installed capacity) units yielding the combined total capacities as shown in the figure below. The unit capacity costs are provided in the following supply curve and are the same for SCGT plants using conventional natural gas or RNG as fuel.

Figure K3-12: SCGT Capacity Supply Curve



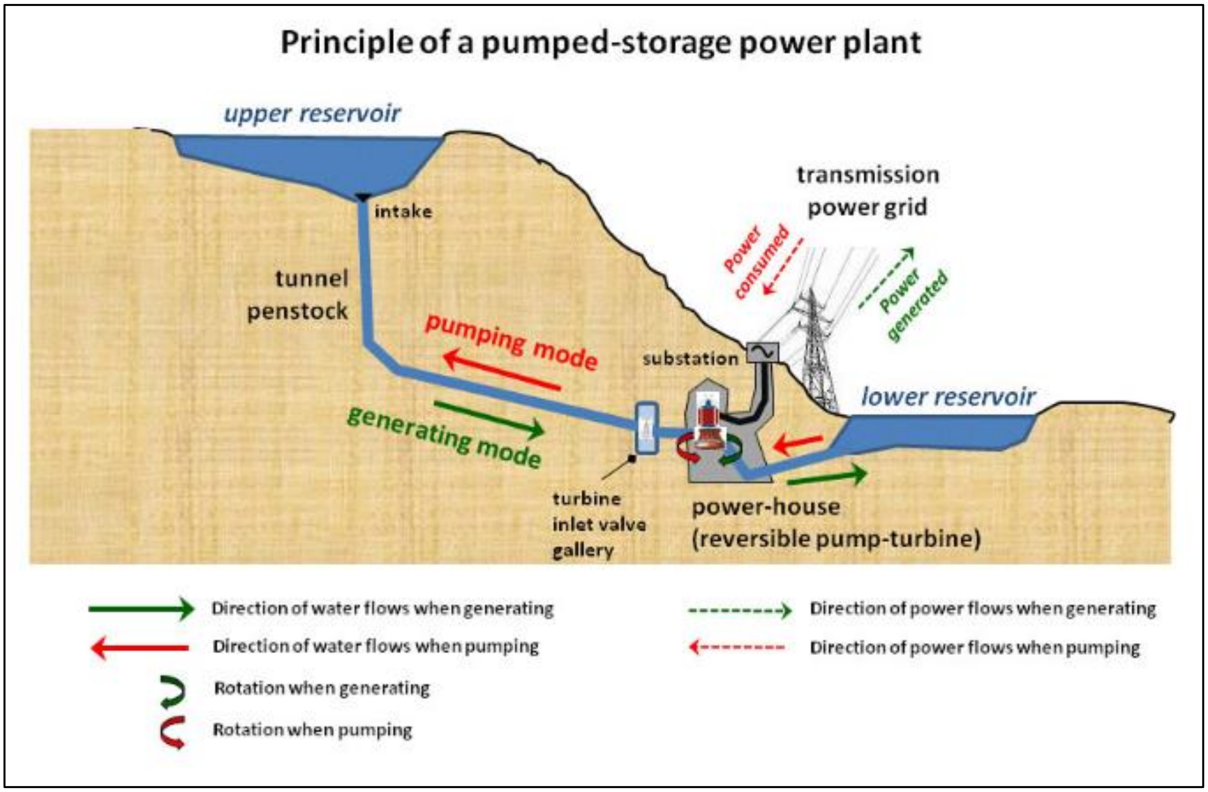
The socio-economic benefits of a SCGT plant would be lower than those for a CCGT plant due to its shorter construction period and lower utilization rate and therefore FBC would characterize this attribute as 'low'.

3.2.2 Pumped Storage

Pumped storage hydro (PSH) involves pumping water from a lower elevation to a high elevation so that capacity can be generated when required. The water is pumped to a higher elevation using electricity during light load hours, such as at night when demand is low. When electricity is required, the water in the higher elevation reservoir is released and runs through hydraulic turbines that generate electricity. Pumped storage units require a considerable amount of energy to pump the water to the higher elevation, recovering only about 70 percent of the energy used.[27] Therefore, they are not efficient energy resources. However, they are good capacity resources as the pumped water can be stored for a long period of time with virtually no energy loss until generation is required. The following figure illustrates how a pumped hydro storage plant works.

[27] BC Hydro 2013 IRP, Page 3-65.

Figure K3-13: Pumped Hydro Storage Plant Operation



While pumped storage is used in many countries worldwide, currently there are no commercial pumped storage facilities operating in BC and only one facility operating in Canada[28]. This is largely due to the fact that pumped storage facilities require unique geologic formations consisting of two large reservoirs with a sufficient elevation differential between them. Such formations are rare or tend to be found in remote off-grid locations and in mountaineous regions, for example, where construction is difficult.

FBC contemplated pumped storage as a capacity resource in its 2012 LTRP. Siting a pumped storage facility in BC would require numerous governmental and regulatory approvals, increasing the uncertainty regarding timing, cost and outcome.

In FBC's portfolio analysis, two sizes of PSH projects were considered – 100 MW and 1,000 MW (installed capacity).

FBC considers PSH a clean and renewable resource option as it produces limited direct GHG emissions associated with its operations. Given the relatively large size of the potential plants, there would be significant construction and operating costs for this resource option. However,

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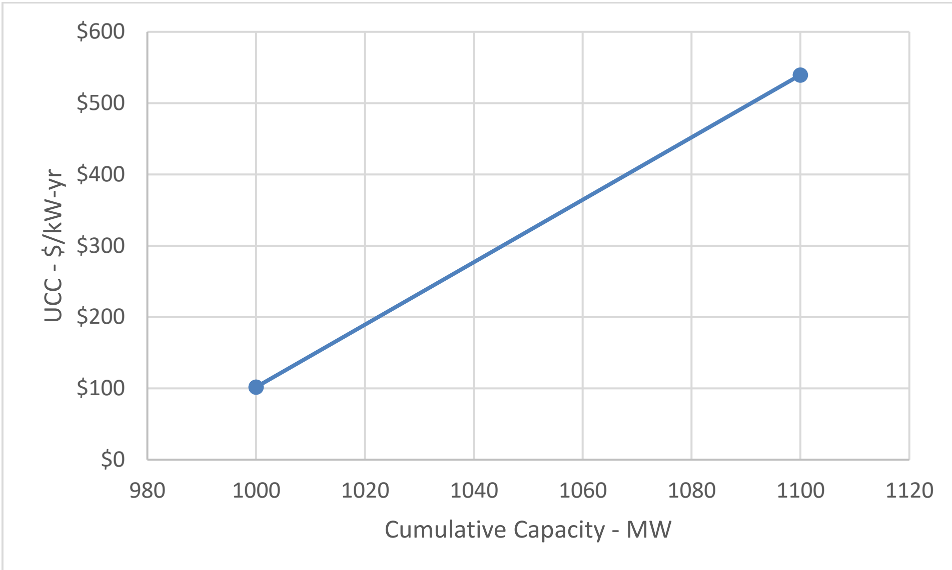
[28] Sir Adam Beck Pump Generating Station at Niagara Falls in Ontario is the only pumped hydro storage facility operating in Canada. Built in 1957, the station has an output of 174 MW.

given the power generated by a PSH plant, on a per MW basis the socio-economic attribute rating for this resource option is 'low'.

Figure K3-14: Pumped Storage Hydro Capacity Supply Curve



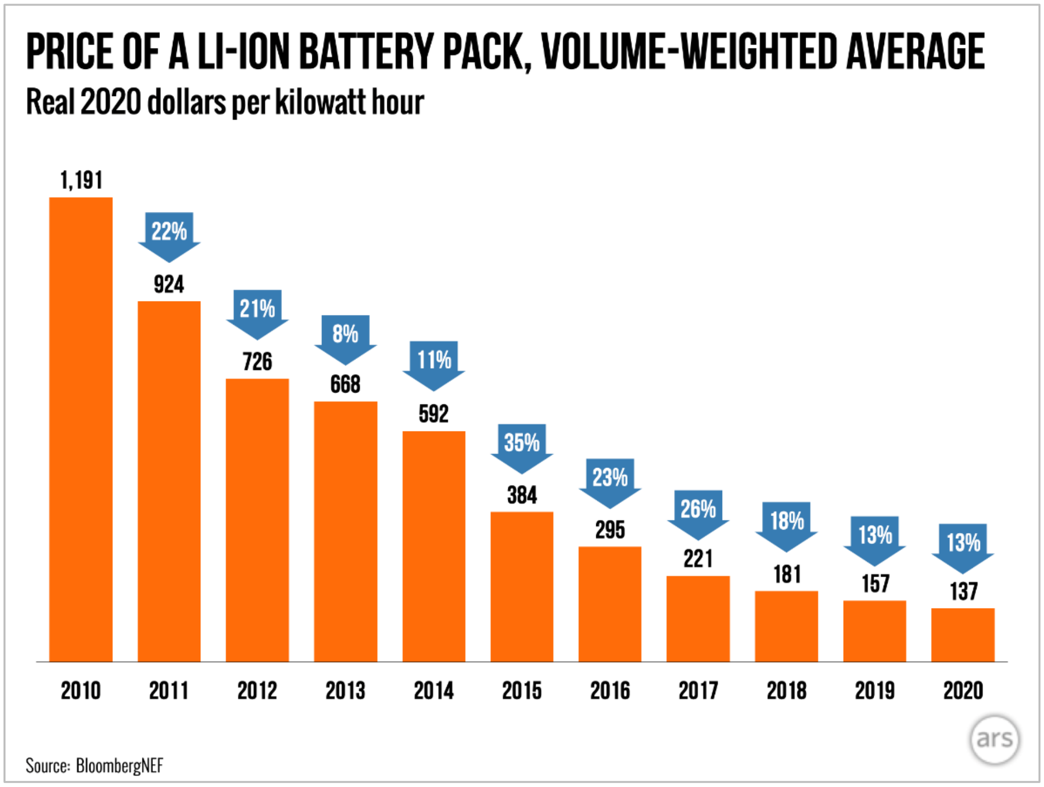
3.2.3 Battery Storage and Distributed Batteries

According to Lazard[29], lithium-ion chemistries continue to be the dominant storage technology for short-duration applications (i.e., 1 to 4 hours), representing approximately 90 percent of the market. Competing technologies are less attractive for most applications given lithium-ion's advantages in commercial acceptance, price, energy density and availability.

The cost of battery storage has declined significantly in recent years due to improvements in technology. The following figure shows the declining unit costs for lithium-ion batteries since 2010.

[29] Lazard Levelized Cost of Storage Analysis, Version 6, October, 2020.

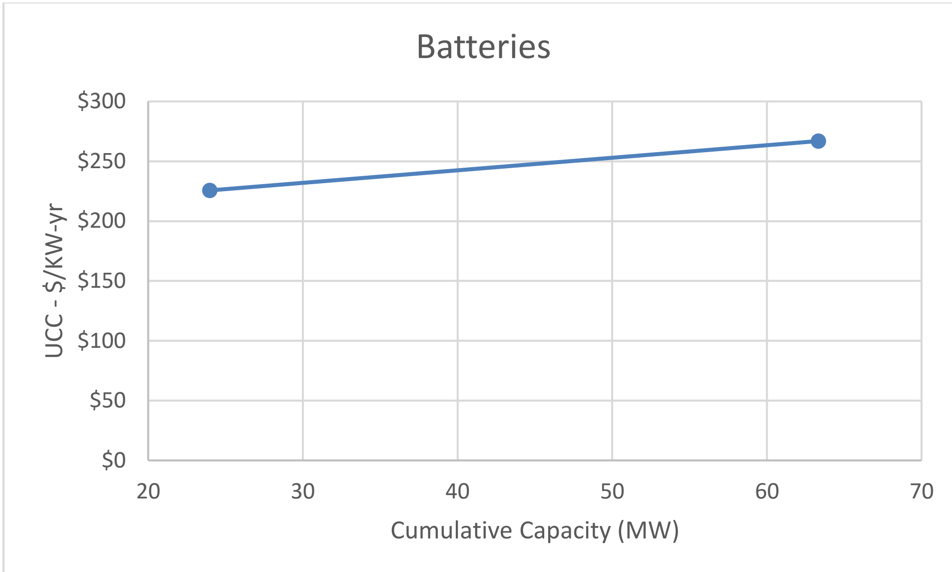
Figure K3-15: Lithium-ion battery price trends[30]



Batteries in the portfolio model were classified either as Battery Storage, which is defined for the purpose of the model as a 50 MW Lithium-ion battery connected to the transmission system, or Distributed Batteries, which is defined as a 25 MW Lithium-Ion battery connected to the distribution system. Each battery is able to sustain a 4-hour duration. One of each battery was utilized in the portfolio model. As FBC has included only one size of Battery Storage and one size of Distributed Batteries in its resource options, it has not presented separate cost curves for each but rather is showing a combined cost curve figure. In the cost curve below, the Distributed Battery has the lower UCC cost.

[30] https://arstechnica.com/science/2020/12/battery-prices-have-fallen-88-percent-over-the-last-decade/

Figure K3-16: Battery Storage and Distributed Battery Capacity Supply Curve



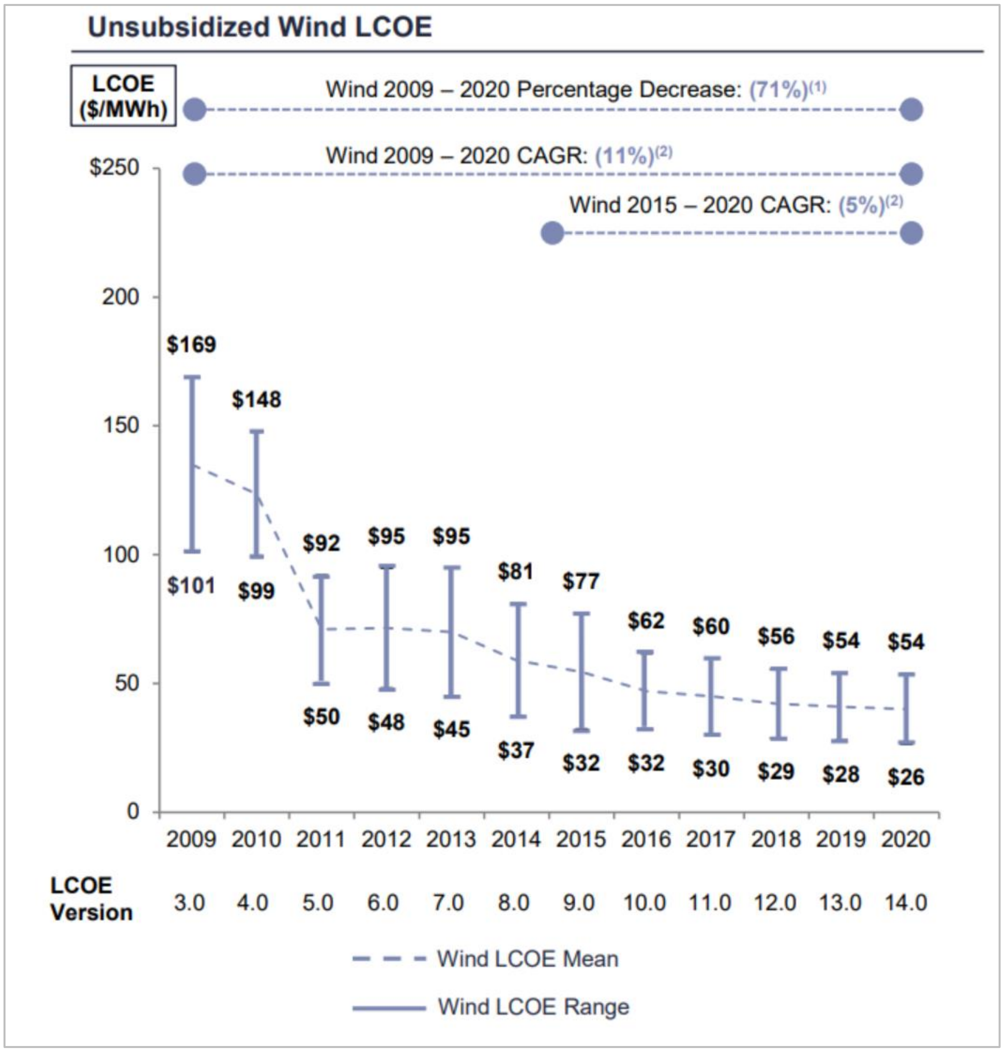
3.3 *INTERMITTENT RESOURCES*

3.3.1 Onshore Wind

Wind power is an intermittent resource and comes from electricity converted from the kinetic energy of the wind. Typical utility-scale wind turbines use rotating blades that drive a generator when the wind blows. Because wind speed is highly variable and difficult to predict, wind power provides energy but cannot be relied upon for capacity. Therefore, greater system flexibility and capacity reserves are required for the integration of wind into a resource portfolio.

The costs for wind generation have fallen significantly in recent years mainly due to two factors: improvements in turbine efficiencies and decreases in turbine costs. Technology improvements have included increased tower heights, blade lengths and rotors designed for lower wind speeds. These have led to improvements in power capacity. Improvements in forecasting wind speeds have also occurred. The following figure shows the decrease in the US cost for wind generation since 2009.

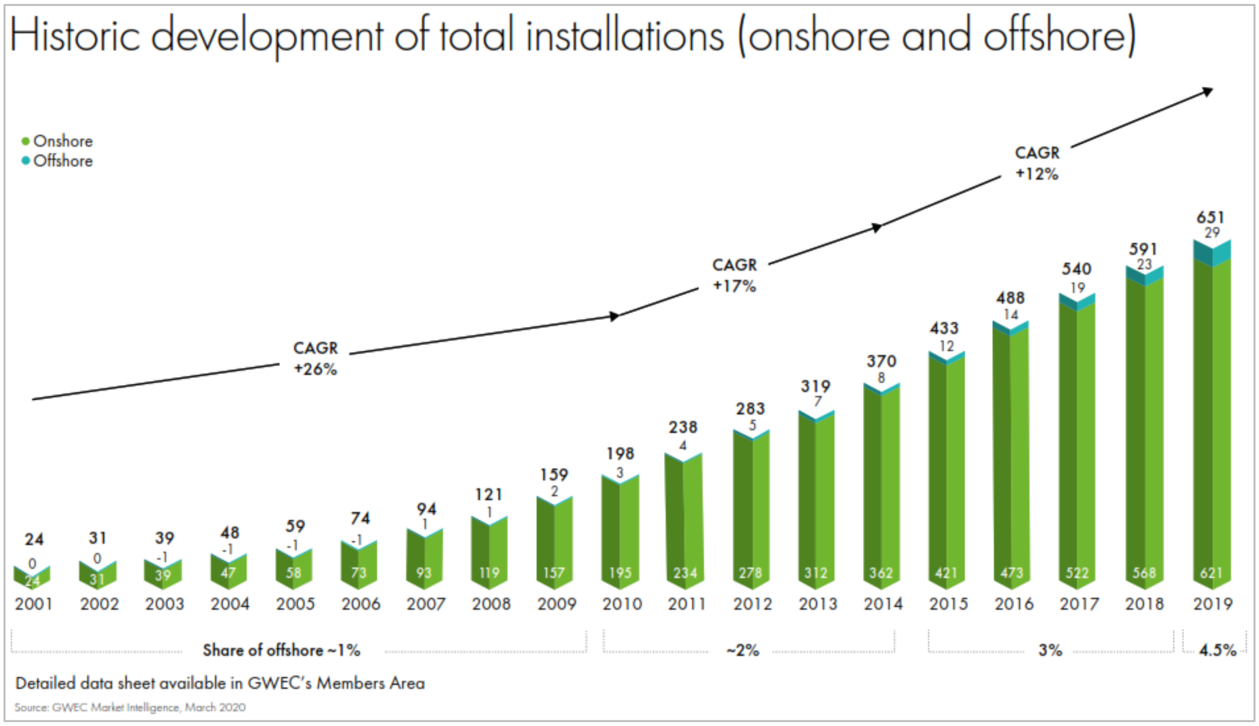
Figure K3-17: US Wind Price Trends[31]



These improvements, along with the environmental benefits of wind power over non-renewable forms of generation, has led to an increase in the growth of wind power in recent years as shown in the following figure.

31 Lazard Levelized Cost of Energy Analysis, Verion 14.0, October 2020, page 9.

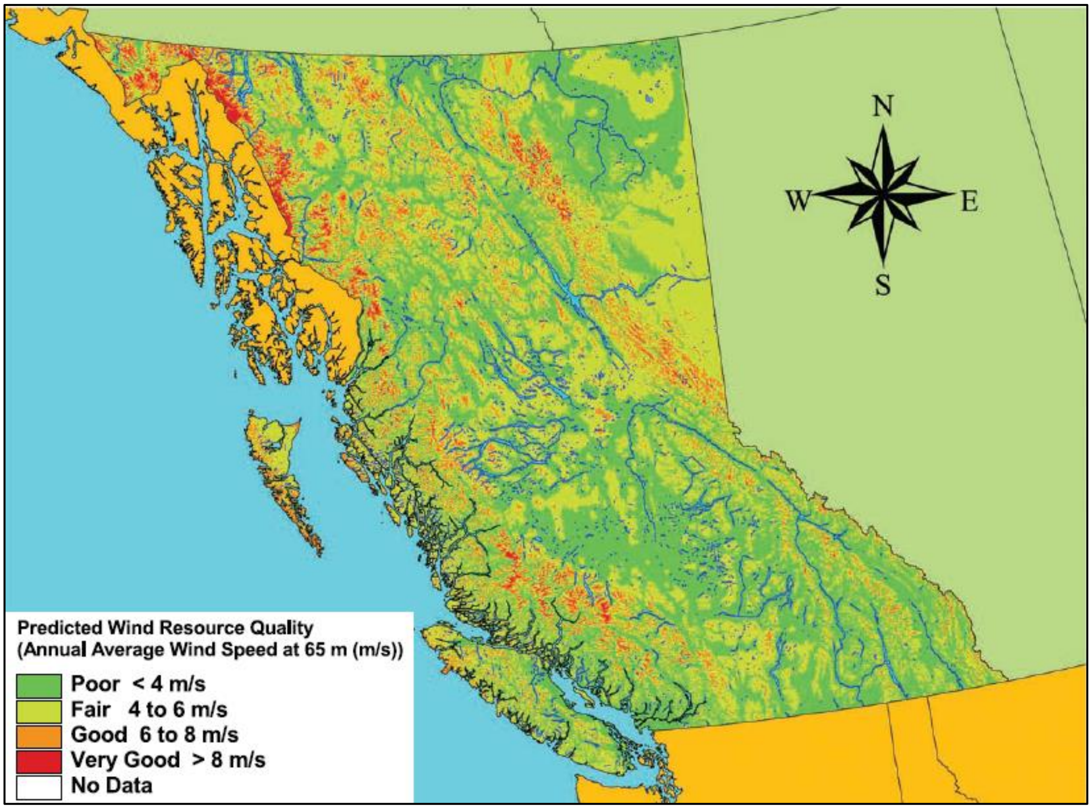
Figure K3-18: Global Cumulative Installed Wind Capacity[32]



The area in BC with the most potential for development of onshore wind as a resource option is in the northwestern part of the province, as reflected in the figure below showing the wind speed quality throughout BC The figure also indicates there are some areas of fair potential for wind energy within FBC's service area.

[32] https://gwec.net/global-wind-report-2019/

Figure K3-19: BC Wind Speed Quality[33]

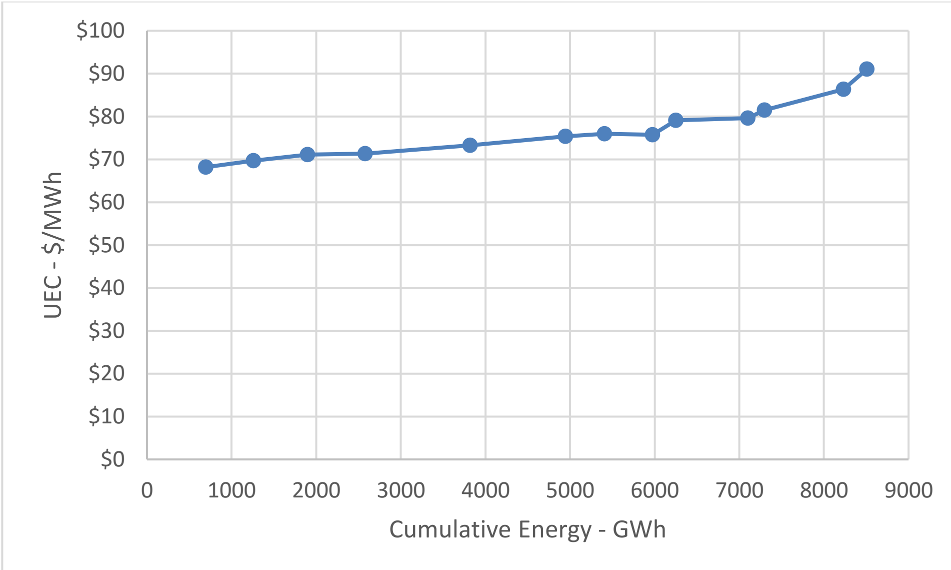


Improvements in the ability to forecast wind more accurately and reductions in costs through design and efficiency improvements are expected to increase the viability of wind energy technologies in the future.

FBC's collaboration with BC Hydro identified over one hundred potential wind projects throughout BC, with many of them in northern BC FBC has evaluated a smaller subset of 13 lower cost sites outside and within its service area for the purposes of this ROR. The supply curve for these lower cost projects is provided in the following figure.

[33] Alternative Energy in the Columbia Basis, Columbia Basin Trust, October 2010.

Figure K3-20: Onshore Wind Supply Curve



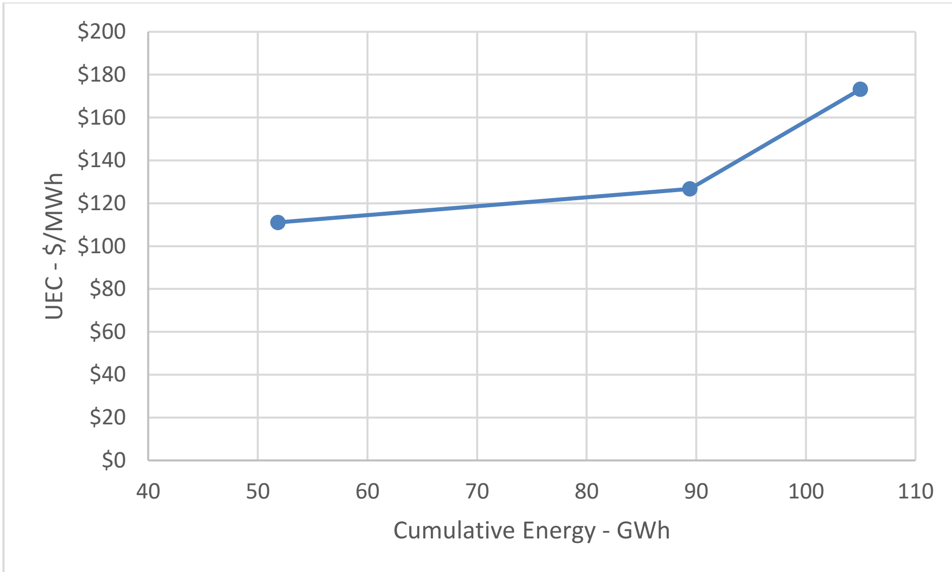
Wind is considered a clean and renewable resource option. FBC ranks this resource option as 'medium' in terms of socio-economic benefits.

3.3.2 Run-of-River Hydroelectricity

Run-of-river hydroelectricity is generated from the potential or kinetic energy of water and is considered a variable resource. Run-of-river generation involves diverting natural stream or river flows and using the drop in elevation to produce electricity. In contrast to hydroelectricity resources with storage, run-of-river projects have no or limited amounts of storage and their output is dependent on seasonal river flows, which peak during the freshet period in late spring/early summer. Run-of-river flows are also subject to annual flow variability, depending on the levels of annual snowpack. As such, run-of-river resources are considered primarily for energy rather than dependable capacity.

There is significant potential for run-of-river generation in BC and FBC's collaboration with BC Hydro identified over seven thousand possible sites. Most of the possible sites would not be considered economic at this time, however. For this ROR, FBC developed a smaller subset of the identified sites by selecting a sampling of three cost-effective different-sized sites. The cost curves for these are provided in the following figure.

Figure K3-21: Run-of-River Supply Curve



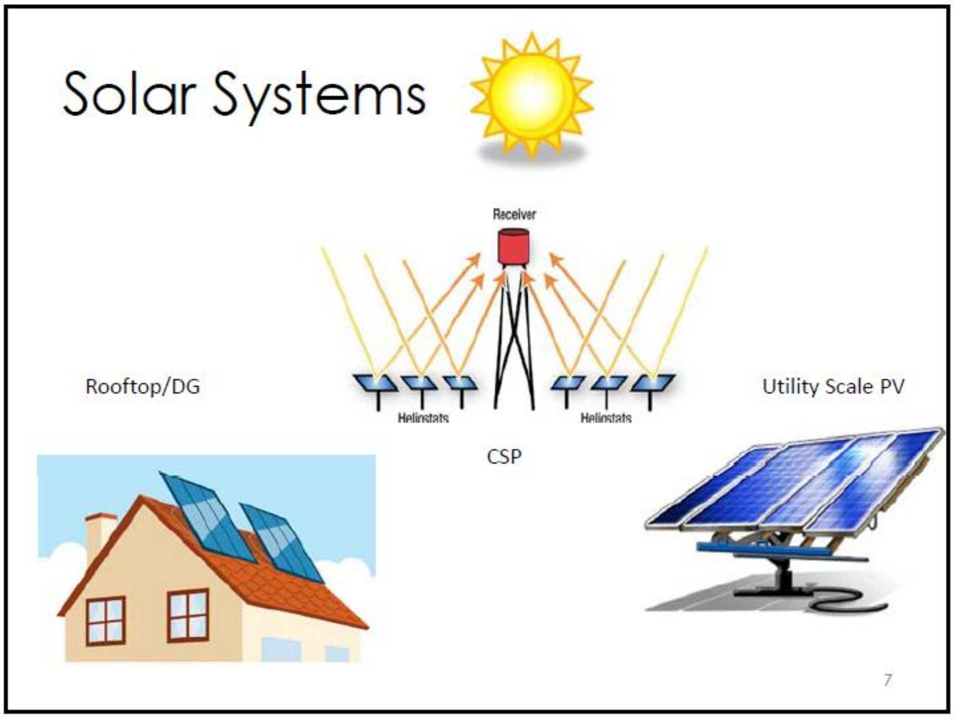
As a variable resource, run-of-river generation is highly dependent on precipitation, snow pack levels and spring runoff. This typically does not correlate well with FBC's peak load requirements during winter hours. In addition, the generation from run-of-river facilities is dependent on annual average water flows and high and low water years may be experienced over a period of time.

Run-of-river generation is considered a clean and renewable resource. FBC considers the socio-economic attribute ranking as 'medium'.

3.3.3 Utility-Scale Solar Power

One intermittent resource option that has both grown in popularity and come down in cost significantly during the past few years is solar power. Solar power can be produced directly by individual households or businesses through rooftop solar panels, as part of what is termed distributed generation (DG), or by utilities to generate electricity for customers. Utility-scale solar power generally falls into two main categories – photo-voltaic (PV) and concentrated solar power (CSP). The following figure shows these different types of solar power.

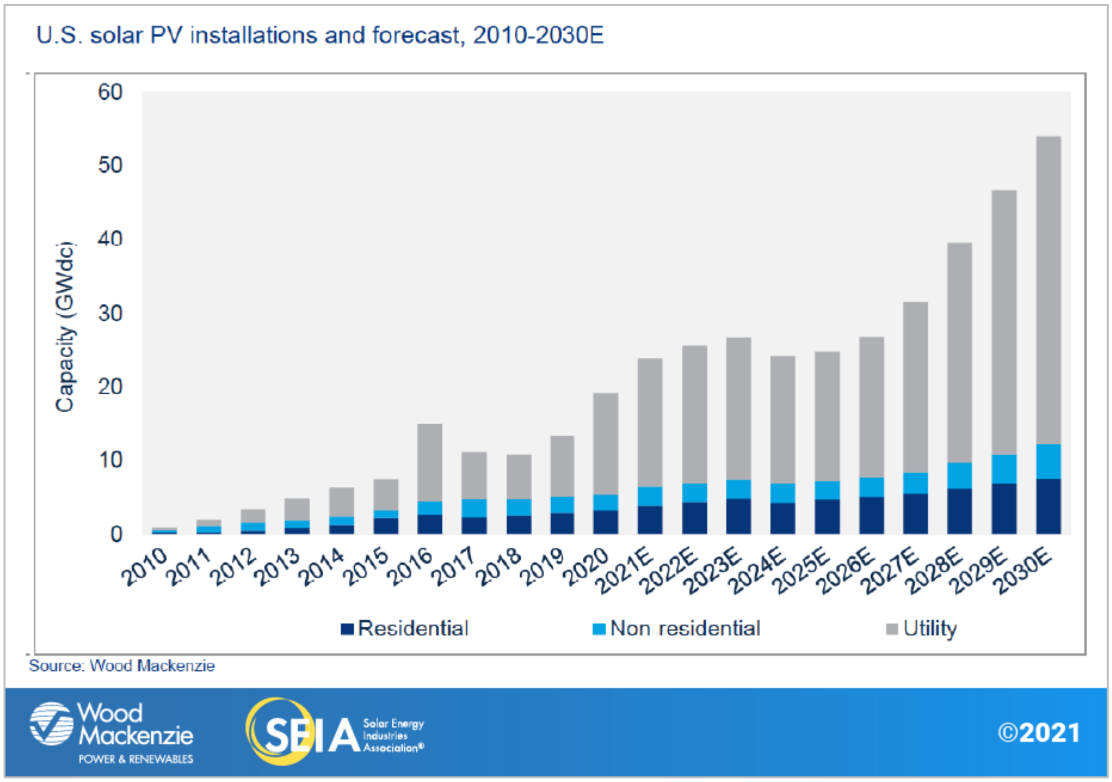
Figure K3-22: Types of Solar Power[34]



In general, because of the low panel cost and innovations in efficiency, PV has dominated the market in recent years. Solar PV modules can be fixed or on trackers that follow the sun. Fixed modules are less expensive to install but have lower capacity factors than tracking systems. Dual-axis trackers are most efficient from a kWh per kW perspective, but also are the most costly and require the most ongoing maintenance. Fixed systems are generally less effective at more northern latitudes. The following figure shows the recent growth in solar power in the US, with the largest growth coming from solar PV.

[34] https://www.nwcouncil.org/media/6871479/p1.pdf

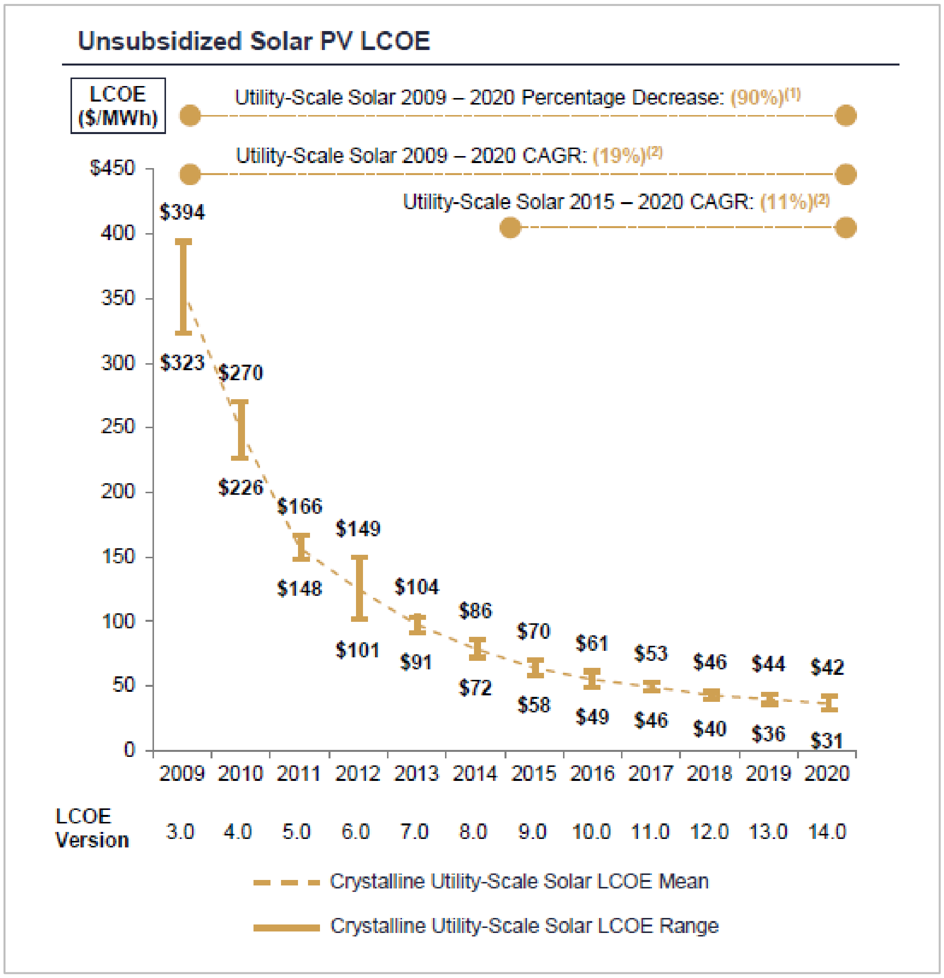
Figure K3-23: Growth in Solar Power in the US[35]



Improvements in technology as well as cost reductions for materials have contributed to the overall decrease in costs for solar PV generation. The following figure shows the decrease in the US cost for solar PV since 2009.

[35] https://www.seia.org/research-resources/solar-market-insight-report-2020-year-review

Figure K3-24: US Solar PV Price Trends[36]



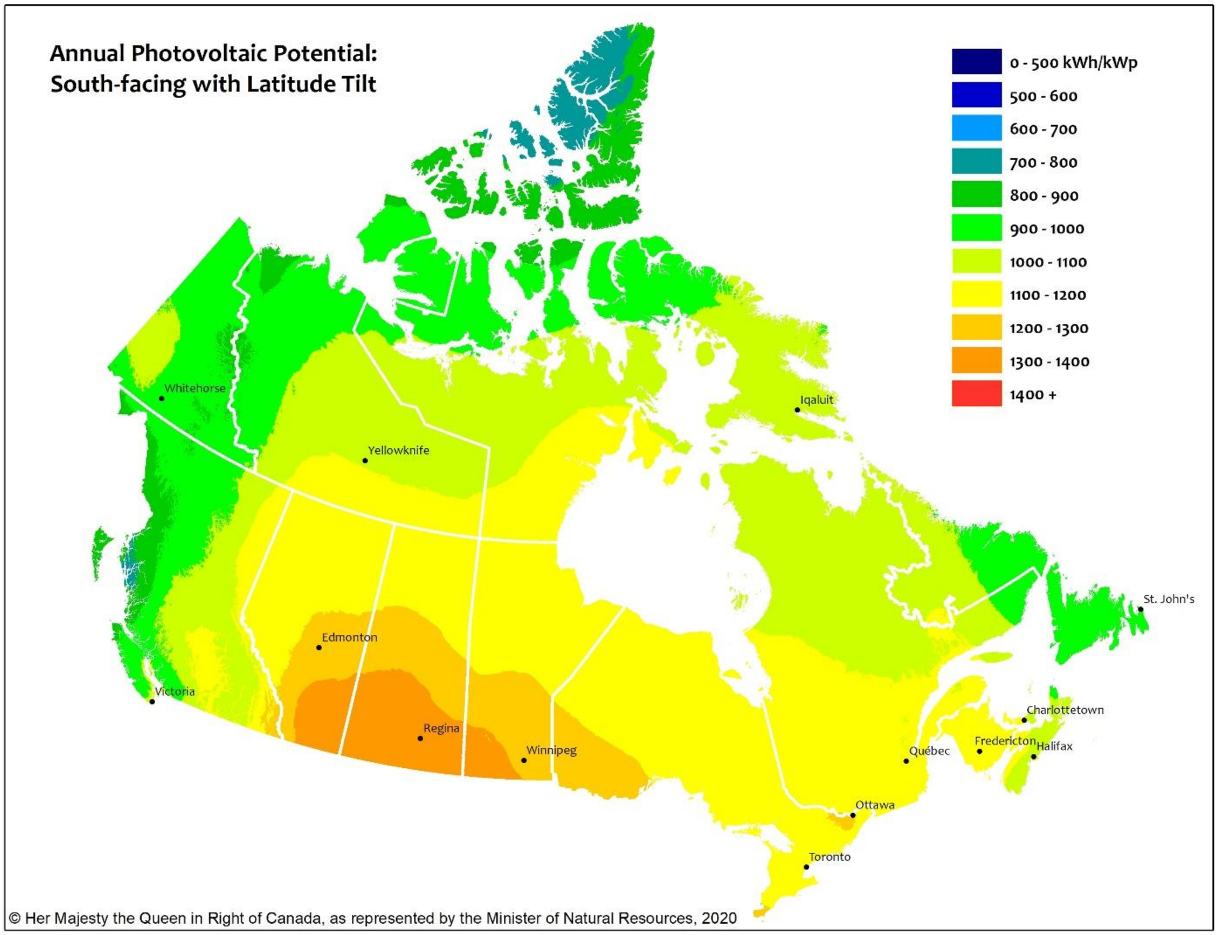
Although solar power can only be generated during daylight hours, it can still be produced during cloudy conditions. The use of a peaking type of resource, such as natural gas-fired generation or energy storage, can help provide the necessary backup for the intermittency of solar power.

Utility-scale solar PV can require large amounts of land. This would have to be taken into account if FBC considers solar PV as a potential resource in the future.

There is significant potential for solar power generation in southern Canada, including FBC's service area in the southern interior region of BC, as shown in the following figure.

[36] Lazard Levelized Cost of Energy Analysis, Verion 14.0, October 2020, page 9.

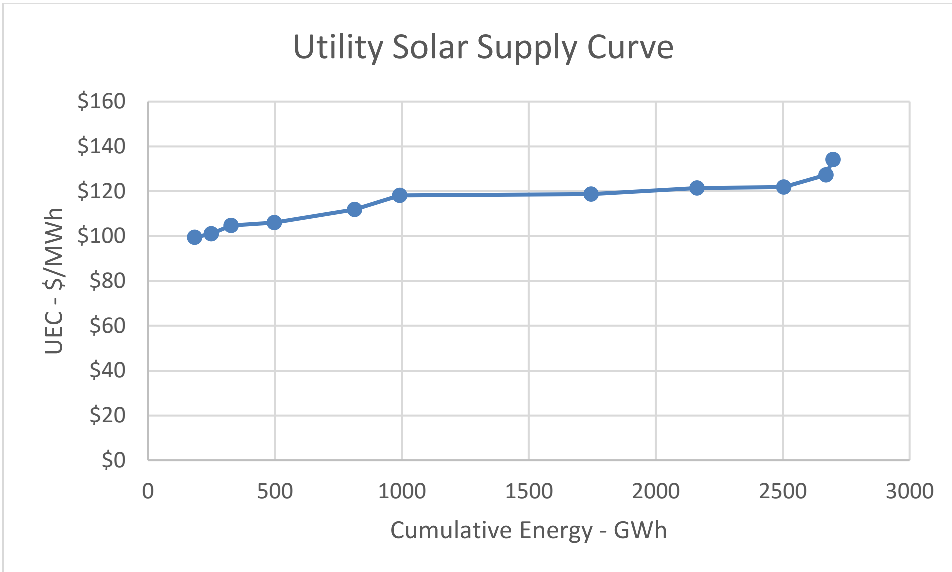
Figure K3-25: Annual Solar PV Yield for Canada [37]



FBC analized a subset of 11 solar projects ranging in nameplate capacity from 17 MW – 490 MW in its portfolio analysis. The supply curve for these options is provided in the following figure.

[37] https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/renewable-energy/solar-photovoltaic-energy/tools-solar-photovoltaic-energy/photovoltaic-potential-and-solar-resource-maps-canada/18366

Figure K3-26: Solar Supply Curve



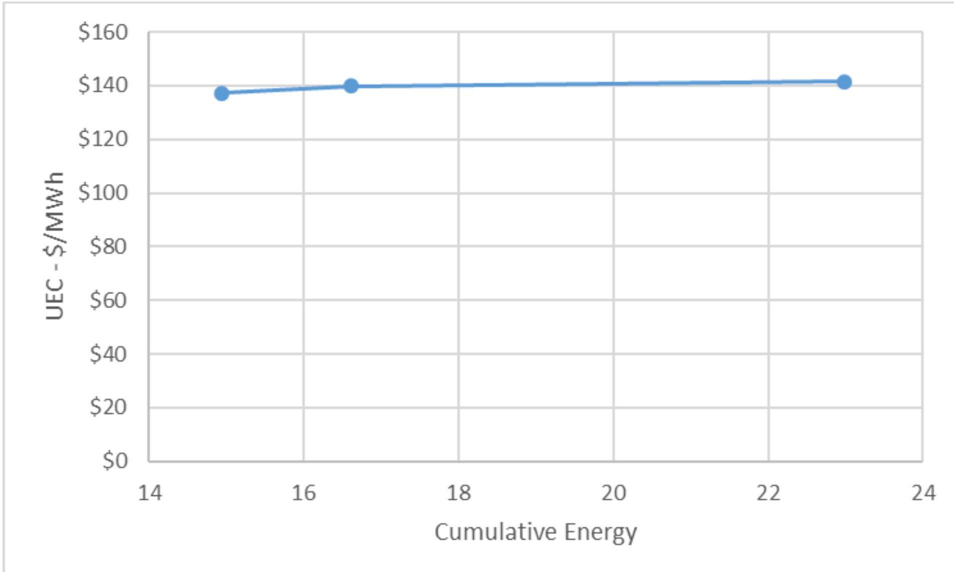
It is worth noting that FBC's estimated unit costs for solar generation are higher than unit costs in many U.S. jurisdictions, despite solar costs coming down generally over the past few years. This is largely due to the lower solar PV yield in Canada compared to the more southerly US states and US government subsidies provided to utilities for solar power.

Solar generation is considered a clean and renewable resource option. In terms of socio-economic benefits, FBC rates utility-scale solar generation as 'low'.

3.4 DISTRIBUTED SOLAR

For the purpose of this ROR, distributed solar is defined as utility-scale PV solar up to 10 MW (installed capacity), connected to the distribution grid. All other characteristics of distributed solar are similar to utility-scale solar power.

Figure K3-27: Distributed Solar Supply Curve



3.5 *MARKET PURCHASES*

Market purchases of energy and capacity can be a cost-effective and reliable resource within FBC's portfolio. FBC has relied on market electricity purchases in the past and this strategy has proven cost effective in recent years given the decrease in market gas and power prices relative to the costs of other resource options, such as the PPA with BC Hydro. On an annual basis, FBC determines the optimal amount of market purchases within its Annual Electric Contracting Plan (AECP), taking into account its forecast load requirements, the annual PPA energy nomination and the price of market supply compared to the PPA Tranche 1 energy rate. On a long-term planning basis, FBC can compare the forecast price of market purchases to the forecast price of the PPA and other resources to help evaluate market purchases within the resource options portfolio.

Based on current base forecasts for market prices (as discussed in Section 2.5 of the LTERP), some reliance on market purchases of energy is more cost effective than other resource options, at least over the short to medium term. Based on Figure 2-4 in Section 2.5 of the LTERP, which shows the base case long term market price for electricity at Mid-C, the levelized unit energy cost for market purchases is about $36 per MWh including transmission costs and losses from Mid-C and the addition of a Clean Market Adder. Overall, this is lower than the base case scenario for the PPA Tranche 1 Energy rate (as provided in Figure 2-6 of Section 2.5 of the LTERP), with a levelized value of about $52 per MWh over twenty years. The price for market purchases and PPA Tranche 1 energy is significantly lower than the unit cost of other supply-side resource options, as listed in Figure K3-1 of this ROR, which have levelized energy unit costs ranging of $68 per MWh to $176 per MWh.

As discussed in Section 2.2.3.2, self-sufficiency under the CEA is still a requirement for BC Hydro and proposed amendments to remove this requirement have not yet been enacted into legislation. For the purpsoes of this LTERP, FBC has assumd that it is not requitred to be self-sufficient and can consider market purchases as a resource option. Althought FBC is comfortable with relying on market purchases for energy, relying on makrt purchase for capacity over the loing run, however, can be risky in terms of availability. There is also no guarantee that FBC will be able to access market supply reliably, especially if there is no access to long-term firm transmission. FBC relies on Line 71 to access US market supply, and there can be transmission constraints both on Line 71 and on the US transmission south of the border that can interrupt supply, as discussed in Section 5.5. Therefore, FBC does not believe that market supply can be relied on as a long-term capacity resource option. In addition, while there are market price forecatss for future energy prices, there is no guarantee that market prices will remain at these levels given the degree of price volatility and uncertainty in the market place. This is why FBC has presented varying market price forecast scenarios in Section 2.5.

3.6 *BC HYDRO PPA*

The PPA is an existing contracted resource with BC Hydro and provides long-term dependable capacity and energy. FBC has access to up to 200 MW of capacity, up to 1,041 GWh of Tranche 1 Energy and up to 711 GWh of Tranche 2 Energy. The cost for this energy and capacity is provided in Section 2.5 and different rate scenarios are also discussed. The PPA is a very flexible resource in the FBC portfolio, enabling FBC to increase or decrease the amount of energy and capacity requirement from year to year, subject to specific limits. Because of this flexibility, FBC has included the PPA in its list of resource options even though it is already an existing contract. More details regarding the PPA are provided in Section 5.4.

3.7 *EXPIRING BC HYDRO ENERGY PURCHASE AGREEMENTS*

As of February 2020, BC Hydro had a total of 127 electricity purchase agreements with independent power producers. About 70 of these agreements are expiring over the next 20 years, representing approximately 9,100 GWh of firm energy and 1,300 MW of dependable capacity. The expiring agreements are primarily small run-of-river facilities as well as some are larger run-of-river, storage hydro, biomass, municipal solid waste, wind, solar, waste heat, biogas, and gas-fired generation facilities. Energy currently provided to BC Hydro from these IPPs may become available when these EPAs expire.

There may be opportunities for FBC to acquire power from these expiring EPAs on a cost-effective basis in the future. FBC will continue to monitor the BC Hydro contract renewals for any resource option opportunities.

3.8 *PURCHASING FROM SELF-GENERATORS*

Electricity purchases from self-generating customers may be a supply option for FBC in the future. Self-generating customers refers to larger, industrial customers that can receive electricity from FBC as opposed to smaller, residential or commercial customers that could provide distributed generation to FBC. Self-generation supply, in addition to benefitting the self-generator, can also have the following benefits for FBC and its customers:

- self-sufficiency and less reliance on market supply;
- reduction of transmission losses depending on location on the FBC system; and
- improved reliability depending on location.

When assessing the value of self-generation supply, in addition to these benefits, FBC must consider other relevant criteria in terms of its supply requirements and its LTERP objectives, as it does with other supply-side resource options. These include the energy and capacity profile (i.e. when is the electricity provided to FBC during each month of the year), adherence to provincial energy and environmental policy and cost effectiveness. The energy and capacity profile of the self-generation supply needs to meet FBC's customer load requirements, providing energy throughout the year and capacity during peak demand periods. Any self-generation must be consistent with BC's energy and environmental policies, such as meeting requirements in terms of clean or renewable generation. In terms of cost, long-term self-generation supply would need to be at least as cost effective as FBC's other resource options and as indicated by FBC's LRMC values, as discussed in Section 11. If the self-generation supply is short term in nature, the FBC would compare the cost to its short-term resource options, such as market supply or its PPA contract.

At this point in time, FBC does not have any specifics or indications of costs or other attributes such as environmental or socio-economic characteristics. FBC is not seeking additional sources of supply at this time and is therefore not actively looking to purchase power from self-generator customers. However, if a self-generator could provide power at a cost lower than FBC's alternatives, there may be an opportunity for FBC to purchase the output of the self-generation.

3.9 *SUPPLY-SIDE RESOURCE OPTIONS EXCLUDED FROM EVALUATION*

FBC has pre-screened the supply-side resource options considered in this ROR for any emerging resource technologies that are not yet commercially viable for utility-scale use or those that are not cost effective or considered viable for FBC or consistent with the *CEA*. This does not mean that these resource options could not be considered in the future and in a future resource plan; however, for the purposes of this ROR these resources have been excluded from evaluation as identified in the Resource Options Summary Table K3-1. These non-viable resources include generation produced by offshore wind, hydrokinetic energy, coal, nuclear power, municipal solid waste (MSW) and biogas.

3.9.1 Offshore Wind Power

While offshore wind generation is a viable resource option in certain regions of BC, it is currently typically less cost effective relative to onshore wind. Offshore wind technology costs are typically higher than those for onshore wind. This is because the higher capital costs for offshore foundation and installation costs typically outweigh the higher energy production for offshore projects. Therefore, FBC has included onshore, but not offshore, wind as a viable resource option within this ROR.

3.9.2 Hydrokinetic Generation

Hydrokinetic technologies include wave and tidal energy. Wave energy is generated by winds blowing over the surface of the ocean. Tidal energy is generated from the kinetic movement of the ocean tides. While there is the potential for significant wave and tidal energy off the coast of BC, these technologies have not yet been proven commercially viable on a utility scale.

3.9.3 Coal-Fired Generation

There is currently no coal-fired electricity generation in BC The 2007 BC Energy Plan requires that any coal-fired generation in BC must meet a zero GHG emission standard through a combination of 'clean coal' technology, carbon sequestration and offset for any residual GHG emissions[38]. The province has signalled that this will be done by adding coal-fired generation to Schedule A of the *Greenhouse Gas Industrial Reporting and Control Act.* FBC has excluded this resource option from its evaluation due to the potential costs for meeting a zero GHG emission standard and social licensing issues.

3.9.4 Nuclear Power

About 15 percent of Canada's electricity comes from nuclear power, with most of the generators located in Ontario[39]. The 2007 BC Energy Plan made explicitly stated that the government will not allow production of nuclear power in British Columbia. In addition, the *CEA* includes the objective to achieve BC's energy objectives without the use of nuclear power.

3.9.5 Municipal Solid Waste

Generating electricity from MSW involves the incineration of municipal waste to produce electricity. Essentially, the waste is burned at high temperatures and the resulting heat and gases pass into a boiler area, where they heat tubes filled with water. That water boils to become steam and the steam turns a turbine generator to create electricity.

MSW typically produces GHG emissions as well as other air contaminants and so is not considered 100 percent clean or renewable. MSW plants are typically located near munipality waste sites and so the nature of the development process for MSW plants can be dictated by the needs of municipalities to dispose of wastes rather than the needs of a power producer to generate power. Therefore, the decision to build these plants lies more with the municipalities

[38] http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/bc_energy_plan_2007.pdf, page 13.
[39] http://www.world-nuclear.org/information-library/country-profiles/countries-a-f/canada-nuclear-power.aspx

and so utilities have less control over when and where they might be located. For this reason, FBC has excluded MSW plants as a resource option in this LTERP.

3.9.6 Biogas

Biogas energy is generated from the decomposition of organic waste with the resulting methane gas captured and used as a fuel source. Sources of biogas energy include landfill sites, sewage treatment plants and anaerobic digestion organic waste processing facilities.

FBC has excluded baseload biogas generation from this analysis as it is assumed that most available biogas in BC would be required for decarbonization of the FEI natural gas system going forward, with minimal amounts possibly providing fuel for SCGT plants.

4. SUMMARY

As discussed throughout this ROR, there are many potential supply-side resource options available to FBC to meet its future energy and capacity gaps. These include base load, peaking and intermittent/variable generation resources as well as purchases from the market or self generators. Of the clean or renewable resources, solar and wind are among the lowest cost energy options. Battery storage and SCGT plants using RNG are among the lowest cost capacity options. Based on current market price forecasts and PPA rate scenarios, market purchases and the PPA are the least-cost resources available to FBC.

However, it is important to remember that unit cost alone is not the only factor to consider when selecting resources. The size and generation profile of the resource options needs to match the FBC monthly energy and capacity gaps to provide value to FBC. Environmental and socio-economic attributes and resiliency should also be considered in meeting the LTERP objectives. The portfolio analysis, discussed in Section 11, will help to determine the optimal mix of these various resource options and their attributes, taking into account the resource planning objectives.

Appendix L

LONG-RUN MARGINAL COST

A Framework for Analyzing Marginal Costs of an Electric Utility

Ryan Steele, FortisBC Inc.
Gail Tabone, EES Consulting
Amber Gschwend, EES Consulting

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EES Consulting
a GDS Associates Company

FORTIS BC™

Executive Summary

The purpose of portfolio analysis is to determine the optimal mix of resources to meet forecasted load over a planning horizon, subject to environmental, regulatory, and other constraints. The long-run marginal cost (LRMC) is derived from the preferred optimal portfolio and reflects the incremental costs to meet incremental load. There are several challenges to developing a representative LRMC, such as capturing utility-specific characteristics, reflecting the value of different resource technologies in a changing operating environment, and selecting the correct calculation approach for its intended application. To assist FBC to understand how these concepts relate to FBC's situation, FBC developed this report in cooperation with EES Consulting[1].

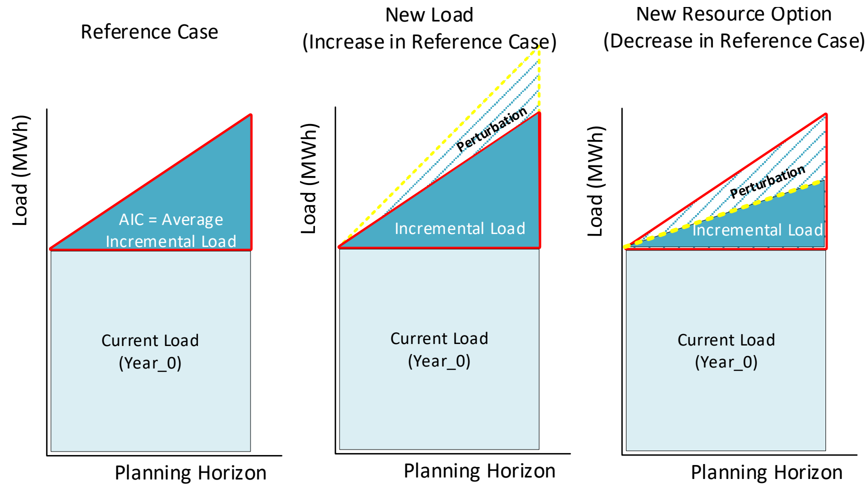
This report reviews common methods for determining the LRMC of an electric utility, namely the unit energy cost (UEC), the unit capacity cost (UCC), the average incremental cost (AIC), and the perturbation approach (alternatively referred to as the Turvey approach). This paper goes on to provide a framework for utilizing the strengths of multiple approaches in combination to express the marginal costs of a utility and value alternative resources.

The LRMC of a utility should be calculated using a portfolio approach to account for changes in energy dispatch among existing and future resources. The performance profiles (and risks) of different technologies need to be taken into account when calculating marginal costs as a combination of resources will be required to address gaps at certain times over the planning horizon. The identified incremental resources contained in the optimal portfolio have attributes that complement the existing resources of the utility.

This report recommends using the AIC approach for stating the LRMC of the utility, which is derived from the preferred portfolio that meets the reference case load forecast as presented in the Integrated Resource Planning (IRP) processes of a utility. The LRMC is a levelized value stated in real terms. Furthermore, this report recommends using the perturbation (Turvey) approach to value marginal changes from the established baseline, represented as an increase or decease in load relative to the reference case forecast. Figure 1 provides an overview of the recommended framework for evaluating the marginal costs of a utility.

1 EES Consulting is familiar with FBC's situation as they have undertaken many complex analysis for FBC relating to the COSA process and other Regulatory matters for many years.

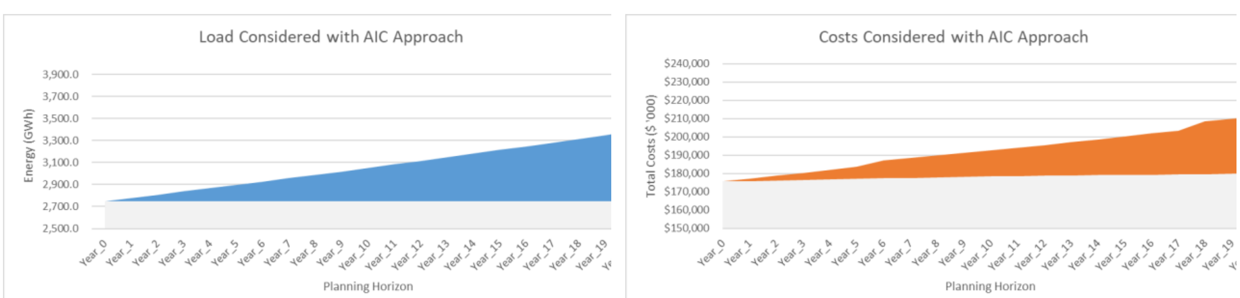
Figure 1: Summary of the Three Costing Scenarios of the Proposed Framework



The utility's preferred optimal portfolio to meet the reference case load forecast provides a baseline for anticipated future costs (see the left side of Figure 1). Marginal costs associated with new load (see the middle of Figure 1) are derived from the advancement cost of resources on a net present value basis and/or changing the incremental resources in the preferred portfolio. The marginal value associated with new alterative resources (see the right side of Figure 1) is derived from the delay or avoidance of future resources in the portfolio that would otherwise be required if an alternative resource was not serving the load.

The LRMC of a utility should be established in an Integrated Resource Plan and calculated using the reference case forecast and AIC approach. The AIC approach reflects the general level and trend of future costs while addressing the unique attributes of a utility's resources (e.g., flexibility in existing and future resources). By considering all incremental load beyond current load, the AIC approach is more likely to provide a steady price signal and is, therefore, better for guiding long-term decisions. Figure 2 shows the hypothetical load growth on the left and the corresponding changes in cost on the right considered in the calculation of the LRMC using the AIC approach.

Figure 2: Load and Costs considered with the AIC Approach

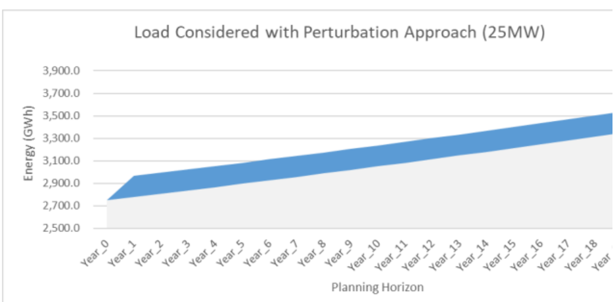


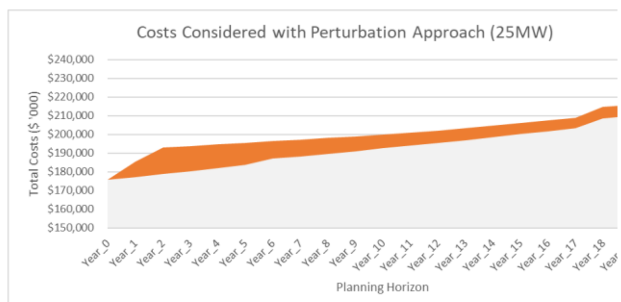
The LRMC of the utility's preferred portfolio is only one of many considerations when assessing the cost-effectiveness of different resource options. A utility should not expect to acquire all available resources up to the LRMC calculated using the AIC approach, nor should the LRMC be viewed as a clearing price in isolation from other prudent resource planning considerations, such as energy and capacity profiles or environmental factors. The characteristics of the LRMC align with the characteristics of the source portfolio, including attributes related to reliability and renewable portfolio standards. Inappropriate applications of the LRMC can lead to negative customer impacts.

Establishing the reference case LRMC using the AIC approach provides a baseline for calculating avoided and incremental costs. This report recommends using the perturbation (Turvey) approach to calculate the cost of a new incremental load beyond the reference case load forecast or the value of a non-utility owned specific resource, respectively. The perturbation (Turvey) approach is useful for scenario analysis, as it allows for the calculation of marginal costs under specific circumstances. For a broader calculation of LRMC, it is more difficult to apply the perturbation approach as it requires a specific set of assumptions to be made regarding increases in load in order to get a single number, and it varies considerably based on those specific assumptions.

As shown in Figure 3, the marginal cost of a new load leads to an increase in costs resulting from the advancement or changes in resources required to serve the new load (or more formally, perturbation) beyond the utility's reference case costs. Marginal costs can vary greatly depending on the size and shape of the new load and the utility's existing load resource balance. Figure 3 shows the hypothetical load perturbation of a new customer on the left as well as the corresponding changes in cost on the right, which are considered in the calculation of marginal costs using the perturbation approach.

Figure 3: Increase in Load and Costs considered with the Perturbation Approach





Conversely, the value of an alternative supply-side resource comes from its ability to delay or avoid otherwise planned resources contained in the reference case portfolio. Different technologies have varying performance profiles, and, therefore, are of unique value to the utility. The value of a resource to the utility is the alignment between the time of delivery of energy and the forecasted utility resource gaps.

It is not possible to draw a direct comparison between two utilities that calculate LRMC values using different methodologies. Furthermore, each utility has its own unique requirements around timing differences for required resources, locational differences in load and generation, volume differences in capacity and energy requirements, varying resource costs, and differences in governing policy that can cause various utilities to consider different resource options. When using the LRMC for the various purposes (DSM, new loads, Distributed Energy Resources (DER)) it needs to be compared to other options in real terms as well.

Table of Contents

Glossary of Terms

This section defines conceptual terms as used in this report. The terms are grouped into four categories, namely defining the profile of a resource, conservation management, resource types, and load shown below.

Profile of a Resource

A profile summarizes the characteristics of a generator. Table 1 provides an example of a resource profile followed by a definition of the corresponding terms used within the table.[2]

Table 1: Example of a Resource Profile

Monthly Profile	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Installed Capacity (MW)	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
Peak Dependable Capacity (MW)	97	58	72	57	36	32	32	48	25	74	103	72	58.7
Maximum Energy (GWh)	186.0	168.0	185.8	180.0	186.0	180.0	186.0	186.0	180.0	186.0	180.3	186.0	2,190.0
Maximum Reliable Energy (GWh)	107.6	79.1	91.4	57.4	65.9	63.1	45.9	36.2	49.8	80.3	93.7	105.6	876.0
Capacity Factor	0.6	0.5	0.5	0.3	0.4	0.4	0.2	0.2	0.3	0.4	0.5	0.6	0.40
Minimum Energy Dispatch (GWh)	102.2	75.2	86.8	54.5	62.6	60.0	43.6	34.4	47.3	76.3	89.0	100.3	832.2

- ***Installed capacity*** refers to the nameplate capacity of a generator. It states the size or how big the generator is in MW units.
- ***[Peak] dependable capacity*** is the amount of energy expected to be available during the peak hours of need for a specific utility within each month. Dependable capacity is used in planning studies as anticipated energy delivered from a generator at the time of the system coincident peak.
- ***Maximum energy*** is the installed capacity multiplied by the number of hours in a month, assuming unrestricted and unlimited fuel sources. For example, if a generator has 250 MW of installed capacity, the theoretical maximum energy in January would be 250 MWh in all 744 hours resulting in a total of 186,000 MWh or 186 GWh.
- ***Maximum reliable energy*** is the amount of energy anticipated to be delivered within each month after considering maintenance/availability and fuel, which includes intermittent factors such as weather. Reliable energy is the volume (GWh) produced, without consideration for the timing of delivery relative to load requirements.
- ***Capacity factor*** is the maximum energy divided by the maximum reliable energy.
- ***Minimum energy dispatch*** is the minimum amount of energy the generator is required to run within each month. For example, a hydro unit may be required to pass a minimum amount of water to meet environmental regulations.

[2] Dependable Capacity and Reliable Energy are derived from historic hourly data. Calculations are beyond the scope of this paper.

Conservation Management

- ***Energy efficiency programs*** are incentives that result in the decrease of energy usage. Examples of energy efficiency programs include incentive rebates for efficient furnaces or housing installation.
- ***Demand response*** are incentives that result in a decrease in energy use at specific times. An example of demand response program is peak-time rebates, which provide a credit for load reductions below a baseline load on critical days.
- ***Demand-side management*** encompasses energy efficiency programs as well as demand response resources. Demand-side management programs focus on changing customer behaviour and consumption patterns.

Resource Types

- ***Intermittent resources*** are those in which the utility is not able to control the dispatch of generation other than curtailment; rather, dispatch is driven by environmental factors, such as weather or time of day. Common examples of intermittent resources are wind and solar generation.
- ***Dispatchable resources*** are those in which the utility is able to control the fuel source, capacity factor, and time of energy production within reasonable limits. Examples of dispatchable resources include hydroelectric and natural gas fired generation.
- ***Distributed generation*** are resources that are not under the control of the utility. The customer controls the marginal decision to install distributed generation as well as the dispatch of excess energy (if dispatchable) to other ratepayers connected to the utility. A common example of distributed generation is rooftop solar photovoltaic. Distributed generation is a form of DER.
- ***Utility generation*** are resources that are owned and maintained by the utility. Utility generation reflects a utility decision to install resources, and the utility is able to schedule the output of the unit in accordance with reliability standards.

Load

- ***Reference case load forecast*** is the most likely estimate of future load requirements over the planning horizon based on best available information. The reference case is the forecast used in the development of the preferred portfolio and represents the load requirements that the utility plans to meet with resources.
- ***Planning horizon*** is the number of years over which the analysis is conducted (e.g., 20 years). The planning horizon should be viewed as a rolling window representing a longer-term outlook of resource requirements and costs.
- ***Load factor*** is the energy billed to the customer divided by the customer's peak demand (capacity requirement) multiplied by all hours. It is similar in concept to a capacity factor, except representing the customer side rather than supply-side perspective.

1 Introduction

Marginal costs are an important consideration in electric utility regulation, as they provide indications of future resources and costs of service. Bonbright, Danielsen, and Kamerschen (1988) defined the marginal cost of a given commodity or service as the increase in the total cost of providing the services or products incurred by the utility resulting from a relatively small (marginal) increase in its rate of output. Marginal costs can be used to inform rates as well as signal the future value of generation resources to a utility. For purposes of this paper, the marginal cost discussed is specific to power supply or generation resources, however, the same theoretical approach can be applied to the transmission and distribution infrastructure required for the delivery of power.

Marginal costs can vary greatly among utilities. There are several utility-specific characteristics such as timing of when resources are required, the specific resource options available to the utility, considerations for locational aspects, differences in volume and economies of scale, and varying governing policies among jurisdictions that can all contribute to material differences in marginal costs between neighbouring utilities. To provide realistic price signals to stakeholders, the unique characteristics of a utility's existing resources, future resource requirements, and resource options should be considered.

Complicating marginal cost analysis is an evolving operating environment. The need to reduce greenhouse gas emissions is becoming a greater priority among stakeholders and regulators. The economics of different technologies, such as renewable energy and storage, are rapidly changing the marginal costs of capacity and energy in different ways than traditional resources. Understanding the relationship between intermittent and dispatchable resources to reliable energy and dependable capacity is essential to understanding the value of different resources to different utilities.

In addition to specific differences among utilities and a changing operational environment, utilities have varying methodologies for calculating marginal costs. The selection of a marginal cost methodology is ultimately a decision put forward by a utility and accepted or rejected by the governing commission.

This report defines long-run marginal cost (LRMC), reviews established approaches for determining marginal costs, and outlines relevant changes in the utility operating environment. This report ultimately provides a framework for expressing utility-specific price signals and valuations of alternative generation resources based on changes in utility cost relative to the utility's optimal portfolio to meet expected load requirements.

1.1 Significance

The levelized unit energy cost approach (UEC) is the simplest approach to expressing the LRMC of a utility and has been widely used in the past; however, its usefulness is declining due to various changes in the industry. The LRMC has traditionally been taken from the Integrated Resource Plan (IRP) and was based on the marginal cost of the expected new resource required to serve growing loads. The UEC approach worked well when utilities typically built their own large-scale dispatchable generating plants, and the newest resource was often fully utilized because it reflected the most recent technology.

For most utilities, this approach no longer reflects the planning process. Stakeholders' focus on energy conservation, widespread wholesale energy markets, requirements related to renewable resources, increasing considerations for resiliency, and growth in the availability of cost-effective distributed energy resources (DER) are beginning to lead to resourcing policies less reliant on a larger, centralized generating resource to meet load growth expectations.

One of the key applications of LRMC theory is in the cost-effective assessment of various demand-side management (DSM) measures. The value of a DSM measure can be approximated as the costs the utility would have otherwise incurred to serve the load with clean or renewable resources. Utility marginal costs may also be a consideration for determining the cost-effectiveness of DER, particularity rooftop solar. The value and cost of customer self-generation can be a subject of differing opinions among many stakeholders.

A further potential use for the LRMC is to support the design of retail rates. Many economists suggest rates should be set with reference to marginal costs, including Bonbright et al. (1988). Although marginal costs are an important consideration in retail rates, there are several other factors to examine when setting rates such as energy policy objectives, customer bill impacts, and/or limited access to alternative energy sources for heat and hot water.

This report establishes a methodology to demonstrate the impacts on the total power portfolio associated with changes in utility load. The LRMC can be a tool for expressing the projected costs of various future load drivers and scenarios.

2 Theoretical Background

This section provides a definition of marginal costs, distinguishes between the short- and long-run marginal costs, and provides an overview of three common approaches used by utilities in various industries to express the LRMC. This section also provides a brief discussion on the economics of a utility. Within each of the three LRMC approaches reviewed, the steps and calculations are given as well as an interpretation and numerical example.

2.1 Definition of Marginal Cost

Bonbright et al. (1988) noted short-term marginal costs are estimated by the increase in utilization of the existing plant and equipment, whereas in the long-term it is assumed that rate of output will continue indefinitely and require a corresponding increase and adaption of plant capacity. This paper adopts the National Economic Research Associates (NERA, 2011) definition of *marginal cost*:

> *The added cost of producing a specified increment of output or, equally, the cost that is avoided by reducing production by a specified amount.* (p. 3)

2.1.1 Short versus Long-Run Marginal Costs

Marginal costs can be estimated from either a long- or a short-run perspective. Consistent with the work of Bonbright et al. (1988), NERA (2011) defined the short-run marginal cost (SRMC) as the operational cost of an incremental change in demand, holding capacity constant. In cases in which there is sufficient existing supply capacity, the SRMC encompasses all operating costs incurred to generate electricity including generation fuel costs, emission taxes, and variable operations and maintenance costs resulting from a change in dispatch. An important distinguishing feature of the SRMC is that, in the event existing capacity is insufficient to meet all demand, the SRMC is represented by whatever price level is necessary to curtail demand to match available supply.[3]

This report focuses on approaches for calculating the LRMC of an electric utility. From a theoretical perspective, the 'long run' reflects a time horizon in which all factors of production and costs are variable (Certified Financial Analyst Institute, 2011). Therefore, the LRMC estimate encompasses all marginal operating costs of meeting additional demand, which includes the SRMC, as well as the marginal capital cost and fixed annual operating costs associated with providing sufficient dependable capacity to meet the demand over a planning horizon (NERA, 2011).

In practice, a utility generally views the distinguishing differences between an SRMC and an LRMC as the time horizon considered, specifically the planning horizon of the long-term integrated resource planning (IRP) process (e.g., 20 years), and more importantly, whether long-term capacity resources can be varied or not (NERA, 2011). SRMCs reflect the marginal cost of additional energy dispatch from existing resources between the current date and the date of the next capacity

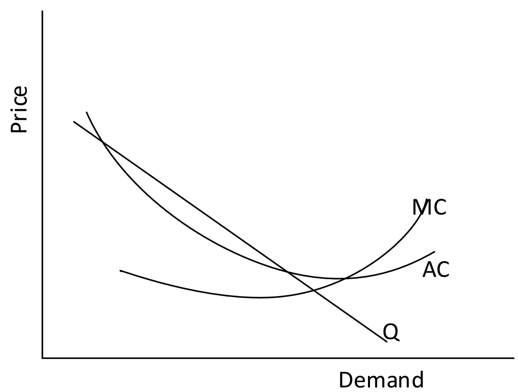
[3] Examples of this concept in practice include critical peak pricing, which assigns higher costs for power during peak periods, or peak time rebates, which provides credits for load reduction.

expansion or the next commission accepted IRP (decision to decision), whichever comes first. In contrast, LRMCs reflect the marginal costs of additional energy dispatch for existing as well as incremental resources between the current date and the end of the planning horizon. The LRMC may encompass multiple capacity expansion projects within the planning horizon depending on the sizes and characteristics of the resource options available.

2.2 Characteristics of a Utility's Costs

A utility's cost curve shape (Figure 2) reflects large fixed costs and economies of scale. As noted in Marsden Jacob Associate's (2004) report, the marginal cost (MC) of an additional unit of electricity demand (Q) is comparatively low once the generation resources are established. As a result, marginal cost is typically lower than average costs (AC).

Figure 2: Typical Cost Curves for a Utility[4]



Note. AC = average costs; MC = marginal cost; Q = unit of electricity demand.

At some point, marginal costs accelerate and surpass average costs. According to Bonbright et al. (1988), three factors in combination tend to explain why marginal costs increase at a rate much greater than the increase in demand:

1. The change in demand is required to be supplied by less efficient, older, more expensive generation that would otherwise be kept in standby reserve.
2. As demand increases, the amount of standby reserves become reduced over time, and, at some point, is not sufficient to meet reliability standards resulting in the need for additional generation capacity to meet planning reserve margin requirements.
3. Power quality deteriorates through voltage drops requiring transmission and distribution reinforcements, which is another economic cost, although less tangible in nature.

When incremental resources are required, utilities have traditionally procured large investments to achieve economies of scale. Consequently, as Marsden Jacob Associates (2004) noted, marginal

[4] This is an illustrative example only; the curves are hypothetical.

costs rise sharply in response to capacity constraints and then fall away as a result of excess capacity following the capacity expansion (Figure 3 and Figure 4).

Figure 3: Capacity and Demand vs. Time

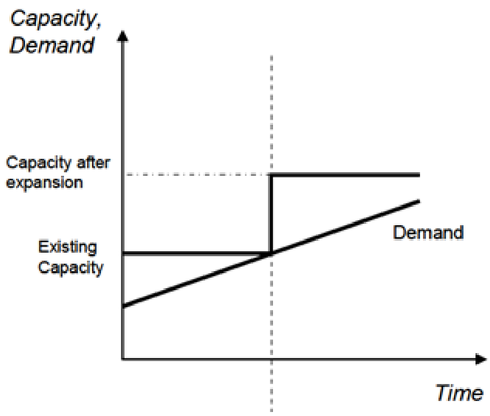
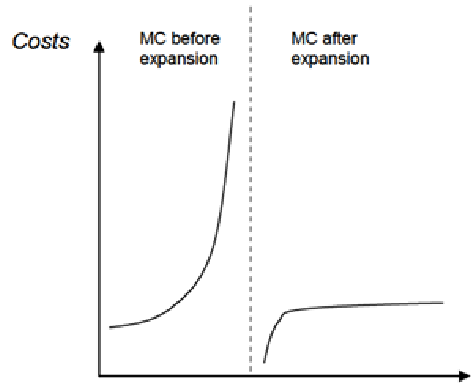


Figure 4: Marginal Costs Before and After an Expansion



The lumpy nature of investment can lead to occasional volatility in SRMCs. For example, if current demand is slightly below the maximum output permitted by existing plant capacity, the marginal cost of service may be a mere fraction of the average cost. In contrast, if the demand increases to a rate only slightly in excess of that for which existing capacity is adequate, the marginal cost may jump to many times the average cost and LRMCs (Bonbright et al., 1988). After capacity expansion, the short run marginal cost decreases reflecting the surplus formed with lumpy investment.

2.3 The LRMC is stated in Real Dollars

Costs and information regarding resource options are collected as of a point in time (YYYY$); therefore, stating marginal costs in real terms aligns with the underlying data used within a utility's portfolio analysis to represent resource options. Furthermore, the LRMC is commonly included in other analyses to represent the long-term cost of power. These subsequent analyses often include an inflation variable, which can vary or introduce the potential for double counting inflation (treating a nominal value as a real value). The formulas and calculations presented in this report are based on real values.

3 Common Approaches to Determining Long-Run Marginal Costs

This report reviews three common approaches used in practice to express the LRMC of a utility. The first is the levelized unit energy cost (UEC), sometimes referred to as the levelized cost of energy (LCOE), of a specific resource. The second and third approaches are portfolio-based methods rather than a resource specific metric, namely the average incremental cost (AIC) approach and the perturbation approach (also referred to as the Turvey approach). This section is a summary of the approaches. Readers interested in explanations that are more detailed are encouraged to review the papers by NERA (2011) and the Alberta Market Surveillance Administrator (2012).

3.1 Levelized Unit Energy Cost Approach

The UEC, also referred to as the LCOE, measures the lifetime energy costs of a specific generator by dividing the total cost of ownership by the assumed total volume of energy expected to be produced over the generator's life.

3.1.1 Steps

1. Gather financial information about the specific resource option including the anticipated investment capital cost to develop the generator, the annual fixed costs of operations, variable costs of maintenance, and variable costs for generating energy as well as any cost of emissions.
2. Develop assumptions of annual future energy production, usually expressed as a capacity factor.
3. Calculate the levelized UEC.

3.1.2 Equation

The UEC or LCOE is calculated at the total cost of the resource over its lifetime, expressed in present value (PV) terms, divided by the total energy anticipated to be produced over its lifetime

$$LCOE = \frac{PV(Sum\ of\ Total\ Costs\ over\ Lifetime)}{PV(Sum\ of\ Energy\ Produced\ Over\ Lifetime)}$$

More formally, the LCOE is calculated as ("Cost of Electricity by Source," 2019):

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + FC_t + VC_t + EC_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{MWh_t}{(1+r)^t}}$$

Where

- I_t = Capital Investment (initial Outlay) in year t

- FC_t = Fixed operations and maintenance expenditures in year t
- VC_t = Variable energy costs (e.g. Fuel) in year t
- EC_t = Variable Emissions Costs (e.g. Carbon Tax) in year t
- MWh_t = Electricity generated in year t
- r = Discount rate
- n = Life of the generator
- t = year in planning horizon

Related to the UEC is the unit capacity cost (UCC), alternatively referred to as the levelized cost of capacity (LCOC). The UCC is the fixed cost portion of the UEC associated with developing and maintaining the generator to a ready state for dispatch (pure capacity). The UEC includes the UCC,[5] because a generating resource must be in service and maintained to be available for dispatch. The UCC equation is similar to the UEC, but it excludes the variable costs of energy and replaces the energy divisor with capacity expected to be available during peak hours of need (referred to as Dependable Capacity in this document).

$$LCOC = \frac{PV(Sum\ of\ Fixed\ Costs\ over\ Lifetime)}{PV(Annual\ Dependable\ Capacity)}$$

More formally, the LCOC

$$LCOC = \frac{\sum_{t=1}^{n} \frac{I_t + FC_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{MW_t}{(1+r)^t}}$$

Where

- I_t = Capital Investment (initial Outlay) in year t
- FC_t = Fixed operations and maintenance expenditures in year t
- MW_t = average Annual Dependable Capacity in peak hours of the month
- r = Discount rate
- n = Life of the asset
- t = year in planning horizon

3.1.3 Interpretation

The UEC or LCOE is a resource-specific calculation of the constant electricity price required to cover all the relevant costs associated with that specific resource, given a set of assumptions. The UEC provides a means for basic comparison of different technologies (e.g., wind, solar, natural gas) of unequal life spans, project size, capital cost, risk, required return, and capacities. The UCC or LCOC

[5] More specifically, the costs are included. The divisor of the UCC is the average dependable capacity, in contrast to the divisor of the UEC, which is the total energy over the economic life of the generator.

measures the cost of dependable capacity, which is the average amount of energy the generator is expected to produce in the peak hours of utility need.

3.1.4 Numerical Example of the UEC or LCOE Approach

Table 2 presents a numerical example showing the calculation of the LCOE for a hypothetical 300-MW combined cycle gas turbine (CCGT). The CCGT resource has a maximum capacity factor of 90% and is assumed to be operating to its full potential as a base load resource over its life.[6]

[6] For ease of presentation, the present value of energy produced and associated costs of the resource over its life are presented as an annuity in the following example, which assumes annual costs and annual energy generated are the same in every year of the generator's life.

Table 2: An Example Calculation of the LCOE for a Hypothetical 300-MW Combined Cycle Gas Turbine

Resource: Combine Cycle Gas Turbine (CCGT_1)			
Installed Capacity (MW)	[A]		300
Capacity Factor	[B]		0.9
Annual Reliable Energy (GWh)	[C] = [A]*[B]*8760/ 1000		2365.2
Fixed Annual Costs ('000)	[D]	$	4,000
Marginal Energy Costs ($/MWh)	[E]	$	35.00
Emissions Rate (CO2e Tonne/MWh)	[F]		0.4
Emissions Cost ($/ CO2e Tonne)	[G]	$	30.00
Real Discount Rate	r		4%
Expected Life (Years)	n		25
Annuity Factor	AF = (1-(1+r)^-n)/r		15.62
PV Energy (GWh)	[H] = [C] * AF		36,949
Outlay Capital Costs ('000)	[I]	$	400,000
PV Fixed Annual Cost ('000)	[J] = [D] * AF	$	62,488
PV Variable Energy Costs ('000)	[K] = [C] * [E] * AF	$	1,293,227
PV Emissions ('000)	[L] = [C] * [F] * [G] * AF	$	443,392
Total PV Costs ('000)	[M] = [I]+[J]+[K]+[L]	$	2,199,107
UEC/ LCOE ($/MWh*)	UEC = [M] / [H]	$	59.52
Average Dependable Capacity (MW)**	[N] = [A] * 95%		285
PV Dependable Capacity	[O] = [N] * AF		4,452
UCC ($/KW-Year)	[P] = ([I] + [J])/[O]	$	103.88
UCC ($/MW-Month)	[Q] = ([P] * 1000)/ 12	$	8,656
* There are 1000MWh/ 1GWh and costs are stated in $ '000			
** Assumes that 95% of the installed capacity would be available during peak hours			

If costs and energy produced are assumed to vary among the years of the horizon, then the use of annuity would not be appropriate, and the present value would need to be calculated based on at least an annual level of granularity. Table 3 shows the first 5 years of the life of the hypothetical CCGT; this table extends the expected 25-year life of the resource. If the costs, dependable capacity, and reliable energy change among the years, this is reflected in the net present value (NPV) analysis.

Table 3: The first 5 Years of a Hypothetical 300-MW Combined Cycle Gas Turbine

Levelized Calculations	NPV	Year_1	Year_2	Year_3	Year_4	Year_5
Peak Dependable Capacity (MW)	4,452	285.0	285.0	285.0	285.0	285.0
Maximum Reliable Energy (GWh)	36,949	2,365.2	2,365.2	2,365.2	2,365.2	2,365.2
Total Capital Outlay ('000)	$ 400,000					
Fixed Annual Costs ('000)	$ 62,488	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000
Variable Energy Costs ('000)	$ 1,293,227	82,782	82,782	82,782	82,782	82,782
Emissions Costs	$ 443,392	28,382	28,382	28,382	28,382	28,382
Total Costs ('000)	$ 2,199,107					

3.2 Average Incremental Cost Approach

The AIC approach uses an optimization routine to determine the lowest-cost combination of available resource options to satisfy the reference case forecast. The AIC is calculated by dividing the change in total cost by the change in total load. Both the total cost and the future load requirements are expressed in present-value terms.

3.2.1 Steps

1. Establish a long-run load forecast (e.g., a reference case load forecast with a 20-year planning horizon).
2. Gather information regarding the characteristics and costs of resource options considered available to meet demand.
3. Determine the optimal combination of resources given a set of constraints (the least cost capital program plus the change in operating costs), in present value terms that can satisfy the forecasted load requirements at each point in the planning horizon as well as meet reliability standards.
4. Determine the present value of the load that is in excess of the current load requirements.
5. Calculate the LRMC by dividing the present value (PV) of the cost of servicing the additional demand by the size of that demand increment.

3.2.2 Equation

$$LRMC_{AIC} = \frac{PV(Portfolio_{Forecast\ Load}) - PV(Portfolio_{Current\ Load})}{PV(Forecast\ Load) - PV(Current\ Load)} = \frac{PV(P_1) - PV(P_0)}{PV(L_1) - PV(L_0)}$$

Where

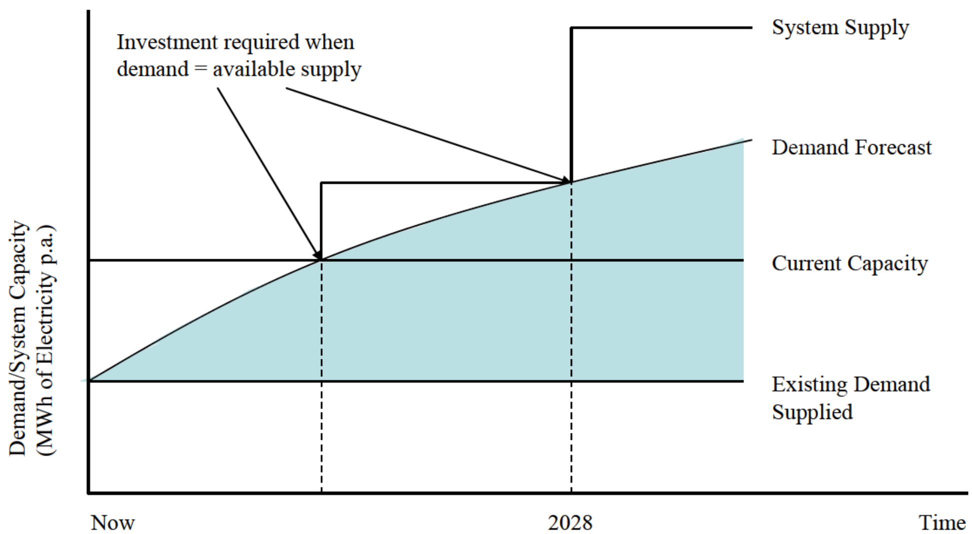
- P_1 = Total portfolio cost to meet reference case forecasted load ($)
- P_0 = Total portfolio cost to meet the current load ($)
- L_1 = Reference case load forecast (MWh)
- L_0 = Current load (MWh)

3.2.3 Interpretation

Figure 5 shows a visual of the AIC approach. Utilizing this approach, the term *additional demand served* (the full area highlighted in blue in Figure 5) refers to demand over and above that which is *currently being supplied,* rather than which *could be supplied* with existing capacity (NERA, 2011). This distinction is particularly important when calculating the LRMC of a system that is not capacity constrained. Note that within the chart the terms demand and capacity are intended as generic terms and can refer to either peak (MW) or energy (MWh) levels. In most cases, utilities must balance loads (demand) and resources (capacity) at both the time of the peak demand and on the basis of annual energy.

The term *marginal cost* includes the operating costs of supplying power over and above that currently being supplied, not the operating costs of supplying power over and above that which could be supplied (NERA, 2011). Therefore, marginal costs reflect both the marginal operating costs of meeting any increases in load with existing resources, which could be material in the cases in which the next required investment in generation capacity is some time into the future, and the marginal capital and associated operating costs of new generation resources.

Figure 5: Demand and System Capacity – Average Incremental Cost Approach



Note. From *Estimating Long Run Marginal Cost in the National Electricity Market* (p. 8), by National Economic Research Associates, 2011. Copyright 2011 by NERA.

The total cost to serve the current load may not be constant over the planning horizon, as the marginal energy costs of existing resources are usually not static. The use of the optimization routine to determine the Year_0 costs (the cost to serve existing load), in contrast to holding Year_0 costs constant, results in only costs associated with serving incremental load included in the AIC calculation, as opposed to including the additional costs associated with existing load. Therefore, two portfolios are required. The optimization routine is used to determine the portfolio cost of meeting the current load (Year_0) over the planning horizon, reflecting any change in costs to meet existing load requirements, and the optimization routine is used to determine the portfolio cost of meeting the reference case forecast. The difference between the two portfolio results provides the level of the AIC.

3.2.4 Numerical Example of AIC Approach

While resource optimization typically considers both peak demand and energy needs in each month, or on an hourly basis, the AIC calculations summarize load requirements based on annual energy levels. Table 4 shows a numerical example of the AIC approach. L_1 (L1) is the reference case forecast, whereas L_0 (L0) is the current load (Year_0), held constant over the planning horizon. P_1 (P1) is the total optimal portfolio cost to meet the Reference Case load forecast in each year, whereas P_0 (P0) is the optimal costs to meet the current load in each year. The costs over the planning horizon are summarized in NPV. The LRMC is expressed as a ratio of change in costs divided by the change in load.

Table 4: A Numerical Example of the Average Incremental Cost Approach

Average Incremental Cost ($/MWh)								
	Energy (GWh)	**Total Costs ($ '000)**	**Energy Year_0**	**Total Costs Yr_0**	**Incremental Energy (GWh)**	**Incremental Total Costs ('000)**	**[L0] Available Capacity (MW-Month)**	**[L1] Available Capacity (MW-Month)**
	[L1]	[P1]	[L0]	[P0]	[L1]-[L0]	[P1]-[P0]		
Year_0	**2,750.0**	**$ 175,859**	**2,750.0**	**$ 175,859**	-	-	**6,947.6**	**6,948**
Year_1	2,778.7	$ 177,150	2,750.0	$ 175,859	28.7	1,290.8	6,947.6	6,948
Year_2	2,807.6	$ 178,751	2,750.0	$ 176,151	57.6	2,600.8	6,947.6	6,948
Year_3	2,836.9	$ 180,375	2,750.0	$ 176,445	86.9	3,930.2	6,947.6	6,948
Year_4	2,866.5	$ 182,022	2,750.0	$ 176,743	116.5	5,279.4	6,947.6	6,948
Year_5	2,896.4	$ 183,692	2,750.0	$ 177,043	146.4	6,648.7	6,947.6	6,948
Year_6	2,926.6	$ 187,069	2,750.0	$ 177,323	176.6	9,746.6	6,947.6	7,652
Year_7	2,957.1	$ 188,401	2,750.0	$ 177,599	207.1	10,802.1	6,947.6	7,652
Year_8	2,988.0	$ 189,764	2,750.0	$ 177,877	238.0	11,886.8	6,947.6	7,652
Year_9	3,019.1	$ 191,159	2,750.0	$ 178,159	269.1	13,000.0	6,947.6	7,652
Year_10	3,050.6	$ 192,576	2,750.0	$ 178,425	300.6	14,151.8	6,947.6	7,652
Year_11	3,082.5	$ 193,997	2,750.0	$ 178,570	332.5	15,426.6	6,947.6	7,652
Year_12	3,114.6	$ 195,474	2,750.0	$ 178,718	364.6	16,756.7	6,947.6	7,652
Year_13	3,147.1	$ 196,975	2,750.0	$ 178,866	397.1	18,108.3	6,947.6	7,652
Year_14	3,180.0	$ 198,534	2,750.0	$ 179,016	430.0	19,517.1	6,947.6	7,652
Year_15	3,213.2	$ 200,150	2,750.0	$ 179,166	463.2	20,984.4	6,947.6	7,652
Year_16	3,246.7	$ 201,774	2,750.0	$ 179,308	496.7	22,466.0	6,947.6	7,652
Year_17	3,280.6	$ 203,428	2,750.0	$ 179,451	530.6	23,976.8	6,947.6	7,652
Year_18	3,314.9	$ 208,460	2,750.0	$ 179,596	564.9	28,864.3	6,947.6	8,264
Year_19	3,349.5	$ 209,816	2,750.0	$ 179,742	599.5	30,074.2	6,947.6	8,264
Year_20	3,384.4	$ 211,203	2,750.0	$ 179,890	634.4	31,313.1	6,947.6	8,264
NPV	**43,942.7**	**2,775,698**	**40,123.4**	**2,593,887**	**3,819.3**	**181,811**	**101,368**	**108,680**
	[PV(L1)]	[PV(P1)]	[PV(L0)]	[PV(P0)]	[A] = PV(L1-L0)	[B] = PV(P1-P0)		
	AIC = ([PV(P1)] - [PV(P0)]) / ([PV(L1)] - [PV(L0)])			**$ 47.60**	AIC = [B]/[A]	**$ 47.60**		

Figures 6 and 7 show the load and costs considered in the AIC approach over the planning horizon. The red line represents the reference case forecast.

Figure 6: Load Considered with AIC Approach

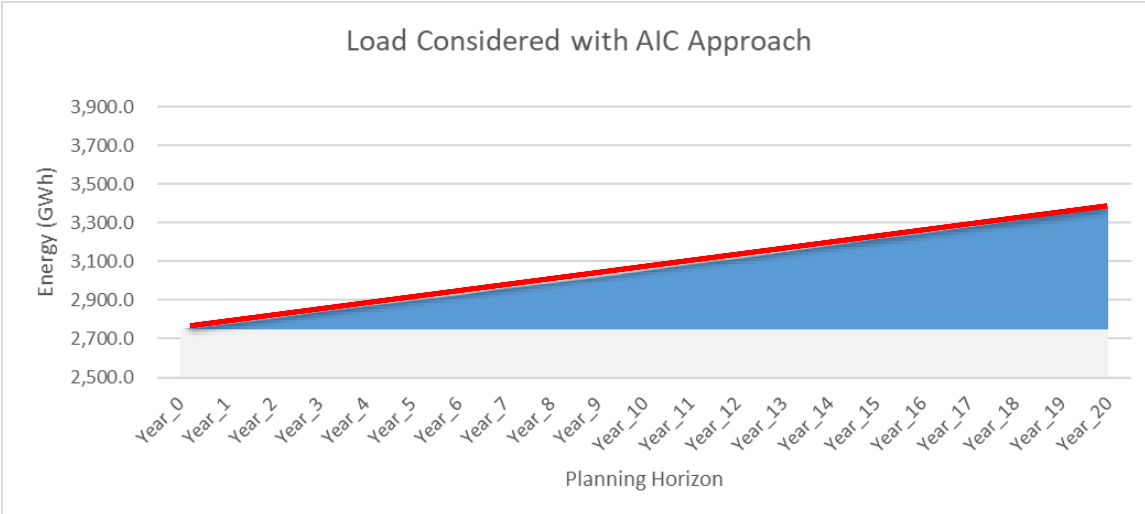
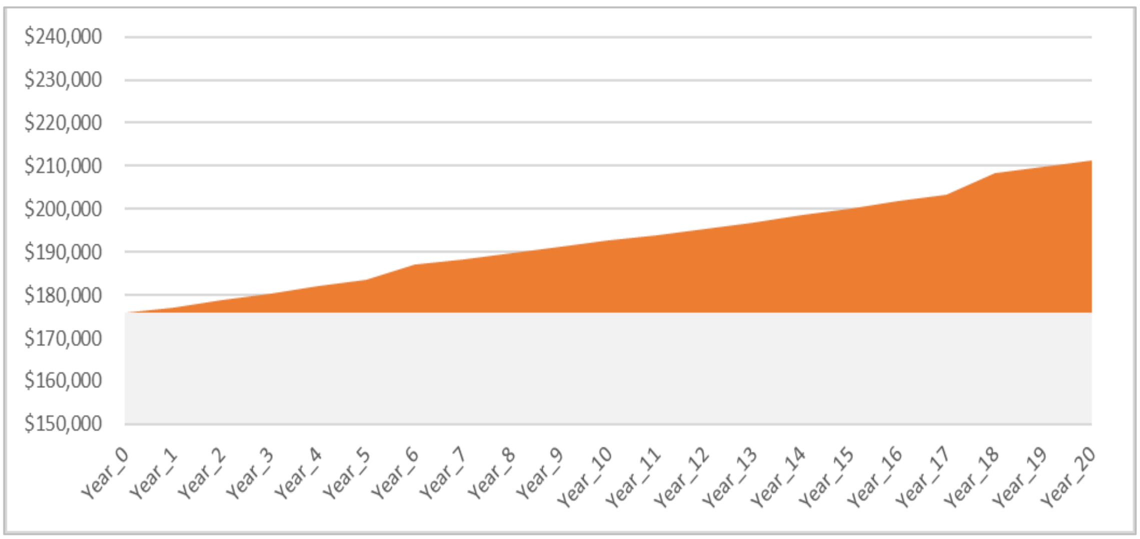


Figure 7: Costs Considered with AIC Approach



3.3 Perturbation Approach (Turvey)

The perturbation approach is a portfolio method like the AIC; however, the perturbation approach differs in how it measures changes in load requirements on future costs (Turvey, 2000). The key difference is the perturbation approach quantifies the effect of a permanent increment (or decrement) to the reference case forecast, as opposed to the current load.

Similar to AIC, the perturbation approach uses an optimization routine used to determine the lowest cost combination of available resource options that can satisfy the reference case forecast. In contrast to the AIC approach, the process is repeated with an augmentation of the reference case forecast that introduces a permanent change in load. This change in load is known as the *perturbation*. The perturbation approach calculates the LRMC as the change in present value terms of the total costs between the first and second optimizations divided by the magnitude of the perturbation used, with all variables expressed in present value terms.

3.3.1 Steps

1. Establish a long-run load forecast (e.g., a reference case forecast with a 20-year planning horizon).
2. Gather information regarding the characteristics and costs of resource options considered available to meet loads.
3. Determine the optimal combination of resources given a set of constraints (the least cost capital program plus the change in operating costs), in present value terms, which can satisfy the reference case forecast load requirements at each point in the planning horizon and meet reliability standards.
4. Increase or decrease the long-run reference case load forecast by a small but permanent amount and recalculate the optimal combination of resources given the same set of constraints that can satisfy the adjusted forecasted requirements at each point in the planning horizon and meet reliability standards.
5. Calculate the LRMC as the PV of the change in the least cost capital program plus the change in operating costs, divided by the PV of the revised forecast compared to the initial reference case forecast.

3.3.2 Equation

$$LRMC_{Turvey} = \frac{PV\left(Portfolio_{Adj.Forecast\ Load}\right) - PV\left(Portfolio_{Refernce\ Load}\right)}{PV(Adj.Forecast\ Load) - PV(Reference\ Load)} = \frac{PV(P_2) - PV(P_1)}{PV(L_2) - PV(L_1)}$$

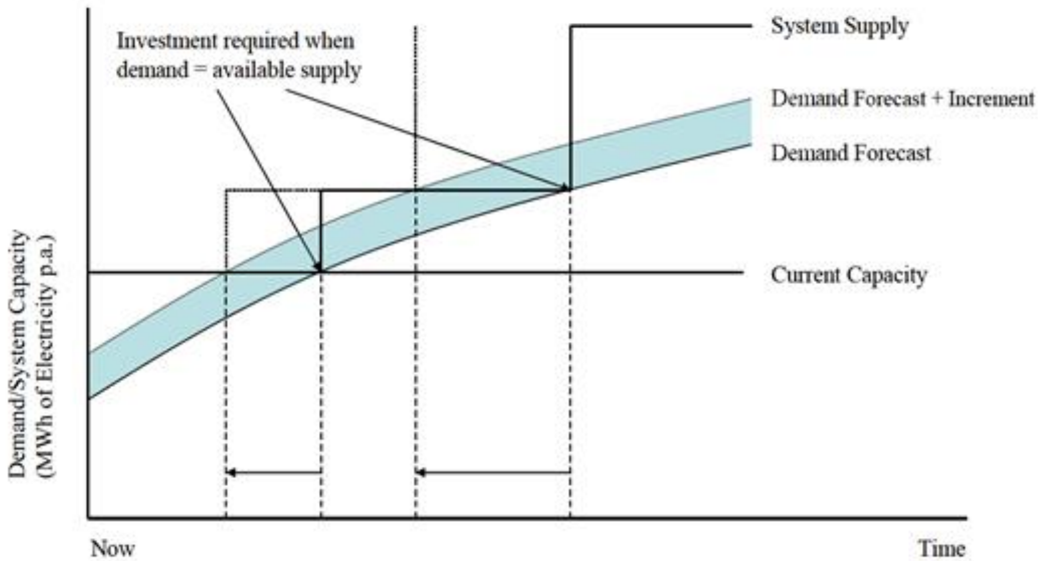
Where

- P_1 = Total portfolio cost to meet reference case forecasted load
- P_2 = Total portfolio cost to meet the load forecast that includes an adjustment or perturbation in load
- L_1 = Reference case load forecast
- L_2 = Load forecast that includes an adjustment or perturbation in load

3.3.3 Interpretation

Figure 8 provides a visual representation of the perturbation approach. The solid stepped line in the figure represents a series of projected increases to system resource capacity, optimized in terms of order and timing to meet future load. The dashed stepped line represents the same projected increases to resource capacity but brought forward as required to meet the reference case load forecast in addition to some assumed permanent increase in load. The LRMC using the perturbation approach represents the change in the portfolio costs to meet the change in the reference case forecast with and without the increment. The blue area in Figure 8 represents the load considered marginal and the arrows show the shifting of the timing of required resource capacity expansion.

Figure 8: Demand and System Capacity - Perturbation Approach[7]



3.3.4 Numerical Example of the Perturbation Approach

In this example, there is an assumed permanent increase in load (perturbation) of 25 MW added to the reference case forecast. The additional 25 MW of load causes the capital expansion plans to be brought forward in the planning horizon and results in an increase in resources needed over the planning horizon. In Figure 9, L1 refers to the annual capacity requirements (in MW-months) of the reference case forecast, and L2 refers to the annual capacity requirements of the augmented load forecast.

7 NERA Economic Consulting. Estimating Long Run Marginal Cost in the National Electricity Market: A Paper for the AEMC. December 19, 2011. Figure 2.1: Perturbation Approach to Estimating LRMC. Page 6.

Figure 9: Comparison of Available Dependable Capacity – Perturbation Approach

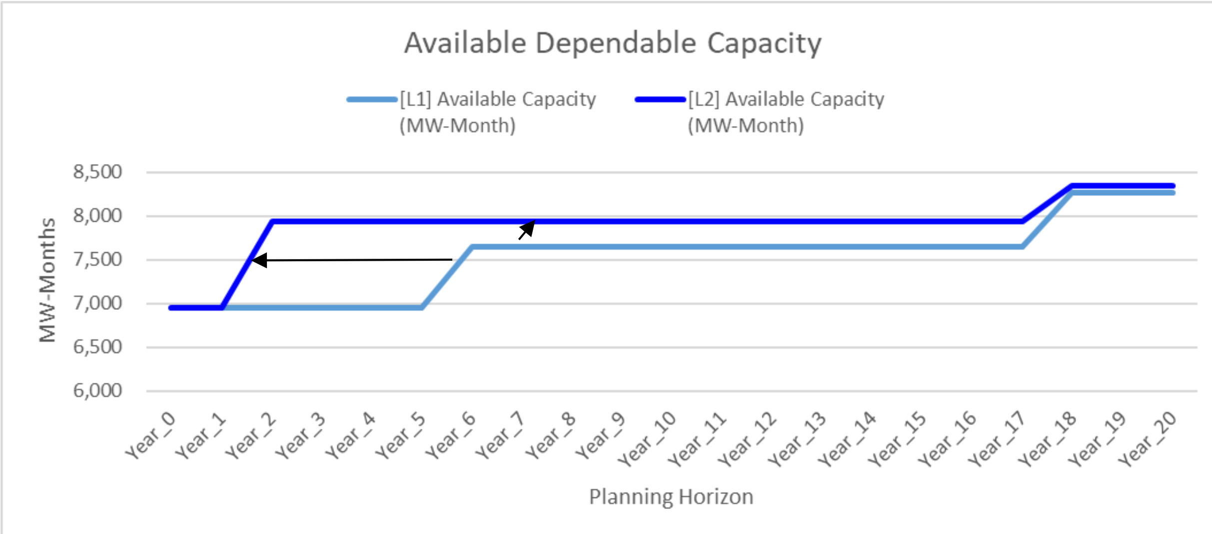


Table 5 shows a numerical example of the perturbation approach. In this table, L1 is the reference case forecast, whereas L2 is the Reference Case load forecast plus the increase in energy requirements associated with the load augmentation over the planning horizon. P1 is the total optimal portfolio cost to meet the reference case load forecast in each year, whereas P2 is the cost to meet the augmented reference case forecast. The costs over the planning horizon are summarized in NPV. The LRMC is expressed as a ratio of change in costs divided by the change in the annual energy load.

Table 5: A Numerical Example of the Perturbation Approach

Turvey Perturbation ($/MWh)							
Perturbation: 25MW -85% Capacity Factor				(25MW*8760hrs*0.85)/1000 =		186.2	
	Energy w/ Perturbation (GWh)	**Total Costs w/ Perturbation ($ '000)**	**Energy (GWh)**	**Total Costs ($ '000)**	**Incremental Energy (GWh)**	**Incremental Total Costs ('000)**	**[L2] Availible Capacity**
	[L2]	[P2]	[L1]	[P1]	[L2]-[L1]	[P2]-[P1]	
Year_0	2,750.0	**$ 175,859**	**2,750.0**	**$ 175,859**	-	-	6948
Year_1	2,964.82	$ 185,553	2,778.7	$ 177,150	186.2	$ 8,403	6948
Year_2	2,993.79	$ 193,050	2,807.6	$ 178,751	186.2	$ 14,298	7934
Year_3	3,023.06	$ 193,861	2,836.9	$ 180,375	186.2	$ 13,485	7934
Year_4	3,052.65	$ 194,692	2,866.5	$ 182,022	186.2	$ 12,670	7934
Year_5	3,082.54	$ 195,545	2,896.4	$ 183,692	186.2	$ 11,853	7934
Year_6	3,112.75	$ 196,394	2,926.6	$ 187,069	186.2	$ 9,325	7934
Year_7	3,143.27	$ 197,260	2,957.1	$ 188,401	186.2	$ 8,859	7934
Year_8	3,174.12	$ 198,147	2,988.0	$ 189,764	186.2	$ 8,383	7934
Year_9	3,205.29	$ 199,057	3,019.1	$ 191,159	186.2	$ 7,898	7934
Year_10	3,236.79	$ 200,018	3,050.6	$ 192,576	186.2	$ 7,441	7934
Year_11	3,268.62	$ 201,070	3,082.5	$ 193,997	186.2	$ 7,073	7934
Year_12	3,300.78	$ 202,199	3,114.6	$ 195,474	186.2	$ 6,725	7934
Year_13	3,333.28	$ 203,448	3,147.1	$ 196,975	186.2	$ 6,474	7934
Year_14	3,366.13	$ 204,719	3,180.0	$ 198,534	186.2	$ 6,186	7934
Year_15	3,399.32	$ 206,008	3,213.2	$ 200,150	186.2	$ 5,858	7934
Year_16	3,432.86	$ 207,425	3,246.7	$ 201,774	186.2	$ 5,652	7934
Year_17	3,466.75	$ 208,892	3,280.6	$ 203,428	186.2	$ 5,464	7934
Year_18	3,501.00	$ 214,688	3,314.9	$ 208,460	186.2	$ 6,228	8342
Year_19	3,535.61	$ 215,948	3,349.5	$ 209,816	186.2	$ 6,131	8342
Year_20	3,570.59	$ 217,233	3,384.4	$ 211,203	186.2	$ 6,030	8342
NPV	**46,472.5**	**2,894,428**	**43,942.7**	**2,775,698**	**2,529.8**	**118,731**	**114,408**
	[PV(L2)]	[PV(P2)]	[PV(L1)]	[PV(P1)]	[A] = PV(L2-L1)	[B] = PV(P2-P1)	
	Turvey = ([PV(P2)] - [PV(P1)]) / ([PV(L2)] - [PV(L1)])			**$ 46.93**	Turvey = [B]/[A]	**$ 46.93**	

Figure 10 shows the increase in load and costs the planning horizon. The red line is the reference case forecast. Figure 11 presents costs the considered with perturbation approach.

Figure 10: Load Considered with Perturbation Approach (25 MW)

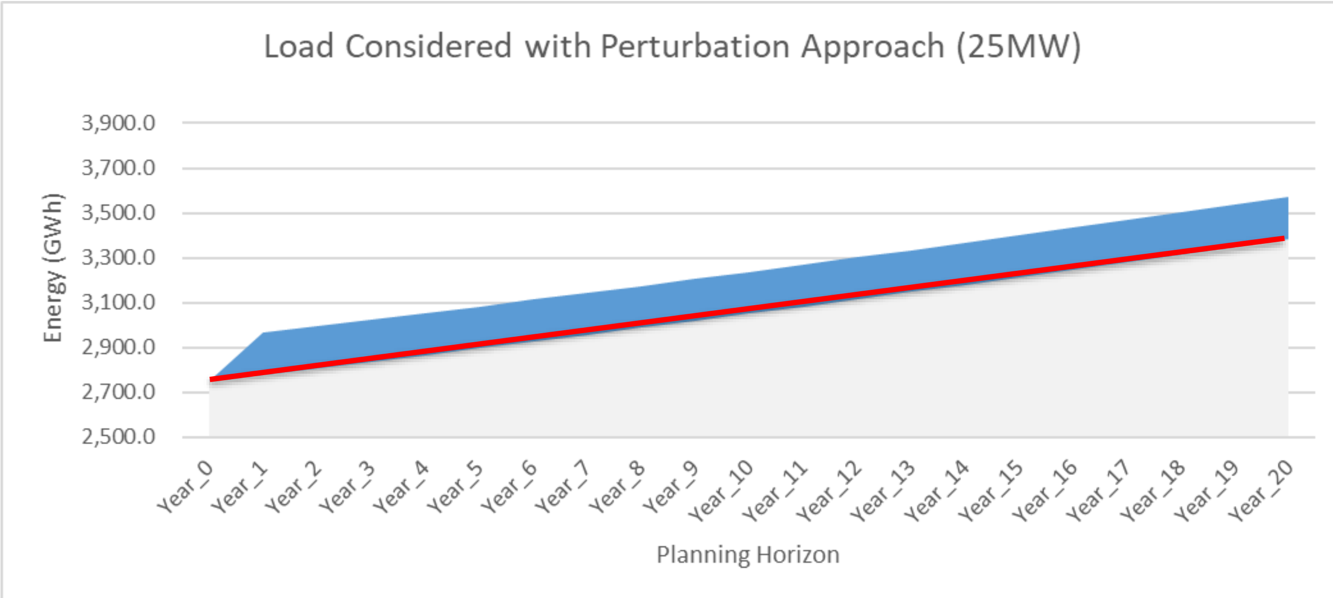
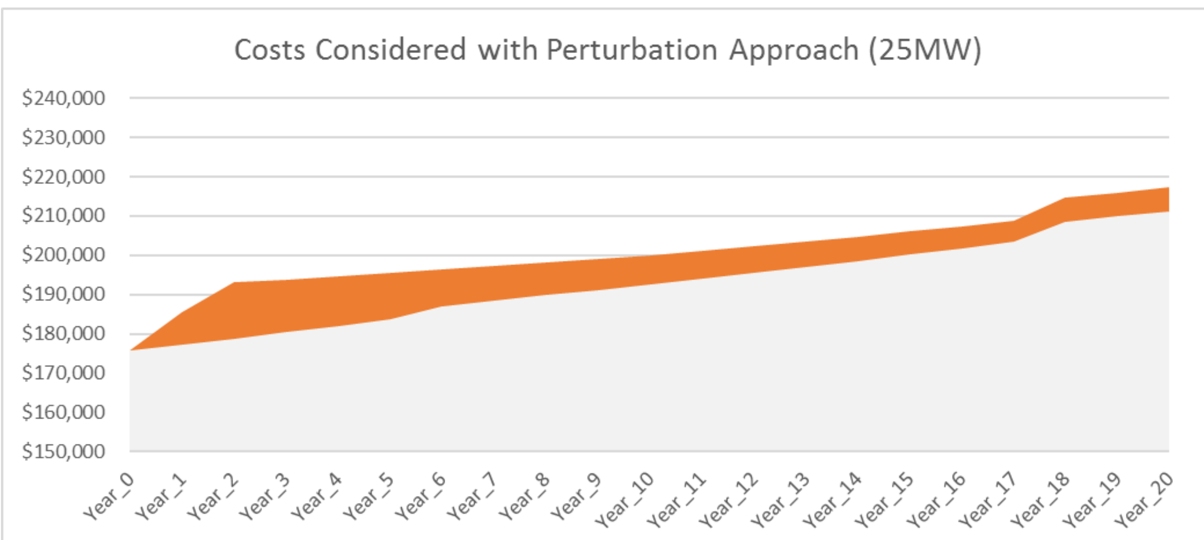


Figure 11: Costs Considered with Perturbation Approach (25 MW)



4 Discussion of LRMC Approaches and Emerging Utility Issues

This section discusses the potential uses of the LRMC, highlights some of the strengths and weaknesses of the different approaches used to express marginal costs. Furthermore, this section discusses the evolving operating environment of an electric utility and the potential impact on future resources and costs.

4.1 Potential Uses of LRMC

While the different approaches used to develop LRMC have specific strength and weaknesses, the context of how the LRMC will be used can play a factor in determining the best approach. Though marginal costs are typically developed as part of the IRP process, the result is generally used outside of the IRP. Although the policies of a specific utility will differ based on jurisdiction, local regulations, and multiple considerations, the following identifies some potential applications of the LRMC.

- ***DSM planning*** often requires the use of the marginal cost to determine the cost-effectiveness of reducing load through various DSM measures in comparison to alternatively acquiring new resources to meet load without DSM measures.
- ***Non-utility generation*** proposed within the service area is often valued with consideration for the marginal cost of power when selling output to the utility. In some cases, this type of generation may be installed by existing industrial customers looking to displace utility purchases, and in other cases, would be projects built by Independent Power Producers looking to sell the output to the utility or a third party.
- ***Distributed energy resources (DER)*** are a subset of non-utility generation, with small customers installing rooftop solar or other distributed energy resources to offset utility purchases. While in some cases the customer is able to avoid the full retail rate when self-generating through net metering policies, in other cases either an average or marginal cost of power supply cost can be used to determine the value of the energy produced.
- ***New large customers*** looking to locate within the service area can be assessed with consideration for the marginal cost associated with the addition of the new large load. Whether to offer new large customers service under existing rates or special contract rates may take into account the impacts to the system.
- ***Line extension policies*** set the financial contributions that customers are asked to pay when connecting to the system. There are various methods used to determine the appropriate credit that new customers should be provided towards new facilities required for interconnection. In some cases, the marginal cost of power may be a factor in developing the amount of the appropriate credit. This may be an issue for new large customers as well as for the addition of typical residential and commercial customers.
- ***Rate design*** is typically based on an embedded cost of service study to determine the appropriate amount of revenues to collect from each customer class. Embedded costs are split between customer, demand and energy components to assist in designing appropriate

rate components. In some cases, utilities look to marginal costs as one factor in developing rate differentials used to incent behavior change, such as when block rates or time of use rates are used.

Considering the applications of the LRMC may help to identify which approaches to stating the LRMC are most appropriate. The appropriate applications of the LRMC is commonly a point of debate and ultimately a policy decision. One single approach may not be the best for all of the potential uses of LRMC as each approach has its unique pros and cons.

4.2 Pros and Cons of Established LRMC Approaches

Each of the approaches discussed measure different aspects of marginal cost. This section provides the pros and cons of each approach reviewed in this paper from the perspective of a utility expressing LRMCs. How the LRMC will be used is one of the factors considered when identifying the pros and cons.

4.2.1 Unit Energy Costs

UEC Pro: Simple and Stable

The UEC or LCOE is a widely utilized approach that provides a means of comparing resource options through a relatively simple calculation. The UEC provides a reasonable cost estimate for large-scale dispatchable generating plants that will be utilized in a manner consistent with the assumed capacity factor.

This approach is best used when a utility is likely to develop its own generating resources and when the next generating resource to include is predictable. As it is based on a single resource, the resulting value is stable and is not impacted by changes in load forecasts or the timing of the need for the resource. A UEC can be applied in all of the various uses of LRMC identified, yet the UEC is not directly comparable in many cases as it does not change on the basis of capacity factor and may not be sized appropriately for specific DSM measures, large customer additions, or DER.

UEC Con: Assumptions around the Dispatch or Capacity Factor

The calculation of LCOE requires assumptions regarding the amount of energy the resource is expected to produce over its economic life, commonly expressed as a capacity factor. This assumption affects the allocation of the fixed costs over the volume of energy. A higher capacity factor implies that fixed costs are allocated over more units of output (energy) relative to a lower capacity factor. Increasing or decreasing the capacity factor assumption can significantly influence the resulting LCOE, expressed in $/MWh. The simplest and most common assumption is to assume the generator will operate to the full degree of its potential, resulting in the most favourable UEC or LCOE possible. In reality, the addition of a new generating resource will be sized to meet long-term needs and the full capacity may not be needed to serve utility load in the initial years of operation.

UEC Con: Does not provide a portfolio estimate

Every resource option will have a different LCOE estimate. The LCOE does not provide a portfolio estimate of the LRMC, as it does not consider the specific resource dispatch in combination with existing resources or in combination with other incremental resources used to meet load over the planning horizon. The dispatch of new resources may alter the dispatch of other resources contained within the portfolio, and/or existing resources may impact the dispatch of the incremental resource. Portfolio analysis is a key component of the utility planning process that includes environmental and resource diversity benefits. Therefore, technically speaking, the LCOE of a specific asset does not provide a measure of a utility's LRMC. Even so, many utilities simply state the LCOE of the next incremental resource (or resources) as the LRMC of the utility.

4.2.2 Average Incremental Cost

AIC Pro: Holistic approach to representing changes in costs and demand over the planning horizon

The AIC approach includes all incremental load above the current load within the calculation, eliminating the need to assume the size and shape of a perturbation. The AIC method provides a reasonable approximation of a utility's LRMC, as it considers the entire planning horizon and takes into account all the resource options available to the utility, including market purchases. The LRMC derived using the AIC approach aligns well with the IRP processes of a utility and provides an approach for expressing the marginal costs of a collection of smaller projects as opposed to a single large dispatchable generating resource.

AIC Pro: Smoother price signal

The AIC approach is likely to generate a smoother estimate of the LRMC over time than the Perturbation approach. The smoothing attribute comes from using the entire increase in demand over the planning horizon, rather than assuming smaller changes in load that may result in large variances in LRMC values depending on existing resources and resource gaps. The AIC approach is best used for overall system considerations, such as DSM planning or treatment of DER through net metering rates and policies.

AIC Con: Averages the value of incremental energy

The AIC approach uses an average of future costs to approximate the likely marginal costs associated with a change in demand. It is subject to change as load forecasts and the timing of resource needs change. An LRMC derived using the AIC approach does not communicate any information regarding the alignment between the time of energy delivery and the timing of the utility's resource gaps. Furthermore, as the AIC is dependent on portfolio analysis, it is difficult to update the LRMC outside of an IRP process in which the reference case forecast and resource options can be scrutinized by stakeholders. Furthermore, this approach may be too simple when looking at specific new large loads or non-utility generation, where the timing, location and load/output are specific to the case in question.

4.2.3 Perturbation Approach (Turvey)

Turvey Pro: Alignment with theoretical definition of LRMC

The perturbation approach directly estimates the change in future costs needed to supply a specific change in demand. The perturbation approach is more precise in circumstances when the size and shape of a specific new load or supply option is known. It is a good approach for cases that have clearly defined parameters, such as a new large customer or non-utility generation.

Turvey Con: Assumptions around perturbation in demand

The perturbation approach requires a demand increment (or perturbation) for the analysis. The size and shape of the increment should be sufficiently large to meaningfully influence the generation dispatch within the portfolio. Determining the appropriate size and shape of the assumed meaningful increment to perform the analysis can be difficult and can lead to materially different LRMC estimates.

Turvey Con: May not be a steady price signal

The perturbation approach reflects the increase or decrease in cost associated with the assumed change in load, rather than full incremental load over the planning horizon. This approach is more sensitive to the size and types of the resource options considered within the portfolio relative to resource gaps of the utility, which may vary over time. Therefore, the nature of the perturbation approach provides a greater possibility for large variances in marginal costs over time depending on when the LRMC is updated and the load resource balance at the start of the analysis.

4.3 Evolving Operating Environment

With changes in technology and regulatory policy, the marginal decisions of customers are changing (e.g., adoption of electric vehicles and distributed generation) as well as the resource options of the utility (e.g., greater adoption of renewables vs. thermal generation), both of which affect existing utility resources and future resources (e.g., change in dispatch). This section provides an overview of qualitative considerations when determining marginal costs of a utility. In general, these considerations address the importance of portfolio planning and resource optimization when considering the addition of new power supply resources.

4.3.1 Marginal Decisions of Customers

Changes in customers' marginal decisions consequently have an impact on the utility load profile, which in turn has an effect on the least cost combination of resources to satisfy demand, thereby impacting the LRMC. The following is a summary of the customer's marginal decisions relevant to the utility within the planning horizon:

1. Determine which appliances[8] to acquire and install (i.e., furnace, dishwasher, hot tub, etc.).
2. When and how to use the appliances that are installed or available.
3. Determine whether to install self-generation (DER) resources.

Many electric utilities have historically motivated customers to change their behaviours (marginal decisions) through a wide range of tactics such as demand-side management incentives that encourage the adoption of more energy efficient appliances through to more sophisticated rate structures such as time of use rates. Recently, the costs of renewable technologies have decreased to a point at which customer-sided generation (DER) must be considered.

From the perspective of the utility, the load required to be served is equal to the customer's net consumption, after accounting for realized savings through energy efficiency and/or demand response programs, and any customer-sited generation occurring at a point in time. For example, if a large number of residential customers opt to install rooftop solar PV and adopt an electric vehicle (EV) that is plugged in after work, the utility's load shape could be impacted to a degree that changes the optimal future resource mix, and, therefore, the value of different technologies to the utility.

4.3.2 Relationship between Intermittent and Dispatchable Resources

This paper suggests there are two different classes of generating resources, namely dispatchable resources and intermittent resources. Intermittent resources have a defining characteristic in that the utility does not control the dispatch. The time of day and month of the year that system peaks occur and the way those system peaks coincide with different intermittent power generation output profiles will have a large impact on the value of the intermittent resources. Examples of intermittent resources are solar and wind projects. In contrast, dispatchable resources can, subject to operating limitations, control the fuel source and time of energy output. Examples of dispatchable resources include natural gas fired generation and hydro generation with storage.

The utility is responsible to ensure there are sufficient resources and operating capacity to provide stability within the system such that the customer receives enough power to meet load requirements at time (t). The relationship between intermittent resources and dispatchable resources is expressed below:

> *Required Dispatchable Resources (t) = Net Load Requirements (t) – Energy produced by Intermittent Utility Resources (t)*

Figure 12 summarizes how changes in the operating environment impact the different type of resources contained in the utility's portfolio.

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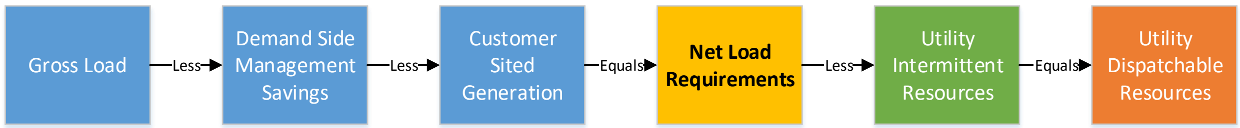
[8] An 'appliance' in this document refers to any generic device that consumes electricity, which can range from a furnace to a phone charger.

Figure 12: How Changes in the Operating Environment Impact Different Resources

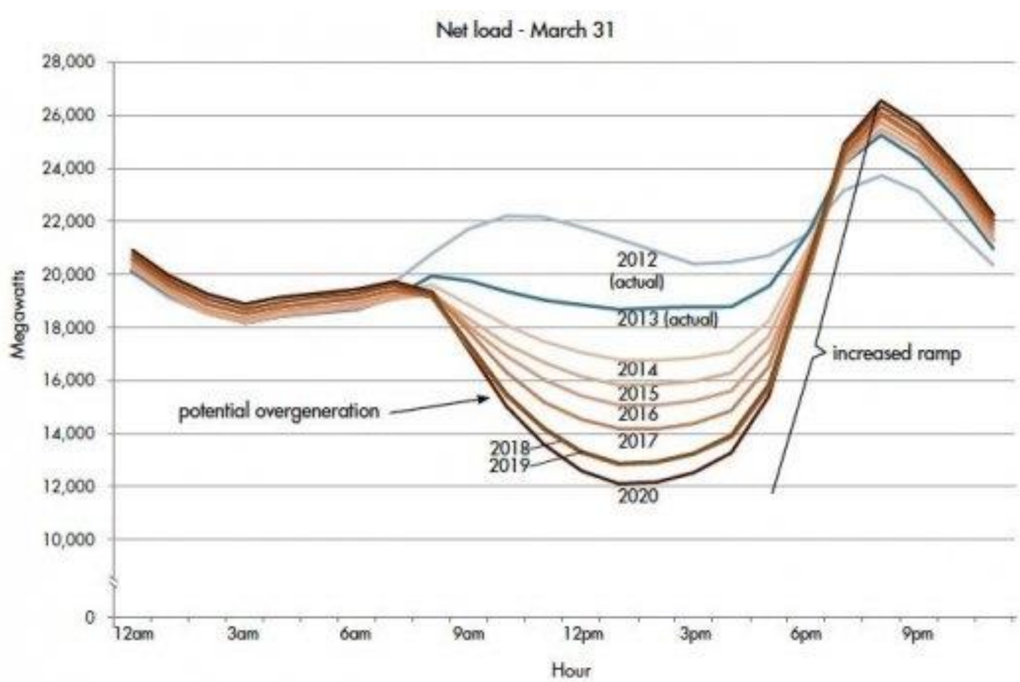


The value of an alternative supply-side resource when a utility has sufficient resources to meet the load is relative to the marginal energy cost of the dispatchable resources contained in the portfolio. In that scenario, the cost of the new resource would only have value to the extent it would displace the operation of existing resources. The value of an alternative resource to a utility with sufficient resources is the variable cost of energy that would otherwise be dispatched after considering minimum contract requirements, environment regulations, and other operating parameters.

4.3.2.1 Example: California Duck Curve

In California, high solar adoption has created a challenge for utilities to balance supply and demand on the grid. This is due to the increased need for electricity generators to quickly ramp up energy production when the sun sets as the contribution from solar falls but there is little change in demand. Another challenge with high solar adoption is the potential for solar to produce more energy than can be used at one time, called over-generation. This leads system operators to curtail solar generation, reducing its economic and environmental benefits. Figure 13 is from the US Office of Energy Efficiency and Renewable Energy (2017) and shows the California duck curve.

Figure 13: The California Duck Curve



4.3.2.2 Impact of technology on costs

The increase of non-dispatchable (intermittent) resources can have a significant impact on the LRMC of a utility and the value of adding new resources to the portfolio as a whole. For technologies with no fuel costs, and comparable operations and maintenance (O&M) costs, such as solar and wind technologies, the LCOE of a resource changes predominantly in proportion to the estimated capital cost. For technologies with significant fuel cost, both fuel cost and capital cost affect LCOE more equally.

Many intermittent renewable resources are characterized as having high fixed costs, but very low variable cost and little control of dispatch. As renewable resources like wind, solar, and run of river hydro projects essentially have free fuel costs and variable costs reflecting the cost of integration (usually standby capacity). As the variable cost of dispatch is a minimal cost, renewable generation typically displaces energy from dispatchable resources that would otherwise be generating energy at a higher variable cost.

The low variable energy cost of intermittent renewable resources affects the marginal cost components of *energy* and *dependable capacity* differently within the portfolio. Although intermittent resources have a lower variable cost of energy, intermittent resources generally require additional operating reserves to maintain system reliability. As intermittent resources replace dispatchable resources in the portfolio, the average unit cost of the dispatchable resources increases.

4.3.2.3 Impact on reliability

A utility is required to maintain reliability to a standard that provides confidence that load obligations of the control area will be met. Reliability is commonly measured through planning reserve margin (PRM) studies. The use of a portfolio approach to calculating LRMCs allows the important inclusion of PRM requirements when evaluating resources.

When the intermittent resources are not available, dispatchable resources need to respond. Resources with dispatchable properties bring dependable capacity. The utility needs capacity resources to address both daily load shapes (i.e., generate more power on peak compared to off peak) as well as address differences in seasonal energy requirements. The least cost combination of generation resources needs to be capable of meeting the relevant demand on a reliable basis as well as matching the particular load profile of the utility, which may incorporate different generation types (NERA, 2011).

All resources have practical operational constraints. For example, hydro generation with storage requires water management, management of hydrology risk, and consideration for environmental requirements (e.g. minimum run rates). All generation resources require some sort of scheduled preventative maintenance. This means that not all generation capacity will be available at all times. System stability requires standby dispatchable resources, which are used to fill the gaps remaining after intermittent generation and forced outages.

4.4 Accounting for Existing Resources

A utility has existing generation assets that will operate in coordination with any additional incremental resources. The optimally selected incremental supply-side resources complement other resources in the portfolio and ultimately affect the optimal dispatch. The change in dispatch of existing resources results in a change in variable costs as well as a change in the rate that the fixed costs of existing resources are recovered through output.

4.4.1 Retirements

Resource planning needs to account for both the addition of new resources as well as the potential for the retirement of existing resources. Resources are taken out of service when they are no longer cost-effective to maintain, are no longer safe or dependable, or when they no longer meet environmental requirements. In the case of power purchase agreements, the life of the contract ends, and the power supply is no longer available to the utility.

The retirement of existing generation resources is a significant decision, usually requiring commission approval. Therefore, retirement decisions are commonly managed outside of the optimization routine and/or hardcoded into the resource model. It is possible for an optimization routine to make retirement decisions for existing resources. To do so, each existing asset would need to be assigned a one-time terminal cost to cover any existing book value, contract termination clauses, or any other costs incurred to close out the asset. The optimization routine could then be extended to include decision variables to represent retirements and corresponding close-out costs. As the retirement of an existing resource impacts the need for new resources, or the dispatch order of remaining resources, it can have a significant impact on the resource portfolio and outcomes of the optimization routine.

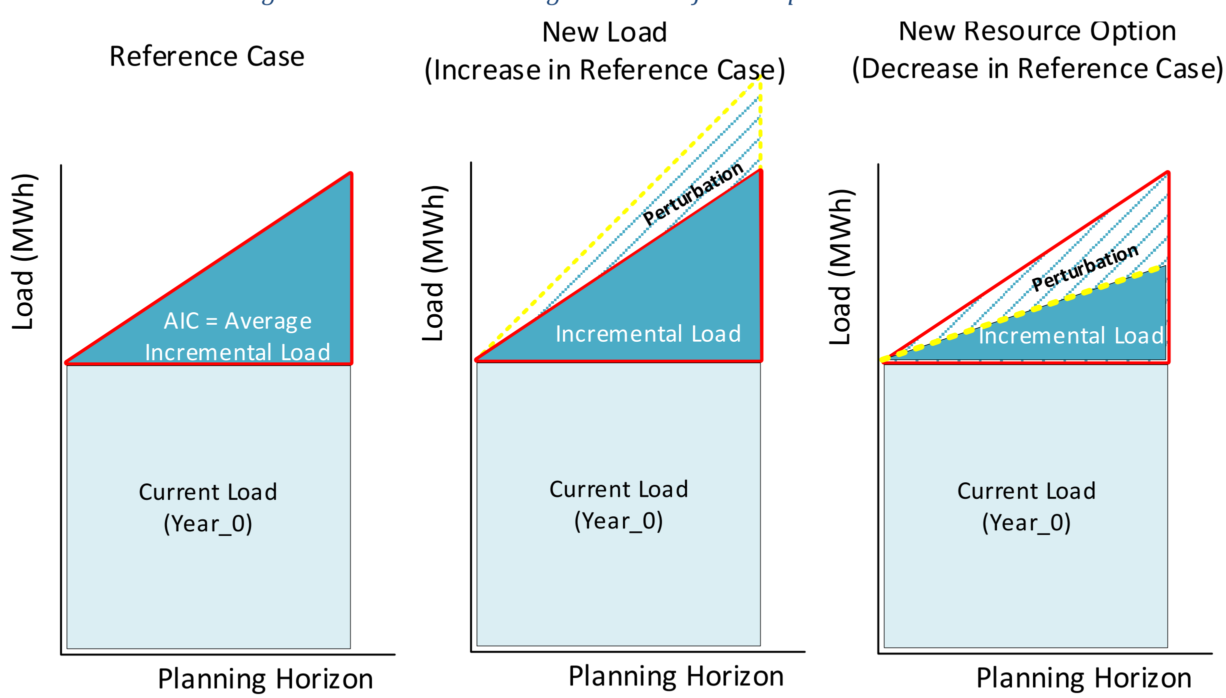
5 Recommended Methodology of Assessing Marginal Costs

Consistent with industry best practices and common commission resource guidelines, utilities generally adopt a portfolio analysis approach to assess resource options. This report advocates for the use of a portfolio approach to determine a utility's LRMC. Developing a LRMC requires solving for the optimum portfolio to meet the reference case forecast. The portfolio from which the AIC LRMC is derived provides the basis to value unique alternative resource options or estimate costs of material new large loads.

The portfolio approach recognizes that a combination of existing resources and incremental supply-side resources will be used to meet the forecast load requirements within the planning horizon. In addition to incremental resources, each existing resource contained in the portfolio has a capacity and energy profile impacted by the future marginal decisions of both the customers and the utility.

This report provides a framework for how to combine the strengths of reviewed common LRMC approaches into a methodology to represent marginal costs and the value of new alternative resource options available to a utility. Figure 14 illustrates three scenarios evaluated by the framework.

Figure 14: The Three Costing Scenarios of the Proposed Framework



The graph on the left of Figure 14 presents the reference case load forecast. The reference case load forecast starts at Year_1, with Year_0 being the current load requirements. The reference case forecast represents a utility's best estimate of future load. In this case, the AIC is the recommended approach to provide the most appropriate LRMC for the utility.

In looking at the two specific cases for new system load or new supply-side resources, the Perturbation approach is recommended as the most appropriate methodology. The middle graph in Figure 14 presents a step increase in load from the reference case as a result of a new large customer (new system load). The cost to serve the new customer is the cost to meet the reference case forecast *plus* the new customer's load. The change in total portfolio cost from the reference case portfolio divided by the change in load, which is the new customer's load, provides an estimate of the marginal cost to serve that new customer.

The graph on the right in Figure 14 shows a decrease in load from the reference case forecast as a result of a new supply-side resource. The anticipated output from the alternative supply resource is subtracted from the reference case forecast. The remaining load is what the load the utility's portfolio is required to serve if the alternative supply is acquired. This adjusted load is less than the reference case forecast which is a consequence of the new alternative resource serving the difference; therefore, the alternative resource is displacing dispatch that would otherwise come from other resources contained in the reference case optimal portfolio. The cost to meet the reference case forecast is a combination of the new alternative resource costs and the change in the portfolio costs to meet the net remaining load.

The UEC approach is a simple resource specific calculation used to compare different technology types. The UEC approach does not provide a portfolio estimate of the change in costs, as it does not account for the impact on the other components within the portfolio. Therefore, the UEC is not recommended for purposes of expressing the marginal costs of a utility as a whole. The related UCC metric does provide a good method to prorate resource specific fixed costs over the planning horizon.

The following sections discuss in further detail the reference case portfolio, the costs for serving a new incremental load not considered in the reference case forecast, and the value of potential new alternative resource options.

5.1 Establishing a Baseline or Reference Case LRMC: The AIC Approach

The purpose of portfolio analysis is to determine the optimal collection of resources required to meet anticipated load. The LRMC is a derivative of the optimal portfolio that expresses the ratio of incremental costs to incremental load. This report recommends a utility adopt the AIC approach to represent the LRMC of a utility. The LRMC of the reference case portfolio reflects the utility's best estimate of load and costs over the planning horizon. The AIC approach reflects the general level and trend of future costs as well as addresses the unique attributes of a utility's existing resources, thereby providing an efficient price signal. The AIC approach includes all incremental load above the existing load (defined as Year-0), which eliminates the need to assume an arbitrary size and shape of a load augmentation as required by the Perturbation approach.

5.1.1 Establishing Year_0 Point of Reference

An important consideration is how to express the costs associated with serving the load of Year_0 over the planning horizon. It is distinctly different to assume the actual costs of serving Year_0 load is constant over the planning horizon versus allowing the optimization routine and corresponding long-term portfolio constraints to determine the resource mix and corresponding costs to best serve Year_0 load. For example, if renewable portfolio standards and other environmental regulations limit non-clean resources or require the retirements of existing assets over time, there may be corresponding impacts on the cost to serve Year_0 load over time, regardless of load growth.

This report advocates that the Year_0 load requirements should allow the optimization routine to find the cost of serving current load levels over the planning horizon. To omit changes in the cost to serve current (Year_0) load, an optimal (lowest-cost) portfolio of resources needs to be developed that can satisfy the Year_0 load while adhering to the portfolio constraints and variable settings of the given portfolio scenario. This involves assuming the load is constant at the current level for the full planning horizon *as well as* setting variables and constraints within the portfolio optimization routine based on the characteristics of the portfolio scenario. If an optimization routine is used to determine the most optimal resources to serve Year_0 load in the AIC calculation, then any changes in costs to serve the current load levels will be netted out. To understand the cost of policy changes and retirements on serving *existing load within the portfolio as well as the costs to serve incremental load*, the portfolio *average* costs (rather than only *incremental* costs associated with *incremental* load) needs to also be considered.

5.1.2 Application of AIC derived LRMC

The AIC approach reflects the optimal marginal supply-side decisions to meet the reference case forecast over the planning horizon thereby providing fair representation of the LRMC. The LRMC developed using the AIC approach should be viewed as an efficient price signal that conveys direction and magnitude.

No single number, regardless of approach, is sufficient to capture the LRMC of a utility under any and all scenarios. The LRMC of the reference case portfolio presents a baseline LRMC value. The reference case optimal portfolio reflects the forecasted load to be served by utility resources and an estimate of costs to provide the incremental power. The AIC provides the fairest single number value to express future incremental costs, and therefore the value of DSM avoided costs.

5.1.2.1 LRMC for demand-side management regulation

DSM regulations commonly require a utility to develop a LRMC for the purposes of evaluating the cost-effectiveness of DSM measures (e.g. BC Utilities Commission Act, Demand-Side Measures Regulation, 2017). To calculate the LRMC for DSM purposes, the gross-load forecast (**before** any DSM savings) is used as the load requirements that an optimal portfolio of supply-side resources is required to meet. Clean energy requirements are applied as constraints within the optimization routine such that the characteristics of the portfolio represents the avoided costs of serving the gross load using only regulation defined 'clean resources.' The LRMC representing avoided costs for DSM purposes is derived from an optimal portfolio of clean and renewable resources that satisfies the gross load forecast (before DSM).

5.1.2.2 Basis for valuing changes in future load requirements

The reference case portfolio provides an economic basis for evaluating the incremental costs of serving new loads or determining the value of a new resource through displacement (opportunity) costs in the optimal portfolio. To calculate the marginal cost of changes in load in the preferred portfolio, the gross-load forecast **after** DSM savings is used. The opportunity cost, and therefore value of the alterative resource, is reflected as costs the utility would have otherwise incurred to supply the load being served by a new resource. DSM is considered a committed resource that cannot be displaced.

5.2 Valuing Power: The Perturbation Approach

The LRMC established through a reference case portfolio using the AIC approach represents the utility's best estimate of future costs. The optimal portfolio to meet the reference case forecast provides an effective jumping-off point, or baseline, representing the current path of the utility. Making adjustments, or perturbation, to the current path and evaluating the marginal costs is the basis for evaluating resource options or new load not explicitly considered in the reference case portfolio.

The concept of marginal cost is vitally important to economists as it relates to the idea of opportunity cost. The concept of opportunity cost is that the value of anything is calibrated in terms of lost alternatives or opportunities (Bonbright et al., 1988). The cost or value of a change in load (increment or decrement) is determined by the change in costs from the optimal portfolio used to meet the augmented forecast and the reference case forecast. The value or cost to a utility is proportional to the degree that the utility could actually change its dispatch operations after considerations for operating constraints, agreement constraints, regulations, and capacity requirements.

The perturbation approach most closely reflects the theoretical definition of marginal cost. The primary issue with the perturbation approach is determining the size of the load augmentation. In the cases of a new large load or alterative resource, the size and shape of the increment or decrement is known.

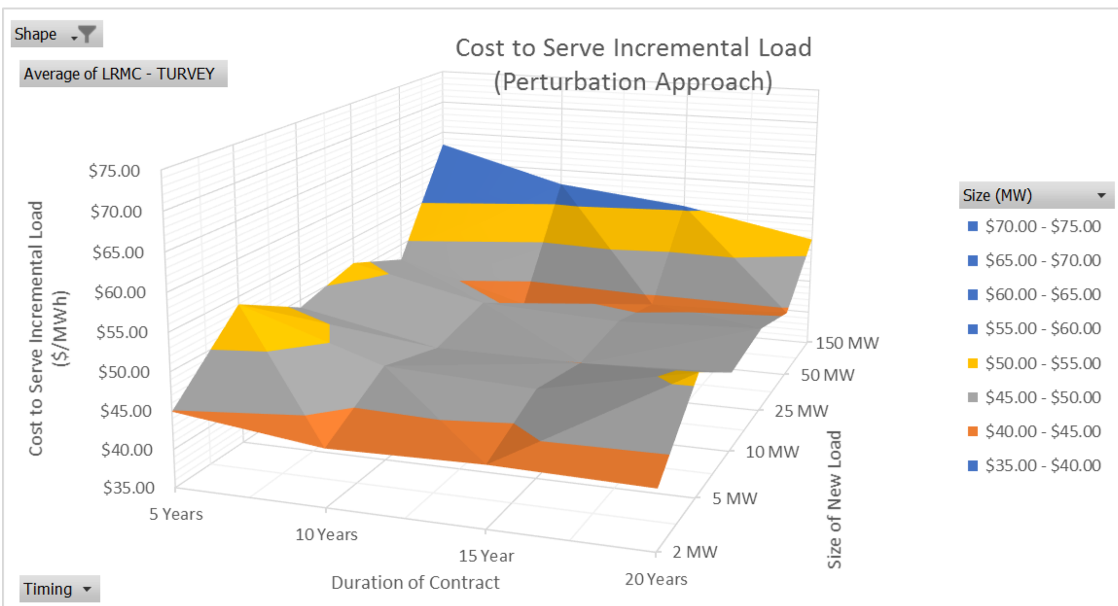
5.2.1 Cost of Adding a New Large Load

Some utilities are beginning to receive requests for service from new large loads, such as data centres, blockchain companies, and legal cannabis growers. These types of market segments embody large, power-intensive customers, potentially having material implications on a utility's load-resource balance. If a new load is suspected of being material to the power supply portfolio, and is not a component of the reference case forecast that the utility has planned resources to serve, the marginal costs for serving the new customer should be calculated using the perturbation approach.

The cost of a new customer reflects the cost of advancement of, or change in, future incremental resources within the optimal portfolio. For example, if a new wind farm is required 10 years into the planning horizon of the reference case portfolio, and the wind farm is advanced to 5 years into the horizon as a result of the new load, the NPV cost difference between the value of the wind farm at 5 years and 10 years are the incremental costs to serve the new load in this example.

Figure 15 shows a hypothetical relationship between the size of the new load, the duration of the service contract, and the resulting marginal costs relative to the reference case portfolio to serve the a new load. In this hypothetical example, the cost to add a large, short-term duration contracts (150MW, 5 years,) results in materially higher marginal cost than the cost to serve a smaller, longer duration contract (2MW, 20Years). The marginal cost to serve large marginal loads is lumpy, reflecting the lumpy nature of utility capital investment. Note the marginal costs are not a constant value and change based on the size and duration of the new load.

Figure 15: Incremental Costs



5.2.2 Value of a New Resource

While the utility considers new resources as part of its resource portfolio planning process, there are sometimes instances where a customer or non-utility generator proposes to interconnect a new resource in the service area. The value of such a new resource is its ability to defer otherwise anticipated capital expansion as determined by the reference case optimal portfolio. The change in net present value costs establishes the value of delaying projects into future years, altering future required resources, or completely omitting the need for otherwise planned incremental resources.

Each individual proposed project should be evaluated on its own merits[9] while giving consideration for the timing and shape of the utility loads and other existing or proposed resources. Preferred incremental resources have specific size and performance shape, timing of resource acquisition with consideration for resources needed within full planning horizon, and alignment with other planning objectives such as clean attributes.

It is not prudent for a utility to acquire all available resources up to the LRMC developed using the AIC approach, nor should the AIC LRMC be viewed as a clearing price in isolation from other prudent resource planning criteria, such as energy or capacity profiles and environmental factors. While a particular resource option may be cost-effective relative to an LRMC value, it may not fit the energy or capacity requirements of the future. Likewise, a resource that is perfectly aligned with future load requirements may be worth more than average. A single calculation of the LRMC is not necessarily applicable in all situations and adjustments are warranted in respect of different circumstances surrounding such characteristics as the time horizons, shape, intermittency, and firmness of the energy being considered.

The difficulty in valuing power is the fact that marginal costs vary by both time of use and output type, such as physical type, location, and other service conditions (Bonbright et al., 1988). Much of the value of a specific resource is its ability to deliver energy when needed, or more precisely, the alignment between the performance profile of the resource and the timing of the gaps in a utility's load-resource balance. For example, if a utility is summer peaking, with air conditioning being a primary load driver, solar would likely be a complimenting resource, as solar would provide its greatest output at time when the air conditioning load is most demanding. Solar resources may not provide the best complementing generation profile to a utility with load driven by space heating during the short days of winter.

The effect of the new resource on the utility is represented as a decrease in load to the reference case forecast, which in turns leads to a decrease in portfolio costs. The change in the portfolio costs from the reference case optimal portfolio, expressed in PV terms, divided by the decrease in load, in PV terms, gives the value of the resource. The assumed net-benefit of a new resource option is therefore derived from the fact that the remaining marginal resources contained in the optimal portfolio do not have to serve the load being served by the specific new resource. The value of a *specific* resource option is equal to the cost of the optimal resources that would have otherwise been dispatched within the preferred optimal portfolio. In other words, *the value of an alternate generation resource is what it can displace in the optimal portfolio* used to meet the reference case load forecast. Additional generation from resources at times when the utility does not need the power is at best worth what the utility can sell it for in the market at the time it is delivered. If there

[9] It may not be practical to evaluate every single resource opportunity; therefore, this report more specifically recommends developing a generalized set of shapes (e.g., wind in a region) and potentially tranche out pricing.

is negative market pricing, this could theoretically become an expense to the utility, depending on curtailment ability.

Figure 16 shows how the value of a hypothetical wind resource can change based on its size and timing of inclusion in the portfolio. In Figure 16, Years refers to the year in the planning horizon the resource was introduced.

Figure 16: How the Value of a Hypothetical Wind Resource Can Change Based on Size and Timing

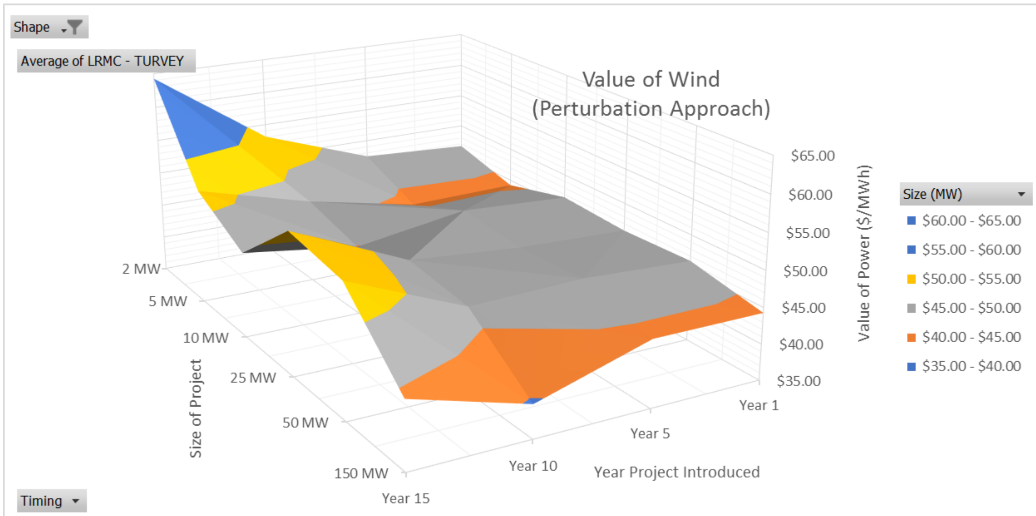
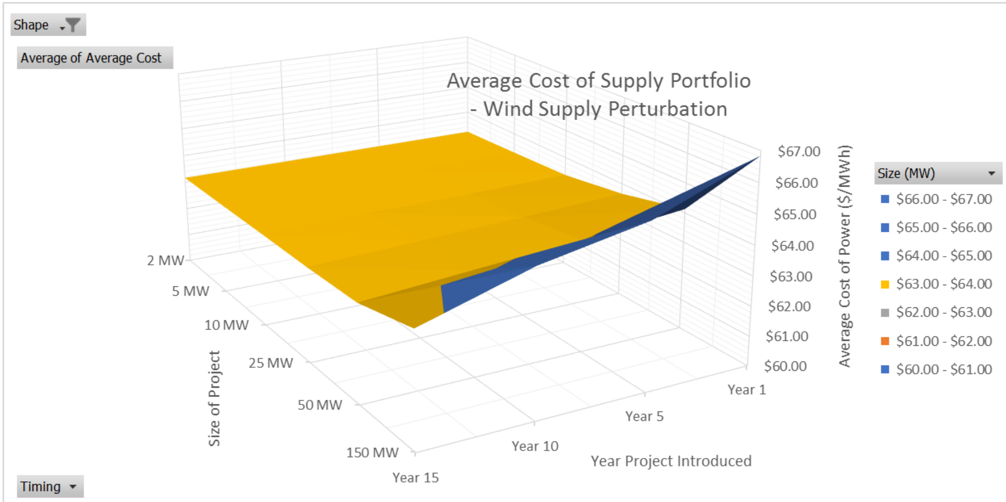


Figure 17 shows the average cost of power to serve the remaining load of the reference case after including an alterative resource within the portfolio. As more load is displaced by the alterative resource, the cost to serve remaining load with existing and optimal incremental resources may increase on a per unit basis depending on the flexibility of the portfolio. The value of an alternative resource is based on the costs that the resource can displace, which is influenced by the remaining costs in the portfolio to serve the remaining portion of the reference case load from both a capacity and energy perspective.

Figure 17: Average Cost of Power within the Optimal Portfolio



5.2.2.1 Self-generating customers

The investment decision of a large commercial or industrial customer in self-generation is not under the utility's control. The dispatch of the customer's resource may be either intermittent and/or driven by the customer's end needs. Regardless, the perturbation approach can be used to value the resulting net savings in the load that the utility would otherwise have to serve using the same methodology applicable to valuing other resource projects. To do so, the self-generating customer would need to provide the expected generation profile of the resource to the utility.

5.2.2.2 Standby Services

This report does not explicitly address the cost of standby charges in those cases where a customer or non-utility generator installs a resource. Standby charges should provide consideration for the utility's cost to provide the service. Most of a utility's costs to serve customers are recovered through variable energy charges. This volumetric base rate structure has the potential to cause cost shifting from customers with a low load factor to customers with a high-load factor, even though customers with a high-load factor are generally more efficient (base load) for the utility to serve. Volumetric energy charges may not be adequate to recover demand-related costs for self-generating customers with lower load factors resulting from self-generation, especially in cases when the non-coincidental peak of the self-generation customer remains the same or increases.

5.2.3 Value of Energy and Capacity Components in Portfolio

It is common for a utility to be required to split the value of marginal energy and marginal capacity. The cost of energy and capacity to the utility is not as clear-cut as using the average fixed costs and average variable costs. To provide energy there must be underlying generating capacity available to convert potential energy (i.e., water, wind, natural gas, etc.) into electrical output. Therefore, this report recommends treating the value of 'pure capacity' as the additional capacity requirements beyond what is required to operate a perfectly efficient system.

The value of energy should include the costs associated with the theoretical minimum capacity required to generate that energy, that is, assume the capacity factor is perfect (100%). For example, if a utility uses 100 GWh of energy in January, there would be 100 GWh/744 hours = 0.134 * 1000 MWh/GWh (rounded up to the nearest MW) = 135 MW of installed capacity operating 100% of the time with flawless reliability.

To estimate the value of the energy and capacity components, two optimal portfolio runs are required. The first run is the reference case portfolio that is able meet the capacity and energy requirements of the reference case forecast. The second run is the total cost to meet the energy only requirements of the reference case forecast. To determine the value of energy using an hourly production model, the monthly energy requirements would need to be reshaped. Theoretically, the energy requirements would be ideally matched to generation output, such that load responds to generation, rather than generation responding to load. It may be more practical to model the energy requirements as constant in each hour such that the load duration curve is flat. The difference in the cost between the portfolio to meet the energy and capacity verses the portfolio cost to meet just the energy requirements defines the portfolio value of capacity.

5.2.3.1 Steps

1. Find the least cost portfolio that is able to meet the reference case load forecast for energy and capacity requirements. This is the same as being able to meet forecast load in every hour of each month (the reference case portfolio).
2. Calculate the least cost portfolio capable of meeting the energy only requirements. The energy is theoretically spread among the hours such that the load shape is ideally suited to the optimal generation output.
3. Determine the portfolio value of capacity as the difference in the PV Cost to meet the reference case energy and capacity requirements and the reference case energy only requirements.

5.2.3.2 Equation

$$Capacity_{value} = \frac{PV\left(Portfolio_{Reference\ Case}\right) - PV\left(Portfolio_{Energy\ only}\right)}{PV(Reference\ Load) - PV(Energy\ Only)} = \frac{PV(P_1) - PV(P_3)}{PV(L_1) - PV(L_3)}$$

Where

- P1 = Total cost to meet the reference case load forecast (*energy and capacity* components)
- L1 = Reference Case load forecast (GWh)
- P3 = Total cost to meet the reference case load forecast (*energy only* portfolio)
- L3 = Energy only, minimum theoretically possible capacity, CF=100% (GWh)

L1 and L3 should be the same energy requirements in both portfolios, which leaves a zero in the denominator. This leaves all energy cancelled out, but some portfolio costs remaining. These costs reflect the value of 'pure capacity.' The pure capacity costs can also be expressed on a per unit basis by dividing the pure capacity costs by the net present value change in dependable capacity between the reference case portfolio and the energy only portfolio.

5.2.3.3 Interpretation

The optimization routine needs to determine what capacity to install and how much energy to dispatch from each resource. The cost of capacity in the portfolio represents the fixed cost to have the generating resources in an operationally ready state capable of dispatching energy such that load can be met in the peak hours. Energy is a variable cost associated with dispatching the resource, whether dispatched by the utility or intermittent in nature.

Storage technologies, such as batteries, do not create energy; rather they alter the timing of when energy is delivered. Therefore, storage technologies are essentially a pure capacity resource with a negative energy output after accounting for losses (assuming the storage is less than 100% efficient). The value of pure dependable capacity will depend on how well the output of resources contained in the portfolio naturally align with the shape of net load requirements and the cost of the additional resources required beyond what is needed to meet the energy requirements.

5.3 Levelized Fixed Capacity Costs: Unit Capacity Cost Approach

LRMC theory regularly includes the assumption that all costs are variable over the long run. This qualification may not be realistic in practice. In reality, not all costs are variable except in the *very* long run, as there is time needed for a complete adaptation of plant and equipment to any change of output (Bonbright et al., 1988). Therefore, setting efficient price signals requires consideration for the inflexibility inherent to a utility's infrastructure.

Resource investments undertaken within the planning horizon have implications beyond the end of the planning horizon. For example, if a new resource is scheduled to come online 2 years prior to the end of the planning horizon, there is a significant capital outlay within the planning horizon, but only a few years of production (benefit) to pair with the upfront capital costs. This results in a significantly higher LRMC as all upfront costs would be included in the numerator of the LRMC calculation but all the energy produced by the new resource past the end of the planning horizon would be omitted from the denominator. Therefore, in cases where major capital investment is scheduled to occur close to the end of the planning period, there is an issue of how to reflect the costs. The most simplistic choice is to determine whether the planning horizon can be truncated just prior to the need of the new resource, or alternatively, whether the planning horizon can be extended (Marsden Jacob Associates, 2004). Marsden Jacob Associates (2004) suggested including a residual value to ensure that the values of the assets are properly reflected at the end of the planning period. Although using a residual value has merit, there are complexities in determining an appropriate methodology for establishing the terminal value given the dispatch of the resource beyond the end of the planning horizon is contingent on other resources contained in the portfolio.

As Bonbright et al. (1988) noted, in practice some cost analysts may opt to treat a portion of the total costs as if it were constant and the remaining portion as variable. This artificial distinction between constant costs and (proportionately) variable costs may permit approximations of a nonlinear cost function in linear terms (Bonbright et al., 1988). This report recommends that LRMC calculations represent the cost of generation capacity based on the levelized cost of capacity (i.e. the UCC of the resource) while allowing variable energy costs to be fully captured. The annual cost of dependable capacity for a specific resource is derived from the UCC, which allocates fixed costs into the planning horizon. The use of levelized capacity costs reflects that a utility (or the market collectively) will generally commit to a generation asset for its full economic life, and that economic life could extend beyond the end of the planning horizon.

5.4 Marginal Cost Details

This section reviews details regarding the interpretation and characteristics of marginal cost values. Although marginal costs are numeric, they are defined by noteworthy metadata.

5.4.1 Marginal Costs Inherit Portfolio Attributes

The characteristics of each portfolio, and therefore the characteristics of the LRMC, are largely formed by the constraints applied within the optimization routine and assumed scenario variables. The portfolio composition and corresponding costs can change considerably depending on portfolio characteristics such as the level of DSM activity, emissions requirements, load forecast, targeted level of reliability, assumed cost of market energy, assumed costs of power purchase agreements (PPAs) with Independent Power Producers or other utilities, and/or the inclusion of self-sufficiency planning objectives. Stating the LRMC of a utility should also include communicating the key attributes used to form the parent portfolio. When comparing marginal costs there needs to be qualifications around constraints and perspectives of the future world.

5.4.2 Market Comparable Value

The LRMC reflects the market value of the commodity to the utility[10] rather than the rate to the customer. The calculation of rate impacts is a distinctly separate analysis, although highly related, based on individual utility policies, accounting practices, and existing rate-based assets. The use of forward-looking costs has the advantage that costs and capital are valued on the basis of an alternative (economic) cost approach, instead of an accounting costs approach. Therefore, resource costs should reflect the cost of financing but exclude depreciation, which is an accounting term (Marsden Jacob Associates, 2004).

[10] At the point of interchange.

5.4.3 When sending price signals to customers in the form of rate design, or when measuring the impacts of new resources on long-term rates, care must be taken to consider the differences between an economic approach and an accounting approach. Stated at Point of Interconnection

The LRMC of a utility is stated at point of interconnection and at transmission voltage. The point of interconnection is a location where the resource interfaces with the utility's existing electrical transmission system. Stating the LRMC at point of interconnection, as opposed to plant gate, accounts for the total costs of selecting a particular resource option, including interconnection costs. The interconnection costs of a specific resource are dependent on the type of resource and location of the resource relative to the utility's existing infrastructure. Interconnection costs can include the wires cost to connect a resource to an existing transmission line as well as the transformer to deliver transmission voltage, or alternatively, the cost to wheel power across a neighbouring utility's system from plant gate to the point of interconnection. Interconnection or generation-integration costs up to the point of interconnection are appropriately included in the power supply LRMC and are not considered a transmission and distribution cost.

There is a distinct difference between sufficient capacity to meet the commodity requirements (hourly *system* load) and the transmission and distribution capacity required to deliver the commodity to the end user. Correspondingly, the LRMC definition makes a clear differentiation between the LRMC of the commodity (generation/supply costs) and the delivery costs to the end user (transmission and distribution costs), represented by Marginal Cost of Delivery (MCD)[11]. The LRMC and MCD values are distinct and should remain separated. The following is a summary of contrasting characteristics between the LRMC and the MCD:

- LRMC (Commodity)
  - Incremental Cost of Energy (energy units – MWh)
  - System number (delivered to a point of interchange)
  - Market value; comparable (Market, Power Purchase Agreements are not rate base)
  - Intended to be a price signal or evaluated directly
- MCD (transmission and distribution costs)
  - Incremental Cost of Delivery (capacity units – kW)
  - Different by regions (locational aspects)
  - Applies to peak hours (time dimension)

5.4.4 Discount Factor

Both the cost and the changes in load requirements are to be calculated in present value terms. Calculating costs and benefits in present value terms is important because they are typically valued less in the future due to alternative uses of financial resources and greater potential for variance in load from forecasted values (Market Surveillance Administrator, 2012). The discount rate, as

[11] the term Marginal Cost of Delivery (MCD) can be used interchangeably with Deferred Capital Expenditures (DCE)

determined by the utility’s finance department, should be applied consistently to all calculations of the various components within the portfolio model.

5.4.5 Frequency of Update

The reference case portfolio and LRMC should be updated within the long-term resource planning process (e.g., an IRP) of a utility. The IRP process allows information regarding resource alternatives to be tested. A utility should revisit and update the LRMC with the most current information available at the time of filing long-term resource plans. The timing of when resources are required, the selection of resource options, and the optimal operation of the preferred portfolio strategy is contingent on a number of dynamic factors that will change over time including load forecasts, market pricing, changing customer behaviour, macro-economic conditions, governing policy, and technological advancement.

6 Conclusions and Recommendations

6.1 Summary of Marginal Cost Methods

Multiple approaches are available to a utility for expressing the Long-Run Marginal Cost of power or LRMC. This paper reviewed the various methods available and provided a definition, discussion and calculation related to each approach. The selection of a preferred approach must take into account the circumstances of the utility, the existing and expected future resources of the utility, and how the LRMC will be used.

This report reviewed three common approaches used in practice to express the LRMC. The first is the levelized unit energy cost (UEC), sometimes referred to as the levelized cost of energy (LCOE), of a specific resource. The second and third approaches are portfolio-based methods rather than a resource specific metric, namely the average incremental cost (AIC) approach and the perturbation approach (also referred to as the Turvey approach).

The UEC method looks at a single resource that is deemed to be the marginal resource of the utility. The cost is based on the average cost of the resource over its expected economic life, assuming the resource is fully utilized. This method works well when a utility has a resource portfolio of large-scale utility-owned projects that results in the selection of a single, clearly defined resource that will be used to generate the majority of the additional power required over the planning horizon.

The AIC approach is based on a future portfolio of one or more resources that will be used to meet the needs of the utility over the planning horizon. The AIC approach best reflects the total increase in power costs over the planning horizon when load growth and regulations require a mix of new resources, or the utility's optimal portfolio consists of multiple resources that collectively meet the energy and capacity requirements while also impacting the economic dispatch of existing resources. The reference case load forecast and preferred portfolio resulting from a utility's IRP define the LRMC under the AIC method.

The perturbation approach can provide meaningful marginal cost results for a defined change in load or resources, but can be difficult to use for a more general approach as marginal costs can vary greatly depending on the amount of the incremental load it is based upon and the utility's existing load resource balance at the time of the analysis. The AIC calculation is basically a specific case of the perturbation approach, with increases in load, as defined by the reference case forecast, being the "perturbation" used to develop the change in costs. This approach is most useful when a specific new large load or non-utility resource is being considered.

6.2 Recommended Marginal Cost Approach

It is recommended that the LRMC of a utility be calculated using the AIC approach as it is more intuitive to interpret and has the ability to reflect the general level and trend of future costs. The AIC approach fits well with the high-level, long term view of the IRP process. This is especially true in cases where a utility has a wide mix of diverse resources, and where future load growth is not expected to be met with a single generating resource. The AIC can also address the unique attributes of a utility's resources (e.g., flexibility in agreements, unique resource options, and market access). The AIC approach is rooted in the optimal portfolio that meets the reference case and is more likely to yield a steady price signal, and therefore better guide to long-term decisions. While the value of the LRMC will change over time based on the timing of the future resources, it is typical to establish a single value that reflects the long-term planning horizon. That LRMC value would then be held constant until the next IRP is completed and the LRMC is updated.

In certain circumstances, it is recommended that the perturbation approach be used to supplement the LRMC value. While the LRMC is best used for broad system-wide analysis, the results from the perturbation approach can provide additional cost information to assist in decision making when a clearly defined change in load or resources in a specific location and at a specific time is identified.

6.3 Potential Use of the LRMC

An LRMC value calculated using the AIC method within the IRP of the utility provides a representation for the value of power that can be used for the majority of purposes. This approach works well for those uses that are more general in nature and are already captured within the reference case forecast of the IRP. When there are potential loads or resources that are both significant and outside of the reference cases, the Perturbation method can be used to supplement the LRMC and determine the impacts associated with the potential load or resource. Note that this paper focuses on the LRMC of power supply only. Based on the uses of the LRMC discussed in Section 4, the recommended LRMC approach may be useful for the following purposes:

- ***DSM planning*** typically uses on a single LRMC value per kWh to compare against the cost of a variety of DSM measures. The utility's LRMC calculated using the AIC approach is appropriate for programs that are designed primarily to conserve energy and are offered broadly across the utility's service area. For targeted demand response programs, the capacity only value per kW of the LRMC is more appropriate to use. Care should be taken to identify the appropriate demand reduction associated with a measure so that it reflects the same time period as used for the LRMC calculation.
- ***Non-utility generation*** reflects large amounts of capacity at a very specific location. The use of a Turvey Perturbation approach is more appropriate in this case as it allows for determining the impact on how new and existing resources are utilized given the change in available resources. The value of the added generation can also vary considerably based on the timing of the new generation coming online and the timing of when energy is delivered once active.
- ***Distributed energy resources (DER)*** are typically small units at the customer location that are used to offset power that would otherwise be provided by the utility. Any individual installation would not impact the overall use of new and existing resources, as long as it was relatively small and already considered within the reference case of the IRP. In the case of

a larger installation, or significant expansion beyond that included in the IRP, a Perturbation approach may be warranted. Once DER in congregate reaches a large threshold, it can impact how other resources are used. This is typically a consideration in the IRP and can be accounted for in that process.

- ***New large customers*** can impact when new resources are needed and how they are dispatched. Using a perturbation approach is appropriate for new large loads. Even if they will not be charged for the marginal cost of energy, it may be appropriate to look at the impacts under a perturbation approach to determine the impacts on the preferred portfolio under the IRP.
- ***Line extension policies*** often look at the marginal cost of adding new customers. If the utility wishes to account for the marginal cost of power when establishing the amount of contribution required by new customers, the LRMC per kWh could be an appropriate metric to consider depending on the situation.
- ***Rate design*** is typically based on an embedded cost of service as a starting point, with several other policy and logistical factors taken into account. Marginal costs can sometimes play a role in the design of specific rate components, but not in the overall level of the rates. The LRMC will only be appropriate to use in rate design under certain conditions and should not be a replacement for looking at the various cost components resulting from an embedded cost of service study.

Aside from this general guidance about when to use a LRMC, there are very specific issues that can arise when using the LRMC. A single value LRMC, as provided by the AIC approach, should be viewed as a price signal, not a threshold. The performance profiles (and risks) of different technologies need to be taken into account when calculating marginal costs as a combination of resources will be required to address gaps at certain times over the planning horizon. The identified incremental resource (or resources) may have attributes that complement existing resources within the context of the portfolio.

A utility should not expect to acquire all available resources up to the LRMC of the reference case profile calculated using the AIC approach, nor should the LRMC be viewed as a clearing price in isolation from other prudent resource planning considerations, such as energy and capacity profiles or environmental factors. The characteristics of the LRMC align with the characteristics of the source portfolio. Inappropriate applications of the LRMC can lead to negative customer impacts. The LRMC calculated using the AIC approach assumes that all electricity is of equal value. This assumption does not hold true in practice. A utility's resource requirements vary at different times of the year and the value of energy in the market varies at different times.

The perturbation approach should be used to evaluate costs associated with marginal changes from the base case portfolio that is formed around the reference case forecast. The value of a specific supply resource or change in load is determined based on the variance in load and costs established through the reference case or base case portfolio. These variances reflect the costs associated with deviating from the current path of the utility (the reference case forecast). The value of marginal resources calculated using the perturbation approach best reflects the opportunity cost of the utility measured through portfolio displacement. Likewise, the costs of new load reflect the change in timing of resource requirement and dispatch.

It is not possible to draw a direct comparison between two utilities that calculate LRMC values using different methodologies. Furthermore, each utility has its own unique characteristics around timing differences for required resources, locational differences in load and generation, volume differences in capacity and energy requirements, and differences in governing policy that can cause various utilities to consider different resource options. The LRMC is only one of many considerations when assessing the cost-effectiveness of different resource options. Lastly, when comparing marginal costs for various purposes, any subsequent analysis should consider the LRMC is stated in real, levelized terms.

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About the Authors

FortisBC Inc. (FBC) is an integrated electric utility that generates, transmits, and distributes electricity to customers in the southern interior of British Columbia, Canada. FBC currently serves approximately 144,000 direct customers plus approximately 38,000 indirect wholesale customers.

Ryan Steele is employed as a Resource Planning Specialist at FBC where he is responsible for modeling long term power supply options. Ryan has experience with regulatory processes relating to the development of Integrated Resource Plans, reliability assessment, and portfolio analysis using Mixed Integer Linear Programming. Ryan has a Master's Degree in Computer Science as well as an undergraduate degree in Business Administration with a major in finance.

EES is a multidisciplinary management consulting and registered professional engineering firm that provides a variety of solutions to clients involved with electric power, natural gas, telecommunications, water, wastewater and other energy and natural resource related businesses. EES is a recognized expert in cost allocation, rate design and related rate policies. EES also offers consulting services relating to strategic planning, resource development and assessment, energy purchasing, and Demand-Side Management.

Gail Tabone is a Senior Consultant with EES. Gail is a subject matter expert in cost of service analysis, integrated resource planning, resource evaluation, load forecasting, economic feasibility studies, conservation planning, and surveys in the many work products related to financial and power supply planning. She holds a Master's Degree in Applied Economics and has over 30 years of experience in the utility industry. She has provided expert witness testimony in various rate hearings and managed hundreds of consulting projects during her time with EES.

Amber Gschwend is a Managing Director with EES. Amber provides management and analytical expertise for EES related to all types of economic and financial studies. Ms. Gschwend's background includes research in electric utilities and rates and also analytical work and forecasting in various fields. Ms. Gschwend assists in Integrated Resource Planning and Conservation Potential Assessments for small and large utilities. She holds a Master's Degree in Economics.

Appendix M

PLANNING RESERVE MARGIN REPORT

FORTISBC INC.

Appendix M

2021 Long-Term Electric Resource Plan

2021 Planning Reserve Margin Report

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EXECUTIVE SUMMARY

Planning Reserve Margin (PRM) is the dependable capacity above the expected peak demand required to maintain a targeted level of system resource adequacy. A common approach to examining PRM is through probabilistic studies using the LOLE metric (Loss-Of-Load-Expectation) or the expected number of days in a year that generation capacity fails to meet the load. FBC has adopted LOLE as the reliability metric for the assessment of PRM adequacy and targets a 1 day in 10 years or 0.1 day per year threshold, which is commonly used by other utilities. Resource Portfolios that meet the LOLE target have a measured probability of maintaining reliable power supply while meeting unforeseen changes in future load as well as unexpected outages of existing and planned capacity.

Utilities noticeably differ in their PRM practices, including how to define the dependability of their capacity resources, whether to rely on the external market or not, which reliability metric to target, and how to derive sufficient PRM to meet the resource adequacy requirements suitable for their operating environment. Alternative approaches to LOLE include the LOLP (Loss-Of-Load-Probability or the probability to fail to meet load), EUE (Expected Unserved Energy or the number of megawatt hours of demand not served), or a targeted percentage.

PRM has historically been expressed as the difference between system dependable generation capacity and peak demand, commonly measured as a percentage of peak demand. The appropriate percentage above peak demand can vary widely depending on the type of resources contained in the utility portfolio, therefore emphasis should be placed on the probability of not being able to meet load rather than a fixed PRM percentage.

As part of the 2021 Long-Term Electric Resource Plan (LTERP) FBC reviewed all relevant portfolios (in Section 11) to ensure they met PRM requirements. Where necessary, additional capacity requirements were added to the scenario portfolios until PRM requirements were met. This appendix provides more detail on the Company's Monte Carlo simulation-based PRM approach. FBC's base resources to meet load consists of the Company's own generation, contracted capacity resources such as entitlements from Waneta Expansion (WAX), 200 MW from BC Hydro under the Power Purchase Agreement (PPA) as well as 370 MW of market access. The optimal portfolios for applicable scenarios were tested for PRM requirements. Portfolio scenarios that included incremental resources had those same resources also included in the PRM model. In the event the portfolio did not meet PRM requirements, additional capacity was added until the resulting resource stack met PRM requirements.

In the sections that follow, Section 1 reviews key concepts related to PRM including operating reserves, planning margins and resource adequacy metrics, then examines industry practices and explains the pros and cons of different methods to determine PRM for resource adequacy requirements. Section 2 provides an overview of the Company's operating environment. Section 3 describes modeling techniques used to study PRM requirements within the portfolio scenarios and finally, the conclusion is provided in Section 4.

1. OVERVIEW OF PLANNING RESERVE MARGIN

1.1 PLANNING RESERVE MARGIN TERMINOLOGY

PRM conceptually is the capacity above expected load necessary to maintain a certain resource adequacy level. The peak demand is the expected load while the generation capacity is dependable capacity. The FBC expected load is net of expected DSM savings. As described by NERC, PRM is designed to measure the amount of generation capacity needed to meet expected demand in the planning horizon[1]. PRM's role is to ensure resource adequacy when dealing with unforeseen increases in demand and forced outages in the system. It serves the utilities' ultimate goal of "keeping the lights on" by confirming that power supply will remain adequate over the planning horizon.

The PRM concept is broader than Operating Reserves (OR) although it includes OR. OR is defined by NERC as "*capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserves*"[2]. These spinning and non-spinning reserves[3] are used to form two major functional OR components:

- Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard and other NERC and Regional Reliability Organization contingency requirements. It is for control under disturbance conditions and at least half of it must be spinning. It is available for only 60 minutes from the time of any contingency event; and
- Regulating Reserve: An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin. It is for control under normal conditions and consists of spinning reserve only.

Utilities must hold capacity for OR to meet NERC (BAL-002[4]) and further sub-regional reliability standards (WECC's BAL-002-WECC-2[5] for FBC). Contingency reserve is not available to be used to meet end-use demand unless there is an unplanned outage event.

It is necessary to hold OR to ensure real-time reliable operation of the system. OR ensures hourly operational reliability whereas PRM must include a sufficient time period to ensure that changes to the resource portfolio can be addressed as needed to ensure system resource adequacy. In other words, PRM includes the resource capacity reserved for OR to address

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1 "M-1 Reserve Margin." NERC, http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx
2 "Glossary of Terms Used in NERC Reliability Standards." NERC, 2 April 2021, p. 19 http://www.nerc.com/files/Glossary_of_Terms.pdf.
3 Ibid, p. 18 and p. 29
4 "Standard BAL-002-0 – Disturbance Control Performance." NERC, http://www.nerc.com/files/BAL-002-0.pdf.
5 "WECC Standard BAL-002-WECC-2 – Contingency Reserve." WECC, https://www.wecc.biz/Reliability/BAL-002-WECC-2%20BC.pdf.

uncertainties caused by hourly load and generation variations as well as any additional capacity needed on a longer term basis.

Comparing PRM values stated by different utilities can be problematic as they may differ in a number of dimensions, and are specific to the type of resources held by each utility and the nature of their loads. Utilities may also use non-firm capacity, and include or exclude market access as a source of capacity. Also, they may use different PRM calculation methods with different results. Finally, although published PRM values frequently include OR, they may also exclude OR if a utility wants to make a clear differentiation between capacity requirements for OR and longer term planning margin. Table 1-1 below illustrates differences in PRM as reported by some of FBC's neighboring utilities.

Table 1-1: PRM Stated by Neighbouring Utilities

	Avista	BC Hydro	Idaho Power Company	NorthWestern Energy	PacifiCorp	Portland General Electric	Puget Sound Energy
PRM	18%	14%[6]	15%	16%	13%	10-12%	17.8%
OR Included?	Yes	Yes	No	Not indicated	Yes	Yes	Yes
Market Included?	Yes	No	No	Yes	Yes	Yes	Yes
Methodology[7]	LOLP	Capacity Margin	PRM	PRM	EUE, LOLH, LOLE	PRM	LOLP
Reference	February 2020 IRP[8]	2008 LTAP and 2013 IRP	June 2019 IRP[9]	2019 Resource Procurement Plan[10]	October 2019 IRP[11]	March 2019 IRP[12]	2019 IRP Progress Report[13]

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6 BC Hydro (BCH) uses capacity margin, defined as (Capacity-Peak Demand)/Capacity instead of PRM.

7 For additional information about the various methodologies please refer to:
NERC. Probabilistic Adequacy and Measures Technical Reference Report. July, 2018.

8 "February 2020 IRP", Avista, p. 7-1 https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2020-electric-irp-final-with-cover.pdf

9 "June 2019 IRP", Idaho Power, p. 102 https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2019/SecondAmended2019IRP.pdf

10 "2019 Electricity Supply Resource Procurement Plan." Northwestern Energy, p. 2-13 https://www.northwesternenergy.com/docs/default-source/documents/defaultsupply/plan19/ch-2019-vol-1-final.pdf

11 "2019 IRP - Volume 1", PacifiCorp, p. 16 https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf

12 "2019 IRP", Portland General Electric, p. 628 https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFlLvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf

13 "2019 IRP Progress Report", Puget Sound Energy, p. 14 https://oohpseirp.blob.core.windows.net/media/Default/Action_Items/UE-180607-UG-180608-PSE-2019-IRP-Progress-Report-Revision_12-10-19.pdf

Utilities that use a PRM approach commonly set their PRMs between 10 percent and 20 percent above the median peak demand. WECC, the NERC regional entity responsible for compliance monitoring and enforcement for the Western Interconnection of which FBC's service area is a part of, does not mandate a PRM on its members. WECC uses a probabilistic approach for determining the reference margin level, holding a LOLP constant equal to a 1 event-in-10 year loss of load.

Each utility should determine its own PRM requirement based on its own operational needs, including consideration of its resources, load requirements, and access to the market. Most utilities in the Pacific Northwest rely on PRM to measure resource adequacy, some using probabilistic modelling to derive an appropriate target PRM, while some smaller utilities can rely on regional targets or rules of thumb for their requirements[14].

Nevertheless, all utilities must ensure that any PRM must at least cover OR requirements for regulating and contingency reserves. FBC is a member of the North West Power Pool (NWPP) contingency reserve sharing group, and therefore is required to hold an amount of capacity equal to 3 percent of load and 3 percent of generation for contingency reserves. Under the Canal Plant Agreement, FBC also holds 2 percent of its capacity for regulating reserves[15].

1.2 *Resource Adequacy Metrics*

The utility industry uses a number of metrics (indices) to measure resource adequacy and determine PRM requirements. The most common metrics are described below:

- *Loss of Load Probability* (LOLP, in percent): LOLP is the probability that at least one shortfall event will occur over the time period being evaluated. Common industry standards are 1-in-10 or 10 percent and 1-in-20 or 5 percent. This approach uses an annual measure. This metric does not reflect the frequency of events such as the LOLE or LOLH because it does not matter if there are one or more shortfall events in the non-compliant year.
- *Loss of Load Hours* (LOLH, in hours per year): LOLH is the expected number of hours in a year when the aggregate resource is insufficient to meet load. This metric is very similar to the LOLE, but using hourly load and generation profiles rather than the daily peak and capacity profiles. Conversion between LOLE and LOLH is, however, not straightforward. LOLE does not equal LOLH/24 because a shortfall event typically does not last for the whole day. If outages were to typically last for 8 hours, the LOLE criterion of 0.1 day/year would be closer to a LOLH criterion of (0.1 * 8) or 0.8 hour/year. This uncertainty in the average outage time makes it very difficult to compare LOLE and LOLH numbers.

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[14] "Exploring a Resource Adequacy Program for the Pacific Northwest", NWPP, October 2019, p. 19, https://www.nwpp.org/resources/exploring-a-resource-adequacy-program-for-the-paci

[15] More precisely, FBC is required to hold 6%/1.06 and 2%/1.02 for contingency reserves and regulating reserves, respectfully. This results in a net OR requirement of 7.51%.

- *Expected Unserved Energy* (EUE, in MWh): EUE is the expected amount of energy not served per year. This metric gives some information of the aggregated magnitude of shortfalls.
- *Loss of Load Expectation* (LOLE, in days per year): LOLE is the expected number of days in a year when the aggregate resource is insufficient to meet load. It does not matter if there are single or multiple shortfall events in a day of resource inadequacy if the analysis is for the daily peak only. Resource capacity is assumed to remain constant throughout the day. This is the most commonly used metric in the industry[16]. The commonly used LOLE criterion is "1 day in 10 years", or equivalently 0.1 day/year if annual analysis is required.

These resource adequacy metrics are sometimes referred to as reliability indices in literature. Since cost consideration makes it practically impossible to have a system totally immune to shortage events, a target metric is chosen to reflect a tradeoff between reliability and cost, taking into account a utility's particular situation. A portfolio that meets a "1 day in 10 years" Loss of Load Expectation criteria is anticipated to have shortfalls that occur at a rate less than or equal to the reliability target.

1.3 *METHODS TO DETERMINE PRM*

This section provides an overview of probabilistic approaches to calculate the PRM capacity and the method chosen by FBC.

1.3.1 Probabilistic Approach

A probabilistic approach directly targets resource adequacy metrics such as LOLP, LOLH, EUE, and LOLE. Assessing these metrics estimates the system risk level and whether the resource adequacy measures is appropriate for a utilities individual situation. One method is called the "Capacity Outage Probability Table" and was frequently used in the 1960s - 1980s. In this method, the utility studies its generators' forced outage rate (FOR), then builds up a complex table of capacity outage probabilities and compared values in this table to a forecast load duration curve to find LOLE. There are two main disadvantages with this method. First, setting up the capacity outage probability table gets more cumbersome and intractable the more generators there are in the system. Second, this method cannot take into account both load variations and system outages at the same time.

To overcome these disadvantages, most utilities have switched to the stochastic method, which is based on a Monte Carlo (MC) simulation. In this method, multiple uncertainties in the system are considered simultaneously and the output is obtained after a high number of sampling iterations. The main advantage of this method is to allow utilities to better approximate real

[16] NERC. Probabilistic Adequacy and Measures Technical Reference Report. July, 2018. Executive Summary – p. vi

operation of the system as both load and generation vary at the same time, which makes planning results more useful.

The resource adequacy metrics mentioned in Section 1.2 are obtained in the MC simulation method as follows. Suppose a MC simulation for a year uses *n* sampling iterations. If there are *m* simulations ($m \leq n$) in which at least one shortfall event occurs (e.g. resource capacity in a day is less than the day's peak demand if the daily load profile is used or resource capacity in an hour is less than the hour's peak demand if the hourly load profile is used), then for this year:

LOLP = *m/n*, and *LOLE* = *Total number of days having shortfalls/n,* if the daily load profile is used (day/year), or

LOLH = *Total number of hours having shortfalls/n* (hour/year) if the hourly load and generation profiles are used.

In the latter case, EUE can be estimated as *Total hourly capacity shortage/n* (MWh/year). EUE is an energy-centric metric derived from an hourly model.

1.3.2 FBC's Method to Determine PRM

The Company believes a probabilistic approach using a Monte Carlo simulation of its operating environment to assess the adequacy of its resources to meet a reliability target provides the most balanced method. The Company has chosen the LOLE of 1 day in 10 years, or as it is more commonly expressed, 0.1 day/year as the target resource adequacy measure, which is consistent with industry practices and suitable for FBC's unique resources.

The PRM model considers the existing and prospective resources contained in a specific portfolio scenario and simulates forced outages of dispatchable resources, varying intermittent generation associated with renewable resources, and variations from expected load. The simulated daily peak is compared to the portfolio resources after accounting for changes in available generation to determine if a resource shortfall has occurred.

2. OVERVIEW OF THE FBC OPERATING ENVIRONMENT

This section details key aspects of the Company's operating environment as applied to the PRM study for the assessment of the portfolio scenarios. First, FBC's resources and expected forced outage rates are discussed. Next, the different types of prospective resource options considered within the portfolio analysis and their assumed forced outage rates are discussed. Third, the characteristics of the peak forecast used to test for PRM adequacy is outlined.

2.1 *FBC EXISTING RESOURCES*

2.1.1 Canal Plant Agreement Entitlement

The Company owns four hydro plants located on the Kootenay River between Nelson and Castlegar in the following order for water in-flows: Corra Linn (three generators), Upper Bonnington (six generators), Lower Bonnington (three generators), and South Slocan (three generators). These facilities are operated under the CPA, and therefore BC Hydro (BCH) directly dispatches the plants and FBC receives guaranteed entitlement energy and capacity provided the generating units are available to be dispatched. The Company's usage of its plants to meet system requirements is therefore insulated from hydrology risk, but is still subject to plant outages. In addition to its four plants, FBC has a long-term contract to purchase the entire output of the four generating units of the Brilliant Plant (BRD) belonging to the Brilliant Power Corporation (BPC), which are located further downstream to the Company's plants. Because BRD is also a CPA entitlement plant the BRD output is also hydrology risk free but subject to outages. FBC has also contracted to purchase entitlement capacity from the Brilliant Expansion (BRX) and Waneta Expansion (WAX) CPA entitlement plants, which will be discussed further in the next section.

In order to assess the availability of its generation units, FBC reviewed their historical performance. In 2012, FBC completed its Upgrade and Life Extension Program (ULE), which extended the lives of 11 of the Company's 15 generating units through its course of maintenance and refurbishment programs. The remaining four units at the Upper Bonnington plant were not refurbished under the ULE, but were completed in 2021. The majority of ULE work was done in the 1995-2008 period, therefore it is more reasonable to use historical outage data after 2008 to estimate the plants' expected forced outage rates (FOR)[17]. Each generator's average FOR from the 2008-2020 period is then used to set the expected FOR associated with the specific generator in the MC simulation, which is found in Table 2-1. The majority of FBC's historical forced outages were less than one day in duration. Subsequently, for simulation

[17] A forced outage is an unplanned/unexpected shutdown of a generating unit or an unexpected failure to start. Forced outage rate is the proportion of time the unit is on forced outage to its total service time. The PRM forced outage rates are calculated based on unit availability over the years 2008-2020 as determined by entitlement calculation records.

purposes, it was assumed that all CPA entitlement generator forced outages will last for less than one day.

2.1.2 Power Purchase Agreement, Brilliant Expansion, and Waneta Expansion

In addition to the CPA entitlement capacity, the Company has also entered into a Power Purchase Agreement (PPA) with BCH. The PPA (approved as per the Commission's Order G-60-14 issued on May 6, 2014) allows capacity purchases of up to 200 MW at any time. Given the resources of BCH and the number of interconnection points with FBC, the 200 MW of PPA capacity is considered 100 percent available (i.e. FOR = 0 percent). In most portfolio scenarios and in FBC's base assumption, the PPA is assumed to be renewed in 2033. For the scenarios that investigated if the PPA was not to be renewed, the corresponding PRM assessment did not consider the PPA as an available resource after September 2033.

Along with the PPA, FBC entered into the Imbalance Agreement with BC Hydro. The imbalance agreement sets out the terms under which FBC will settle with BC Hydro for any inadvertent flows of electricity between the BC Hydro system and FBC due to unexpected conditions or circumstances. The Imbalance Agreement is not a service and FBC cannot rely on or plan on the use of imbalance as a resource for meeting its system requirements. Therefore, the Imbalance Agreement is not considered a resource within the PRM analysis.

FBC's capacity resources also include entitlement capacity from the BRX plant. In the LTERP and the PRM study, the BRX contract is assumed to be in place to the end of December 2027. The BRX expected FOR was calculated over the same 2008-2020 period.

Furthermore, the Company receives capacity from the WAX plant, which came online in the spring of 2015. The Company receives WAX entitlement capacity from two WAX units, each with a capacity of 165 MW. The WAX expected FOR was calculated over the 2015-2020 period.

FBC is also party to the Residual Capacity Agreement (RCA). Under the RCA, FBC sells unit-contingent[18] WAX capacity blocks of up to 50MW for all months (i.e. typically 50 MW except in June where the WAX capacity available to FBC is less than 50 MW) to BC Hydro up until September 2025. As a result, for the purposes of the MC simulation, these monthly blocks are deducted from FBC's WAX entitlement capacity. The remaining FBC WAX entitlement capacity is then considered available to meet the monthly load. The RCA is not expected to be renewed after September 2025 in the LTERP and PRM study.

2.1.3 Market Access

FBC's view is that dependence on market capacity to meet expected load on a planning basis over the long term is not a prudent policy due to the uncertainty associated with both resource

[18] Unit contingent sales are sales that require a particular unit to be available to support the sale.

availability and market prices. Recent studies for the Pacific Northwest region have shown that the region is expected to face a capacity deficit in the near term[19].

However, it is not unreasonable for utilities that have access to market supply to consider the market as a supplemental resource to meet system requirements under unexpected conditions. For example, Portland General Electric's Planning Reserve Margin and Reliability Study as part of their 2019 IRP showed the utility relying on up to 250 MW of winter market availability and 500 MW of summer market availability[20]. A survey conducted for E3's 2018 study of resource adequacy in the Northwest revealed that most utilities expect to meet a portion of their peak capacity requirements for reliability needs using market purchases or front office transactions[21].

In practice, utilities' opinions differ substantially on relying on market imports for resource adequacy purposes as illustrated in Table 1-1 with some neighboring utilities counting market capacity as a supplemental resource and others not. FBC does consider market capacity an available backup resource that can only be called upon in case of contingencies where the utility's own and contracted resources are unexpectedly not sufficient to meet load.

As of the 2021 LTERP, FBC considered the Capacity and Energy Purchase and Sale Agreement (CEPSA) to be ever greening over the planning horizon. The CEPSA provides provisions for real-time nominations to cover unexpected conditions. FBC is able to import electricity from the Mid-C market via transmission connected to the Waneta plant (71 Line) as well as through the BC Hydro transmission system. 71 Line has a transmission capacity of 370 MW, but Teck has priority over FBC for use of this line if it is needed.

The historic forced outage rate associated with market access via 71 Line is 0.69 percent. This forced outage rate covers both the risk of transmission outages and market availability due to transmission curtailments in the U.S. portion of the transmission system. The transmission outage rate is based on historical operations of 71 Line for 2001-2020. Furthermore, a portion of 71L capacity was simulated as in use by Teck based on historic monthly usage patterns thereby decreasing the amount of available market capacity to FBC in some iterations of the MC analysis.

[19] Potentially as early as 2020, but a much larger deficit by the mid-2020s.
[20] "2019 IRP", Portland General Electric, p. 644 https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFlLvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf
[21] "Resource Adequacy in the Northwest", E3, p. 7, https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf

2.1.4 Summary of FBC Historical CPA Entitlement Forced Outage Rates

The following table shows the historical FOR of FBC's generating units used to evaluate PRM adequacy requirements among the different portfolio scenarios. FBC calculated the Forced Outage Rate for each of its contracted resources based on historical entitlement outages for CPA plants, which are in the range of 0.04 percent to 4.04 percent.

Table 2-1: PRM Forced Outage Rates for FBC's Generating Units

Plant	Generator	PRM CPA Entitlement Forced Outage Rate
P1- Lower Bonnington	LBO-G1-Upgrade	0.14%
	LBO-G2-Upgrade	0.09%
	LBO-G3-Base	0.04%
P2 - Upper Bonnington	UBO-G1-Small	0.96%
	UBO-G2-Small	0.21%
	UBO-G3-Small	1.32%
	UBO-G4-Small	0.31%
	UBO-G5-Upgrade	0.32%
	UBO-G6-Base	0.11%
P3 - South Slocan	SLC-G1-Base	0.76%
	SLC-G2-Base	0.31%
	SLC-G3-Base	0.09%
P4 - Corra Linn	COR-G1-Base	0.07%
	COR-G2-Base	4.04%
	COR-G3-Base	0.12%

2.1.5 Regulating Reserve and Contingency Reserve Obligations

The Company reserves a certain percentage of its capacity for regulating and contingency purposes. This reserved capacity cannot be counted on to meet expected load for planning purposes as discussed in Section 1.1.

FBC and BC Hydro are both members in the Northwest Power Pool (NWPP), which is a contingency reserve sharing group for utilities in the Pacific Northwest[22]. The NWPP groups all reserve contributions from its members according to their load and generation attributes. In a situation where a contingency event occurs that is beyond the resources of the utility experiencing the event, reserves are allocated to them from the other members of the NWPP. The biggest advantage of the NWPP is that each individual utility member is not required to hold

[22] Members. Northwest PowerPool, https://www.nwpp.org/about/members/

reserves to deal with its most severe single contingency. This is of great benefit to FBC especially after WAX came online, as a single unit WAX outage (165 MW) would represent the most severe single contingency for FBC.

Under the CPA, the Company sets 2 percent of its generation capacity to regulate frequency. In addition, the Company's contingency reserve obligation to the NWPP is equal to 3 percent of load and 3 percent of generation inclusive of BRD, BRX and WAX contracted capacity. The first 60 minutes of a contingency can be covered by contingency reserves. After 60 minutes the contingency reserves must be restored. Therefore, forced outages lasting for less than one hour are not included in this analysis. The likelihood of the outage being less than an hour is set for each generator based on the specific generator's historical percentage of forced outages that lasted for less than one hour. For example, if a generator has a FOR of 0.5 percent and its forced outages have a likelihood of 70 percent of being more than one hour, then it will experience outages lasting for more than one hour about 0.35 percent of the time.

2.2 NEW PORTFOLIO RESOURCES

As discussed in Section 10 of the LTERP, FBC has considered several different potential supply-side resource options to meet the forecast load requirements. These include the following:

- SCGT / RNG SCGT
- CCGT
- Batteries
- Run of River Hydro
- Hydro (with storage)
- Pumped Storage Hydro
- Geothermal
- Solar
- Biomass
- Wind

Within the resource portfolio model, each of the resource options has a profile that tables the installed capacity, dependable capacity, reliable energy, and corresponding capacity factor for each month of the year. The monthly dependable capacity of a resource option is the average capacity FBC can expect to be available to meet load in peak hours of each month. The approach of using resource profiles recognizes that the different resource types are expected to have varying performance during different months of the year. For example, the profile for a wind resource will differ from a solar resource. Operating reserve requirements were applied to the monthly dependable capacity and all new resource options were assumed to have OR requirements of 2 percent to regulate frequency, 3 percent of load, and 3 percent of generation[23].

When the optimization routine in the resource portfolio model selects a resource option, the average monthly dependable capacity is added to the total available monthly capacity. The planning reserve margin model investigates the possibility that the dependable capacity available to serve peak load can vary from the average monthly profile. The resource options were grouped into two broad categories, namely those considered dispatchable and those considered intermittent. Dispatchable resources were assigned a forced outage rate that was used to simulate outages resulting in the unavailability of the unit. Furthermore, for the purposes of evaluating the PRM adequacy, FBC expected a portion of the forced outages would last for more than one hour but less than one day. Intermittent resources used a distribution of possible generation on peak hours to simulate varying resource output.

The resource options considered to be dispatchable were grouped into five broad classifications for purposes of the PRM Monte Carlo Simulation. The following table shows the presumed forced outage rates associated with each dispatchable resource classification.

Table 2-2: PRM Assumed Forced Outage Rates for New Dispatchable Resources

Resource Option Type Classification	Assumed Forced Outage Rate
Thermal Resources (SCGT, CCGT, RNG_SCGT)	2.74%[24]
Hydro with Storage (includes Pumped Storage Hydro)	3.36%[25]
Geothermal	3.32%[26]
Batteries	1.00%[27]
Biomass	6.36%[28]

To calculate the dependable capacity for intermittent resources (e.g. wind and solar), historic hourly generation data for each specific resource option was analyzed. For each month of the year, traditional utility peak hours were used in combination with the historic hourly generation data to derive a frequency table of observed generation output for each intermittent resource option. This analysis determined the expected average dependable capacity for each new intermittent resource option used in the resource portfolio as well as the distribution of available

[23] More precisely, 6%/1.06 and 2%/1.02 of average dependable capacity for contingency reserves and regulating reserves, respectfully. This results in a net OR requirement of 7.51%, which is the same as other FBC generation.
[24] Based on WECC's State of the Interconnection – Generation Outages report: https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Generation-Outages.aspx
[25] Ibid.
[26] Ibid.
[27] Based on data provided by Tucson Electric Power Company.
[28] Based on the CEA 2019 Generation Equipment Status Annual report, Table 6.2.17.

capacity on peak hours used in the planning reserve margin analysis. The available peak hour generation from a new intermittent resource in any specific iteration of the MC analysis was determined through the developed frequency tables. A correlation matrix was also incorporated into the MC analysis to capture the relationship of new intermittent resource's generation to load and other new intermittent resources contain in the portfolio scenario.

2.3 *PEAK FORECAST*

The daily peak load was chosen to calculate the LOLE. The use of the daily peak aligns with the company's current resource stack primarily made up of fixed entitlements. The entitlements of FBC owned and contracted resources may vary by month, but are constant among all hours within the day.

FBC accounted for the potential of variance from the scenario load forecast to test the robustness of the prospective portfolios. To create a distribution of potential load variances, FBC used a classic multiplicative decomposition model[29] to decompose historic peak loads into trend, seasonal, and irregular (random) components. FBC then used the portfolio scenario specific peak forecast after DSM savings as the average expected load in combination with a distribution representing load variance created using the components of the decomposition model.

[29] Anderson, Sweeney, and Williams. Statistics for Business and Economics – 9th edition. 2005. pp. 799-807

3. MONTE-CARLO SIMULATION RESULTS

3.1 MONTE-CARLO SIMULATION AND ASSUMPTIONS FOR A PORTFOLIO SCENARIO

The MC simulation model for PRM was developed in-house using Microsoft Excel and its programming language Visual Basic for Applications (VBA).

As part of the LTERP, the Company considered a number of resource portfolios before determining its preferred portfolio. All portfolios presented were designed to meet forecast monthly capacity and energy requirements for each month of each year in the planning horizon.

To assess the robustness of various portfolio scenarios, the company simultaneously investigated a number of factors to represent plausible deviations from the expected operating environment. Each MC simulation consisted of 5,000 iterations for each year. The notable factors considered are variations in load and the possibility for multiple outages. These factors were addressed by:

1. Utilizing load uncertainty to account for variance in the peak demand forecast;
2. Using a distribution of historically observed generation on peak hours for intermittent resources;
3. Simulating outages for dispatchable resources based on an projected FOR, and
4. Allowing for more than one forced outage to occur. Outages included both existing resources and prospective new resources included in the specific portfolio scenario.

A summary of the key assumptions contained in the PRM analysis are as follows:

1. FBC's own and contracted generators' FORs are assumed as explained in Section 2.1.4;
2. Forced outages will last for less than one day and an outage on any given day does not influence whether the following day will have an outage as well;
3. Market access is 370 MW with an average monthly FOR of 0.69 percent;
4. Prospective new resources deliver dependable capacity as per the assumed performance profile in the resource portfolio model;
5. Prospective new dispatchable resources have an assumed FOR as per Table 2-2;
6. Prospective new intermittent resources provide dependable capacity based on a distribution of what was historically observed during traditional peak hours of the month, and
7. WAX capacity for unit-contingent sales associated with RCA is not available to meet FBC peak demand.

3.2 PROCESS FOR EVALUATING A PROSPECTIVE PORTFOLIO

The following process was used to determine the optimal PRM compliant portfolio of a specific portfolio scenario:

1. Using the Resource Portfolio model, find an optimal portfolio that meets the forecast load requirements and the constraints of the specific scenario.
2. Test the resulting resource stack for robustness using the planning reserve model and the LOLE target. If the optimal portfolio met the LOLE target in each year of the planning horizon, the portfolio was deemed to meet PRM requirements.
3. If the optimal portfolio did not met the LOLE target, additional capacity requirements were added to all months proportional to the monthly contribution to the LOLE starting in the first year of the planning horizon the LOLE target was not met.
4. The Resource Portfolio for the specific scenario was then re-optimized with the additional PRM capacity requirements
5. Steps 2 through 5 were repeated until the optimal portfolio for the specific portfolio scenario met the LOLE target in all years of the planning horizon.

3.3 RESULTS

3.3.1 General Observations

With the CEPSA being assumed as ever greening over the planning horizon, and containing clauses specific to contingency conditions, FBC is able to recognize the full 370MW of 71L capacity as available in the PRM model. The 370MW of 71L capacity is sufficient to overcome many contingency events resulting in a lower LOLE.

The portfolios considered for the preferred portfolio all maintain a capacity self-sufficiency objective as a planning criteria. As market energy, and to a lesser extent PPA energy, are cost effective in comparison to other energy resource options, new resources in the portfolio scenarios are generally being selected for their contribution to the capacity gaps. Many of the portfolio scenarios include a SCGT peaker plant which is able provide dependable capacity in all months of the year. Portfolios that exclude peaker plants contain a collection of intermittent resources to meet the capacity gaps on the planning basis. Although both types of portfolios meet the LOLE target of 0.1/day with market access being a contingency resource, portfolios without peaker plants are more reliant on the 370MW of market capacity to firm up the intermittent generation. If the conditions of FBC market access were to change or FBC had materially less than 370MW of market access in the future, portfolios reliant on intermittent resources to meet capacity gaps would likely carry greater reliability risk and require additional resources to meet PRM requirements than a portfolio that contained dispatchable capacity resources.

FBC takes the position that it is not prudent to plan to rely on market capacity to meet expected load. If a portfolio was suggested that required significant amounts of market power to meet expected capacity gaps, it would not meet PRM requirements. If the market is also used as a planning resource to meet expected gaps, then if the market is not available as a failover resource, it is also not available as a base resource and there is a greater probability of capacity shortages. Therefore, reliance on the market as both a base and a backup resource is not a prudent approach in the long run.

3.3.2 Preferred Portfolio

As discussed in LTERP Section 11, the Company selected portfolio C3 as its preferred portfolio (assuming current market access conditions). This preferred portfolio includes a distributed battery, RNG SCGTs, solar, and wind as supply side resources. Table 3-1 below shows the LOLE of the preferred portfolio (C3) over the planning horizon, and demonstrates that the PRM requirement of LOLE equal to or less than 0.1 days per year has been met over the planning horizon.

There are noticeable variations in the LOLE value among the years in the planning horizon that can be explained. The WAX RCA agreement expires September 2025, effectively adding 50 MW of available capacity to FBC in all months. In both the Resource Portfolio and the PRM Model, the BRX agreement is assumed to be expire December 2027. Correspondingly, in 2028 the LOLE value increases. In 2031, the LOLE again decreases when the RNG SCGT is brought into service adding approximately 100 MW of dependable capacity. In the later years of the planning horizon, the annual LOLE begins to increase as the peak demand forecast grows.

Table 3-1: LOLE in the Preferred Portfolio C3 (0.1 day per year as the target)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	LOLE
2021	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.03
2022	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.03
2023	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.03
2024	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.03
2025	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.03
2026	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2027	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2028	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.04
2029	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.04
2030	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.04
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2033	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2034	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01
2035	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2036	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2037	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.02
2038	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.02
2039	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.02
2040	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.03

4. CONCLUSION

One of the main objectives of the LTERP is to ensure reliable, secure and cost-effective power supply for customers. In line with this objective, PRM resource adequacy requirements need to be met. FBC has determined that a MC probabilistic is the best approach to assessing PRM requirements. FBC has adopted the common LOLE with a 1 day per 10 years or 0.1 day per year target.

FBC has investigated a series of portfolio scenarios within the LTERP. When capacity gaps begin to emerge in the planning horizon, the portfolio optimization routine commonly selects SCGT and battery resources as the most cost-effective way to fill a large portion of the forecasted capacity gaps within the various portfolio scenarios. Portfolios that exclude SCGT resources contain multiple intermittent resources that collectively meet the capacity gaps on the planning basis. Although all portfolios meet the reliability metric, portfolios containing more intermittent resources to meet peak capacity requirements are more dependent on market access as a contingency resource to meet reliability requirements.

To ensure robustness, multiple aspects of the operating environment were varied from expected conditions using a MC simulation. FBC has confirmed the preferred portfolio (C3) meets resource adequacy requirement with respect to the LOLE target of 1 day in 10 years. It is important to note a portfolio that meets the LOLE target of 1 day in 10 years can still have outages. Furthermore, the PRM model is designed to evaluate reasonable variations in load and supply and can not explicitly account for every unforeseen circumstance such as extremely rare or catastrophic events leading to numerous simultaneous outages.

Appendix N

CUSTOMER SURVEY

Long Term Electric Resource Planning Survey

PREPARED FOR

Walter Wright

FORTIS BC™

Updated: June 2, 2021

500 – 602 West Hastings Street, Vancouver, BC V6B 1P2
thesentisgroup.com

Adam DiPaula | adipaula@sentisresearch.com
Ayden Verhulst | averhulst@sentisresearch.com

Objectives & Approach

OBJECTIVES

sentis

FortisBC partnered with Sentis to conduct a survey among residential and commercial customers regarding FortisBC's Long-Term Electric Resource Plan (LTERP). The survey seeks to gather insight on the following:

- Importance of LTERP Objectives
- Preferences for Resource Options
- Demand for Electric Vehicles
- Demand for Rooftop Solar Panels

METHOD

sentis

Approach

FortisBC electric customers living in the Shared Services Territory (SST) region.

- Residential customers were invited to the survey via consumer panels.
- Commercial customers were invited to the survey via email, using lists provided by FortisBC.

12-minute online survey.

Prize draw offered to commercial customers to increase participation.

Survey Responses

Year	Date	Stakeholder	Method	Invitations	Completed Surveys
2021	Mar 18 – Apr 1	Residential	Panel	n/a	379
	April 15 – May 4	Commercial	Email	535	61

Total residential results accurate to **±5%**
(maximum margin of error 19 times out of 20)

Residential results weighted by age and gender to accurately reflect the total SST population

Total commercial results accurate to **±13%**
(maximum margin of error 19 times out of 20)

Commercial results are not weighted

Highlights

sentis

What Customers Want FortisBC's Long Term Electric Resource Plan to Deliver

Keeping electricity costs as low as possible and **ensuring the reliability of the power supply** are the two objectives that the substantial majority of customers want FortisBC's Long Term Electric Resource Plan (LTERP) to achieve. Commercial customers are more likely to consider cost and reliability as essential compared to residential customers.

While customers rate greenhouse gas (GHG) reduction strategies and conservation and energy management (C&EM) solutions as relatively important (although commercial customers rate GHG reduction as less important than residential customers do), only small percentages of customers consider these as the most important objectives for the LTERP to achieve:

	Most Important Objective Residential	Most Important Objective Commercial
Ensures the cost of electricity is as low/reasonable as possible	39%	33%
Ensures reliable power for customers	30%	43%
Includes strategies to reduce greenhouse gas emissions	13%	7%
Includes conservation and energy management solutions	7%	7%
Focuses on job creation in BC communities	4%	0%

sentis

Options that Customers Want FortisBC to Consider in Order to Meet Future Electricity Needs

The objectives that customers want the LTERP to achieve does of course have a significant impact on the options that they want FortisBC to consider in meeting the future energy needs of customers.

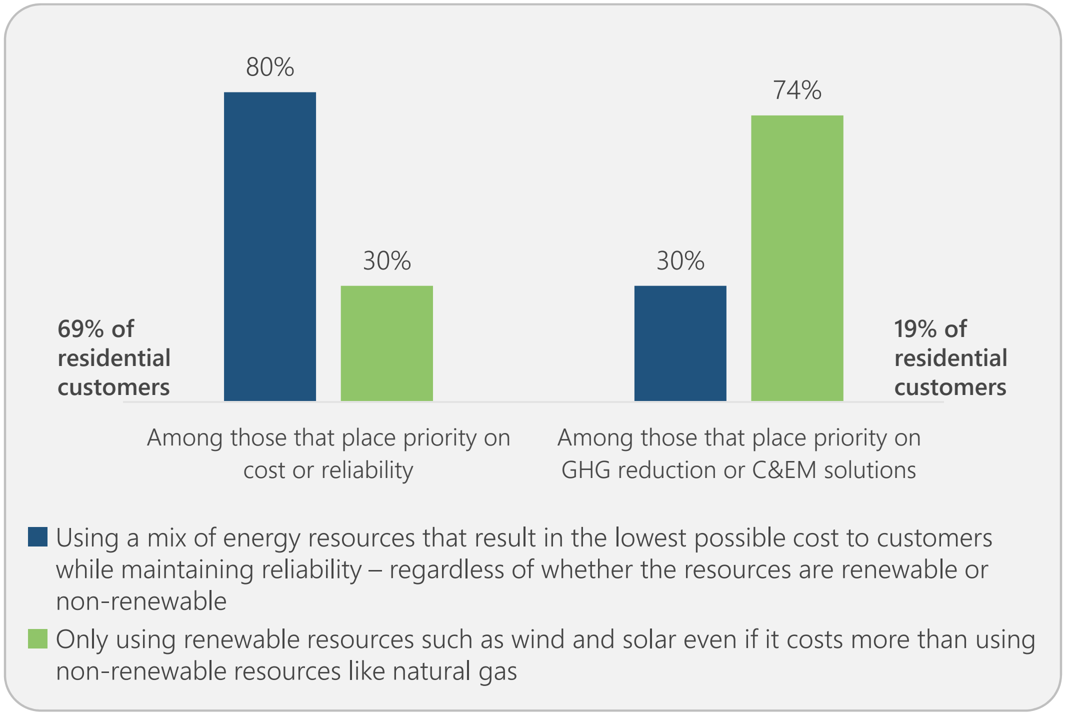
In line with the importance that customers place on keeping costs as low/reasonable as possible and reliability, customers are most likely to support FortisBC using **a mix of energy resources that result in the lowest possible cost to customers while maintaining reliability – regardless of whether the resources are renewable or non-renewable** (70% residential, 63% commercial).

Only 41% of residential customers and 36% of commercial customers support FortisBC only using renewable resources such as wind and solar even if it costs more than using non-renewable resources like natural gas.

However, even though those who place the priority on cost and reliability currently outnumber those who place the priority on energy reduction initiatives by a wide margin (69% vs. 19%), FortisBC should be mindful of how these two groups differ (see next slide). The significant push toward GHG reduction and conservation may expand the size of the latter group at the expense of the former.

Options that Customers Want FortisBC to Consider in Order to Meet Future Electricity Needs (cont'd)

This chart* shows the levels of support that two groups – one group placing priority on cost or reliability – the other on GHG reduction or C& EM solutions – have for two options.



Relative to those who place priority on cost or reliability, **residential customers who place priority on GHG reduction or C&EM solutions are more likely to**:

- Be under age 44
- Be women
- Have completed university
- Use electricity for home heating
- Intend to buy or lease an electric vehicle (EV) in the next three years
- Intend to install rooftop solar panels in the next five years

→ In the coming years, this group could account for a very high share of kilowatt hours use.

*This analysis could not be conducted among Commercial customers due to limited sample sizes.

sentis

Electric Vehicles: Intentions and Incentive Preferences

A substantial percentage of residential customers (43%) - and commercial customers (37%) that own or lease vehicles for their business indicate that they are either definitely or somewhat likely to own or lease an EV in the next three years.

Residential customers are most likely to be motivated by an incentive that would reward them with lower electricity rates for charging during off-peak times, while commercial customers are most likely to be motivated by rebates for buying electric vehicle chargers that automatically charge during off-peak times.

→ *Among both customer groups, focusing on rewards for helping to reduce demand during peak is more effective than focusing on penalties for not helping to reduce demand during peak times.*

Rooftop Solar Panels: Intentions and Incentive Preferences

One-third of residential customers (34%) and just under half of commercial customers (49%) indicate that they are likely to install rooftop solar panels in the next five years.

In terms of incentives, both residential and commercial customers have a stronger preference for rebates on installation and being able to sell surplus energy to FortisBC than they do for receiving account credits for allowing FortisBC to manage their home battery energy storage.

→ *It is likely that this latter option lags behind the other two not because customers don't like the idea of account credits, but because the credits are in exchange for allowing FortisBC to manage their battery energy storage.*

→ *Many customers view this – and things like giving their utility some control of their thermostat – as a form of surveillance. A significant amount of customer education is probably still needed to allay customer concerns in this regard.*

A Note of Caution on Incentives

FortisBC should be mindful of the fact that customers evaluate incentives through a lens of what is fair or appropriate. This helps explain customer reactions to the EV incentives. Among residential customers indicating that they are likely to buy or lease an EV in the next three years, almost three quarters (75%) consider lower electricity rates for charging during off-peak times to be an appropriate incentive.

However, only 28% of residential customers who indicate that they are not at all likely to buy or lease an EV in the next three years think lower rates for charging during off-peak times is an appropriate incentive. The majority of these customers (61%) either prefer that those with EVs be penalized for charging during peak times (37%) or prefer that no incentive be offered at all (24%).

Those who won't be in a position to benefit from a FortisBC EV incentive, tend not to want EV drivers to benefit either.

Summary of Findings

SUMMARY OF FINDINGS

Satisfaction with FortisBC

SATISFACTION WITH OVERALL SERVICE

Overall, three-quarters (76%) of residential customers, and 87% of commercial customers, are satisfied with the service they receive from FortisBC – and only a small percentage are dissatisfied.

S6./S3. How satisfied are you with the overall service provided by FortisBC? *This question was only asked of those who indicated that they receive their electricity bill directly from FortisBC.

SUMMARY OF FINDINGS

Importance of LTERP Objectives

LTERP OBJECTIVES RELATIVE IMPORTANCE

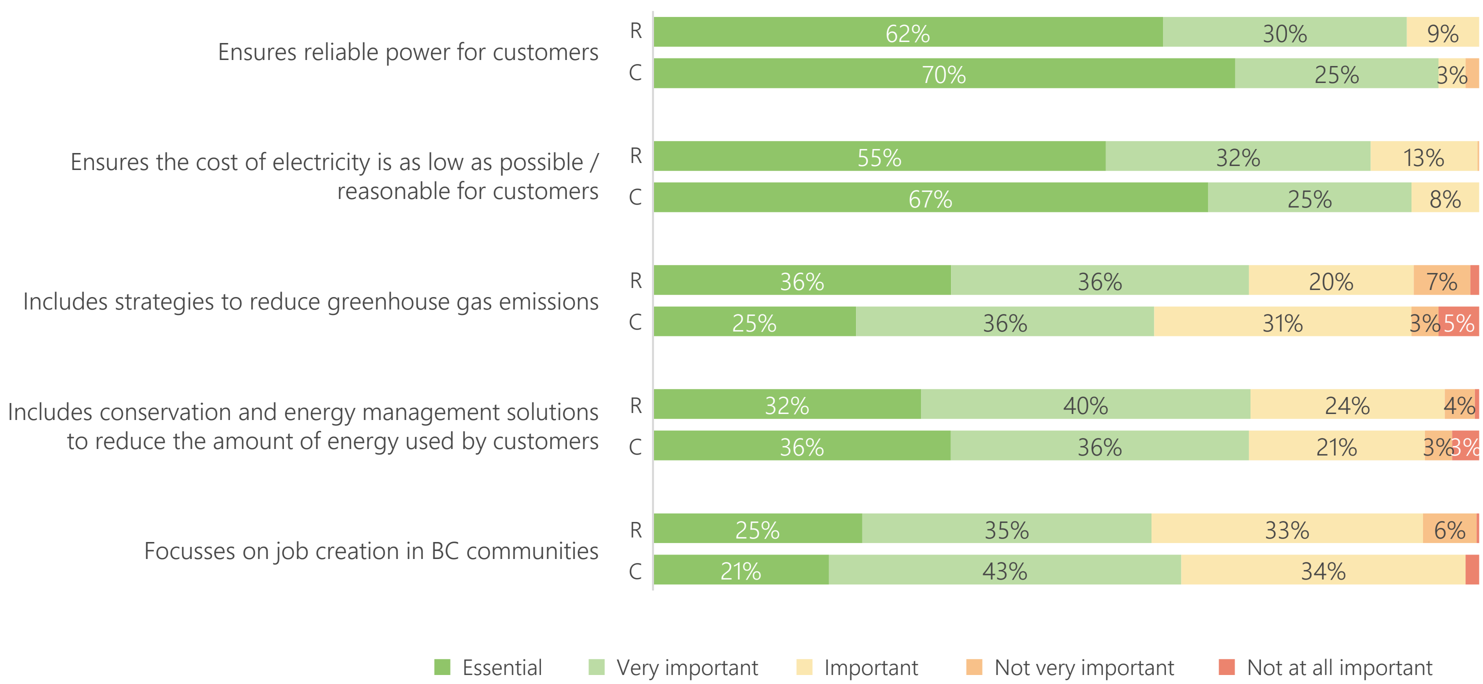
Reliable power and low cost are by far the two objectives that residential customers consider most important for FortisBC to achieve through its Long Term Electric Resource Plan (LTERP).

After ensuring reliability and low cost, residential customers want FortisBC to focus on solutions that will reduce GHGs and conserve energy.

While job creation is not considered unimportant, it is less important to residential customers than the other four objectives.

Commercial customers are particularly likely to consider reliability and providing electricity at a reasonable cost as essential objectives for the LTERP. They are less likely than residential customers to consider GHG reduction as essential.

Residential & Commercial Customer Priorities for the LTERP



Base: Residential (379), Commercial (61)

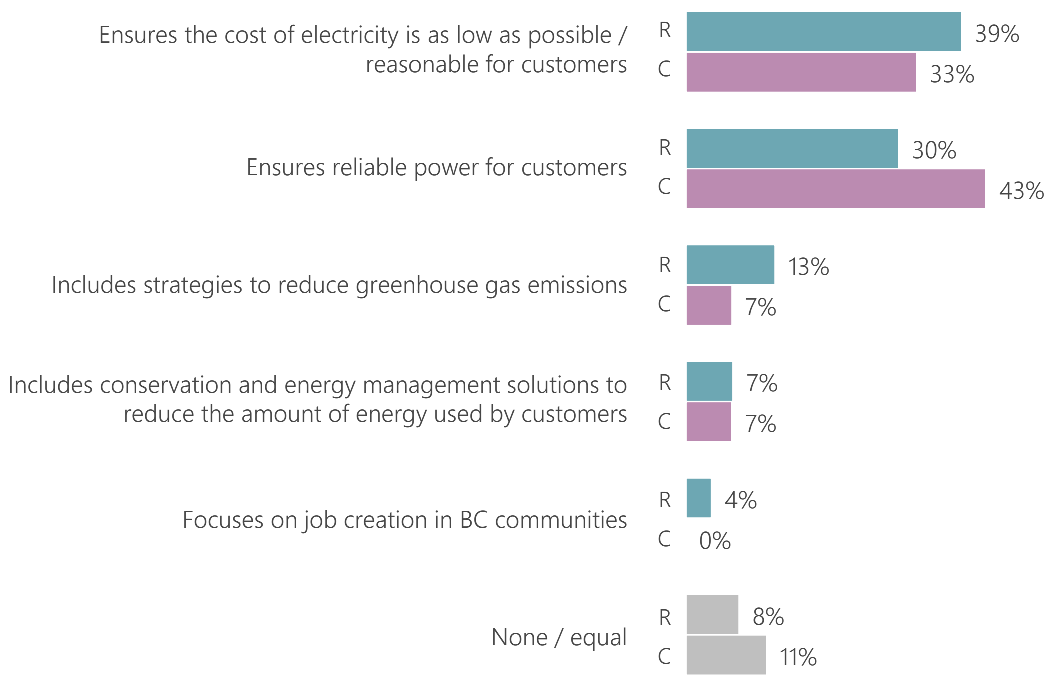
A1. FortisBC develops a long-term plan to make sure it can meet the future energy needs of its customers. In developing its Long-Term Electric Resource Plan, FortisBC consults with a number of groups, including customers, to make sure the plan reflects the needs and values of its stakeholders. [Please think about your organization when answering the following questions.] How important is it to your organization that the Long Term Electric Resource Plan?

LTERP OBJECTIVES MOST IMPORTANT

Customers were asked which objective is **most important** to them.

Among both residential and commercial customers, the results underscore the **relative importance of low/reasonable cost** and **reliability** in relation to GHG reduction and energy conservation.

LTERP Attribute Customers Think Is Most Important



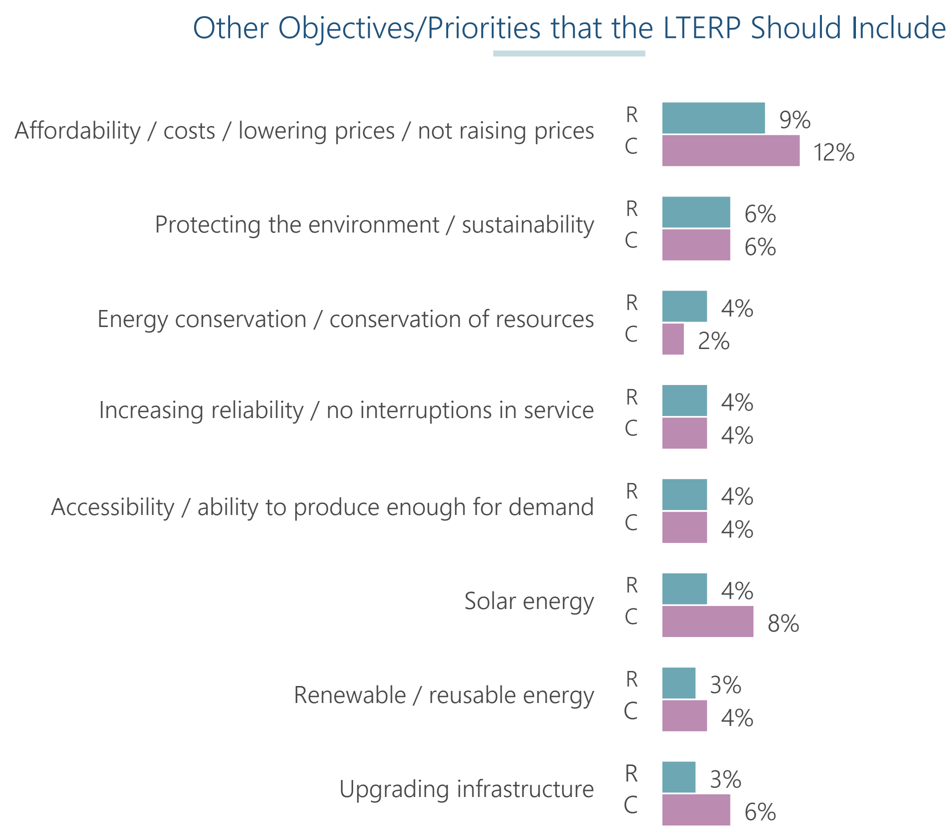
Base: Residential (375), Commercial (61)

A1. How important is it to your organization that the Long Term Electric Resource Plan…? / A1c. You rated [INSERT OPTIONS] as equal in importance. When you consider these objectives again, is there one that is most important to you compared to the other(s)?

ADDITIONAL OBJECTIVES/PRIORITIES FOR LTERP

Just over half of residential customers (57%) and commercial customers (52%) gave a response when asked if there are any other objectives or priorities that the LTERP should include.

As can be seen in the chart, their responses are largely restatements of one of the current objectives.



Note: showing major mentions only (3% or more residential)
Base: Residential (363), Commercial (49)
A2. Are there any other objectives or priorities that the Long Term Electric Resource plan should include? [OPEN-END]

SUMMARY OF FINDINGS

Preferences for Resource Options

PREFERENCES FOR RESOURCE OPTIONS

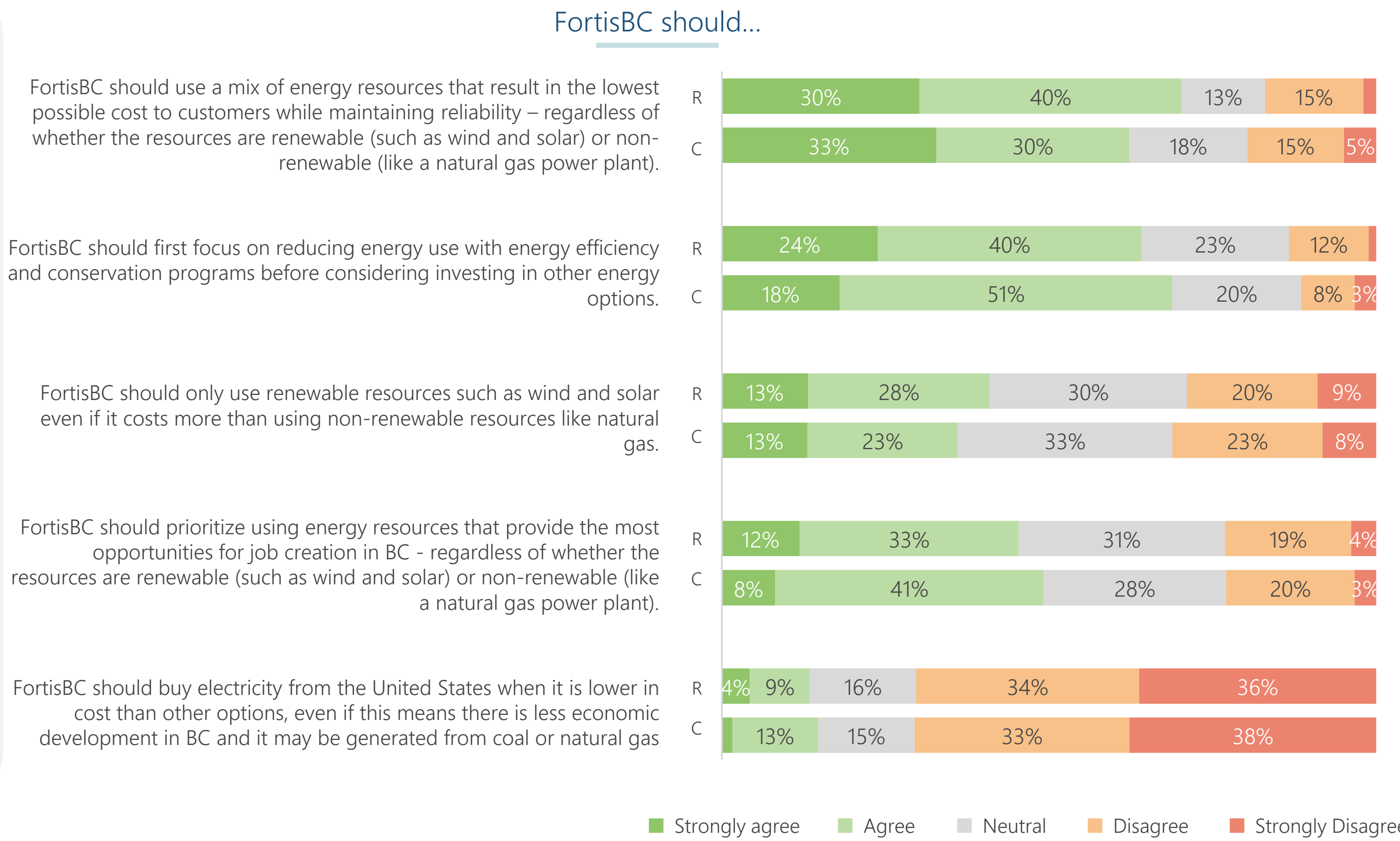
Consistent with the high priority that customers place on keeping electricity prices as low/reasonable as possible, they are most likely to strongly support FortisBC using a mix of energy resources that result in the lowest possible cost to customers while maintaining reliability.

There is also relatively strong support for FortisBC taking a ‘energy use reduction first’ approach by promoting energy efficiency and conservation programs before investing in other options.

While a strong majority of residential customers (72%), and a majority of commercial customers (61%), consider strategies to reduce GHGs as either very important or essential (see slide 14), they are lukewarm when it comes to only using renewables ‘even if it costs more’.

Similar to the results for the LTERP objectives, customers are less likely to support FortisBC engaging in energy resource planning with a view to job creation.

Customers are also decidedly against FortisBC buying electricity from the U.S.



Base: Residential (379), Commercial (61)

A3. FortisBC considers different options that it can use to meet its customers’ future electricity needs. There are 5 options altogether - please read the first option below, and then click next. To what extent do you agree or disagree with the following statements?

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SUMMARY OF FINDINGS

Electric Vehicles

CURRENT USAGE AND FUTURE DEMAND FOR ELECTRIC VEHICLES

Only one residential customer surveyed currently has a fully electric vehicle – 9% have either a hybrid or a plug-in hybrid, some what lower than the 14% of commercial customers who report having either a hybrid or a plug-in hybrid.

A substantial percentage of residential customers (43%) indicate that they are likely to buy or lease a fully electric vehicle in the next three years; however, only seven percent indicate that they are definitely likely to do this in the next three years.

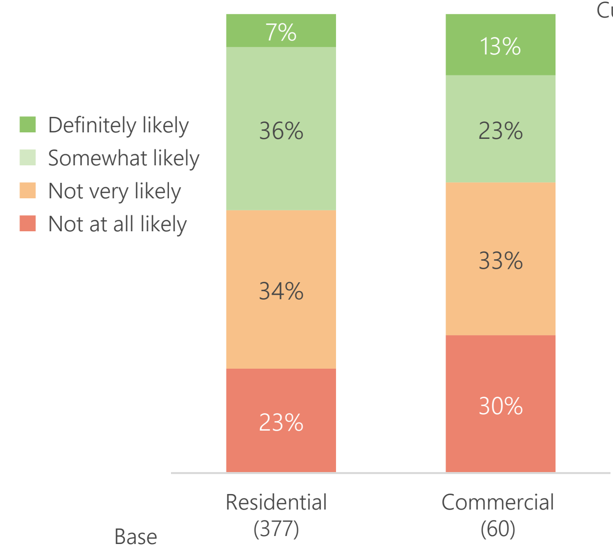
Commercial customers who currently own/lease a vehicle of any kind are more likely to indicate that they are likely to buy or lease a fully electric vehicle in the next three years (45%) compared to all commercial customers (36%).

Type of Vehicle(s) Currently Own/Lease

	Residential	Commercial
Base	379	61
Own/lease a fully electric vehicle	.003%	**2%**
Do not own/lease a fully electric vehicle	**100%**	**98%**
Own/lease a gas / diesel vehicle	84%	**70%**
Own/lease a hybrid vehicle	8%	**11%**
Own/lease a plug-in hybrid vehicle	1%	**3%**
Do not own/lease an electric, hybrid or gas/diesel vehicle	7%	**21%**

Likelihood of Buying/Leasing a Fully Electric Vehicle in Next 3 Years

Among customers who don't currently own/lease a fully electric vehicle



Among Commercial Customers Who Currently own/lease vehicles:

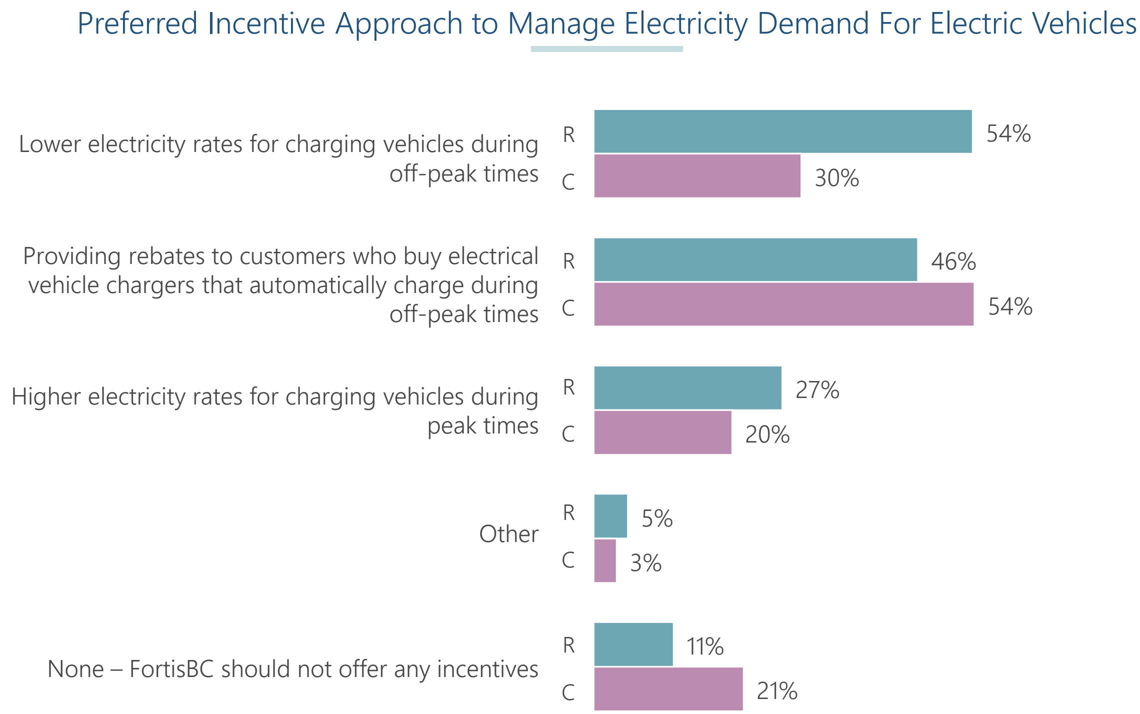
17% Definitely likely
28% Somewhat likely

B1. Which of the following is true of your household? (Select all that apply). / B2. In the next three years, how likely are you to buy or lease a fully electric vehicle?
B1. Does your organization own or lease any of the following? Select all that apply. / B2. In the next three years, how likely is your organization to buy or lease a fully electric vehicle?

PREFERRED INCENTIVE APPROACH

Overall, residential customers have a much stronger preference for EV users being rewarded for charging during off-peak times than being penalized for charging during peak times.

Commercial customers have a clear preference for rebates if they buy electrical vehicle chargers that automatically charge during off-peak times.



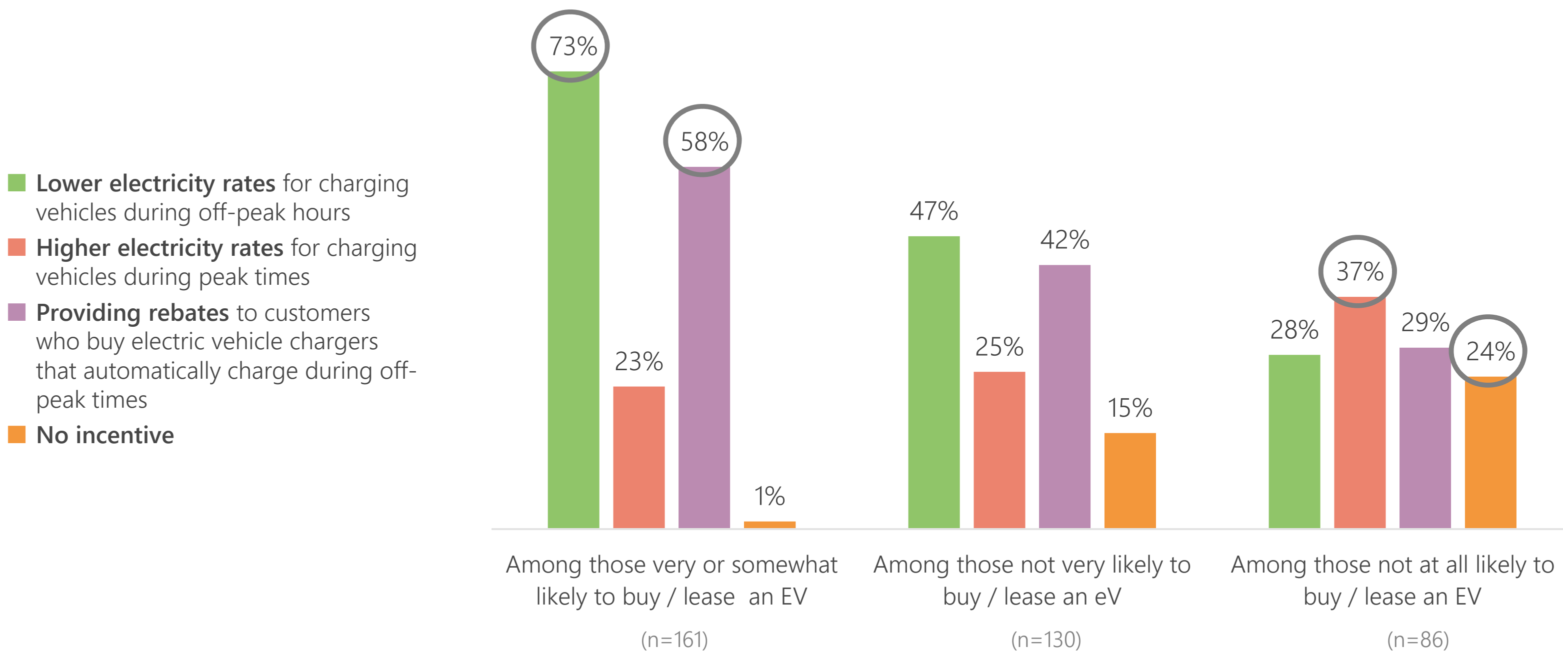
Base: Residential (379), Commercial (61)

B3. As more people use electric vehicles, the demand for electricity to charge them also increases, especially during the times of the day when people are more likely to charge their cars and use other appliances - such as in the morning and evening. During these peak times, more resources are needed to produce electricity, which could increase the cost of electricity for all customers. To help manage the demand for electricity, FortisBC is considering offering incentives to those who own or lease electric vehicles to charge their vehicles during off-peak periods, when demand for electricity is lower. Which of the following incentives, if any, should FortisBC offer?

PREFERRED INCENTIVE BY INTENT TO PURCHASE

Incentive preferences vary as a function of how likely residential customers are to get an electric vehicle in the next three years. Those who are likely get an EV have the strongest preference for lower electricity rates if they charge during off-peak times.

*This analysis could not be conducted among commercial customers due to limited sample sizes.



B2. In the next three years, how likely are you to buy or lease a fully electric vehicle? / B3. As more people use electric vehicles, the demand for electricity to charge them also increases, especially during the times of the day when people are more likely to charge their cars and use other appliances - such as in the morning and evening. During these peak times, more resources are needed to produce electricity, which could increase the cost of electricity for all customers. To help manage the demand for electricity, FortisBC is considering offering incentives to those who own or lease electric vehicles to charge their vehicles during off-peak periods, when demand for electricity is lower. Which of the following incentives, if any, should FortisBC offer?

SUMMARY OF FINDINGS

Rooftop Solar Panels

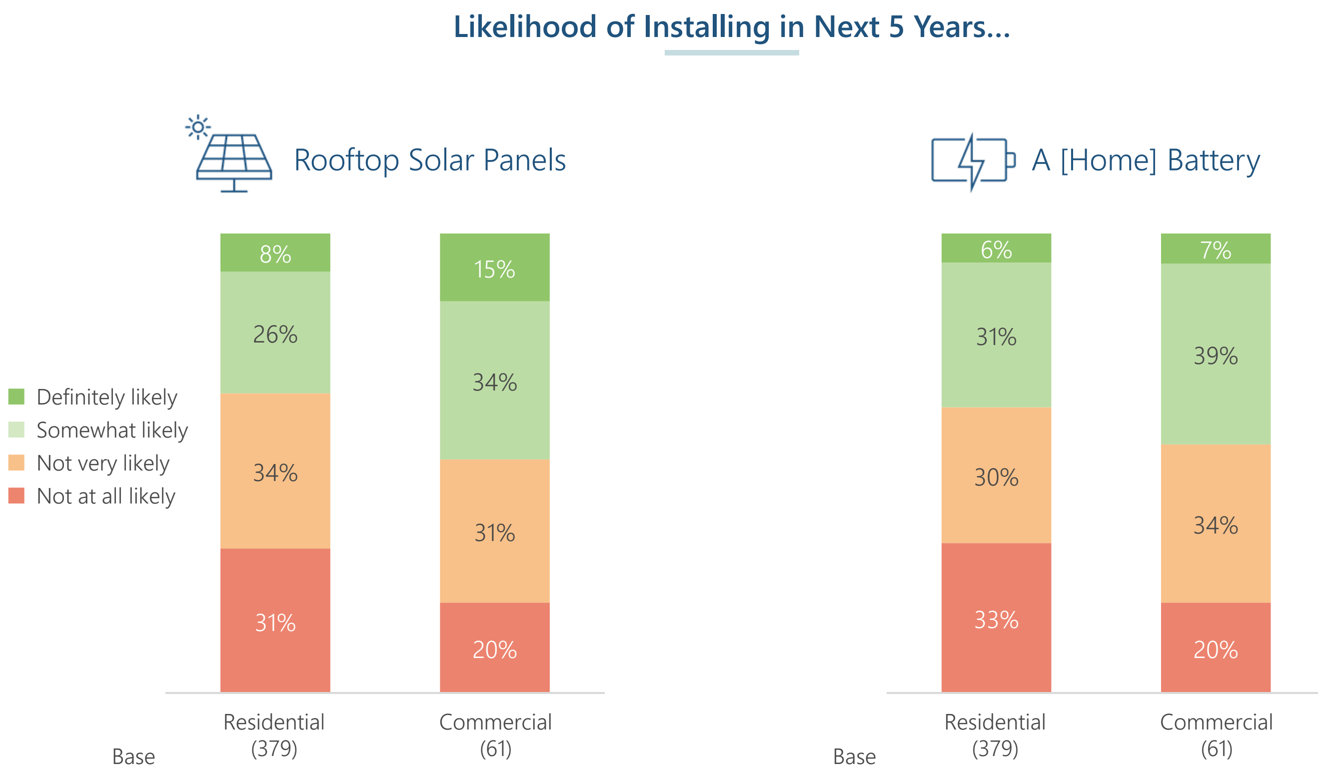
LIKELIHOOD TO INSTALL ROOFTOP SOLAR PANELS

One-third of residential customers (34%) indicate that they are likely to install rooftop solar panels in the next five years – with eight percent indicating that they are definitely likely to install them.

Intentions are somewhat stronger among commercial customers – with just under half (49%) indicating that they are either very (15%) or somewhat likely (34%) to install rooftop solar panels in the next five years.

Virtually all residential and commercial customers who are likely to install rooftop solar panels in the next five years are likely to install a home battery than can store solar energy (94% residential, 87% commercial).

A small percentage of residential customers mistakenly assume that they can install a home battery to store solar energy without installing solar panels. This is why the overall percentage of those who indicate that they are likely to install a home battery (37%) is slightly higher than the percentage who indicate that they are likely to install solar panels.



C1. When customers install solar panels on their roofs it means they require less electricity from FortisBC (as long as there is sunlight). And if customers also installed home battery units, they can store this solar energy generated during the daytime and use it later after the sun goes down. FortisBC is interested in customers' rooftop solar plans because they will impact how much energy FortisBC needs to provide in the future to meet customers' needs. In the next 5 years, how likely [are you / is your organization] to install…

REASONS FOR BEING LIKELY TO INSTALL ROOFTOP SOLAR PANELS

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Saving money and being environmentally friendly are the main reasons residential customers are likely to install solar panels.

Commercial customers are more squarely focussed on saving money.

Reasons For Being **Likely** to Install Rooftop Solar Panels

Among those definitely or somewhat likely to install solar panels in the next 5 years

	Residential	Commercial
Base	118	28*
Save money / cost effective	22%	**57%**
Better for environment / climate change / renewable resources	18%	**14%**
Like the idea / interested	16%	n/a
Would depend on cost to install	14%	n/a
Planning to in near future / will consider	8%	**7%**
Already have / had previously	7%	n/a
Save energy / provide energy	6%	**4%**
FortisBC / Hydro[1] too expensive / raising rates	6%	**4%**
Planning on building / buying more efficient home / can accommodate in future plans	6%	n/a

[1]Hydro refers to electricity
**Caution: Small base size (n<30)*
Note: only main mentions are shown (6% or more residential mentioning)
C2. And why are you [INSERT RESPONSE FROM C1.1] to install rooftop solar panels in the next 5 years?

REASONS FOR BEING NOT LIKELY TO INSTALL ROOFTOP SOLAR PANELS

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Cost is the main barrier to both residential and commercial customers installing rooftop solar panels.

Two-in-ten residential customers are prevented from installing solar panels because they rent or their strata doesn't allow them.

Reasons For Being **Not Likely** to Install Rooftop Solar Panels

Among those not very or not at all likely to install solar panels in the next 5 years

	Residential	Commercial
Base	257	29*
Cost / too expensive	43%	**45%**
Renting / Strata / Sr Residence / don't own home / not up to me	22%	**10%**
Not worth it / no payback / payback too long	12%	**10%**
Live in condo / apt / no roof / not up to me	10%	**3%**
Too old / retired / would not benefit	7%	**14%**
Concerns about battery safety, reliability, place to put them	6%	**7%**
Planning on moving / downsizing / not paying for someone else	5%	**3%**
Limited sunlight / not facing sunlight	4%	**7%**

**Caution: Small base size (n<30)*
Note: only main mentions are shown (4% or more residential mentioning)
C2. And why are you [INSERT RESPONSE FROM C1.1] to install rooftop solar panels in the next 5 years?

PREFERRED INCENTIVE APPROACH TO MANAGE ELECTRICITY DEMAND | ROOFTOP SOLAR PANELS

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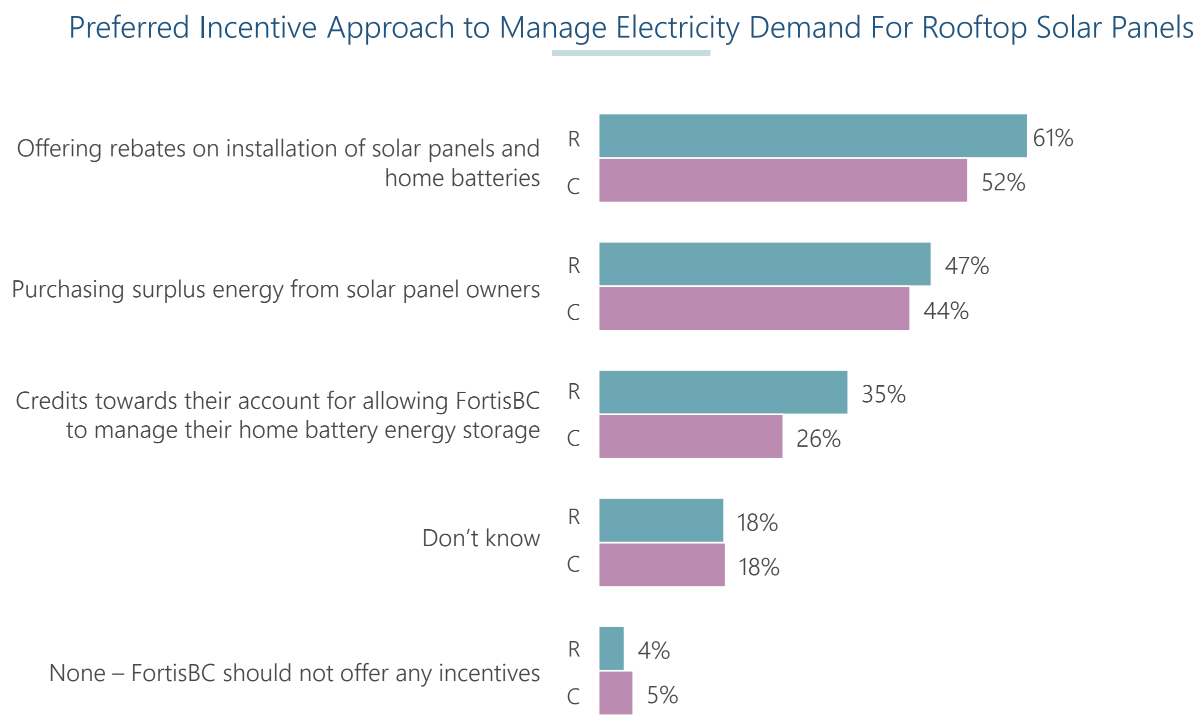
Residential and commercial customers have similar preferences when it comes to incentives for solar panels. Customers have the strongest preference for installation rebates, followed by the opportunity to sell surplus energy back to FortisBC, followed by receiving account credits for allowing FortisBC to manage their battery energy storage.



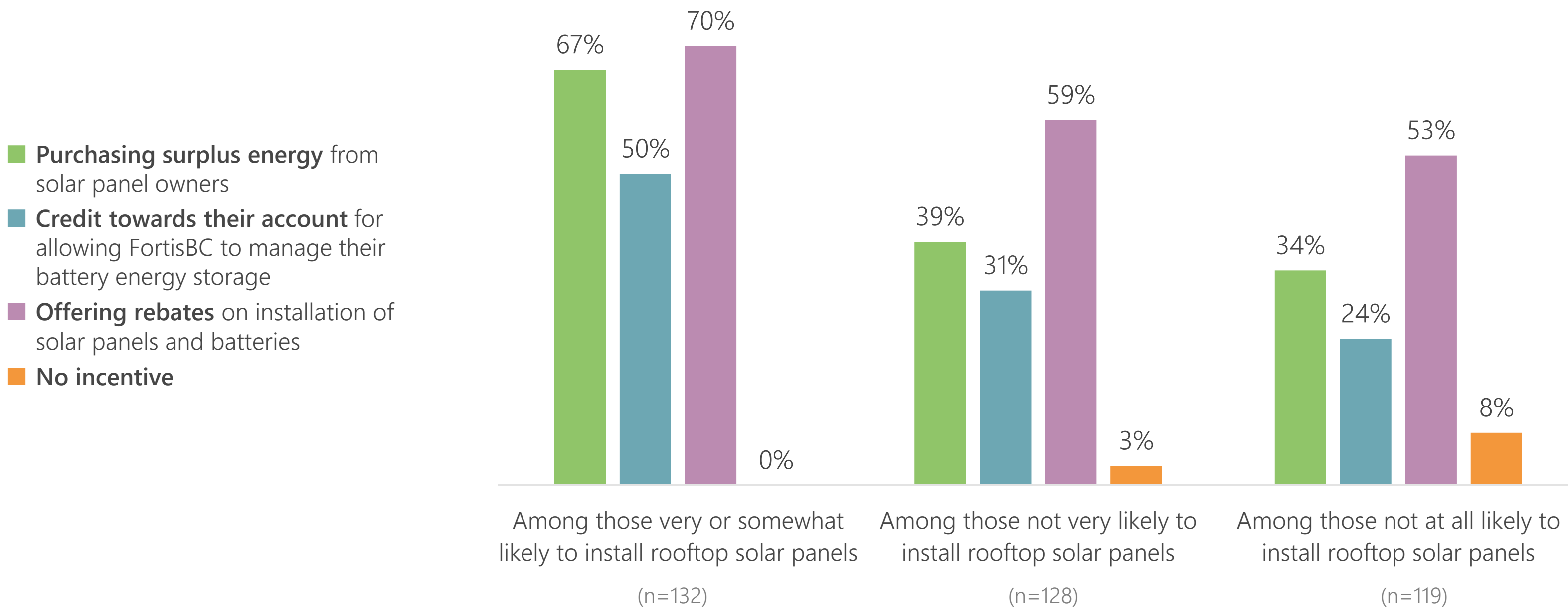
Base: Residential (379), Commercial (61)

C3. To help manage the demand for electricity, FortisBC is considering offering incentives to those who have rooftop solar panels with home battery storage. Which of the following incentives, if any, should FortisBC offer?

PREFERRED INCENTIVE BY LIKELIHOOD TO INSTALL

Incentive preferences vary as a function of how likely residential customers are to install solar panels. Those who are likely to install solar panels have equally strong preferences for rebates and being able to sell surplus energy to FortisBC. Only half consider account credits for allowing FortisBC to manage their home battery energy storage to be appealing.

*This analysis could not be conducted among commercial customers due to limited sample sizes.



C1. In the next 5 years, how likely are you to install rooftop solar panels? / C3. Which of the following incentives, if any, should FortisBC offer?

Appendix

RESPONDENT PROFILE | RESIDENTIAL

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Gender (base)	Residential 379
Female	52%
Male	48%
Other or Non-Binary	0%
Age	
18-34	22%
35-44	14%
45-54	16%
55-64	19%
65-74	20%
75+	9%
Household Composition	
Single with no children at home	25%
Couple with no children home	48%
Family with children under at home	18%
Family with adult children at home	7%
Other	2%
Prefer not to say	0%
Household Size	
1 person	21%
2 people	51%
3 people	13%
4 people	13%
5 people	2%
6 people	1%
7 or more people	0%

Issuer of Electricity Bill (base)	Residential 379
FortisBC	82%
City of Grand Forks	0%
City of Nelson	5%
City of Penticton	10%
District of Summerland	2%
Household Income	
Low Income	24%
Moderate Income	60%
High Income	16%

RESPONDENT PROFILE | RESIDENTIAL

Home Ownership (base)	Residential 379
Own	79%
Rent	21%
Dwelling Type	
Single-detached house	60%
Condominium	8%
Apartment	10%
Townhouse	11%
Duplex or triplex	3%
Suite contained within a house	0%
Mobile or manufactured home	5%
Basement suite	1%
Other	1%
Prefer not to answer	0%
Main Heat Source For Home	
Natural gas (furnace or boiler)	67%
Electric baseboards	18%
Air source heat pump	6%
Ground source heat pump	5%
Oil	0%
Propane	0%
Wood	2%
Solar	0%
Other	2%

Highest Level of Education (base)	Residential
Elementary school	0%
Some high school	2%
High school graduate	12%
Some college or technical school	12%
College or technical school / CE	26%
Some university	10%
University graduate	20%
Post graduate studies (masters / doctoral)	17%
Prefer not to answer	1%
Employment Status	
Self-employed	9%
Employed full-time (30 or more hours a week)	39%
Employed part-time (less than 30 hours a week)	8%
Currently not working	3%
Student	0%
Retired	33%
Taking care of family / homemaker	5%
Taking care of parents / extended family or other dependents	0%
Disabled / on disability	1%
Other	1%
Prefer not to answer	1%

RESPONDENT PROFILE | COMMERCIAL

Type of Building/Facility/Business (base)	Commercial 61
Automotive	7%
Educational Facility	2%
Food Store	2%
Health Care Facility	2%
Lodging	3%
Manufacturing/Agriculture	11%
Office Building and Mixed-use Building	10%
Public Assembly	2%
Restaurant	5%
Retail and Personal Services	10%
Warehouse	3%
Other	43%
Don't know	2%
Building Ownership	
Own or co-own the **entire** building(s) it occupies	61%
Own or co-own **part** of the building(s) it occupies	8%
Lease or sub-lease the building(s) it occupies	30%
Don't know	3%

Number of Buildings Occupied by Organization (base)	Commercial 61
1	57%
2	16%
3	13%
4	3%
5 or more	8%
Don't know	2%
Amount of Space Occupied by Organization (ft^2)	
2,000 sqft or less	28%
2,001 to 4,000 sqft	23%
4,001 to 10,000 sqft	28%
10,001 sqft or more	21%
Main Heat Source For Business	
Natural gas (furnace or boiler)	62%
Electric baseboards	16%
Air source heat pump	13%
Propane	2%
Ground source heat pump	0%
Oil	0%
Wood	0%
Solar	0%
Other	7%

RESPONDENT PROFILE | COMMERCIAL

Company Age (base)	Commercial 61
Less than 2 years	3%
2 years to less than 5 years	21%
5 years to less than 10 years	11%
10 years to less than 20 years	18%
20 years or longer	41%
Don't know	0%
Prefer not to answer	5%
Number of Full Time Employees	
1 employee	20%
2 to 19 employees	59%
20 to 50 employees	10%
51 to 150 employees	5%
151 to 300 employees	2%
300+ employees	0%
Don't know	5%

Role at Organization (base)	Commercial 61
Owner	39%
Accountant/Controller	18%
Business manager/ General Manager/ Administrator	18%
CEO/President	13%
Partner	7%
COO	2%
Vice President/ Senior executive	2%
CFO	0%
Other	2%

WHAT MAKES THIS OBJECTIVE THE MOST IMPORTANT?

	Ensures the cost of electricity is as low as possible		Ensures reliable power for customers		Includes conservation and energy management solutions to reduce the amount of energy used by customers		Includes strategies to reduce greenhouse gas emissions		Focusses on job creation in BC communities	
	Residential	Commercial	Residential	Commercial	Residential	Commercial	Residential	Commercial	Residential	Commercial
Rated the attribute as most important	**39%**	**33%**	**30%**	**43%**	**7%**	**7%**	**13%**	**7%**	**4%**	**0%**
Base	150	19*	115	24*	29*	4	38	4	8*	0
It is expensive / electricity costs are increasing (as compared to wages and pension)	**35%**	**26%**								
I have a fixed income / don't make a lot of money	**29%**	**11%**	0%	0%	0%					
To save money / keep cost of living low / affordability	**26%**	**5%**								
Cost / money is the most important	**7%**	**53%**	1%		2%					
Electricity is essential / cannot live without it	**8%**	**5%**	**39%**	**13%**			0%			
To keep family home running e.g. food preservation / warmth	1%	**5%**	**22%**	0%						
Dependable service / ensure supply of power / nothing else matters if it's not reliable		**5%**	**20%**	**83%**	0%					
Providing power is the sole purpose of the corporation (Fortis)		0%	**12%**	**8%**						
Don't want service interruptions / blackouts			**10%**	**17%**		Insufficient base		Insufficient base	Insufficient base	n/a
For medical / health / and safety reasons		**5%**	**8%**	**8%**			8%			
To reduce our emissions / usage			1%		**49%**		**20%**			
The environment / conservation is the most important	0%		0%		**19%**		4%			
Long term sustainability / for future		0%	1%		**17%**		**24%**			
Climate change / global warming			0%	0%	2%		**31%**			
Killing our planet / we need to save the environment			0%		3%		**15%**			
Supporting the local economy		**5%**	1%		0%		0%			
Job creation is the most important		0%	0%							

*Caution: small base size. Results are directional only.

A1B. You rated [INSERT OPTION] as more important than the other three. What makes this objective the most important one for you? [OPEN-END] / A1D. What makes this objective the most important one for you? [OPEN-END]

REASONS FOR CHOOSING INCENTIVE APPROACH

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	Lower electricity rates for charging vehicles during off-peak times		Providing rebates to customers who buy electrical vehicle chargers that automatically charge during off-peak times		Higher electricity rates for charging vehicles during peak times	
	Residential	Commercial	Residential	Commercial	Residential	Commercial
Base	140	8	108	26*	65	7
Cost savings	42%	Insufficient base	9%	12%	9%	Insufficient base
Encourage usage during off-peak hours	14%		7%	0%	1%	
Rebates work / money back	0%		24%	31%	0%	
Encourages buying electric vehicles	4%		12%	0%	0%	
Customer has control / can schedule charges when they want	6%		9%	4%	0%	
Easy to do	4%		8%	19%	0%	
Spreads load from peak times	2%		4%	4%	1%	
Encourages energy conservation	0%		0%	0%	1%	
More of a friendly incentive (instead of punishing users with higher costs)	7%		7%	8%	0%	
Negative reinforcement / would discourage use during peak times	0%		0%	0%	40%	
People don't want to pay extra	2%		1%	8%	18%	
Cost is user-based	0%		1%	4%	16%	
Electric vehicles aren't a good idea / don't like electric vehicles	0%		0%	4%	12%	
Responsibility for the charges are on those who own electric cars	2%		1%	4%	6%	

**Caution: small base size. Results are directional only.*
B5. Why do you think that option would be most effective?

Appendix O

GUIDEHOUSE PATHWAYS STUDY

PATHWAYS FOR BRITISH COLUMBIA TO ACHIEVE ITS GHG REDUCTION GOALS

Submitted by:
Guidehouse
100 King Street West, Suite 4950
Toronto, ON M5X 1B1
416.777.2440 | guidehouse.com
Reference No.: 205334
August 2020

NAVIGANT
A Guidehouse Company

PREPARED FOR

FORTIS BC™
Energy at work

DISCLAIMER

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FOREWORD

In 2018, FortisBC Energy Inc. (FortisBC) developed its Clean Growth Pathway to 2050, which outlined actions the company would take to help British Columbia (BC) achieve its greenhouse gas (GHG) emissions targets. The Clean Growth Pathway takes a diversified approach to GHG reduction by using BC's electricity and gas infrastructure. As owners and operators of reliable gas, electric, and thermal energy infrastructure, FortisBC will have a key role in leading the transition to lower carbon energy. As a regulated utility, FortisBC is accountable to the BC Utilities Commission and obligated to serve the interests of over 1 million homes and businesses across BC.

The provincial government's CleanBC plan aims to significantly reduce provincial GHG emissions and strengthen BC's economy. FortisBC delivers more energy to consumers than any other entity in the province and will be critical to ensuring BC can efficiently, reliably, and affordably achieve its plan. To help do so, FortisBC commissioned Guidehouse to chart a viable path for BC to achieve its 2050 targets while identifying solutions that are in the best interest of its customers.

FortisBC and Guidehouse worked with the BC Ministry of Energy, Mines and Petroleum Resources and the Climate Action Secretariat to ensure that CleanBC, provincial data, and projects are included in the analysis as much possible.

The goal of this report is to generate dialogue and solutions-focused thinking on how BC can achieve the transition to a lower carbon energy system while building understanding on factors such as maintaining a flexible, reliable, and resilient provincewide energy system. The report's analysis presents two pathways to achieving GHG emission reductions; neither reflect what is an expected future outcome by either Guidehouse or FortisBC. FortisBC welcomes an ongoing discussion on the merits and key challenges of the various pathways available. FortisBC has a long-standing role in serving British Columbians and, by engaging with the communities it serves, the company aims to continue providing low carbon, affordable, and reliable energy in the decades to come.

Guidehouse is a leading global provider of consulting services to the public and commercial markets with broad capabilities in management, technology, and risk consulting. We help clients address their toughest challenges with a focus on markets and clients facing transformational change, technology-driven innovation, and significant regulatory pressure. Across a range of advisory, consulting, outsourcing, and technology/analytics services, our teams help clients create scalable, innovative solutions that prepare them for future growth and success. Headquartered in Washington, DC, the company has more than 7,000 professionals in more than 50 locations. Guidehouse recently completed the Gas Decarbonisation Pathway 2020-2050 study for the Gas for Climate consortium; the study analyzes the transition toward the lowest cost climate-neutral system in Europe by 2050.

1. EXECUTIVE SUMMARY

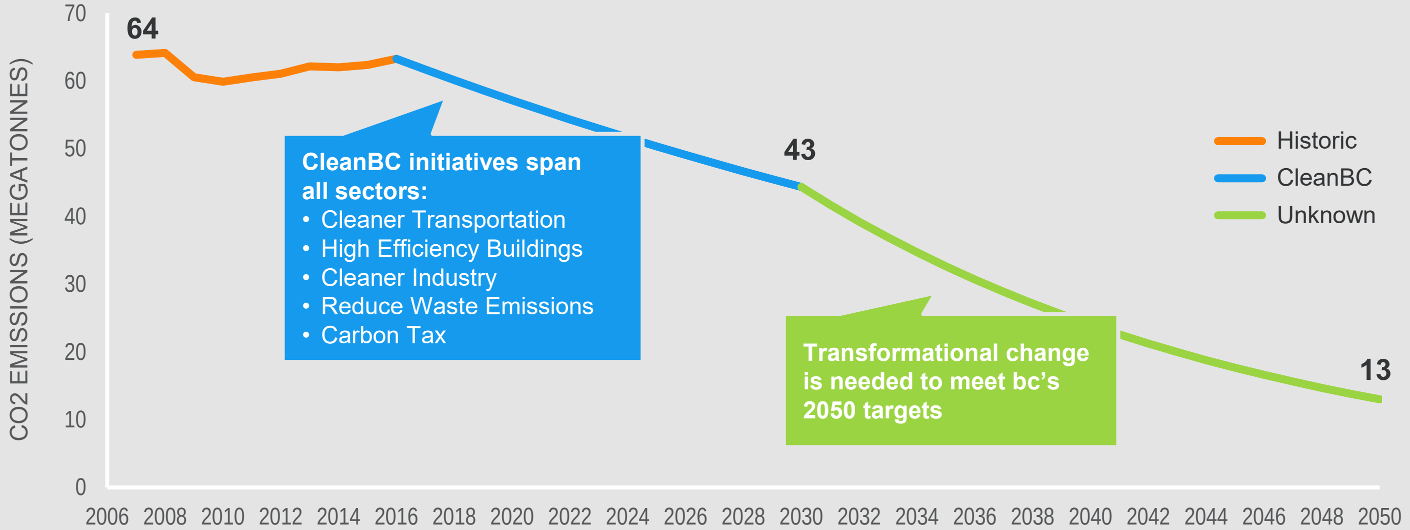
As part of its Climate Change Accountability Act, British Columbia (BC) has committed to reducing greenhouse gas (GHG) emissions to 80% below 2007 levels by 2050. The CleanBC plan puts the province on a path toward this goal, but only sets in action initiatives designed to meet a 2030 target (30% reduction below 2007 levels).[1] The pathway to meeting the 2050 goal is definable but a challenge. (Figure 1).

FortisBC commissioned Guidehouse to explore the role of the company's energy delivery system and the advantages that system could provide under ambitious decarbonization in the province. Over the past several years, Guidehouse has conducted detailed analyses of the role of utilities in decarbonization in Europe and North America.

Guidehouse experts have consistently found that a moderate, targeted approach to electrification tied with deployment of renewable gases while fuel switching away from petroleum is the most cost-effective and resilient method to achieve a lower carbon energy future.

To estimate the gas system's societal value, Guidehouse developed two energy pathways: an Electrification Pathway that focuses on deep electrification of all sectors, and a Diversified Pathway that includes a mix of expanded electrification and advances in low carbon gases and gas delivery infrastructure. The Diversified Pathway reflects the climate initiatives included in FortisBC's Clean Growth Pathway to 2050.

FIGURE 1. BC GHG EMISSIONS AND TARGETS

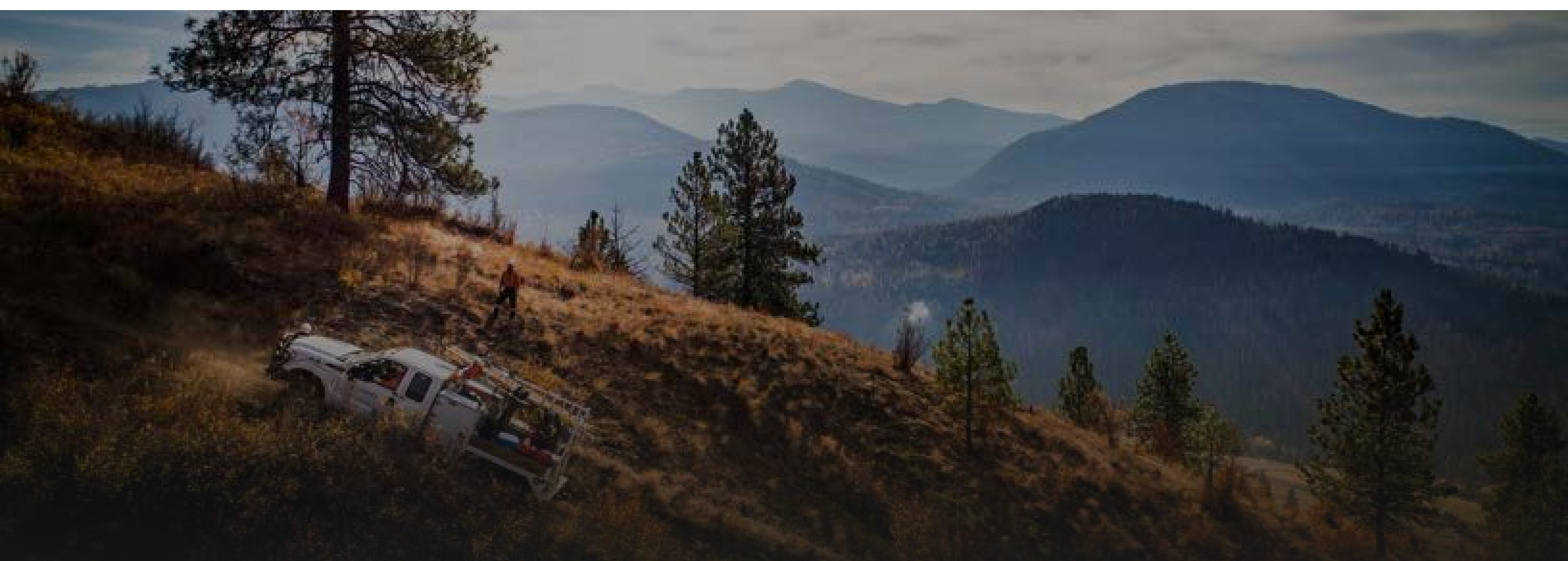


Source: Government of Canada – Canada's Greenhouse Gas Inventory; Government of British Columbia – CleanBC; Guidehouse Analysis

[1] The 30% reduction represents an adjustment of the interim 40% reduction by 2030 target, originally set in the Climate Change Accountability Act. The adjustment aligns with the provincial government's CleanBC plan, while the 80% reduction by 2050 target set in the Climate Change Accountability Act still stands.

The study's core conclusions are as follows:

- The Electrification and Diversified Pathways both achieve significant domestic GHG reductions in-line with the provincial government's 2050 targets.[2]
- The Diversified Pathway uses gas infrastructure and saves in excess of $100 billion by 2050.
- Both scenarios face challenges, including massive energy infrastructure deployment, and require significant technological improvement.
- Peak demand is an important factor that needs to be considered.
  - The Diversified Pathway will more efficiently meet customers' peak energy use.
- Peak demand in the Electrification Pathway would require thousands of megawatts of firm renewable electricity generation and energy storage to be built, which is made more difficult by the challenges of developing new large-scale hydroelectric power stations.
- Policy decisions made today will have long-term implications beyond the 2030 time horizon of CleanBC. Consequently, BC's approach to climate policy should consider how factors like peak demand will be met well beyond 2030 and what the long-term implications will be for costs.
- Hydrogen can be a key low or no carbon fuel that can be injected into the existing gas system. Hydrogen produced from renewable electricity can be stored in the gas system for use in peak times, which helps increase the value of renewable electricity in decarbonization pathways.
- The gas system provides valuable reliability and resiliency to the province's energy system. As decarbonization progresses, this resiliency increases in importance. As the gas system grows into serving new markets where decarbonization is more difficult, the system will be relied on as a fundamental tool. For example, liquefied natural gas (LNG) for international marine vessels is one of the primary near-term options to make meaningful GHG reductions.

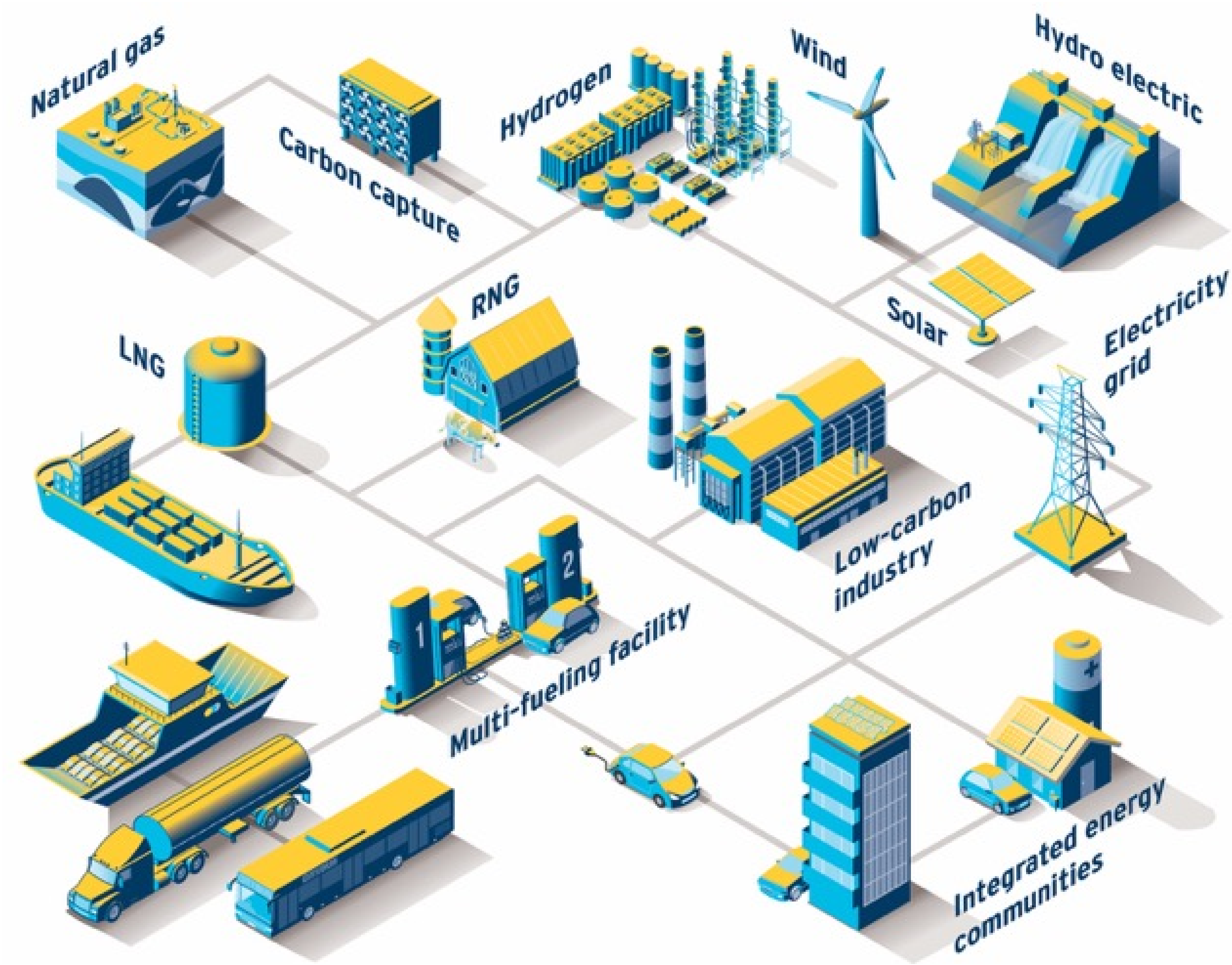


[2] Both pathways developed in this study achieve 95% of the domestic reductions required by 2050.

FortisBC's Clean Growth Pathway to 2050 is a diversified and flexible approach that supports BC's energy needs and GHG reduction targets. In 2050, gas infrastructure transports renewable natural gas (RNG), low carbon hydrogen (largely made from renewable electricity), and synthetic methane developed from captured carbon and hydrogen as well as natural gas. The system delivers this low carbon energy for specific end uses with high energy needs: space and water heating, medium and heavy duty (MHD) road vehicles, marine transportation, and industrial processes (Figure 2).

The Clean Growth Pathway also supports targeted electrification. Excess renewable power that would otherwise be curtailed or stored using expensive applications such as batteries or mechanical storage could instead produce hydrogen for use in the gas system.[3] In addition to providing flexible peak capacity, gas systems are key in stabilizing and securing the power grid, underpinning firm dispatchable electricity capacity and providing longer duration and affordable energy storage. Furthermore, Guidehouse's Gas for Climate study[4] demonstrates that deploying gas-fired dispatchable power (hydrogen and biomethane) as compared to more expensive solid biomass-fired dispatchable power can lead to annual cost savings of €54 billion across Europe.

FIGURE 2. FORTISBC'S CLEAN GROWTH NETWORK TO 2050



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[3] It is unlikely that battery storage alone will be sufficient to meet the energy storage needs of the Electrification Pathway.

[4] Guidehouse, *Gas Decarbonisation Pathways 2020–2050*, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

POLICY IMPLICATIONS

To moderate costs, reduce risks, enhance GHG reduction options, and maintain a reliable provincial energy system while achieving the 2050 goal, a number of outcomes need to be pursued:

- **Policy should be focused on fostering an integrated low carbon energy system.** It is critical to acknowledge that electricity and gas complement each other—both are needed and can reinforce each other. Taking a systemwide view of energy infrastructure that recognizes the value and coordinates the gas and electric systems to manage decarbonization affordability and resiliency provides the greatest overall benefits for BC.
- **Focus electrification efforts where they are most effective** to maximize limited ability to expand clean and firm generation resources. For example, in the passenger transport sector.
- **Prioritize the expansion and supply of renewable gas through a coordinated strategy** that invests in research and development (R&D), addresses policy barriers, and offers incentives for renewable gas development.
- **Support new technologies** that leverage the GHG reduction potential of the gas system including gas heat pumps, compressed natural gas (CNG)- and LNG-powered commercial vehicles, and carbon capture and storage.
- **Maintain the operational and financial health of the gas system** to allow for continued investment in infrastructure and programs that align with the 2050 target.
- **Leverage the potential of the gas sector to reduce GHG emissions internationally** through LNG marine refuelling (referred to as bunkering) and LNG exports.
- **Consider the cost and source of energy post-2030** in current and ongoing policy decisions.

2. INTRODUCTION

This report discusses potential pathways for BC to achieve its 2050 GHG reduction target, focusing on the roles of the gas and electric systems in the province. The report takes a BC-specific view of decarbonization considering the province's unique energy systems and resources. The objective is to discuss the tradeoffs of different approaches and to emphasize important points to consider when embarking on a long-term decarbonization pathway. The report is organized into the following sections:

- **BC's Energy Systems:** Focuses on the roles of energy delivery infrastructure and key operational and practical considerations.
- **Study Approach:** Describes the methodology used to analyze decarbonization pathways for BC. This section also outlines the main differences between the pathways and the key inputs and assumptions that went into the analysis.
- **Study Results – Side-by-Side Comparison of Pathways:** Compares the outcomes of the analysis, pathways, and key considerations.
- **Other Benefits of Using the Gas System for Decarbonization:** Discusses other benefits, in addition to results from the analysis of decarbonization pathways, that emphasize the importance of the gas delivery system.
- **Conclusions:** Provides general conclusions of the study.

3. BC'S ENERGY SYSTEMS

BC has an expansive energy system that includes the following:

- A large electrical grid primarily administered by BC Hydro and FortisBC electric
- A gas system operated primarily by FortisBC gas and Pacific Northern Gas
- Vast amounts of renewable electric and natural gas resources

BC has a large supply of biomass that could be used to sustainably produce renewable energy such as RNG. BC is connected to the US and other Canadian provinces and territories through electric interties and natural gas pipelines.

BC'S NATURAL GAS AND ELECTRIC SYSTEMS TODAY

FortisBC operates approximately 49,000 km of natural gas transmission and distribution pipelines in BC.

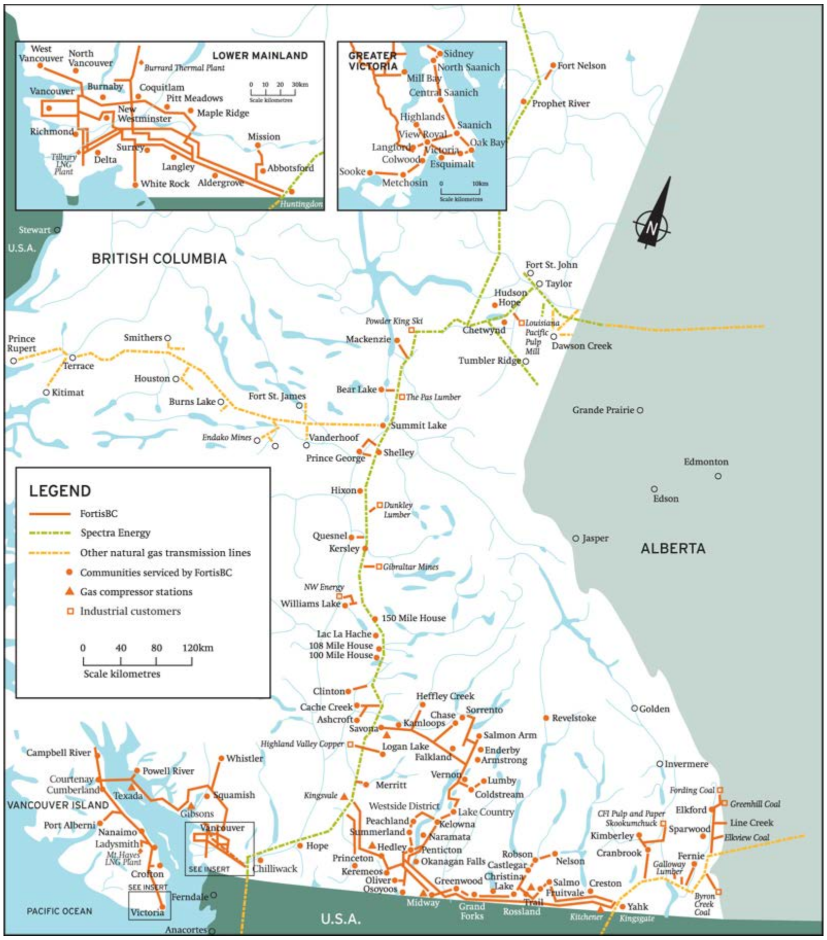
This infrastructure, along with the natural gas pipelines owned by Pacific Northern Gas, TC Energy, Enbridge, and other organizations, spans across the province. The system has multiple import/export points on the borders between Alberta, Yukon, and the US, as well as LNG on the west coast. All of this infrastructure is part of an integrated provincial system that represents billions of dollars of investment to supply natural gas to domestic markets and for export.

BC depends on energy delivered by the natural gas system (Figure 4). Over 30% of BC's total energy consumption[5] is transported through gas infrastructure.[6] Natural gas represents approximately 50% of residential and commercial end-use demand and almost 40% of industrial end-use demand in BC. The extensive coverage and interconnectivity of the gas network makes the system a critical vehicle to deliver low carbon energy to British Columbians.

BC also has an expansive electric system primarily administered by BC Hydro and FortisBC.

[5] Includes upstream energy consumption
[6] Canada Energy Regulator, "Canada's Energy Future 2019: Energy Supply and Demand Projections to 2040, Macro Indicators," accessed March 2, 2020.

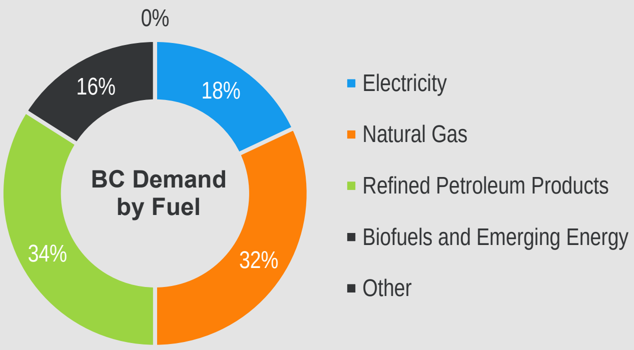
FIGURE 3. NATURAL GAS INFRASTRUCTURE SERVING BC

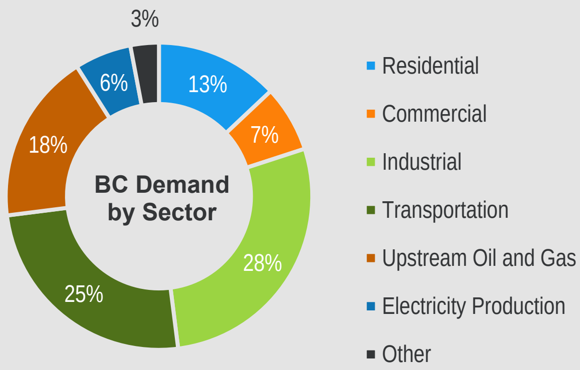


Combined, the two utilities serve over 2.16 million electricity customers through over 86,000 km of electric transmission and distribution lines. BC's electricity system is part of the Northwest Power Pool and is connected to Alberta and the US. Approximately 90% of BC's electric capacity is made up of hydro, with the remainder from wind, other renewables, and natural gas for peak electricity supply.

BC has large domestic resources of natural gas and electricity. In 2018, net electricity imports made up 2% of domestic generation. Over 90% of the natural gas consumed in BC is produced in BC (remaining supply is imported from Alberta). However, BC's total natural gas production is greater than its domestic demand and is exported to Alberta or the US. BC relies on deliveries from other provinces and from imports from the US for refined petroleum products like gasoline and diesel. BC imports almost double the volume of gasoline and diesel from Alberta and the US then it refines in domestic refineries.

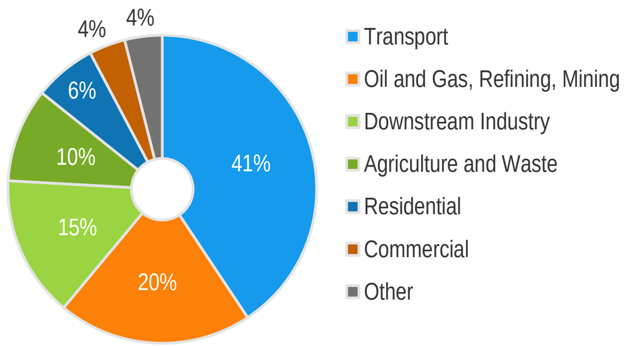
FIGURE 4. BC 2019 ENERGY DEMAND





Source: Canada Energy Regulator – Canada's Energy Future 2019 and CanESS (CANSIM)

FIGURE 5. BC EMISSIONS BY SECTOR



Source: BC GHG Inventory

The transport sector has the largest emissions footprint in BC, consisting of 41% of all GHG emissions (Figure 5). Industry, including oil & gas extraction and downstream manufacturing, makes up 35% of provincial GHG emissions. Residential and commercial buildings make up a comparatively smaller 10% of provincial GHG emissions.

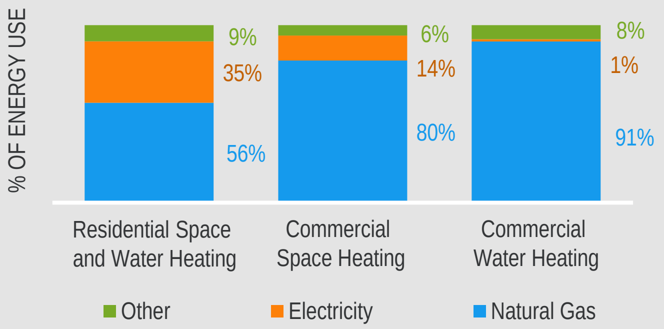
A focus on reduction of emissions across all sectors will be required to achieve the reductions targeted by 2050. Given the significant emissions associated with the transportation and industrial sectors, substantial efforts will be required in these sectors.

GAS SYSTEM IN BC ALLOWS FOR FLEXIBLE SUPPLY, SECURITY, AND STORAGE

Natural gas is one of the most flexible forms of energy because it can be stored relatively inexpensively for long periods of time. This flexibility allows the gas system to deal with large fluctuations in demand and volume, which is common in BC due to the seasonal nature of space and process heating loads in the province.

Most residential and commercial energy customers in BC depend on natural gas for space and water heating as well as cooking (Figure 6). Natural gas is also well-suited for combustion for heat. Many industries rely on natural gas because they can handle the high temperatures used in industrial applications. As well, natural gas use as a transport fuel for commercial vehicles and marine vessels is growing.

FIGURE 6. BC SPACE AND WATER HEATING BY SOURCE, 2016



Natural gas demand peaks in the winter and declines in the summer. Demand can be handled by the existing gas system seasonally. Figure 7 highlights the gas system's role in meeting peaks—i.e., the coldest days of the year.[7] On a summer day, throughput is approximately 3,000 MW, representing mostly water heating and industrial energy consumption. On an average winter day when most homes are using their gas heating systems, throughput on the system can increase by over three times and approaches the equivalent of 10,000 MW in electrical terms.

The gas system is designed to deliver significant volumes of energy to meet demand on very cold days. For example, on the coldest day in 2019, the volume of gas delivered was 40% higher than an average winter day and over three times the energy delivered on a summer day.

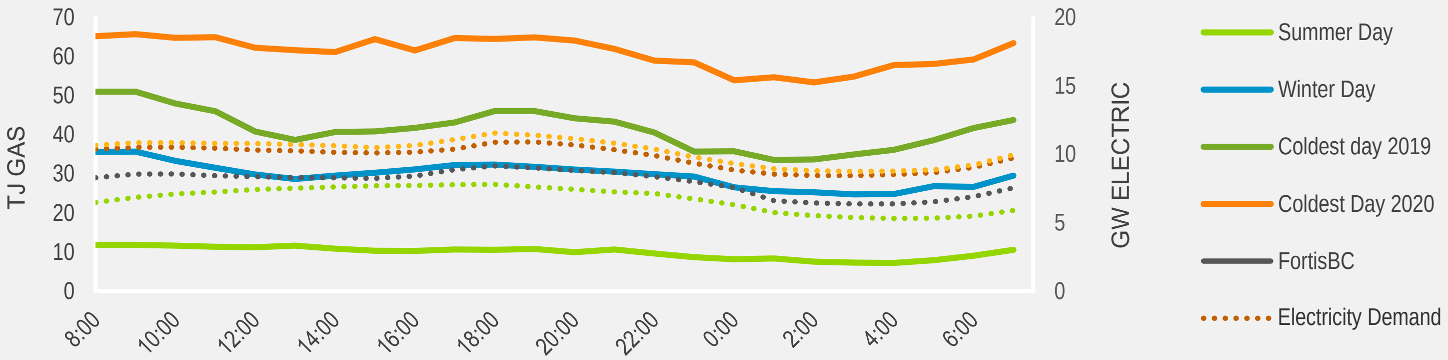
On a very cold day, such as January 14, 2020 when temperatures in the Lower Mainland approached -10°C, the energy delivered by the gas system can be double an average winter day and 50% higher than the coldest day in 2019.

The gas system provides critical versatility to meet peak energy demand. The electricity system needs to generate enough electrical energy at any one time to match the amount of consumption, whereas the gas system can store the energy and regulate flow on the system to meet demand. This means that electric systems need to have enough generating capacity to meet peaks while the gas system needs enough storage and pipeline throughput.

On January 14, 2020, the peak volume of gas delivered between 7:00 a.m. and 8:00 a.m. was equivalent to over 18,000 MW of electrical generating capacity, approximately 60% greater than the peak on the electric system during the same day and 50% larger than the entire hydroelectric generating capacity owned by BC Hydro (11,900 MW). While January 14, 2020 was one of the highest demand days on the gas system, some capacity remained to be distributed if demand continued to increase.

One of the gas system's main strengths is its ability to meet extreme peaks. It can store, ramp up, and deliver high volumes of energy on short notice and can handle large changes in volumes over time without operational, reliability, or financial strain. The electricity system would require significant investment to meet the province's space and water heating needs seasonally and daily in the electrification scenario.

FIGURE 7. HOURLY GAS AND ELECTRICITY DEMAND IN BC



Source: FortisBC

[7] Figure 7 represents actual natural gas flows in FortisBC's service territory. Electricity demand is gross telemetered load on BC's electricity transmission system.

The ability of natural gas to be stored adds to its value as a reliable energy source. FortisBC's affiliate, Aitken Creek Gas Storage, owns a large underground natural gas storage facility, which has over 90 PJ of gas storage to provide seasonal storage.[8] Gas storage is low cost—on average, the cost of storage at Aitken Creek is approximately $1 per GJ or 0.3 cents ($0.003) per kilowatt-hour in electricity storage equivalent.

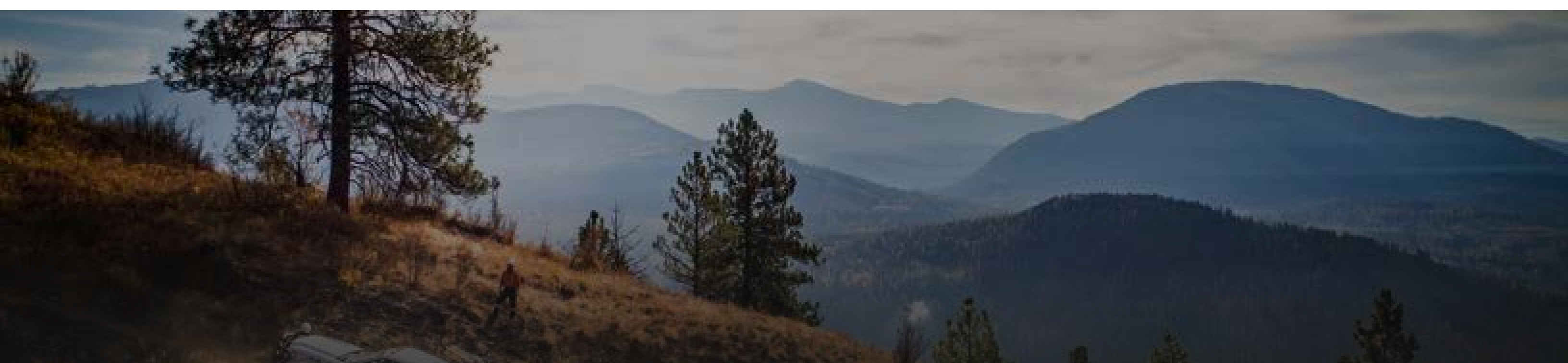
Although electric storage costs are falling significantly, they are still much more costly between $50 and $90 per GJ equivalent comparatively.[9] In addition to Aitken Creek, several smaller natural gas storage facilities exist throughout BC. Natural gas is injected into seasonal storage in summer months when demand is low and is withdrawn in the winter when demand for natural gas is higher. Low cost gas storage allows for year-round gas production and for production to deviate from gas consumption. Storage more effectively manages the costs of gas production and disruptions in production when they occur.

Gas can also be stored in the transmission pipelines themselves—typically referred to as line pack. Transmission pipelines operate within a minimum and maximum pressure as determined by the volume of gas in the line. Line pack can allow segments of the gas line, for short periods in a day, to deliver more gas per hour to consumers than is being delivered per hour by suppliers.

Line pack poses small incremental costs and can be cycled, meaning it can be maintained or used with relative ease. The estimated seasonal variation in line pack of FortisBC's transmission pipelines between a period of high demand and low demand can be as high as 0.15 PJ. In electrical terms, this would be equivalent to 40 GWh—over 30 times larger than the entire electrical energy storage capacity of utility-scale batteries in the US in 2018.[10]

Natural gas and the gas delivery system can serve a critical role in extreme conditions. Global climate change has resulted in the increased prevalence of wildfires, which can severely impact electricity systems. California has experienced severe wildfires in recent years, including a 2019 wildfire that resulted in mass evacuations and blackouts, leaving millions of people without electricity.[11] A study by the California gas and electric utilities indicated that Southern California Gas' natural gas storage assets has played a vital role in addressing emergency situations like extreme weather and wildfires.[12]

Over the past 20 years, the average number of hours a customer is without electric power in a year has increased. With the large expected growth in electricity demand, this trend is expected to continue, highlighting the importance of natural gas use as a heating source; its use is especially important during the cold winters experienced in many parts of BC.



[8] Canada Energy Regulator, "Market Snapshot: Where does Canada store natural gas," May 23, 2018, https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2018/05-03whrdscncstrngrlgs-eng.html.

[9] Lazard, *Lazard's Levelized Cost of Storage Analysis—Version 5.0*, November 2019, https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.

[10] U.S. Energy Information Administration, "Most utility-scale batteries in the United States are made of lithium-ion," Today in Energy, October 30, 2019, https://www.eia.gov/todayinenergy/detail.php?id=41813.

[11] Newburger, Emma, "More than 2 million people expected to lose power in PG&E blackout as California wildfires rage," CNBC, October 26, 2019, https://www.cnbc.com/2019/10/26/pge-will-shut-off-power-to-940000-customers-in-northern-california-to-reduce-wildfire-risk.html.

[12] California Gas and Electric Utilities, *2018 California Gas Report*, 2018, https://www.socalgas.com/regulatory/documents/cgr/2018_California_Gas_Report.pdf

4. STUDY APPROACH

The Electrification and Diversified Pathways developed in this study achieve 95% of the domestic reductions required by 2050.[13] The remaining emissions are assumed to be addressed with continued advances in technology and changing consumer behaviors, as well as emissions reductions related to non BC-specific initiatives (e.g., commercial airline emissions reductions). The pathways differ in the extent to which renewable electricity and low carbon gas play a role in the scenarios. The Electrification Pathway aims to increase the use of electricity for all applicable end uses, so renewable and low carbon natural gas use is limited to those sectors where no alternatives are available. In the Diversified Pathway, renewable and low carbon natural gas is used to its full potential.

Guidehouse worked closely with FortisBC to characterize initiatives under each pathway that could contribute to reducing GHG emissions. The goal of the characterization was to identify, understand, and define GHG mitigation options relevant for BC and to develop a common understanding of initiatives to implement in the model and analyze deeply. Guidehouse leveraged other studies it conducted on the role of the gas system in decarbonization, as well as FortisBC's internal research group and BC-specific research, to build a set of technologies and initiatives that were characterized and input into the Canadian Energy Systems Simulator (CanESS), an economy-wide model. Guidehouse also used data from the BC Climate Action Secretariat to align modelling assumptions with those used in the CleanBC climate plan. Figure 8 highlights how initiatives were developed across four major sectors and modelled into the two pathways, which were compared to a business-as-usual (BAU) scenario.

FIGURE 8. PATHWAY DEVELOPMENT AND MODELLING

1. GHG MITIGATION INITIATIVES

BUILDING EFFICIENCY
- Improved building envelopes
- Building automation and controls

TRANSPORTATION
- # light duty EVs
- # heavy duty EVs and CNG vehicles
- # trips on E-public transit
- # of CNG buses

2. PATHWAY MODELING

FUEL SWITCHING
- Building heating and cooling
- Floor space serviced by heat pump
- Water heated with heat pump
- Floor space serviced by alternative fuels

RENEWABLE GAS
- Volume of RNG supply
- # of vehicle KMs fueled by RNG
- Litres of ethanol blends

BUSINESS AS USUAL SCENARIO
- Baseline energy demand and economic activity
- LTGRP
- Consensus alterations

COMBINED INITIATIVES SCENARIO SCENARIO
- Baseline energy demand and economic activity
- LTGRP
- Consensus alterations
- Electrification initiatives
- Low Carbon Fuels initiatives

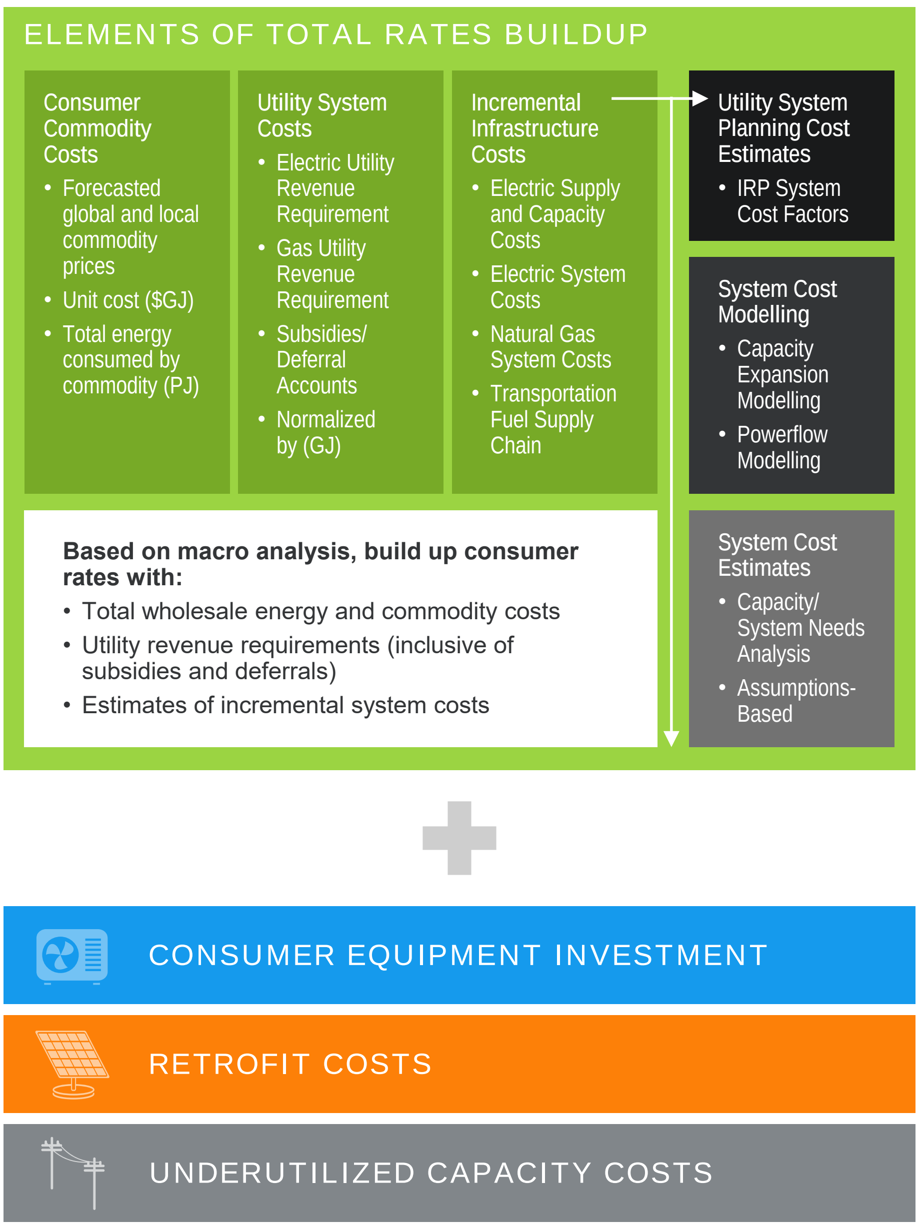
ELECTRIFICATION INITIATIVES SCENARIO
- Baseline energy demand and economic activity
- LTGRP
- Consensus alterations
- Electrification initiatives

Note: LTGRP refers to FortisBC's Long-Term Gas Resource Plan. Source: Guidehouse

[13] This study develops two future scenarios to achieve BC's GHG reduction targets and analyzes the required changes to the energy system and incremental societal cost to the province. The intent of the study was to determine the extent of change required in BC to meet climate reduction targets. The economy-wide energy models used in this exercise are key tools to outline the magnitude of changes required over the coming decades. These models are built from historical data and are extrapolated into the future based on announced policy initiatives, observed historical trends, and other assumptions. As such, the results of this energy modelling engagement are intended to be indicative of possible future scenarios, but they are not intended to be taken as definitive results. Various opportunities for emissions reductions were not included in this analysis, including emissions trading, initiatives targeted at international sectors (e.g., airlines and shipping), etc.

Technologies and initiatives were selected with consideration for how practical and defensible they are. The total societal cost for each pathway was assessed by considering the consumer commodity costs, utility system costs, incremental infrastructure costs, consumer equipment costs, retrofit costs, and government subsidies (Figure 9). The costs of an underutilized gas system were also estimated to reflect additional costs to customers should gas system utilization be meaningfully reduced.

FIGURE 9. PATHWAY TOTAL SOCIETAL COST IMPACTS



Source: Guidehouse

PATHWAYS

Table 1 shows how Guidehouse modelled the five major initiative categories differently across the two pathways. In general, the Electrification Pathway focused on energy efficiency, fuel switching to electricity for space/water heating, industrial processes, and transportation. The Diversified Pathway focused on energy efficiency, implementation of efficient gas end uses, and the deployment of renewable gas. **The analysis described in this section presents two pathways to achieving GHG emissions reductions. While both are theoretically potential pathways, they are not forecasts of the future.** Guidehouse welcomes an ongoing discussion on the merits and key challenges of various pathways available.

TABLE 1. INITIATIVES BY PATHWAY

Initiative	Electrification Pathway	Diversified Pathway
Electric Peak Demand	Peak demand increases to 21,600 MW in 2050, requiring 8,800 MW of new peak capacity versus the BAU case.	Peak demand increases to 17,700 MW in 2050, requiring 4,900 MW of new peak capacity versus the BAU case.
Renewable Gas	Of end-use natural gas demand, 35% (26 PJ) is served by renewable gas in 2050 (mix of hydrogen and renewable natural gas). Incremental 1.8 MT of carbon sequestered per year through carbon capture by 2050.	Of end-use natural gas demand, 73% (136 PJ) is served by renewable gas in 2050 (mix of hydrogen, renewable natural gas, and synthetic methane). Incremental 1.8 MT of carbon sequestered per year through carbon capture by 2050.
Transportation	Transition to 100% zero-emissions light duty vehicles. Significant role for MHD electric vehicles (EVs) (60% EV, 40% CNG/LNG and internal combustion).	Transition to 100% zero-emissions light duty vehicles. Significant role for gases in MHD vehicles (75% CNG, 20% EV, 5% fuel cell vehicles).
Fuel Switching	Transition 100% of residential and commercial space and water heating to electricity with electric heat pumps and other appliances, 20% of industrial fuel switching.	Transition up to 25% of residential and commercial space and water heating to electricity, 10% of industrial fuel switching.
Energy Efficiency	Improve envelope of 1.6 million homes and 436 million m^2 of commercial floor space.	Improve envelope of 1.7 million homes and 328 million m^2 of commercial floor space. Deploy gas heat pumps in ~70% of buildings.

Table 2 includes select modelling inputs that have a major impact on the results. These inputs have been informed by:

- Past engagements carried out by Guidehouse
- Pilot programs and research assessments carried out by FortisBC
- Discussions with key BC stakeholders
- Various public sources

The assumptions in the table represent theoretically possible future scenarios—they are not forecasts of the expected future by either Guidehouse or FortisBC.

TABLE 2. SELECT MODELLING INPUTS

Input	Assumption/Description
Cost of New Electricity Generation	$126/MWh was assumed in both pathways. This value represents an estimate of the expected cost of Site C[14] and is considered a conservative estimate of new renewable power costs. It is conservative because solar, wind, and energy storage costs are significantly higher and do not provide the same level of inter-seasonal storage. These higher priced renewable assets may need to be deployed due to the difficulty of developing large hydro in Canada. It is assumed that hydro resources will be available at the levels modelled in the pathways, which further assumes the deployment of multiple large hydro facilities (similar in size to Site C) in both pathways.
Renewable Gas Costs	RNG production costs were derived from Hallbar Consulting's report on RNG potential in BC and range from $14 to $28 per GJ.[15] It is assumed that progress will be made in wood-to-RNG technology to achieve the levels of RNG modelled in the two pathways. Green hydrogen (i.e., hydrogen produced with renewable electricity) and synthetic methane costs were developed from current production cost estimates (roughly $40/GJ for hydrogen, ~$10/GJ extra to create synthetic methane based off FortisBC pilot projects). These costs were extrapolated for the forecast, taking into consideration cost declines due to technology improvements. Guidehouse also aligned hydrogen production costs with the cost of renewable electricity because that is the primary input for producing green hydrogen. The weighted average cost across all renewable gases for each pathway in 2050 are: • Electrification Pathway: $19/GJ ($0.068/kWh equivalent) • Diversified Pathway: $23/GJ ($0.083/kWh equivalent) The Diversified Pathway renewable gas cost is higher because it requires more RNG at higher prices and includes a small amount of synthetic methane, which is the most expensive renewable gas.
Peak Demand Impacts	Annual hourly load shapes were selected or developed using public sources for each of the initiatives described in Table 1. These load shapes were applied to the energy consumption of each initiative to determine peak demand impact.
Electric Heat Pump Characteristics	Electric heat pump costs were modelled to align with the BC Conservation Potential Review, which included a specific assessment of the achievable potential of electric heat pumps in BC. The incremental cost for electric heat pumps was modelled as approximately $376 per residential household and $16,500 per 1,000 m^2 of commercial floor space. Electric heat pumps were modelled with 190% efficiency for both residential and commercial applications.[16] This efficiency depends on climate and likely will vary by region within BC.

[14] Guidehouse calculated a levelized cost of energy (LCOE) for Site C based off capital cost estimates from the BCUC Site C inquiry, historical financials from BC Hydro, and internal estimates. The results were benchmarked against Lazard's published LCOEs.

[15] Hallbar Consulting, *Resource Supply Potential for Renewable Natural Gas in B.C.*, March 2017, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

[16] The 190% value is a conservative estimate for heat pump efficiency, which aligns with a baseline assumed efficiency for air-source heat pumps in Guidehouse's 2019 BC Conservation Potential Review. This conservative assumption was used to attempt to represent provincial efficiency as a whole because heat pump efficiency is assumed to vary significantly by climate zone.

Input	Assumption/Description
Gas heat Pump Characteristics	Gas heat pump costs were derived from a heat pump feasibility study provided by FortisBC and interviews with developers.[17] Initial costs were set at roughly $6,800 and $45,000 for a residential home and commercial building, respectively. Both residential and commercial gas heat pumps were modelled with a 140% gas utilization efficiency. This efficiency depends on climate and likely will vary by region within BC.
Natural Gas System Utilization	The utilization of the gas system differs significantly between the two pathways. In the Electrification Pathway, the 2050 throughput drops to roughly 40% of the 2019 throughput. Conversely, the 2050 throughput of the Diversified Pathway is not significantly less than the 2019 throughput.[18] Electrification Pathway: • 2019 throughput = 200 PJ • 2050 throughput = 75 PJ Diversified Pathway: • 2019 throughput = 200 PJ • 2050 throughput = 186 PJ

CanESS, which Guidehouse used to complete the pathway modelling, is an integrated, multifuel, multisector, provincially disaggregated energy systems model for Canada. CanESS enables bottom-up accounting for energy supply and demand, including energy feedstocks (e.g., coal, oil, natural gas), energy-consuming stocks (e.g., vehicles, appliances, dwellings), and all intermediate energy flows (e.g., electricity), including interprovincial imports and exports that may offer incremental opportunities to contribute to achieving regional GHG reduction targets.

Note: CanESS projections were based on extended trends observed in historical data (key data sources include CANSIM, Natural Resources Canada, and Environment Canada) and projections obtained from the Canada Energy Regulator (CER, Energy Future 2017). In addition, CanESS projections account for the expected effects of all approved legislation and regulation (including the CleanBC plan) and was driven by the best publicly available data from government sources. (Canada Energy Regulator (CER), Canada's Energy Future 2017, https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2017/index-eng.html)

[17] Posterity Group, Prefeasibility Study on Natural Gas Heat Pumps, May 2017.

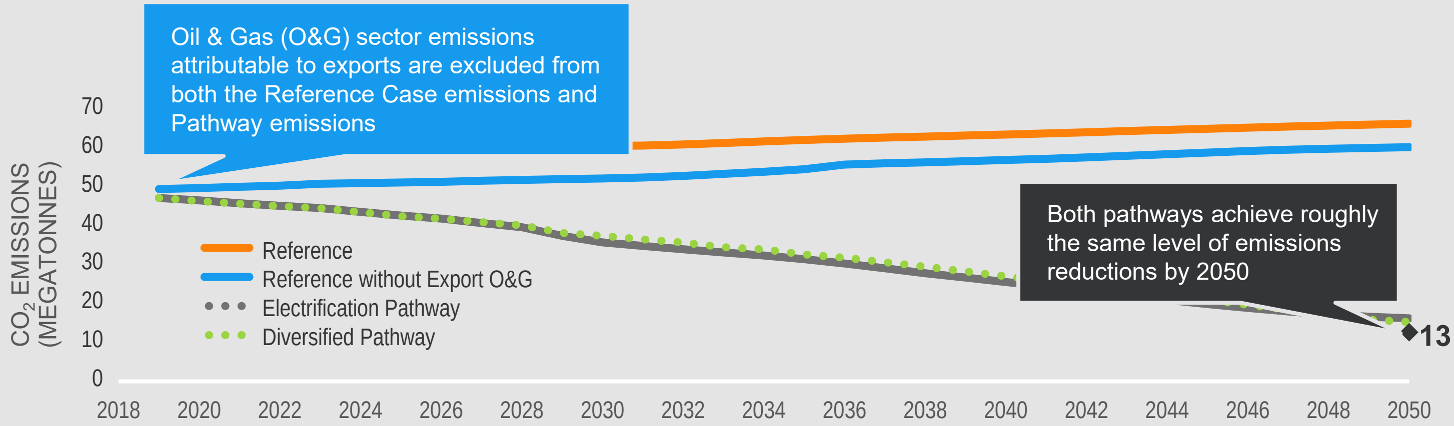
[18] Gas system utilization includes only gas consumed by the buildings, industry, and transport domestic end-use sectors. Natural gas throughput for LNG for marine vessels and for international export are excluded.

5.1 EMISSIONS REDUCTIONS

Each pathway meets 95% of the reductions required by 2050, representing greater than 32 million tonnes of CO_2e emissions avoided from BC annually in 2050 from a BAU scenario. The pathways use initiatives to different extents, but both pathways require transformative changes in every sector. The remaining 5% of emissions reductions must be achieved through initiatives that target sectors that cannot be modelled for BC in isolation—e.g., aviation fuel. These sectors are beyond the scope of this study.

The scope of this report is focused on BC's domestic GHG emissions. The pathways reduce domestic emissions by 80%. Emissions associated with energy exports, notably for LNG and other oil & gas for export, are separated out and are assumed to be addressed through a combination of nature-based carbon offsets, internationally transferred mitigation outcomes,[19] and technology improvements.

FIGURE 10. BRITISH COLUMBIA EMISSIONS REDUCTIONS UNDER ENERGY VISION PATHWAYS



Source: Guidehouse Analysis

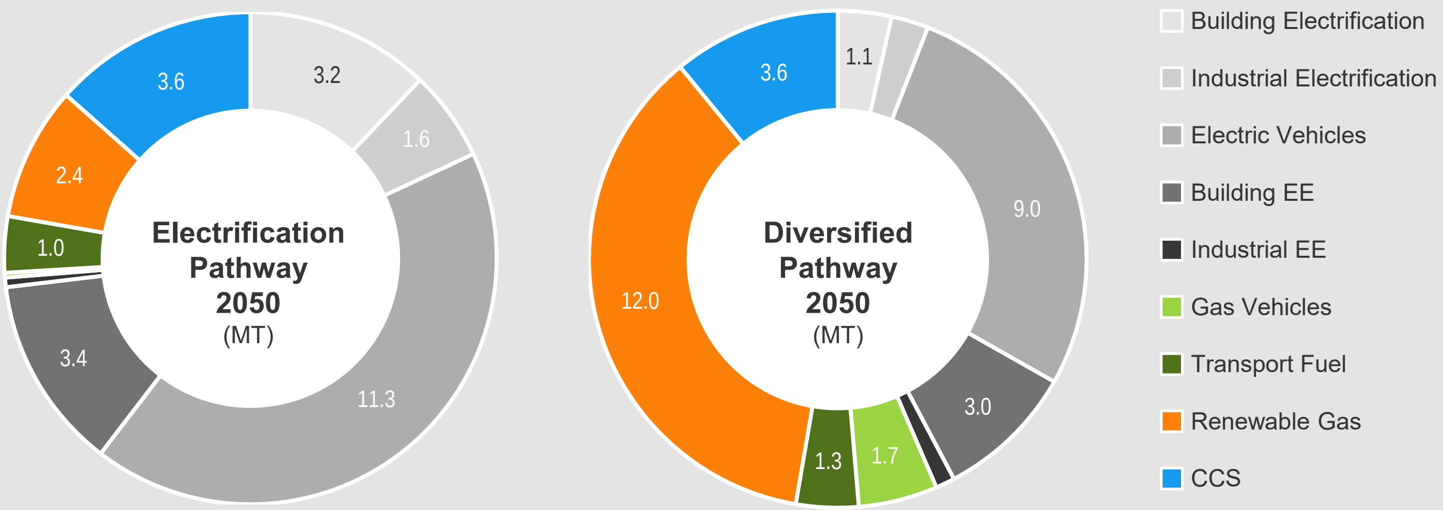
As Figure 11 shows, light duty EVs have a large role to reduce GHG emissions in both pathways, as both pathways were modelled to include the Zero-Emission Vehicles[20] Act; the Zero-Emission Vehicles Act requires 100% of light duty vehicles sold in 2040 to be zero-emissions vehicles.[21] MHD vehicles is the second-most impactful initiative in the Electrification Pathway, which has been modelled such that 60% of MHD vehicles on the road in BC are electric by 2050. The most impactful initiative to reduce BC's domestic GHG emissions in the Diversified Pathway is renewable gas, which results in over 5 million tonnes of emissions reductions in 2050 by transforming the natural gas fuel mix to be mostly made up of RNG and hydrogen. Energy efficiency in buildings is also a critical initiative in both pathways. This initiative results in over 3 million tonnes of reductions by 2050 through the implementation of improved building envelopes, high efficiency heat pumps, and commercial automated building controls.

[19] Internationally transferred mitigation outcomes are identified in the Paris Agreement to facilitate compliance with national GHG reduction goals through the trade of emissions reductions between nations.

[20] ZEVs are modelled in this study as EVs and fuel cell vehicles.

[21] Province of British Columbia, Zero-Emission Vehicles Act, May 2019, https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/clean-transportation-policies-programs/zero-emission-vehicles-act.

FIGURE 11. GHG REDUCTIONS BY INITIATIVE: 2050



* Note that summing up all the initiatives will not exactly match total emission reductions values in earlier slides. Source: Guidehouse Analysis

5.2 GAS SYSTEM ENABLES GHG EMISSIONS REDUCTIONS OUTSIDE BC

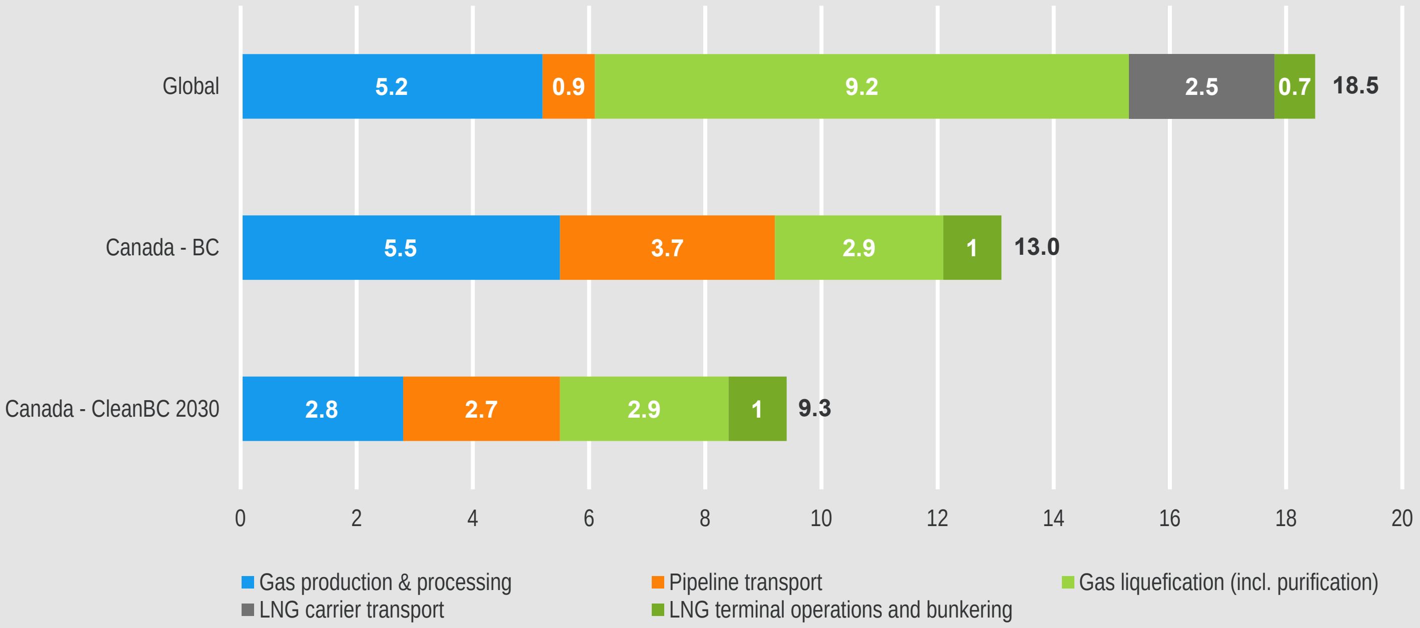
The gas system can also lead to GHG emissions reductions outside of BC. Although these reductions were not evaluated in this analysis, FortisBC has conducted separate evaluations on the role of the gas system to supply LNG to marine vessels and to displace carbon-intensive energy consumption in China with LNG exports. Both of these activities could have significant near-term emissions reductions.

For marine vessels, LNG from FortisBC's Tilbury facility has a 27% lower carbon intensity than the global average for LNG.

This means that LNG from FortisBC used in marine vessels would reduce life cycle emissions by between 20% and 27%. As the measures in CleanBC take hold, reducing methane emissions and extending electrification in natural gas production, LNG from BC could reduce GHG emissions by up to 30% and would make the carbon intensity of LNG from Tilbury half that of the global average. Because the GHG emissions associated with international marine vessels in their journeys to and from ports in BC are higher than BC's total annual GHG emissions, this would make an important contribution to global GHG reduction efforts.[22]

[22] thinkstep, *Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase*, 2020, https://www.thinkstep.com/content/life-cycle-ghg-emission-study-use-lng-marine-fuel-1 .

FIGURE 12. WELL TO TANK LNG CARBON INTENSITIES (g CO_2e/MJ)



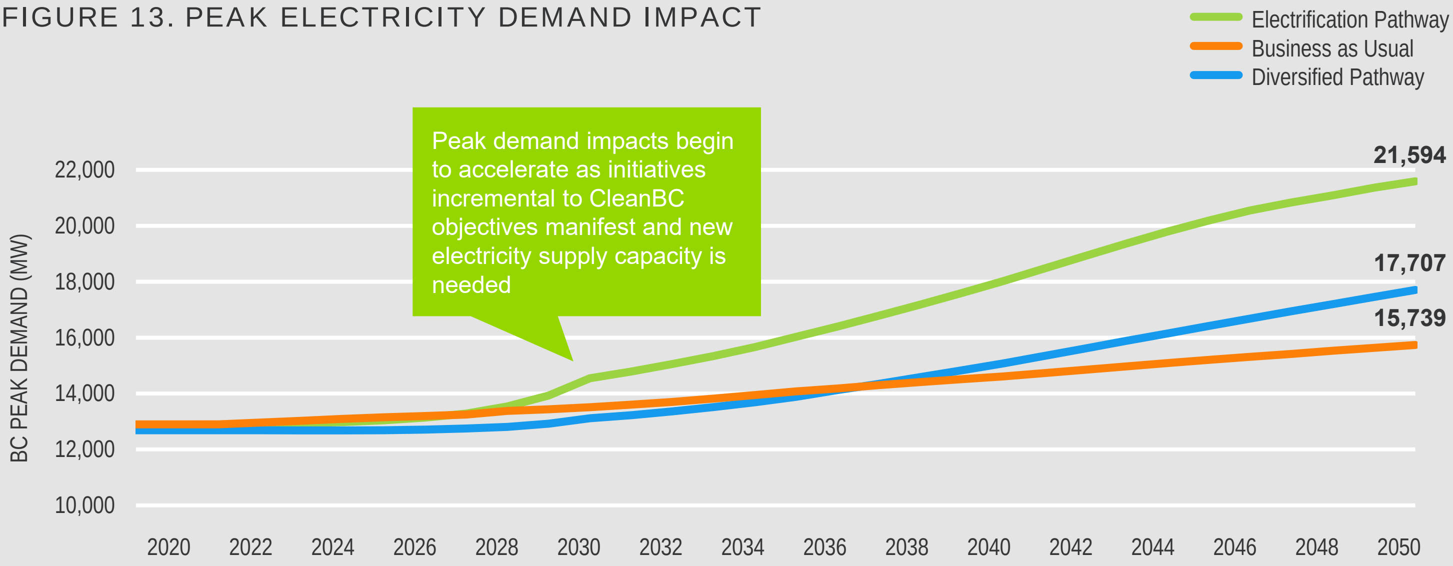
Source: Thinkstep, Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase, 2020

5.3 GROWTH IN LOW CARBON ENERGY SUPPLY

The 2050 peak demand of the Electrification Pathway is estimated to be 68% higher than the peak electricity demand of 2018. This will require the deployment of over 8,700 MW of peak capacity in the Electrification Pathway, which is double the requirement for the Diversified Pathway and triple the BAU requirement. The peak demand in both pathways increases from 2018 levels because of the significant deployment of EVs, electric heating, and fuel switching. However, the net increase in peak demand is significantly higher in the Electrification Pathway.[23] To achieve the 2050 GHG reduction targets, peak demand must be met with low or no carbon firm generating capacity. In this study, Guidehouse used the lowest cost supply option for peak capacity—hydroelectric generation. There are practical limitations to developing new hydroelectric generation in BC, however. This report does not assess those limitations but acknowledges other sources of peak capacity may be preferred.

[23] Peak demand impacts are based on conservative assumptions in both pathways (e.g., majority of MHD vehicle charging occurs in non-peak times).

FIGURE 13. PEAK ELECTRICITY DEMAND IMPACT

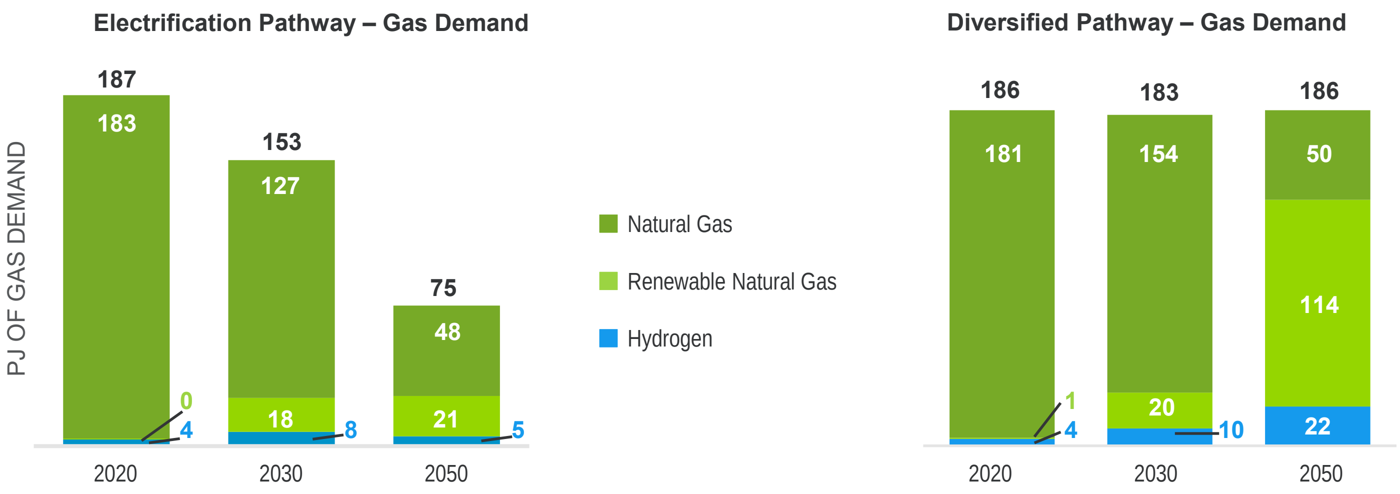


*Peak demand impacts are based on conservative assumptions in both pathways (e.g., majority of MHD vehicle charging occurs in non-peak times)
Source: Guidehouse Analysis

Natural and renewable gases are critical in the Diversified Pathway and support a more robust energy system in the province. Figure 14 shows that renewable gases will make up 35% of natural gas demand in the Electrification Pathway by 2050, aligning with current BC targets. Renewable gases make up 73% of natural gas demand in the Diversified Pathway.

In the Electrification Pathway, total gas demand declines by almost 60% between 2020 and 2050, while total gas demand (natural gas and RNG) remains flat during the same period in the Diversified Pathway.

FIGURE 14. END-USE GAS DEMAND IN EACH PATHWAY



Note: End-use natural gas demand includes consumption in residential and commercial buildings, industry, and transport but excludes gas consumption in upstream gas extraction, processing, and transmission.

Source: Guidehouse Analysis

TABLE 3. RENEWABLE GAS DESCRIPTIONS

Renewable Gas	Assumption/Description
Renewable Natural Gas (RNG)	RNG is natural gas created from renewable energy sources such as organic waste (i.e., from landfills) and agricultural waste. Guidehouse used a report by Hallbar Consulting commissioned by the Province of British Columbia, FortisBC, and Pacific Northern Gas to determine the level of RNG potential in BC and its associated production costs. The RNG amounts modelled in 2050 align with the long-term technical potential in the Hallbar Consulting report, which assumes improvements will be made in wood-to-RNG technology. It is assumed RNG can be injected directly into existing natural gas infrastructure without any associated complications, and all associated costs are covered in the production costs.
Hydrogen	Two types of hydrogen were considered in this report: green hydrogen, which is produced from an electrolysis reaction of renewable electric power with water, and blue hydrogen, which is produced from fossil fuel natural gas and cleaned up using carbon capture and storage. Blue hydrogen is cheaper than green, and its cost is not forecast to decline significantly in the forecast period. Guidehouse modelled the hydrogen mix to increasingly be composed of green hydrogen under the assumption that costs are likely to decline. Green hydrogen costs were based off production cost assessments from the *British Columbia Hydrogen Study*[24] and are forecast to decrease due to technology improvements. Guidehouse benchmarked these costs with production costs observed in other regions (e.g., Europe).[25] Green hydrogen costs are highly dependent on the price of electricity, so Guidehouse aligned the forecast to the cost of new renewable power in the future. Hydrogen was modelled to make up a maximum of 15% (by volume) of BC's natural gas mix to represent the estimated operational limitations of the gas system to incorporate higher volumes.[26]
Synthetic Methane	Synthetic methane is hydrogen that has been upgraded with CO_2 to create methane (CH_4) and that can be safely injected into the natural gas mix at any level. Synthetic methane is modelled as the most expensive renewable gas because its price includes the cost of hydrogen plus an incremental cost related to carbon capture and storage to provide the required CO_2. Guidehouse only modelled the production of synthetic methane when the requirement for renewable gas exceeded both the technical potential of RNG and the physical limit of hydrogen (i.e., 5% of the fuel mix).

Electricity's share of the energy supply increases significantly in both pathways. Refined petroleum, which makes up over 33% of total end-use energy demand in BC, will decline to less than 15% of end-use demand by 2050 in both pathways. This decline is due to the widespread adoption of vehicles that use alternative fuels to diesel and gasoline in both pathways—i.e., electric, fuel cell, CNG, and LNG. This analysis highlights the importance, costs and scarcity of low-carbon energy whether in the form of renewable gas molecules for the gas system or electrons through the electric grid.

Maximizing the potential of clean electrons or clean gas molecules should be pursued to harness the differences between these energy carriers. Because of the high cost of building new clean reliable electricity generation and transmission, electrification initiatives should be matched to their most effective and valued uses to reduce GHG emissions, while natural gas and renewable gas molecules should be delivered to end-uses where there are high-costs of electrifying and/or the GHG reduction potential is lower. This integrated approach to system-wide decarbonization should be pursued rather than a compartmentalized sector by sector approach.

[24] Zen and the Art of Clean Energy Solutions, British Columbia Hydrogen Study, June 2019, https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/zen-bcbn-hydrogen-study-final-v6.pdf.

[25] Guidehouse, Gas Decarbonisation Pathways 2020–2050, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

[26] A maximum hydrogen blend concentration by volume in FortisBC's gas system is being analyzed and depends on several factors. FortisBC is conducting feasibility studies to outline the minimum safe blending volume with the current system. The gas system can also adapt over the coming decades as scheduled maintenance, asset integrity, and operational management advancements and infrastructure upgrades offer opportunities to increase the system's compatibility with hydrogen.

Renewable gases have been an area of growing interest around the world. Large utilities in North America are moving to expand the supply of RNG into their portfolios. In Quebec, the provincial government has set a 5% RNG blend target by 2025 and has devoted $70 million to increase the production of RNG. Southern California Gas has set a corporate target to expand RNG supply to 20% of its throughput in 2030. In some European countries, promotion of biogas and RNG has been an ongoing policy objective. Denmark is producing over 15 PJ of biogas, with approximately 10% of the throughput through its gas grid being RNG. In France, the government has set an objective to inject 10% RNG into the country's pipelines by 2030.

Hydrogen is also taking on a larger role in meeting global energy needs. Natural gas utilities in France recently recommended the government set a hydrogen target of 10% of the natural gas mix in 2030, increasing up to 20% thereafter.[27] The Guidehouse Gas for Climate work in the EU demonstrates support in the EU for setting a binding mandate for 10% gas from renewable sources (i.e., RNG and green hydrogen) by 2030. [28] Hydrogen is being considered as a replacement fuel for coal in electricity production. The largest municipal utility in the US, Los Angeles Department of Water and Power (LADWP), announced it would transform a coal-fired plant to run on green hydrogen. LADWP plans to run the coal plant on a blend of 30% hydrogen, 70% natural gas by 2025. By 2045, the plant is expected to be run completely on hydrogen.[29]

5.4 COST COMPARISONS

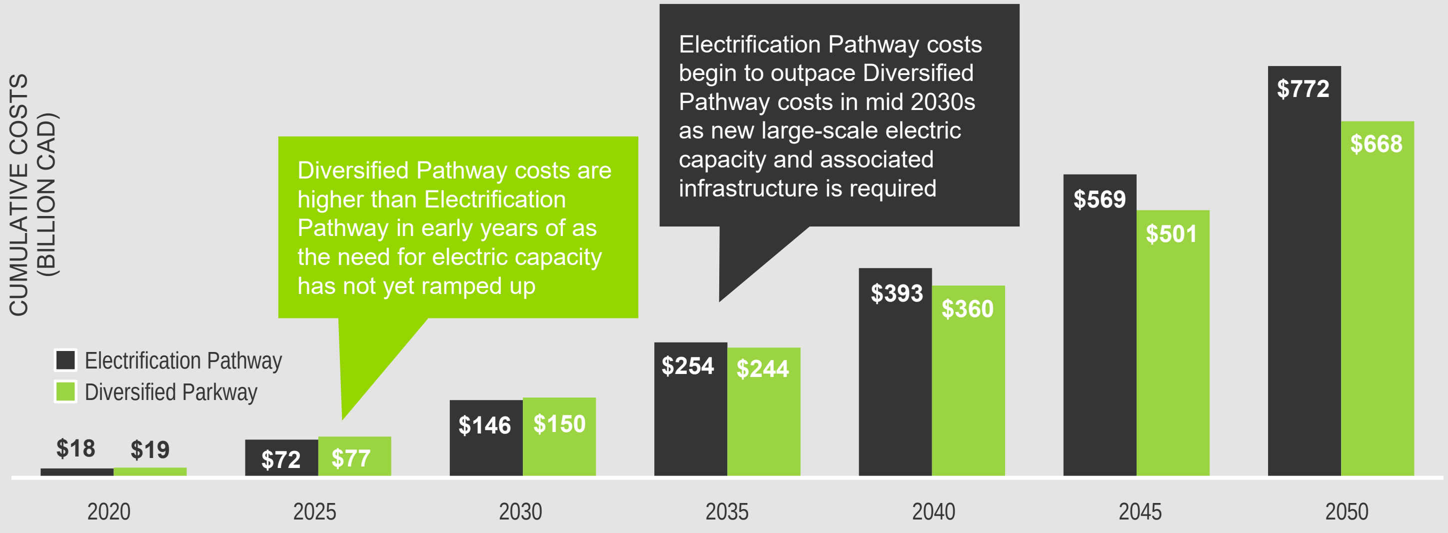
By 2050, the societal value of the Diversified Pathway is expected to be at least $100 billion higher than the Electrification Pathway. The cost of each pathway is roughly the same until the mid-2030s, when the costs of the Electrification Pathway rises much higher than the Diversified Pathway. This finding emphasizes the need to prioritize pathways over a longer time horizon because pathway costs represent incremental costs borne by society relative to the BAU case. These costs include commodity (the electricity and natural gas itself), infrastructure (the poles, wires, and pipelines needed to deliver energy), and initiative costs (the cost of efficient alternatives to existing equipment and fuel).

[27] Hydrocarbon Processing, "France plans hydrogen blending with natgas to tackle carbon emissions," November 15, 2019, https://www.hydrocarbonprocessing.com/news/2019/11/france-plans-hydrogen-blending-with-natgas-to-tackle-carbon-emissions.

[28] Guidehouse, *Gas Decarbonisation Pathways 2020–2050*, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

[29] Smith, Carl, "America's Largest Municipal Utility Invests in Move from Coal to Hydrogen Power," *Governing: The Future of States and Localities*, April 15, 2020, https://www.governing.com/next/Americas-Largest-Municipal-Utility-Invests-from-Coal-to-Hydrogen-Power.html.

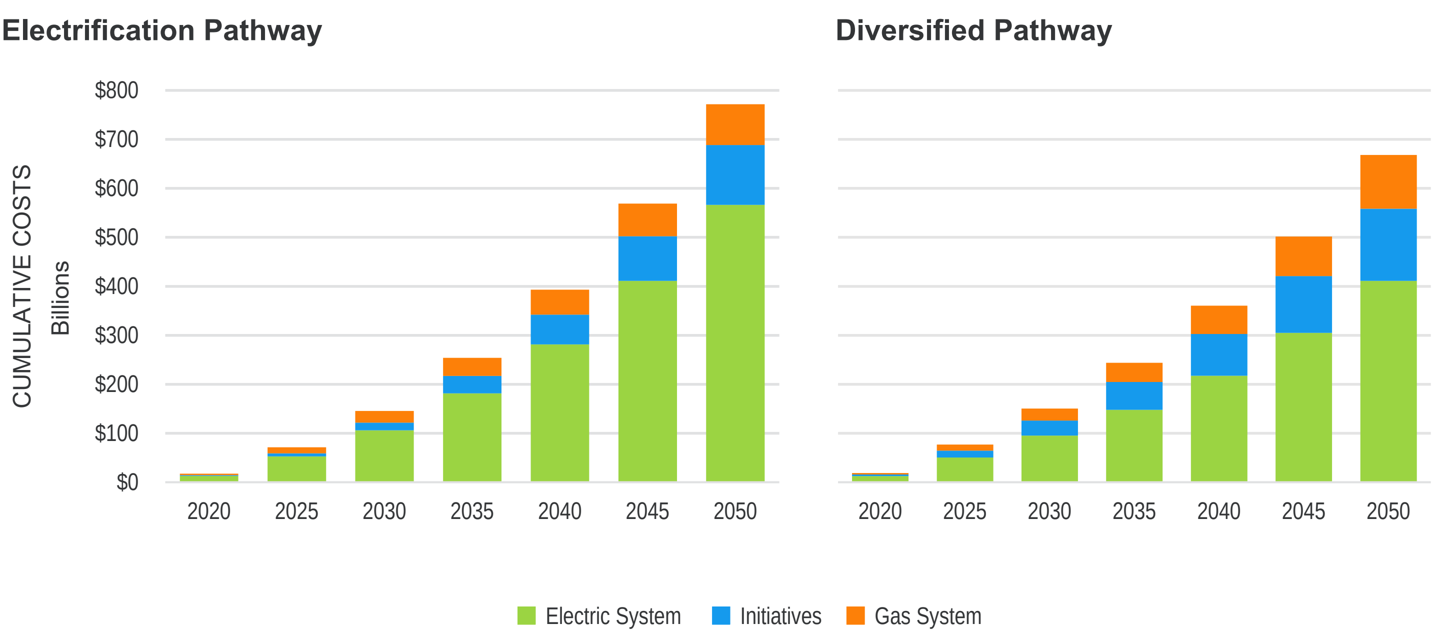
FIGURE 15. PATHWAY COSTS



Source: Guidehouse Analysis

The Diversified Pathway has higher initiative and gas system costs but significantly lower electricity system costs than the Electrification Pathway. Figure 16 compares the Diversified Pathway costs relative to the Electrification Pathway costs; the text following the figure describes the costs by component.

FIGURE 16. PATHWAY COSTS BY COMPONENT



Source: Guidehouse Analysis

- **$155 billion less spent on the electricity system:** Electricity system costs represent the incremental infrastructure needed to meet peak demand in both pathways. These costs include generation asset buildout, currently modelled to be the implementation of several large hydro generating stations in each pathway. These costs also include transmission and distribution infrastructure—this is money spent on the delivery system itself as opposed to the energy that passes through it. The Electrification Pathway has significantly higher electricity system costs due to the comparatively higher peak demand requirements.

- **$25 billion more spent on initiatives:** These initiatives are summarized in Table 1 and include vehicles, building envelope improvements, space and water heating, industrial process improvements, and renewable gases. The Diversified Pathway has higher initiative costs than the Electrification Pathway due to the large amount of renewable gas needed to decrease emissions. Further, the Diversified Pathway implements higher priced energy efficiency initiatives (e.g., gas heat pumps are more expensive than electric heat pumps).

- **$26 billion more spent on the gas system:** Gas system costs represent the expenses associated with the maintenance and operation of gas infrastructure. The Diversified Pathway has higher gas system costs because there is higher throughput during the forecast period.

The costs for both electric and natural gas ratepayers is higher in the Electrification Pathway as compared to the Diversified Pathway. Costs for electricity customers are higher because of the higher system costs in the Electrification Pathway, which are passed on to customers through electricity rates. Costs for natural gas customers are higher because significant reductions in gas consumption will not be enough to offset the cost of operating the system for a smaller number of remaining customers.

A cost sensitivity analysis was completed to determine the impact of a number of variables and found that cost drivers could increase the cost differential between the two pathways by $5 billion to $7 billion, or could narrow the gap by $5 billion to $12 billion. If conservative assumptions about key factors including the capital cost, the capital structure, or the cost of RNG or hydrogen are lower than expected, the cost differential between the two pathways will be greater. If these costs are higher, the Diversified Pathway will still be less expensive than the Electrification Pathway.

6. OTHER BENEFITS OF USING THE GAS SYSTEM FOR DECARBONIZATION

FortisBC asked Guidehouse to look at the total benefits of the gas system in BC. From a modelling perspective, the Diversified Pathway can achieve the same level of emissions reductions as the Electrification Pathway at a significantly lower cost in BC. In addition, the gas system can deliver other benefits related to security, stability, and flexibility that can advance BC's work toward a low carbon future.

GAS SYSTEM ALLOWS FOR A BROADER SET OF SOLUTIONS TO REDUCE EMISSIONS

Using the gas system to achieve GHG reductions diversifies the approach across multiple energy systems. A pathway that focuses on electrification could have higher risks should key barriers like developing new peak demand emerge. A broader approach to GHG reductions further into the scenario period could lower the risk of missing BC's 2050 target.

A significant amount of R&D has gone into various electrification and renewable technologies, resulting in widespread acceptance and economies of scale. For example, the cost on a dollars-per-watt basis of distributed solar PV has dropped over 55% between 2011 and 2018 (-11% compound annual growth rate). However, the opportunities for advancement in electrification may be reaching saturation and the development and improvement of some of these technologies is declining (e.g., the rate of solar PV cost declines is expected to slow down in the coming decade).[30]

There is more opportunity for R&D and efficiency improvements in the gas supply and corresponding end-use equipment that can be investigated alongside electrification initiatives. This opportunity could result in more economic development and societal benefit than if only electrification measures were prioritized.

Renewable gases are a major target for innovation and can play a vital role in the future of the natural gas industry. RNG, hydrogen, and synthetic methane all have great potential for the province. BC has the potential to be a major producer of RNG given its large forestry industry, which produces a large amount of woody biomass. Technical advancements are needed to more efficiently convert wood biomass waste to RNG, and researchers and organizations are identifying recommendations for technological improvement.[31] Assuming this technology meets its potential in the coming years, BC's RNG production potential could be 90 PJ per year, representing almost half of the natural gas currently delivered by FortisBC.[32] This estimate assumes only wood waste within a 50 km-75 km of natural gas compressor stations is used. If this radius can be expanded, BC's RNG potential would increase further.

[30] Navigant Research (now Guidehouse Insights), *Market Data: Solar PV Global Forecasts*, 3Q 2018, https://guidehouseinsights.com/reports/market-data-solar-pv-global-forecasts.

[31] Gas Technology Institute, *Low-Carbon Renewable Natural Gas (RNG) from Wood Wastes*, February 2019, https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf.

[32] Hallbar Consulting, *Resource Supply Potential for Renewable Natural Gas in B.C.*, March 2017, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

Hydrogen and synthetic methane also represent key initiatives to lower emissions in BC. Hydrogen and synthetic methane production technologies have not reached the limit of technical ability and offer a great opportunity for improvement through R&D and pilot projects.

Natural gas heat pumps are a gas-consuming technology that represent an opportunity for R&D and innovation. Gas heat pumps are more efficient than conventional gas space heating systems, but they have not yet reached their full market potential in Canada due to cost, availability, and other factors. However, there is strong federal support for gas heat pumps because they are expected to be instrumental in helping Canada meet its 2030 and 2050 emissions reductions targets.[33]

DROP-IN FUELS CAN BE MORE FEASIBLE AND COST-EFFECTIVE THAN FUEL SWITCHING

For many residences and businesses, switching to different heating systems may be difficult or undesirable. For policymakers focused on reducing GHG emissions, relying on broad-based fuel switching to different heating systems will involve mobilizing millions of building owners to switch. The policies and strategies to make this happen are not well understood or are infeasible.

Deploying low carbon drop-in fuels like renewable gas would leverage existing policy and regulatory frameworks and involve fewer players.[34] While it would be a challenge to develop the volume of low carbon fuels needed by 2050, governments and industry have experience in promoting low carbon energy in other sectors—notably in the electricity sector, where policy and financial incentives have led to a massive increase in renewable power investment. This model could be emulated for renewable gases.

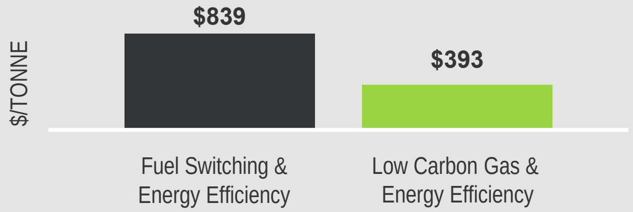
The findings in this analysis suggest drop-in fuels would be more cost-effective than fuel switching to electricity. The cost per tonne of reducing emissions in difficult-to-address sectors like buildings with renewable gases is approximately half that of fuel switching when accounting for the full system cost impacts. Figure 17 shows that the cost per tonne to reduce residential building emissions by fuel switching is higher than reducing residential building emissions using low carbon fuels in both pathways. The components of each option are summarized below:

- Fuel switching includes residential electric heat pump costs, electric system impact costs (i.e., system buildout to meet peak demand), and energy costs to switch from electricity to gas. Both electric system impact costs and energy costs are net of energy efficiency improvements.
- Low carbon gas includes the deployment of RNG/hydrogen and the implementation of gas heat pumps, building envelope improvements, and other efficiency measures.

[33] Energy and Mines Ministers' Conference, *Paving the Road to 2030 and Beyond: Market transformation road map for energy efficient equipment in the building sector*, August 2018, https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/2018/en/18-00072-nrcan-road-map-eng.pdf.

[34] Drop-in fuel refers to a fuel that can be added to an existing energy system without significant reconfiguration.

FIGURE 17. COST PER TONNE OF FUEL SWITCHING VS. LOW CARBON GAS AND ENERGY EFFICIENCY



Source: Guidehouse Analysis

SOCIO-ECONOMIC IMPACT OF AN OPTIMIZED GAS SYSTEM

The Electrification Pathway would eliminate portions of BC's natural gas industry. This elimination may result in the loss of thousands of jobs and billions of dollars of unused gas pipelines that the province has committed to financially. As a result, the province will have an under-utilized gas system, which does not provide a significant benefit. The cost to maintain and oversee this infrastructure will adversely impact British Columbians. In contrast, the Diversified Pathway optimizes the gas system to continue to deliver low carbon solutions, resulting in higher societal value.

GAS SYSTEM CAN BE USED TO REDUCE GLOBAL CARBON EMISSIONS

BC has significant natural gas resources, with remaining raw reserves of approximately 1,165 billion cubic metres. Over 60 billion cubic metres of natural gas was produced in 2018.[35] However, domestic use will likely decrease over time to reach BC's 2050 target. BC's natural gas can be exported as LNG to Asia to displace higher carbon fuels like coal, which could result in a net reduction of global GHG emissions. BC's LNG can also power large ocean vessels, which would displace higher emissions fuels like diesel and heavy oil. An analysis conducted by thinkstep concluded that LNG from BC used in marine shipping could reduce GHG emissions by up to 27%.[36]

As the policies in CleanBC are implemented (e.g., electrifying upstream gas production and implementing regulations to reduce methane emissions), the carbon intensity of the LNG supply chain in BC in 2030 would be half that of the current global average.

MAINTAINING THE GAS SYSTEM WILL SPEED INNOVATION AND ALLOW FOR FLEXIBILITY IN FUTURE TECHNOLOGY SOLUTIONS

We have modeled two pathways that both nearly achieve the required GHG emission reductions in 2050. Each pathway has been modelled by relying primarily on existing proven technologies and solutions. Continued innovation is expected to accelerate decarbonization, particularly in years after 2030. Maintaining both the gas and electric infrastructure as part of the future energy system will provide more flexibility in which innovative solutions can be easily developed and deployed. This will allow BC to achieve accelerated deployment of innovations in clean technologies and even faster decarbonization.

ROLE OF THE GAS SYSTEM IN OTHER JURISDICTIONS

Guidehouse carried out an analysis similar to this one for Gas for Climate, a group of European natural gas companies. The group commissioned a study to assess the possible role and value for gas used in existing gas infrastructure in a net-zero emissions EU energy system compared to a situation in which a minimal quantity of gas would be used.

[35] BC Oil and Gas Commission, *British Columbia's Oil and Gas Reserves and Production Report*, 2018, https://www.bcogc.ca/node/15819/download.

[36] thinkstep, *Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase*, 2020.

The Gas for Climate analysis[37] involved developing two scenarios to meet the EU's decarbonization requirements by 2050:

- **Minimal gas scenario:** Almost full electrification of buildings, industry, and transportation sectors.
- **Optimized gas scenario:** Moderate electrification of the abovementioned sectors, as well as large deployment of renewable and low carbon gases in select applications (heavy road transport, building heating in peak demand times, and some electricity production).

Guidehouse found the following conclusions from the Gas for Climate analysis:

- Both scenarios meet EU decarbonization requirements by 2050.
- Both scenarios need substantial quantities of renewable electricity.
- Green/blue hydrogen and RNG can help meet heating and industrial needs at low/no carbon.
- Significant benefits exist in the optimized gas scenario related to energy flexibility (i.e., gas and electric systems are used).
- Higher societal value of optimized gas pathway (over €200 billion annually across the energy system by 2050).
- The cost to decommission the gas infrastructure (in minimal gas pathway) is high.

The results of this analysis mirror that of the FortisBC study and support to the concept that gas networks have a clear role in a decarbonized future.

[37] Guidehouse, *Gas Decarbonisation Pathways 2020–2050*, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

7. CONCLUSIONS

This analysis indicates that the Diversified Pathway can achieve the same level of provincial GHG emissions reductions as the Electrified Pathway at a significantly lower cost to British Columbians. Although initiatives are used to different extents, both pathways defined in this study would require transformative changes in every sector of BC's economy. By 2050, the societal value of achieving the Diversified Pathway is expected to be in excess of $100 billion higher than the Electrification Pathway.

Other benefits of maintaining a robust natural gas system are preserved by adopting a strategically diversified approach. The existing gas infrastructure represents a vital component to servicing current energy demand and can continue to benefit BC by providing security, flexibility, and storage to the overall energy system. The gas system delivers cost-effective energy services, energy reliability, and significant economic benefits to the province. The gas system also provides an opportunity for a broader set of technologies and initiatives to help achieve BC's 2050 GHG reduction goal.

Appendix P

DRAFT ORDERS

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
2021 Long Term Electric Resource Plan and 2021 Long Term Demand-Side Management Plan

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On August 4, 2021, FortisBC Inc. (FBC) filed its 2021 Long Term Electric Resource Plan (2021 LTERP) including its 2021 Long Term Demand-Side Management (DSM) Plan (2021 LT DSM Plan), as Volumes 1 and 2, respectively, for acceptance by the British Columbia Utilities Commission (BCUC) pursuant to section 44.1(6) of the *Utilities Commission Act* (UCA);

B. The 2021 LTERP presents a long term plan for meeting the forecast peak and energy requirements of FBC customers with demand-side and supply-side resources at the lowest reasonable cost to customers over the next 20 years;

C. The 2021 LTERP analyzes the external regulatory, policy and planning environment within which FBC operates, compares energy and capacity forecasts against current resource capabilities and evaluates the potential for load reduction with DSM initiatives and portfolios of resource options to meet forecast customer needs under different scenarios. The 2021 LTERP includes a preferred portfolio to meet the long term requirements of FBC's customers. The LTERP also includes an action plan that identifies activities that FBC expects to take during the first four years of the 20-year planning horizon;

D. The 2021 LT DSM Plan includes an assessment of the energy efficiency and conservation potential for FBC customers. The 2021 LT DSM Plan provides FBC with different levels of demand-side resource options to assess along with supply-side resource options in order to address the forecast load-resource balance gaps identified in the 2021 LTERP over the 20-year planning horizon. The 2021 LT DSM Plan also identifies FBC's preferred DSM scenario for long term planning purposes;

E. Section 44.1(5) of the UCA provides that the BCUC may establish a process to review a long-term resource plan;

F. The BCUC commenced review of the 2021 LTERP and 2021 LT DSM Plan and considers that the establishment of a public hearing is warranted.

NOW THEREFORE the BCUC orders as follows:

1. A public hearing for the review of FBC's 2021 LTERP and 2021 LT DSM Plan is established in accordance with the regulatory timetable as set out in Appendix A to this order.

2. FBC is to publish, as soon as possible, the Public Notice, attached as Appendix B to this Order, in print/display-ad format in appropriate news publications, such as but not limited to, local and community newspapers to provide adequate notice to those parties who may have an interested in or be affected by the plans outlined in FBC's 2021 LTERP and 2021 LT DSM Plan.

3. FBC must provide a copy of this Order to the key parties consulted in FBC's Stakeholder and First Nations Engagement outlined in Section 12 of FBC's 2021 LTERP.

4. As soon as practicable, FBC is directed to publish, together with any supporting materials, FBC's 2021 LTERP and 2021 LT DSM Plan, this order and the accompanying Regulatory Timetable and Public Notice by using appropriate communication methods, including FBC's website and social media accounts.

5. In accordance with the BCUC's Rules of Practice and Procedure, parties who wish to actively participate in this proceeding must submit the Request to Intervene Form, available on the BCUC's website at https://www.bcuc.com/get-involved/get-involved-proceeding.html, by the date established in the Regulatory Timetable..

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment

FortisBC Inc.
2021 Long Term Electric Resource Plan and 2021 Long Term Demand-Side Management Plan

REGULATORY TIMETABLE

Action	Date (2021)
FBC publishes Public Notice	Week of September 20
Intervener Registration	Wednesday, October 13
BCUC Information Request (IR) No. 1	Thursday, October 21
Intervener IR No. 1	Thursday, October 28
FBC Responses to BCUC and Intervener IR No. 1	Thursday, December 9
Intervener Notice of Intent to File Evidence	Thursday, December 16
	Date (2022)
BCUC and Intervener IR No. 2	Thursday, January 20
FBC Responses to IR No. 2	Thursday, March 3
FBC and Intervener Submissions on Further Process	Thursday, March 10

bcuc
British Columbia
Utilities Commission

PUBLIC NOTICE

FORTISBC INC. 2021 LONG TERM ELECTRIC RESOURCE PLAN AND 2021 LONG TERM DEMAND-SIDE MANAGEMENT PLAN

On August 4, 2021, FortisBC Inc. filed its 2021 Long Term Electric Resource Plan (2021 LTERP) and 2021 Long Term Demand Side Management Plan (LT DSM Plan) for acceptance by the British Columbia Utilities Commission (BCUC), pursuant to section 44.1(6) of the *Utilities Commission Act.*

The 2021 LTERP presents a long term plan for meeting the forecast peak and energy requirements of FBC customers with demand-side and supply-side resources at the lowest reasonable cost to customers over the next 20 years.

The 2021 LTERP analyzes the external regulatory, policy and planning environment within which FBC operates, compares energy and capacity forecasts against current resource capabilities and evaluates the potential for load reduction with demand-side management initiatives and portfolios of resource options to meet forecasted customer needs under different scenarios. The 2021 LTERP also includes an action plan that identifies activities that FBC expects to take during the first four years of the 20 year planning horizon.

The 2021 LT DSM Plan includes an assessment of the energy efficiency and conservation potential for FBC customers. The 2021 LT DSM Plan provides FBC with different levels of demand-side resource options to assess along with supply-side resource options in meeting the forecast load-resource balance gaps over the planning horizon identified within the 2021 LTERP.

To provide your insights, thoughts and perspectives on the Application, submit a letter of comment, request intervener status or register as an interested party at http://www.bcuc.com/get-involved. All submissions will be posted on www.bcuc.com and will be considered by the Panel in its review of the Application.

HOW TO PARTICIPATE

- **Submit a letter of comment**
- **Register as an intervener**
- **Request intervener status**

IMPORTANT DATES

1. **Wednesday, October 13**, 2021 - Deadline to register as an intervener or file a letter of comment with the BCUC.

GET MORE INFORMATION

FortisBC Energy Inc. Regulatory Affairs

16705 Fraser Highway
Surrey, BC Canada V4N 0E8

E: gas.regulatory.affairs@fortisbc.com

P: 604.592.7664

British Columbia Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3

E: Commission.Secretary@bcuc.com

P: 604.660.4700

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
2021 Long Term Electric Resource Plan and 2021 Long Term Demand-Side Management Plan

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On August 4 2021, FortisBC Inc. (FBC) filed its 2021 Long Term Electric Resource Plan (2021 LTERP) including its 2021 Long Term Demand-Side Management (DSM) Plan (2021 LT DSM Plan), as Volumes 1 and 2, respectively, for acceptance by the British Columbia Utilities Commission (BCUC) pursuant to section 44.1(6) of the *Utilities Commission Act* (UCA);

B. The 2021 LTERP presents a long term plan for meeting the forecast peak and energy requirements of FBC customers with demand-side and supply-side resources at the lowest reasonable cost to customers over the next 20 years;

C. The 2021 LTERP analyzes the external regulatory, policy and planning environment within which FBC operates, compares energy and capacity forecasts against current resource capabilities and evaluates the potential for load reduction with DSM initiatives and portfolios of resource options to meet forecast customer needs under different scenarios. The 2021 LTERP includes a preferred portfolio to meet the long term requirements of FBC's customers. The LTERP also includes an action plan that identifies activities that FBC expects to take during the first four years of the 20-year planning horizon;

D. The 2021 LT DSM Plan includes an assessment of the energy efficiency and conservation potential for FBC customers. The 2021 LT DSM Plan provides FBC with different levels of demand-side resource options to assess along with supply-side resource options in order to address the forecast load-resource balance gaps identified in the 2021 LTERP over the 20-year planning horizon. The 2021 LT DSM Plan also identifies FBC's preferred DSM scenario for long term planning purposes;

E. By Order G-XX-XX dated [DATE], the BCUC established a written hearing process to review the 2021 LTERP and 2021 LT DSM Plan;

F. The BCUC has reviewed the 2021 LTERP and 2021 LT DSM Plan and the evidence submitted in the proceeding and considers that acceptance of the 2021 LTERP and 2021 LT DSM Plan is warranted.

NOW THEREFORE pursuant to section 44.1(6) of the UCA, the BCUC orders as follows:

1. The BCUC accepts the FortisBC Inc. 2021 Long Term Electric Resource Plan, including the 2021 Long Term Demand-Side Management Plan as being in the public interest.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

FortisBC Inc.

2021 Long-Term Electric Resource Plan

Volume 2

2021 Long-Term Demand-Side Management Plan

August 4, 2021

Table of Contents

List of Appendices

Index of Tables and Figures

1. OVERVIEW

FortisBC Inc. (FBC or the Company)'s 2021 Long Term Demand-Side Management Plan (LT DSM Plan), as part of the 2021 Long-term Electric Resource Plan (LTERP), is filed pursuant to section 44.1(2)(b) of the *Utilities Commission Act* (*UCA*). The Company is *not* seeking approval of the proforma DSM expenditures listed in section 3.3 of the LT DSM Plan.

The CleanBC Plan and the *Clean Energy Act* (*CEA*) emphasize the deployment of demand-side measures to meet growing electricity demand in British Columbia. The *UCA* and the *Demand Side Measures Regulation* (DSM Regulation) enacted under the *UCA* set out more specific requirements for a public utility in developing a plan of how it intends to reduce customer demand for energy by taking cost-effective DSM measures and to include certain measures (programs) in the public utility's DSM plan portfolio.

The Company's objective for DSM activities is to offer customers in its service territory a range of programs within a cost-effective portfolio of measures that address the majority of end uses for each major customer sector.

The key objective for the LT DSM Plan is to determine the appropriate level of cost-effective DSM resource acquisition to support the Company's resource needs over the LTERP's planning horizon (2021 to 2040). The proposed DSM Scenario target is to acquire 435 GWh of cost-effective savings over the 20 year period.

1.1 *The UCA and DSM Regulation*

Table 1-1 in Section 1.4.1 of the LTERP lists the relevant sections of the *UCA* for resource planning requirements. The following requirements for a long term resource plan in s. 44.1(2) of the UCA are specifically relevant to the LT DSM Plan:

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

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

In addition, s. 44.1(8) of the *UCA* requires the BC Utilities Commission (BCUC) in determining whether to accept a long term resource plan, to consider:

> (c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures.

The DSM Regulation, enacted pursuant to the *UCA*, defines what DSM measures must be included in the public utility's DSM plan for it to be "adequate" within the meaning of s. 44.1(8)(c) of the UCA. A public utility's DSM plan portfolio is only adequate for the purposes of section 44.1 (8)(c) of the *UCA* if it includes the items in Table 1-1 below.

Table 1-1: Adequacy Requirements in a Long Term DSM Plan

Section of the *DSM Regulation*	Adequacy Requirement	Section of LT DSM Plan Addressing Requirement
3(a)	A demand-side measure intended specifically (i) to assist residents of low-income households, or (ii) in housing owned or operated by certain entities, including local government and first nations, as described in the regulation	4.1.7
3(b)	A demand-side measure intended specifically to improve the energy efficiency of rental accommodations	4.1.8
3(c)	An education program for students enrolled in schools in the public utility's service area	4.4.4
3(d)	An education program for students enrolled in post-secondary institutions in the public utility's service area	4.4.4
3(e)	Provides financial or other resources to eligible recipients to support the development of standards respecting energy conservation or the efficient use of energy	4.6.2
3(f)	Measure(s) to support adoption by governments, including indigenous communities, of a Step Code	4.6.2

The DSM Regulation, in section 4, also defines the basis for FBC's marginal electricity costs and sets out the test the BCUC must use in making determinations of cost effectiveness. These provisions, and where they are addressed in the LTERP and/or LT DSM Plan, are set out in Table 1-2 below.

Table 1-2: BCUC Considerations for Accepting a Long Term DSM Plan

Section of the *DSM Regulation*	Cost-effectiveness Requirement	References Addressing Requirement
4(1.1)	The BCUC must make determinations of cost effectiveness by applying the total resource cost test as follows …	LT DSM Plan Section 2.4
4(1.1)(b)	subject to subsection (1.3), the avoided electricity cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is (i) in the case of a demand-side measure of FortisBC Inc., an amount that the BCUC is satisfied represents FortisBC Inc.'s long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia	LTERP Section 11.3.1 and LT DSM Plan Section 2.4

Accordingly, the Company has developed a long-run marginal cost (LRMC) for DSM purposes, based on BC clean and renewable resources, of $90 per MWh, which reflects the cost of firm energy i.e. inclusive of generation capacity. Additionally, FBC is using a Deferred Capital Expenditure (DCE) value of $51.22 per kW-yr as its avoided capacity cost of deferred infrastructure, consistent with the methodology presented in Appendix C of FBC's 2017 DSM Expenditure Plan Application, accepted by the BCUC in its Decision and Order G-9-17.

Based on the avoided costs outlined above, and the Company's proposed Base DSM Scenario level, the CPR model estimates the portfolio TRC test to be 2.0.

In conclusion, the Company believes the LT DSM Plan meets the applicable requirements of the DSM Regulation, as amended March 24, 2017.

1.2 *THE CLEAN ENERGY ACT*

Section 44.1(8)(a) of the UCA requires the BCUC to consider the applicable of British Columbia's energy objectives in determining whether to accept the LTERP for filing.

Relevant energy objectives under the *CEA* are discussed in Section 1.4.2 of the LTERP, and include the objective "to take demand-side measures and to converse energy…"[1] The *CEA* defines a "demand-side measure" to mean a rate, measure, action or program undertaken:

(a) to conserve energy or promote energy efficiency;

(b) to reduce the energy demand a public utility must serve; or

(c) to shift the use of energy to periods of lower demand;

[1] …including the objective of *the authority* reducing its expected increase in demand for electricity *by the year 2020* by at least 66%. [emphasis added].

but does *not* include:

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate measure, action or program prescribed.

FBC has prepared the LT DSM Plan taking into consideration "the applicable of British Columbia's energy objectives" set out in the *CEA*[2]. Table 1-3 below lists the objectives set out in the *CEA* that are directly relevant to the Company's LT DSM Plan.

Table 1-3: Relevant *Clean Energy Act* Objectives

Clean Energy Act Objectives	2021 LT DSM Plan Satisfies Objective	
(b) to take demand-side measures and to conserve electricity…	✓	FBC proposes to adopt its Base DSM Scenario to be implemented over the LTERP planning horizon
(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia	✓	FBC has been active in supporting the installation of public EV charging stations. FBC's 2019-2022 DSM Plan includes DR pilot funding to manage/shift EV charging loads (Section 4.6.3)
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiency;	✓	Supporting Initiatives include Community Energy Planning (Section 4.5.2)

1.3 BCUC DIRECTIVES

Directives from the 2016 LTERP under Order G-117-18 that are specific to the LT DSM Plan are listed in Table 1-4 below, and are addressed in the 2021 LTERP and LT DSM Plan as indicated.

Table 1-4: Order G-117-18 BCUC Directives Applicable to LT DSM Plan

BCUC Directive	Section of LTERP Addressing Directive
1. Develop a richer analysis of DSM alternatives for the first five years of the LT DSM Plan.	LTERP Section 8.1 and LT DSM Plan Section 3.2.
2. Use average cost approach outlined in the DSM Regulation as the basis for its comparative analysis of DSM portfolios.	LTERP Section 8.1 and LT DSM Plan Section 3, Table 3-1
3. File next LTERP and LT DSM Plan by Dec 1, 2021.	Filed on August 4, 2021.

[2] British Columbia's energy objectives as defined in the *CEA* are fully identified in Table 1-3 of the LTERP.

2. DSM PLAN DEVELOPMENT

2.1 *PLANNING PRINCIPLES*

The objective of the LT DSM Plan is to determine the total quantity of DSM savings that are appropriate to fulfill FBC's resource needs over the planning horizon of the LTERP. It is not a detailed DSM Plan allocating savings to program areas (sectors), nor is FBC seeking acceptance of the DSM proforma cost estimates presented in the LT DSM Plan.

FBC used the following guiding principles to develop the LT DSM Plan:

1. Customer focused by including a range of measures within programs areas that address the key end-uses of the principal customer rate classes;
2. Cost effective by including only those measures, with the exception of adequacy measures, that have a Total Resource Cost (TRC) Benefit/Cost (B/C) ratio greater than unity on a portfolio basis (see Section 2.4); and,
3. Compliant with the applicable sections of the *UCA*, the *CEA*, and the DSM Regulation.

The Company expects to file its next multi-year DSM expenditure schedule by mid-2022.

2.2 *PLANNING STEPS*

The LT DSM Plan was developed using the following steps:

1. Quantify the program level energy savings potential available over the LTERP planning horizon (see Section 2.3);
2. Develop a range of DSM scenarios (low, base, medium, high, and maximum) to be modeled as part of the resource portfolios analyzed in the LTERP process;
3. Present the CPR Update and DSM scenario to stakeholders through the LTERP process; and
4. Select the DSM scenario that is the preferred option for the LT DSM Plan and the LTERP.

The following sections explain the above steps.

2.3 *CONSERVATION POTENTIAL REVIEW (CPR)*

FBC engaged Lumidyne Consulting (Lumidyne) to determine the updated energy efficiency potential for FBC's electric service area, in the residential, commercial, and industrial sectors over the planning horizon of 2021 to 2040. The CPR Report is provided in Appendix A of this LT DSM Plan.

The scope of the FBC 2021 CPR Results and Report (FBC CPR) included assessing the conservation potential of the total loads in its service territory, including those partially supplied by self-generating customers. In the case of Nelson Hydro, the self-generation portion of the conservation potential was allocated to the residential and commercial sectors of the CPR, and for the industrial sector the self-generation portion of conservation potential was allocated to the relevant segments (e.g. Pulp & Paper).

The FBC CPR used the model initially developed for the 2016 BC CPR[3]. The BC CPR used three distinct steps to estimate potential: generating a reference case forecast, characterizing energy savings measures, and estimating the economic savings potential.

For the first step, Lumidyne developed the base year and a reference case forecast of energy consumption. The base year establishes a profile of energy consumption for the utility based on an assessment of energy consumption by customer sector and segment, end-use, fuel, and types of equipment used.

Primary inputs to the base year were the Company's 2017 Residential and 2019 Commercial End-Use Surveys (R/CEUS). The key objectives of the R/CEUS are to collect detailed information about the characteristics and features of customer homes and businesses, as well as different ways in which electricity is used in them. Additionally the surveys solicit customer opinions, attitudes and behaviours related to electricity and conservation. This information was a key input to the FBC CPR and is further used to develop programs and communications strategies that are suited to the needs of FBC's customers.

Lumidyne also used data from the FortisBC Energy Inc. (FEI) R/CEUS and the previous FBC 2016 CPR assumptions as inputs into this CPR.

After calibrating the 2019 base year to actual utility energy sales, Lumidyne generated a reference case forecast that estimates the electricity demand over the CPR period absent incremental DSM activities. The technical and economic potential scenarios were then calculated against the reference case forecast. Lumidyne used two key inputs to construct the reference case forecast for each customer sector: stock growth rates and energy use intensity trends.

The next step was to develop a comprehensive list of energy efficiency measures to include in the analysis. One hundred and three electrical energy savings measures were included across the residential, commercial, and industrial sectors. Measures were prioritized for inclusion in the study based on impact, data availability, and likelihood to be cost-effective. Key measures, such as LED lighting, were reviewed in detail with updated cost and savings metrics and

[3] In 2016 FBC partnered with FEI, BCH to perform a provincial, dual-fuel conservation potential review (BC CPR).

incorporating recent program activity levels. A list of measures is included in the FBC CPR Appendix B1.

Once the reference case forecast and list of measures were established, Lumidyne estimated the technical, economic and market savings potential for electric energy and demand across FBC's service territory. Technical potential includes energy savings that could be achieved if all existing end uses were immediately replaced with an efficient measure, wherever technically feasible, regardless of the cost, market acceptance, or whether a measure has failed the economic test. Economic potential is a subset of the technical potential, but includes only measures that have passed the TRC (or the modified TRC, as need be) test using the LRMC and DCE avoided cost values. As a final step, Lumidyne determined the market potential, which is the potential uptake by customers of the economic potential and resulting savings over the planning horizon, taking into account factors such as the propensity of customers to participate in DSM program offers. In the sections below, any reference to potential refers to the market potential unless otherwise specified.

2.4 *THE TRC AND FBC AVOIDED COSTS*

The TRC is the governing test used in British Columbia to determine the cost-effectiveness of a utility's DSM portfolio. It comprises of benefits (the present value of the measures' energy savings, over their effective measure life, valued at the utility's avoided costs) divided by the costs (incremental cost of the measures plus program administration costs). The TRC can be expressed on an individual measure basis, for a program (group of measures), on a sector (program area) level, and/or at the portfolio level.

The TRC test was done at the measure level in the CPR modelling tool[4]. The benefits are FBC's "avoided costs", calculated as the measures' present value over the effective measure life of:

- energy savings, valued at the LRMC of $90 per MWh; and
- demand savings, valued at the DCE of $51.22 per kW-yr.

The measures' energy and demand savings are grossed up by the avoided transmission and distribution energy losses (line losses) value of 7.6 percent[5], before the benefits are calculated. A 7.9 percent pre-tax nominal discount rate was used to calculate the present value of the benefits.

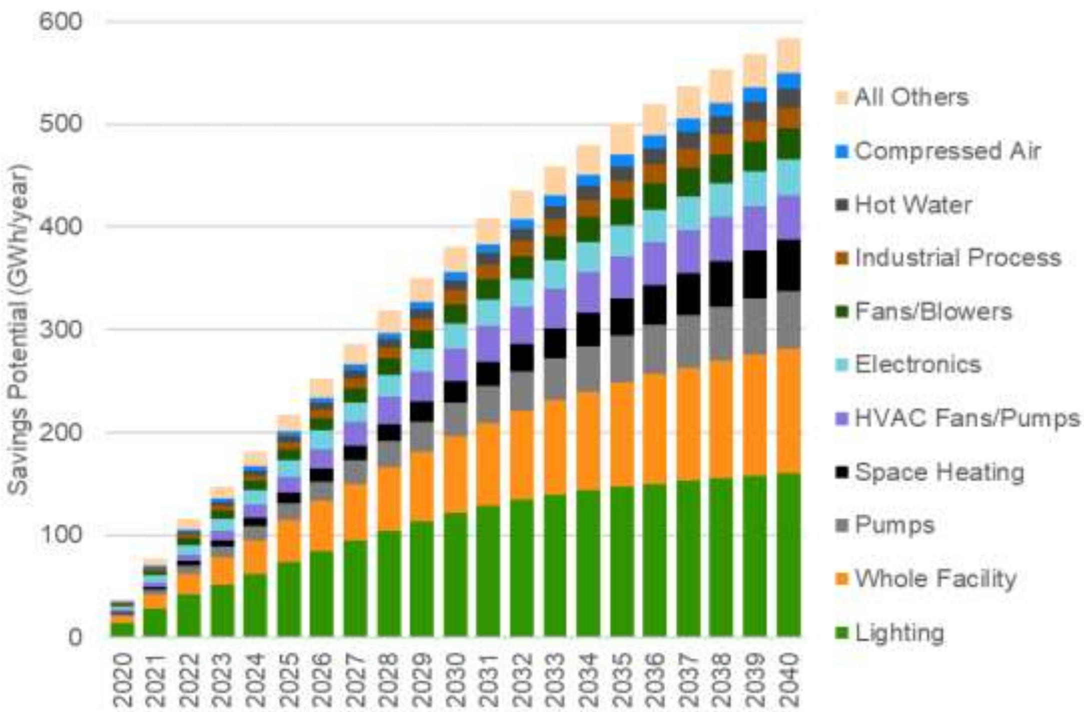
[4] FBC's 2021 CPR update uses DSMSim™ a bottom-up technology diffusion and stock tracking model implemented using a System Dynamics framework that was created for the 2016 BC CPR by Navigant Consulting.

[5] MRP Appendix B3.

2.5 CPR RESULTS – MARKET POTENTIAL

The following, taken from the FBC CPR, shows the cumulative market potential by end-use, aggregated across customer sectors, for new construction and retrofit measures combined. The top three categories include: lighting, whole-facility that includes new efficient building construction as well as behavioural energy management programs, and industrial pumps. Space heating, including building envelope improvements and equipment such as heat pumps, followed closely behind as the fourth measure in terms of market potential.

Figure 2-1: Cumulative Energy Savings Market Potential by End Use



Figures 2-2 and 2-3 show the potential of the key sectors in terms of energy savings and capacity savings potential, respectively.

Figure 2-2: Energy Savings Potential by Program Area

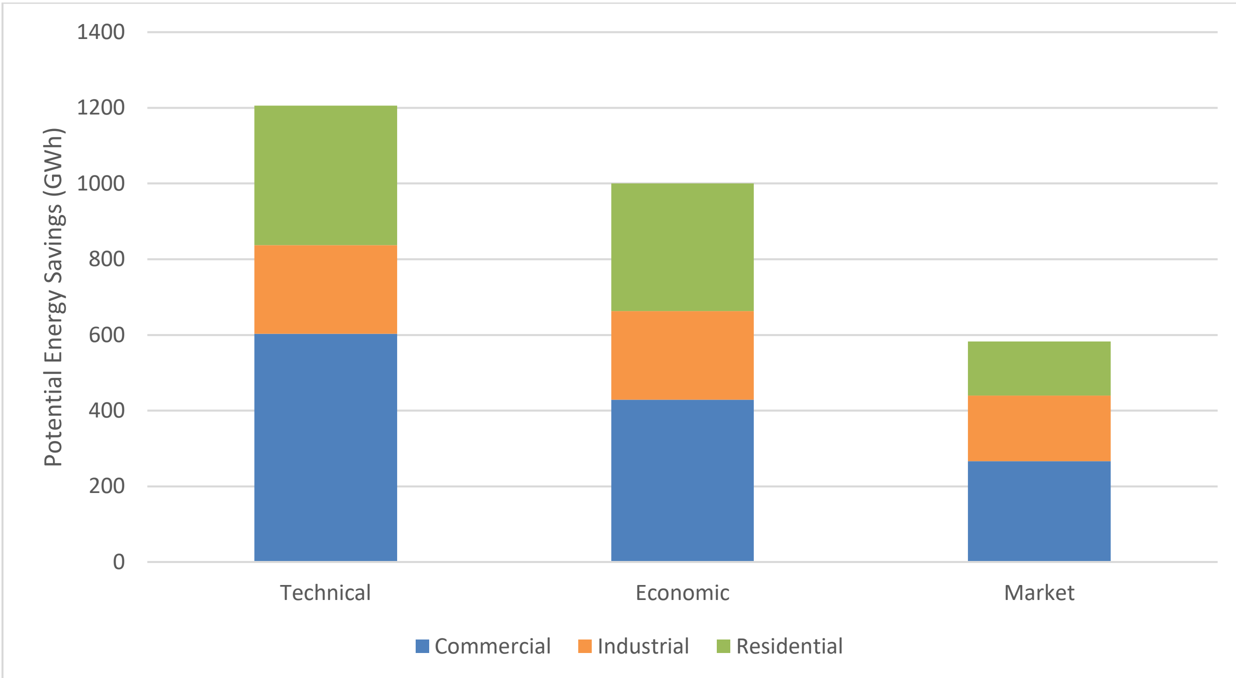
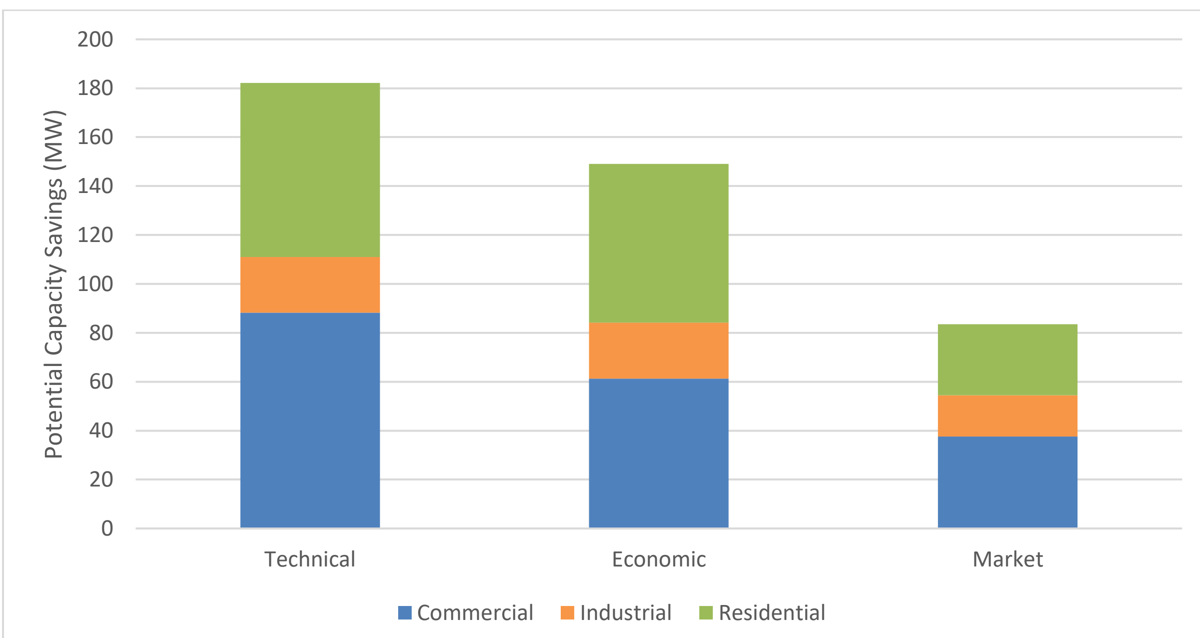


Figure 2-3: Capacity Savings Potential by Program Area



Figures 2-4 through 2-6 show the top measures within each sector, based on cumulative market savings potential over the 20 year planning period.

Figure 2-4: Top Measures within the Residential Sector

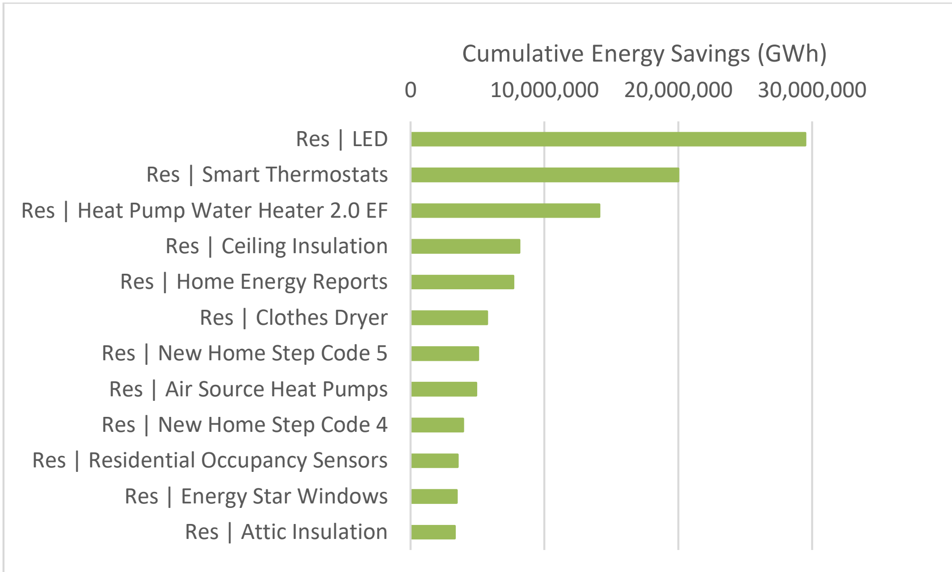


Figure 2-5: Top Measures within the Commercial Sector

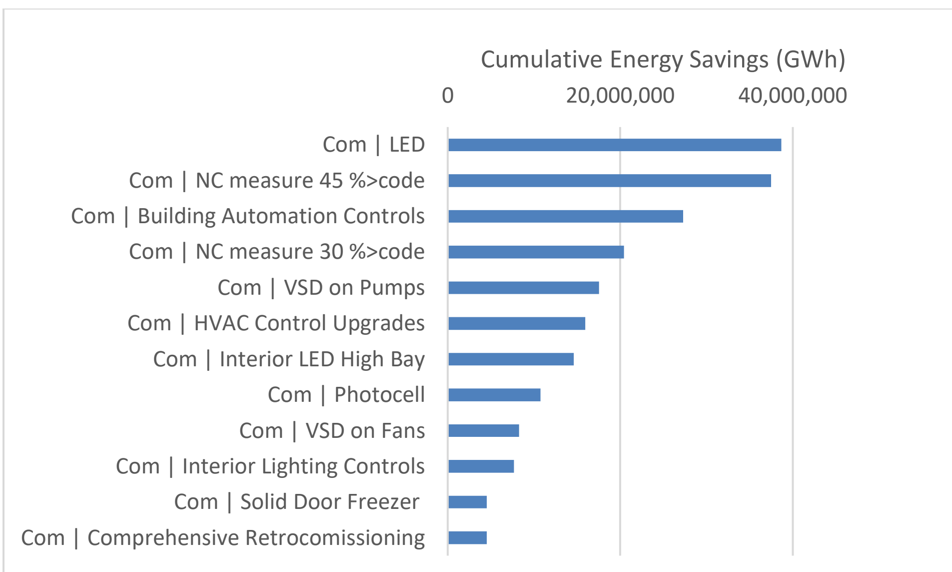
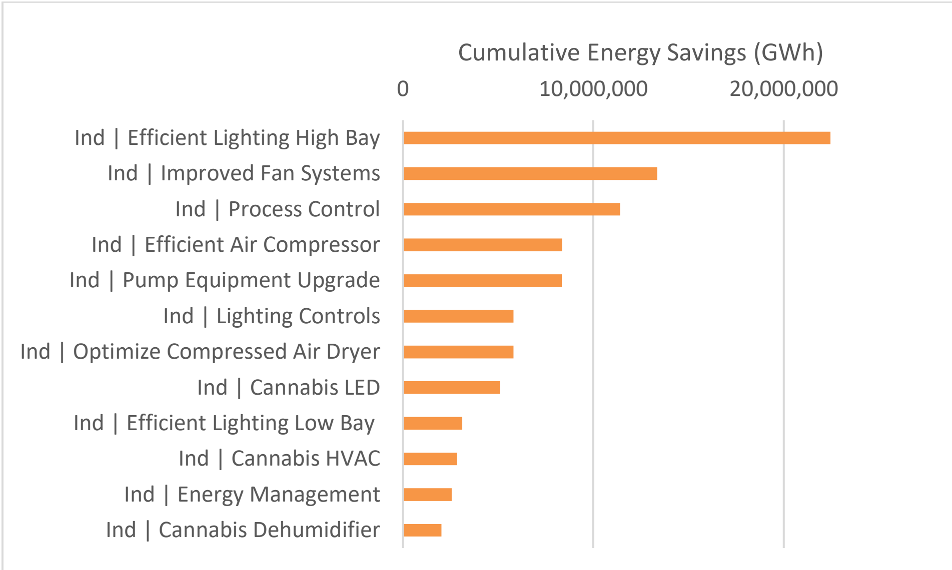


Figure 2-6: Top Measures within the Industrial Sector



While the above three figures above show the market potential results, the top measures across all sectors are the same as those identified in the economic potential. These results also provide a higher level of granularity than Figure 2-1, Cumulative Energy Savings Market Potential by End Use, and identify specific opportunities within the measures such as industrial efficient high bay lighting (lighting applications for buildings with high ceilings) and potential by BC Step Code level.

3. DSM SCENARIO DEVELOPMENT

The following section describes how FBC developed and analyzed DSM scenarios to plan for its long term resource needs. FBC developed five different DSM scenarios including Low, Base, Medium (Med), High and Maximum (Max) cases that were subsequently tested with various supply-side resource options in the Resource Planning portfolio analyses (Section 11 of the LTERP).

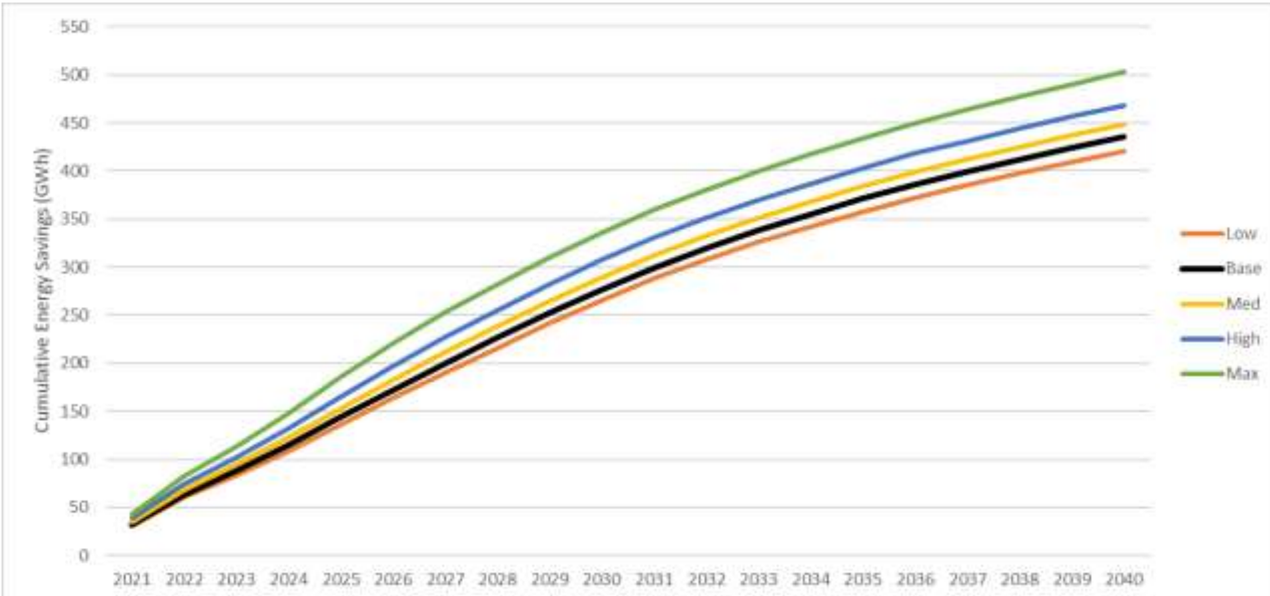
The DSM program scenarios FBC considered are based on incenting ever larger proportions of the DSM measures' incremental costs. The same DSM measures were included in all scenarios, and the uptake was based on the market potential. This approach supplants the prior metric of expressing DSM savings targets as a percent of load growth offset. That metric, which originated in the 2007 BC Energy Plan, included targets only to the end of 2020. New load growth forecasts are significantly impacted by electric vehicle growth, which DSM has no energy savings measures thus the existing approach was abandoned in favour of one that aligns with incremental costing, similar to other utility conservation potential reviews, including FEI.

The DSM program scenarios represent FBC paying levelized incentives[6] to cover 50, 62, 72, 84 and 100 percent of incremental measure costs respectively. The CPR model estimates the additional take-up and timing of measure installations based on the proportion paid by FBC. The non-linear response to the increasing incentive levels paid results in relatively small incremental savings at significantly higher portfolio costs (see Table 3.1).

[6] Levelized incentives refer to the principle that incentives support the most cost-effective measures. In the lower DSM program scenarios, the measures that are less cost-effective receive lower levels of funding.

Figure 3-1 shows the cumulative energy savings results of the five DSM program scenarios considered in the current LT DSM Plan, over the LTERP planning horizon.

Figure 3-1: Cumulative Energy Savings across Low, Base, Med, High and Max DSM Scenarios



As can be seen in Figure 3-1, the various scenarios follow a similar trend of the energy savings achieved, and the higher scenarios (where more incentive dollars were spent) result in greater cumulative energy savings. Despite the increase of incentive dollars spent across the various portfolios, the cumulative energy savings differentials are not very substantial between the various scenarios, especially within the first five years of the plan. In the final year, 2040, there is a modest 15 percent savings differential between the Max and Base DSM scenarios.

The following Table 3-1 shows key DSM scenario data, including the total of DSM savings (GWh, MW) to be targeted over the planning horizon. For context, relative to the 435 Total GWh (2021-2040) savings projected in the Base Scenario, FBC has reported 491 GWh of DSM program savings over the prior twenty years (2001-2020 inclusive).

The table also shows the average resource cost of the various DSM scenarios, and the incremental cost of incurring higher incentive levels in Med, High and Max scenarios.

Table 3-1: Key DSM Scenario Data

Category	DSM Scenario				
	Low	Base	Med	High	Max
Energy Savings, GWh					
Average per annum ('21 - '40)	21.0	21.8	22.4	23.4	25.2
Average per annum ('21 - '29)	26.8	28.0	29.4	31.4	34.5
Total (2021 to 2040)	421	435	449	468	503

Category	DSM Scenario				
	Low	Base	Med	High	Max
Capacity Savings, MW					
Total (2021 to 2040)	61.6	64.0	65.6	68.1	72.7
Resource Cost, 2020 ($000s)					
Average Cost ($/MWh)	$38	$44	$49	$57	$75
Incremental cost compared to base case ($/MWh)	N/A	-	$183	$190	$234

Table 3-1 further highlights the similarities between energy savings across the various scenarios, while highlighting the differences between the costs to achieve these incremental energy savings. Notably, the incremental energy savings above the Base scenario are substantially more expensive per MWh than the average cost of savings.

3.1 *DSM SCENARIO ENGAGEMENT*

The FBC 2021 CPR preliminary results, based on proxy avoided costs (LRMC and DCE), were presented during the LTERP Resource Planning Advisory Group (RPAG) stakeholder meeting held in November 2020. The FBC CPR, based on finalized avoided costs, and the range of DSM program scenarios developed were presented and discussed at the RPAG stakeholder meeting in June 2021.

In reviewing the DSM Scenarios, the RPAG had questions whether all scenarios passed the TRC. FBC confirmed that while each DSM Scenario had a different TRC, all DSM Scenarios passed the TRC. FBC also clarified that all DSM Scenarios included the same selection of cost-effective DSM measures. However, the difference between DSM Scenarios was the percentage of incremental cost that would be covered by DSM incentives. For example, the High scenario would have FBC cover a larger percentage of the incremental costs for the same measure, as compared to the Base scenario, capturing higher participation and consequently more savings.

There were also discussions as to whether DSM levels were cumulative or annual incremental. FBC confirmed that DSM savings were calculated on both a cumulative (Figure 3-1) and annual incremental basis (Figure 3-2). RPAG also discussed whether rate impact was factored in as a part of the LT DSM plan. FBC confirmed that detailed rate impact analysis was not part of the scope of the LT DSM plan, but noted that rate impact would be reflected and presented in the next DSM expenditures plan under the rate impact measure (RIM) test.

The RPAG also discussed the role of codes and standards (C&S) and whether they impacted the available savings potential. FBC confirmed that the CPR update reflects known changes to C&S in its model – in particular, FBC pointed out how BC Energy Step Code changes gradually reduce new construction savings potential as each lower step is adopted by municipalities.

More detailed results of the community consultation process, including the RPAG engagement, can be found in section 12 of the LTERP.

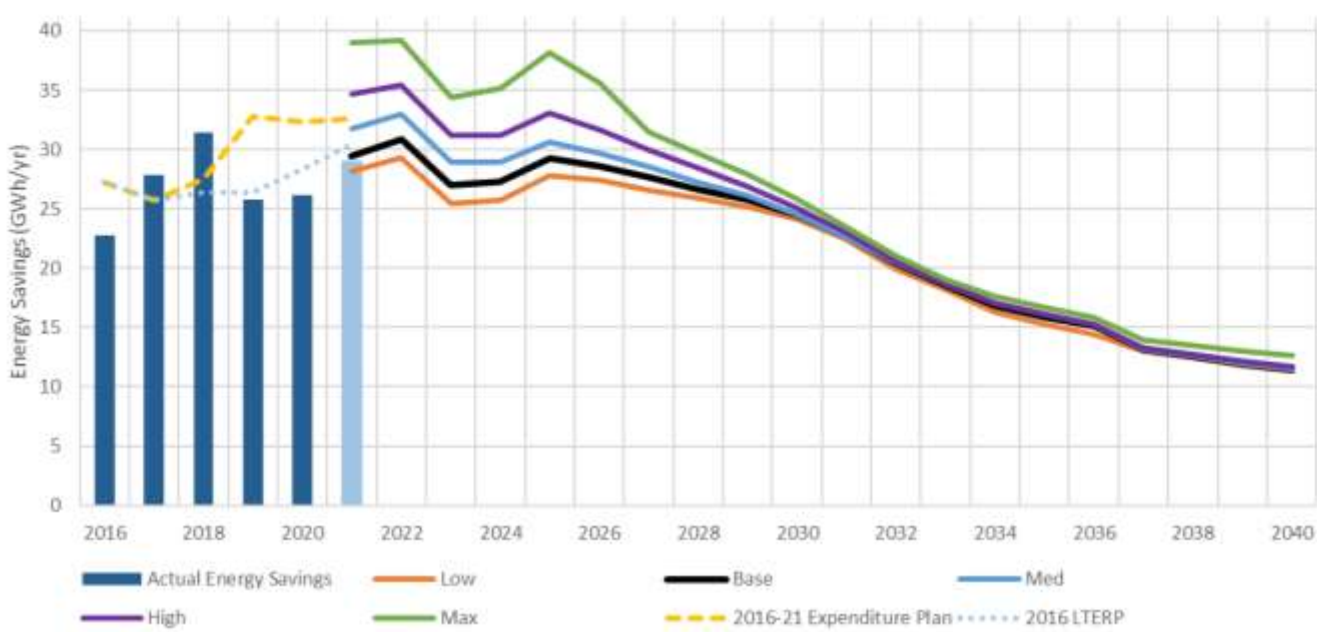
3.2 *DSM SCENARIO SELECTION*

The left-hand side of Figure 3-2 shows the following over the period 2016-2021:

1. the 2016 LTERP savings target trajectory (blue dotted line) to 2021;
2. expenditure plan saving targets (yellow dotted line);
3. actual results (blue bars) up to 2020 inclusive; and
4. the 2021 year-end forecast energy savings results.

The right-hand side of Figure 3-2 shows the trajectory of the five DSM program scenarios modelled by increasing the incentive portion of incremental measure costs. The current 2019-2022 DSM Plan target savings of approximately 32 GWh generally aligns with the Med scenario curve. However, the actual reported results in 2019 and 2020 were approximately 26 GWh/yr and, together with the 2021 year-end forecast of 29 GWh/yr, better aligns with the Base scenario.

Figure 3-2: Annual Energy Savings (Plan, Actual, DSM Scenarios)



The DSM Scenario curves are all relatively flat in the first five years (2022-2026), then begin to decline and converge in the next five years, with little differential evident in the final ten years. The decline in annual savings indicates the market take-up of available measures in the first period, followed by declining potential and take-up activities. The decline is a natural attribute of the Bass diffusion curve upon which the CPR model is built, as it follows a bell curve shape.

FBC selected the Base DSM scenario as its preferred scenario in the LT DSM Plan. The Base DSM Scenario can be characterized as a continuation of the 2016 LT DSM Plan's "High" scenario, in which the target savings increased from 26.4 to 30.4 GWh by 2022 and which used a constant 32 GWh/yr as a placeholder thereafter. As shown in Figure 3-2, the energy savings achieved to date and forecast in 2021 align with the Base scenario.

Though the Low DSM scenario was more cost effective than the Base scenario (see LTERP section 11.3.1), it was not chosen because:

- The Base scenario maintains consistency with the previous DSM plan, which had support from customers and stakeholders;
- Transitioning to the Low scenario may require FBC to remove existing program offerings or reduce program incentives, potentially resulting in a reputational impact with customers and trade allies;
- The Low scenario requires pullback of program offerings which limits FBC's ability to scale up programs in the future if new cost-effective measures are identified. Selecting the Base scenario provides flexibility to meet future market demands; and
- The Base scenario includes additional budget to further investigate DR programs that have the potential to cost-effectively defer capacity costs.

The Med, High and Max DSM scenarios were not chosen for the following reasons:

- They are less cost-effective than other resource options. FBC would be paying an increased incremental incentive proportion of measure costs, especially in comparison to the relatively low cost of power supply options, such as market electricity purchases. The *Incremental cost compared to base case ($/MWh)* row in Table 3-1 highlights the resource cost of the additional savings; and
- They present higher risks of insufficient customer participation. DSM participation is voluntary and FBC cannot have assurance that customer participation will be sufficient to meet the higher scenarios. The fact that FBC had below-target energy savings in recent program results indicates that it may not be readily feasible to achieve higher levels of DSM.

3.3 *PREFERRED DSM SCENARIO*

The following Table 3-2 shows the Base DSM scenario as FBC's preferred DSM scenario, including the anticipated rollout of target savings and proforma[7] costs in constant ($2020) dollars over the LTERP planning horizon. The Base scenario total energy savings of 435 GWh differs slightly from the total below as the 2021 and 2022 years refer to numbers from the current plan, rather than the CPR forecast.

[7] Finalized DSM Plan savings and expenditures will be submitted in the next DSM plan expenditure filing.

Table 3-2: Proforma DSM Savings Targets

Year	Description	Proforma DSM Budget (2020, $000s)	Target DSM Savings (GWh/yr)
2021	Plan - Forecast	$ 11,000	29.0
2022	Plan*	$ 11,400	33.1
2023	Forecast	$ 10,600	27.0
2024	Forecast	$ 11,000	27.3
2025	Forecast	$ 11,900	29.3
2026	Forecast	$ 11,500	28.6
2027	Forecast	$ 12,200	27.6
2028	Forecast	$ 12,100	26.7
2029	Forecast	$ 12,000	25.7
2030	Forecast	$ 11,800	24.4
2031	Forecast	$ 10,500	22.6
2032	Forecast	$ 10,900	20.4
2033	Forecast	$ 10,500	18.6
2034	Forecast	$ 9,600	16.8
2035	Forecast	$ 9,800	15.9
2036	Forecast	$ 8,200	15.1
2037	Forecast	$ 7,800	13.2
2038	Forecast	$ 7,700	12.6
2039	Forecast	$ 7,600	11.9
2040	Forecast	$ 7,500	11.4
Totals	**Forecast**	**$ 205,600**	**437.0**

4. DEMAND-SIDE MANAGEMENT PROGRAMS

DSM programs have been offered to qualified FBC customers since 1989 and are available to all direct customers, as well as indirect customers served by FBC's municipal electricity Wholesale customers of Grand Forks, Nelson, Penticton, and Summerland.

The LT DSM Plan portfolio includes programs for the Residential, Commercial, and Industrial customer classes and is intended to capture market potential savings over the long term, as identified in the FBC CPR. There are also low-income programs, portfolio-level supporting initiatives, and planning and evaluation activities required to support the DSM Plan.

The LT DSM Plan was developed in compliance with the provincial DSM Regulation, including program measures mandated to meet the Regulation's adequacy provisions[8], namely measures for rental and low income customers, education (elementary and secondary), post-secondary schools, and specified codes and standards expenditures.

The following sections and sub-sections describe the current program offerings in each sector that target key end-uses with cost-effective measures identified in the FBC CPR. Over the LTERP's planning horizon the various program offers and names, including the list of eligible measures, will likely change to suit the evolving marketplace, legislative requirements (applicable DSM Regulation amendments) and FBC customer needs.

4.1 *RESIDENTIAL SECTOR PROGRAMS*

The DSM Plan focuses on the opportunities in residential energy retrofits, addressing major end-uses (space heating, hot water and lighting), and new home construction where the majority of economic potential was identified in the FBC CPR. A general description of each program and the primary delivery mechanisms follows.

4.1.1 Home Renovation Rebates

The Home Renovation Rebate Program (HRR) encourages customers to take a whole-home approach to their energy efficiency upgrades. Rebates include space heating (including heat pumps), water heating, building envelope measures, ENERGY STAR appliances, as well as Bonus Offers to encourage the completion of multiple energy efficiency upgrades. By design, the program enables partnerships with BC Hydro, FEI, and all levels of government.

FBC and its program partners support BC's evolving home performance industry with activities that include trades outreach, training, quality installation initiatives, and contractor accreditation. These activities provide value to participating customers through improved performance and longevity of installed equipment and improved comfort of their homes.

[8] Section 3 of the DSM Regulation 326/2008 as amended March 24, 2017.

As an alternative to direct financial incentives for heat pumps, FBC offers heat pump loans for qualifying customers at a below market interest rate. To ensure customers continue to attain high efficiencies from their heat pump technology, FBC also offers a heat pump tune-up rebate and seasonal promotion.

4.1.2 Retail Rebates

To build market transformation and improve customer uptake on self-install measures, FBC collaborates with retailers, distributors and BC Hydro to offer in-store point-of-sale incentives on a variety of measures including LED light bulbs, lighting controls, bathroom fans, draft-proofing, water savers, and connected thermostats.

4.1.3 New Home Rebates

FBC provides incentives to encourage a higher level of whole home energy efficiency via a performance path aligned with the BC Energy Step Code. To enable uptake of energy-efficient construction, the New Home Program will provide additional incentives for pre-construction design activities such as building envelope design, mechanical design and Integrated Design Process (IDP), in addition to energy advisor services.

FBC, in partnership with FEI, supports local governments in their adoption of the BC Energy Step Code as part of an ongoing initiative for market transformation to high performance homes. FBC and its program partners support adoption of the BC Energy Step Code through builder and trades outreach, training and customer education about the benefits of high performance homes and other initiatives. Rebates for high performance water heaters are available as an optional path to the home performance rebates. Additionally, ENERGY STAR appliances, connected thermostats and drain water heat recovery in new homes are available for further energy savings.

4.1.4 Rental Apartment Program

The Rental Apartment Program offers no-cost walkthrough energy assessments and direct install of energy efficiency measures (such a screw-in light bulbs) to property managers of rental apartments. Additional technical and project management support is offered to encourage customers to implement the findings of the assessment. Customer participation is managed by FBC Technical Advisors and Key Account Managers.

4.2 *LOW-INCOME HOUSEHOLD PROGRAMS*

FBC continues to offer energy saving opportunities for low income customers including some Indigenous communities, low income customers living independently, and low income customers living in non-profit social housing. These offers are delivered through the Self Install Program, Direct Install Program and other initiatives.

4.2.1 Self Install

This program consists of a bundle of energy savings measures that are delivered to the participant's home and the participant installs these measures on their own. The bundle includes LED light bulbs, weather-stripping, faucet aerators, and other equipment that can be easily installed by the participant. This is a partnership program with FEI.

4.2.2 Direct Install

Recognizing that some low income customers do not have the expertise and/or physical capabilities to install energy efficient measures, these programs aim to remove that barrier by having a program delivery agent/contractor perform the installation. Measures include the types of measures found in the Self Install Program and also includes customized customer coaching on opportunities to save energy and some participations receive the installation of insulation, Energy Star fridges, and draft proofing of their homes. This is a partnership program with FEI and BC Hydro.

4.2.3 Other Initiatives

Other initiatives include supports for non-profit housing providers to perform energy studies, implement measures, and receive rebates for installed measures which may include energy efficient lighting, space and water heating-related measures, and envelope improvements. Additionally FBC provides supports for energy efficiency education, training and behavioural change initiatives.

4.3 *COMMERCIAL SECTOR PROGRAMS*

Program offers for the Commercial sector focus on the economic opportunities with respect to lighting, HVAC, motors, and refrigeration through a number of program offers/channels. The programs are detailed in the following sections.

4.3.1 Product Rebate Program

The product rebate program offers financial incentives for customers to complete simpler, high efficiency retrofits encompassing a number of well-characterized end-uses such as LED lighting, commercial heat pumps, and refrigeration.

Incentives for retrofit projects are offered through multiple channels including:

- point-of-purchase product rebates at authorized Point-of-Sale partners in FBC's Trade Ally Network;
- direct custom application through our online rebate application portal; and
- application assistance from FBC Technical Advisors.

4.3.2 Custom Efficiency Program

This program offers financial incentives for customers to implement complex and comprehensive retrofits, such as mechanical, motor, and HVAC upgrades. Customer participation is solicited and managed by FBC Technical Advisors and Key Account Managers. Key incentives are broken down as follows:

- Energy Study Incentive – An incentive to complete a third-party energy study from qualified energy consultants.
- Implementation Incentive – An incentive to cover a portion of the project costs based on the energy savings.

Larger projects are subject to Measurement and Verification to assess actual savings achieved.

4.3.3 Commercial New Construction Program

This program offers financial incentives for customers and developers constructing high performance buildings, such as those qualified under the BC Energy Step Code. Customer participation is managed by FBC Technical Advisors and Key Account Managers. The program provides a pathway for buildings subject to the BC Energy Step Code and another for buildings that are not subject to the BC Energy Step Code.

Key incentives are broken down as follows:

- Energy Modeling Incentive – An incentive to complete a third party energy model of the proposed building by a qualified energy modeller.
- Implementation Incentive – An incentive to cover a portion of the project costs. For projects subject to the BC Energy Step Code, the incentive is based on the achieved Step. For projects not subject to the BC Energy Step Code, the incentive is based on percent better than BC Building Code.
- Air Tightness Testing Incentive – An incentive to cover a portion of the cost to conduct a compliant mid-construction and/or post-construction air tightness test.

4.3.4 Continuous Optimization Program

The Continuous Optimization Program offers financial incentives for customers to recommission their existing HVAC system that has a building management system / direct digital control system. Incentives cover the cost of having a qualified third party consultant evaluate and recommission their existing HVAC system. The customer journey in the program is managed by FBC Technical Advisors and Key Account Managers.

4.4 *INDUSTRIAL SECTOR PROGRAMS*

Program offers for the Industrial sector are focused on the economic opportunities with respect to industrial process optimization, lighting, pumps and fans, compressed air, hydraulics, and other motor systems. The programs are detailed in the following sections.

4.4.1 Product Rebate Program

The Product Rebate Program offers financial incentives for customers to complete simpler high efficiency retrofits encompassing a number of well-characterized end-uses such as LED lighting, motors, compressed air, and irrigation.

Incentives for retrofit projects through multiple channels including:

- point-of-purchase product rebates at authorized Point-of-Sale partners in FBC's Trade Ally Network;
- direct custom application through our online rebate application portal; and
- application assistance from FBC Technical Advisors.

4.4.2 Custom Efficiency Program

This program offers financial incentives for customers to implement complex and comprehensive retrofits, such as industrial process, compressed air, motor and irrigation upgrades. The customer journey in the program is managed by FBC Technical Advisors and Key Account Managers. Key incentives are broken down as follows:

- Energy Study Incentive – An incentive to complete a third party energy study from qualified energy consultants.
- Implementation Incentive – An incentive to cover a portion of the project costs based on the energy savings.

Larger projects are subject to Measurement and Verification to better account for the actual savings achieved.

4.4.3 Strategic Energy Management

The program offers no-cost energy management support to industrial customers to use energy more efficiency. The program provides customers with tools and coaching to encourage them to implement both operational savings projects and larger capital retrofits. The program brings together a group of industrial customers in a cohort setting to work together and share knowledge related to energy management in their facilities.

4.5 SUPPORTING INITIATIVES

Supporting initiatives are important for the implementation of the DSM portfolio because they provide the program support, education for customers and students, build trade ally capacity and promote market transformation, all of which are necessary to enable the identified potential savings. The supporting initiatives, which complement the incentive-based programs listed previously, are characterized as portfolio level spending as they do not result in direct DSM savings.

4.5.1 My Energy Use

In collaboration with FEI, FBC's Customer Engagement Tool, "My Energy Use", launched in June of 2021 to FortisBC electric customers. My Energy Use is an enhancement to Account Online that provides customers with a better understanding of their home's energy use. Through the My Energy Use portal, customers can receive personalized insights into their individual home energy use and earn reward points for participating in energy-savings activities. In addition to the portal, FBC sent home energy reports to approximately 12,000 electric customers. The reports help customers understand their energy usage in comparison to energy used by similar homes, and encourages customers to reduce their energy use through actionable advice. My Energy Use promotes energy literacy and residential conservation and efficiency behaviour changes. Reports are sent up to six times per year.

4.5.2 Community Energy Planning

This element of Supporting Initiatives provides financial assistance to local governments, including Indigenous communities, and qualified institutions to facilitate energy efficiency planning activities like the development of community energy efficient strategic plans, energy efficient design practices and organizational policies like energy efficiency building code bylaws. The planning must be aimed at specifically reducing electricity usage and demand.

4.5.3 Trade Ally Network/Trades Training

FBC is committed to making the buildings in BC more energy efficient, and the Trade Ally Network (TAN), comprised of contractors, equipment manufacturers, distributors and Point of Sale partners, supports FBC in advancing energy efficiency messaging. FBC provides trade allies with the tools and resources that enable them to offer energy efficient upgrades to residential and commercial customers, and guide them towards making energy efficient choices.

FBC aims to improve industry's level of knowledge, expertise and functional skills in the areas that include deep energy retrofits, appliance safety, installation and best practices, by sponsoring and promoting eligible training and initiatives offered by non-profit trade organizations, including Thermal Environmental Comfort Association (TECA), Heating, refrigeration and Air Conditioning Institute of Canada (HRAI), and Southern Interior Construction Association (SICA), among others. In addition, FBC provides trade allies with co-op funding for eligible pre-approved advertising that promotes energy efficiency and innovative technologies in support of FBC's DSM program goals.

4.5.4 Education Programs

FBC, in collaboration with FEI, offers an online education program that supports the development of energy education in BC classrooms. It provides high quality, engaging, curriculum-connected resources and programs that highlight the BC energy story and encourages a bias-balanced development of energy literacy in classrooms for kindergarten through to Grade 12. Virtual and live interactive Energy Is Awesome classroom presentations augment the on-line program.

In addition, FBC provides funding support for several external third party non-profit educational organizations to deliver conservation messaging.

FBC also provides financial and in-kind support for post-secondary initiatives for curriculum-based class-room instruction, energy efficiency related curriculum development and broader campus-wide behaviour change programs.

4.6 *PORTFOLIO*

4.6.1 Planning and Evaluation

FBCs planning and evaluation activities include non-program area specific projects used to develop, support, and assess current and future C&EM expenditure applications, as well as for directional input into program development.

Planning activities include, but are not limited to:

- Conservation potential review studies;
- Residential and commercial end-use surveys; and
- Studies to better understand customer energy usage, such as disaggregation studies.

Primary types of Evaluation, Measurement and Verification (EM&V) activities include the following:

- Process evaluations, where surveys and interviews of participants and trade allies are used to assess customer satisfaction and program success;
- Impact evaluations, to measure the achieved energy savings attributable from the program, including realization rates, free-ridership and spillover impacts;
    - Secondary evaluation findings of market effects may be revealed through interviews of market players such as trade allies; and

- Measurement & Verification (M&V) activities, to confirm project specific energy savings associated with energy conservation measures.

4.6.2 Codes and Standards

FBC collaborates with a number of international and national organizations such as the Consortium for Energy Efficiency and the Canadian Standards Association to set new efficiency standards for consumer electronics, appliances, and lighting products among other equipment and technologies.

FBC also works with local, provincial, and federal governments who are setting policy and regulations to increase the minimum performance of electricity consuming equipment and/or as-built building performance level. The BC Energy Step Code is a notable example of such policies and regulations.

FBC supports codes and standards policy development and research, through in-kind and financial co-funding arrangements to meet this adequacy requirement.

4.6.3 Demand Response Pilots

FBC's 2019-2022 DSM Expenditure Plan includes funding to conduct Demand-Response (DR) pilot projects to test the opportunity, and customer willingness, to undertake load shifting during peak demand periods. In 2019-2020 the Company undertook the first phase of DR pilot with commercial & industrial customers that focused on, but was not limited to, offsetting summer loads in the Kelowna area, the results of which are summarized in the 2019 and 2020 DSM Annual reports.

The Company currently has a residential DR pilot phase out to tender. It will seek to control and shift key household end-uses such as: space cooling, hot water and possibly other devices such as pool pumps. Importantly, the scope includes controls of residential home EV charging, which has been identified as the largest demand growth factor in this LTERP.

The current DR pilots are intended to provide proof of concept, i.e. magnitude of load shifted and propensity of customers to participate. The results are expected to inform a business case for an ongoing DSM program to scale up DR capacity over time, the benefits of which may include deferral of T&D infrastructure upgrades and power supply operational flexibility.

4.6.4 Innovative Technologies

FBC supports the development or increased use of a technology, a system of technologies, or a building or industrial facility design that could achieve significant reductions of energy use or significantly more efficient use of energy. FortisBC supports feasibility studies, field studies, and pilots to validate customer acceptance and energy savings of innovative equipment and systems. Technologies that show potential are incorporated into DSM programs. Innovative technologies are considered to be a specified demand-side measure, which means that the program and the technologies are evaluated as part of the DSM portfolio as a whole.

Innovative technologies that will be looked at within this planning period include, but are not limited to, deep energy retrofits (whole building analysis and construction techniques used to improve building performance), connected appliances, and building-level controls systems.

5. OTHER MATTERS

5.1 *ELECTRIFICATION*

This LT DSM Plan relies on the LTERP Load Scenarios (section 4 of Volume 1) to explore the impacts of Deep Electrification, and other less intense variants thereof, on FBC's LRB.

The 2016 BC CPR estimated 36 GWh of fuel-switching potential, primarily commercial space heating and a small 1 GWh portion of residential space heating. Using the provincially prescribed cost test, only the commercial space heating measure achieved unity – after rounding – on the base measure only. Once program administration costs were included all the measures failed at the program level.

In light of anticipated fuel cost increases, e.g. the federally announced carbon tax escalation to $170/tonne by 2030, the Company is updating its electrification potential as part of its 2021 CPR scope of work. Those results are not ready at the time of this filing.

Appendix A

2021 CONSERVATION POTENTIAL REVIEW REPORT

FortisBC Electric Conservation Potential Review

Prepared for:

Prepared By:

Lumidyne Consulting, LLC
lumidyneconsulting.com

Primary Contact:
James Milford
Director of Technology

July 2021

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Disclaimer

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LUMIDYNE
CONSULTING LLC

Executive Summary

FortisBC Inc. engaged Lumidyne Consulting Inc. in 2020 to prepare a Conservation Potential Review (CPR) that estimates electric energy and demand savings potential from a broad collection of energy-saving measures in FortisBC's electric service territory. This effort builds on the data and methodology from the previous CPR that began in 2015 and finalized its results in 2018. The CPR identifies energy-efficient equipment and building practices, operational and maintenance activities, and end-user behaviors that reduce electric energy consumption, which often leads to the secondary benefit of reducing electric peak demand.

The analysis estimated the technical, economic and market potential for each conservation measure. Market potential is the focus of this report because it incorporates barriers to adoption stemming from delays in stock turnover, customers' awareness and willingness to adopt, and substitutive effects among efficient measures serving the same application. FortisBC can use this analysis to inform conservation goals, demand side management (DSM) program planning, load forecasting, and integrated resource planning.

Approach

The 2021 CPR follows a similar methodological approach to that used in Navigant's 2017 technical and economic potential assessment and Navigant's 2018 market potential assessment, where the combination formed FortisBC's 2016 CPR.[1,2] We refer the reader to those documents for an in-depth description of the underlying methodology. This report provides a high-level methodological summary, and it highlights notable updates or enhancements relative to the previous CPR.

The main components of the analysis were:

- development of a 2019 *Base Year* accounting of building stocks, end use intensity and energy consumption;
- development of a 2020-2040 *Reference Case* forecast of building stocks, end use intensity and energy consumption;
- development of savings profiles for monthly energy savings and peak-coincidence factors for summer and winter demand savings;
- update and expansion of the measure characterization; and
- estimation of savings potential.

Each of these tasks is briefly described below.

Base Year

Estimation of the *Base Year* began with 2019 actual sector-level customer counts and annual energy consumption for FortisBC's direct and indirect customers.[3] The team allocated sector-level consumption to customer segments and end uses based on data and trends observed in FortisBC's end use surveys and Natural

[1] Navigant's 2017 technical and economic potential report can be found in Appendix A (p. 513) of FortisBC's "2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan)," accessible at https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/161130_fbc_2016_lterp_ltdsm_plan.pdf.
[2] Navigant's 2018 market potential report can be found in Appendix B (p. 86) of FortisBC's "Application for Acceptance of Demand Side Management (DSM) Expenditures Plan for the period covering 2019 to 2022," accessible at https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/180802_fbc_2019-2022_dsm_expenditures_application_ff.pdf.
[3] Indirect customers purchase electricity from wholesalers who purchase their electricity from FortisBC. Indirect customers are eligible to participate in FortisBC's DSM programs, so their consumption is considered in the CPR.

Resource Canada's Comprehensive Energy Use Database (NRCan CEUD). The *Base Year* estimates include the following:

Residential

- Number of households by archetype
- End use intensity by customer segment and end use
- Annual energy consumption by customer segment and end use

Commercial

- Number of multi-unit residential building units by height category
- Floor space by customer segment
- End use intensity by customer segment and end use
- Annual energy consumption by customer segment and end use

Industrial

- Floor space for cannabis facilities
- End use intensity for cannabis facilities
- Annual energy consumption by customer segment and end use

The team calibrated all assumptions listed above to ensure that the summation of *Base Year* energy consumption over customer segments and end uses in each sector was identical to the actual 2019 sectoral load. As a result, the *Base Year* avoids double-counting DSM savings previously achieved by FortisBC programs.

Reference Case

The *Reference Case* is a forecast of consumption-related indicators from 2020 through 2040 that uses the 2019 *Base Year* as the starting point for forecast changes in the market. All indicators from the *Base Year*—such as building stocks, end use intensities, and annual consumption—and the addition of industrial output activity have associated forecasts in the *Reference Case*.

Forecast trends in industrial output activity—and thus consumption—relied on output indicators used in FortisBC's 2021 Long Term Electric Resource Plan (LTERP). Trends in residential and commercial end use intensity came from integration of data from end use surveys, NRCan's CEUD, and long-term trends identified in FortisBC's 2016 CPR.

Lumidyne calibrated the *Reference Case's* consumption forecasts to the LTERP "Reference" scenario's sector-level consumption forecasts after removing the impact of electric vehicles and planned DSM savings. To align components of the *Reference Case's* consumption with the LTERP, the team chose to calibrate the most uncertain assumptions. For the commercial sector, the team calibrated floor space estimates to ensure that the multiplication of the CPR's floor space and EUI forecasts aligned with the LTERP's commercial consumption forecast. The industrial sector's consumption forecasts relied on calibrated industrial output indicators, while the residential sector used calibrated customer growth rates.

To summarize, the *Reference Case* stems from actual 2019 consumption captured by the *Base Year*, follows the LTERP's sector-level consumption forecast, and includes observed trends in EUIs from multiple data sources. Since the *Reference Case* forms the scaling basis for per-measure savings, the team carefully developed the *Reference Case* to create a solid foundation for savings potential estimates.

Measure Characterization

The study considers 167 distinct conservation measures, most of which are further differentiated and tailored to their applicable customer segments. The measures pertain to 24 customer segments and 19 end uses, resulting in 973 measure-and-segment combinations. Compared with the previous CPR, the team made several measure additions and removals:

Measure additions

- Cannabis lighting, dehumidification, and heating/ventilation/air conditioning (HVAC)
- BC Energy Step Codes for residential and commercial new building construction

Measure removals

- Measures that are now minimum code: commercial LED exit lights and general service CFL lamps.
- Measures substituted with BC Energy Step Codes: ENERGY STAR home, R-2000 Standard home, passive house, net-zero home, apartment new construction 30% above code.
- Measures associated with the “Oil & Gas” and “Metal Mining” customer segments.
- Measures tracking savings from already-implemented building codes or appliance standards that FortisBC did not administer or incentivize: general service lamp, reflector lamp, metal halide lamp, refrigerator, freezer, and packaged terminal AC/HP codes and standards.

Additionally, the team implemented many updates to the measure characterizations to account for current equipment saturation and penetration levels, end use intensities, costs and efficiency levels. Sources for these updates include FortisBC program evaluation data, end use surveys, literature review, market research and the *Base Year* analysis. Notably, the characterizations of commercial and industrial lighting measures offered through FortisBC’s programs were updated to align the CPR’s incremental savings and costs with findings from FortisBC’s evaluation studies.

Monthly Savings Profiles & Peak-Coincidence Factors

To provide FortisBC with more visibility into the timing of savings, Lumidyne generated monthly energy savings profiles and differentiated demand savings for summer and winter peak coincidence. The analysis used measured and simulated hourly load profiles for dozens of customer segments and end uses from similar climate zones to construct a bottoms-up representation of hourly loads. The team scaled the hourly end use profiles to align with the *Base Year’s* annual energy consumption by end use and customer segment. Next, Lumidyne aggregated the hourly loads to the sector level and calibrated them against each sector’s 2019 actual monthly consumption. This process included steps to keep the monthly relationships between average daily temperature and space heating and cooling loads, and it preserved the relationship between hours of daylight and lighting loads.

After calibrating all customer segment and end use hourly load shapes, the team aggregated the load estimates to the system level and compared it with FortisBC’s systemwide actual 2019 hourly load. This validation exercise confirmed that there was sufficient alignment—in diurnal load shapes and summer and winter peak coincidence—between the aggregated load shape estimates and actual hourly load. The output from this analysis is monthly allocation factors for energy savings (expressed as the percentage of annual savings occurring in each month) and peak-coincident demand factors (expressed as kW of summer or winter peak savings per kWh/year of energy savings). Multiplication of these factors by the study’s annual energy savings potential provides insight into the timing of energy savings and the associated peak demand savings.

Estimation of Savings Potential

The study estimated electric energy savings and electric summer/winter peak demand savings, along with gas energy savings for dual-fuel measures and those having interactive effects with gas-consuming end uses. All results in the report reflect cumulative at-the-meter savings, which exclude savings from avoided line losses. Additionally, most results show gross savings, unless they explicitly say they include the effects of natural change. Potential after natural change is analogous to net savings, and it accounts for changes in equipment saturation and end use intensities that are forecast to naturally occur absent any DSM program support or incentivization.

The report's focus is on market savings potential, but the analysis began by estimating technical and economic potential. Technical potential is the hypothetical savings for each end use application, where the CPR measure having the highest efficiency immediately replaces its corresponding low-efficiency or minimum-code baseline measure wherever it is technically feasible. Economic potential is the subset of technical potential that has a benefit-cost ratio of 1.0 or higher. Commercial and industrial economic potential used a total resource cost (TRC) benefit-cost ratio for economic screening, while residential potential used a modified total resource cost (mTRC) benefit-cost ratio. The mTRC was similar to the TRC, except that it included a 15 percent increase to avoided costs. The 15 percent increase in avoided costs captured non-energy benefits, as allowed by British Columbia DSM Regulation.[4] Applying the mTRC increased residential market potential by less than 4 percent, indicating that most residential potential was economic under the TRC test.

Market potential is a subset of economic potential, and its intent is to capture real-world dynamics influencing measure adoption. For example, equipment turnover of replace-on-burnout measures constrains the market potential by limiting the opportunities for replacing failed inefficient equipment with efficient equipment. Market potential requires customer awareness and familiarity with efficient measures before adoption occurs. Lastly, relative economic attractiveness—after considering utility bill savings, incremental costs, operation and maintenance costs, and incentives—among high- and low-efficiency measures influences customers' purchasing decisions that drive market potential.

Importantly, market potential differs from program potential. Program potential considers various methods of administering DSM programs, constraints on program staffing, limited budgets for administration and incentives, and other factors influencing program design and goalsetting. Additionally, program potential excludes measures such as ENERGY STAR household electronics like televisions, which are regulated by government codes and standards and not typically incented under utility programs.

Market potential omits these components and instead focuses on a less-constrained assessment of savings based on customers' expected sensitivity to cost and plausible adoption rates. In practice, program designers often use market potential studies to investigate new conservation opportunities and to provide directional guidance as they tailor detailed plans for program implementation and goalsetting.

[4] Under British Columbia Utilities Commission DSM Regulation s4.(1.1)(c), the modified total resource cost rules allow for a 15 percent increase for non-energy benefits, up to a limit of 10 percent of the electric DSM portfolio expenditure.

Findings

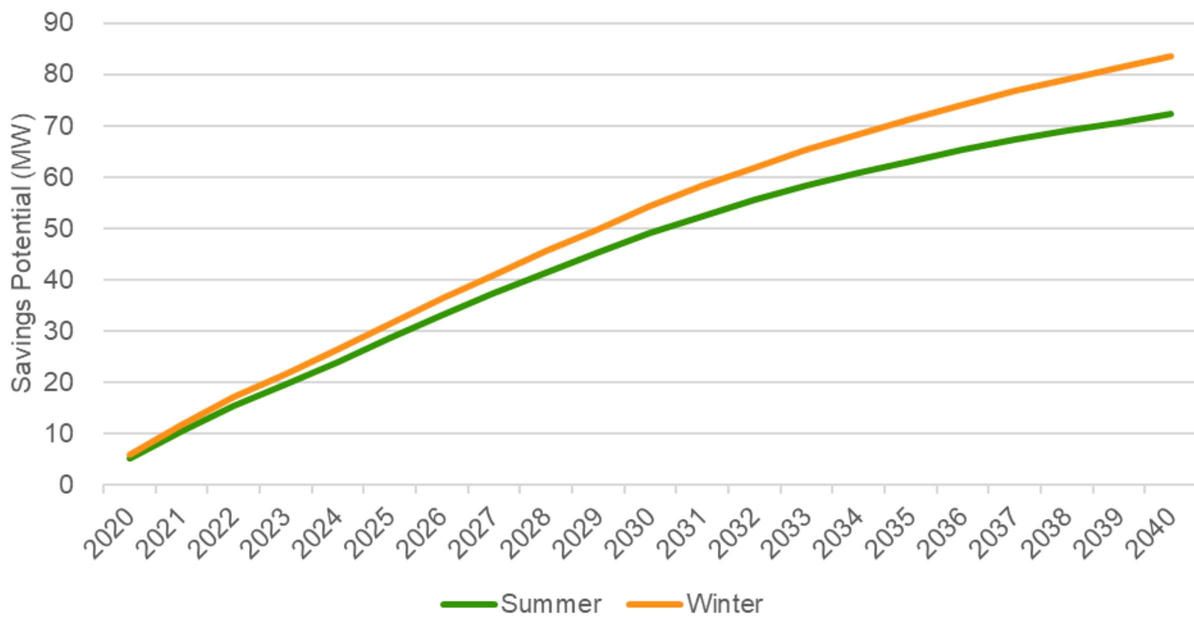
The analysis found cumulative electric energy market potential to begin at 38 GWh/year in 2020 and grow to 583 GWh/year by 2040, as shown in Figure 1. The average incremental annual savings over the horizon is slightly less than 28 GWh/year. Incremental annual savings slowly decline over time due to efficient measures saturating the replace-on-burnout and retrofit markets and due to Step Codes' raising of the minimum-code baseline in the new construction markets, which leads to a corresponding reduction in incremental savings from efficient measures. Energy savings in 2020 equate to 1 percent of FortisBC's total energy sales to direct and indirect customers. By 2040, the cumulative market potential is 12.5 percent of sales.

Figure 1. Total Cumulative Electric Energy Savings Market Potential (GWh/year, % of Sales)

Source: Lumidyne

The forecast of cumulative electric winter demand market potential, shown in Figure 2, begins at 6 MW and reaches 84 MW by 2040. The market potential for summer demand is slightly lower, starting at 5 MW and reaching 72 MW. Winter potential corresponds to demand savings averaged between 5:00pm and 7:00pm in January and February. Summer potential averages demand savings between 5:00pm and 7:00pm in July and August. Though the analysis estimated demand savings across the two peakiest months in the summer and winter seasons, Lumidyne's load shape analysis suggests that the demand savings would be similar for adjacent months (e.g., December, March, June and August).

Figure 2. Total Cumulative Electric Demand Savings Market Potential (MW)



Source: Lumidyne

As a percentage of the FortisBC 2021 LTERP's forecast summer and winter peak loads before DSM and losses, the market potential begins at about 0.8 percent of peak loads and grows to just under 8 percent by 2040. This is true for both winter and summer demand savings market potential. However, FortisBC set a new summer peak record in 2021, so it is possible that summer peak loads might grow faster than the 2021 LTERP had forecast.

Comparing this CPR's market potential with the previous CPR, the average incremental energy savings are similar in magnitude. However, this CPR's average incremental winter demand savings are about 33 percent lower than the previous CPR. The lower winter demand savings mostly result from the use of bottom-up hourly load profiles, which apply greater rigor to the estimation of demand savings via calibration with actual FortisBC systemwide hourly load.[5] In contrast, the previous CPR made no attempt to reconcile demand savings estimates with the temporal diversity observed in actual FortisBC loads.

[5] Lumidyne's development of bottom-up hourly load profiles started with load shapes at the equipment and end use levels for each customer segment. After aggregating to the end-use level for each customer segment, the team scaled the profiles to ensure that the resulting annual consumption aligned with *Base Year's* end use intensities. To confirm the reasonableness of the hourly profiles, Lumidyne aggregated all profiles across end uses and customer segments and compared it with FortisBC's 2019 actual systemwide hourly loads. Compared with the 2019 actual hourly loads, the CPR's aggregate hourly loads showed similar summer and winter peaks, seasonal variations and monthly diurnal shapes.

1 Introduction

FortisBC Inc. engaged Lumidyne Consulting Inc. in 2020 to prepare a Conservation Potential Review (CPR) that estimates electric energy and demand savings potential from a broad collection of energy-saving measures in FortisBC's electric service territory. This effort builds upon the data and methodology from the previous CPR that began in 2016 and finalized its results in 2018. The CPR identifies energy-efficient equipment and building practices, operational and maintenance activities, and end-user behaviors that reduce electric energy consumption, which often leads to the secondary benefit of reducing electric peak demand.

The analysis estimated the technical, economic and market potential for each conservation measure. Market potential is the focus of this report because it incorporates barriers to adoption stemming from delays in stock turnover, customers' awareness and willingness to adopt, and substitutive effects among efficient measures serving the same application. FortisBC can use this analysis to inform conservation goals, demand side management (DSM) program planning, load forecasting, and integrated resource planning.

1.1 Report Organization

The remainder of this report follows the outline below:

- ***Section 1***: describes methodological changes from the previous CPR and highlights the study's caveats and limitations.
- ***Section 2***: details the approach to estimating savings potential, with discussion on the *Base Year*, *Reference Case*, monthly savings profiles and peak-coincident factors, and technical, economic and market potential.
- ***Section 3***: provides market potential results at different levels of aggregation, along with cost effectiveness by sector and portfolio.
- ***Appendices***: supplies tabular data associated with the report's charts and figures.

1.2 Changes from Previous CPR

The 2021 CPR follows a similar methodological approach to that used in 2016 FBC CPR technical and economic potential assessment and the subsequent FBC market potential assessment.[6,7] We refer the reader to those documents for an in-depth description of the underlying methodology. Lumidyne devoted most of its efforts toward updating data assumptions to reflect current market conditions, rather than changing the methodological approach. As such, this report provides a more concise methodological summary highlighting notable updates or enhancements relative to the previous CPR.

The remainder of this section describes this study's most significant changes compared with the 2016 CPR.

[6] FBC's 2016 technical and economic potential report can be found in Appendix A (p. 513) of FortisBC's "2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan)," accessible at https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/161130_fbc_2016_lterp_ltdsm_plan.pdf.
[7] FBC's 2016 market potential report can be found in Appendix B (p. 86) of FortisBC's "Application for Acceptance of Demand Side Management (DSM) Expenditures Plan for the period covering 2019 to 2022," accessible at https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/180802_fbc_2019-2022_dsm_expenditures_application_ff.pdf.

Base Year

Estimation of the *Base Year* used 2019 actual sector-level customer counts and annual energy consumption for FortisBC's direct and indirect customers, while the previous CPR relied on 2014 data.[8] The revision led to a 10 percent decrease in residential households—with an increase in the share of households associated with multi-unit residential buildings (MURBs) compared with single-family homes—and a 15 percent decrease in residential electricity consumption.

Commercial floor space estimates increased by 45 percent and consumption increased by 30 percent. Though speculative, this appreciable change might be attributed to having better data in this analysis to allocate indirect customers to their respective sectors. Additionally, this study classified as commercial buildings any facility on large power electric rates that had characteristics similar to commercial building types—for example, colleges, universities, hospitals, hotels and public office buildings. It is possible that the 2016 CPR treated all customers on large power electric rates as industrial customers.

Industrial consumption decreased by 9.5 percent, mostly stemming from the loss of load from the "metal mining" segment. Additionally, this CPR did not evaluate the "oil and gas" segment because FortisBC has no customers in that industry.

Reference Case

Where useful, Lumidyne calibrated the *Reference Case's* consumption forecasts to FortisBC's 2021 Long Term Electric Resource Plan (LTERP) "Reference" scenario's sector-level consumption forecasts after removing the impact of electric vehicles and planned DSM savings. The 2016 CPR performed a similar calibration process to FortisBC's 20-Year Load Forecast from an unspecified year, which FortisBC likely developed around 2016.

This CPR's reference case projected that total direct and indirect electricity consumption would grow at an average annual rate of 0.94 percent per year, while the 2016 CPR assumed a 0.98 percent per year average growth rate.

Monthly Savings Profiles & Peak-Coincident Demand Factors

To provide FortisBC with more visibility into the timing of savings, Lumidyne generated monthly energy savings profiles and differentiated demand savings for summer and winter peak coincidence. The analysis used measured and simulated hourly load profiles for dozens of customer segments and end uses from similar climate zones to construct a bottoms-up representation of hourly loads. The output from this analysis was monthly allocation factors for energy savings (expressed as the percentage of annual savings occurring in each month) and peak-coincident demand factors (expressed as kW of summer or winter peak savings per kWh/year of energy savings). Multiplication of these factors by the study's annual energy savings potential provided insight into the timing of energy savings and the associated peak demand savings.

Comparing this CPR's market potential with the 2016 CPR, the average incremental winter demand savings are about 33 percent lower than the previous CPR. The lower winter demand savings mostly resulted from the use of bottoms-up hourly load profiles, which applied greater rigor to the estimation of demand savings via calibration with actual FortisBC systemwide hourly load. In contrast, the previous CPR made no attempt to reconcile demand savings estimates with the temporal diversity observed in actual FortisBC loads.

[8] Indirect customers purchase electricity from wholesalers who purchase their electricity from FortisBC. Indirect customers are eligible to participate in FortisBC's DSM programs, so their consumption is considered in the CPR.

Measure Characterization

This CPR's measure characterization was founded on much of the prior characterizations compiled for the 2016 CPR. Beginning with the prior database, the team made several measure additions and removals:

Measure additions

- Cannabis lighting, dehumidification, and heating/ventilation/air conditioning (HVAC)
- BC Energy Step Codes for residential and commercial new building construction

Measure removals

- Measures that are now minimum code: commercial LED exit lights and general service CFL lamps.
- Measures substituted with BC Energy Step Codes: ENERGY STAR home, R-2000 Standard home, passive house, net-zero home, apartment new construction 30% above code.
- Measures associated with the Oil & Gas and Mining & Metal customer segments.
- Measures tracking savings from already-implemented building codes or appliance standards that FortisBC did not administer or incentivize: general service lamp, reflector lamp, metal halide lamp, refrigerator, freezer, and packaged terminal AC/HP codes and standards.

Additionally, the team implemented many updates to the measure characterizations to account for current equipment saturation and penetration levels, end use intensities, costs and efficiency levels. Sources for these updates include FortisBC program evaluation data, end use surveys, literature review, market research and the *Base Year* analysis.

For example, FortisBC provided evaluation data for program measures analogous to the CPR measures listed below. The evaluation data included average incremental savings and costs from incented projects, and Lumidyne used that information, along with saturation and penetration data from the CEUS, to update the measure characterizations. The commercial measures that experienced the largest positive change in TRC benefit-cost ratios were lighting controls and LED luminaires or retrofit kits, while high bay LED's TRC ratios decreased relative to the 2016 CPR. For industrial measures, the high bay lighting TRC ratios improved significantly, and the remaining measures experienced slight improvements.

- Commercial Interior LED
- Commercial LED Luminaire or Retrofit Kit Replacing HID
- Commercial High Bay LED
- Commercial LED Backlit Signage
- Commercial Photocell
- Commercial Interior Lighting Controls
- LED Street Lighting
- Industrial Efficient High Bay Lighting
- Industrial Efficient Low Bay Lighting
- Industrial Lighting Controls

Economic Assumptions

Lumidyne updated the key economic assumptions influencing benefit-cost tests, and the differences between the starting assumptions in 2016 CPR (2016 start year) and the current CPR (2020 start year) appear in Table 1 below. For economic metrics that changed over time, the annual escalation rates differed minimally between studies.

Table 1. Comparison of Economic Assumptions

Economic Assumption	2016 CPR (2016 nominal values)	2021 CPR (2020 nominal values)
Long-Run Marginal Cost	$100/MWh	$89/MWh
Deferred Capital Expenditures	$80/kW-year	$51/kW-year
Discount Rate	8.12%	7.90%
Electric Rates	Residential: 13.3 cents/kWh Commercial: 9.7 cents/kWh Industrial: 8.1 cents/kWh	Residential: 13.9 cents/kWh Commercial: 10.2 cents/kWh Industrial: 8.2 cents/kWh
Gas Rates	Residential: $7.7/GJ Commercial: $5.2/GJ Industrial: $4.3/GJ	Residential: $8.5/GJ Commercial: $7.4/GJ Industrial: $6.8/GJ

Source: FortisBC

The study's cost effectiveness tests used the long-run marginal cost for electric energy avoided costs, and the tests applied deferred capital expenditures as the electric demand avoided costs.

1.3 Caveats and Limitations

Customary for any forecasting activity, especially one as expansive as a CPR, this study's approach and findings have caveats and limitations. The commentary below describes the most important issues to consider when interpreting the results of the analysis.

Gross versus Net Savings

All savings potential results, except those shown in Section 3.2.5, are gross savings and are premised on the assumption that any increase in customer adoption of CPR measures is directly attributable to DSM programs. Section 3.2.5 shows savings after natural change, which is analogous to net savings and assumes that some of the increase in customer adoption may occur naturally in the absence of DSM programs. Of note, this aspect of gross versus net savings is separate from the program-level free-rider and spillover effects applied to DSM reporting.

At-the-Meter versus At-the-Generator Savings

All savings potential results are at-the-meter savings and do not include savings from avoided delivery losses. However, the cost effectiveness analysis appropriately used at-the-generator savings when calculating avoided costs. One can convert at-the-meter savings to at-the-generator savings by dividing by *1 – Loss Percentage*, where the annual average loss percentage at the time of this study was 7.6 percent.[9]

Data Availability

The granularity of a CPR requires a large number of input assumptions, many of which cannot be furnished by the considered utility and do not exist for the geographic area. As such, analysts look to similar utilities and

[9] Loss percentage from FortisBC 2020-2024 MRP Application, Appendix B3 – FBC Losses Study (p. 65), accessible at https://www.bcuc.com/Documents/Proceedings/2019/DOC_53565_B-1-1-FortisBC-2020-2024-Multi-YearRatePlan-Appendices.pdf.

geographic areas for data on which the team can benchmark uncertain input assumptions. In these circumstances, analysts make use of many sources of data to triangulate a reasonable estimate for unavailable data. When presented with these challenges during the development of the *Base Year, Reference Case* and measure characterization, Lumidyne took great effort to calibrate input assumptions to be consistent with actual, surveyed or vetted data specific to FortisBC and its customer base.

Measure Representation

The suite of measures included in this analysis is, by design, not exhaustive. Data and resources available for the measure characterization limit the list to measures meeting the following requirements:

- There is sufficient data and/or industry experience to characterize the measure within a reasonable confidence interval.
- The technical savings potential is sufficiently large that customer adoption would meaningfully reduce energy consumption.
- Expected TRC ratios have the potential to be larger than 1.0 for the upper bound of likely avoided cost scenarios.
- Feasible delivery mechanisms exist for staff to administer the measure through DSM programs.

Emerging technologies not yet commercialized will undoubtedly present new opportunities with lower costs, novel applications, and increased savings over the forecast horizon. Moreover, unforeseen structural changes in commerce and societal changes in energy consumption may arise. These speculative scenarios, nevertheless, are outside the scope of this study.

Interactive Effects

When a customer installs two or more efficient measures in the same building, there is a possibility that the combined savings are less than the sum of each measure's savings in isolation. This outcome stems from interactive effects, whereby a measure like better wall insulation reduces the heating/cooling requirements of a building, and therefore an efficient heating/cooling system's incremental savings slightly decline. This study does not consider the interactive effects among distinct CPR measures due to the exponential number of measure combinations that are possible. However, the CPR does include distinct measures that represent bundles of measures—for example, whole-facility Step Codes—and the team generally estimated the savings from those measures using building energy simulation tools that do account for interactive effects.

Adoption Rates and Customer Sensitivity to Price

Researchers have studied product diffusion for many decades and have developed a plethora of models for simulating customer adoption. In an ideal situation, analysts would gather a large quantity of market data for every measure under consideration, use the data to parameterize multiple adoption models, and select the model that shows the best predictive ability for each measure. Given the size of this CPR—which has 973 measure-and-segment combinations—the analysis relied on modeling approaches for adoption rates and customer sensitivity to price that respond well across diverse measures and customer types without requiring an impractical amount of data and labor. Additionally, Lumidyne calibrated the market potential's adoption models to coincide with actual participation in FortisBC DSM programs, and, for practicality, these calibrations pertained to aggregations of actual measure adoption.

Market Potential versus Program Potential

Lastly, market potential differs from program potential. Program potential considers various methods of administering DSM programs, constraints on program staffing, limited budgets for administration and incentives, and other factors influencing program design and goalsetting. Additionally, program potential excludes measures such as ENERGY STAR household electronics like televisions, which are regulated by government codes and standards and not typically incented under utility programs.

Market potential omits these components and instead focuses on a less-constrained assessment of savings based on customers' expected sensitivity to cost and plausible adoption rates. In practice, program designers often use market potential studies to investigate new conservation opportunities and to provide directional guidance as they tailor detailed plans for program implementation and goalsetting.

2 Methodological Approach

This section describes the study's methodological approach to:

- development of a 2019 *Base Year* accounting of building stocks, end use intensity and energy consumption;
- development of a 2020-2040 *Reference Case* forecast of building stocks, end use intensity and energy consumption;
- development of savings profiles for monthly energy savings and peak-coincidence factors for summer and winter demand savings;
- update and expansion of the measure characterization; and
- estimation of technical, economic and market savings potential.

2.1 Base Year Calibration

Estimation of the *Base Year* began with 2019 actual sector-level customer counts and annual energy consumption for FortisBC's direct and indirect customers. Indirect customers belonged to the municipal utilities of Penticton, Nelson, Summerland and Grand Forks, all of whom purchase wholesale electricity from FortisBC and resell it to their respective customers. The team included electricity consumption from indirect customers in the CPR because they are eligible to participate in FortisBC DSM programs.

A key task in developing the *Base Year* was to allocate 2019 actual consumption to customer segments and end uses within each sector. Data availability by sector influenced the allocation process that Lumidyne applied. Regardless of the sector, it was imperative to ensure that underlying assumptions like household counts, floor space and end use intensities (EUIs) were internally consistent with the allocation of consumption to customer segments. The following subsections describe Lumidyne's approach to allocating electricity consumption to each customer segment and end use.

2.1.1 Residential Base Year

The richness of data available for the residential sector allowed a highly detailed *Base Year* calibration. In particular, the 2012 and 2017 FortisBC Residential End Use Surveys (REUSs) supplied sufficient information for Lumidyne to develop household counts and a bottoms-up accounting of equipment loads by residential customer segment.

The first step used trends between the 2012 and 2017 share of residential dwelling units by customer segment to extrapolate 2019 shares. After estimating the 2019 share of dwellings in each customer segment, Lumidyne split the 2019 actual total number of direct and indirect residential dwellings into counts by customer segment.

Next, the team developed a bottoms-up accounting of equipment loads. Figure 3 illustrates how this analysis used REUS equipment saturation and penetration survey results, REUS Conditional Demand Analysis' unit energy consumption (UEC) and EUI estimates, and other sources providing equipment efficiencies to calibrate segment-specific UEC and EUI.

Lumidyne performed a calibration with REUS data for all residential customer segments and MURBs (i.e., apartments and condominiums), and for both 2012 and 2017 REUS years. By evaluating both years, it was possible to identify trends in EUIs and overall consumption. The team extrapolated those trends to the 2019 *Base Year* to arrive at initial end use intensities for all residential customer segments and end uses.

Figure 3. Bottoms-Up Accounting of Equipment Loads for Single-Family Detached Homes for 2017

Equipment Type	End Use	Saturation (units/home)	Equipment Share (% of equipment)	Penetration (% of homes)	Efficiency or Intensity	Efficiency/Intensity Units	Estimated TTD (kWh/year-unit)	Estimated UEC (kWh/year-unit)	Estimated EUI (kWh/year-home)	CDA UEC (kWh/year-unit)	CDA EUI (kWh/year-home)
Forced air furnace	Primary Space Heating	Null	37.84%	11.13%	100%	%	7,608	7,608	847	Null	Null
Wired-in electric baseboards	Primary Space Heating	Null	25.14%	7.39%	100%	%	7,608	7,608	562	Null	Null
Heat pump - air source	Primary Space Heating	Null	25.48%	7.49%	200%	%	7,608	3,804	285	Null	Null
Heat pump - geothermal	Primary Space Heating	Null	4.08%	1.2%	300%	%	7,608	2,536	30	Null	Null
Wired-in electric wall heater (fan forced)	Primary Space Heating	Null	2.38%	0.7%	100%	%	7,608	7,608	53	Null	Null
Electric radiant heat (floors, walls, and/or ceilings)	Primary Space Heating	Null	2.38%	0.7%	100%	%	7,608	7,608	53	Null	Null
Portable electric heaters	Primary Space Heating	Null	2.72%	0.8%	100%	%	7,608	7,608	61	Null	Null
Segment/End Use Average	Primary Space Heating	Null	Null	28%	Null	Null	7,608	6,432	1,892	6,432	Null
Sector/End Use Average	Primary Space Heating	Null	Null	41%	Null	Null	5,924	5,117	1,767	4,749	1,934
Forced air furnace	Secondary Space Heating	Null	2.95%	1.41%	100%	%	1,664	1,664	23	Null	Null
Wired-in electric baseboards	Secondary Space Heating	Null	29.07%	13.9%	100%	%	1,664	1,664	231	Null	Null
Heat pump - air source	Secondary Space Heating	Null	15.9%	7.6%	200%	%	1,664	832	63	Null	Null
Heat pump - geothermal	Secondary Space Heating	Null	1.05%	0.5%	300%	%	1,664	555	3	Null	Null
Wired-in electric wall heater (fan forced)	Secondary Space Heating	Null	7.95%	3.8%	100%	%	1,664	1,664	63	Null	Null
Electric radiant heat (floors, walls, and/or ceilings)	Secondary Space Heating	Null	10.46%	5%	100%	%	1,664	1,664	83	Null	Null
Portable electric heaters	Secondary Space Heating	Null	32.63%	15.6%	100%	%	1,664	1,664	260	Null	Null
Segment/End Use Average	Secondary Space Heating	Null	Null	32%	Null	Null	1,664	1,520	727	1,520	Null
Sector/End Use Average	Secondary Space Heating	Null	Null	25%	Null	Null	1,425	1,325	557	1,427	361
Low Efficiency	Furnace Fan (Gas Furnace)	Null	64.13%	39.12%	100%	Relative Consumption ...	Null	184	72	Null	Null
High Efficiency	Furnace Fan (Gas Furnace)	Null	35.87%	21.88%	63%	Relative Consumption ...	Null	116	25	Null	Null
Segment/End Use Average	Furnace Fan (Gas Furnace)	Null	Null	61%	Null	Null	Null	159	97	159	Null
Sector/End Use Average	Furnace Fan (Gas Furnace)	Null	Null	49%	Null	Null	Null	175	80	163	81
Central air conditioner	Space Cooling	0.55	67.07%	53.4%	314.85%	%	2,688	854	456	Null	Null
Portable air conditioner	Space Cooling	0.11	13.41%	9.5%	234.47%	%	1,617	690	66	Null	Null
Room window air conditioner	Space Cooling	0.16	19.51%	11.5%	336.84%	%	1,617	480	55	Null	Null
Segment/End Use Average	Space Cooling	Null	Null	Null	Null	Null	2,335	759	577	Null	Null
Sector/End Use Average	Space Cooling	Null	Null	Null	Null	Null	2,061	672	531	Null	512
Segment/CentralAC Average	Space Cooling	Null	Null	53%	Null	Null	Null	854	456	854	Null
Sector/CentralAC Average	Space Cooling	Null	Null	28%	Null	Null	Null	783	381	774	367
Sector/Room-Portable Average	Space Cooling	Null	Null	47%	Null	Null	Null	515	150	515	145
Conventional storage tank	Water Heating	0.93	92.08%	46.28%	90%	%	2,739	3,043	1,408	Null	Null
On-demand (tankless)	Water Heating	0.04	3.96%	1.94%	99%	%	2,739	2,766	54	Null	Null
Combined space and water heater	Water Heating	0.03	2.97%	1.31%	99%	%	2,739	2,766	36	Null	Null
Hybrid heat pump heater (tank)	Water Heating	0.01	0.99%	0.47%	200%	%	2,739	1,369	6	Null	Null
Segment/End Use Average	Water Heating	Null	Null	50%	Null	Null	2,739	3,007	1,505	3,007	Null
Sector/End Use Average	Water Heating	Null	Null	41%	Null	Null	2,536	2,785	1,203	2,874	1,187

Source: Lumidyne

Note: Blue cells highlight where Lumidyne calibrated the CPR's estimated UECs to the REUS's Conditional Demand Analysis of UECs. This figure shows five of the eleven REUS end uses considered in the residential REUS calibration, and the six remaining end uses applied a similar approach.

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The final step reconciled differences between 2019 actual electricity consumption for the residential sector and the implied consumption derived from initial residential EUI estimates and the customer segment dwelling counts. This final calibration applied a uniform scaling factor to all EUIs such that the CPR's total residential consumption matched the actual values. The final residential *Base Year* data appears in **Error! Not a valid bookmark self-reference.** and The total residential dwellings count decreased by 10 percent compared with the 2016 CPR, and residential consumption decreased by 15%. The change in dwellings stems from having better data from wholesale utilities, permitting more accuracy in assigning indirect customers to their respective sectors.

Table 3.

Table 2. Base Year 2019 Residential Housing Stocks and Annual Consumption (dwellings, GWh/year)

Customer Segment	Residential Dwellings	Consumption (GWh/year)
Single Family Detached	93,332	1,169
Single Family Attached/Row	14,926	122
Other Residential	8,575	81
Apartments <= 4 Storeys	35,270	276
Apartments > 4 Storeys	2,811	21
Total	154,914	1,669

Source: Lumidyne analysis of multiple data sources[10]

The total residential dwellings count decreased by 10 percent compared with the 2016 CPR, and residential consumption decreased by 15%. The change in dwellings stems from having better data from wholesale utilities, permitting more accuracy in assigning indirect customers to their respective sectors.

Table 3. Base Year 2019 Residential End Use Intensity (kWh/year-dwelling)

End Use	Single Family Detached	Single Family Attached/Row	Other Residential	Apartments <= 4 Storeys	Apartments > 4 Storeys	Weighted Average
Appliances	3,069	2,727	2,790	1,947	1,964	2,745
Electronics	1,076	478	534	778	784	915
Hot Water	1,459	859	1,410	468	434	1,154
Lighting	1,281	984	770	560	519	1,046
Other	1,275	386	696	989	574	1,080
Space Cooling	559	400	948	341	316	511
Space Heating	2,539	1,529	1,678	1,911	2,114	2,244
Ventilation	1,169	699	518	810	786	999
Totals	12,523	8,175	9,411	7,826	7,521	10,772

Source: Lumidyne analysis of multiple data sources[11]

Across customer segments and end uses, the total residential energy intensity decreased by 5.8 percent from the previous CPR. Less electricity consumption from lighting, electronics and space heating drove this reduction, though the reduction was partly offset by an increase in consumption from space cooling and ventilation.

2.1.2 Commercial Base Year

Calibration of the commercial sector started with the customer segment and end use data applied in the previous CPR. New information from the 2019 FortisBC Commercial End Use Study (CEUS) and Natural Resource

[10] Data sources include: FortisBC 2012 and 2017 REUS; FortisBC, Penticton, Nelson, Grand Forks and Summerland actual consumption and customer counts; and NRCan Comprehensive End Use Database.
[11] Data sources include: FortisBC 2012 and 2017 REUS; FortisBC, Penticton, Nelson, Grand Forks and Summerland actual consumption and customer counts; and NRCan Comprehensive End Use Database.

Canada's Comprehensive End Use Database (NRCan CEUD) informed updates to floor space estimates and end use intensities.

Next, Lumidyne identified FortisBC customers on industrial rates that corresponded to building types more typical of the commercial sector. These included colleges/universities, hospitals, hotels and public office buildings, so their actual 2019 consumption and floor space was added to the corresponding commercial customer segments. The team summed the 2019 actual consumption from direct and indirect commercial customers—including additions of commercial-like customers on industrial rates—to compare against the estimated consumption resulting from revised floor space and EUI data. A final scaling factor adjusted floor space estimates to ensure the *Base Year* consumption matched actual consumption at the sector level. Table 4 and Table 5 provide the commercial *Base Year's* floor space, annual consumption and end use intensities.

Table 4. Base Year 2019 Commercial Floor Space and Annual Consumption (1000m^2, GWh/year)

Customer Segment	Floor Space (1000m^2)	Consumption (GWh/year)
Accommodation	1,566	159
Colleges & Universities	264	46
Food Service	359	96
Hospital	215	43
Logistics & Warehouses	712	55
Long Term Care	391	42
Office	1,820	214
Other Commercial	2,066	187
Retail - Food	298	106
Retail - Non Food	1,991	217
Schools	595	45
Streetlights/Traffic Signals	NA	14
Totals	10,279	1,225

Source: Lumidyne analysis of multiple data sources[12]

Total commercial floor space estimates increased 45 percent relative to the previous CPR, and total commercial consumption increased 30 percent. The inclusion of commercial-like customers on industrial electric rates was one factor driving the increase. Another difference was the availability of sector-specific actual customer counts and consumption from wholesalers allowed Lumidyne to assign indirect load more accurately to the proper sectors.

[12] Data sources include: FortisBC 2015 and 2019 CEUS; FortisBC, Penticton, Nelson, Grand Forks and Summerland municipal utilities 2019 consumption and customer counts; NRCan Comprehensive End Use Database; and the 2016 CPR.

Table 5. Base Year 2019 Commercial End Use Intensity (MWh/1000m²)

Customer Segment	Cooking	Hot Water	HVAC Fans/Pumps	Lighting	Office Equipment	Other	Refrigeration	Space Cooling	Space Heating	Totals
Accommodation	0.8	3.2	24.0	45.8	8.3	7.5	1.5	6.9	3.9	101.9
Colleges & Universities	1.2	3.9	64.4	70.2	11.5	10.5	1.1	5.4	4.5	172.8
Food Service	11.4	23.3	47.3	86.9	1.0	43.1	10.3	38.8	5.7	267.8
Hospital	3.0	0.3	56.5	63.9	3.2	49.7	2.3	13.1	9.5	201.5
Logistics & Warehouses	0.4	1.2	10.6	36.1	1.5	16.2	6.3	2.9	2.5	77.6
Long Term Care	2.4	3.3	27.4	43.9	2.3	10.1	2.1	4.9	11.9	108.2
Office	0.4	2.0	33.1	49.7	8.1	12.9	0.4	9.1	2.0	117.8
Other Commercial	0.3	1.8	35.2	27.2	0.6	8.0	11.2	4.0	2.1	90.4
Retail - Food	1.4	3.2	34.4	98.2	0.1	23.8	187.3	5.0	1.0	354.4
Retail - Non Food	0.4	0.9	17.0	58.4	1.9	21.4	0.7	6.1	2.1	108.9
Schools	0.5	0.5	20.3	32.4	1.9	15.0	0.1	2.7	2.5	75.9
Weighted Average	1.0	2.6	28.3	47.6	3.9	15.1	9.1	7.1	3.1	117.8

Source: Lumidyne analysis of multiple data sources[13]

Across all commercial segments and end uses, total commercial energy intensity decreased 9.5 percent. Lighting and "other" end uses were responsible for most of the decrease. Space cooling was the only end use that increased, with a gain of 8.8 percent.

2.1.3 Industrial Base Year

Development of the industrial *Base Year* profited from detailed data on actual industrial customer consumption by industry type. Lumidyne mapped this information to the CPR's industrial customer segments for both direct and indirect customers. The final segment-specific industrial consumption excluded commercial-like customers on industrial electric rates whose consumption was re-allocated to commercial segments. Importantly, the analysis' industrial consumption does not subtract electricity that Kraft Pulp and Paper customers offset through self-generation. The team did not exclude self-generation because a portion of those customers' consumption is eligible for FortisBC DSM programs.

The second step allocated industrial consumption to end uses, relying largely on the previous CPR's end use allocations. Actual FortisBC DSM program data highlighted end uses whose consumption was likely to have changed since the last CPR. Accordingly, Lumidyne adjusted those end uses to reflect expected end use consumption in 2019, while ensuring that totals across end uses matched the 2019 segment-level consumption. Table 6 shows the final industrial *Base Year* consumption data.

[13] Data sources include: FortisBC 2015 and 2019 CEUS; FortisBC, Penticton, Nelson, Grand Forks and Summerland actual consumption and customer counts; NRCan Comprehensive End Use Database; and FortisBC's 2016 CPR.

Table 6. Base Year 2019 Industrial Consumption (GWh/year)

End Use	Agriculture	Cannabis	Food & Beverage	Manufacturing	Pulp & Paper - Kraft	Wood Products	Other Industrial	Totals
Compressed Air	5.3	0.0	0.9	8.0	14.6	18.6	12.7	60.1
Fans & Blowers	8.6	0.0	0.9	10.7	54.8	25.1	17.1	117.1
Industrial Process	1.6	0.0	2.3	29.4	136.0	65.8	46.7	281.7
Lighting	15.4	0.0	2.4	19.2	6.8	8.3	30.5	82.6
Material Transport	1.1	0.0	0.1	2.5	7.4	17.2	4.0	32.3
Product Drying	0.0	0.0	0.0	0.0	0.0	8.4	0.0	8.4
Pumps	11.8	0.0	1.0	4.8	146.0	0.4	7.6	171.5
Refrigeration	8.0	0.0	4.2	1.0	0.0	0.5	1.6	15.3
Space Heating	0.5	0.0	0.4	7.2	0.0	3.1	11.5	22.7
Totals	52.3	0.0	12.1	82.8	365.5	147.3	131.7	791.7

Source: Lumidyne analysis of multiple data sources[14]

Note: There were no industrial Cannabis customers in FortisBC's territory in 2019, but the Reference Case included forecast consumption from this customer segment.

Relative to the last CPR, this analysis did not include consumption from "Oil & Gas" and "Metal Mining" customer segments because FortisBC no longer served those customers. This study also moved consumption from commercial-like customers on large electric power rates into the commercial sector's consumption. Customer segments that experienced increases in consumption were "Agriculture" and "Other Industrial", where data centres, including cryptocurrency mining, spurred significant growth in "Other Industrial". On net across the industrial sector, this CPR found a 9.5 percent decrease in consumption.

2.2 Reference Case Forecast

The *Reference Case* is a forecast of consumption-related indicators from 2020 through 2040 that uses the 2019 *Base Year* as the starting point for forecast changes in the market. All indicators from the *Base Year*—such as building stocks, end use intensities, and annual consumption—and the addition of industrial output activity have associated forecasts in the *Reference Case*.

In brief, the *Reference Case* stems from actual 2019 consumption captured by the *Base Year*, follows FortisBC's 2021 Long Term Electric Resource Plan's (LTERP's) sector-level consumption forecast, and includes observed trends in EUIs from multiple data sources. Since the *Reference Case* forms the scaling basis for per-measure savings, the team carefully developed the *Reference Case* to create a solid foundation for savings potential estimates.

The following sections further describe each sector's *Reference Case*.

2.2.1 Residential Reference Case

The residential *Reference Case* began with total direct and indirect customer counts, to which the team applied forecast customer growth rates from FortisBC's 2021 LTERP. Lumidyne used segment-specific growth trends appearing in the 2012 and 2017 REUSs to temporally modify the *Base Year's* allocation of customers among

[14] Data sources include: FortisBC, Penticton, Nelson, Grand Forks and Summerland actual consumption; FortisBC actual DSM program data; and FortisBC's 2016 CPR.

customer segments. The resulting forecast of shares of customers by segment provided a method for allocating total residential customer counts to each customer segment—as shown in Table 7—while maintaining the same sector-wide growth rate as the LTERP.

Table 7. Residential Housing Stock Forecast (dwellings)

Customer Segment	2020	2025	2030	2035	2040
Apartments <= 4 Storeys	35,852	39,352	42,253	44,502	46,236
Apartments > 4 Storeys	2,857	3,136	3,367	3,546	3,685
Other Residential	8,585	8,702	8,871	9,051	9,222
Single Family Attached/Row	15,194	16,840	18,228	19,306	20,131
Single Family Detached	93,617	95,787	98,234	100,595	102,723
Total	156,105	163,818	170,953	177,000	181,996

Source: Lumidyne analysis of multiple data sources[15]

The forecast showed apartments and single-family detached homes growing faster than other segments. Given the lower energy intensity of these dwelling types, the change in the shares of dwelling types would lead to lower average residential household consumption—even if EUI's did not change over time.

To estimate trends in residential EUI's, the team again relied on trends observed in the 2012 and 2017 REUSs. The analysis converted the trends into expected annual rates of change and used the rates to modify the *Base Year's* EUIs over time. Multiplication of the housing stock and EUI forecasts resulted in the consumption forecasts shown in Table 8.

Table 8. Residential Consumption Forecast (GWh/year)

Customer Segment	2020	2025	2030	2035	2040
Apartments <= 4 Storeys	278	305	328	347	361
Apartments > 4 Storeys	21	24	25	27	28
Other Residential	82	82	84	86	88
Single Family Attached/Row	125	137	149	158	165
Single Family Detached	1,167	1,182	1,209	1,237	1,264
Total	1,674	1,730	1,795	1,854	1,906

Source: Lumidyne analysis of multiple data sources[16]

Embedded in the residential consumption forecast were time-changing EUIs, which declined by a little over 3 percent from 2020 to 2040, when averaged across end uses and customer segments. Although the analysis found that lighting energy intensities were quickly decreasing, there was nearly an equal increase in space cooling and electronics intensities. Over the forecast period, total residential consumption increased by almost 14 percent.

It is worth noting that the residential sector was the only sector for which the team chose not to directly calibrate *Reference Case* consumption with the LTERP's consumption forecasts. Lumidyne took this approach because the analysis made use of well-informed and plausible trajectories for EUIs and customer shares among segments—which created a reliable and internally-consistent framework for estimating residential consumption at a granular level. To gauge the impact of this decision, the team compared the CPR's consumption forecast for residential direct customers to the LTERP's and found that the CPR's 2040 residential consumption was about 8

[15] Data sources include: FortisBC's 2012 and 2017 Residential End Use Surveys; NRCan's CEUD; FortisBC's 2021 LTERP; and FortisBC's 2017/2018 CPR.
[16] Data sources include: FortisBC's 2012 and 2017 Residential End Use Surveys; NRCan's CEUD; FortisBC's 2021 LTERP; and FortisBC's 2017/2018 CPR.

percent higher than the LTERP. This difference stemmed from the LTERP's implication that EUIs would decrease faster than the CPR's in the near term.

2.2.2 Commercial Reference Case

The study used NRCan CEUD data and insights about long-term trends identified in the 2016 CPR to estimate annual rates of change for the commercial *Reference Case*'s EUIs and floor space. The team applied the rates of change to the commercial *Base Year*'s values to develop forecasts of segment-specific EUIs and floor space. Multiplying these forecasts generated an uncalibrated forecast of consumption. After temporarily removing consumption from indirect customers and commercial-like customers on industrial rates, the team compared the resulting uncalibrated consumption to the LTERP's consumption forecast. To align the two consumption forecasts at the sector-level, Lumidyne uniformly applied scaling factors to all customer segment's floor space estimates. The same floor space scaling factors were then applied to indirect customers and commercial-like customers on industrial rates. The final commercial building stock and consumption forecasts are shown in Table 9 and Table 10, respectively.

Table 9. Commercial Floor Space Forecast (1000 m^2)

Customer Segment	2020	2025	2030	2035	2040
Accommodation	1,579	1,937	2,228	2,533	2,865
Colleges & Universities	266	320	362	406	452
Food Service	361	434	490	547	608
Hospital	218	270	314	360	411
Logistics & Warehouses	703	773	799	816	830
Long Term Care	399	524	642	773	925
Office	1,818	2,118	2,317	2,509	2,702
Other Commercial	2,059	2,369	2,561	2,740	2,915
Retail - Food	296	337	360	381	402
Retail - Non Food	1,973	2,192	2,295	2,387	2,470
Schools	595	693	760	828	897
Total Floor Space	**10,267**	**11,966**	**13,128**	**14,279**	**15,475**
Streetlights/Traffic Signals*	1.03	1.14	1.22	1.30	1.37

Source: Lumidyne analysis of multiple data sources[17]

**Data for Streetlights/Traffic Signals represent a dimensionless growth indicator.*

Long term care, hospitals and accommodation segments grew at the fastest rates, which coincided with expectations related to age demographics in FortisBC's service territory. Across all segments, the commercial floor space grew 50 percent during the 20-year forecast.

[17] Data sources include: FortisBC's 2015 and 2019 Commercial End Use Surveys; NRCan's CEUD; FortisBC's 2021 LTERP; and FortisBC's 2017/2018 CPR.

Table 10. Commercial Consumption Forecast (GWh/year)

Customer Segment	2020	2025	2030	2035	2040
Accommodation	158	184	206	228	254
Colleges & Universities	45	52	57	62	68
Food Service	96	111	123	136	150
Hospital	43	51	57	64	72
Logistics & Warehouses	54	56	56	56	56
Long Term Care	42	52	61	71	82
Office	212	239	257	276	295
Other Commercial	184	204	217	229	242
Retail - Food	103	108	110	111	113
Retail - Non Food	211	220	221	223	225
Schools	44	49	51	54	57
Streetlights/Traffic Signals	14	14	14	14	14
Total	1,207	1,341	1,430	1,525	1,629

Source: Lumidyne analysis of multiple data sources[18]

Across all customer segments and end use, the electric energy intensity of the commercial sector decreased by 10 percent from 2020 to 2040. Lighting, "other", and refrigeration end uses drove most of the reduction, despite being partly offset by increasing energy intensity of HVAC fans/pumps and space cooling end uses. Total commercial consumption increased by 35% throughout the forecast horizon.

2.2.3 Industrial Reference Case

FortisBC provided Lumidyne with short term industrial consumption forecasts by customer that extended through 2024. Additionally, the FortisBC LTERP included industrial output indicators through 2040. The combination of this data allowed Lumidyne to grow the short-term forecasts according to the industrial output indicators, which resulted in LTERP-calibrated consumption forecasts by industrial customer segment.

Next, the team adjusted the industrial *Base Year's* allocations of consumption by end use to reflect expectations about time-changing end use intensities. Lastly, a scaling of the industrial output indicators ensured that the resulting consumption forecast appropriately captured changes in end use allocations and aligned with the LTERP consumption. Table 11 and Table 12 show the final industrial output indicators and consumption forecasts.

[18] Data sources include: FortisBC's 2015 and 2019 Commercial End Use Surveys; NRCan's CEUD; FortisBC's 2021 LTERP; and FortisBC's 2016 CPR.

Table 11. Industrial Output Indicators (dimensionless)

Customer Segment	2020	2025	2030	2035	2040
Agriculture	1.01	1.07	1.14	1.22	1.31
Food & Beverage	1.01	1.04	1.14	1.25	1.38
Manufacturing	1.02	1.05	1.13	1.23	1.34
Other Industrial*	0.83	1.09	1.21	1.33	1.45
Pulp & Paper - Kraft	0.99	0.98	0.96	0.92	0.88
Wood Products	1.06	1.14	1.08	1.02	0.97
Cannabis**	2.7	23.8	25.4	26.9	28.4

Source: Lumidyne analysis of multiple data sources[19]

**Note: Other Industrial includes data centers and cryptocurrency mining.*
***Note: data for Cannabis represent floor space in 1000 m^2.*

Table 12. Industrial Consumption Forecast (GWh/year)

Customer Segment	2020	2025	2030	2035	2040
Agriculture	53	54	57	60	63
Food & Beverage	12	12	13	15	16
Cannabis	10	83	86	89	92
Manufacturing	84	85	90	97	104
Other Industrial	109	141	153	166	179
Pulp & Paper - Kraft	361	359	349	336	321
Wood Products	155	167	158	149	140
Total	784	901	906	910	915

Source: Lumidyne analysis of multiple data sources[20]

Consumption in the cannabis and the “other industrial” segments grew fastest, with the expectation of acquiring a single large customer in the “other industrial” segment driving a significant amount of that growth. Conversely, consumption from wood-related segments declined. The total industrial consumption increased 17% during the forecast period.

To conclude this section on the *Reference Case*, it is worth noting that there was less than 1 percent difference in total 2040 consumption between the CPR and the LTERP—when normalized for self-generation, losses, electric vehicle consumption and planned DSM savings. However, the CPR’s consumption forecasts were not perfectly aligned with the LTERP at the sector level. The key drivers for sector-level differences were as follows:

- The LTERP data did not specify the sector for indirect customers’ consumption, so the CPR allocated 2019 indirect consumption to each sector—based on wholesale utilities’ actual sector-specific consumption—and grew it according to each sector and segment’s respective growth trajectory.
- The CPR intentionally allowed the residential forecast to differ from the LTERP because reliable end use intensity and housing stock data were available at a granular level.
- The CPR removed commercial-like customers on large power electric rates from the industrial sector and added them to the commercial sector.

2.3 Monthly Savings Profiles & Peak-Coincidence Factors

To provide FortisBC with more visibility into the timing of savings, Lumidyne generated monthly energy savings profiles and differentiated demand savings for summer and winter peak coincidence. The analysis used measured

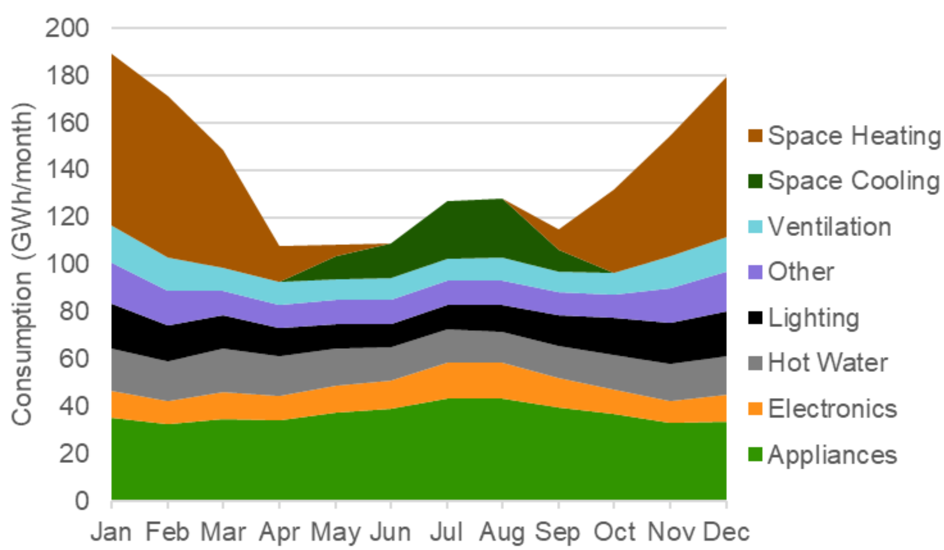
[19] Data sources include: FortisBC’s 2021 LTERP; NRCan’s CEUD; and FortisBC’s 2017/2018 CPR.
[20] Data sources include: FortisBC’s 2021 LTERP; NRCan’s CEUD; and FortisBC’s 2017/2018 CPR.

and simulated hourly load profiles for dozens of customer segments and end uses from similar climate zones to construct a bottoms-up representation of hourly loads. The team scaled the hourly end use profiles to align with the *Base Year's* annual energy consumption by end use and customer segment. Next, Lumidyne aggregated the hourly loads to the sector level and calibrated them against each sector's 2019 actual monthly consumption. This process included steps to keep the monthly relationships between average daily temperature and space heating and cooling loads, and it preserved the relationship between hours of daylight and lighting loads.

After calibrating all customer segment and end use hourly load shapes, the team aggregated the load estimates to the system level and compared it with FortisBC's systemwide actual 2019 hourly load. This validation exercise confirmed that there was sufficient alignment—in diurnal load shapes and summer and winter peak coincidence—between the aggregated load shape estimates and actual hourly load. The output from this analysis is monthly allocation factors for energy savings (expressed as the percentage of annual savings occurring in each month) and peak-coincident demand factors (expressed as kW of summer or winter peak savings per kWh/year of energy savings). Multiplication of these factors by the study's annual energy savings potential provides insight into the timing of energy savings and the associated peak demand savings.

Figure 4 illustrates the *Base Year's* residential monthly consumption by end use. Of all sectors, the residential sector showed the most seasonal variability, with winter space heating loads playing the largest role in the variability.

Figure 4. Base Year 2019 Residential Monthly Consumption Shape by End Use (GWh/month)



Source: Lumidyne analysis of multiple data sources[21]

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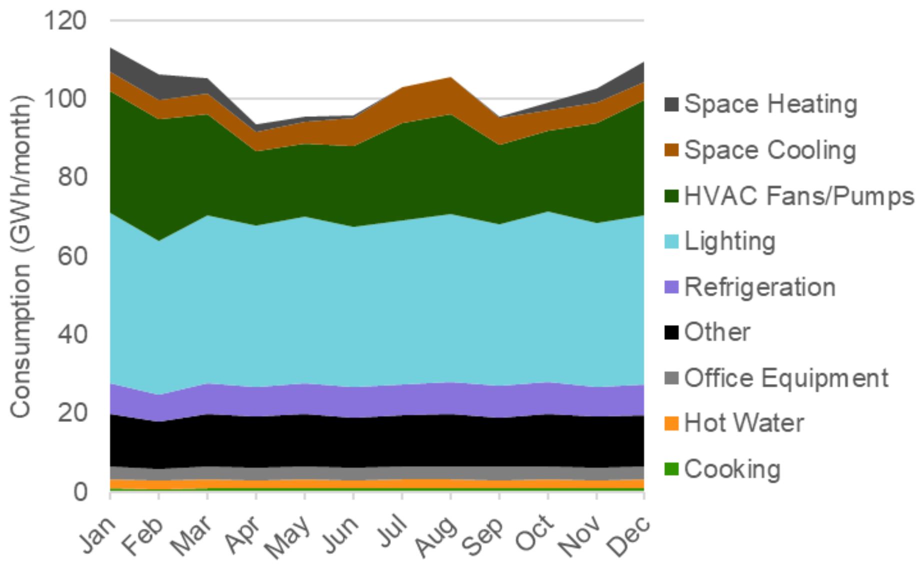
[21] Data sources include: FortisBC 2019 actual consumption by month; all sources listed for residential *Base Year* analysis; California Investor Owned Utility Load Shapes, accessible at https://ww2.energy.ca.gov/2019publications/CEC-500-2019-046/CEC-500-2019-046.pdf; and US Department of Energy Reference Building Models, accessible at https://openei.org/doe-opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states.

For the commercial sector, Figure 5 shows that the difference between summer and winter consumption was appreciably smaller than the residential sector. Additionally, the figure highlights the large contribution from commercial lighting.

Figure 5. Base Year 2019 Commercial Monthly Consumption Shape by End Use (GWh/month)

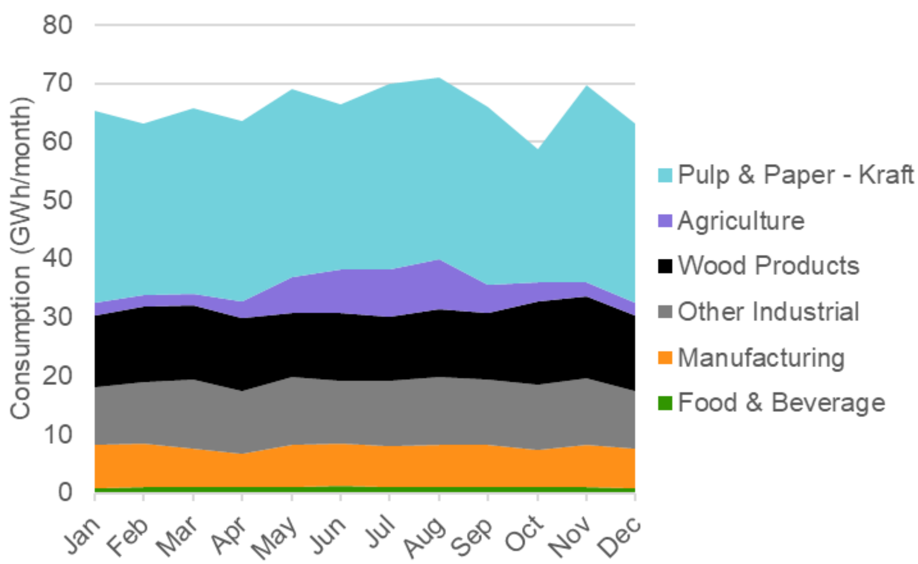


Source: Lumidyne analysis of multiple data sources[22]

[22] Data sources include: FortisBC 2019 actual consumption by month; all sources listed for commercial *Base Year* analysis; California Investor Owned Utility Load Shapes, accessible at https://ww2.energy.ca.gov/2019publications/CEC-500-2019-046/CEC-500-2019-046.pdf; and US Department of Energy Reference Building Models, accessible at https://openei.org/doe-opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states.

Viewing the industrial sector's *Base Year* monthly consumption by customer segment provides insight into the various industries' roles in overall consumption. Figure 6 shows that industrial consumption was relatively flat across seasons. The drop in October may have been an operational anomaly that occurred in 2019 in the pulp and paper segment. Notably, the consumption from this segment is prior to reductions from self-generated electricity, and thus it does not reflect the net load that FortisBC served.

Figure 6. Base Year 2019 Industrial Monthly Consumption Shape by Customer Segment (GWh/month)



Source: Lumidyne analysis of multiple data sources[23]

2.4 Measure Characterization

The study considered 167 distinct conservation measures, most of which were further differentiated and tailored to their applicable customer segments. The measures pertain to 24 customer segments and 19 end uses, resulting in 973 measure-and-segment combinations. Table 13 provides a list of the key parameters that the CPR considered for each measure.

Table 13. Key Measure Characterization Parameters

Parameter (units)	Description	Examples
Efficient measure	description of efficient measure	heat pump storage water heater (2.0 EF)
Baseline measure	description of baseline measure	electric storage water heater (0.9 EF)
Replacement type	applicable installation type	retrofit (RET), replace-on-burnout only (ROB), new construction only (NEW), ROB & NEW

[23] Data sources include: FortisBC 2019 actual consumption by month; all sources listed for industrial *Base Year* analysis; California Investor Owned Utility Load Shapes, accessible at https://ww2.energy.ca.gov/2019publications/CEC-500-2019-046/CEC-500-2019-046.pdf; and US Department of Energy Reference Building Models, accessible at https://openei.org/doe-opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states.

Parameter (units)	Description	Examples
Unit basis	unit of measurement for savings, costs and saturation	lamp, refrigerator, home, 1000m^2, kWh of measure consumption, kWh of end use consumption, etc.
Scaling basis	type of forecast used to scale per-unit savings across applicable customers	№ of homes, 1000m^2, kWh/year of end use consumption, kWh/year of customer segment consumption
End use category	applicable end use category	space heating, lighting, hot water, etc.
Customer segment	applicable customer segment	offices, apartments, agriculture, etc.
Sector	applicable sector	residential, commercial, industrial, street lighting
Competition group	group name for 2 or more efficient measures competing for the same baseline replacement	water heaters, reflector lamps, general service lamps, compressors, etc.
Efficient lifetime (years)	expected useful life of the efficient measure	10 years
Baseline lifetime (years)	expected useful life of the baseline measure	10 years
Remaining useful life (years)	expected life remaining for functioning measures that can be retrofit	4 years
Efficient cost ($/unit basis)	cost of the efficient measure per unit basis, or the incremental cost if the baseline cost is not readily available	$2/lamp, $2000/heat pump, $100/home, $1.50/kWh of end use consumption, etc.
Baseline cost ($/unit basis)	cost of the baseline measure per unit basis, which is always zero for retrofit measures	$1/lamp, $1000/heater, $80/home, $1.10/kWh of end use consumption, etc.
Efficient electricity consumption (kWh/year-unit basis)	annual electricity consumption of efficient measure per unit basis	5 kWh/yr-lamp, 2300 kWh/yr-heat pump, 500 kWh/yr-home, 0.8 kWh/yr per kWh/yr of customer segment consumption, etc.
Baseline electricity consumption (kWh/year-unit basis)	annual electricity consumption of baseline measure per unit basis	18 kWh/yr-lamp, 3000 kWh/yr-heater, 900 kWh/yr-home, 1 kWh/yr per kWh/yr of customer segment consumption, etc.
Efficient electric peak-coincident demand (kW/unit basis)	peak-coincident demand of efficient measure per unit basis, derived from load shape analysis	0.02 kW/lamp, 3 kW/heat pump, 2 kW/home, 0.001 kW per kWh/yr of customer segment consumption, etc.
Baseline electric peak-coincident demand (kW/unit basis)	peak-coincident demand of baseline measure per unit basis, derived from load shape analysis	0.04 kW/lamp, 4 kW/heater, 3 kW/home, 0.003 kW per kWh/yr of customer segment consumption, etc.
Efficient gas consumption (MJ/year-unit basis)	annual indirect gas consumption of efficient measure per unit basis, for interactive effects	800 MJ/yr-home, 950 MJ/yr-1000m^2, etc.
Baseline gas consumption (MJ/year-unit basis)	annual indirect gas consumption of baseline measure per unit basis, for interactive effects	820 MJ/yr-home, 1000 MJ/yr-1000m^2, etc.
Total efficient + baseline saturation (unit basis/scaling basis)	saturation/prevalence of relevant equipment per scaling basis	40 lamps/home, 1.2 refrigerator/home, 0.3 kWh/yr of measure consumption per kWh/yr of end use consumption.
Technical suitability (%)	percentage of baseline measures technically suitable for replacement by efficient measures	75%
Initial efficient penetration (%)	percentage of equipment that is the efficient measure in forecast's start year	20%
Initial baseline penetration (%)	percentage of equipment that is the baseline measure in forecast's start year	80%

Source: Lumidyne

Section 1.2 has already described the measures that this study removed relative to the last CPR, so the remainder of this section describes the new cannabis and BC Energy Step Code measures.

Cannabis Measures

To address the expectation of significant growth in the cannabis market, the team performed a literature review on the cannabis industry to understand the main drivers of energy consumption and to characterize measures with the best savings potential. The review clarified that there are appreciable differences between growing facilities using warehouses versus those using greenhouses. Greenhouses tend to be significantly larger, and British Columbia surveys suggested greenhouses had six to fifty-five times as much floor space as warehouses. The team estimated that, on average, warehouse's end use intensity per square-meter of floor space was 54 percent higher than greenhouses. FortisBC anticipated that warehouse-based growing facilities would likely represent about 90 percent of cannabis electricity consumption, with greenhouses making up the remaining 10 percent. An estimate of composite end use intensities, as shown in Table 14, helped the analysts focus their attention on the biggest loads.

Table 14. Cannabis End Use Intensity in 2019 Base Year (MWh/1000m^2)

End Use	EUI
Air Conditioning	184
CO2 Injection	55
Drying	54
Lighting	1,348
Space Heat	758
Ventilation & Dehumidification	1,100
Water Handling	103
Total	3,602

Source: Lumidyne analysis of multiple sources[24]

Relying on the end use intensities, the study identified lighting, space heating/cooling, dehumidification as the best opportunities for energy savings. The team addressed these high consumption end uses by characterizing three new measures, and descriptions of each are presented in Table 15.

[24] References considered in the literature review and cannabis analysis were: American Council for and Energy-Efficient Economy, Trends and Observations of Energy Use in the Cannabis Industry, 2017; BOTEC Analysis Corporation & UC Berkeley, Environmental Risks and Opportunities in Cannabis Cultivation, 2013; Cube Resources, Boulder County Energy Impact Offset Fund (BCEIOF) Demand Side Management Study Phase 1, 2018; Desert Aire, Application Note 27, HVAC Systems and Grow Room Energy Usage, 2019; Mills, E. 2012. "The Carbon Footprint of Indoor Cannabis Production." Energy Policy 46: 58–67; New Frontier Data, The 2018 Cannabis Energy Report; Northwest Power and Conservation Council, Electric Seventh Power Plan - Appendix E: Demand Forecast, 2016.

Table 15. Cannabis Measures

End Use	Efficient Measure	Baseline Measure
Lighting	LED Composite of: LED 630W, 1850 PPF, 1.75 PPE Grow Light Canopy LED 645W, 1550 PPF, 2.46 PPE Grow Light Canopy	High Pressure Sodium 1000 W Double-Ended
Space Heating/ Air Conditioning	High-Efficiency Ductless Split-System Heat Pump/Air Conditioning Unit	Standard Practice Composite of: Air Cooled Chiller Packaged Terminal Air Conditioner Rooftop HVAC Unit Split System Window Units
Dehumidification	ENERGY STAR Portable Dehumidifier 3.3 L/kWh	Standard Portable Dehumidifier 2.8 L/kWh

Source: Lumidyne

The team characterized non-lighting cannabis measures to only be applicable to warehouse facilities that did not include an integrated HVAC and dehumidification system. The research suggested larger facilities would likely use integrated HVAC and dehumidification systems that would be more efficient and provide fewer savings opportunities.

BC Energy Step Codes

The Province of British Columbia established the BC Energy Step Code to provide a performance-based approach to ensuring new buildings meet efficiency targets. The codes provide builders with more flexibility in building design, rather than prescribing minimum efficiency levels of specific building equipment and systems.[25] FortisBC requested that Lumidyne model the impact of these Step Codes in lieu of several measures included in the last CPR: ENERGY STAR home, R-2000 Standard home, passive house, net-zero home, and apartment new construction 30% above code. The customer segments impacted by the BC Energy Step Code can be split into two categories: residential occupancies (Part 9) and commercial occupancies (Part 3). Residential buildings include single-family detached, single-family attached and low-rise apartments. Part 3 buildings include high-rise apartments, hotels, offices, and retail. While not all commercial buildings are currently subject to the BC Energy Step Code, those excluded segments have equivalent Steps based on their savings compared with the BC Building Code.

Though there are targeted compliance dates for the various steps, there was—at the time of this analysis—much uncertainty about when local jurisdictions would adopt the codes and whether compliance would be strongly enforced. Accordingly, the team extended the compliance dates by five years to account for any lag time. Upon a modelled compliance year, the potential analysis updated the minimum code baseline to reflect the newly enacted Step Code level, which implied that lower-level Step Codes could no longer generate additional market potential.

[25] Information about BC Energy Step Codes can be accessed at: https://energystepcode.ca/.

Savings estimates for the Step Code measures relied on FortisBC's residential analysis and a large database of simulated performance for various commercial Step Code configurations.[26] Lumidyne chose commercial Step Code configurations that focused primarily on electric savings and had the best economics for each level of the Step Codes. Table 16 shows the modelled saving as a percentage of electricity consumption from baseline new construction relying heavily on electric appliances and systems. Additionally, the table provides the modelled compliance years.

Table 16. BC Energy Step Code Measures

Sector	Step Code Level	Approx. Savings %	Applied Compliance Year
Residential	Step 2	2%	NA
Residential	Step 3	10-20%	2027
Residential	Step 4	40%	2032
Residential	Step 5	60%	2037
Commercial	Step 2	10-20%	NA
Commercial	Step 3	20-30%	2027
Commercial*	Step 4	40-45%	2032

Source: Lumidyne

**Commercial Step Code 4 only applies to Accommodation and Apartments.*

Lastly, the team implemented many updates to the CPR's other measure characterizations to account for current equipment saturation and penetration levels, end use intensities, costs and efficiency levels. Sources for these updates include FortisBC program evaluation data, end use surveys, literature review, market research and the *Base Year* analysis. Notably, the team updated most commercial lighting measures to reflect recent cost and savings estimates from FortisBC program evaluation data.

2.5 Estimation of Savings Potential

The study estimated electric energy savings and electric summer/winter peak demand savings, along with gas energy savings for dual-fuel measures and measures having interactive effects with gas-consuming end uses. For each CPR measure, the analysis calculated technical, economic, and market potential. The remainder of this section describes the approach to estimating all forms of savings potential.

2.5.1 Technical Potential

Technical potential is the hypothetical savings when each CPR measure immediately replaces its corresponding low-efficiency or minimum-code baseline measure wherever it is technically feasible. Not all baseline measures are technically suitable for an efficient replacement. For example, the ground-source heat pumps' ability to replace electric furnaces is significantly constrained by the availability of land that can be used for a ground-loop heat exchanger. In comparison, an air-source heat pump has higher technical suitability for electric furnace replacements. In situations where two or more efficient measures compete for the same baseline replacement, the measure that offers the most total savings potential appears in the technical potential. Thus, using the air-source versus ground-source heat pump example, the air source heat pump's technical potential might be larger than the ground-source heat pump's potential, despite the ground-source heat pump's higher efficiency. As such,

[26] The Step Code database was a product of BC Housing's "2018 Metrics Research: Full Report Update." The report is accessible at: https://www.bchousing.org/research-centre/library/residential-design-construction/energy-step-code-2018-full-report.

only the savings from the air-source heat pump would be included in the technical potential. This approach ensures that savings from competing CPR measures are not double counted.

Furthermore, technical potential ignores stock turnover dynamics that delay potential from replace-on-burnout (ROB) measures, which in practice are only replaced upon failure of the baseline equipment. Instead, technical potential treats ROB measures like retrofit measures that can be replaced immediately regardless of operating status. For new construction measures, technical potential is only realized in years when new buildings are constructed in a given customer segment.

2.5.2 Economic Potential

Economic potential is the subset of CPR measure that have a benefit-cost ratio of 1.0 or higher. Like technical potential, when two or more economic measures compete for the same baseline replacement, the economic potential only includes the competing measure that offers the most economic savings. Economic potential also ignores stock turnover dynamics of ROB measures.

Commercial and industrial economic potential used a total resource cost (TRC) benefit-cost ratio for economic screening, while residential potential used a modified total resource cost (mTRC) benefit-cost ratio. The mTRC is similar to the TRC, except that it includes a 15 percent increase to avoided costs. The 15 percent increase in avoided costs captures non-energy benefits, as allowed by British Columbia DSM Regulation.[27] Equation 1 shows the formulas that the analysis applied for each cost test.

Equation 1. Benefit-Cost Tests for Economic Measure Screening

Sector	Benefit-Cost Ratio
Commercial* & Industrial	$TRC = \frac{NPV(DiscountRate,\ AvoidedCost_{year} + OMSavings_{year})}{NPV(DiscountRate,\ IncrementalCost_{year})}$
Residential	$mTRC = \frac{NPV(DiscountRate,\ AvoidedCost_{year} * 115\% + O\&MSavings_{year})}{NPV(DiscountRate,\ IncrementalCost_{year})}$

**MURBs were treated as commercial customer segments.*

Where…

TRC: the benefit-cost ratio for the Total Resource Cost test

$mTRC$: the benefit cost ratio for the modified Total Resource Cost test

$NPV(\,)$: the net present value formula that sums discounted cash flows over time

$DiscountRate$: the discount rate applied to future cash flows

$AvoidedCost$: FortisBC's avoided energy and demand costs generated through conservation

$O\&MSavings$: operating and maintenance cost savings from installation of efficient measures

$IncrementalCost$: the efficient measure's incremental equipment cost relative to the baseline measure

$year$: each year of the measure's expected useful life

[27] Under British Columbia Utilities Commission DSM Regulation s4.(1.1)(c), the modified total resource cost rules allow for a 15 percent increase for non-energy benefits, up to a limit of 10 percent of the electric DSM portfolio expenditure.

The economic screening used cost tests that excluded program administrative costs because measure-specific administrative costs are difficult to assess. It is generally more insightful to include administrative costs when evaluating aggregate cost effectiveness for an entire program or sector, as is done in Section 3.3, rather than burdening measure-level cost effectiveness with uncertain administrative costs. Additionally, measure-specific administrative costs are highly dependent on program implementation, which is outside the scope of this study.

2.5.3 Market Potential

Market potential is the focus of this report because it incorporates barriers to adoption stemming from delays in stock turnover, customers' awareness and willingness to adopt, and substitutive effects among efficient measures serving the same application. This section's discussion on market potential covers:

- Customer adoption dynamics
- Treatment of behavioural measures
- Approach to incentivizing measures
- Accounting of utility spending
- Treatment of re-participation
- Calibration of market potential

2.5.3.1 Adoption Dynamics

Market potential is a subset of economic potential, and its intent is to capture real-world dynamics influencing measure adoption. For example, equipment turnover of replace-on-burnout measures constrains the market potential by limiting the opportunities for replacing failed inefficient equipment with efficient equipment. Market potential requires customer awareness and familiarity with efficient measures before adoption occurs. Lastly, relative economic attractiveness—after considering utility bill savings, incremental costs, operation and maintenance costs, and incentives—among high- and low-efficiency measures influences customers' purchasing decisions that drive market potential.

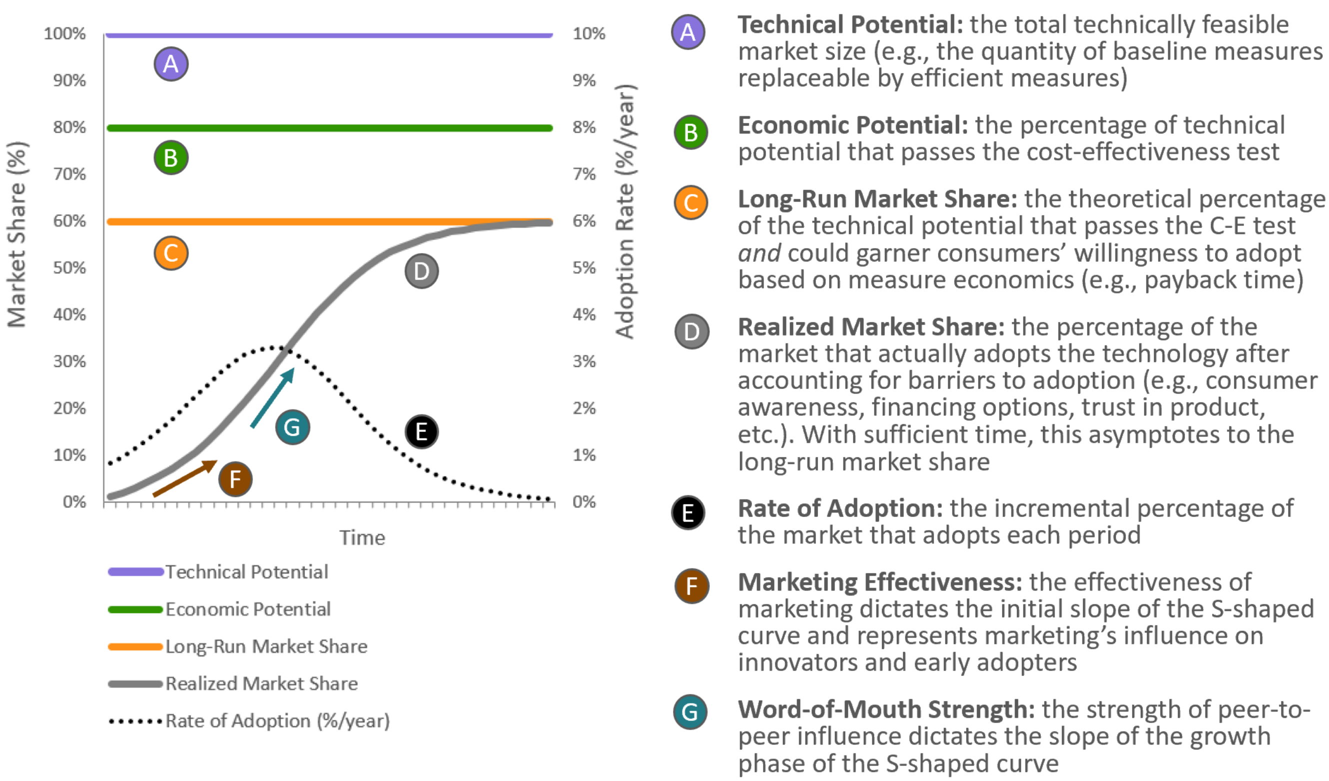
In contrast with technical and economic potential, market potential accounts for equipment turnover over time in the calculation of replace-on-burnout potential. Measure lifetimes dictate the rates at which measures fail and are eligible for replacement. If failed equipment is replaced by baseline-efficiency equipment, then, on average, that replacement is not eligible for another replacement until the replacement's lifetime has expired. This coincides with the conservation industry referring to ROB measures as being "lost opportunity" measures.

Market potential relies on payback acceptance curves to estimate the percentage of customers who would be willing to adopt a high-efficiency measure based entirely on economic payback. When two or more efficient measures compete for the same baseline replacement, the relative economics of each measure determines each measure's share of the total replacements. This approach allows a mix of efficient measures to replace the same baseline measure, which is more robust than the technical and economic potentials' approach of selecting a single efficient measure. Since the payback curves do not account for non-economic barriers to adoption, the resulting percentage of willing customers represents what could be achieved in the long run after market barriers are removed. This long-run market potential is the upper bound on market savings—and determining how quickly the market can reach that upper bound is where product diffusion models provide insight.

The analysis used a Bass diffusion model to forecast the trajectory on which the customer adoption reaches the long-run market potential. The Bass diffusion model generates the S-shaped curve widely observed in the uptake of products. The steepness of the S-curve and the speed at which realized adoption can reach the long-term market potential is a function of two key considerations: marketing effectiveness and word-of-mouth strength. Marketing effectiveness mostly dictates how quickly consumers become aware of or familiar with a product when the product is just beginning to enter the market. Word-of-mouth strength influences the rate at which adopters of a product spread information about the product, which in turn inspires others to purchase the product and continue the spread of information.[28]

Figure 7 illustrates the relationships between technical, economic, long-run market, and realized market potential. Realized market potential is analogous to the market potential results described and presented throughout this report. For clarity, the graph represents potential as the share of all baseline measures that are suitable for replacement by an efficient measure, and it portrays a scenario where economic and long-run market shares are static over time. Lastly, the figure is illustrative of the diffusion dynamics of new construction and retrofit measures, but not replace-on-burnout measures.

Figure 7. Bass Diffusion Model's Relationship to Efficient Measures' Market Share



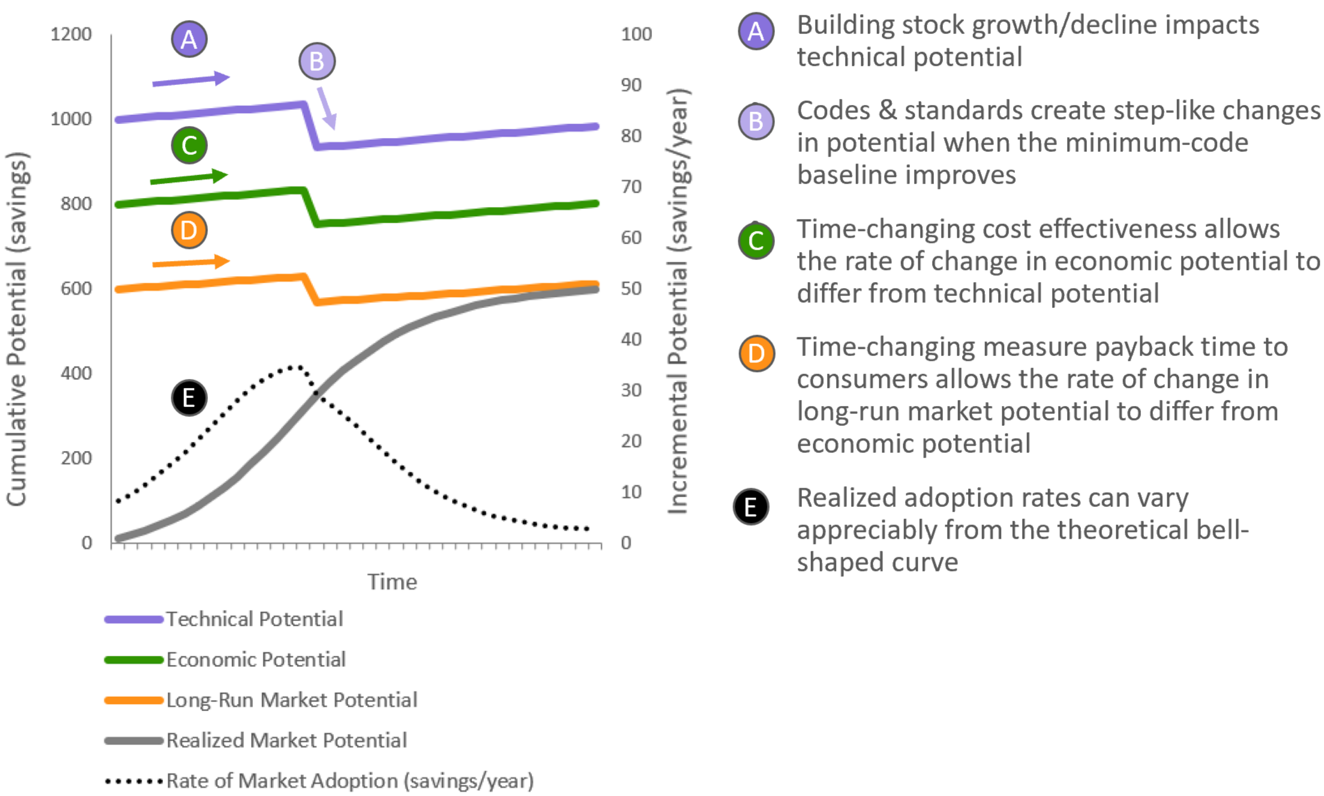
Source: Lumidyne

Note: "Rate of Adoption (%/year)" corresponds to the rightmost vertical axis.

[28] Bass, Frank M. 1969. 'A New Product Growth Model for Consumer Durables', Management Science, 15: 215-27.

One can expand on the diffusion example above by translating it into savings potential, as shown in Figure 8, and incorporating more real-world dynamics like time-changing building stocks, baseline efficiencies, benefit-cost ratios and payback times.

Figure 8. Dynamic Bass Diffusion Model Translated to Savings Potential

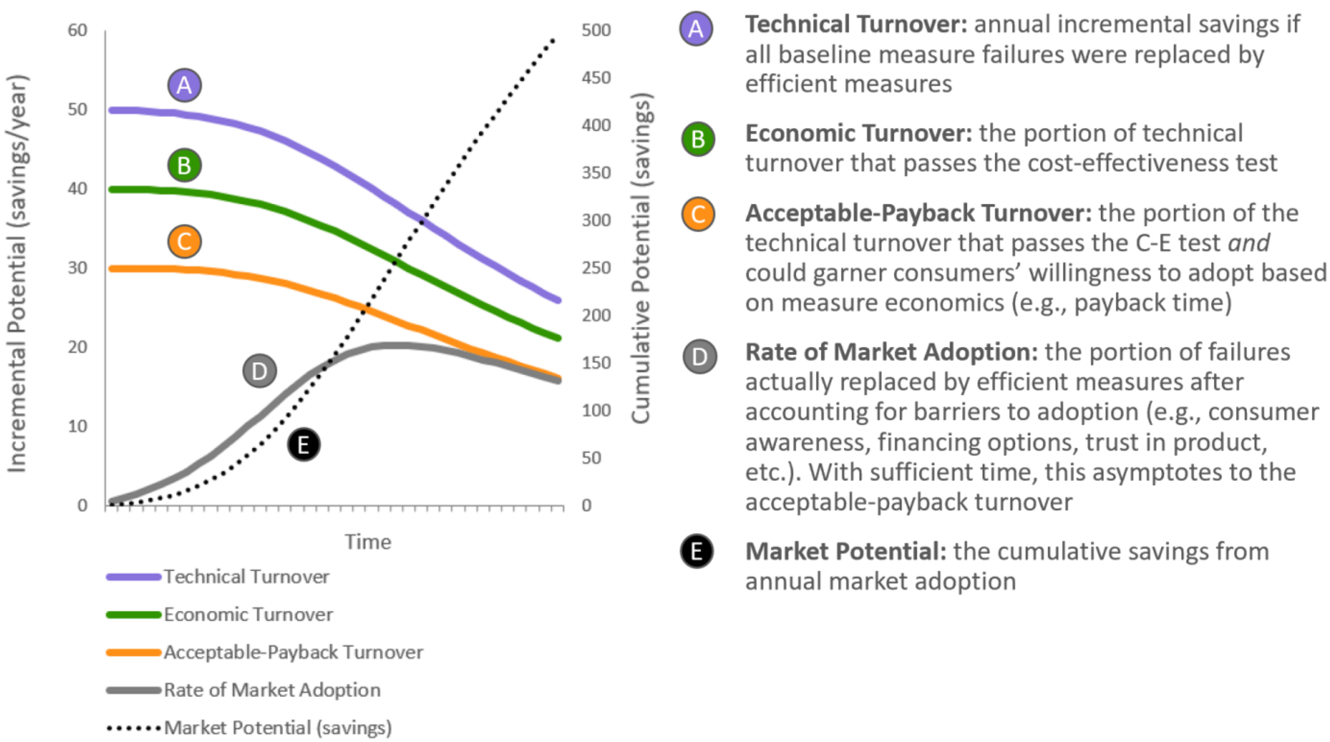


Source: Lumidyne

Note: "Rate of Market Adoption (savings/year)" corresponds to the rightmost vertical axis.

Figure 9 is the last adaptation of this example, and it shows the diffusion dynamics for replace-on-burnout measures. In this case, adoption rates are constrained by both baseline equipment turnover and market barriers implied by Bass diffusion. When consumers replace failed baseline equipment with efficient measures, the turnover of baseline measures declines because there are fewer of those measures remaining and able to fail.

Figure 9. Bass Diffusion for Replace-on-Burnout Measures



Source: Lumidyne

Note: "Market Potential (savings)" corresponds to the rightmost vertical axis.

FortisBC provided Lumidyne with the model used in the 2016 CPR, which Navigant developed and delivered to FortisBC. Lumidyne populated the model with revised data and ran the savings potential simulations for this CPR. Navigant described its model as follows:

> *DSMSim™ is a bottom-up technology diffusion and stock tracking model implemented using a System Dynamics framework. The model explicitly accounts for different types of efficient measures such as retrofit, replace-on-burnout, and new construction and the impacts these measures have on savings potential. The model then reports the technical and economic potential savings in aggregate by service territory, sector, customer segment, end-use category, and highest-impact measures.*[29]

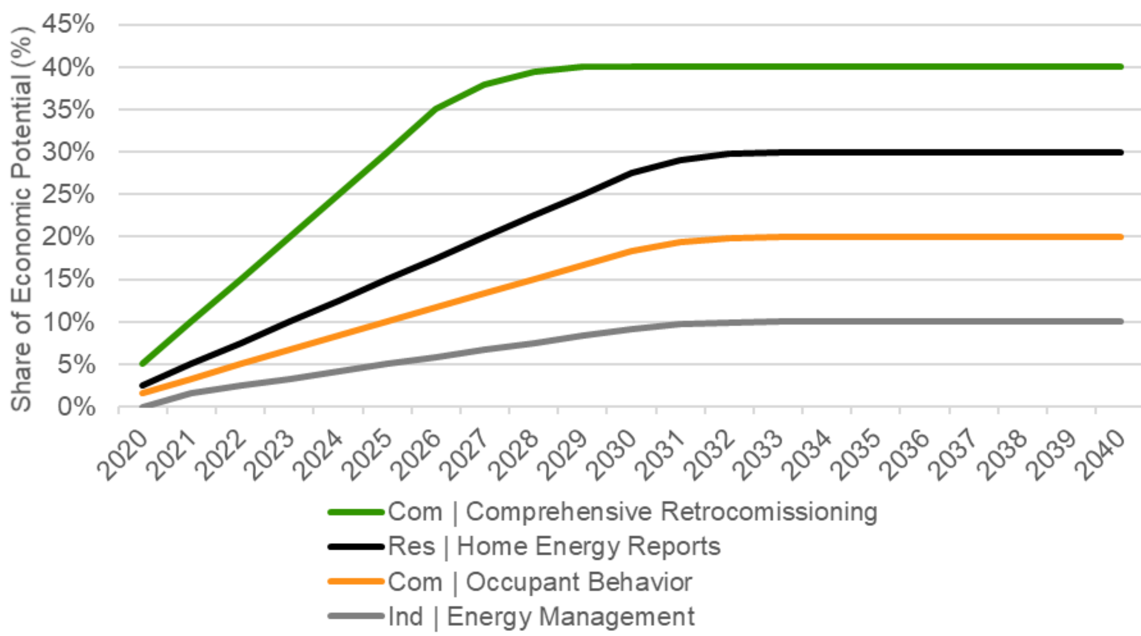
[29] Sourced from Navigant's "British Columbia Conservation Potential Review" dated August 2017.

For more information about Navigant's model and methodology, we refer the readers to FortisBC's 2016 CPR assessments.[30,31]

2.5.3.2 Behavioural Measures

The study included behavioural measures that required different treatment from other measures. Differing from a piece of equipment or an installed system, participants in behavioural programs generally do not incur an upfront capital cost. As such, potential models cannot use payback acceptance curves to estimate adoption of behaviour measures. Instead, utility incentives and recruitment efforts influence the adoption rates. The team developed adoption targets as a percentage of economic potential to address this dynamic, as shown in Figure 10. Specifying the adoption targets in this way ensured that market potential dynamically responded to changes in economic potential.

Figure 10. Behavioural Measure Adoption as a Percentage of Economic Potential (%)



Source: Lumidyne

2.5.3.3 Incentivization Approach

Incentive levels played a role in the market potential forecasts by improving the customer payback times and increasing customers' willingness to adopt CPR measures. Consistent with the 2016 CPR, the team specified incentive levels as dollars per net present value (NPV) of energy savings (e.g., $/kWh), where the NPV accounts

[30] FBC's 2016 technical and economic potential report can be found in Appendix A (p. 513) of FortisBC's "2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan)," accessible at https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/161130_fbc_2016_lterp_ltdsm_plan.pdf.

[31] FBC's market potential report can be found in Appendix B (p. 86) of FortisBC's "Application for Acceptance of Demand Side Management (DSM) Expenditures Plan for the period covering 2019 to 2022," accessible at https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/180802_fbc_2019-2022_dsm_expenditures_application_ff.pdf.

for a measure's savings across its expected useful lifetime. Compared with an incentive approach based on first-year savings or a percentage of incremental costs, the advantage of using a dollar-per-NPV-of-savings incentive is that it favours measures with greater lifetime savings. A beneficial side-effect of this incentive approach is that the NPV of avoided costs increases, which improves the TRC and mTRC benefit-cost tests across the portfolio. Though challenging to implement this incentive approach in actual program design, it results in a market potential portfolio that maximizes TRC and mTRC, which can be instructive for program planners.

For illustration, assume there are two measures having identical incremental costs, operations and maintenance (O&M) savings, and annual energy savings, as shown in Table 17. If one measure has a ten-year lifetime and the other has a five-year lifetime, the participant's cost per lifetime savings (as defined in Equation 2 below) is lower for the ten-year measure. If both measures are incentivized at the same dollar-per-NPV-of-savings rate, then the incentive represents a larger percentage of participant costs for the 10-year measure. By reducing a larger percentage of the 10-year measure's participant costs, the participant's payback time improves, which leads to greater adoption of that measure relative to the shorter-lived measure. Though the participant economics are more favourable for the longer-lived measure, from the utility's perspective both measures are compensated equally per present value of savings.

Table 17. Illustration of Incentivization Approach

	10-Year Measure	5-Year Measure	Symbol	Calculation
Measure Lifetime (years)	10	5	A	
Incremental Cost ($)	100	100	B	
O&M Savings ($/year)	0	0	C	
Annual Energy Savings (kWh/year)	500	500	D	
NPV of Participant Costs ($)	100	100	E	= B
NPV of Savings (kWh)	3,372	2,002	F	= PV(DiscountRate, D, A)
Participant Cost of Lifetime Savings ($/kWh)	0.03	0.05	G	= E / F
Incentive per NPV of Savings ($/kWh)	0.02	0.02	H	
Incentive Percentage of Participant Cost (%)	67%	40%	I	= H / G

Source: Lumidyne

Equation 2. Participant Cost of Lifetime Electric Energy Savings ($/kWh)

$$SavingsCost = \frac{NPV(DiscountRate,\ IncrementalCost_{year} - OMSavings_{year})}{NPV\left(DiscountRate,\ AnnualSavings_{year}\right)}$$

Where…

$SavingsCost$: the participant's cost, prior to incentives, per discounted kWh of electric energy savings across the measure lifetime

$NPV(\,)$: the net present value formula that sums discounted cash flows over time

$DiscountRate$: the discount rate applied to future cash flows

$IncrementalCost$: the efficient measure's incremental equipment cost relative to the baseline measure

$O\&MSavings$: operating and maintenance cost savings from installation of efficient measures

$AnnualSavings$: the incremental annual savings of the measure for each year of the measure lifetime

$year$: each year of the measure lifetime

2.5.3.4 Utility Spending

Since the focus of the CPR was market potential instead of program potential, incentive and administrative spending was not capped or targeted to a specific budget level. Incentive rates per kWh, fixed administrative costs, and per-kWh variable administrative costs escalated at the inflation rate, meaning they stayed constant in real dollars over the analysis horizon. Depending on the forecast's annual mix of adopted measures, the utility spending per kWh of realized market savings varied over time.

2.5.3.5 Re-Participation

Sometimes cumulative market potential is adjusted to reflect that some percentage of high-efficiency measure adopters revert to lower-efficiency equipment at burnout. This study assumed that, once customers had converted to high-efficiency measures, they continued to replace that equipment with high-efficiency equipment. When high-efficiency equipment failed at the end of its useful lifetime, the analysis did not credit the replacement with new savings or incur additional utility spending.

2.5.3.6 Market Potential Calibration

Forecast adoption rates can vary significantly depending on the study's incentive levels and Bass diffusion model parameters like marketing effectiveness and word-of-mouth strength. To ground the market potential analysis on actual and near-term expected program performance, Lumidyne calibrated the first several years of market potential to multiple benchmark values. The following commentary describes each of these benchmarks and the team's calibration approach.

Actual and Planned Program Savings

FortisBC provided Lumidyne with a list of measures recently offered through DSM programs, along with their actual and planned near-term savings. Lumidyne used the list to identify the subset of CPR measures corresponding to FortisBC's recent offerings. The actual and planned savings provided a benchmark to which the team calibrated near-term modelled savings from the subset of CPR measures. Calibration relied on adjusting incentive rates and Bass diffusion parameters until there was reasonable alignment in savings trajectories. Since the full collection of CPR measures included many measures that FortisBC DSM programs had not offered historically, the CPR's resulting total 2020 market potential from non-traditional measures generated 36 percent more savings compared with 2019 actual program savings.

Utility DSM Acquisition Costs

In addition to program savings, FortisBC provided actual and planned program spending broken out by incentives and fixed and variable administrative costs. The team normalized these spending summaries by the associated program savings to identify sector-level dollar-per-kWh acquisition costs. While calibrating the subset of recently offered CPR measures, Lumidyne ensured alignment between modelled acquisition costs and FortisBC's recent and expected values.

Incentive Percentage of Program Spending

Lumidyne took the spending calibration one step further by ensuring that the percentage of spending from incentives was similar to actual and planned values. By calibrating both the dollars-per-kWh acquisition costs and the incentive percentages, the team had assurance that the market potential applied reasonable incentive rates.

All three of the benchmarking tasks were interdependently related, which required an iterative approach to calibration. The outcome was a near-term market potential forecast grounded in observed and planned program metrics. Beyond the first several calibrated years, the market potential—and thus acquisition costs and incentive percentages of spending—dynamically evolved based on modelled assumptions regarding building stocks, equipment turnover, measure economics, and Bass diffusion dynamics.

3 Savings Potential Results

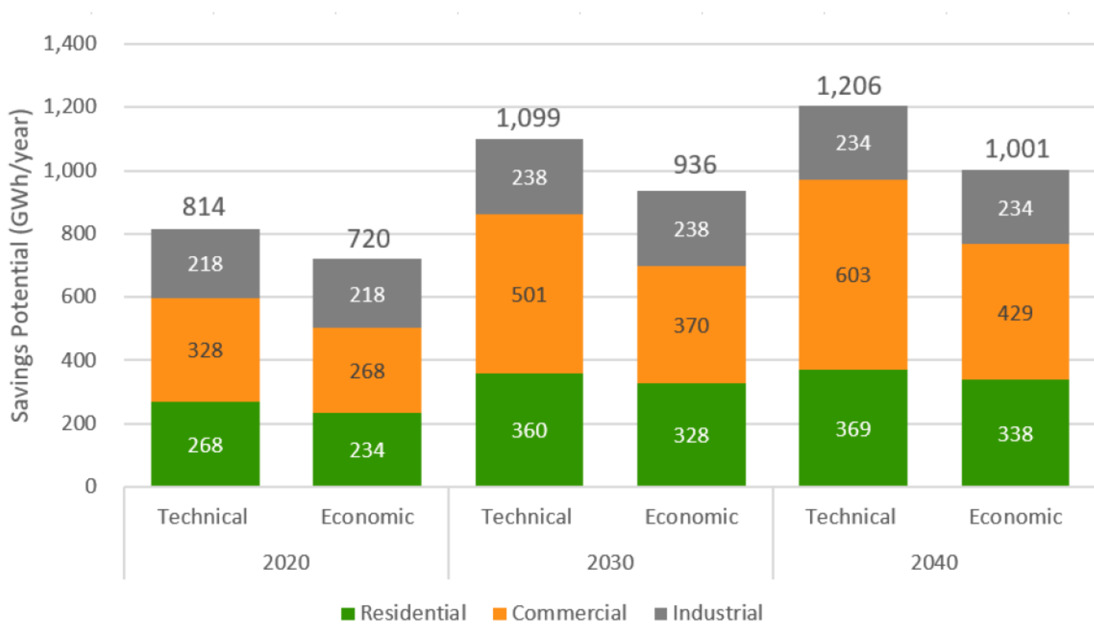
The remainder of the report highlights key study findings. All charts and figures included in this section have corresponding tabular data in Appendix A – Tabular Data for Charts. To complement these findings, Lumidyne provided attachments with detailed model assumptions and measure-level results, as listed in Appendix B – Attachments.

This section begins with a brief review of technical and economic potential. Then it presents market potential totals and aggregations by sector, customer segment, end use, and measures, along with a high-level comparison of market potential before and after natural change. The section concludes with a summary of cost effectiveness metrics.

3.1 Technical and Economic Potential

The study's focus was market potential results, though technical and economic potential are provided at a high level to give some context to market potential results. Figure 11 shows that technical potential grew from 814 GWh/year in 2020 to 1,206 GWh/year by 2040. The commercial sector drove 70 percent of the growth in technical potential, which coincided with the commercial sector having the highest forecast consumption growth in the *Reference Case*.

Figure 11. Technical & Economic Cumulative Electric Energy Savings Potential by Sector (GWh/year)



Source: Lumidyne

Economic potential captured 83 percent of the technical potential by 2040, and it grew 39 percent over the forecast period. Though the commercial sector still played a large role in economic potential, the residential and industrial sectors' percentage contributions grew relative to technical potential.

For both technical and economic potential, the end uses contributing the most savings were whole facility, lighting and space heating. Single-family detached homes, offices and non-food retail customer segments gained the most economic potential. The highest-saving measures in economic potential were commercial new construction

45% above code, new home Step Code 5, industrial pump equipment upgrades and commercial LEDs. The measures with the greatest reduction in potential between technical and economic potential were commercial new construction 45% above code, residential ductless mini-split heat pumps and commercial new construction Step Code 4.

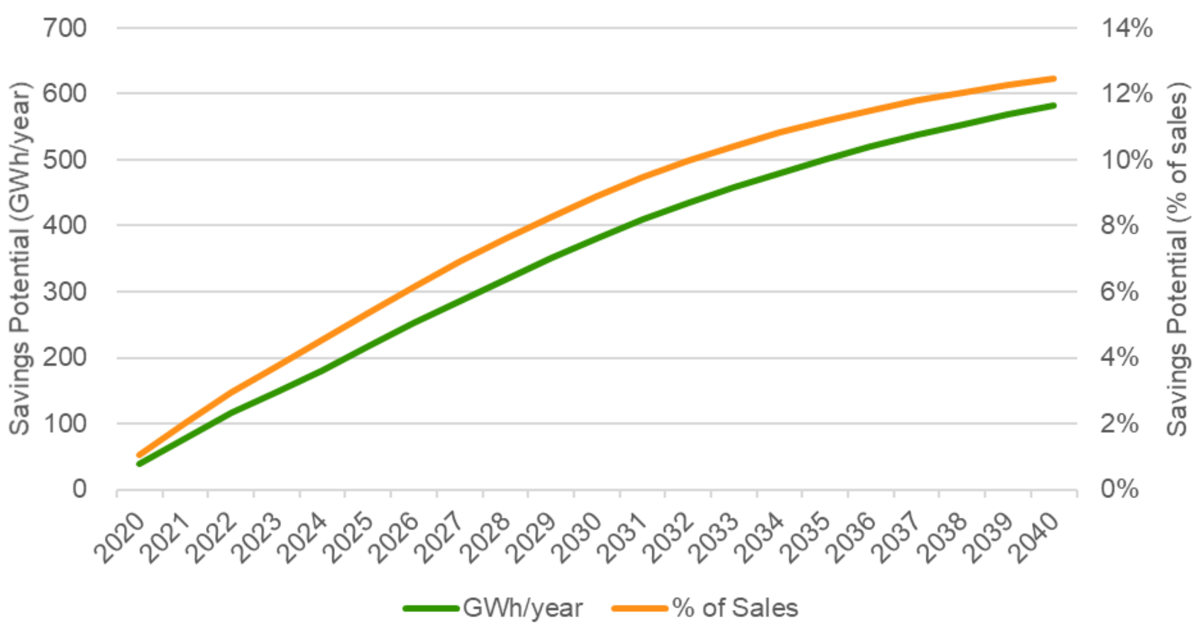
3.2 Market Potential

From this section onward, all results pertain to cumulative market savings. The review of gross market potential examines different levels of aggregation, from total market potential to measure-level potential. After discussing gross market potential, the report provides a comparison with net market potential.

3.2.1 Total Potential

The analysis found cumulative electric energy market potential to begin at 38 GWh/year in 2020 and grow to 583 GWh/year by 2040, as shown in Figure 12Figure 1. The average incremental annual savings over the horizon was slightly less than 28 GWh/year. Incremental annual savings slowly declined over time due to efficient measures saturating the replace-on-burnout and retrofit markets and due to Step Codes' raising of the minimum-code baseline in the new construction markets, which led to a corresponding reduction in incremental savings from efficient measures. Energy savings in 2020 equated to 1 percent of FortisBC's direct plus indirect sales. By 2040, the cumulative potential was 12.5 percent of sales.

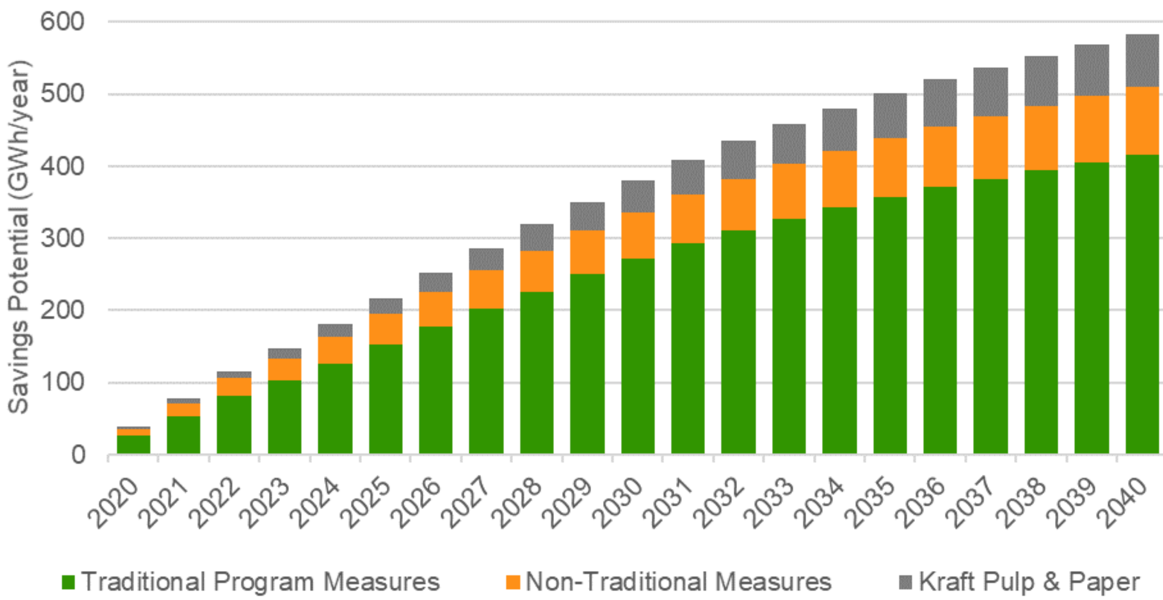
Figure 12. Total Cumulative Electric Energy Savings Potential (GWh/year, % of sales)



Source: Lumidyne

Figure 13 breaks out total market potential by the kraft pulp and paper segment and traditional and non-traditional measures. One goal of this breakdown is to show the opportunity of non-traditional measures that haven't been included in FortisBC's recent program offerings. The ratio of 2040 non-traditional potential to traditional potential was about 1:4. The figure also highlights the kraft pulp and paper segment's potential because much of its potential is not eligible for incentives—because a significant amount of kraft pulp and paper consumption is offset by self-generated electricity.

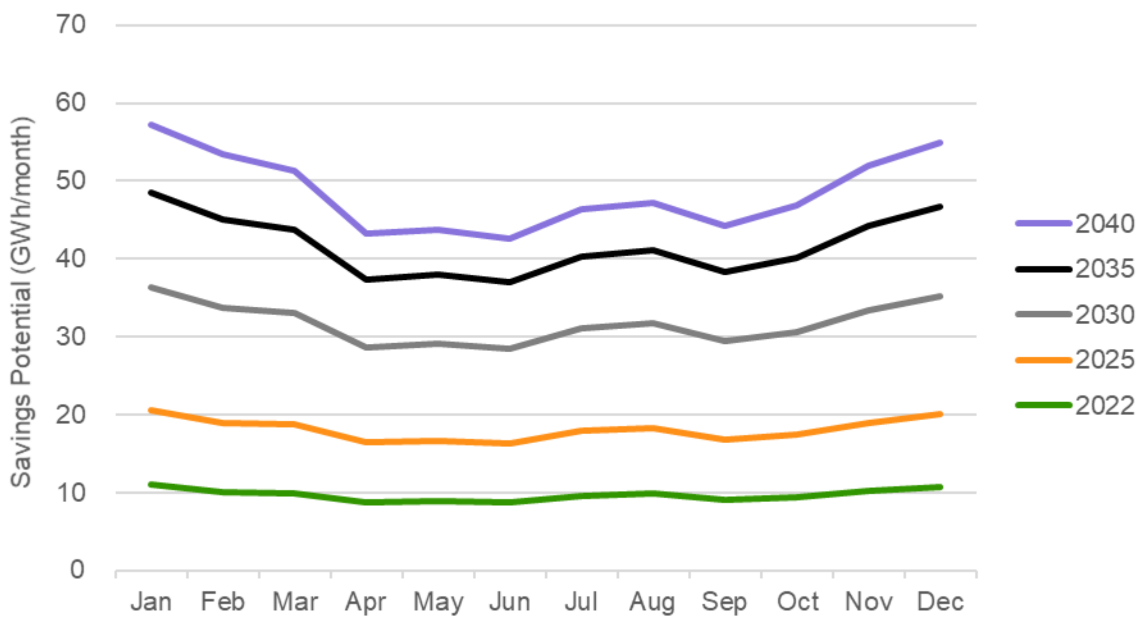
Figure 13. Cumulative Energy Savings Potential by Source (GWh/year)



Source: Lumidyne

Regarding the timing of market savings, the analysis found highest savings during winter months, as illustrated in Figure 14. Though the shape of the monthly savings was able to shift over time depending on the mix of measures included in market potential, the monthly distribution changed very little over the forecast horizon.

Figure 14. Total Cumulative Energy Savings Potential by Month (GWh/month)

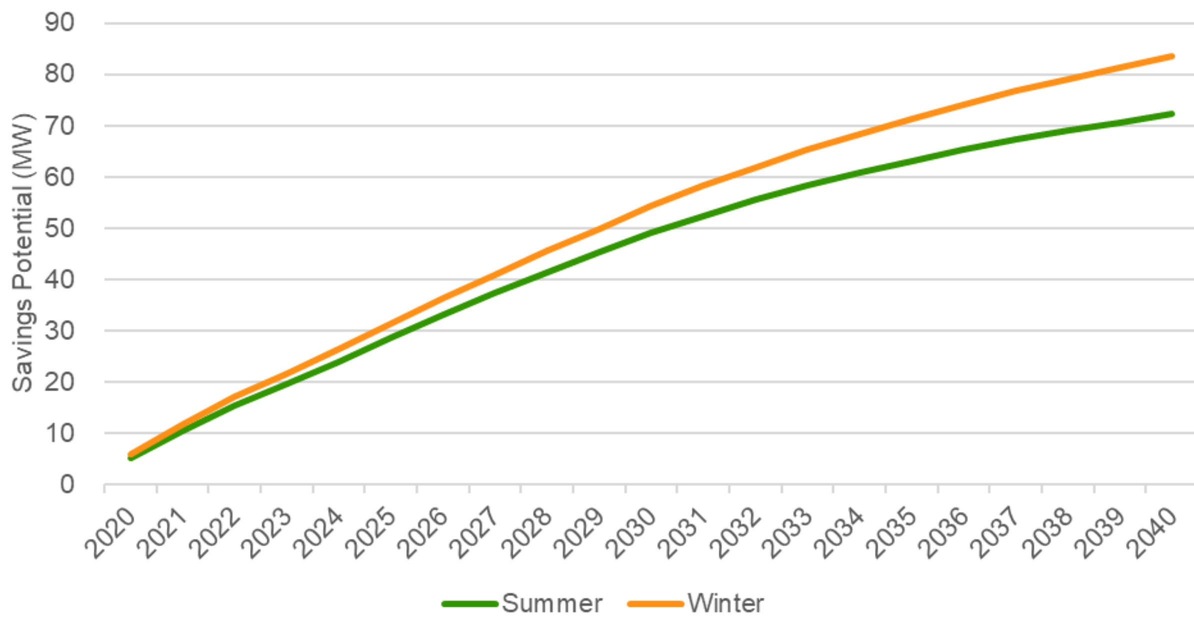


Source: Lumidyne

Savings in the lighting end use category boosted the winter and summer energy savings more than any other end use. The whole building end use came in second for winter and summer energy savings. The third most influential end uses were space heating for winter savings and industrial pumping for summer savings.

The forecast of cumulative electric winter demand market potential, shown in Figure 15, begins at 6 MW and reaches 84 MW by 2040. The market potential for summer demand is slightly lower, starting at 5 MW and reaching 72 MW. Winter potential corresponds to demand savings averaged between 5:00pm and 7:00pm in January and February. Summer potential averages demand savings between 5:00pm and 7:00pm in July and August. Though the analysis estimated demand savings across the two peakiest months in the summer and winter seasons, Lumidyne's load shape analysis suggests that the demand savings would be similar for adjacent months (e.g., December, March, June and September).

Figure 15. Total Cumulative Electric Demand Savings Potential (MW)



Source: Lumidyne

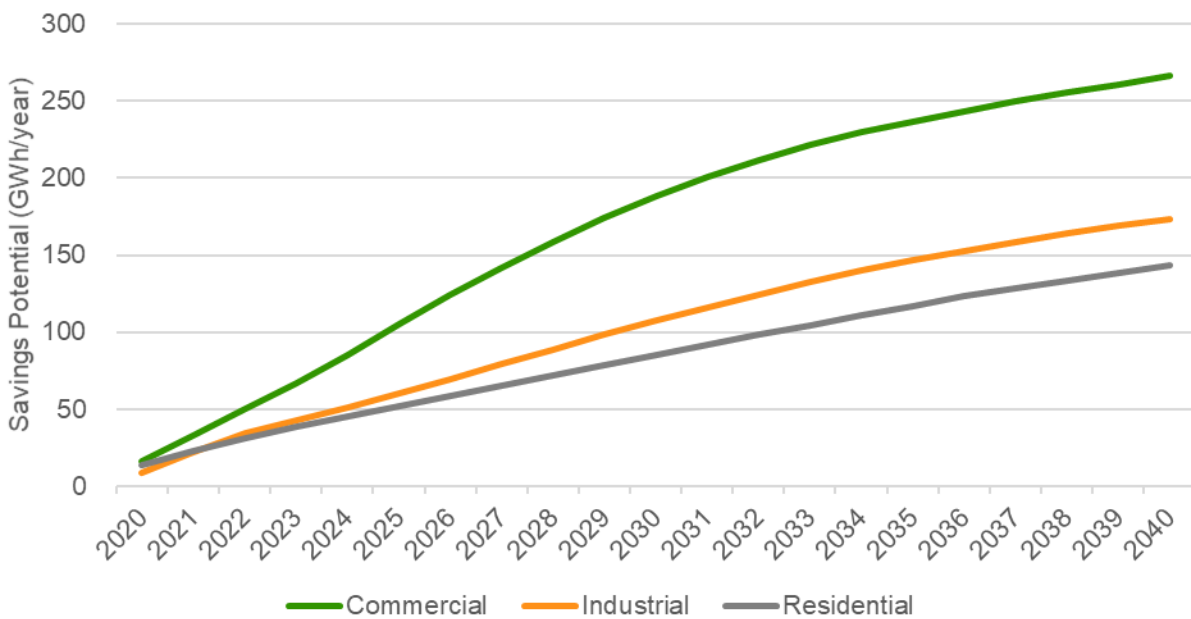
Winter demand savings tracked winter energy savings, where lighting, whole building and space heating end uses contributed the most. Lighting and whole building end uses drove much of the summer demand savings, with residential and commercial electronics being the next highest end use.

3.2.2 Potential by Sector

Next, the report looks at cumulative market potential by sector. Per FortisBC's guidance, the results categorized MURBs with the commercial sector. Thus, the residential sector only included single-family detached, single-family attached and other residential dwelling types.

Though the commercial and residential sectors started with similar 2020 potential, Figure 16 shows that the commercial sector quickly outpaced the residential sector. This reflected the *Reference Case's* projection that the rate of growth in commercial consumption would be more than double that of the residential and industrial sectors. For comparison, the study found 2040 cumulative savings from the new construction market to be 16 GWh/year in the residential sector and 69 GWh/year in the commercial sector. More than 80% of the growth in the industrial sector came from retrofit measures.

Figure 16. Cumulative Energy Savings Potential by Sector (GWh/year)

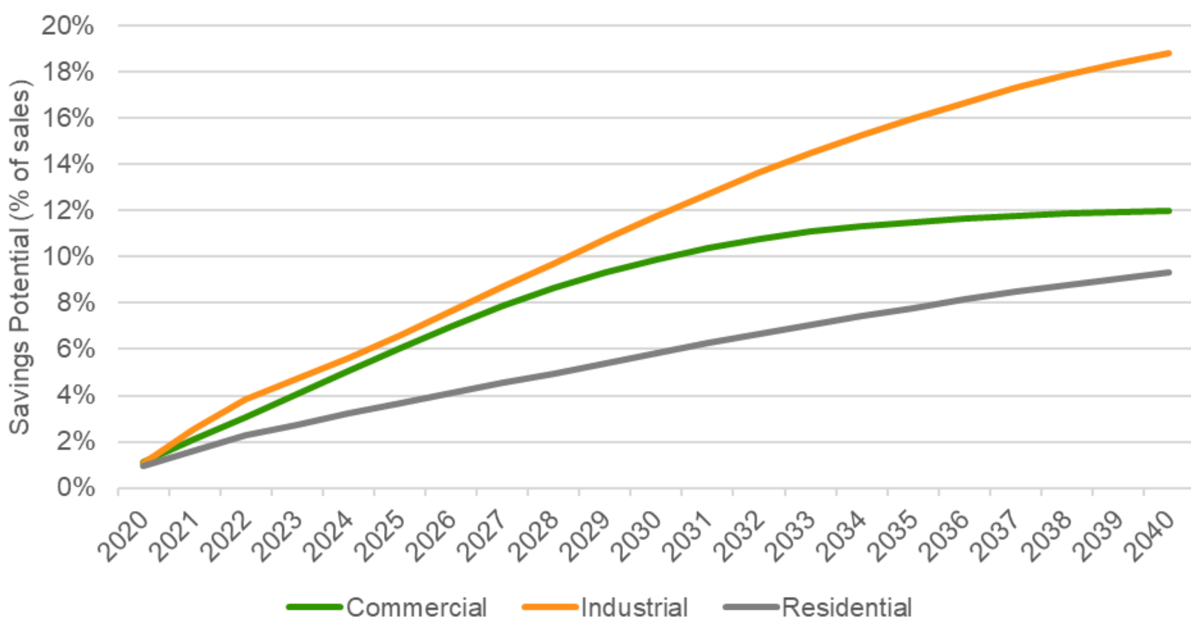


Source: Lumidyne

The rate of change in the commercial sector's potential slowed in the 2030s as the retrofit market saturated, particularly for LED lighting, building automation systems and variable-speed drives on pumps. Similarly, incremental potential for residential LED lighting dropped off quickly in the replace-on-burnout market, and half of the lighting potential in that market was achieved within the first four simulation years.

When viewed as a percentage of sector-level sales, the industrial sector achieved the highest savings percentages, reaching just above 18 percent by 2040. Saturation of the commercial sector is more apparent in Figure 17, where commercial savings percentages nearly flattened out by the end of the forecast. Despite having the lowest market potential as a percentage of sales, the residential sector showed a consistent upward trend.

Figure 17. Cumulative Energy Savings Potential as a Percentage of Sales by Sector (%)

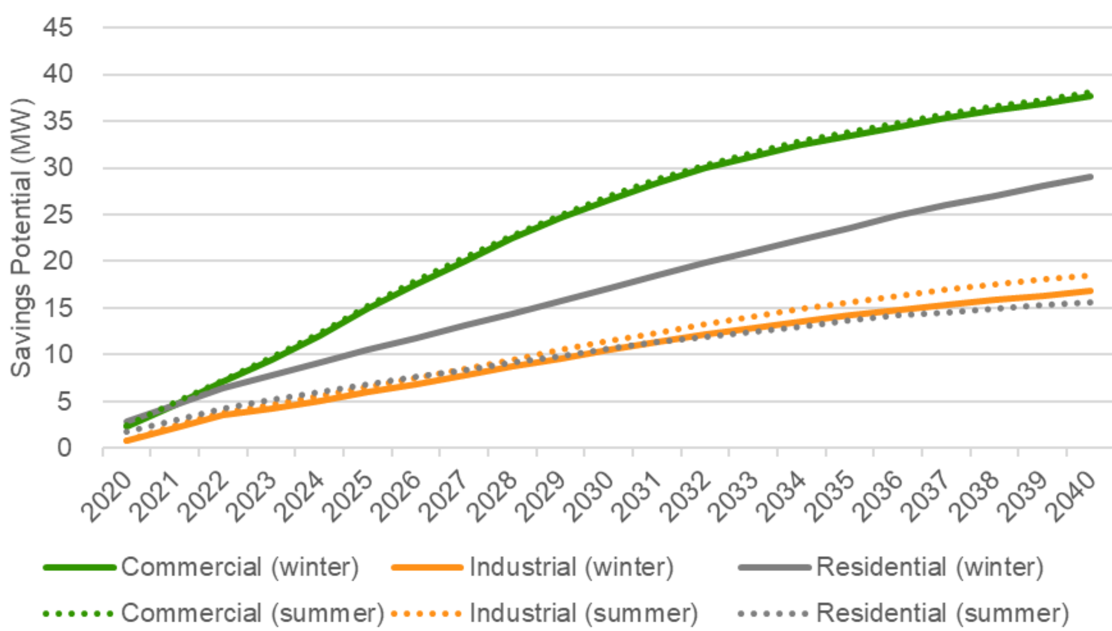


Source: Lumidyne

The *Base Year* analysis indicated that the residential sector's largest loads were space heating, appliances and hot water, so an inspection of those end uses' market potential provided insight into why residential savings were a lower percentage of sales. The team found that the space heating end use was achieving appreciable savings from smart thermostats and building shell measures. On the other hand, the market potential showed little contribution from the appliance end use. The highest-saving appliance measures were efficient electric clothes dryers by a large margin, followed by ENERGY STAR freezers. Notably, ENERGY STAR refrigerators did not pass the economic screen. The minimal difference in efficiency levels between high-efficiency and baseline appliances was likely a factor in the lack of significant market potential from appliances. A review of the hot water end use uncovered that heat pump water heaters and electric storage water heaters had the largest economic potential. However, the participant economics were not attractive enough to spur much adoption. In fact, much of the hot water heater adoption went to the electric storage water heater, and heat pump water heaters only reached 12 percent of their economic potential.

Despite differences in summer and winter demand savings potential within each commercial end use, the aggregate commercial demand savings were nearly identical between seasons, as shown in Figure 18. Industrial demand savings were highest in the summer, owing largely to pumping and fans and blowers end uses. The residential sector's 2040 summer demand savings were 46 percent lower than winter savings even though summer-month energy consumption was only 30 percent lower than winter-month energy consumption. One driver for this outcome is that efficient space cooling equipment showed very little technical potential and no market potential. However, if summer temperatures increase appreciably and residential space cooling equipment has higher operating hours and becomes more prevalent in homes, then space cooling will likely become a larger contributor to residential energy consumption and peak summer demand. Consequently, this scenario would likely lead to more favourable economics for high-efficiency space cooling measures.

Figure 18. Cumulative Demand Savings Potential by Sector (MW)

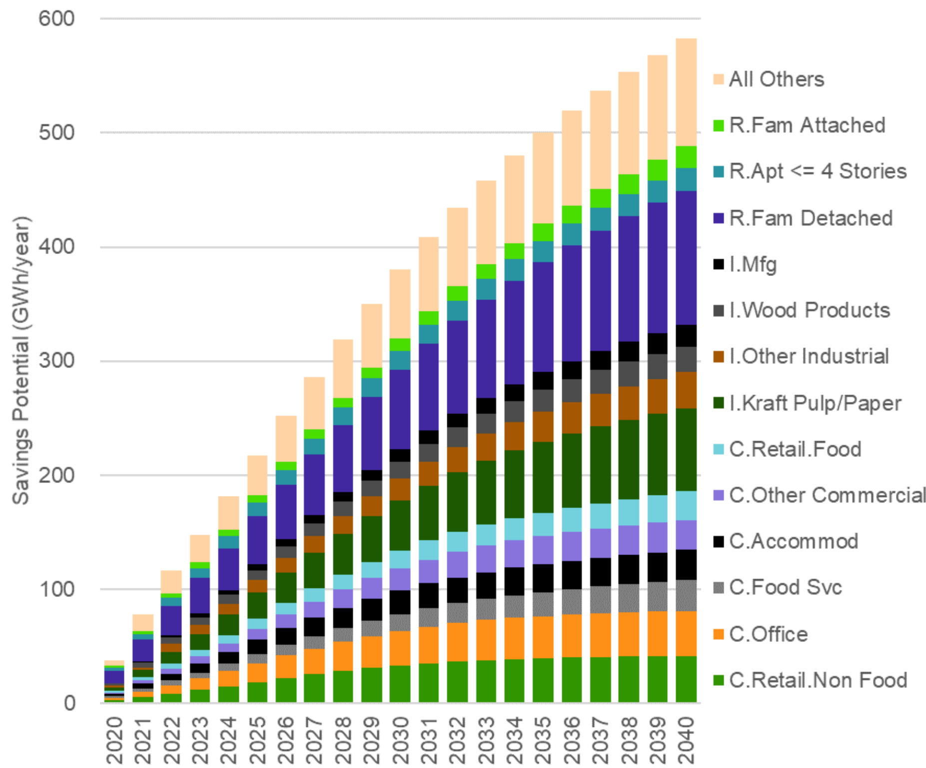


Source: Lumidyne

Potential by Customer Segment

An inspection of market potential by customer segment, given in Figure 19, showed that single-family detached homes accounted for 20 percent of 2040 energy savings. Kraft pulp and paper represented 13% of the 2040 potential, while non-food retail and offices were both at about 7%.

Figure 19. Cumulative Energy Savings Potential by Customer Segment (GWh/year)[32]



Source: Lumidyne

Note: Customer segments comprising the "All Others" category have individual savings ranging from 0.3% to 2.6%—for a combined sum of 16.3%—of the 2040 total, and they include: I.Agriculture, C.College/Univ, C.Long Term Care, C.Hospital, I.Cannibis, C.Logistic/Warehouse, R.Other Residential, C.Schools, C.Streetlights/Signals, I.Food/Beverage, and R.Apartments > 4 Storeys.

When looking at market potential as a percentage of sales, the highest customer segments were kraft pulp and paper, agriculture, colleges/universities and food retail. Apartments and residential segments fell on the low end

[32] Segment abbreviations have the following descriptions:
"Fam Attached" -- single-family attached homes;
"Apt <= 4 Stories" -- apartments less than or equal to four storeys in height;
"Fam Detached" -- single-family detached homes;
"Mfg" -- manufacturing;
"Accomod" -- accommodations;
"Food Svc" -- food services;

of savings as a percentage of sales. Apartments' economic potential was appreciably lower than technical potential, and this played a role in the low market potential as a percentage of sales.

Table 18, Table 19 and Table 20 provide a 2030 mid-forecast breakdown of savings for customer segments within each sector. In this 10-year view, non-food retail, offices and accommodation provide close to half the commercial savings, whereas kraft pulp & paper and "other industrial" garner about 60% of industrial potential. Lastly, over 80% of 2030 residential potential savings come from detached homes.

Table 18. Commercial Cumulative Energy Savings Potential in 2030 by Customer Segment

Customer Segment	GWh/year	% of Sector
C.Retail.Non Food	33	17.6%
C.Office	30	16.1%
C.Accommod	21	11.0%
C.Other Commercial	19	10.3%
R.Apt <= 4 Storeys	17	8.8%
C.Retail.Food	15	8.2%
C.Food Svc	15	7.9%
C.College/Univ	8	4.3%
C.Hospital	7	4.0%
C.Long Term Care	7	3.9%
C.Logistic/WHouse	7	3.6%
C.Schools	5	2.4%
C.Streetlights/Signals	2	1.2%
R.Apt > 4 Storeys	1	0.8%
Total	**188**	**100.0%**

Table 19. Industrial Cumulative Energy Savings Potential in 2030 by Customer Segment

Customer Segment	GWh/year	% of Sector
I.Kraft Pulp/Paper	44	41.3%
I.Other Industrial	19	17.8%
I.Wood Products	15	13.7%
I.Mfg	11	9.8%
I.Cannabis	9	8.2%
I.Agriculture	8	7.8%
I.Food & Bev	1	1.3%
Total	**107**	**100.0%**

Table 20. Residential Cumulative Energy Savings Potential in 2030 by Customer Segment

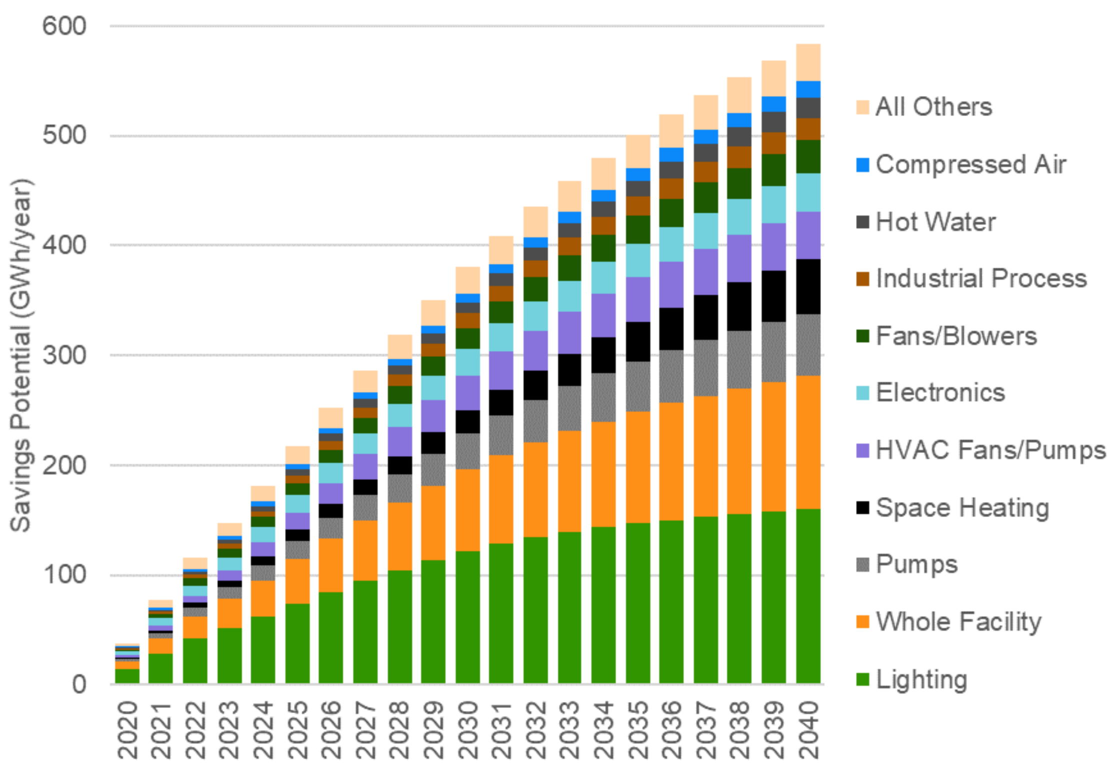
Customer Segment	GWh/year	% of Sector
R.SingleFam Detached	70	82.3%
R.SingleFam Attached	11	12.7%
R.Other Residential	4	5.0%
Total	**85**	**100.0%**

Source: Lumidyne

3.2.3 Potential by End Use

Figure 20 shows the market potential by end use and highlights the large impact from lighting, which was concentrated in the single-family detached, non-food retail, and office segments. However, incremental lighting potential slowed in the 2030s due to saturation of the retrofit and replace-on-burnout markets. Despite the slowing growth rate in lighting, it accounted for 27 percent of 2040's market potential. In contrast, whole facility measures like commercial efficient new construction and building automation systems continued an upward trajectory throughout the forecast horizon and landed at 21 percent of the final year's market potential. The customer segments with the highest whole facility savings were food service, single-family detached and food retail. Notably, industry-specific end uses like pumps, fans/blowers and industrial process were some of the highest-saving end uses.

Figure 20. Cumulative Energy Savings Potential by End Use (GWh/year)



Source: Lumidyne

Note: End uses comprising the "All Others" category have individual savings ranging from 0% to 1.8%—for a combined sum of 5.8%—of the 2040 total, and they include: Refrigeration, Appliances, Office Equipment, Material Transport, Space Cooking, Other, Product Drying, and Ventilation.

Mid-forecast savings breakdowns by end use and sector appear in Table 21, Table 22 and Table 23. The commercial sector's market potential was dominated by lighting, whole facility and HVAC fans/pumps. The residential sector's savings were distributed more evenly across its end uses. Interestingly, 21 percent of residential potential came from electronics, one of the few end uses that the *Reference Case* found to be increasing in energy intensity. The absence of space cooling potential in the residential sector flags an opportunity for future exploration of lower-cost space cooling measures. Lastly, the industrial sector was the only sector not to have lighting as the highest-saving end use. In fact, savings from industrial pumping was 33 percent larger than lighting savings.

Table 21. Commercial Cumulative Energy Savings Potential in 2030 by End Use

End Use	GWh/year	% of Sector
Lighting	75	39.7%
Whole Facility	59	31.4%
HVAC Fans/Pumps	32	17.0%
Electronics	6	3.2%
Refrigeration	5	2.6%
Office Equip	4	2.2%
Space Cooling	3	1.5%
Hot Water	2	1.0%
Other	1	0.6%
Space Heating	1	0.4%
Cooking	0	0.3%
Appliances	0	0.1%
Total	**188**	**100.0%**

Table 22. Industrial Cumulative Energy Savings Potential in 2030 by End Use

End Use	GWh/year	% of Sector
Pumps	32	30.2%
Lighting	24	22.7%
Fans/Blowers	19	17.7%
Industrial Proc	13	12.1%
Compressed Air	8	7.5%
Whole Facility	3	3.2%
Mat Transport	3	2.6%
Refrigeration	3	2.6%
Space Heating	1	1.2%
Product Drying	0	0.2%
Total	**107**	**100.0%**

Table 23. Residential Cumulative Energy Savings Potential in 2030 by End Use

End Use	GWh/year	% of Sector
Lighting	23	26.5%
Space Heating	19	22.5%
Electronics	18	21.4%
Whole Facility	12	14.0%
Hot Water	8	9.4%
Appliances	5	6.2%
Total	**85**	**100.0%**

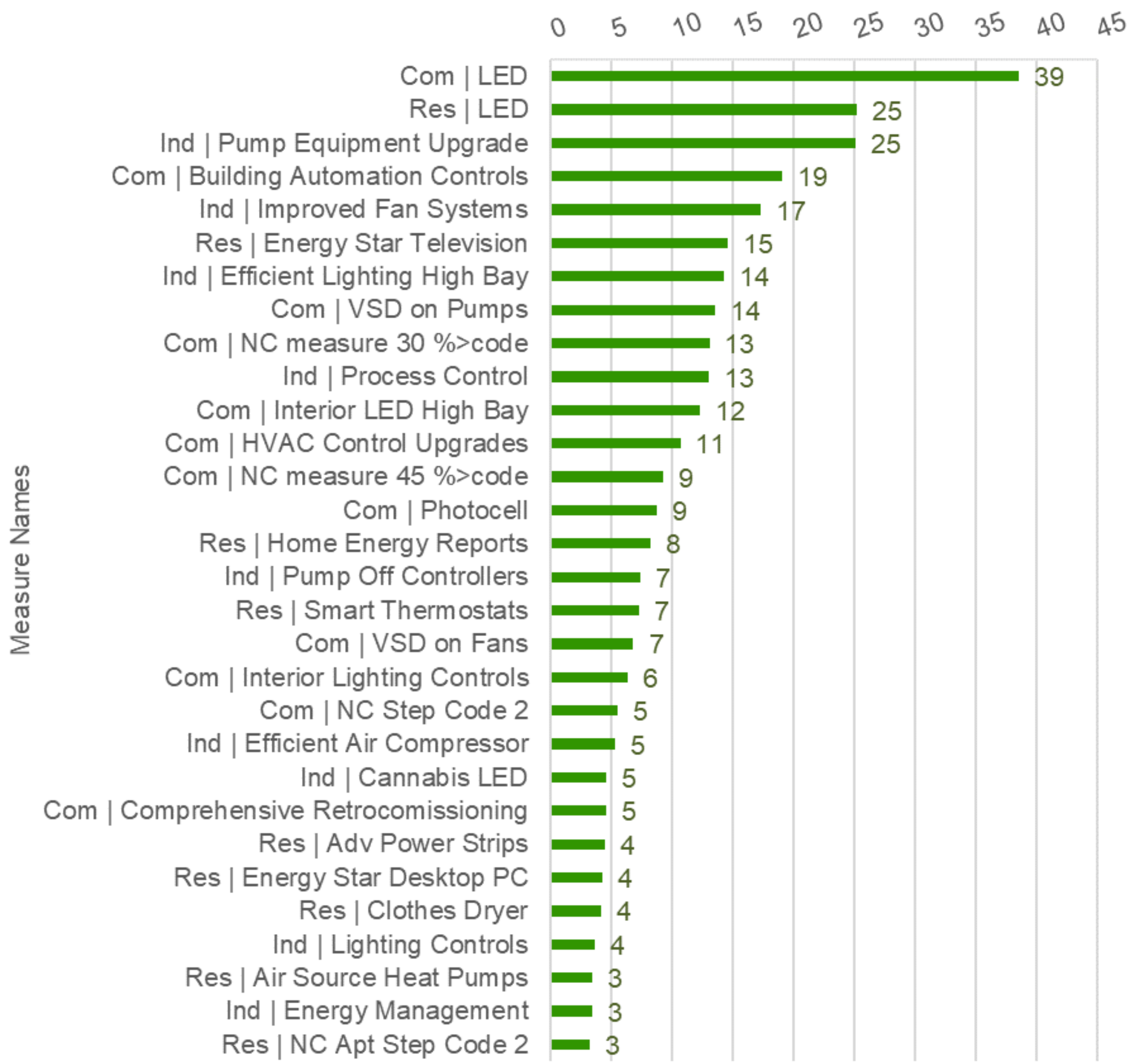
Source: Lumidyne

3.2.4 Potential by Measure

The following figures show energy and summer/winter demand savings by measure. In some instances, the measure names consist of groups of similar measures. For example, the "Com | LED" measure group includes interior LED, interior LED MR/PAR, LED luminaire and troffer LED.

Figure 21 shows the top 30 measures for cumulative energy savings midway through the forecast period. This view is insightful because it illustrates that, relative to the CPR's full list of 167 unique measures, most savings come from a small subset of high-impact measures. For energy savings, the top 10 measures accounted for 50 percent of the 2030's total potential, while the top 26 measures accounted for 80 percent. The remaining 141 measures contributed the other 20 percent of potential. Commercial LEDs accounted for 10 percent of total potential, and the sum of residential and commercial LED potential contributed 17 percent.

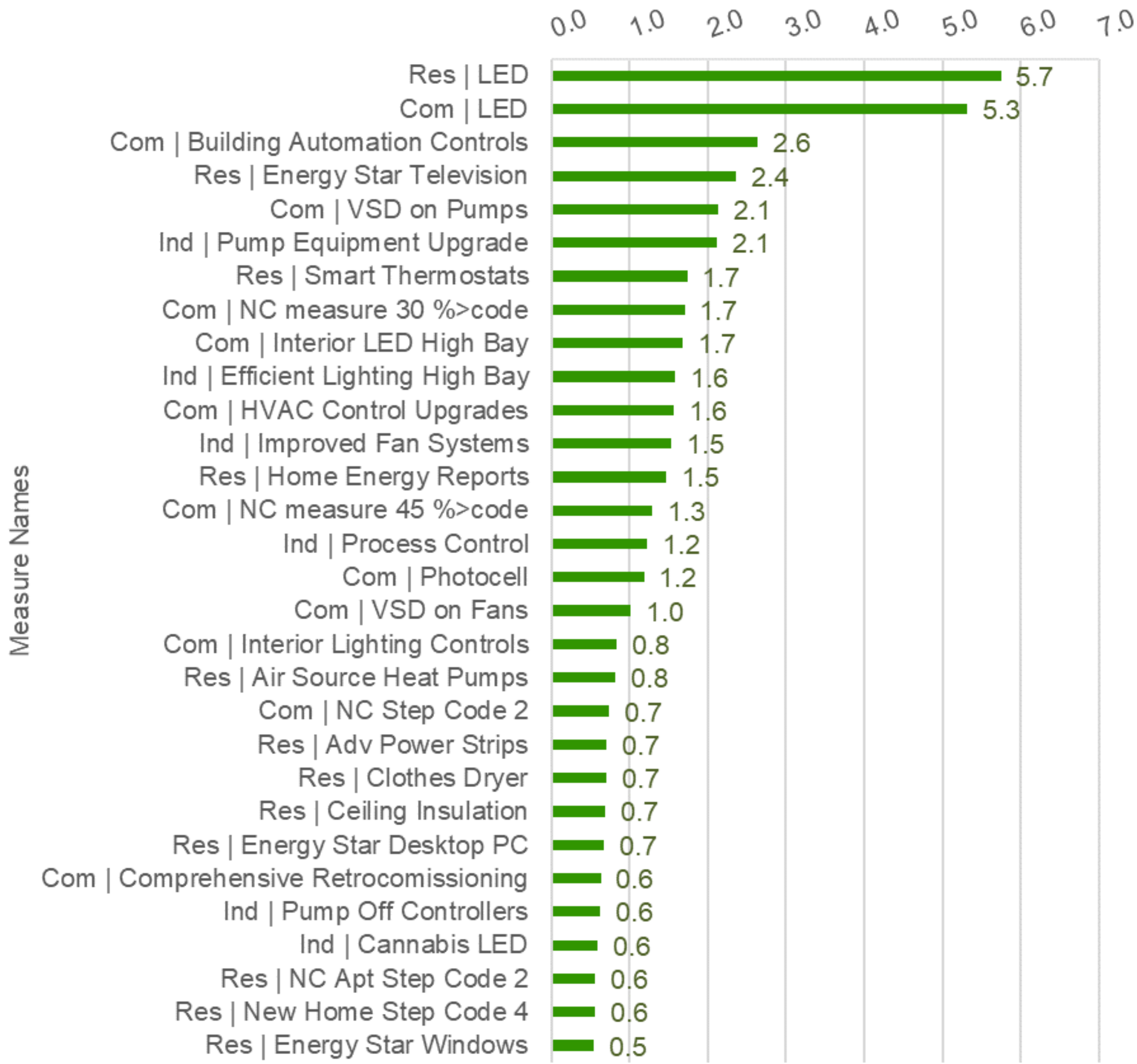
Figure 21. Top 30 Measures for Cumulative Energy Savings in 2030 (GWh/year)



Source: Lumidyne

Eight of the top ten energy-saving measures also appeared in the top 10 winter-demand-saving measures shown in Figure 22. Though commercial LED had higher energy savings than residential LED, those rankings reversed for winter demand savings. Additionally, the combined winter demand potential from these two LED measures increased to 20 percent of the total 2030 winter demand savings. Once again, the top ten measures accounted for 50 percent of the total demand potential, and 80 percent of 2030's potential came from the top 27 measures.

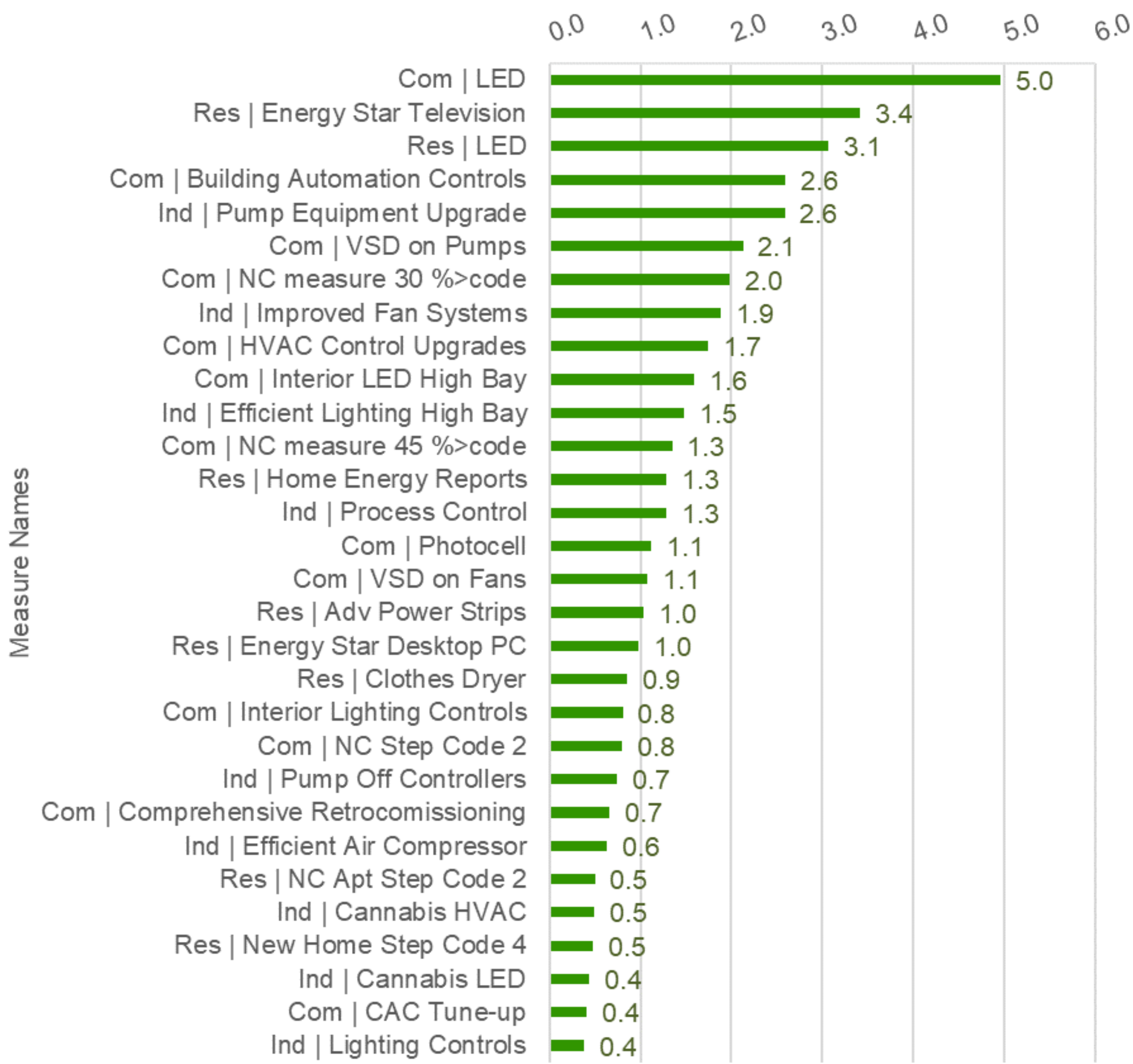
Figure 22. Top 30 Measures for Cumulative Winter Demand Savings in 2030 (MW)



Source: Lumidyne

Figure 23 shows the top 30 measures for summer demand savings in 2030. Most of the top ten energy-saving and winter-demand-saving measures landed in the top ten measures for summer demand saving. The implication is that most of the top energy-saving measures will also contribute appreciably to reducing both winter and summer peak demand. For summer demand potential, the top nine measures generated 50 percent of 2030's total savings, and the top 23 measures generated 80 percent. Commercial LEDs provided 10 percent of the savings, and the sum of commercial and residential LEDs accounted for 17 percent.

Figure 23. Top 30 Measures for Cumulative Summer Demand Savings in 2030 (MW)



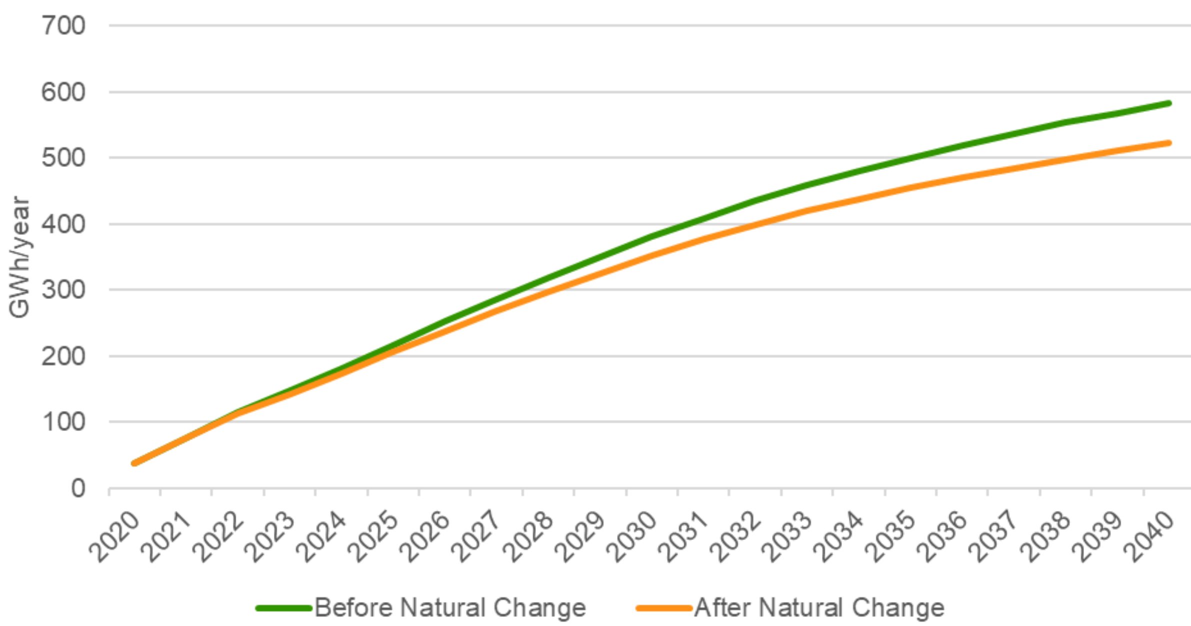
Source: Lumidyne

3.2.5 Potential Adjusted for Natural Change

Thus far in the report, all market potential results have implicitly attributed all increases in efficient measure adoption to DSM program activity, which is akin to representing gross savings potential. In real-world markets, there is some likelihood that utility customers, absent any utility incentives or recruitment, will still pursue energy conservation measures. The implication is that the *Reference Case's* end use intensity trends likely included some combination of program-driven change in efficiency and some "natural change" that was not program-driven. Using the rate of change in end use intensities and the modelled savings as a percentage of consumption, the team estimated by how much each customer segment and end use's potential could be attributed to DSM program activities versus natural change.

The results in Figure 24 show total market potential before and after addressing natural change. Potential before natural change is identical to the total market potential shown previously in this report. Potential after natural change is similar to net savings potential and corrects for efficiency changes that might occur in absence of utility-sponsored DSM programs. The difference between the two curves represents the net natural conservation that might be expected based on recent trends in end use intensities. Importantly, this aspect of gross versus net savings is separate from the free-rider and spillover effects applied to DSM reporting at the program level.

Figure 24. Total Cumulative Energy Savings Potential after Natural Change (GWh/year)



Source: Lumidyne

3.3 Market Potential Cost Effectiveness

The final section of this report summarizes the cost effectiveness of market potential at the sector and portfolio level. Differing from the approach used in measure-level economic screening, the benefit-to-cost ratios and net benefits shown in Table 24 and Table 25 included administrative costs where appropriate to the given cost test. Additionally, these metrics represent cost effectiveness across the entire 2020-2040 forecast horizon.

The benefit-cost ratios were favourable for all costs tests and sectors, except for the Rate Impact Measure Test (RIM). Relative to the previous CPR, avoided energy and demand costs decreased appreciably and electric rates increased slightly, as shown earlier in Table 1. Both factors negatively impacted the RIM test, which treats avoided costs as benefits and lost revenues as costs.

Table 24. Benefit-to-Cost Ratios across 2020-2040 Horizon (ratio)

Sector	Total Resource Cost Test	Utility Cost Test	Participant Cost Test	Rate Impact Measure Test
Commercial	2.45	3.95	3.37	0.80
Industrial	2.91	4.39	3.15	0.97
Residential*	2.26	2.33	4.68	0.63
Portfolio	2.05	2.62	3.65	0.73

Source: Lumidyne

**Note: the residential sector relied on a modified Total Resource Cost (mTRC) test.*

Though the analysis applied an mTRC test to residential measures, more than 96 percent of residential market potential passed the more restrictive TRC test.

Net benefits subtract total costs from total benefits, so all positive values represent an improvement in financial standing. Notably, the net present value of market potential over the 20-year horizon is more than $173 million in 2020 dollars from the TRC perspective. Net present values are also positive for the utility and participant perspectives, and negative only for the rate RIM test. Since the BC governing legislation forbids use of the RIM test for approval purposes, it is presented for informational purposes only.

Table 25. Net Present Value of Net Benefits across 2020-2040 Horizon (million 2020$)

Sector	Total Resource Cost Test	Utility Cost Test	Participant Cost Test	Rate Impact Measure Test
Commercial	$95.4	$118.3	$142.0	-$39.8
Industrial	$56.9	$67.0	$60.5	-$2.4
Residential*	$50.4	$53.8	$111.4	-$54.9
Portfolio	$173.1	$209.6	$314.0	-$126.7

Source: Lumidyne

**Note: the residential sector relied on a modified Total Resource Cost (mTRC) test.*

4 Appendix A – Tabular Data for Charts

This appendix provides tabular data for charts included in the body of the report.

Table 26. Base Year 2019 Residential Monthly Consumption Shape by End Use (GWh/month)

End Use	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Appliances	35.3	32.5	34.7	34.3	37.5	39.0	43.2	43.1	39.5	36.7	32.9	33.4
Electronics	11.0	9.9	11.2	10.1	11.2	11.6	15.4	15.6	12.6	10.6	9.4	11.4
Hot Water	18.0	16.7	18.2	16.9	15.5	14.4	13.8	12.9	13.3	14.6	15.4	16.1
Lighting	18.9	15.1	14.4	11.7	10.8	9.9	10.4	11.5	13.0	15.8	17.7	19.5
Other	17.3	14.8	10.5	10.2	9.9	10.0	10.2	10.3	9.7	9.7	14.5	16.4
Space Cooling	0.0	0.0	0.0	0.0	9.6	14.7	24.0	25.2	8.9	0.0	0.0	0.0
Space Heating	72.9	68.4	49.4	15.1	4.7	0.0	0.0	0.0	8.9	35.2	51.3	67.7
Ventilation	16.0	13.7	9.8	9.4	9.2	9.2	9.5	9.5	8.9	9.0	13.4	15.1

Table 27. Base Year 2019 Commercial Monthly Consumption Shape by End Use (GWh/month)

End Use	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Cooking	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Hot Water	2.3	2.1	2.3	2.2	2.3	2.2	2.3	2.3	2.2	2.3	2.2	2.3
Office Equipment	3.4	3.1	3.4	3.3	3.4	3.2	3.3	3.4	3.3	3.4	3.3	3.4
Other	13.2	11.9	13.2	12.8	13.2	12.6	12.9	13.2	12.7	13.3	12.8	13.1
Refrigeration	7.8	7.0	7.8	7.6	7.9	7.7	8.0	8.2	7.9	8.0	7.6	7.8
Lighting	43.4	39.0	42.9	41.3	42.5	40.7	41.8	42.6	41.3	43.5	41.9	43.1
HVAC Fans/Pumps	31.1	31.1	25.8	18.7	18.6	20.7	24.7	25.7	20.0	20.4	25.4	29.1
Space Cooling	4.7	4.9	5.0	5.0	5.5	7.1	9.2	9.4	6.8	5.4	5.2	4.8
Space Heating	6.3	6.3	4.1	1.8	1.3	0.5	0.0	0.0	0.5	1.9	3.6	5.2

Table 28. Base Year 2019 Industrial Monthly Consumption Shape by Segment (GWh/month)

Customer Segment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Food & Beverage	0.9	1.0	0.9	1.0	1.1	1.3	1.0	1.0	1.1	0.9	1.0	0.9
Manufacturing	7.3	7.3	6.6	5.6	7.1	7.1	7.0	7.2	7.2	6.3	7.1	6.8
Other Industrial	9.8	10.7	11.9	10.9	11.5	10.7	11.1	11.6	11.1	11.3	11.4	9.8
Wood Products	12.2	12.7	12.7	12.4	10.9	11.5	10.9	11.6	11.3	14.1	14.1	12.8
Agriculture	2.2	2.1	2.0	2.8	6.3	7.4	8.2	8.5	4.9	3.3	2.4	2.2
Pulp & Paper - Kraft	32.8	29.4	31.5	31.0	32.1	28.3	31.8	31.0	30.4	22.9	33.6	30.7

Table 29. Technical & Economic Cumulative Electric Energy Savings Potential by Sector (GWh/year)

Year	Potential Type	Residential	Commercial	Industrial	Total
2020	Technical	268	328	218	814
2020	Economic	234	268	218	720
2030	Technical	360	501	238	1,099
2030	Economic	328	370	238	936
2040	Technical	369	603	234	1,206
2040	Economic	338	429	234	1,001

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Table 30. Total Cumulative Electric Energy Savings Market Potential (GWh/year, % of Sales)

Year	GWh/year	% of Sales
2020	38	1.0%
2021	78	2.0%
2022	116	3.0%
2023	148	3.7%
2024	181	4.5%
2025	217	5.3%
2026	252	6.1%
2027	286	6.9%
2028	319	7.6%
2029	351	8.3%
2030	381	8.9%
2031	409	9.5%
2032	435	10.0%
2033	459	10.4%
2034	480	10.8%
2035	501	11.2%
2036	520	11.5%
2037	537	11.8%
2038	553	12.0%
2039	568	12.3%
2040	583	12.5%

Table 31. Cumulative Energy Savings Market Potential by Source (GWh/year)

Year	Traditional Program Measures	Non-Traditional Measures	Kraft Pulp & Paper
2020	26	9	3
2021	54	17	7
2022	81	25	10
2023	103	31	14
2024	126	37	18
2025	152	43	23
2026	177	48	27
2027	202	53	31
2028	226	57	36
2029	250	61	40
2030	272	65	44
2031	292	68	48
2032	311	72	52
2033	328	75	56
2034	343	78	59
2035	357	81	62
2036	371	84	65
2037	382	87	67
2038	394	90	69
2039	405	92	71
2040	415	95	73

Table 32. Total Cumulative Energy Savings Potential by Month (GWh/month)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	3.7	3.3	3.3	2.8	2.8	2.8	3.1	3.1	3.0	3.1	3.4	3.6
2025	20.6	18.9	18.7	16.4	16.7	16.4	17.9	18.3	16.9	17.5	19.0	20.0
2030	36.3	33.7	33.0	28.6	29.2	28.5	31.1	31.7	29.4	30.6	33.4	35.2
2035	48.4	45.1	43.8	37.4	38.0	37.0	40.3	41.1	38.3	40.2	44.2	46.7
2040	57.2	53.4	51.4	43.2	43.8	42.6	46.3	47.2	44.2	46.8	51.9	55.0

Table 33. Total Cumulative Electric Demand Savings Potential (MW)

Year	Summer	Winter
2020	5	6
2021	10	12
2022	15	17
2023	20	22
2024	24	26
2025	29	31
2026	33	36
2027	37	41
2028	41	46
2029	45	50
2030	49	54
2031	52	58
2032	56	62
2033	58	65
2034	61	68
2035	63	71
2036	65	74
2037	67	77
2038	69	79
2039	71	81
2040	72	84

Table 34. Cumulative Energy Savings Potential by Sector (GWh/year)

Year	Commercial	Industrial	Residential
2020	16	8	13
2021	33	22	22
2022	50	35	31
2023	67	43	38
2024	85	51	45
2025	105	60	52
2026	124	70	58
2027	142	79	65
2028	159	89	71
2029	174	98	78
2030	188	107	85
2031	201	116	92
2032	212	125	98
2033	221	133	105
2034	230	140	111
2035	237	147	117
2036	244	153	123
2037	250	159	129
2038	255	164	134
2039	261	169	139
2040	266	173	143

Table 35. Cumulative Energy Savings Potential as a Percentage of Sales by Sector (%)

Year	All	Commercial	Industrial	Residential
2020	1.0%	1.1%	1.1%	1.0%
2021	2.0%	2.1%	2.6%	1.6%
2022	3.0%	3.1%	3.8%	2.3%
2023	3.7%	4.0%	4.7%	2.7%
2024	4.5%	5.0%	5.6%	3.2%
2025	5.3%	6.1%	6.6%	3.6%
2026	6.1%	7.0%	7.7%	4.1%
2027	6.9%	7.9%	8.7%	4.5%
2028	7.6%	8.6%	9.7%	5.0%
2029	8.3%	9.3%	10.8%	5.4%
2030	8.9%	9.9%	11.8%	5.8%
2031	9.5%	10.4%	12.7%	6.3%
2032	10.0%	10.8%	13.6%	6.7%
2033	10.4%	11.1%	14.5%	7.0%
2034	10.8%	11.3%	15.3%	7.4%
2035	11.2%	11.5%	16.0%	7.8%
2036	11.5%	11.6%	16.7%	8.2%
2037	11.8%	11.8%	17.3%	8.5%
2038	12.0%	11.9%	17.8%	8.8%
2039	12.3%	11.9%	18.4%	9.1%
2040	12.5%	12.0%	18.8%	9.3%

Table 36. Cumulative Demand Savings Potential by Sector (MW)

Year	Commercial (winter)	Commercial (summer)	Industrial (winter)	Industrial (summer)	Residential (winter)	Residential (summer)
2020	2.3	2.4	0.8	0.9	2.8	1.8
2021	4.7	4.9	2.2	2.4	4.7	3.0
2022	7.1	7.3	3.5	3.9	6.5	4.2
2023	9.4	9.7	4.3	4.7	7.9	5.1
2024	12.0	12.4	5.1	5.5	9.2	6.0
2025	14.9	15.2	6.0	6.5	10.5	6.8
2026	17.6	17.9	6.9	7.5	11.8	7.6
2027	20.1	20.4	7.8	8.5	13.1	8.4
2028	22.4	22.8	8.7	9.5	14.4	9.1
2029	24.6	25.0	9.6	10.5	15.8	9.9
2030	26.6	27.0	10.5	11.5	17.2	10.6
2031	28.4	28.7	11.3	12.4	18.5	11.3
2032	29.9	30.3	12.1	13.3	19.8	12.0
2033	31.3	31.7	12.9	14.1	21.1	12.5
2034	32.5	32.8	13.6	14.9	22.3	13.1
2035	33.5	33.9	14.2	15.6	23.6	13.6
2036	34.4	34.8	14.8	16.3	24.9	14.2
2037	35.3	35.7	15.4	16.9	26.0	14.6
2038	36.1	36.5	15.9	17.5	27.0	15.0
2039	36.9	37.3	16.4	18.0	28.1	15.3
2040	37.7	38.1	16.8	18.5	29.1	15.7

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Table 37. Cumulative Energy Savings Potential by Customer Segment (GWh/year)

Customer Segment	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
C.Accommod	2	4	6	8	10	13	15	17	18	20	21	22	23	23	24	25	25	25	26	26	26
C.College/Univ	1	1	2	2	3	4	5	6	7	7	8	9	9	10	11	11	12	12	13	13	14
C.Food Svc	1	3	4	5	6	8	9	11	12	13	15	16	17	19	20	21	22	24	25	26	28
C.Hospital	1	1	2	2	3	4	5	5	6	7	7	8	9	9	10	10	11	11	12	12	13
C.Logistic/WHouse	0	1	1	2	3	3	4	5	6	6	7	7	8	8	8	9	9	9	9	9	9
C.Long Term Care	0	1	2	2	3	4	4	5	6	7	7	8	9	9	10	10	11	11	12	12	13
C.Office	2	5	7	10	13	16	20	23	25	28	30	32	34	35	36	37	38	38	39	39	39
C.Other Commercial	1	3	4	6	8	10	12	14	16	18	19	21	22	23	24	25	25	25	26	26	26
C.Retail.Food	2	3	5	6	7	9	10	12	13	14	15	17	18	19	20	21	21	22	23	24	25
C.Retail.Non Food	3	5	8	11	15	18	22	25	28	31	33	35	36	38	39	39	40	40	41	41	41
C.Schools	0	1	1	1	2	2	3	3	4	4	5	5	5	6	6	6	6	6	6	6	6
C.Streetlights/Signals	0	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3
I.Agriculture	1	1	2	3	3	4	5	6	7	8	8	9	10	11	11	12	13	13	14	14	15
I.Food & Bev	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	3
I.Cannabis	1	6	8	8	8	8	8	8	9	9	9	9	9	9	9	9	9	10	10	10	10
I.Mfg	1	1	2	3	4	5	6	7	8	9	11	12	13	14	15	15	16	17	18	18	19
I.Other Industrial	1	2	7	8	9	11	13	14	16	18	19	21	22	24	25	26	27	29	30	31	32
I.Kraft Pulp/Paper	3	7	10	14	18	23	27	31	36	40	44	48	52	56	59	62	65	67	69	71	73
I.Wood Products	2	4	5	7	8	9	10	11	12	14	15	16	17	18	19	19	20	21	21	22	22
R.Apt <= 4 Storeys	3	5	7	9	10	12	13	14	15	16	17	17	18	18	19	19	19	19	20	20	20
R.Apt > 4 Storeys	0	0	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2
R.Other Residential	1	1	2	2	2	3	3	3	4	4	4	5	5	5	5	6	6	6	6	7	7
R.Fam Attached	2	3	4	5	6	6	7	8	9	10	11	12	13	13	14	15	16	17	17	18	19
R.Fam Detached	11	18	26	32	37	43	48	53	59	64	70	76	81	86	91	96	101	106	110	114	118

Table 38. Cumulative Energy Savings Potential by End Use (GWh/year)

End Use	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Appliances	1	1	2	3	3	4	4	4	5	5	5	6	6	6	7	7	7	7	7	8	8
Compressed Air	1	2	3	4	4	5	5	6	7	7	8	9	9	10	11	11	12	13	13	14	14
Cooking	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1
Electronics	4	7	9	12	14	16	18	20	21	23	24	26	27	28	29	30	31	32	33	34	35
Fans/Blowers	1	4	6	7	9	11	12	14	16	17	19	21	22	23	25	26	27	28	28	29	30
Hot Water	1	2	3	4	5	5	6	7	8	9	10	11	12	13	14	14	15	16	17	18	19
HVAC Fans/Pumps	2	4	7	10	13	16	20	23	26	29	32	34	37	38	40	41	41	42	43	43	43
Industrial Process	1	2	3	5	6	7	8	9	11	12	13	14	15	16	17	18	18	19	20	20	20
Lighting	15	28	42	52	63	74	84	95	105	114	122	129	135	140	144	147	150	153	155	158	160
Mat Transport	0	1	1	1	1	2	2	2	2	3	3	3	3	3	4	4	4	4	4	5	5
Office Equip	0	1	1	2	2	2	3	3	4	4	4	4	4	5	5	5	5	5	5	5	5
Other	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2
Product Drying	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumps	2	5	8	10	13	16	20	23	26	29	32	36	39	41	44	47	49	51	53	54	56
Refrigeration	1	3	4	5	5	6	6	6	7	7	8	8	8	9	9	9	9	10	10	10	10
Space Cooling	1	1	1	2	2	2	2	2	3	3	3	3	3	3	3	3	3	3	3	4	4
Space Heating	1	3	5	6	8	10	12	14	16	19	21	24	27	30	32	35	38	41	44	47	50
Whole Facility	7	14	20	26	33	41	49	55	61	68	74	81	86	91	96	101	106	110	114	118	122

Table 39. Top 30 Measures for Cumulative Energy Savings Potential in 2030 (GWh/year)

Measure	Market Potential
Com | LED	39
Res | LED	25
Ind | Pump Equipment Upgrade	25
Com | Building Automation Controls	19
Ind | Improved Fan Systems	17
Res | Energy Star Television	15
Ind | Efficient Lighting High Bay	14
Com | VSD on Pumps	14
Com | NC measure 30 %>code	13
Ind | Process Control	13
Com | Interior LED High Bay	12
Com | HVAC Control Upgrades	11
Com | NC measure 45 %>code	9
Com | Photocell	9
Res | Home Energy Reports	8
Ind | Pump Off Controllers	7
Res | Smart Thermostats	7
Com | VSD on Fans	7
Com | Interior Lighting Controls	6
Com | NC Step Code 2	5
Ind | Efficient Air Compressor	5
Ind | Cannabis LED	5
Com | Comprehensive Retrocommissioning	5
Res | Adv Power Strips	4
Res | Energy Star Desktop PC	4
Res | Clothes Dryer	4
Ind | Lighting Controls	4
Res | Air Source Heat Pumps	3
Ind | Energy Management	3
Res | NC Apt Step Code 2	3

Table 40. Top 30 Measures for Cumulative Winter Demand Savings in 2030 (MW)

Measure	Market Potential
Res | LED	5.7
Com | LED	5.3
Com | Building Automation Controls	2.6
Res | Energy Star Television	2.4
Com | VSD on Pumps	2.1
Ind | Pump Equipment Upgrade	2.1
Res | Smart Thermostats	1.7
Com | NC measure 30 %>code	1.7
Com | Interior LED High Bay	1.7
Ind | Efficient Lighting High Bay	1.6
Com | HVAC Control Upgrades	1.6
Ind | Improved Fan Systems	1.5
Res | Home Energy Reports	1.5
Com | NC measure 45 %>code	1.3
Ind | Process Control	1.2
Com | Photocell	1.2
Com | VSD on Fans	1.0
Com | Interior Lighting Controls	0.8
Res | Air Source Heat Pumps	0.8
Com | NC Step Code 2	0.7
Res | Adv Power Strips	0.7
Res | Clothes Dryer	0.7
Res | Ceiling Insulation	0.7
Res | Energy Star Desktop PC	0.7
Com | Comprehensive Retrocommissioning	0.6
Ind | Pump Off Controllers	0.6
Ind | Cannabis LED	0.6
Res | NC Apt Step Code 2	0.6
Res | New Home Step Code 4	0.6
Res | Energy Star Windows	0.5

Table 41. Top 30 Measures for Cumulative Summer Demand Savings in 2030 (MW)

Measure	Market Potential
Com | LED	5.0
Res | Energy Star Television	3.4
Res | LED	3.1
Com | Building Automation Controls	2.6
Ind | Pump Equipment Upgrade	2.6
Com | VSD on Pumps	2.1
Com | NC measure 30 %>code	2.0
Ind | Improved Fan Systems	1.9
Com | HVAC Control Upgrades	1.7
Com | Interior LED High Bay	1.6
Ind | Efficient Lighting High Bay	1.5
Com | NC measure 45 %>code	1.3
Res | Home Energy Reports	1.3
Ind | Process Control	1.3
Com | Photocell	1.1
Com | VSD on Fans	1.1
Res | Adv Power Strips	1.0
Res | Energy Star Desktop PC	1.0
Res | Clothes Dryer	0.9
Com | Interior Lighting Controls	0.8
Com | NC Step Code 2	0.8
Ind | Pump Off Controllers	0.7
Com | Comprehensive Retrocommissioning	0.7
Ind | Efficient Air Compressor	0.6
Res | NC Apt Step Code 2	0.5
Ind | Cannabis HVAC	0.5
Res | New Home Step Code 4	0.5
Ind | Cannabis LED	0.4
Com | CAC Tune-up	0.4
Ind | Lighting Controls	0.4

Table 42. Total Cumulative Energy Savings Potential After Natural Change (GWh/year)

Year	Before Natural Change	After Natural Change
2020	38	38
2021	78	76
2022	116	113
2023	148	143
2024	181	173
2025	217	206
2026	252	238
2027	286	268
2028	319	297
2029	351	325
2030	381	352
2031	409	377
2032	435	399
2033	459	419
2034	480	438
2035	501	455
2036	520	471
2037	537	485
2038	553	498
2039	568	511
2040	583	522

5 Appendix B – Attachments

Lumidyne delivered to FortisBC the following attachments:

Appendix B1

- See “Appendix_B1_2021-07-08.xlsx” with measure-level results.

Appendix B2

- See “Appendix_B2_2021-07-08.xlsx” with measure characterization data.

Appendix B3

- See “Appendix_B3_2021-07-08.xlsx” with key assumptions about building stocks, end use intensities, avoided costs, discount rates, retail rates, etc.