Clean Power 2040
Powering the future

BC Hydro
Power smart

BC Hydro and Power Authority

2021 Integrated Resource Plan

2023 UPDATE

Table of contents

1

Executive summary

An integrated resource plan is a guidebook for what, when, and how to meet customers' evolving electricity needs. This 2021 Integrated Resource Plan (2021 IRP) looks at a 20-year time frame and will guide decisions on our integrated system to meet the future electricity needs of our customers.[1]

The 2021 IRP aligns with government policy objectives, such as greenhouse gas reduction targets and preference for demand-side measures (DSM) over new facilities and meets the requirements of the *Utilities Commission Act* and the British Columbia Utilities Commission (BCUC). Its development was also informed by our commitment to reconciliation with Indigenous communities. A broad consultation process occurred throughout the development of the 2021 IRP and final feedback showed overall positive or neutral alignment of the 2021 IRP elements to participants' values and interests.

Our planning objectives for the 2021 IRP are informed by the above policies, commitments and consultation feedback, and they are: keeping costs down for customers, reducing greenhouse gas (GHG) emissions through clean electricity, limiting land and water impacts, and supporting the growth of B.C.'s economy.

The 2021 IRP compares our existing and committed resources against our forecast of future customer needs and shows that we will have surplus electricity for some time. Before demand-side measures, new energy needs are not expected to occur until fiscal 2029, while capacity needs are not expected to occur until fiscal 2032. However, growing demand for electricity on the province's South Coast means we expect to need additional regional capacity resources in fiscal 2027.

Three defining features of this 2021 IRP are that it:

- Relies more on customer-based solutions through demand-side measures, including new voluntary rate structures, to encourage customers to use less electricity and use it more efficiently, and less on adding new physical assets with their land and water impacts, and financial commitment;
- Is flexible, preparing BC Hydro for a possible future of higher electricity demand due to electrification, and a possible future with lower demand resulting from economic downturns, making it a resilient plan; and
- Supports BC Hydro's mandate to incorporate the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) and the Truth and Reconciliation Calls to Action into our business. Early engagement is an important part of advancing reconciliation and the 2021 IRP is the earliest BC Hydro can engage with Indigenous Nations on meeting our customers' future electricity needs.

The 2021 IRP consists of a Base Resource Plan and several Contingency Resource Plans. BC Hydro is taking steps to implement the Base Resource Plan and to ensure that we are able to implement elements of the Contingency Resource Plans on a timely basis. We call these steps our Near-term Actions. The first one is to submit our planned demand-side measures expenditures for fiscal years 2023–2025 to the BCUC for review and approval. Another Near-term Action is to apply to the BCUC for approval of voluntary time-of-use rates for residential customers. Another is to study, consult on and pilot utility-scale battery resources.

In developing the Base Resource Plan, we considered resource options, including demand side-measures, rates, acquiring power via renewing electricity purchase agreements (EPA), upgrading our facilities, and new clean or renewable sources.

1 This term and several terms and acronyms are defined in the 2021 IRP glossary, which can be found in Attachment 2.

The legal framework for the 2021 IRP indicates a clear policy preference for the priority use of demand-side measures, and much of what we heard from Indigenous communities, public, customers, and stakeholders during consultation was consistent with this preference. So, our first step was to decide the levels of demand-side measures which we ought to pursue. They make up the first part of our Base Resource Plan, as follows:

- Continue with a base level of energy efficiency programs and plan to ramp up to higher levels in future years to achieve 1700 gigawatt hours per year (GWh/year) of energy savings and 280 megawatts (MW) of capacity savings at the system level by fiscal 2030;
- Pursue voluntary time-varying rates supported by demand response programs to achieve approximately 220 MW of capacity savings at the system level by fiscal 2030, and advance the Industrial Load Curtailment Program to achieve approximately 100 MW of incremental capacity savings at the system level by no later than fiscal 2030; and
- Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers. These would support a voluntary residential time-of-use rate to shift home charging by 50 per cent of residential electric vehicle drivers to off-peak demand periods to achieve 100 MW of capacity savings at the system level by fiscal 2030.

After these demand-side measures, new energy needs are not expected to occur until fiscal 2030, while capacity needs are not expected to occur until fiscal 2037. Meanwhile, additional regional capacity resources to serve the South Coast are not required until fiscal 2032.

After demand-side measures, our Base Resource Plan also includes the following elements:

- Offer a market-price-based renewal option to existing clean or renewable independent power producers with electricity purchase agreements expiring within five years. There are 19 existing clean or renewable projects that produce a total of roughly 900 Gigawatt hours (GWh), with electricity purchase agreements set to expire before April 1, 2026;
- Advance the first sequential step of upgrades to existing transmission infrastructure into the South Coast region to achieve 750 MW of capacity for the South Coast region by fiscal 2033; prepare to initiate a second step of upgrades of existing equipment to achieve an additional 550 MW of capacity for the South Coast region by fiscal 2040;
- Beyond the elements identified above and after demand-side measures, plan to acquire new energy resources starting with 810 GWh in fiscal 2031, then shifting to primarily capacity resources starting with 160 MW in fiscal 2038. We'll select these future resources from amongst:
  - Expiring electricity purchase agreements with independent power producers;
  - New clean or renewable energy resources; and
  - Upgrades to BC Hydro facilities.
- Undertake a structured decision making approach to evaluate small BC Hydro plants that are requiring end of life investment decisions on a facility-by-facility basis to determine whether to decommission or refurbish these facilities.

Finally, Contingency Resource Plans were developed for scenarios where our customers' electricity needs are significantly higher or lower than our reference case and/or our Near-term Actions do not deliver as expected.

The scenarios included in the 2021 IRP are:

- Electricity demand stagnates;
- Electrification accelerates more quickly;
- Electrification accelerates and demand-side measures don't perform as expected; and
- North Coast (NC) electrification.

BC Hydro is taking steps now to ensure that we can implement the Contingency Resource Plans on a timely basis if the need arises. We will monitor the evolving policy environment and trends in our customers' electricity needs and be ready to adapt to these changes.

Many of the Near-term Actions will require further consultation and separate approvals from the BCUC, and the 2021 IRP will inform the consultation and the BCUC's consideration of those applications.

1.1 2023 UPDATE

Since the 2021 IRP was filed in December 2021, there have been indications of increased load as well as decreased supply, resulting in an earlier need for future resources. The net impact totals approximately 4,000 GWh in fiscal 2030 under the April 2023 Reference Energy Load Forecast and 2021 IRP Base Resource Plan. This shift means that the current 2021 IRP Near-term Actions are insufficient to meet the future needs of our customers. Accelerated, extended and new Near-term Actions are required. As a result, BC Hydro is updating the 2021 IRP by:

- Accelerating or extending the timing of several of the existing Near-term Actions, including actions on energy efficiency, demand response, industrial load curtailment, electricity purchase agreement renewals, and utility-scale batteries.
- Adding a new Near-term Action to acquire approximately 3,000 GWh of new clean or renewable energy from greenfield facilities in the province able to achieve commercial operation as early as fiscal 2029 and approximately 700 GWh of new clean or renewable energy from existing facilities prior to fiscal 2029.

These actions will position BC Hydro to meet the potential electrification load associated with the Government of B.C.'s greenhouse gas emission reduction targets, as represented in the Accelerated electrification scenario.

The Updated 2021 IRP focuses on being ready for the potential pace of change, emphasizing ranges rather than static targets for various plan elements to increase flexibility to respond to changing circumstances.

To support this approach, BC Hydro is proposing a new "living" long-term resource plan cycle, with regular long-term resource plan filings that are better able to match the potential pace of change in this time of energy transition, starting with a 2025 Long-Term Resource Plan (2025 LTRP) to be filed approximately 18 months after the Commission's decision on the Updated 2021 IRP.

2

Introduction

2.1 About BC Hydro

BC Hydro is one of the largest electric utilities in Canada and is publicly owned by the people of British Columbia (B.C.). We generate and provide electricity to 95 per cent of B.C.'s population and serve over four million people. The electricity we generate and deliver to customers throughout the province powers our economy and quality of life.

BC Hydro's integrated system is backed by 30 hydroelectric plants, a thermal generating station, and approximately 80,000 kilometres of transmission and distribution lines. As of October 2021, we also have 123 electricity purchase agreements with independent power producer facilities in our integrated system, with fuel sources for electricity generation such as hydro, wind, solar, natural gas and biomass. In aggregate, our system electricity generation is 98 per cent clean or renewable.

As a Crown corporation, BC Hydro reports to the Provincial Government through the Minister of Energy, Mines and Low Carbon Innovation. BC Hydro is also a public utility regulated by the BCUC under the *Utilities Commission Act*.

2.2 What is the 2021 Integrated Resource Plan?

An integrated resource plan is a guidebook for what, when, and how to meet customers' evolving electricity needs.

This 2021 Integrated Resource Plan looks at a 20-year time frame and will guide decisions on meeting future customer needs for electricity until our next integrated resource plan. The 2021 IRP is aligned with government policy objectives, such as provincial greenhouse gas emission reduction targets and the requirements of the *Utilities Commission Act* and the BCUC.

The 2021 IRP consists of three main components:

- A Base Resource Plan, which is our strategy to meet the future needs of our customers if future needs reflect our Reference Load Forecast;
- Several Contingency Resource Plans, which are the strategies we will pursue if the future needs are higher or lower than those reflected under the Base Resource Plan; and
- Several Near-term Actions, which are the specific steps we will take to implement elements of the Base Resource Plan and prepare for the Contingency Resource Plans before our next integrated resource plan is filed. Many of the Near-term Actions in the 2021 IRP will require separate approvals from the BCUC to be implemented. The 2021 IRP will inform the BCUC's consideration of those applications.

The Near-term Actions for the Contingency Resource Plans are designed to prepare BC Hydro to implement elements of the Contingency Resource Plans if new information indicates the need to do so. This approach allows planned resources to be advanced incrementally as future customer needs become more certain.

The 2021 IRP, therefore, prepares BC Hydro to meet future customer needs under a range of scenarios, including an Accelerated electrification scenario where BC Hydro's Electrification Plan (Electrification Plan) targets are fully realized; B.C.'s greenhouse gas emission reduction targets are met; and, there are no offsetting reductions in load relative to what's included in the Reference Load Forecast. Our Electrification Plan was filed with the BCUC in August 2021 as part of our Fiscal 2023 to Fiscal 2025 Revenue Requirements Application. It includes our efforts supporting electrification and greenhouse gas emission reductions through low carbon electrification programs, electric vehicle charging infrastructure, support for customer connections, and expansions of the transmission system.

2.3 Our planning objectives in developing the 2021 IRP

BC Hydro's planning objectives were the subject of consultation in late 2020 and into 2021. Through this consultation, BC Hydro set its planning objectives for the 2021 IRP as keeping costs down for customers, reducing greenhouse gas emissions through clean electricity, limiting land and water impacts, and supporting the growth of B.C.'s economy.

As a Crown utility, BC Hydro has an important role in advancing reconciliation with Indigenous peoples. An initial objective was considered early in developing the Draft IRP: supporting reconciliation with Indigenous peoples. Although supporting reconciliation had strong support, input from Indigenous participants viewed it as being inappropriately expressed as an objective which could be traded off against other objectives when comparing alternatives. We heard that all the other planning objectives have Indigenous interests that cannot be easily separated from supporting reconciliation. Based on this perspective, BC Hydro considered Indigenous interests as part of each planning objective.

2.4 Our next integrated resource plan

The 2021 IRP has a 20-year planning horizon; however, that does not mean we will not prepare another IRP for 20 years. We will have a number of integrated resource plans over that period. The planning context will continue to evolve and forecasts will need to be updated. The Contingency Resource Plans included in the 2021 IRP address some related uncertainties, but they cannot address all of them.

We expect to complete integrated resource plans every five years, or sooner if load or supply updates show that the Near-term Actions in our 2021 IRP are not sufficient to meet future needs.

2.5 2023 UPDATE

BC Hydro is proposing a new "living" long-term resource plan cycle, with regular long-term resource plan filings that are better able to match the potential pace of change in this time of energy transition.

BC Hydro proposes to complete and file the first update within this "living" long-term resource planning cycle approximately 18 months from the Commission's decision on the Updated 2021 IRP. This first update will be the 2025 LTRP.

To accommodate this faster paced approach to long-term resource planning and regulatory oversight, BC Hydro intends to make targeted, rather than comprehensive, updates to the load forecast, existing, committed and planned resources forecasts, resource options database and other resource planning inputs, where appropriate, so that time and resources can be focused on the areas that current circumstances indicate require the most attention.

For the 2025 LTRP, BC Hydro suggests that, in addition to areas the Commission may decide to highlight in its Decision on the Updated 2021 IRP, important areas of focus would be:

- Targeted updates to the Load Resource Balances and certain portfolio analysis to reflect updated resource planning inputs.
- A review of resource adequacy standards.
- Targeted updates for future capacity resource options with long lead times including a second transmission line to the North Coast, the Vancouver Island Transmission Reinforcement Project No. 2, and Revelstoke Unit 6.
- Targeted updates for future energy resource options where BC Hydro will not receive updated cost and lead time information through the planned acquisition process for new clean energy set out in this Updated 2021 IRP (e.g., obtaining better information on the potential, cost and customer interest related to customer solar/ solar and battery resource options through the initiation of program offers).

BC Hydro will carry out consultation and planning work on certain capacity and energy resource options to inform the consideration of these options in the 2025 LTRP. BC Hydro is not seeking acceptance of these activities as part of the Updated 2021 IRP. Rather, BC Hydro will seek any required regulatory approvals, as appropriate, as these activities are advanced.

3

Where does BC Hydro find itself today?

3.1 Introduction

Reconciliation with Indigenous peoples, climate action, evolving customer needs and electricity consumption, and technological advancements are changing how electrical utilities do business. BC Hydro's 2021 IRP has been developed within this broader evolving planning context.

3.2 The importance of reconciliation with Indigenous Peoples

Canada's Truth and Reconciliation Commission has described the United Nations Declaration on the Rights of Indigenous Peoples as a framework for reconciliation for all sectors of Canadian society. The Truth and Reconciliation Commission has defined reconciliation as, "establishing and maintaining mutually respectful relationships between Indigenous and non-Indigenous peoples." As a Crown utility, we have an important role to play in supporting the broader societal effort of reconciliation. We recognize that maintaining and developing the system has impacts on the lives and interests of Indigenous Nations. We also recognize that relationships with Indigenous Nations are critical to operating and growing our system of clean electricity.

BC Hydro's Statement of Indigenous Principles forms part of our Code of Conduct and guides our approach to the ongoing work of reconciliation, and the implementation of United Nations Declaration on the Rights of Indigenous Peoples and the Truth and Reconciliation Commission Calls to Action. The Statement of Indigenous Principles includes a commitment that: We will inform First Nations communities, to the best of our ability, of our multi-year planning, identifying potential projects and works as early as possible for discussion. Early engagement is an important element of advancing reconciliation and the 2021 IRP is the earliest BC Hydro can engage with Indigenous Nations on meeting our customers' future electricity needs.

In addition, incorporating the United Nations Declaration on the Rights of Indigenous Peoples and the Truth and Reconciliation Commission Calls to Action into our business is much broader than the 2021 IRP. BC Hydro is working with Indigenous Nations to find meaningful paths to reconciliation through many areas of our business. Building relationships with Indigenous Nations, particularly those most impacted by our presence in their territory, will continue to be a focus for BC Hydro and will inform how we incorporate the declaration into our business.

3.3 We have an energy and capacity surplus

BC Hydro is well positioned to serve our customers' province-wide electricity needs for most of the next decade with additional demand-side measures, before adding any new clean or renewable energy resources. Our integrated system is currently in surplus. This is illustrated in Chapter 4, entitled "Load Resource Balances before Planned Resources."

This means we're ready to support growth in B.C.'s population and economy while playing our part in achieving the Provincial Government's greenhouse gas reduction targets. It also means we're prepared to deal with uncertainties such as the speed of our recovery from the COVID-19 pandemic or the incremental opportunities from electrification. Chapters 7 and 8, entitled "The Base Resource Plan – our strategy to meet the future electricity needs of our customers" and "The Contingency Resource Plans: preparing for change" respectively, detail our plans to move forward with certain "Near-term Actions" that prepare us for a range of potential future needs.

3.4 Our climate is changing

There is an important conversation happening around the globe about how we use energy, and the impact our choices have on climate change. And in B.C., we have an opportunity to switch from fossil fuels to clean electricity. B.C. is already western North America's leader in clean electricity generation.

BC Hydro's Electrification Plan aims to increase awareness of existing programs and further address barriers to electrification with new programs. It offers customers the support, tools and incentives to choose clean electricity over fossil fuels that are currently being used to power homes, businesses, industries and vehicles across the province. The Electrification Plan is expected to result in additional electric load and associated greenhouse gas emission reductions relative to BC Hydro's December 2020 Load Forecast, which is further discussed in section 4.2. The magnitude and timing of additional load and greenhouse gas emission reduction achieved through electrification will depend on the collective efforts of BC Hydro, our customers, and government initiatives. For example, as government funded initiatives and regulations change, BC Hydro's Electrification Plan may also be adjusted.

At this time, potential growth in electricity demand arising as a result of greenhouse gas reduction targets and Electrification Plan actions are included in our high electricity demand scenarios which inform the Contingency Resource Plans in the 2021 IRP.

With the 2021 IRP's Base Resource Plan, our power system will be ready to meet the future needs of customers across a range of scenarios. The 2021 IRP's Near-term Actions will allow BC Hydro to be ready and flexible, incrementally advancing planned resources as changing load and supply when there is a need to do so. We monitor our operating environment and update our supply and demand forecasts to reflect strategic changes in our operating environment and, if circumstances dictate, we can implement steps from the 2021 IRP's Contingency Resource Plans to address these changes continue meeting our customers' needs.

BC Hydro also plays an ongoing role in monitoring and considering the impacts of climate change on our ability to supply electricity and to remain reliable and resilient as our economy grows. Section 4.5 describes how the 2021 IRP has considered climate impacts on changes to future electricity demand and the generation capability of our system.

3.5 We're part of an evolving, regional energy landscape

B.C.'s electricity grid is connected to a much larger grid covering B.C., Alberta, portions of 14 western U.S. states and a small part of Mexico. Wholesale electricity trade is important both to B.C. and its neighbours for reliability and for lowering the costs to provide service.The 2021 IRP contains a wholesale electricity price forecast, including high and low bands, used in the valuation of aspects of the 2021 IRP, such as surplus electricity.

Capacity is produced by firm, dependable sources of power that can be relied upon whenever needed. Resources that provide dependable capacity at peak times and have flexibility associated with storage are key to integrating intermittent renewables, such as wind and solar. Hydroelectricity with storage, such as BC Hydro's system is a clean way of providing this dependable capacity and flexibility. Hydroelectric storage also enables water to be stored during periods of high supply / low demand and to be used for generation in times of low supply / high demand.

New technology is also introducing opportunities to develop flexibility and control for both electricity demand and supply. For example, the cost of small-scale battery storage technology has decreased in recent years. While still relatively early in their technology lifecycle, utility-scale batteries can provide short-term storage and shift output from renewables (such as solar power) into periods with more demand. While this technology remains relatively expensive and has limited storage duration today, costs are expected to decline, and its capabilities are expected to increase.

Another emerging trend is demand response technology — the ability to manage demand such as electric vehicle charging or home appliances (e.g., water heaters) by shifting electricity demand out of peak times and into periods when supply is more available.

Chapter 5 summarizes BC Hydro's Resource Options Database which discusses many of these technologies.

3.6 Our customers' demand for electricity is changing

Customer demand for electricity is also changing. Electrification activities are causing electricity growth, such as being seen in the transportation sector. With the passing of the *Zero-Emission Vehicle Act*, by 2040 every new light-duty vehicle sold in B.C. will be a zero-emission vehicle. B.C. currently leads North America in the sale of electric vehicles (EVs), with electric vehicles representing 10 per cent of all new cars sold in the province in 2020. TransLink and BC Transit are both moving to replace their diesel buses with battery electric versions.

However, in some resource-based industries, economic factors are combining to cause decreases in demand for electricity. New demand presents an opportunity for us to mitigate the risk of declines in demand, as declines in demand can result in the need for our existing system costs to be recovered from the remaining customers, which has rate impacts.

3.7 Our customers' expectations are changing

Customer expectations from energy providers are broadening beyond reliable service to include technology and data on energy use.

Demand-side measures (rates, measures, actions, or programs undertaken to conserve energy or promote energy efficiency) can reduce the amount of energy demand or shift the use of energy to periods of lower demand. Demand-side measures that reduce peak load can help defer the need for new capacity investments. Optional rates can provide customers with more choices, and programs can provide customers with new ways to manage their energy use and take advantage of those choices.

Affordability for all customers is a key priority for BC Hydro. BC Hydro can support affordability by advancing cost-effective demand-side measures to help meet our future electricity needs and to help customers save money on their bills.

Customers are also increasingly concerned about how their energy choices impact the environment and sustainability. By using clean or renewable electricity instead of higher emitting fuels to power their homes, vehicles, and businesses, customers can help to reduce greenhouse gas emissions and contribute to meeting climate goals.

We cover how we gathered and considered customer values and interests in Chapter 6, where we outline the process used to build the 2021 IRP.

3.8 2023 UPDATE

BC Hydro's 2021 IRP is being advanced at a time of energy transition and global economic uncertainty. This is reflected in developments that have occurred at the global, national, provincial and local levels. For example:

- At a global level, current trends include high inflation, increasing interest rates, concerns about an economic recession, supply chain disruptions and the implementation of policies in response to climate change;
- At a national level, there have been important climate funding and policy developments such as the recent federal budget, which provides support and incentives for the clean energy sector and to decarbonize and expand Canada's electricity infrastructure. The adoption of the United Nations Declaration on the Rights of Indigenous Peoples by the Government of Canada and the Government of B.C. as well as the Truth and Reconciliation Commission's Call to Action No. 92 to adopt the United Nations Declaration on the Rights of Indigenous Peoples as a framework for reconciliation has resulted in efforts to advance reconciliation with First Nations, including with regard to resource development;
- At a provincial level, there have been steps towards advancing greenhouse gas emission reduction policies, such as the recent announcement regarding the new clean energy action framework. BC Hydro's recent expression of interest process on the North Coast also demonstrated a high amount of interest from industrial customers in the North Coast region wanting to use clean electricity to power their operations instead of fossil fuels. In addition, market conditions and limited fibre availability in B.C.'s forestry industry have led to temporary and indefinite production curtailments by some of BC Hydro's large industrial customers as well as a decrease in expected electricity generation from biomass facilities; and
- At a local level, municipalities continue to enact new and revised bylaws to encourage energy efficiency and the reduction of greenhouse gas emissions in buildings. For example, the City of Victoria will require all new construction to be zero carbon by 2025.

4

Load Resource Balances before Planned Resources

4.1 Introduction

A Load Resource Balance is a comparison of the load and the resources over a 20-year planning horizon. When only existing and committed resources (i.e., resources that are already in place or are actively being implemented) are included, the Load Resource Balance shows the timing and volume of additional resources required to meet customers' demand. We call this the Load Resource Balance before planned resources.[1] It forms the basis for the 2021 IRP development.

Load Resource Balances are developed for both energy and capacity. An energy Load Resource Balance addresses the electrical energy needs for each year of our planning horizon (expressed as gigawatt-hours per year, GWh/year). A capacity Load Resource Balance addresses the peak electricity use at any point in time in the planning horizon (expressed as megawatts, MW).

4.2 Load forecast

A key input into Load Resource Balances is the load forecast. For the 2021 IRP, we use the reference case of the 20-year load forecast finalized in December 2020 (December 2020 Load Forecast).[2] The reference energy and peak forecasts have been adjusted for rate impacts but do not include demand-side measure savings. This will be referred to in the 2021 IRP as the Reference Load Forecast. The Reference Load Forecast is derived from deterministic forecasting models for the residential, commercial and portions of the light industrial forecasts. It also uses customer-based forecasts with probability weightings for the large industrial and portions of the light industrial sector forecasts.[3]

The Reference Load Forecast, which is used in developing the Base Resource Plan, projects moderate growth averaging about 1.4 per cent per year over the planning horizon (again, before accounting for demand-side measures). Growth is primarily due to electric vehicle and oil & gas sector load growth (including liquefied natural gas), but it is partially offset by declines in the forestry sub-sector.

Load forecasts are sensitive to many input variables, each of which has varying degrees of uncertainty. Uncertainties influence the risk that future demand will be lower or higher than forecast. They can exist at the customer-specific level up through to sector-wide or economy-wide levels. Alongside the Reference Load Forecast, other load scenarios were developed to explore the future customer needs associated with different future outcomes. Our Contingency Resource Plans are based on these scenarios.

4.3 Existing and committed resources

Another key input into the Load Resource Balances are resources already in place. These include existing and committed resources on both the supply-side and the demand-side. Existing resources are resources that are currently operating and are expected to continue to operate into, if not to the end of, the planning horizon. Committed resources are those resources that have received necessary internal authorizations to proceed to implementation as well as any required regulatory approvals and are expected to begin operating during the planning horizon. Existing and committed resources include BC Hydro generation resources and bulk transmission resources, electricity purchase agreements until the date of their expiry, and forecasted savings associated with current and/or approved demand-side measures.[4,5,6] A more detailed description of existing and committed resources is provided in Attachment 1.

1 Base and Contingency Resource Plans are also load resource balances, but they show the timing and volume of the additional resources required to fill any gaps.
2 The December 2020 Load Forecast includes a suite of forecasts including reference, high, and low cases for both energy and peak, before and after various adjustments.
3 This means that the reference load forecast is not derived from probabilistic, or stochastic, models that produce a probability distribution of load outcomes.
4 The transmission capabilities of bulk transmission resources are included as a 'resource' in the Load Resource Balances at regional levels.
5 Facilities under electricity purchase agreements, and certain potential electricity purchase agreements under the Standing Offer Program, that have yet to achieve commercial operation date but are expected to within the planning horizon of the 2021 IRP, are considered committed resources.
6 Existing and committed demand-side measures include forecasted savings from current and future codes and standards, current rate structures (including net metering), and the savings from the fiscal 2021 program expenditures which was approved in the fiscal 2020 – 2021 RRA.

4.4 Planning criteria

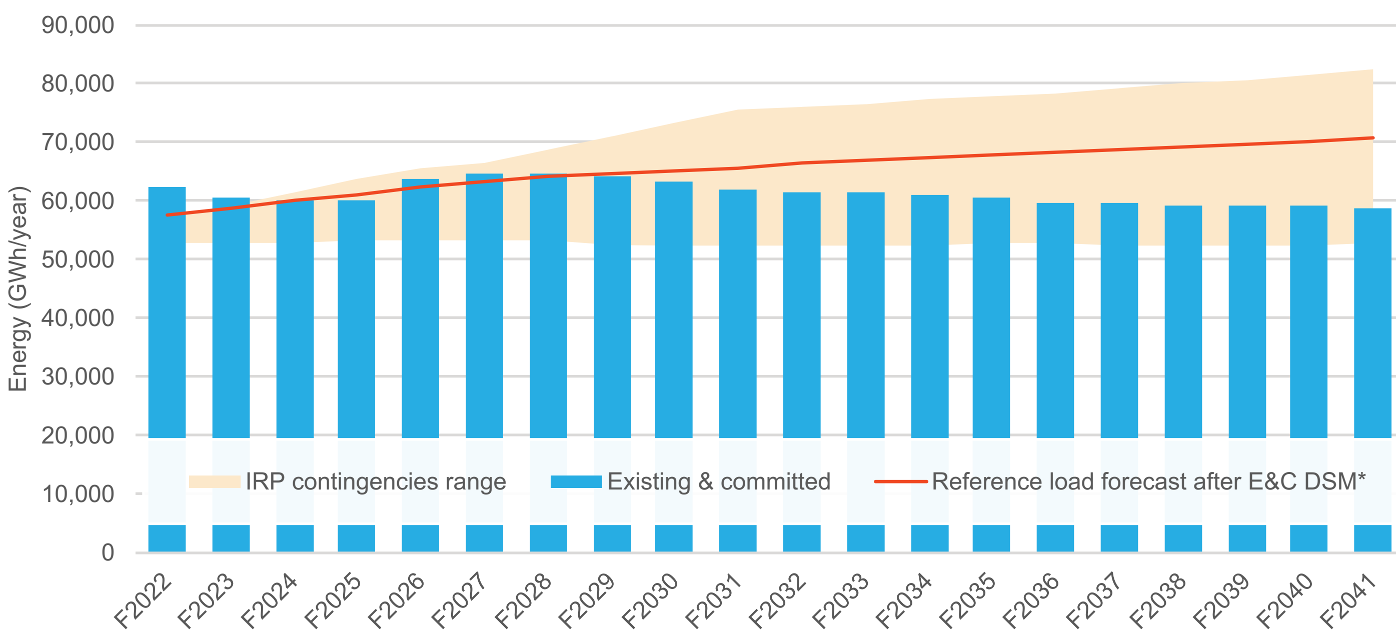
BC Hydro uses generation and transmission planning criteria in developing plans so that we have a reliable electrical system, including adequate generating capability (energy and capacity), and adequate transmission capability. They provide, in effect, the capability of the existing and committed generation and transmission resources, as well as planning guidance for the reliability contribution of future resources, used to develop the Base Resource Plan and Contingency Resource Plans. These criteria are periodically reviewed, and if necessary, updated, to reflect best electric utility practices and information about the performance of our electrical system. Our three criteria are:

- The energy planning criteria is used to determine the amount of electrical energy our generation system can be relied upon to generate for long-term planning purposes. In setting the energy planning criteria, BC Hydro must consider the variability of its primary fuel (water), the ability of its reservoir systems to store and regulate that water, and its access to other electricity sources, including external markets. Currently, BC Hydro uses a "self-sufficiency" energy planning criterion, consistent with the requirements of the *Clean Energy Act* and the *Electricity Self-Sufficiency Regulation*.
- The capacity planning criteria is used to determine, for long-term planning purposes, the amount of capacity our generation system can reliably generate to meet peak electricity demand. This is particularly important when considering resources whose output is uncertain (e.g., wind and solar) and resources that can only sustain their energy production (or savings) for short periods of time (e.g., batteries and demand response technologies). As with the energy planning criteria, BC Hydro's capacity planning criteria is consistent with the requirements of the *Clean Energy Act* and the *Electricity Self-Sufficiency Regulation*.
- BC Hydro's transmission planning criteria are a set of rules that define the transmission system capability when the system is operating normally and contingency conditions when some components of the system are malfunctioning.

4.5 How much electricity BC Hydro will require and when

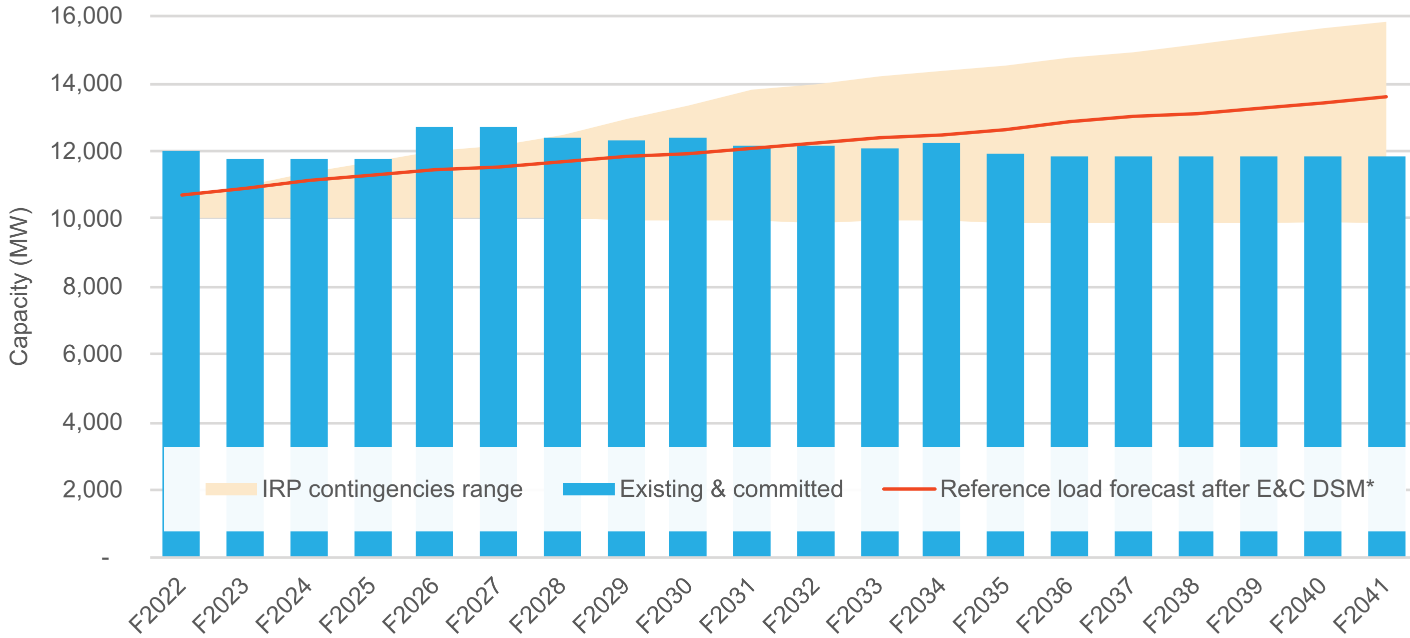
After applying the criteria laid out above to our existing and committed resources, we establish the capability of our electric system. By comparing these resources to the future electricity needs of our customers, as outlined by the Reference Load Forecast, we establish when we will need additional energy and capacity resources. The resulting Load Resource Balances before planned resources are illustrated in Figure 4-1 and 4-2.

Figure 4-1 System energy Load Resource Balance before planned resources



* E&C DSM denotes existing and committed demand-side measures

Figure 4–2 System capacity Load Resource Balance before planned resources



* E&C DSM denotes existing and committed demand-side measures

The blue bars represent the capability of our existing and committed resources according to our planning criteria. The orange line shows the Reference Load Forecast adjusted with the savings from the existing and committed demand-side measures. This is the net customer electricity demand over the next twenty years. The year that a gap begins between the orange line and the blue bar is the year we first need additional resources. The system-wide graphs show that, under the Reference Load Forecast, new energy needs occur in fiscal 2029 while capacity needs occur in fiscal 2032, in both cases before any planned resources.

In addition to the system-level Load Resource Balances, we also developed capacity Load Resource Balances for three regions — South Coast, Vancouver Island and North Coast — to address region-specific planning issues that result from large regional load growth and/or considerable disparity between regional supply and demand.[7] Whereas the system capacity Load Resource Balance shown in Figure 4-2 includes generation resources from a province-wide integrated system perspective, the regional capacity Load Resource Balances (shown in Figures 4-3, 4-4, and 4-5) consider load, generation resources and the transmission capability from a regional perspective. The latter reflects that future electricity needs could be met by both the local generation resources and transmitted from other regions of B.C.

7 South Coast encompasses the Lower Mainland and Vancouver Island regions of B.C.

Figure 4‑3 South Coast capacity Load Resource Balance before planned resources

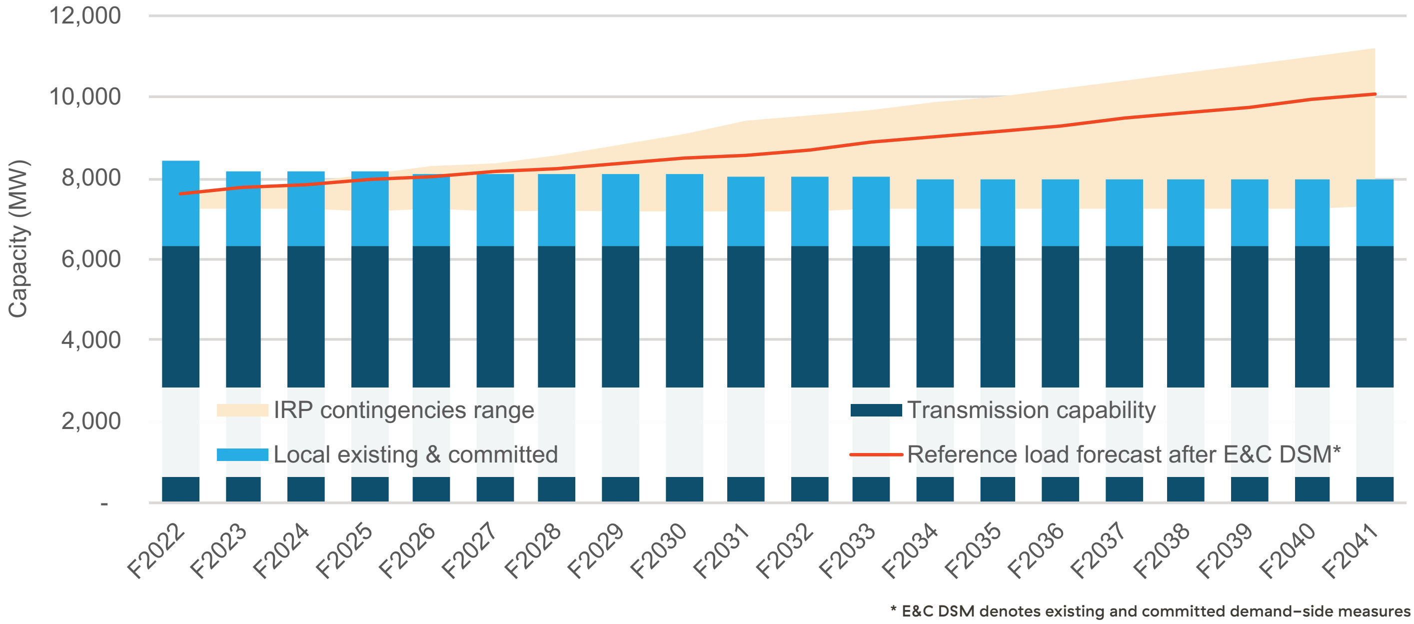


Figure 4‑4 Vancouver Island capacity Load Resource Balance before planned resources

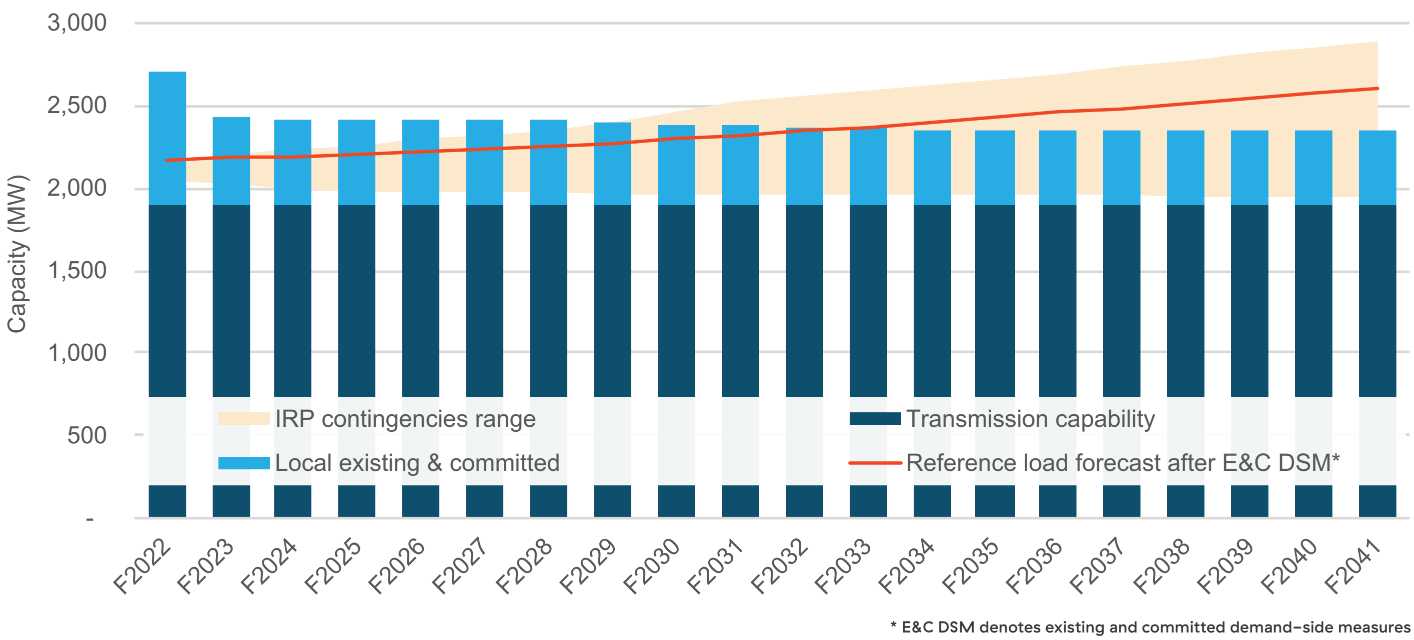
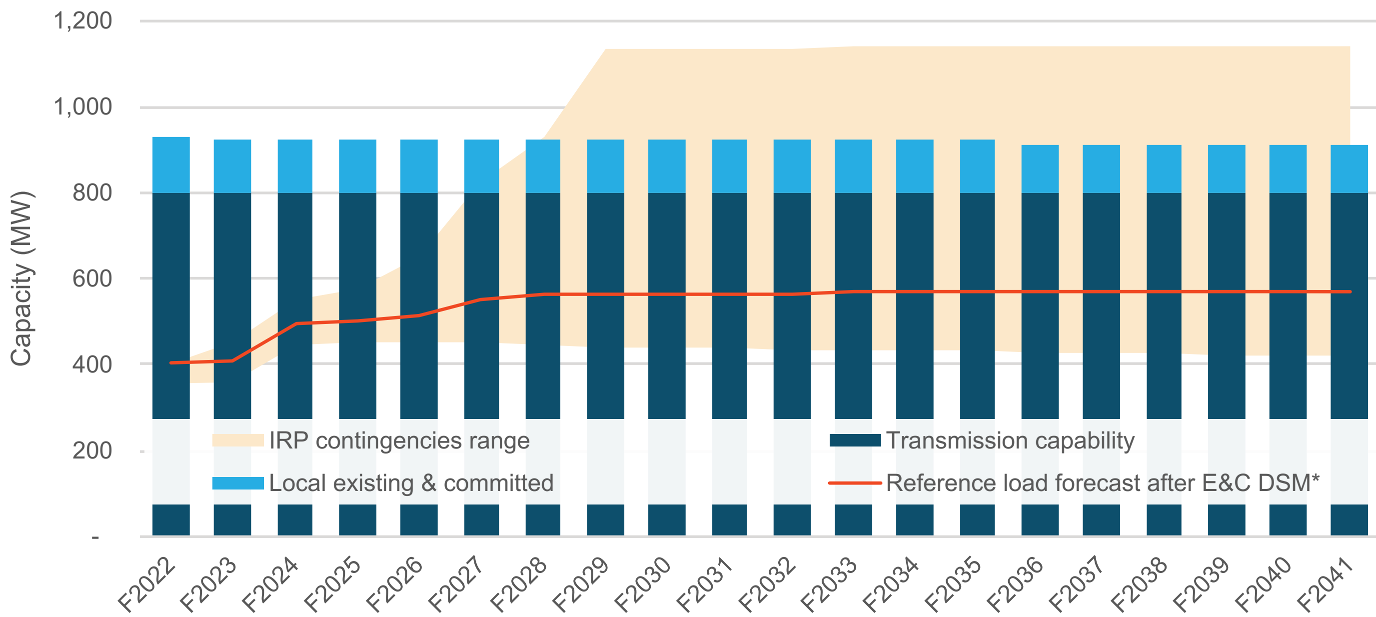


Figure 4–5 North Coast capacity Load Resource Balance before planned resources



* E&C DSM denotes existing and committed demand-side measures

The South Coast capacity Load Resource Balance before planned resources, shown in Figure 4–3, indicates that under the Reference Load Forecast, additional capacity resources are needed for the South Coast region by fiscal 2027 (before any planned resources), which is earlier than the need at the system level. The higher load growth in the South Coast region compared to the rest of the province is attributed, in part, to the adoption of electric vehicles. The Vancouver Island capacity Load Resource Balance before planned resources, shown in Figure 4–4, indicates that additional capacity resources are not required for the Vancouver Island region until fiscal 2034. Finally, the North Coast capacity Load Resource Balance before planned resources, shown in Figure 4–5, indicates that additional capacity resources are not required for the North Coast region under the Reference Load Forecast. However, the North Coast region has the potential for considerable load growth as a result of liquified natural gas and mining developments.

The 2021 IRP uncertainty band in all figures represents the unknowns surrounding the Reference Load Forecast. We plan for uncertainty by looking at situations where electricity demand could be higher or lower than our Reference Load Forecast. The 2021 IRP uncertainty band represents a range of possible electricity demand outcomes.

Relative to the Reference Load Forecast, the lower part of the 2021 IRP uncertainty band includes lower levels of electrification, no growth in residential and commercial demand, and some closures of industrial operations. The upper part of the 2021 IRP uncertainty band is represented by an Accelerated electrification scenario.[8] For the North Coast region, the upper part of the 2021 IRP uncertainty band assumes that several of the mines and liquified natural gas facilities that have been proposed in the region proceed into operation within the next decade. These scenarios are described further in Chapter 8.

In assessing the amount of electricity BC Hydro will require, we have examined how the two primary inputs to the Load Resource Balances may be impacted by climate change: (i) the system generation capability, and (ii) future electricity demand. Our studies show that, under a range of climate change scenarios drawn from the Intergovernmental Panel on Climate Change (IPCC), the system generation capability at the end of the century is within +/– five per cent of the existing system generation capability.

In terms of future electricity demand, we may see a roughly two per cent decrease in both energy and capacity demand, due to the impacts of climate change. While we have recently seen hotter summers with increased demand for electricity, we expect BC Hydro to remain a winter-peaking utility, meaning the most demand placed on our integrated system in the winter during the coldest days when space heating is required. With winters warming on average, we may see a reduction in the average amount of electricity required to serve winter demand. That said, the decrease in future electricity demand due to changes in temperature is small in comparison to other factors such as climate action policies, and hence is considered within the existing bounds of load uncertainty tested in the 2021 IRP.

8 The Accelerated electrification scenario is composed of the demand associated the BC Hydro Electrification Plan as well as an electrification scenario developed by Navius Research to meet all the provincial greenhouse gas reduction targets.

4.6 2023 UPDATE

There are indications of increased load as well as decreased supply, relative to the 2021 IRP. Specifically:

- BC Hydro has updated the four load scenarios (i.e., three system load scenarios and one regional load scenario) considered in the 2021 IRP.
  - The April 2023 Reference Energy Load Forecast is approximately 2,300 GWh higher after fiscal 2030 primarily due to higher large industrial and commercial loads.[6] The reference load forecasts represent BC Hydro's assessment of expected future electricity demand considering future load additions and subtractions that can be forecast with reasonable certainty. The April 2023 Reference Load Forecast reflects a comprehensive load forecast for the residential, commercial, and large industrial sectors with select updates to other sectors;
  - The 2023 Low load scenario is approximately 4,300 GWh higher each year on average for energy, primarily due to a new forecast start point which reflects actual load in fiscal 2022. The low load scenarios represent potential prolonged stagnation in electricity demand; and
  - The 2023 Accelerated electrification load scenario is approximately 2,000 GWh lower in fiscal 2030 primarily due to adjustments to the timing of forecast electrification in the natural gas industry, and approximately 3,400 GWh higher in fiscal 2040 primarily due to forecast load from the additional production of hydrogen through electrolysis. The accelerated electrification scenarios represent the electricity load impacts associated with one of many, potential pathways to meet the Government of B.C.'s greenhouse gas reduction targets in the years 2025, 2030 and 2040.
  - The 2023 North Coast load scenario is relatively unchanged compared to the 2020 North Coast load scenario, with a slightly slower ramp up due to adjustments to assumed in-service dates of potential projects.
- Approximately 800 GWh of energy savings from DSM activities implemented in fiscal 2021 and fiscal 2022 are now embedded in historic billed electricity sales and no longer reflected as a resource for future years; and
- The forecast energy and capacity contribution from existing, committed and planned resources are lower than the values used in the 2021 IRP primarily due to reductions in the expected energy generation from biomass generating facilities related to future fuel supply risks. The total reduction in forecast energy contribution totals approximately 900 GWh in fiscal 2030.

Taken together, in fiscal 2030, relative to the April 2023 Accelerated Reference Energy Load Forecast, and the 2021 IRP Base Resource Plan show a total shift of approximately 4,000 GWh.

6 This is after rates adjustments and before future DSM activities.

5

Resource options

5.1 Resource Options Database: new electricity resources available to meet the future needs of our customers

BC Hydro maintains a database of information on a broad range of resources to meet future electricity needs, including technical, financial, social and environmental attributes (Resource Options Database). The database includes information on upgrades to BC Hydro-owned generation facilities, demand-side measures, electricity purchase agreement renewals, upgrades to BC Hydro bulk transmission facilities, and new clean or renewable generation resources.

The technical attributes of each resource option describe how much energy and/or capacity can be delivered to the grid, how quickly a resource can be brought online, and the flexibility the resource adds to the system to respond to changes in load.

The financial attributes describe the cost to build, operate and maintain a resource option.

The social attributes are an estimate of the jobs created from resource development.

The environmental attributes are an estimate of the greenhouse gas and impacts on land from resource development. These attributes are currently only ascribed to new supply-side resources.

5.2 Demand-side measures

Demand-side measures include energy efficiency programs, as well as time-varying rates and demand response programs. We describe each below.

5.2.1 ENERGY EFFICIENCY PROGRAMS

Energy efficiency programs generally include incentives for customer studies and projects, and marketing and awareness initiatives. Energy efficiency programs provide energy as well as capacity savings.

Several different portfolios of energy efficiency resource options have been defined, reflecting differing scales of marketing and education efforts and incentive levels. They include an array of custom and prescriptive offers to residential, commercial, and industrial customers in B.C. for energy efficiency projects, energy management and operational improvements, and new construction. The portfolios of options we developed and that are in our Resource Options Database are as follows:

- Base energy efficiency: maintain a base level of demand-side measure programs that can readily be scaled up in future years.
- Higher energy efficiency: increased incentives and marketing efforts relative to the Base energy efficiency portfolio.
- Higher plus energy efficiency: further increase marketing efforts and incentives, relative to the Higher energy efficiency portfolio, to cover 100 per cent of incremental customer costs.
- New construction: incentives for new buildings to achieve a higher efficiency level than the current building code.
- Customer solar: capital incentives to support customer adoption of small solar rooftop systems.
- Customer batteries with solar: capital incentives for both solar and batteries on single-family homes, with utility management of batteries to help meet system capacity.

5.2.2 TIME-VARYING RATES AND DEMAND RESPONSE PROGRAMS

The options developed to reduce electricity use during high demand, or peak periods, include time-varying rates and demand response programs.

Time-varying rates encourage customers to shift their electricity consumption from periods of high system electrical demand to periods of lower demand in response to a price signal. Common examples of time-varying rates include time-of-use and critical peak pricing rates. These can be offered to different types of customers (residential, commercial, and industrial) and may be offered as voluntary (opt-in), default (with an option to opt-out), or mandatory.

Individual rate options were arranged into four rate suites which combined different voluntary and default rate options across the various customer classes.

Demand response programs enable customers to shift their load away from peak demand periods through voluntary programs that manage and control customers' electricity demand. Demand response programs can be coordinated with time-of-use rates to give customers different options to reduce their electricity consumption during peak periods. For example, a customer can participate in a program where the utility controls a customer's device (e.g., space or water heating equipment). The utility turns off the device during a peak event, and the customer receives an incentive. In a load curtailment program, commercial and industrial customers commit to providing a firm load reduction during a peak event in exchange for an incentive. In the peak saver incentive program, residential customers are given 24-hours notice of an upcoming peak event and receive an incentive if they successfully reduce load during that event.

Individual demand response programs were arranged into Demand Response Program A or B, which are groups of demand response programs with a base or higher level of funding, respectively.

Table 5-1 Summary of rate suite and demand response option combinations

Rates suite 1 Voluntary time-of-use rates (for residential and large commercial customers) and voluntary critical peak pricing (for large commercial and industrial customers).	**Demand Response Program A** Base level of funding for direct control incentive programs and marketing and education activities; load curtailment for commercial customers; and peak saver incentives for residential customers.
Rates suite 2 Voluntary time-of-use rates (for residential, large commercial and industrial customers) and voluntary critical peak pricing (for residential and large commercial customers).	**Demand Response Program A** Base level of funding for direct control incentive programs and marketing and education activities; load curtailment for commercial customers; and peak saver incentives for residential customers.
Rates suite 3 Default time-of-use rates (for residential, large commercial and industrial customers) and voluntary critical peak pricing (for residential and commercial customers).	**Demand Response Program B** Higher level of funding for direct control incentive programs and marketing and education activities; load curtailment for commercial customers; and peak saver incentives for residential customers.
Rates suite 4 Default time-of-use rates and critical peak pricing (for residential, large commercial and industrial customers).	**Demand Response Program B** Higher level of funding for direct control incentive programs and marketing and education activities; load curtailment for commercial customers; and peak saver incentives for residential customers.

To determine how much time-varying rates and demand response programs to pursue in the 2021 IRP, we analyzed combinations of rate suites and demand response programs.[1,2] The groupings compared in the analysis are shown in the table above.

For industrial customers, a potential industrial load curtailment resource option was also developed.

Industrial load curtailment has substantial development and operational history from a pilot conducted in the late 2010s. As there are relatively few large customers in the industrial group, it is possible to tailor individual agreements, enabling more customers to participate in the program. Industrial load curtailment targets similar savings as voluntary critical peak pricing but allows for more flexibility for BC Hydro and the customer. Many large industrial customers have expressed support for an Industrial Load Curtailment Program; and, given BC Hydro and customers' previous experience, we believe industrial load curtailment can be implemented with shorter lead times compared to time-varying rates or demand response programs.

Electric vehicle peak reduction is focused on encouraging customers to defer electric vehicle charging to off-peak periods. The electric vehicle market is rapidly increasing in size. From a utility perspective, the ability to satisfy electric vehicle charging demand can be a challenge if most electric vehicles are charged during peak demand periods, such as in the early evening.

Electric vehicle peak reduction in the 2021 IRP, combine time-varying rates with supporting programs to shift electric vehicle charging outside of system peak periods:

- 35 per cent electric vehicle driver participation: marketing and education efforts to support a voluntary residential time-of-use rate intended to shift home charging by 35 per cent of residential electric vehicle drivers to off-peak demand periods;
- 50 per cent electric vehicle driver participation: more aggressive marketing and education efforts, combined with customer smart-charging technology incentives to support a voluntary residential time-of-use rate intended to shift home charging by 50 per cent of residential electric vehicle drivers to off-peak demand periods; and
- 75 per cent electric vehicle driver participation: most aggressive combination of marketing and education efforts and customer smart-charging technology incentives to support a residential time-of-use rate intended to shift home charging by 75 per cent of residential electric vehicle drivers to off-peak demand periods.

5.3 Electricity purchase agreement renewals

As of October 2021, BC Hydro had 123 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. There are also larger run-of-river, storage hydro, biomass, municipal solid waste, wind, solar, waste heat, biogas, and natural gas-fired generation facilities. These agreements are all considered as existing resources until the year they expire.

As BC Hydro does not own these facilities, we must make assumptions, for the purposes of evaluation, about the viability of each facility and the potential for entering into a renewal agreement with the independent power producer based on the resource type and facility age.

1 Rate suite 1 with Demand Response Program A was defined in the Resource Options Database but not included as an option in portfolio analysis because it offered far fewer MW savings at a comparable cost to Rate Suite 2 with Demand Response Program A.

2 Rate suite 4 with Demand Response Program B was defined in the Resource Options Database but not included as an option in portfolio analysis because of the challenges associated with implementing all-default time-varying rates.

5.4 Upgrades to BC Hydro generation and transmission resources

5.4.1 UPGRADES TO BC HYDRO TRANSMISSION SYSTEM

Upgrades to BC Hydro's bulk transmission system increase the ability to transfer electricity from where it is generated to where it is needed. Transmission upgrades may be required in response to either new customer demand or new generation supply, and typically have long project lead times. Several conceptual transmission upgrades are presented in our Resource Options Database and include improvements to existing infrastructure as well as options to add additional transmission facilities.

Most of BC Hydro's customer load is located in the South Coast region of the province with most of the electricity required to serve this customer load transmitted to the region from the Interior of the province through five transmission lines.

Table 5–2 outlines the incremental upgrades to transmission lines serving the South Coast that are identified in the Resource Options Database and are considered in the 2021 IRP.

Table 5–2 South Coast transmission upgrade resource options

Transmission resource options (sequential)	**Capacity**	**Lead time**
Step 1 upgrades (series compensation, shunt capacitors, thermal upgrades)	750 MW (–200 / +100)	10 years
Step 2 upgrades (static volt–ampere reactive (VAR) compensators)	800 MW (–200 / +100)	10 years
Step 3 upgrades (new stations, transformers and more thermal upgrades)	500 MW (–200 / +100)	10 years

The North Coast region has the potential for significant load growth, especially from new liquified natural gas (LNG) or mining customers. Existing customers in the region are served by a single transmission line from Prince George to Terrace.

Table 5–3 outlines the upgrade to the line serving the North Coast included in the Resource Options Database.

Table 5–3 North Coast transmission upgrade resource options

Transmission resource options	**Capacity**	**Lead time**
Prince George to Terrace upgrade (transformer, series capacitors)	500 MW	6 years

5.4.2 UPGRADES TO BC HYDRO GENERATING FACILITIES

Expansions to existing BC Hydro generating facilities can provide additional generation capacity but typically have long lead times. Potential expansions include an additional generating unit at the Revelstoke generating facility or upgrades to existing units at the G.M. Shrum generating facility. There is also a range of reliability-focused upgrades that could be undertaken at other facilities.

In addition, BC Hydro has a number of older, smaller generating facilities that are the subject of future decisions to decommission or to refurbish. The facilities currently in service are considered existing resources for the entire time horizon of the 2021 IRP, while those facilities not in service are not considered either existing or committed resources. Our Resource Options Database includes all previously identified potential upgrades to BC Hydro generation facilities except those with very high incremental energy or capacity costs.

5.5 Future resources

Many different types of new sources of electricity are available across B.C. BC Hydro monitors the potential and characteristics of these resources.

Table 5–4 illustrates the range of new supply options currently included in our Resource Options Database.

Table 5–4 New supply resource options in the Resource Options Database

New supply and renewable resources	
Primarily energy options	**Primarily capacity options**
Biomass	Battery storage – utility-scale
Distributed Solar	Battery storage – distribution-scale
Geothermal	Natural gas or renewable natural gas
Municipal solid waste	Pumped hydro storage
Natural gas	
Offshore wind	
Onshore wind	
Renewable natural gas	
Run-of-river hydro	
Small storage hydro	
Solar – utility-scale	
Solar – distribution-scale	

Current costs of these resources were assessed based on input from technical stakeholders and previous BC Hydro studies. Future costs of these resources were assessed based on the National Renewable Energy Laboratory's 2019 Annual Technology Baseline report, which accounts for future cost reductions associated with evolving technologies.

Based on BC Hydro's high-level analysis of comparative unit energy costs, onshore wind resources are likely the lowest cost supply-side energy resource in the near-term. While difficult to predict decades out, large-scale solar resources are expected to become more competitive over the long-term.

Utility-scale batteries are a newer capacity resource with a relatively short lead-time, which can be deployed on a flexible and scalable basis, and are expected to see cost declines over the next 10 years.

5.6 Reference Prices

Our Resource Options Database provides us with information necessary for building our Base Resource Plan and Contingency Resource Plans. The resource options information is also an input to the development of our reference prices. Reference prices (including a set of cost numbers) are used as a cost benchmark against which the cost of potential projects, programs, or initiatives are compared. These reference prices are applied in various ways to evaluate the cost-effectiveness of BC Hydro's capital investments, electricity purchase agreements, and demand-side management measures (including rates).

While they help create a consistent price signal, it's important to note that reference prices are not adjusted for reliability, safety, risk, or other considerations (e.g., environmental) of the underlying investments.

Where the reference prices are based on the expected cost of greenfield clean or renewable resources, they are not intended as clearing prices for electricity purchase agreements. BC Hydro does not use reference prices as the sole decision-making factor for any business case.

BC Hydro uses two sets of reference prices:

- One set is for generation, for each of energy and capacity; it is generally representative of resource costs utilized in BC Hydro's Base Resource Plan and includes the cost of bulk transmission upgrades required to deliver generation from remote regions to the Lower Mainland load centre.
- Another set is for non-bulk transmission and distribution; it is applicable for capacity only and is based on the cost of load growth driven non-bulk transmission and distribution upgrades.

The two figures below illustrate the transition from surplus to deficit, specifically with existing and committed resources compared to when planned demand-side measures, and market-price based electricity purchase agreement renewals in the next five years are added into the resource mix.

Figure 5-1 Reference prices (fiscal 2022$) for the duration of the 2021 Integrated Resource Plan

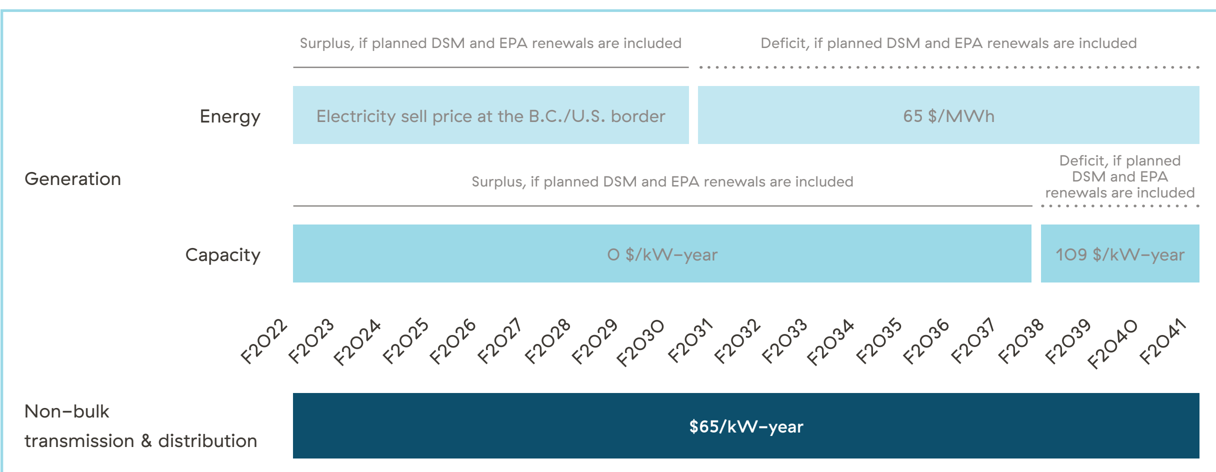


Figure 5-1 illustrates the two sets of reference prices, all in fiscal 2022 dollars, for the 2021 IRP duration after existing and committed resource and the demand-side measures and electricity purchase agreement renewals in the Base Resource Plan.

Figure 5–2 Reference prices (fiscal 2022$) without planned demand–side measures and electricity purchase agreement renewals included

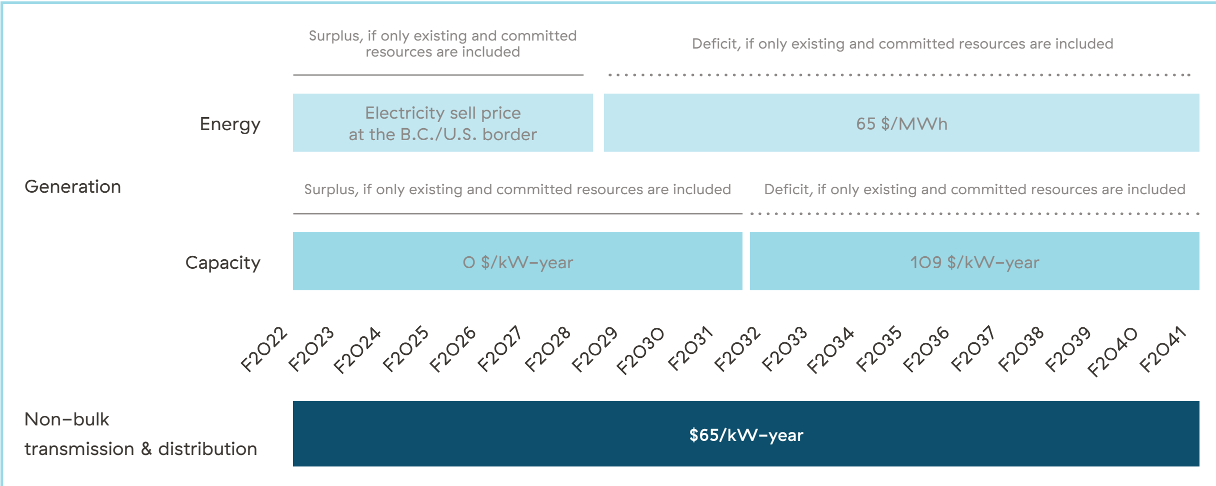


Figure 5–2 illustrates the reference prices (fiscal 2022$) with the transition from surplus to deficit reflecting only existing and committed resources and before the demand–side measures and electricity purchase agreement renewals in the Base Resource Plan. In this case, the transition from surplus to deficit would occur for energy in fiscal 2029 and for capacity in fiscal 2032.

Table 5–5 Non–bulk Transmission and Distribution reference prices (fiscal 2022$)

Cost Element	$/kW–year; fiscal 2022$
Non–bulk transmission	30
Distribution	35
Total	**65**

Table 5–5 provides the references prices for non–bulk transmission and distribution for the 2021 IRP duration.

The non–bulk transmission and distribution reference price provides a system average view of the wire system investment costs and applies to provincial wide projects. For any project impacting the non–bulk transmission and distribution network at a specific location, BC Hydro would assess the cost or value specifically to the project.

5.7 2023 UPDATE

BC Hydro has updated the Reference Prices and Long-Run Marginal Costs presented in Appendix L of the 2021 IRP. The updates reflect the changes to the Load Resource Balances that show the forecast timing of the switch from an energy surplus to deficit has advanced and changes to BC Hydro's Weighted Average Cost of Capital (WACC) that has increased to 6% nominal, up from 5%.

Figure 1 Reference Prices (Fiscal 2022$) for the Duration of the 2021 Integrated Resource Plan – Updated

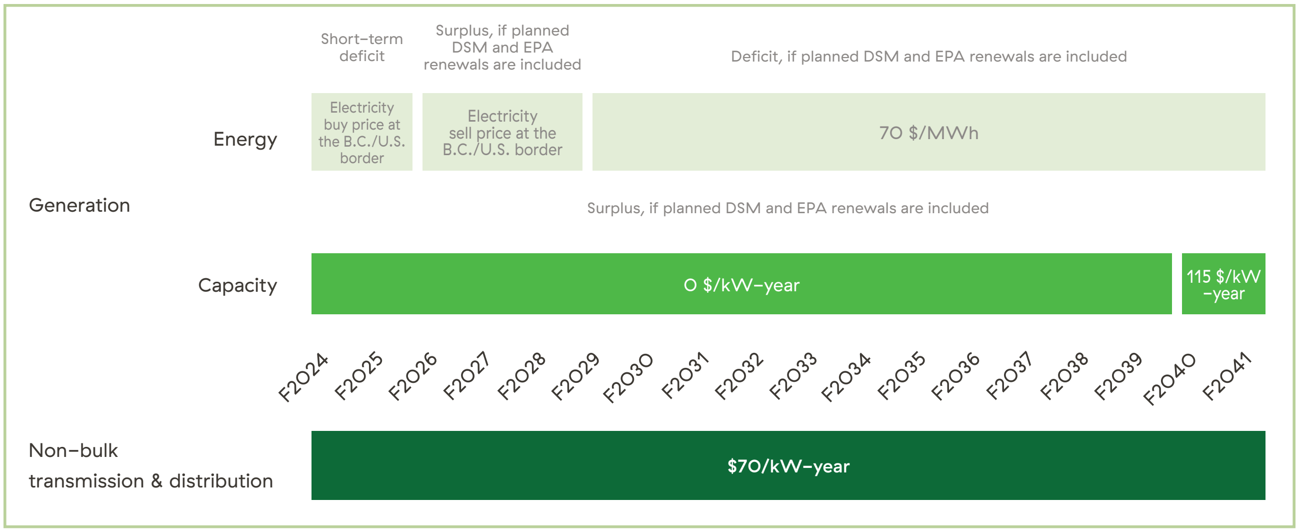
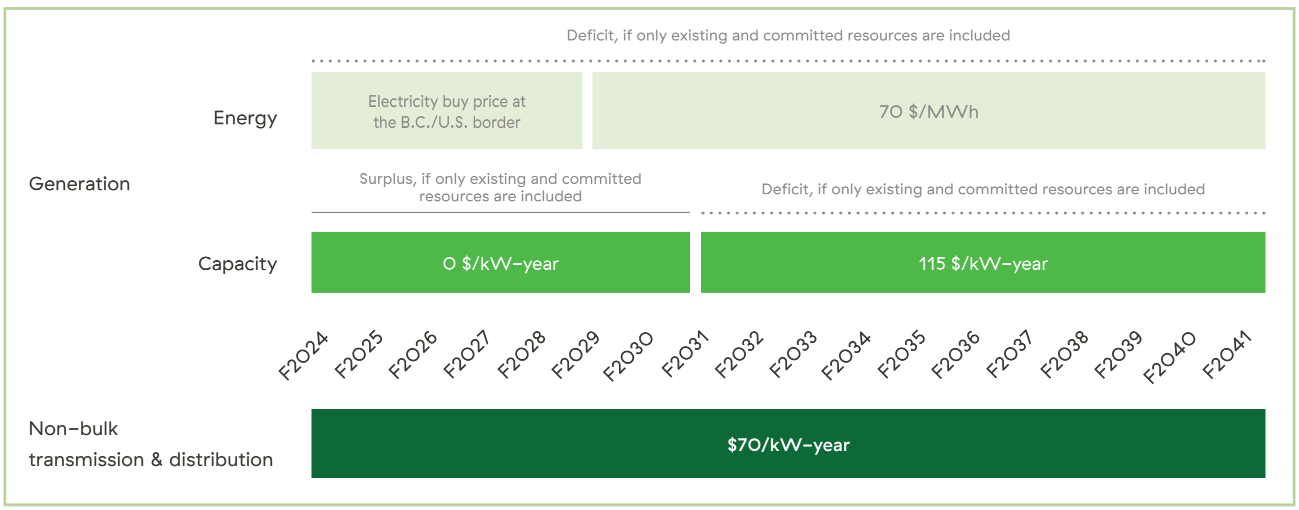


Figure 2 Reference Prices (Fiscal 2022$) Without Planned DSM and EPA Renewals Included – Updated



The updated Reference Prices and Long-Run Marginal Costs are shown in the figures above. Figure 1 and Figure 2 illustrates the two sets of reference prices and are updated Figure L-1 and Figure L-2 from Appendix L to the Application. Figure 1 shows the transition from surplus to deficit reflecting existing and committed resources and planned demand-side measures and Electricity Purchase Agreement (EPA) renewals, and Figure 2 shows the transition from surplus to deficit reflecting only existing and committed resources before planned demand-side measures and EPA renewals.

5.7 2023 UPDATE

The make-up of the non-bulk transmission and distribution reference prices are summarized in Table 1. This is an updated version of Table L-1 in Appendix L to the Application

Table 1 Non bulk Transmission and Distribution Reference Prices (Fiscal 2022$) – Updated 2021 IRP

Cost Element	**$/kWyear; fiscal 2022$** (rounded to nearest $5)
Nonbulk transmission	35
Distribution	35
Total	70

6

The process used to build the 2021 IRP

6.1 Introduction

To develop our plan, we used a structured decision making approach. This approach allowed us to be explicit about our planning objectives and the measures we used to evaluate whether we have met these objectives. The approach helped clarify the choices and trade–offs we made between potential options.

6.2 The process we used to generate portfolios and make decisions

Figure 6–1 illustrates the process of developing and evaluating portfolios of options using portfolio modelling and structured decision making.

Figure 6–1 Process of developing and evaluating portfolios

Section 44.1 of the *Utilities Commission Act* sets out the requirements for an integrated resource plan. It indicates a clear policy preference for the priority use of cost-effective demand-side measures. This priority was also consistent with the consultation feedback we received as we developed the 2021 IRP. Accordingly, developing and evaluating portfolios to create a Base Resource Plan started with examining demand-side measures by testing in sequence the cost-effective levels of energy efficiency, time-varying rates and demand response programs. Once the cost-effective level of demand-side measures was determined, supply-side resources were established to round out what resources, what timing and what volumes would make up a complete Base Resource Plan.

The general process steps are as follows:

1. We gather our technical inputs and assumptions. These include all our potential resource options in our Resource Options Database and other inputs like our load forecast, our planning criteria, major bulk transmission options, and other technical inputs.
2. We use a computer model (System Optimizer) to select the available resources to fill the gap between the forecast load and the available supply. The process starts with the selection of a particular resource and different assumptions about the size or volume of that particular resource. We then generate least-cost portfolios around each of the assumptions to compile a complete set of resources, the timing of those resources, and an overall portfolio cost.

   System Optimizer also calculates some non-financial impacts (e.g., greenhouse gas emissions). Additional non-financial impacts are then modelled outside of System Optimizer to develop a broader view of how the portfolio of resources impacts all the relevant decision objectives.

   Inputs to the model (e.g., load scenarios, resource availability, resource choices) can be changed to generate new portfolios, based on those inputs, to explore uncertainties or policy options.
3. We then conduct a trade-off analysis, including considering consultation input, between the different portfolios to determine how they perform relative to one another and against the planning objectives and measures. This comparison is a qualitative exercise conducted using a consequence table. A trade-off analysis is not an exact science. Rather it is used to inform decisions and to be transparent about the reasons for those decisions.
4. The resource option analyzed is then set at its selected level for the remainder of the analyses and the process is repeated using the next resource under consideration.

This process is repeated until the gap between forecasted load and the supply is filled by choices balancing the decision objectives.

6.3 The decision objectives we used to compare IRP options

As discussed in section 2.3, our planning objectives are keeping costs down for customers, reducing greenhouse gas emissions through clean electricity, limiting land and water impacts, and supporting the growth of B.C.'s economy.

Table 6-1 expands on the list of planning objectives by providing sub-objectives and associated measures that were used to evaluate the relative performance of portfolios against the planning objectives. These measures are used in the consequence tables that evaluate the trade-offs between different portfolios.[1]

1 Not all of the objectives and sub-objectives in Table 6-1 will be relevant for each portfolio being considered.

Table 6-1 Planning objectives

Planning Objective (sub-objective)	Measure	What is better	Description
Keep costs low for customers			
Minimize Net Total Resource Cost	$M PV	Lower	Millions of dollars in present value (**PV**).[2] Net Total Resource Cost measures the total costs to the utility and program participants.
Minimize Net Utility Cost	$M PV	Lower	Millions of dollars in PV. Net utility cost measures the costs of resources in terms of utility expenditures (program costs and incentive payments).
Minimize cost risk from demand-side measures' under-delivery	MW below fiscal 2030 planned estimates	Lower	The amount of megawatts (MW) change between planned savings and lower than expected savings in fiscal 2030. This is a proxy measure for cost risk as larger divergences could lead to the addition of more costly resources.
Minimize cost risk from transmission upgrade schedule uncertainty	In-service date for Step 2 and Step 3 transmission upgrades to the South Coast	Later	The earliest in-service date for the transmission upgrade. This is a proxy measure for cost risk as shorter lead times increase the likelihood that temporary stop gaps might be needed to bridge to the in-service date, incurring additional costs.
Minimize rate impact	Per cent	Lower	Rate increases incremental to the portfolio of existing and committed resources.
Maximize the ability for all to benefit from a rate	Opt-in or opt-out time-varying rate	Opt-in	Customers who choose to enroll in an opt-in time-varying rate are more likely to be those who can achieve bill savings, relative to customers who are automatically enrolled in a rate by the electric utility on an opt-out basis.
Limit land and water impacts			
Minimize land and water impacts	Index	Lower	The index represents an aggregate score for each portfolio based on its biophysical footprint which considers many land and water-based environmental attributes.

2 A present value calculation considers the fact that financial impacts (costs or benefits) that occur in the future have less weight from today's perspective. A present value calculation will take a stream of annual financial impacts (costs or benefits), translate them using a discount rate into current values, and them sum them up into one present value.

Planning Objective (sub-objective)	Measure	What is better	Description
Reduce greenhouse gas emissions			
Minimize greenhouse gas emissions	t CO_2e	Lower	Tonnes (t) of carbon dioxide equivalent emissions from system generation.
Support growth of B.C.'s economy			
Maximize economic development of communities	Gross provincial full-time equivalent positions, annualized over 20 years	Higher	Number of jobs (construction and operations) arising from direct, indirect, and induced spending on supply side resources (new and contract renewals), incremental transmission, and new energy efficiency demand-side measures.

6.4 How consultation helped build the 2021 IRP

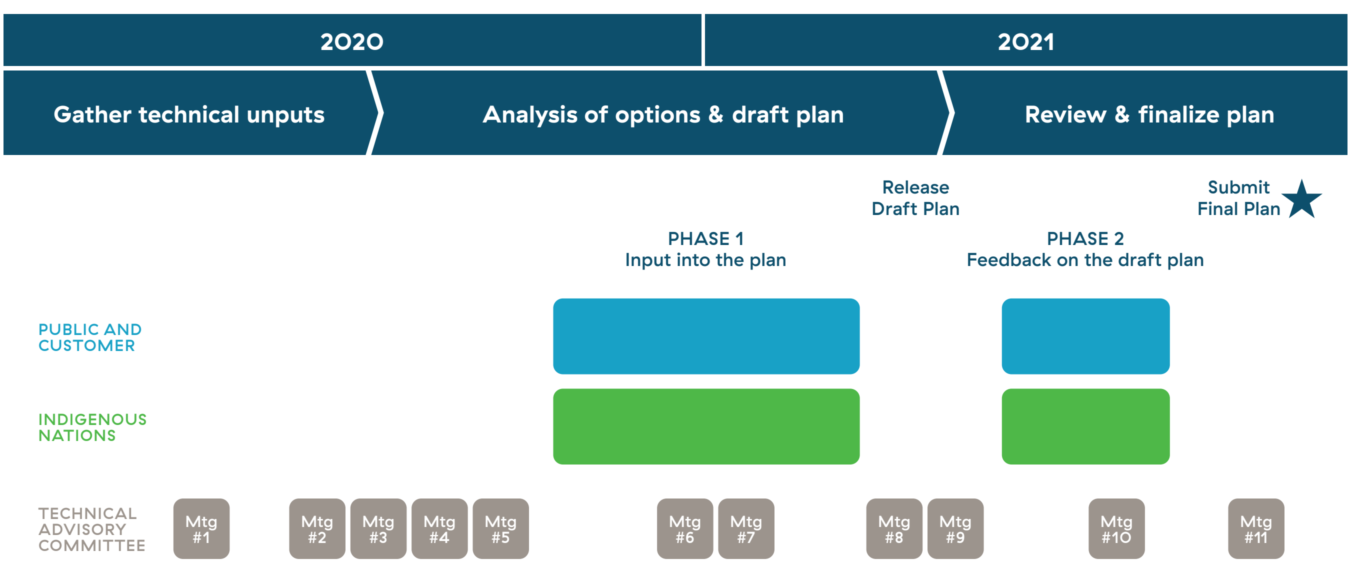
Building the 2021 IRP incorporated a broad consultation process consisting of three consultation streams: the public and customers; Indigenous Nations; and a technical stream. Engagement efforts were valuable in supporting the alignment of the 2021 IRP elements with broad values and interests, understanding related interests for future planning and subsequent applications, and checking our planning assumptions and analysis with technical experts along the way.

An additional objective in the Indigenous consultation stream was to fulfil our legal obligations to consult, and demonstrate our commitment to implementing the United Nations Declaration of the Rights of Indigenous Peoples.

The consultation process occurred throughout the development of the 2021 IRP and was referred to as "Clean Power 2040". Information about our engagement activities for all three streams is available at **bchydro.com/cleanpower2040**.

Figure 6-2 illustrates the consultation that occurred in building the 2021 IRP.

Figure 6-2 Consultation streams and phases



Public and customers, and Indigenous Nations streams

We undertook consultation with the public and customers, and with Indigenous Nations in two broad phases. All sessions during both phases were virtual in adherence to provincial public health guidelines.

Phase One (input), which occurred in fall/winter 2020/2021, gathered input on interests and values by finding out 'what matters' to people about various planning topics, including the initial planning objectives. We gathered input using methods tailored to each stream.

For the public and customer stream we sought diverse perspectives through an array of forums, including online engagement surveys (a short and a long survey), public interactive workshops, local government sessions, an online digital dialogue, a telephone town hall, and a youth engagement. Over 6,000 members of the public and customers participated in Phase One of the consultation.

The Indigenous Nations stream included three five-hour regional workshops in which all Indigenous Nations in the province were invited to attend, supplemental meetings with some individual Indigenous Nations, an online engagement survey (long survey) and written correspondence. Sixty-four Indigenous Nations and organizations participated in Phase One of the consultation.

Input from Phase One was considered, along with technical, financial, and other environmental and economic development analysis, to develop the Draft IRP.

Phase Two (feedback) occurred through the summer of 2021 and gathered feedback on how the Draft IRP elements aligned with participants' values and interests.

The methods used to gather feedback on the Draft IRP were similar to those used in Phase One in that all of the same forums were used, with some notable differences. For Phase Two, we made the full Draft IRP available for review. The public and customer stream added a customer survey that provided a representative sample of BC Hydro's residential customers, and also provided an online comment form for organization representatives to be used for feedback in conjunction with the Draft IRP.

Over 2,300 members of the public and customers and fifty-three Indigenous Nations and organizations participated in Phase Two of the consultation. Feedback from the second phase of consultation was considered as we finalized the 2021 IRP.

Technical stream

The technical stream consisted of a Technical Advisory Committee established to provide ongoing, detailed, technical advice and feedback from a group of knowledgeable parties with experience relevant to BC Hydro's resource planning.

The Technical Advisory Committee members represented a variety of interests such as customer groups, Indigenous, environmental, independent power producers, sustainable energy, municipal government, low income, other utilities, and academic. Staff representatives from the Ministry of Energy, Mines and Low Carbon Innovation and the BCUC were invited to attend Technical Advisory Committee meetings as observers.

The Technical Advisory Committee met 11 times from March 2020 to October 2021 for discussions on planning assumptions, planning inputs and analysis, and to provide feedback on the Draft IRP.

Ongoing advice and feedback from the Technical Advisory Committee was considered as we developed the 2021 IRP.

The progression of consultation input and feedback used to build the 2021 IRP

As the public and customers, and Indigenous consultations were undertaken in two distinct phases, there was a logical progression to how results of those engagement efforts informed the development of the 2021 IRP. Phase One gathered input on values and interests that informed the development of the Draft IRP. Phase Two gathered feedback on how the Draft IRP elements aligned with participants' values and interests.

Within Chapters 7 and 8, where we describe the elements of the Base Resource Plan and the Contingency Resource Plans, we've included summaries of how the overall consultation results show alignment with each of the plan elements.

6.5 2023 UPDATE

To develop the 2021 IRP, BC Hydro conducted a broad consultation with three streams (Indigenous, public/customer and technical streams) and two phases. Consultation results from the public and customer participants showed strong positive alignment for all of the plan elements in the 2021 IRP. Consultation results from Indigenous Nations were generally aligned with or neutral for all of the plan elements in the 2021 IRP.

The updates to the Base Resource Plan and the Contingency Resource Plans were informed by our prior consultation on the 2021 IRP.

Public and Customers

During consultation on the 2021 IRP, public and customer respondents expressed strong support for demand-side measures. Accelerating the timing of the ramp up of energy efficiency and demand response programs is aligned with this support.

During consultation on the 2021 IRP, public and customer respondents expressed positive alignment of the EPA renewal element as it keeps costs low and avoids new environmental impacts. The extension of the EPA renewal assumption beyond 2026 is consistent with our approach to EPA renewals in the 2021 IRP which included relying on existing infrastructure to keep costs down and limit land and water impacts.

During consultation on the 2021 IRP, we heard a strong interest from customers and the public in renewable resources. The addition of a new element to acquire new clean or renewable energy resources is aligned with this interest.

Indigenous Nations

During consultation on the 2021 IRP Indigenous Nations were supportive of conservation. One of the top priorities expressed by Indigenous participants during consultation was limiting land and water impacts. Accelerating the timing of the ramp up of energy efficiency and demand response programs is aligned with support for conservation and the interest in limiting land and water impacts.

The extension of the EPA renewal assumption beyond 2026 is consistent with our approach to EPA renewals in the 2021 IRP which included relying on existing infrastructure to keep costs down and limit land and water impacts. During Indigenous consultation on the 2021 IRP there was interest in giving priority to renewing EPAs that benefit Indigenous communities including those with Indigenous ownership. We have not determined the details of how EPAs will be renewed after 2026 and will consider Indigenous interests as we develop our approach to these future renewals.

We also heard a strong interest from Indigenous Nations in participating in new clean energy opportunities. The addition of a new element to acquire new clean energy resources is aligned with this interest. BC Hydro will be engaging Indigenous Nations and stakeholders on the design of an energy acquisition process for new clean energy resources with a particular focus on how we can include a role for First Nations ownership in all projects.

7

The Base Resource Plan: our strategy to meet the future electricity needs of our customers

7.1 Introduction

The Base Resource Plan is BC Hydro's strategy to meet the future needs of our customers if the future load aligns with our Reference Load Forecast. In the 2021 IRP, the Base Resource Plan was developed through the process set out in Chapter 6 and with consideration of input and feedback received during consultation. Some of the Base Resource Plan elements require further approvals from the BCUC or other regulatory bodies, such as those who issue permits for capital projects.

7.2 The elements of the Base Resource Plan

The Base Resource Plan consists of seven elements, as follows:[1]

- Continue with a base level of energy efficiency programs (Base energy efficiency) and plan to ramp up to higher levels (Higher energy efficiency) in future years to achieve approximately 1,700 GWh/year of energy savings and approximately 280 MW of capacity savings at the system level by fiscal 2030;
- Pursue voluntary time-varying rates supported by demand response programs to achieve approximately 220 MW of capacity savings at the system level by fiscal 2030, and advance the Industrial Load Curtailment Program to achieve approximately 100 MW of incremental capacity savings at the system level by no later than fiscal 2030;
- Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers to support a voluntary residential time-of-use rate to shift home charging by 50 per cent of residential electric vehicle drivers to off-peak demand periods (50 per cent electric vehicle driver participation) to achieve approximately 100 MW of capacity savings at the system level by fiscal 2030;
- 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 19 existing clean or renewable projects that produce a total of approximately 900 GWh, with electricity purchase agreements set to expire before April 1, 2026;
- Advance the first step of sequential upgrades to transmission infrastructure into the South Coast region, including series compensation, shunt capacitors, and thermal upgrades to achieve approximately 750 MW of capacity by fiscal 2033. Prepare to initiate a second step of upgrades to achieve approximately 550 additional megawatts of capacity for the South Coast region by fiscal 2040;
- Undertake a structured decision making approach to evaluate small BC Hydro plants requiring end-of-life investment decisions on a facility-by-facility basis to determine whether to decommission or refurbish these facilities. These facilities would be evaluated on the following schedule:

1 The GWh/yr and MW numbers quoted in the Base Resource Plan are consistent with the volumes in the Load Resource Balances with Base Resource Plan Actions shown in section 7.3.

Table 7-1 BC Hydro small plants at or reaching end-of-life

Facility	Timing to review end-of-life investment decision
Shuswap (near Vernon)	Analysis in progress
Elko (near Cranbrook)	2025
Spillimacheen (near Golden)	2029
Alouette (near Maple Ridge)	2030
Falls River (near Kitimat)	In operation – date not set
Walter Hardman (near Revelstoke)	In operation – date not set

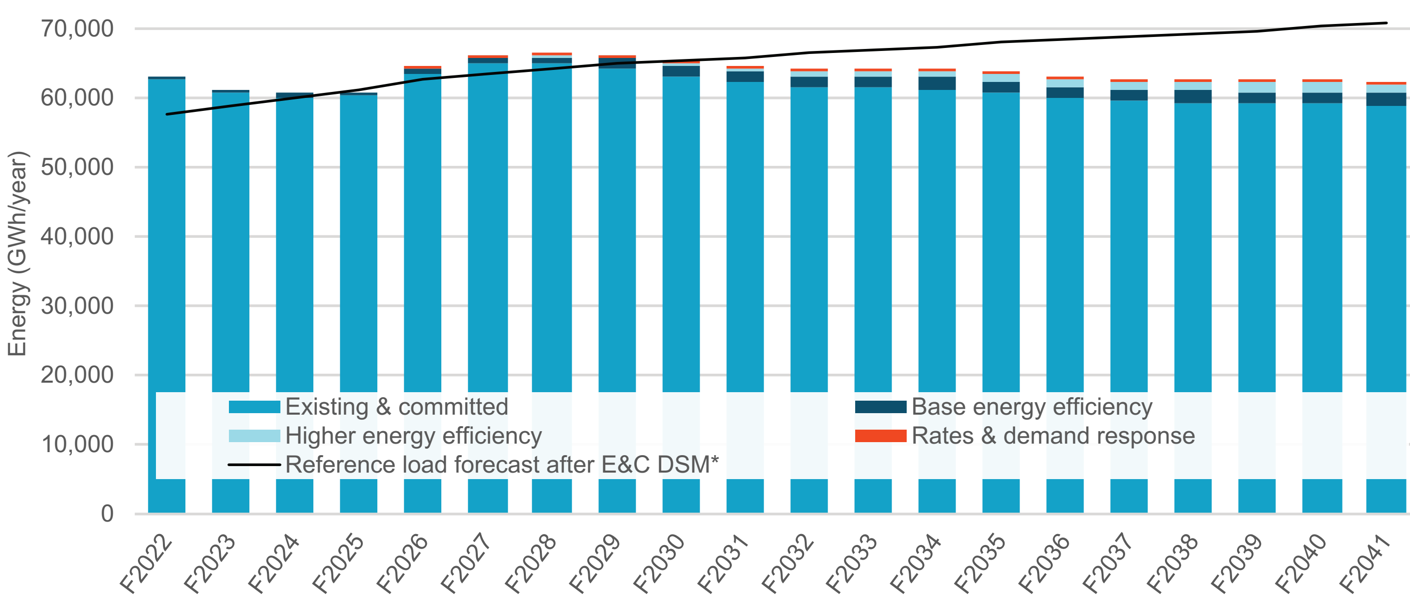
- Beyond the elements identified above and after demand-side measures, plan to acquire new energy and capacity resources as follows: 810 GWh in fiscal 2031 ramping up to 7,800 GWh by fiscal 2041, and 160 MW in fiscal 2038 ramping up to 510 MW by fiscal 2041. These future resources would be selected from:
  - Expiring electricity purchase agreements with independent power producers;
  - New clean and renewable energy resources; and
  - Upgrades to BC Hydro facilities.

7.3 How the plan meets the future electricity needs of our customers over time

The Base Resource Plan described in section 7.2 is shown here in Figures 7-1 through 7-6. The figures illustrate which resources come online, when they come online, and how much of that resource will be used.

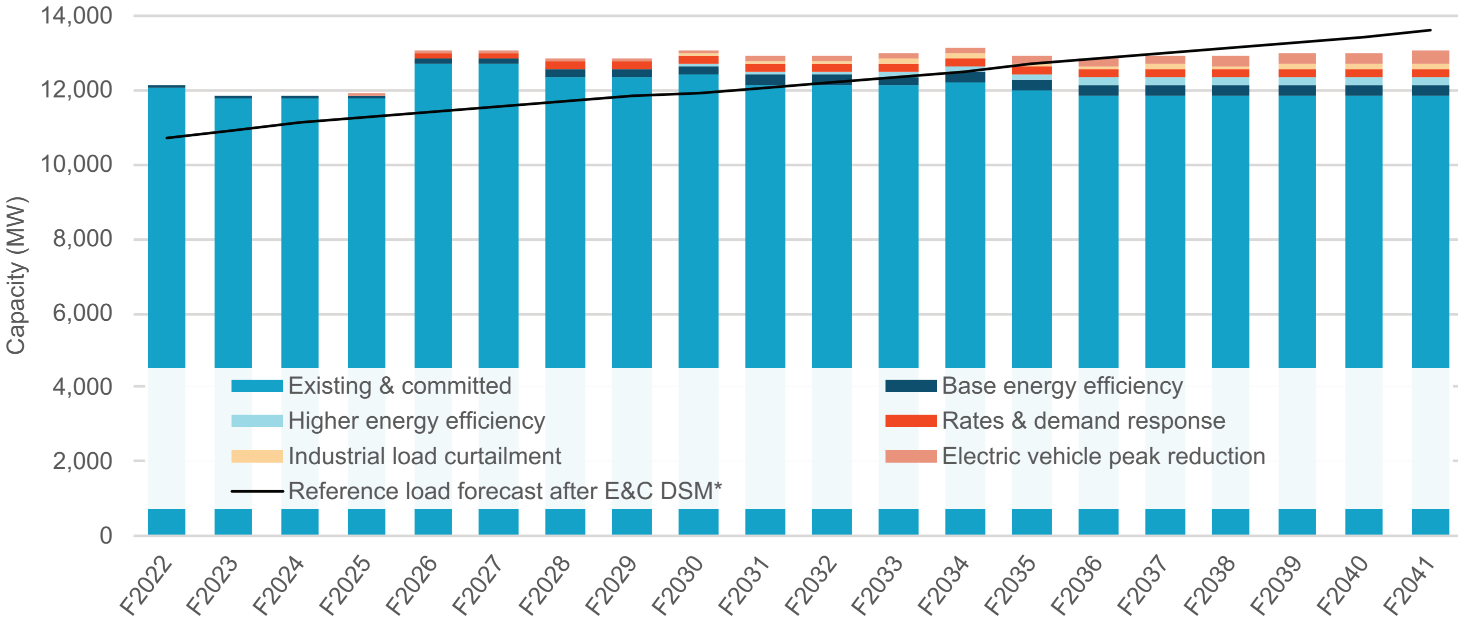
Figures 7-1 and 7-2 show how "Planned demand-side measures" (i.e., the demand-side measure elements as described in the Base Resource Plan) would help to serve our customers' anticipated future needs for energy and capacity, respectively. Figure 7-3 provides a similar view of capacity on the South Coast.

Figure 7-1 System energy Load Resource Balance with planned demand-side measures only



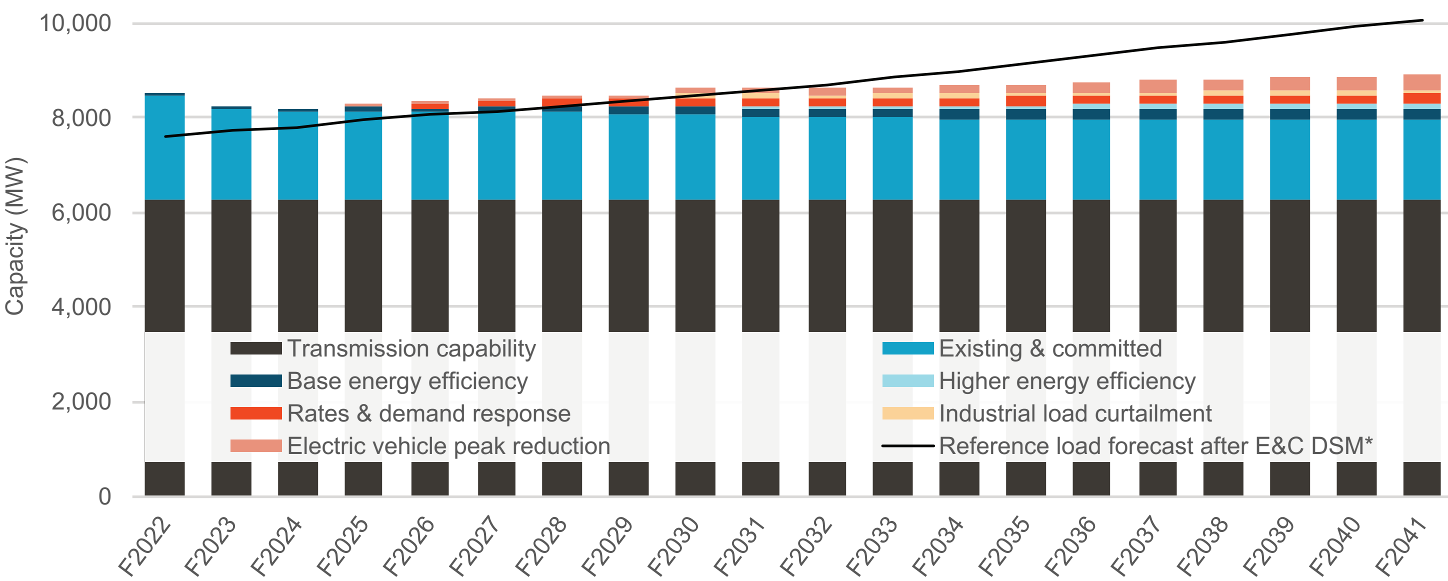
* E&C DSM denotes existing and committed demand-side measures

Figure 7–2 System capacity Load Resource Balance with planned demand–side measures only



* E&C DSM denotes existing and committed demand–side measures

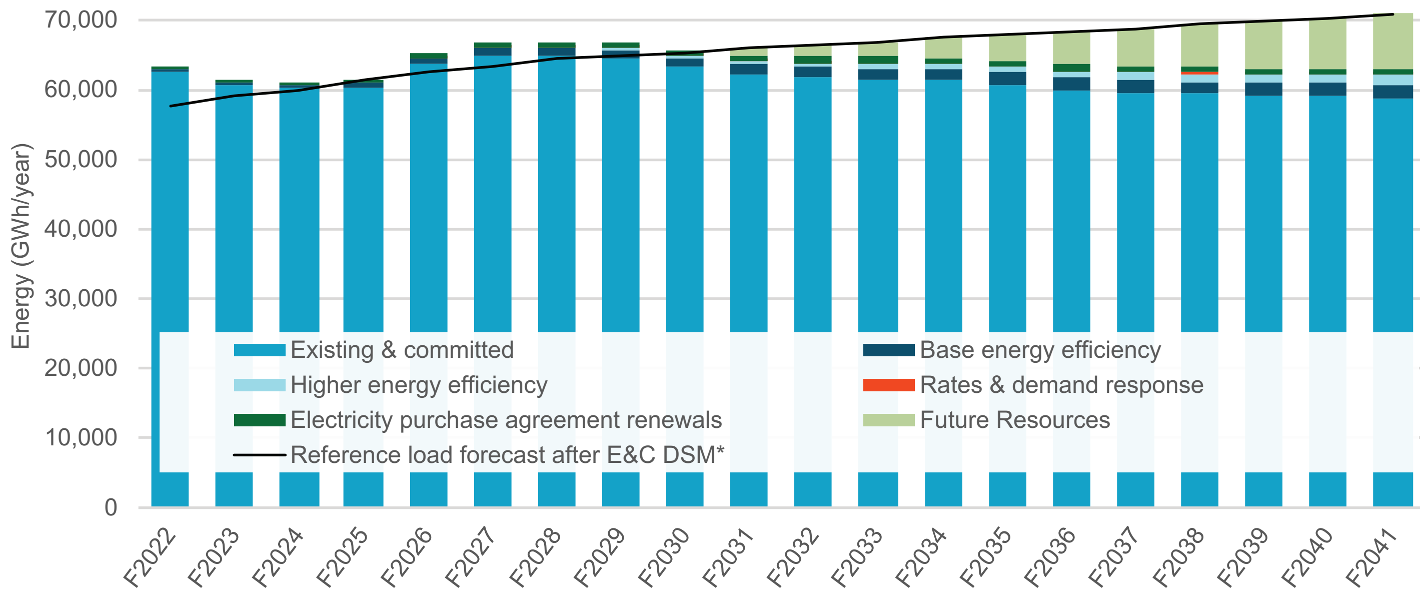
Figure 7–3 South Coast capacity Load Resource Balance with planned demand–side measures only



* E&C DSM denotes existing and committed demand–side measures

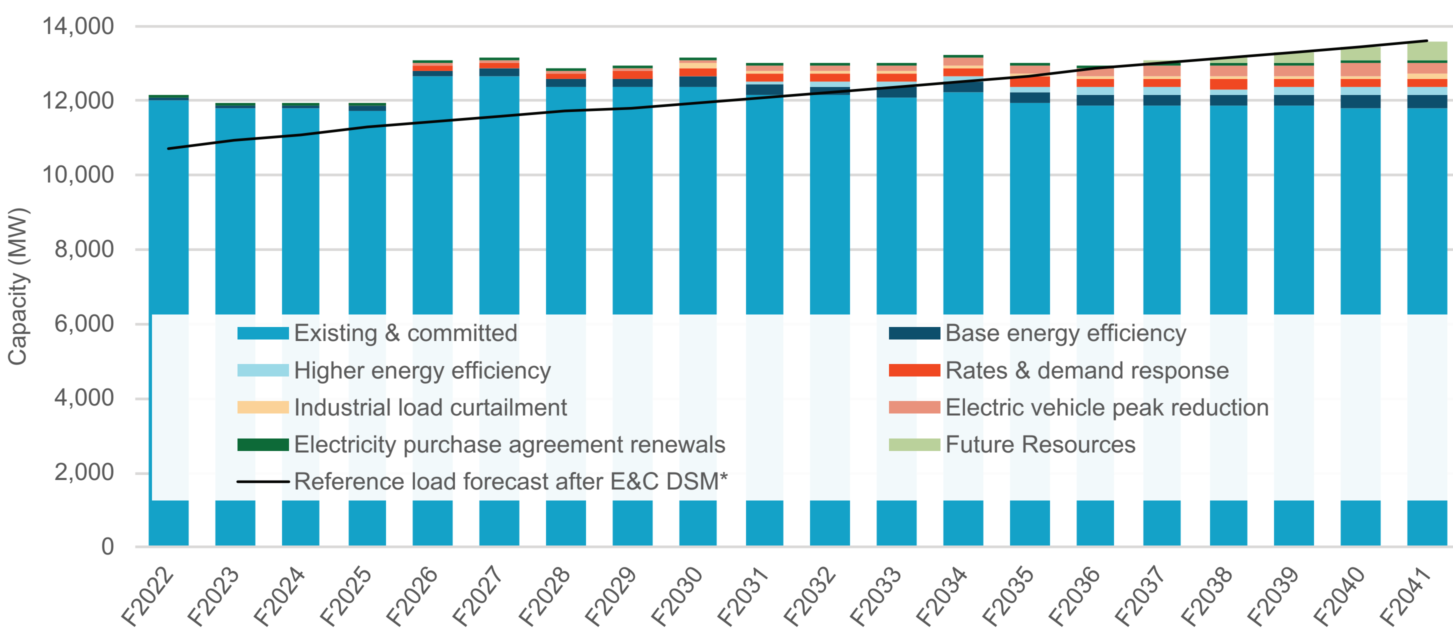
Figures 7–4 and 7–5 present the same view but with the full suite of Base Resource Plan elements. Similarly, Figure 7–6 provides that view for capacity on the South Coast.

Figure 7–4 System energy Load Resource Balance with all Base Resource Plan elements



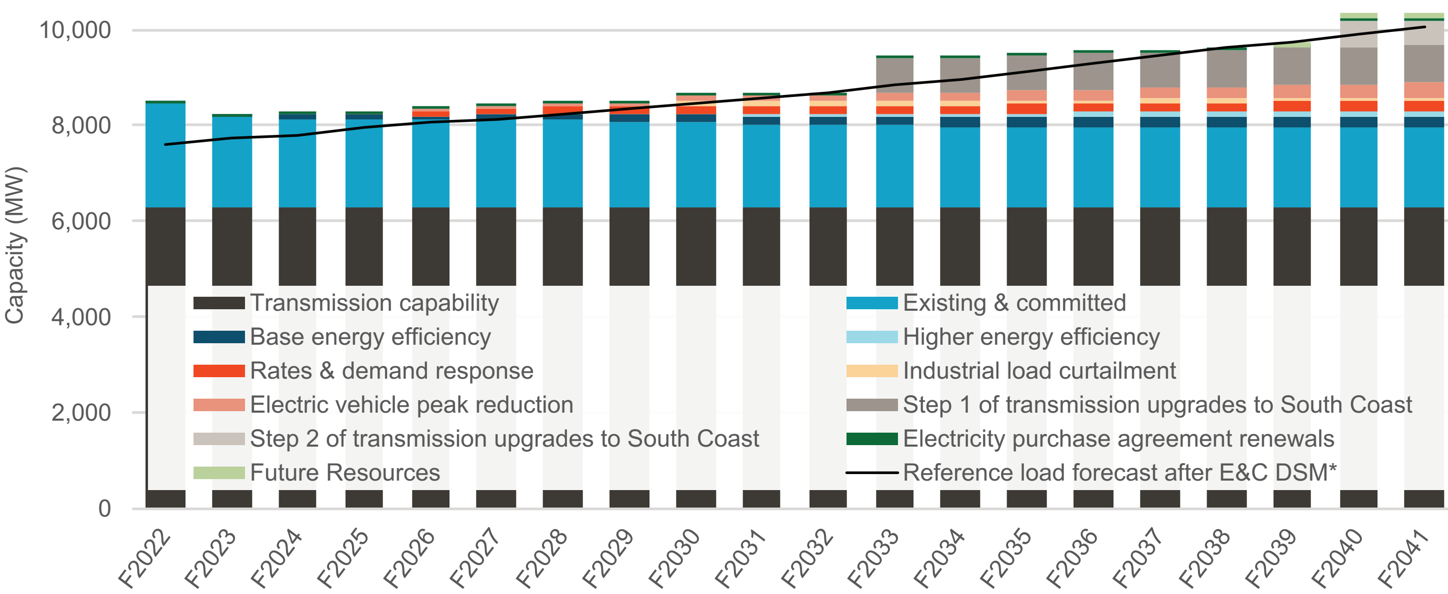
* E&C DSM denotes existing and committed demand-side measures

Figure 7–5 System capacity Load Resource Balance with all Base Resource Plan elements



* E&C DSM denotes existing and committed demand-side measures

Figure 7-6 South Coast capacity Load Resource Balance with all Base Resource Plan elements



* E&C DSM denotes existing and committed demand-side measures

7.4 The analysis that led to the Base Resource Plan

We developed and evaluated portfolios for the Base Resource Plan starting with demand-side measures (energy efficiency, time-varying rates, and demand response programs). Once we determined the demand-side measures resources, we established the other resources required to fill the remaining gap. The following sections describe each step of this process.

7.4.1 HOW THE ENERGY EFFICIENCY PROGRAMS WERE SELECTED

Energy efficiency programs provide both energy and capacity savings and are flexible and scalable. We analyzed four levels of energy efficiency savings: No energy efficiency, Base energy efficiency, Higher energy efficiency; and Higher Plus energy efficiency. Table 7-2 provides a consequence table outlining the trade-offs between portfolios.

Table 7-2 Consequence table of portfolios comparing levels of energy efficiency demand-side measures

ABOUT THIS TABLE

Each column corresponds to a portfolio, or a bundle of resource options. Each portfolio was created by selecting a specific level of energy efficiency and then letting the optimization model fill in the rest of the resource choices. The table shows the consequences, or impacts, of these different portfolios on identified objectives and measures. Choosing one portfolio as a base of comparison against the alternatives lets us identify where a portfolio performs better or worse than the base for each objective (colour-coded for ease of reference).

Legend

- Blue: This portfolio is used as the basis of comparison
- Red: This alternative is worse than the base portfolio
- Green: This alternative is better than the base portfolio
- White: This alternative is roughly the same as the base portfolio

Planning Objective (measure)	What is better	No energy efficiency	Base energy efficiency	Higher energy efficiency	Higher plus energy efficiency
Net Total Resource Cost ($M PV)	Lower	$2,510	$1,280	$680	$110
Net Utility Cost ($M PV)	Lower	$2,510	$1,630	$1,410	$1,210
Cost risk from DSM under-delivery* (MW below plan by 2030)	Lower	0	80	130	140
Cost risk from transmission schedule uncertainty* (year in service, Step 1)	Later	2032	2032	2033	2033
Cost risk from transmission schedule uncertainty* (year in service, Step 2)	Later	2036	2037	2038	2039
Rate Impact (% change in F2030)	Lower	-1.0%	0.0%	1.0%	1.8%
Rate Impact (% change in F2041)	Lower	-0.8%	0.0%	1.5%	3.8%
Land and Water Impacts (Index)	Lower	5.0	3.5	2.7	1.5
Economic Development (provincial gross FTEs, annualized)	Higher	4,040	4,030	4,060	4,510

*These are not represented in dollars as they are a proxy for cost risk, not an assessment of financial risk.

7.4.1.1 Trade-offs in the consequence table

Pursuing different levels of energy efficiency impacts multiple objectives. BC Hydro views the major trade-offs as balancing portfolio cost, rate increases, and land and water impacts. The magnitude to which these portfolios impact the other objectives (i.e., under-delivery risk and new provincial employment) is relatively small in comparison.

Across the full range of options, Table 7-2 shows that pursuing higher levels of energy efficiency results in lower portfolio costs. Table 7-2 also shows that doing any energy efficiency, as opposed to no energy efficiency, avoids significant land and water impacts.

However, while higher levels of energy efficiency cause overall costs to decrease, the amount of electricity being sold to customers to recover those costs also decreases. This means that pursuing higher levels of energy efficiency can also result in higher rates for customers.

For example, moving from Base energy efficiency to Higher energy efficiency, and then from Higher energy efficiency to Higher plus energy efficiency results in approximately $600 million portfolio cost savings at each incremental level (measured as Net Total Resource Cost). However, moving from Base energy efficiency to Higher energy efficiency means 1.5 per cent higher cumulative long-term (i.e., by fiscal 2041) rate increases. Similarly, moving from Base energy efficiency to Higher plus energy efficiency means 3.8 per cent higher cumulative long-term rate increases.

The consequence table also shows that pursuing higher levels of energy efficiency comes with increased under-delivery risk.

7.4.2 HOW THE TIME-VARYING RATE SUITE AND SUPPORTING DEMAND RESPONSE PROGRAMS WERE SELECTED

With the level of energy efficiency selected, we then addressed capacity-focused demand-side measures. Time-varying rates and demand response programs are two measures to encourage customers to shift their consumption out of peak periods. We analyzed rates suites and supporting demand response programs, and an industrial load curtailment program, all of which are outlined in section 5.2.2.

Table 7-3 Consequence table of portfolios comparing levels of voluntary time-varying rates and demand response programs

ABOUT THIS TABLE

Each column corresponds to a portfolio, or a bundle of resource options. Each portfolio was created by selecting a specific Rate suite and level of demand response programs, combining these with the previously selected levels of energy efficiency and then letting the optimization model fill in the rest of the resource choices. The table shows the consequences, or impacts, of these different portfolios on identified objectives and measures. Choosing one portfolio as a base of comparison against the alternatives lets us identify where an alternative portfolio performs better or worse than the base for each objective (colour-coded for ease of reference).

Legend

- This portfolio is used as the basis of comparison
- This alternative is worse than the base portfolio
- This alternative is better than the base portfolio
- This alternative is roughly the same as the base portfolio

Planning Objective (measure)	What is better	No rate suite or Demand Response Programs	Rate suite 2 with Demand Response Program A	Rate suite 3 with Demand Response Program B
Net Total Resource Cost ($M PV)	Lower	$680	$650	$590
Net Utility Cost ($M PV)	Lower	$1,410	$1,440	$1,290
Cost risk from DSM under-delivery* (MW below plan by 2030)	Lower	130	270	330
Cost risk from transmission schedule uncertainty* (year in service, Step 2)	Later	2038	2038	2038
Rate Impact (% change in F2030)	Lower	1.0%	1.1%	1.2%
Rate Impact (% change in F2041)	Lower	1.5%	1.9%	1.7%
Default Rate (Y/N)	No	No	No	Yes
Land and Water Impacts (Index)	Lower	2.7	2.2	2.6
Economic Development (provincial gross FTEs, annualized)	Higher	4,060	3,820	3,870

*These are not represented in dollars as they are a proxy for cost risk, not an assessment of financial risk.

Table 7-3 provides a consequence table outlining the trade-offs between three portfolios. Each portfolio consists of the Higher level of energy efficiency programs, and each suite of time-varying rates and supporting demand response programs are fixed at different levels. Finally, any remaining gap is filled by non-demand-side measure resources to complete a set of contrasting portfolios that meet our load-serving obligations.

7.4.1.2 What level of energy efficiency was chosen?

We have chosen the Base energy efficiency level for the near-term, ramping up to the Higher energy efficiency level over time, as described in section 7.2 and shown in section 7.3.

Our assessment is that:

- The lower cost, and lower land and water impacts of moving from a portfolio with No energy efficiency to one with Base energy efficiency is worth the incremental rate increase;
- Some level of energy efficiency programs is needed to provide the flexibility to ramp up energy efficiency efforts as needed;
- The lower cost, and lower land and water impacts of moving from a portfolio with Base energy efficiency to one with Higher energy efficiency is worth the incremental rate increase;
- Because load growth is uncertain, a staged approach – moving from Base energy efficiency to Higher energy efficiency, can take advantage of the flexibility of energy efficiency and allow us to minimize incremental rate impacts while in surplus and ramp up to the Higher energy efficiency as load growth in the Reference load forecast emerges;
- Moving to Higher Plus energy efficiency is not warranted at this time:
    - With their slow ramp up, the early years of Higher and Higher Plus show outcomes that are largely the same, meaning that there are neither substantial differences in target outcomes by fiscal 2030 nor substantial present value benefits over the same time period. This gives us additional flexibility to monitor and ramp up from Higher to Higher Plus in support of the Base Resource Plan or a Contingency Resource Plan as needed;
    - There is heightened under-delivery risk around the level of savings that will be achieved with Higher Plus as well as the expected PV benefits.[2] An analysis has shown the PV benefits of Higher Plus drop by roughly $600 million if the lower end of the range of savings is achieved;
    - Gaining experience with the Higher level of energy efficiency programs will provide operational experience which will inform our understanding of the uncertainty with Higher Plus levels and support a ramp up to Higher Plus levels when needed; and
    - Under currently expected load conditions, there are additional incremental rate increases associated with the Higher plus energy efficiency option.

Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:

- Input (Phase One) results showed strong support for our energy efficiency programs and for increasing those programs when needed. Public and customers', and Indigenous Nations' input indicates support for these programs because they keep costs down and limit land and water impacts by mitigating the need to build new infrastructure. BC Hydro was encouraged to consider accessibility issues, including the unique circumstances of Indigenous communities.
- Feedback (Phase Two) results from the public and customers showed broad alignment with their values and interests on this element. Indigenous feedback was mainly aligned with or neutral on this element of the plan. Similar to what we heard in Phase One, BC Hydro was encouraged to consider accessibility issues, including the unique circumstances of Indigenous communities.[3]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

2 This proxy measure of cost risk focuses on differences in fiscal 2030. The full timeline of savings shows that this downside is small in the early years when Higher and Higher Plus ramp slowly and track closely to each other. But the downside grows substantially larger for Higher Plus in the latter part of the plan as Higher Plus is moving to a level of savings at incentive levels well outside BC Hydro's experience.

3 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.2.1 Trade-offs in the consequence table

Table 7-3 shows that several of the objectives are in conflict when choosing the "best" level of rate suites and demand response programs and that these trade-offs are not simple. However, the range of modelled outcomes across the three options is relatively small, which increases the importance of other factors not included in the modelling when comparing options.

Table 7-3 shows that pursuing more savings via time-varying rates and demand response programs provides modest financial benefits.

Adopting Rate suite 3 and Demand Response Program B will yield financial savings and result in only a moderate rate increase from the "No rate suite" starting point. However, getting there would require imposing default rate structures, under which the time-varying rates are opt-out. In other words, the time-varying rates are voluntary, but customers would make a request to BC Hydro in order to not take service on a time-varying rate.

Through the consultation process some customers raised concerns with the concept of time-varying rates, expressing the concern they may unduly penalize those that cannot shift their electricity use. If an opt-out rate was implemented and customers did not have adequate knowledge about their choice to opt-out, or have the resources to understand whether or not a time-varying rate would increase or decrease their bill, then they may be unable to take appropriate action, and they may experience higher electricity bills. This would be counter to BC Hydro's planning objective of keeping costs down for customers.

The middle option, Rate suite 2 and Demand Response Program A, is an intermediate step between no changes and Rate suite 3 with Demand Response Program B. This intermediate step has smaller financial benefits compared to the larger change but avoids the use of Default time-varying rates.

Rate suite 2 and Demand Response Program A, by relying on opt-in time-varying rates, does represent the highest level of savings uncertainty. It also poses the largest rate increase to customers by the end of the planning horizon.

7.4.2.2 What time-varying rate and supporting demand response programs were chosen?

We have chosen Rate suite 2 with Demand Response Program A, as described in section 7.2 and shown in section 7.3.

Our assessment is that Rates suite 2 and Demand Response Program A:

- Allows BC Hydro and our customers to gain more experience in this area, which is relatively new to us, improving our ability to successfully implement more challenging options, as required, in response to future needs;
    - Relative to other electric utilities and other resource options, BC Hydro has little experience in the use of time-varying rates as a resource option. Advancing voluntary time-varying rates on an opt-in basis will allow BC Hydro to build capability and reduce uncertainty in the use of this resource option;
- Provides a platform to enable various electric vehicle peak reduction resource options (covered in the next section);
- Achieves the above benefits with no net cost and provides a modest financial benefit compared to the No rate, No demand response option;
- Avoids the potential customer concerns associated with implementing default (opt-out) time-of-use rates, justifying the modest foregone financial benefits associated with Rate suite 3 and Demand Response Program B;
- Can provide the same or greater product and service differentiation as the Default (opt-out) rates of Rate suite 3;

- Has the flexibility to be advanced in the sequence that best aligns with the timing of the need for capacity, the current state of knowledge regarding suitable pricing terms and conditions, and the expected level of customer interest.
  - For example, an opt-in residential time of use rate could be advanced earlier than other time-varying rates, given that an opt-in residential time of use rate would provide capacity in the South Coast where it is needed earliest, has broad customer support as demonstrated by consultation, and would benefit from well developed industry knowledge of appropriate pricing, terms and conditions given its widespread adoption by electric utilities across North America; and,
- Aligns with Section 44.1 of the *Utilities Commission Act* which indicates a clear policy preference for the priority use of cost-effective demand-side measures.

Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:

- Input (Phase One) results from results from the public and customers, and Indigenous Nations results, showed an overall openness and support for time-varying rates; however, concerns were raised about equity for customers who cannot take advantage of time-varying rates to lower their bills may be penalized.
- Input (Phase One) results showed an overall openness and support for demand response technologies; however, many participants were not familiar with these technologies and concerns were raised about data privacy.
- Feedback (Phase Two) results from the public and customers showed broad alignment with their values and interests on this element. Indigenous feedback was mainly aligned with or neutral on this element of the plan. Across both streams, there remained some concerns for customers who may be penalized because they were not able to shift their electricity use.[4]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

7.4.3 HOW THE ELECTRIC VEHICLE PEAK REDUCTION WAS SELECTED

With the level of energy efficiency, rate design, and supporting demand response programs in place, we next considered specific measures to target electric vehicle loads. Electric vehicle peak reduction options provide capacity benefits, with most of those benefits realized in the South Coast region. We analyzed each of the electric vehicle peak reduction options from section 5.3.2: No electric vehicle driver participation, 35 per cent electric vehicle driver participation, 50 per cent electric vehicle driver participation, and 75 per cent electric vehicle driver participation.

4 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback received by BC Hydro during the consultation process. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

Table 7-4 Consequence table of portfolios comparing levels of electric vehicle peak reduction

ABOUT THIS TABLE

Each column corresponds to a portfolio, or a bundle of resource options. Each portfolio was created by selecting a specific level of EV driver participation, combining this with the previously selected levels of energy efficiency, demand response, and rate suite, and then letting the optimization model fill in the rest of the resource choices. The table shows the consequences, or impacts, of these different portfolios on identified objectives and measures. Choosing one portfolio as a base of comparison against the alternatives lets us identify where a portfolio performs better or worse than the base for each objective (colour-coded for ease of reference).

Legend

- Blue: This portfolio is used as the basis of comparison
- Red: This alternative is worse than the base portfolio
- Green: This alternative is better than the base portfolio
- White: This alternative is roughly the same as the base portfolio

Planning Objective (measure)	EV driver participation portfolios				
	What is better	No EV driver Participation	35% EV driver Participation	50% EV driver Participation	75% EV driver Participation
Net Total Resource Cost ($M PV)	Lower	$650	$540	$500	$390
Net Utility Cost ($M PV)	Lower	$1,440	$1,320	$1,220	$1,220
Cost risk from DSM under-delivery* (MW below plan by 2030)	Lower	270	310	390	270
Cost risk from transmission schedule uncertainty* (year in service, Step 1)	Later	2033	2033	2034	2034
Cost risk from transmission schedule uncertainty* (year in service, Step 2)	Later	2038	2038	2039	>2042
Rate Impact (% change in F2030)	Lower	1.1%	1.1%	1.2%	1.3%
Rate Impact (% change in F2041)	Lower	1.9%	1.6%	1.6%	1.8%
Default Rate (Y/N)	No	No	No	No	Yes
Land and Water Impacts (Index)	Lower	2.2	2.6	2.2	2.6
Economic Development (provincial gross FTEs, annualized)	Higher	3,820	3,810	3,740	3,860

*These are not represented in dollars as they are a proxy for cost risk, not an assessment of financial risk.

Table 7-4 provides a consequence table outlining the trade-offs between portfolios where the level of energy efficiency programs, rates suites, and demand response are set at the solutions described in the previous sections. Then the electric vehicle peak reduction options are varied to create contrasting portfolios. Finally, any remaining gap is filled by non-demand-side measure resources to complete a set of contrasting portfolios that meet our load-serving obligations.

7.4.3.1 Trade-offs in the consequence table

Table 7-4 shows that higher levels of participation by electric vehicle drivers in voluntary residential time-varying rates to shift home charging demand to off-peak periods has portfolio cost benefits from a Net Total Resource Cost perspective. In addition, implementing some electric vehicle peak reduction also provides cost benefits from a Net Utility Cost perspective. However, the forecast cost differences amongst the three portfolios with electric vehicle rates are small enough to fall within the precision of the modelling estimates.

Increased participation also pushes out the required in-service date of Step 2 of the transmission upgrades to the South Coast. However, counting on higher levels of electric vehicle driver participation comes with large level of savings uncertainty, both in incremental and total portfolio terms.

We view the major trade-offs here to be the upside of portfolio cost reductions and the further delay of the need for the sequential steps of transmission upgrades to the South Coast, balanced against the increased savings uncertainty arising from a capacity resource that is relatively new to us, customers, and to electric utilities across North America.

7.4.3.2 What electric vehicle peak reduction option was chosen?

We have chosen the 50 per cent electric vehicle driver participation option, as described in section 7.2 and shown in section 7.3.

Our assessment is that:

- Higher participation levels for electric vehicle peak reduction result in lower portfolio costs;
- The 50 per cent electric vehicle driver participation option has portfolio cost benefits over the no participation option and the 35 per cent electric vehicle driver participation option with only a small increase in the relative risk of under-performance;
- There are practical barriers to achieving the 75 per cent electric vehicle driver participation.

Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:

- Electric vehicle peak reduction was not identified as a planning topic in Phase One, but was added for feedback in Phase Two.
- Feedback (Phase Two) results from the public and customers showed broad positive alignment of this element with their values and interests. Indigenous feedback was mainly neutral on this element of the plan.[5]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

5 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.4 HOW THE INDUSTRIAL LOAD CURTAILMENT PROGRAM WAS SELECTED

The Industrial Load Curtailment Program is a low-cost option to meet capacity needs compared to new supply-side capacity resources. For all the demand-side measures options modelled above, the System Optimizer selected Industrial Load Curtailment over other built capacity options whenever it was given the choice. The inference here is that the curtailment of industrial load is a lower cost solution than the other built capacity options not chosen.

Over and above the advantages it offered to the modelled Base Resource Plan solution, Industrial Load Curtailment Program can also be tailored to meet customers' needs, has greater curtailment period capability than other demand response programs and can be implemented quickly, and with relatively low risk, given BC Hydro's previous pilot activity in this area. No additional modelling was carried out on this question.

The detailed actions needed to be undertaken in the first five years of the planning period to support this aspect of the plan can be found in Chapter 9, Near-term Actions.

7.4.5 OUR APPROACH TO ELECTRICITY PURCHASE AGREEMENT RENEWALS

We focused on developing an approach for electricity purchase agreement renewals in the next five years leading up to the development of the next IRP. There are 19 clean or renewable projects, totaling approximately 900 GWh of annual energy, with electricity purchase agreements set to expire before April 1, 2026. There are two additional existing electricity purchase agreements, for the Island Generation and SEEGEN facilities, with contracts set to expire before April 1, 2026.[6]

We expect to have sufficient energy and capacity until the early 2030s with the demand-side measures outlined in the previous sections. Additional energy from electricity purchase agreement renewals would be surplus to domestic need for a period of time but may be required later in the 20-year planning period. However, since most of these projects are expected to have a low cost of service (because they have remaining asset life, have had time to pay off their fixed investments, and have low operating costs), we expect that they will want to continue operating and will be able to operate economically with market based prices in contracts. Contracts with the Independent Power Producers keep these facilities available for a situation in which the generation is required to meet domestic need.

Portfolio analysis demonstrated that longer-term contracts at market-based pricing that would be surplus to need in the near term would be cost-effective options for meeting longer-term requirements compared to meeting future load with new clean resources acquired at a later date. In particular, System Optimizer selected all available electricity purchase agreement renewals in the first five years of the modelling horizon over the purchase of new clean resources timed more closely to the emergence of need.[7]

To explore the cost effectiveness of the modelled Base Resource Plan solution for electricity purchase agreement renewals for the first five years, a more in-depth comparison was carried out where the following two portfolios were tested against the Reference Load Forecast:

- Renew all clean or renewable electricity purchase agreements during the first five years of the plan (up to 2026) for a term extending for 18 to 20 years based on the remaining asset life of the facility ("All renewals portfolio"); and
- Renew none of the larger clean or renewable electricity purchase agreements (those that provide greater than 50 GWh per year) during the first five years of the plan ("No renewals portfolio").

For these two approaches, the model was free to optimize to find a least-cost solution outside of these assumptions and the demand-side measure solutions described in previous sections. This included other electricity purchase agreement renewals (i.e., SEEGEN and electricity purchase agreements expiring after five years) and greenfield resources. Table 7-5 shows a comparison of the results of these two approaches.

6 SEEGEN is a municipal solid waste project located in Burnaby and owned by Metro Vancouver. A portion of the electricity from the SEEGEN facility is considered clean or renewable because a portion of the feedstock used to generate electricity is biogenic. Biogenic waste is a clean or renewable resource according to the Clean or Renewable Resource Regulation (B.C. Reg. 81/2011).

7 The modelling focused on the larger projects (i.e., greater than 50 GWh/yr) with System Optimizer being given the option of selecting them in coming up with a least cost portfolio. A number of smaller projects were assumed to be renewed in order to reduce modelling time and effort. Of the 19 clean or renewable projects with electricity purchase agreements expiring in the next five years, thirteen were included in this group of assumed electricity purchase agreements renewals making up ~275GWh/year. The remaining six projects were available for selection in System Optimizer.

Table 7-5 Consequence table of portfolios comparing electricity purchase agreement renewal options

ABOUT THIS TABLE

Each column corresponds to a portfolio, or a bundle of resource options. Each portfolio was created by selecting a specific level of EPA Renewal, and combining this with the previously selected levels of energy efficiency, demand repsonse, and rate suite, and electric vehicle peak reduction, and then letting the optimization model fill in the rest of the resource choices. The table shows the consequences, or impacts, of these different portfolios on identified objectives and measures. Choosing one portfolio as a base of comparison against the alternatives lets us identify where a portfolio performs better or worse than the base for each objective (colour-coded for ease of reference).

Legend

- (blue) This portfolio is used as the basis of comparison
- (red) This alternative is worse than the base portfolio
- (green) This alternative is better than the base portfolio
- (white) This alternative is roughly the same as the base portfolio

Planning Objective (measure)	What is better	No renewals portfolio	All renewals portfolio
Net Total Resource Cost ($M PV)	Lower	690	500
Cost risk from transmission schedule uncertainty* (year in service, Step 1)	Later	2034	2034
Cost risk from transmission schedule uncertainty* (year in service, Step 2)	Later	2039	2039
Land and Water Impacts (Index)	Lower	3.0	2.2
Economic Development (provincial gross FTEs, annualized)	Higher	3,780	3,660

*These are not represented in dollars as they are a proxy for cost risk, not an assessment of financial risk.

7.4.5.1 Trade-offs in the consequence table

The modelling shows that renewing all of the electricity purchase agreements over the first five years of the plan (for an assumed term of 18 to 20 years) is a lower-cost solution than renewing none of the electricity purchase agreements over that time period and then meeting system needs through least cost future generation options in later years.

A key assumption in the portfolio modelling is that we can renew all electricity purchase agreements at market prices and that the electricity purchase agreements can be renewed at this price for terms of 18 to 20 years. Both assumptions are uncertain because:

- Some independent power producers with expiring electricity purchase agreements in the next five years may choose not to renew their electricity purchase agreement; and
- For those independent power producers that choose to renew, the term of the renewals will be the subject of future discussions.

As a result, the analysis above serves as bookends on the potential value of the electricity purchase agreement renewal approach in the next five years based on the assumptions utilized.

BC Hydro notes that renewing these agreements now, even for shorter-term periods, provides us with greater certainty that the independent power producer facilities will continue to be available when needed to displace new greenfield supply. If we do not renew, these projects may be available later, but there is less certainty.

In terms of non-financial trade-offs, not renewing electricity purchase agreements in the first five years of the plan results in a greater need for greenfield generation in the long term that comes with additional gross employment across the province primarily driven by new construction. However, this also leads to an increase in land and water impacts.

7.4.5.2 Sensitivity analysis

We carried out additional sensitivity analysis to examine the implications of a decision to proceed with the All renewals portfolio and ending up in a situation where load or market prices are higher or lower than expected. Table 7-6 below provides the net total resource cost of both sensitivity portfolios. In Table 7-6 below, a lower value indicates a greater benefit.

Table 7-6 Comparing Electricity Purchase Agreement renewal options under various outcomes ($M, PV)

	No renewals portfolio	All renewals portfolio
Net Total Resource Cost ($M, PV)		
Reference load and mid market price	690	500
Sensitivity Analysis		
Reference load and low market price	1,110	890
Reference load and high market price	-460	-590
Accelerated electrification load and mid market price	8,830	8,560
Low load and mid market price	-7,660	-7,630

In Table 7-6, the Reference Load and mid-market price scenario indicates a $190M net benefit for the All renewals portfolio relative to the No renewals portfolio. The sensitivity analysis demonstrates the following:

- Under all but the Low load scenario, the All renewals portfolio has a lower cost relative to the No renewals portfolio;
- Under the Reference Load with a low market price, the net benefit of the All renewals portfolio increases a small amount. This is because the cost of electricity purchase agreement renewals that are tied to the market price become more favourable than the cost of alternative greenfield projects that need to be developed over the longer term.
- Under a Reference Load with a high market price, the net benefit of the All renewals portfolio decreases a small amount. This is because the cost of electricity purchase agreement renewals that are tied to the market price become less favourable than the cost of alternative greenfield projects that need to be developed over the longer term.
- The net benefit of the All renewals portfolio increases under the Accelerated electrification scenario as alternative greenfield resources are advanced in the No renewals portfolio relative to the timing in the reference load scenario.
- There is a small net cost of the All renewals portfolio in the Low load scenario as the electricity purchase agreement renewals increase the load resource balance surplus relative to the No renewals portfolio and result in lower valued market sales.

7.4.5.3 Our approach to renewing clean or renewable electricity purchase agreements

In order to maintain flexibility for the future and to limit cost-risk to ratepayers we have chosen to offer market-based pricing agreements to all 19 clean or renewable electricity purchase agreements expiring in the plan's first five years. This approach has the following key results:

- There are $190M in financial benefits to BC Hydro ratepayers;
- Using existing electricity purchase agreements to meet future load would reduce or avoid land and water footprint impacts arising from the construction of new generation and the associated transmission interconnections.
- Provided the electricity purchase agreement renewals are structured properly and are based on market prices that can adjust to market conditions, the cost risk to BC Hydro's customers in low market conditions and low load scenarios should be limited;
- Acquiring electricity purchase agreement renewals with market-based pricing now could provide significant benefits if load is higher than expected; and
- Electricity purchase agreement renewals result in less economic development due to a relative reduction in incremental construction activity.

Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:

- Input (Phase One) results from the public and customers showed an interest in keeping costs down and maintaining these facilities to meet future demand growth while prioritizing contracts that have Indigenous interests. Indigenous input emphasized the economic benefits associated with renewing electricity purchase agreements that have Indigenous participation. A number of participants indicated that renewing electricity purchase agreements would help limit land and water impacts by making use of existing facilities to meet future need.
- Feedback (Phase Two) results from the public and customers showed broad positive alignment of this element with their values and interests. Indigenous feedback was mainly aligned with or neutral on this element of the plan. Concerns were raised by stakeholder participants regarding the proposed market price-based approach. Indigenous participants sought incentives which would encourage Indigenous economic participation and/or benefits, including higher than market prices for renewals with Indigenous owned projects.[8]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

8 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.5.4 Our approach to renewing natural gas electricity purchase agreements

Two of the biggest sources of greenhouse gas emissions within our integrated system are the gas-fired independent power producer facilities: McMahon and Island Generation. The renewal of these contracts will be examined separately below.

As a gas cogeneration facility, the McMahon facility (located in the Peace region) operates as a baseload facility to meet neighbouring industrial requirements. With an installed capacity of 105 MW and a high capacity factor, this facility is the single largest source of greenhouse gas emissions on the system at about 340,000 tonnes of carbon dioxide equivalent (CO_2e) per year. The electricity purchase agreement with McMahon expires in fiscal 2030.

We ran two portfolios, each of which contained the demand-side measures identified previously. One allowed System Optimizer to select the remaining generation resources in an optimal (low-cost) manner. The second portfolio assumed McMahon is renewed in 2030. The portfolio with McMahon renewed in 2030 is roughly $100 million (PV) more expensive.[9]

Based on this result, McMahon is not assumed to be renewed in the applicable Load Resource Balances after fiscal 2030, and its renewal is not contemplated in the Base Resource Plan.

The 275 MW Island Generation facility (located on Vancouver Island in the South Coast region) operates as a dispatchable facility based on system requirements and market conditions. Generally, we operate the facility on an infrequent basis, which means that its greenhouse gas emissions (about 10,000 tonnes of carbon dioxide equivalent per year) are lower than a facility like McMahon. The electricity purchase agreement with Island Generation expires at the end of fiscal 2022.

In the past, we have had discussions with the owner of Island Generation – Capital Power – to understand potential terms of a long-term renewal. More recently, BC Hydro has been in discussions with Capital Power to determine if the Island Generation facility can provide additional economic back-up capacity and supply over the next two to four years while repairs are being made to the shore-end segments of some of our submarine cables that incurred some damage in July 2021.[10]

Despite these discussions, there is no basis, at this time, to assume that the electricity purchase agreement with this facility will be renewed. Accordingly, Island Generation is not assumed to be renewed in the Base Resource Plan. As the Load Resource Balances demonstrate, Island Generation is not required to meet system planning requirements. As discussions with the Island Generation counterparty are ongoing, no modelling results will be presented in the 2021 IRP.

While no input or feedback was asked about the renewal of any specific facility, input (Phase One) results from the public and customers showed a top priority ranking of the objective to reduce greenhouse gas emissions through clean electricity.

During the feedback phase (Phase Two), we heard concerns from the local community about not assuming Island Generation would be renewed, citing loss of jobs, community tax benefits, and reliability of the power supply for Vancouver Island.

9 Includes a $30M adjustment in relative costs for region-specific transmission required in the No McMahon portfolio. This assessment was performed outside of System Optimizer.

10 In July, BC Hydro detected oil leaks and buckling in the above-ground portions of some of its submarine cables, which extend from the Sunshine Coast to Vancouver Island. Initial repairs to the cables were completed by October 2021. However, additional work will likely be required over the next two to four years. BC Hydro expects to take the cables out of service for short periods of time to ensure that the repairs can be completed safely.

7.4.6 HOW THE UPGRADES TO THE TRANSMISSION SYSTEM WERE SELECTED

In section 5.5.1, we describe the three sequential steps of transmission upgrades developed and analyzed as options to serve the South Coast region. The transmission upgrade options were identified through detailed analysis of various portfolios. In all cases the transmission options are conceptual, and the required scope options will be refined in further transmission studies after the 2021 IRP is complete.

The portfolio analysis outlined in section 6.1 shows that these transmission upgrade options competed with other options to meet South Coast regional capacity needs (for example, pumped hydro storage, small storage hydro, and utility-scale batteries). In all cases, the first step of the transmission upgrades to the South Coast was selected for meeting these capacity needs. When given the option, the System Optimizer software almost always selected the second step of the transmission upgrades to the South Coast as part of the lowest cost portfolio to meet capacity needs on the South Coast.

The portfolio assembled as the Base Resource Plan is detailed in Attachment 1. The inference to be taken from System Optimizer's selections is that these first and second steps of the transmission upgrades to the South Coast, when selected, are the lowest cost solutions available.

In no cases was the third step selected by System Optimizer when creating portfolios to meet the Reference Load Forecast, as lower-cost solutions were available to meet system needs. Since the third step of the transmission upgrades to the South Coast requires more impactful greenfield developments, this outcome aligns with feedback from customers, the public and from Indigenous Nations who emphasized the importance of avoiding land and water impacts and keeping costs low. Accordingly, further analysis of strategies that included the third step as a way of meeting the Reference Load Forecast was not undertaken.

Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:

- Input (Phase One) results showed keeping costs down and limiting land and water impacts as a key priority for the public and customers. Many participants supported upgrading our system; however, participants also raised concerns if upgrades included new large transmission lines. Indigenous Nations input indicated a strong interest in limiting land and water impacts.
- Feedback (Phase Two) results showed broad positive alignment from the public and customers on this element with their values and interests. Indigenous feedback was mainly aligned with or neutral on this element of the plan.[11]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

11 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback received by BC Hydro during the consultation process. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.7 WHAT THE ROLE IS FOR EXISTING BC HYDRO GENERATING FACILITIES

We considered upgrades to existing BC Hydro facilities, as described in section 5.4.2, in conjunction with other sources of generation when building least cost portfolios to meet future customer needs. Of the potential upgrades of BC Hydro's generation facilities, a sixth unit at the Revelstoke Generating Station and the capacity upgrades at the G.M. Shrum facilities are two of the largest. However, neither was selected as part of a least-cost portfolio, and neither is included in the Base Resource Plan.

As described in section 5.4.2, six small plants will require end-of-life investment decisions within the planning horizon of the 2021 IRP. Our assessment is that:

- With the current energy surplus BC Hydro does not need to accelerate decisions on the future of its small plants. A later decision allows BC Hydro to respond, as required, based on future needs; and
- A staged approach provides an opportunity to align refurbishment with evolving load requirements and the extent to which BC Hydro's planned demand and supply-side resources perform as expected.

> **Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:**
>
> - Input (Phase One) results from the public and customers showed an interest in decommissioning, habitat restoration and keeping costs low, as well as focusing on newer, more viable options. Input also favoured evaluations being conducted on a facility-by-facility basis. Indigenous Nations input emphasized the need for consultation with the Nations where the specific facility is located. Indigenous interests could include decommissioning and restoring habitat or refurbishment and associated economic development opportunities.
> - Feedback (Phase Two) results showed positive or neutral alignment from the public and customers on this element with their values and interests. Indigenous feedback was mainly aligned with or neutral on this element of the plan. One Indigenous Nation was opposed to the proposed timeframe for addressing the future of the Alouette facility.[12]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

12 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.8 HOW FUTURE RESOURCES WERE CONSIDERED

The selected demand-side measures and other elements described above push out the need for new clean resources into the 2030's.

Under our current forecasts of technology capabilities and costs, preliminary modelling results suggest wind will be the predominant source of new energy supply in the Base Resource Plan from the second half of the planning horizon onwards. The remaining capacity needs could be met with different sources of new clean resources since specific location and size attributes play an important role in meeting regional capacity needs. While these assumptions were inputs into the System Optimizer modelling, when the need arises BC Hydro will choose from amongst a variety of types of supply options (developing new clean resources, renewing expiring electricity purchase agreements, and expanding BC Hydro generation assets) closer to the time they are required in order to benefit from more up-to-date cost and system information.

> **Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:**
>
> Input (Phase One) results from public and customers showed a strong interest in renewable power as well as customer generated distributed resources. Indigenous input showed a strong interest in new clean energy development opportunities.
>
> Feedback (Phase Two) results showed broad positive alignment from public and customers on this element with their values and interests. Similar to what we heard in Phase One, interest continued to focus on renewable power (wind and solar) and distributed generation opportunities. Indigenous feedback was mainly aligned with or neutral on this element of the plan, with a strong interest in Indigenous participation in clean energy development opportunities.[13]

As the need for new clean resources does not occur until the latter half of the planning horizon, BC Hydro does not anticipate any Near-term Actions related to this element of the Base Resource Plan.

7.4.9 WHY WE DON'T PURSUE MORE DEMAND DEMAND-SIDE MEASURES TO MEET ALL OF OUR FUTURE NEEDS

Sections 7.3.1 to 7.3.3 show that we can meet much of our future needs through demand-side measures. In particular, advancing the demand-side measures described in the Base Resource Plan will shift the date of system energy and capacity shortfalls from fiscal 2029 to fiscal 2030 and from fiscal 2032 to fiscal 2037, respectively, and shift the South Coast capacity shortfall from fiscal 2027 to fiscal 2032.

We did not choose the demand-side measure portfolios that would result in the highest energy and capacity savings level. On balance, our assessment is that the selected portfolios of demand-side measures represent a cost-effective way to meet future customer needs.

Our assessment is that pursuing more demand-side measures could:

- Increase bills for those not able to take advantage of energy efficiency programs;
- Default customers into opt-out time-varying rates that are not well-suited to them; and
- Increase the risk to ratepayers of demand-side measures under-delivering on their expected savings, leading BC Hydro to pursue quicker but more expensive options in response.

Our assessment of our chosen level of demand-side measures is that they:

- Provide time for BC Hydro to learn, and gain customer acceptance, which will reduce savings uncertainty and potentially improve ramp up rates to higher levels of savings if needed; and
- Leave us in a balanced, flexible position to increase or decrease savings, depending on future load conditions.

13 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback received by BC Hydro during the consultation process. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.10 HOW THE BASE RESOURCE PLAN MEETS OUR PLANNING OBJECTIVES

The planning objectives laid out in Section 2.3 are:

- Keeping costs down for customers;
- Reducing greenhouse gas emissions;
- Limiting land and water impacts; and
- Supporting the growth of B.C.'s economy.

The Base Resource Plan addresses these objectives in the following ways:

- Keeping costs down for customers: the Base Resource Plan positions us to meet load growth cost-effectively. It provides flexibility for a wide range of options upon which we then develop the Contingency Resource Plans. While the Base Resource Plan does not represent the lowest cost portfolio studied, it prudently allows BC Hydro to manage cost risk if load decreases or market prices decline. In addition, it reflects the input and feedback from our consultation process and provides opportunities for us to gain experience with time-varying rates and additional demand-side measures in order to ramp up quickly if load growth accelerates.
- Reducing greenhouse gas emissions: None of the Base Resource Plan elements would increase greenhouse gas emissions from our system, and, over time, these Base Resource Plan elements will allow us to reduce the greenhouse gas emissions associated with electricity generation. In addition, demand-side measures for electric vehicle charging will support the adoption of electric vehicles and reduce greenhouse gas emissions more broadly.
- Limiting land and water impacts: our Base Resource Plan relies on cost-effective demand-side measures to meet our customers growing needs; this avoids the land and water impacts of new generation and transmission projects. Where we do rely on additional generation, we will be looking to renew our agreements with existing power producers' projects; this will also avoid land and water impacts. Finally, we have focused on upgrades — as opposed to new lines — to increase transmission capabilities to the South Coast to once again minimize land and water impacts.
- Supporting the growth of B.C.'s economy: our analysis of the employment impacts arising from our portfolio choices shows that the options considered in the 2021 IRP do not have a significant impact at a provincial scale — positively or negatively. The main way we can support B.C.'s economy is by providing reliable, affordable, clean electricity to meet the needs of our customers.

7.5 2023 UPDATE

The Updated 2021 IRP focuses on being ready for the potential pace of change, emphasizing ranges rather than static targets for various plan elements to increase flexibility to respond to changing circumstances. In alignment with this approach, BC Hydro has removed the distinction between Near-term Actions associated with the Base Resource Plan and Near-term Actions associated with the Contingency Resource Plans. To support this presentation, the updates to the Base Resource Plan and Contingency Resource Plans are provided together in Section 8.6 of Chapter 8.

8

The Contingency Resource Plans: preparing for change

8.1 Introduction

Our Contingency Resource Plans set out our plans for scenarios other than the Reference Load Forecast. As outlined at the end of Chapter 7, the Base Resource Plan is a starting point for these contingencies that provides flexibility for both higher and lower load scenarios, alongside potential electricity supply challenges that could arise. The Base Resource Plan prudently allows for a wide range of options upon which we developed Contingency Resource Plans, ranging from a prolonged stagnation in electricity consumption that might occur from a 2008 like recession on the low side through to full implementation of federal and provincial climate action plans on the high side.

The analyses supporting the Contingency Resource Plans are not as extensive as those underpinning the Base Resource Plan. Given the uncertainty around the scenarios, our focus has been on developing plausible plans rather than optimizing the plans. The intent was to identify any necessary Near-term Actions required to prepare for each scenario.

With approval of the 2021 IRP by our Board of Directors, BC Hydro begins monitoring whether the IRP's Near-term Actions continue to be appropriate as the future unfolds. We will watch for signposts including updates to policies and legislation, deviations in our load forecast, and changes in our existing, committed and planned resources. As changes are identified and incorporated into our planning, we will determine whether the 2021 IRP's Near-term Actions to meet future demand remain enough to meet the projected future needs of our customers. We will take steps, guided by the Contingency Resource Plans to position BC Hydro to meet future customer demand while also managing costs. If the 2021 IRP's Near-term Actions are not enough, we will initiate the development of the next integrated resource plan.

The first signpost for the 2021 IRP has already arrived, in the form of the CleanBC Roadmap to 2030, released by the Provincial Government on October 25, 2021. BC Hydro will assess the implications of this announcement on future electricity demand and supply. We will also be watching for corresponding legislation, regulation, programs, and funding to implement the Roadmap.

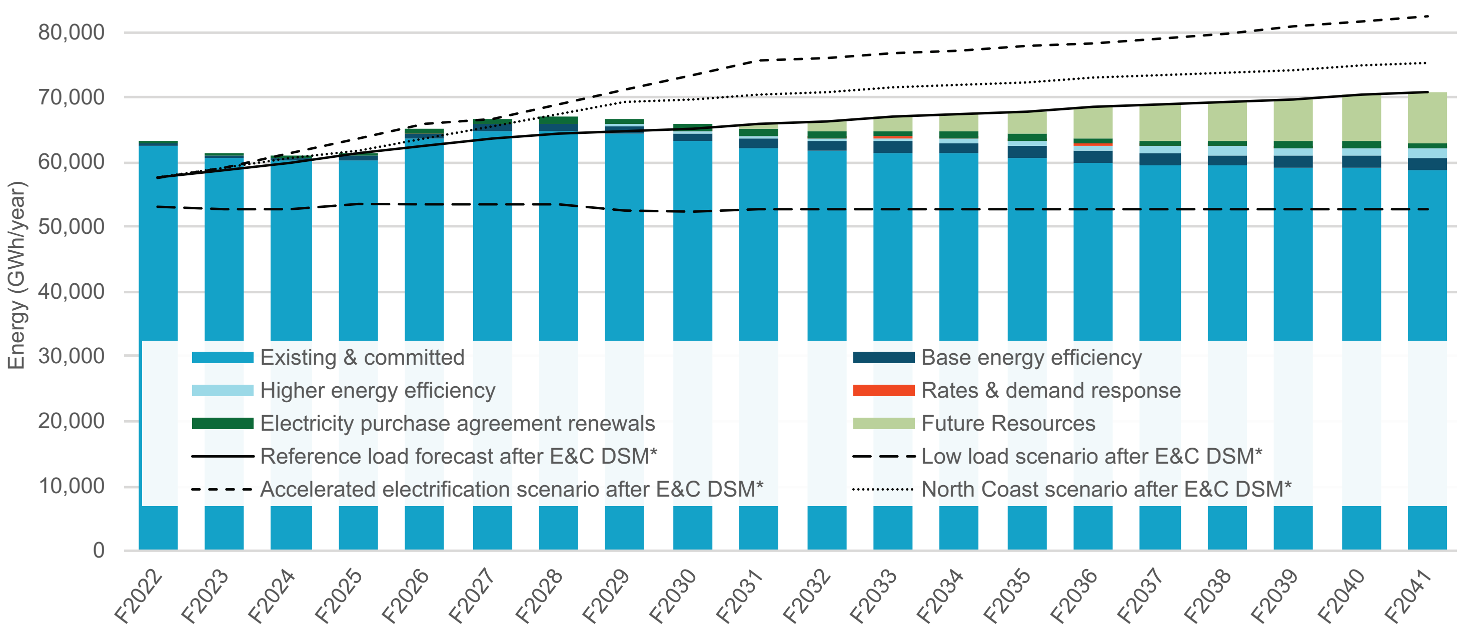
8.2 The contingency scenarios we are preparing for

We have developed four contingency scenarios for the 2021 IRP. These scenarios cover a broad range of potential future demand both above and below the Reference Load Forecast. In addition, they look into uncertainties at the system and regional level, particularly in the South and North Coast regions, where potential supply constraints might arise:

- Accelerated electrification load scenario represents a case where load grows rapidly. It looks at the demand that could arise from BC Hydro's Electrification Plan and electricity demand from actions to meet the Province's 2025, 2030, and 2040 greenhouse gas reduction targets. This scenario examines significant load growth in the South Coast region.
- Accelerated electrification load scenario with under-delivery of the Base Resource Plan's rates and demand-side measures programs is a variation of the Accelerated electrification scenario and looks at a situation in which our demand-side measures efforts underperform at the same time as the Accelerated electrification scenario is unfolding.
- Low load forecast (Low load scenario) looks at a situation where demand drops somewhat and then stagnates throughout the planning period.
- North Coast liquified natural gas & mining load scenario looks at the possibility of significant industrial activity in that region.

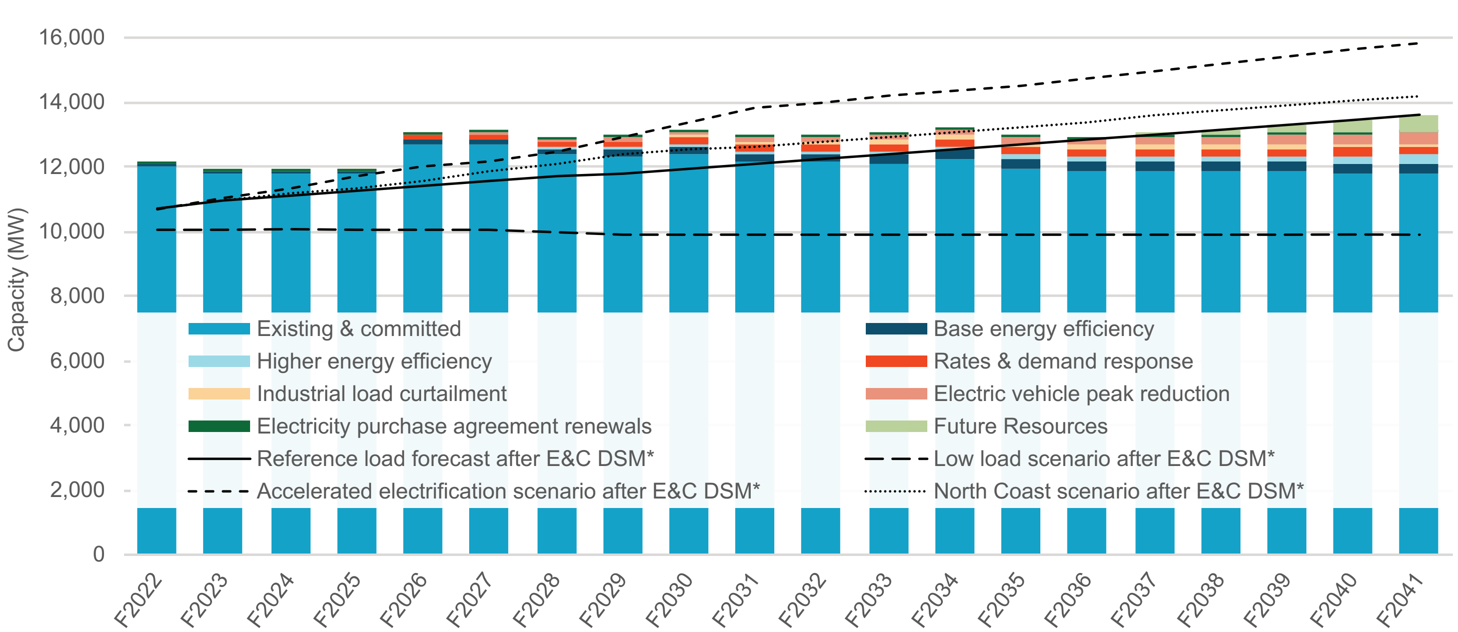
Figures 8-1 and 8-2 show system-level views of the energy and capacity outlook for the contingency scenarios, while Figures 8-3 and 8-4 show the outlook for the South Coast and North Coast regions, respectively.

Figure 8–1 System energy Load Resource Balance with Base Resource Plan and contingency scenarios



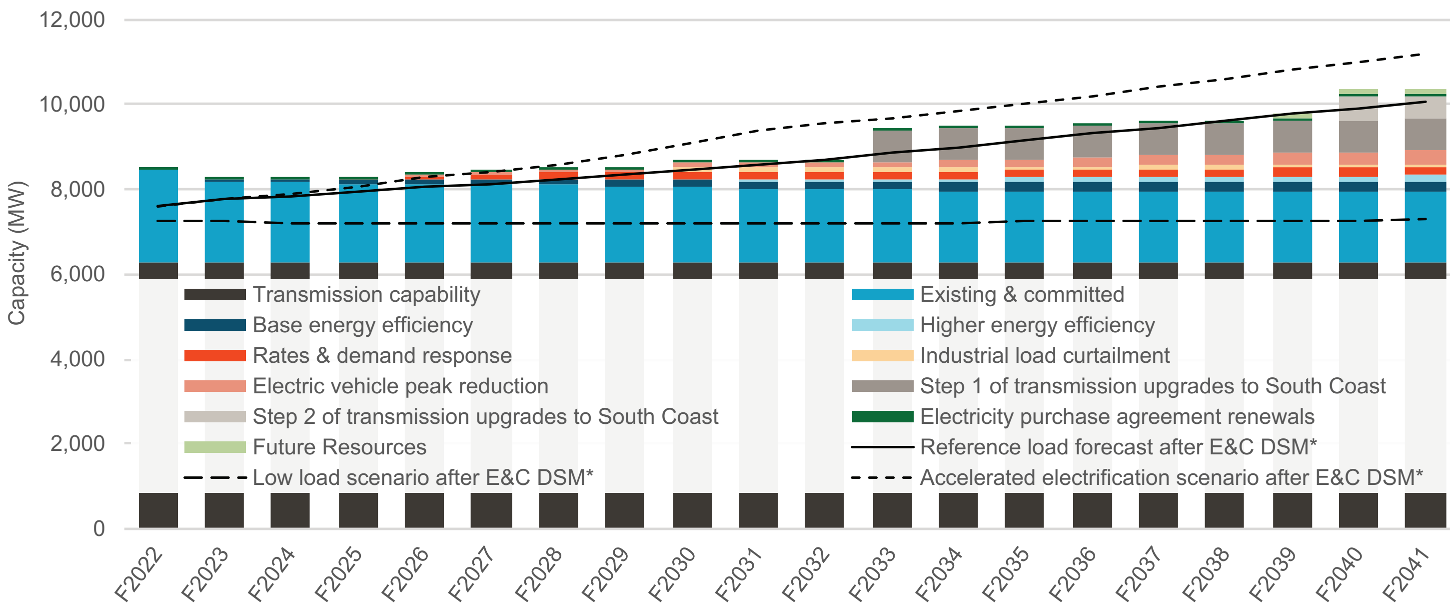
* E&C DSM denotes existing and committed demand-side measures

Figure 8–2 System capacity Load Resource Balance with Base Resource Plan and contingency scenarios



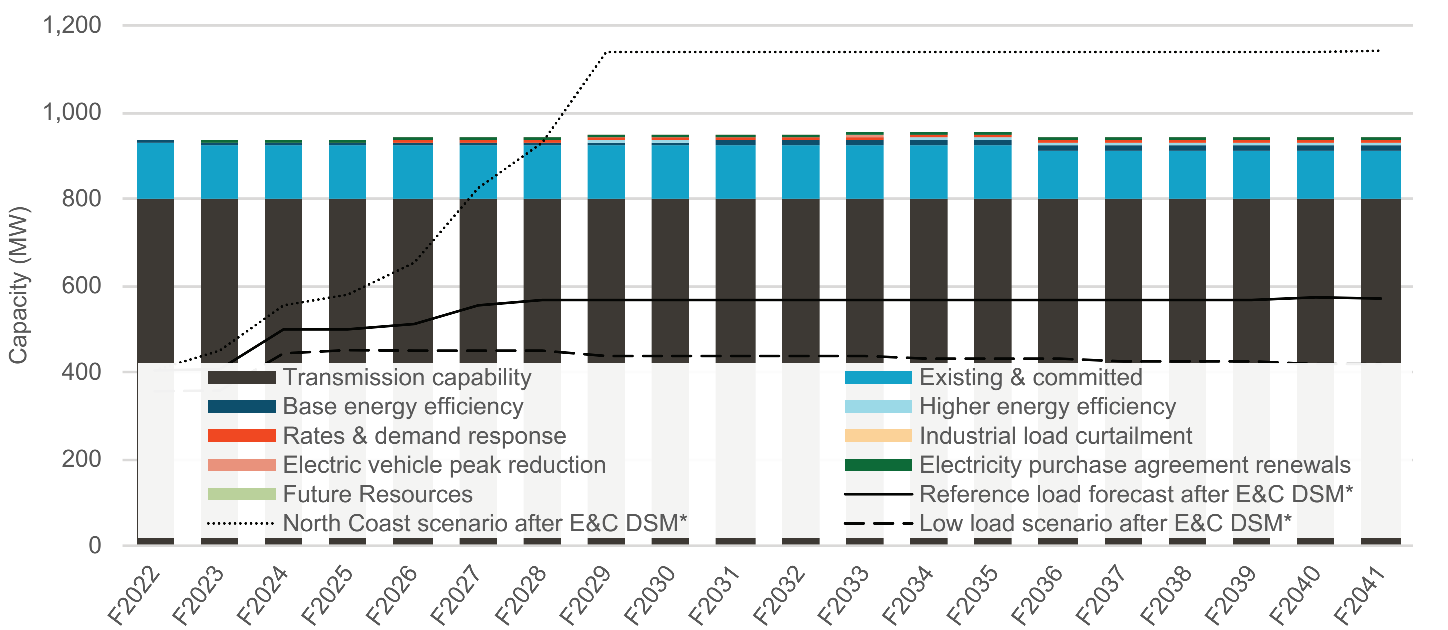
* E&C DSM denotes existing and committed demand-side measures

Figure 8-3 South Coast region capacity Load Resource Balance with Base Resource Plan and contingency scenarios



* E&C DSM denotes existing and committed demand-side measures

Figure 8-4 North Coast region capacity Load Resource Balance with Base Resource Plan and contingency scenarios



* E&C DSM denotes existing and committed demand-side measures

8.3 Accelerated electrification scenario

The Accelerated electrification scenario assumes a full realization of the load growth in the Electrification Plan and that the Province moves forward with the development and implementation of a plan to fully meet Provincial greenhouse gas reduction targets in 2025, 2030, and 2040.[1] In addition, this scenario assumes that downside risks to the Reference Load Forecast do not materialize.

This scenario has load impacts almost immediately across the province, both in the South Coast, where our main load centre is, and elsewhere in the province, where the natural gas sector would be expected to electrify.

If there is rapid growth in electricity use consistent with this scenario, BC Hydro will initiate processes to draw on future resources in the Base Resource Plan earlier than planned and will rely on temporary supply of market energy to meet near-term needs. The following illustrative elements of this Contingency Resource Plan demonstrate the resources needed to meet this higher load growth scenario in the timeframe and volume required.[2]

- Ramping-up from base to higher levels of energy efficiency programs to achieve approximately 2,080 GWh/year of energy savings and approximately 380 MW of capacity savings at the system level by fiscal 2030;
- Implementing voluntary time-varying rates and supporting programs to achieve approximately 320 MW of capacity savings at the system level by fiscal 2030;[3,4]
- Implementing electric vehicle peak reduction initiatives to achieve 75 per cent electric vehicle driver participation and approximately 170 MW of capacity savings by fiscal 2030;
- Initiating processes to renew electricity purchase agreements expiring in the next five years to provide approximately 900 GWh/year of energy supply by fiscal 2030;[5]
- Advance the first step of sequential upgrades to transmission infrastructure into the South Coast region, including series compensation, shunt capacitors, and thermal upgrades by fiscal 2033 and prepare to initiate a second step of upgrades to the South Coast region by fiscal 2039;
- Initiating processes to acquire future resources to achieve approximately 7,100 GWh/year of energy supply and approximately 400 MW of capacity at the system level by fiscal 2030. These future resources would be selected from expiring electricity purchase agreements with independent power producers and new clean and renewable energy resources;
- Implementing BC Hydro facility upgrades at Revelstoke, G.M. Shrum, and Wahleach in the later years of the IRP period to achieve 530 MW of capacity at the system level by fiscal 2038;
- Temporarily bridging load with market supply of up to 2,000 GWh/year of energy for a total of five years; and
- Advancing utility-scale batteries, with the first units installed in fiscal 2029, ramping up to provide approximately 480 MW of additional dependable capacity by fiscal 2032.

> A broad theme of the public and customers' consultation was interest in electrification and climate action, including how the 2021 IRP would adequately prepare us for meeting Provincial greenhouse gas reduction targets.

1 The Accelerated Electrification scenario in the final 2021 Integrated Resource Plan has been updated to assume the full realization of the load growth in the Electrification Plan and that the Province moves forward with the development and implementation of a plan to fully meet Provincial greenhouse gas reduction targets in 2025, 2030, and 2040. This scenario also assumes that downside risks to the Reference Load Forecast do not materialize.

2 Energy and capacity additions are described here as incremental to existing and committed resources rather than as incremental to the Base Resource Plan.

3 This element entails the same level of effort as the corresponding element in the Base Resource Plan.

4 Supporting programs include demand response and load curtailment initiatives.

5 This element is the same as the corresponding element in the Base Resource Plan.

8.3.1 ACCELERATED ELECTRIFICATION – DEMAND-SIDE MEASURES UNDER-DELIVERY SCENARIO

The Accelerated electrification – demand-side measures under-delivery scenario is the most challenging scenario with a near-term need for system energy and the medium-term need for capacity in the South Coast region. It combines the load growth of the Accelerated electrification scenario with a reduction in the delivered savings from demand-side measures. To develop this scenario demand-side measures savings forecasts were split into a "mid-level", a "low level", and a "high level". Demand-side measures under-performance is when all demand-side measures perform at the "low level", and was the level used in this scenario.

The rapid changes in load and the diminished success of demand-side measures that define this scenario would provide early signposts indicating that additional actions are required to meet the future load. If there are indications that this scenario is being realized, BC Hydro will initiate processes to draw on future resources in the Base Resource Plan earlier than planned and rely on temporary supply of market energy to meet near-term needs. The following illustrative elements of this Contingency Resource Plan demonstrate the future resources needed to meet this higher load growth scenario in the timeframe and volume required.[6]

- Adjusting our energy efficiency programs and program designs to achieve approximately 1,300 GWh/year of energy savings and approximately 230 MW of capacity savings by fiscal 2030, based on learnings from the under-delivery of previous initiatives;
- Adjusting our voluntary time-varying rates and/or supporting programs to achieve 100 MW of capacity savings at the system level by fiscal 2030, based on learnings from recent performance;[7,8]
- Implementing electric vehicle peak reduction initiatives to achieve 75 per cent electric vehicle driver participation and approximately 170 MW of capacity savings by fiscal 2030;
- Initiating processes to renew electricity purchase agreements expiring in the next five years to provide approximately 900 GWh/year of energy supply by fiscal 2030;[9]
- Initiating processes to acquire future resources to achieve approximately 6,000 GWh/year of energy supply and approximately 380 MW of capacity supply at the system level by fiscal 2030. These future resources would be selected from expiring electricity purchase agreements with independent power producers and new clean and renewable energy resources;
- Advance the first step of sequential upgrades to transmission infrastructure into the South Coast region, including series compensation, shunt capacitors, and thermal upgrades by fiscal 2033 and prepare to initiate a second step of upgrades to the South Coast region by fiscal 2038;
- Implementing BC Hydro facility upgrades at Revelstoke, G.M. Shrum, and Wahleach in the later years of the IRP period to achieve 530 MW of capacity at the system level by fiscal 2038;
- Temporarily bridging load with market supply of up to 2,000 GWh/year of energy for a total of six years; and,
- Advancing utility-scale batteries, with the first units installed in fiscal 2028, ramping to approximately 800 MW of additional capacity by fiscal 2032.[10]

This Contingency Resource Plan requires future resources that provide capacity to the South Coast. The capacity need in this scenario has two defining characteristics: early (as soon as fiscal 2028) and large (nearly 800 MW in fiscal 2032). Utility-scale batteries are uniquely suited to meet some or all of this need due to the technology's short lead times and scalability.

6 Energy and capacity additions are described here as incremental to existing and committed resources rather than as incremental to the Base Resource Plan.
7 This illustrative element entails the same level of effort as the corresponding element in the Base Resource Plan, but with a lower level of achieved capacity savings due to the assumed demand-side measures under-delivery in this scenario.
8 Supporting programs include demand response and load curtailment initiatives.
9 This element is the same as the corresponding element in the Base Resource Plan.
10 The volume of batteries required will depend on the nature and capacity contribution from the future resources. In this illustration, future resources have been assumed to be wind that provides a relatively small amount of capacity contribution.

Utility-scale battery resources are a relatively new technology within the utility sector and a novel technology at this scale within the BC Hydro system. Therefore, in order to include utility-scale batteries as a viable option for Contingency Resource Plans, the 2021 IRP includes a Near-term Action that will allow BC Hydro to explore integration and operationalization of utility-scale batteries. This Near-term Action is an effective way to:

- De-risk the schedule of implementing utility-scale batteries, which are an important element of the Accelerated electrification – demand-side measures under-delivery scenario Contingency Resource Plan; and
- Gain experience integrating the operations of utility-scale batteries into our grid.

> **Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:**
>
> - Input (Phase One) results from the public and customers showed support for the use of utility-scale batteries. Indigenous Nations input showed openness for new power sources such as batteries and stated BC Hydro should be working with local Nations to develop opportunities for Indigenous partnerships. Both streams raised some environmental concerns about their production and disposal.
> - Feedback (Phase Two) results from the public and customers showed broad positive alignment of this element with their values and interests. Overall, feedback from Indigenous participants was supportive or neutral of this element. Participants across both streams expressed some concerns over environmental impacts. Interest in Indigenous economic opportunities were also expressed.[11]

8.4 Low load scenario

The Low load scenario assumes lower economic growth and resource sector development relative to the Reference Load Forecast, combined with lower light-duty electric vehicle penetration rates and lower industrial electrification uptake. This scenario also assumes long-term structural changes occur in the B.C. economy that reduce electricity consumption. These changes could result from several factors, including the way people interact and approach economic activities after the COVID-19 pandemic ends, and reduced industrial load in the province.

The decline in load across multiple sectors in this scenario would provide an early signpost that the Near-term Actions described in the Base Resource Plan should be deferred for an indefinite period or discontinued. The Base Resource Plan, as we have constructed it, allows for significant flexibility in response to this type of scenario because of its priority on demand-side measures. The Low load scenario Contingency Resource Plan elements are described below in terms of adjustments to the Base Resource Plan.

- Defer the implementation of Higher energy efficiency programs;
- Defer implementation of new voluntary time-varying rates and supporting programs, and scale back efforts to enroll and support customer response to any time-varying rates already implemented;
- Scale back efforts to enroll customers and support customer response to electric vehicle peak reduction initiatives;
- Defer implementation of the Industrial Load Curtailment Program;
- Discontinue offers to renew electricity purchase agreements past fiscal 2026; and
- Defer the first step of sequential upgrades to transmission infrastructure into the South Coast region and the initiation of the second step of transmission upgrades.

11 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback. For detailed summaries of what we heard and how we considered the input and feedback, please see bchydro.com/cleanpower2040.

8.5 North Coast liquified natural gas and mining scenario

The North Coast region in northwestern B.C. is connected to the rest of the BC Hydro system via a 450 km single radial 500 kilovolt transmission line from Prince George to Terrace. The North Coast region poses unique planning challenges due to its remote location, large range of load potential, and limited local clean or renewable capacity resources.

The North Coast liquified natural gas and mining scenario considers potential liquified natural gas and mining loads that may materialize in the North Coast over and above the Reference Load Forecast. The scenario assumes several of the proposed mines and liquified natural gas facilities in the region proceed into operation within the next decade. These loads increase the system need for energy and capacity in the first decade of the 2021 IRP relative to the Reference Load Forecast, but do so to a lesser extent than the Accelerated electrification scenario. In this scenario, the North Coast region sees a rapid increase in the need for capacity relative to the Reference Load Forecast, with the need reaching a plateau by fiscal 2029. Final investment decisions by project proponents would provide strong signposts to indicate that this scenario is unfolding. At that time, BC Hydro will initiate processes to draw on future resources earlier than indicated in the Base Resource Plan and rely on a temporary supply of market energy to meet near-term needs at the system level.

The rapid load growth in the North Coast exceeds the region's existing and committed capacity resources. As mentioned, there are few local resources that could meet these needs. Higher demand-side measures or new local generation resources are not likely to be available at the volume or within the timeframe that this scenario requires. In addition, utility-scale batteries and pumped hydro storage systems are ill-suited to support the operations of the new industrial loads that operate nearly 24-hours per day.

The Prince George to Terrace Capacitor Project (PGTC Project) is an existing project first initiated in 2012 and represents a cost-effective means of delivering capacity to the North Coast region. It has been the subject of extensive and continuing consultation for several years. The project will provide sufficient capacity to the region and can be in-service as early as fiscal 2028. The need and feasibility of the PGTC Project has already been determined and it is now in the detailed design phase. The PGTC Project anticipates early construction work beginning in early 2023. To meet the rapid increase in load described in this scenario, the 2021 IRP includes a Near-term Action that reflects the continuation of PGTC Project and its earliest in-service date of fiscal 2028. This will ensure that we are able meet the potential demand under this scenario for liquified natural gas initiatives, mines, and other customers on a timeline that aligns with their investment decisions and project in-service dates.

The following illustrative set of elements for this Contingency Resource Plan demonstrate that there are adequate future resources to meet this higher load growth scenario in the timeframe and at the volume required.[12]

- Ramping-up from base to higher levels of energy efficiency programs to achieve approximately 1,700 GWh/year of energy savings and approximately 280 MW of capacity savings at the system level by fiscal 2030;[13]
- Implementing voluntary time-varying rates and supporting programs to achieve approximately 310 MW of capacity savings at the system level by fiscal 2030;[14,15]
- Implementing electric vehicle peak reduction initiatives to achieve 50 per cent electric vehicle driver participation and approximately 100 MW of capacity savings by fiscal 2030;[16]
- Initiating processes to renew electricity purchase agreements expiring in the next five years to provide 900 GWh/year of energy supply by fiscal 2030;[17]
- Continue to advance the Prince George to Terrace Capacitor Project to maintain its earliest in-service date of fiscal 2028;
- Initiating processes to acquire future resources to achieve approximately 4,100 GWh/year of energy supply and approximately 340 MW of capacity at the system level by fiscal 2030. These future resources would be selected from expiring electricity purchase agreements with independent power producers and/or new clean and renewable energy resources; and
- Temporarily bridging load with market supply of up to 2,000 GWh/year of energy for two years (fiscal 2025 and fiscal 2028).

During consultation, the First Nations Climate Initiative and the First Nations Major Projects Coalition raised an interest in proactively advancing transmission infrastructure to the North Coast to facilitate low-carbon economic development opportunities in the region.

12 Energy and capacity additions are here described as incremental to existing and committed resources rather than as incremental to the Base Resource Plan.
13 This illustrative element is the same as the corresponding element in the Base Resource Plan.
14 This element entails the same level of effort as the corresponding element in the Base Resource Plan.
15 Supporting programs include demand response and load curtailment initiatives.
16 This illustrative element is the same as the corresponding element in the Base Resource Plan.
17 This illustrative element is the same as the corresponding element in the Base Resource Plan.

8.6 2023 UPDATE

The updates to the Base Resource Plan and Contingency Resource Plans include:

- Accelerating the ramp-up of energy efficiency programs;
- Accelerating the ramp-up of demand-response programs and industrial load curtailment;
- Extending our assumptions regarding electricity purchase agreement renewals past fiscal 2026;
- Acquiring new clean or renewable energy resources from greenfield projects as well as from existing facilities; and
- Accelerating utility-scale battery projects.

We have set ranges rather than static targets for various plan elements to increase flexibility to respond to changing circumstances.

The Updated 2021 IRP element for energy efficiency is to:

- Advance the ramp-up from Base Energy Efficiency to Higher Energy Efficiency to achieve approximately 1800 GWh/year of energy savings and 300 MW of capacity savings by fiscal 2030 while maintaining the option to ramp up to Higher Plus Energy Efficiency in future years to achieve approximately 1,950 GWh/year of energy savings and 350 MW of capacity savings by fiscal 2030. Retain the flexibility to ramp up or ramp down based on future need within an overall energy savings range of 1,250 GWh/year to 2,000 GWh/year by fiscal 2030 and an overall capacity savings range of 200 MW to 350 MW by fiscal 2030.

The Updated 2021 IRP element for time-varying rates and demand response programs is to:

- Pursue voluntary time-varying rates supported by demand response programs to achieve up to approximately 220 MW of capacity savings at the system level by fiscal 2030.
- Advance the timing of the implementation of programs, technology and product offers for customers to facilitate an earlier understanding of the achievable capacity savings and to maintain the flexibility to ramp up in response to future needs.
- Advance industrial load curtailment to achieve up to approximately 100 MW of incremental capacity savings at the system level as early as fiscal 2025.
- Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers to support a voluntary residential time-of-use rate to shift home charging by 50 to 75 % of residential electric vehicle drivers to off-peak demand periods to achieve up to approximately 170 MW of capacity savings at the system level by fiscal 2030, with a planned amount of 100 MW by fiscal 2030.

The Updated 2021 IRP element for Electricity Purchase Agreement Renewals is 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.
- Renew agreements with existing clean or renewable independent power producers that have electricity purchase agreements expiring after April 1, 2026 on a cost-effective basis, which may include continuing market-priced based renewal offers.

The Updated 2021 IRP adds a new element with regard to the Acquisition of New Clean Energy Resources:

- Acquire approximately 3,000 GWh of new clean or renewable energy from greenfield facilities in the province able to achieve commercial operation as early as fiscal 2029 and approximately 700 GWh of new clean or renewable energy from existing facilities prior to fiscal 2029. The timing, volume, and the period across which projects are required to be in service will be adjusted, as required, based on future need.

8.6 2023 UPDATE

BC Hydro estimates there is approximately 700 GWh per year of new clean or renewable energy available from existing facilities that are already connected to the BC Hydro system but that are not selling this additional energy to BC Hydro. We plan to seek to acquire energy from these existing facilities within the next several years and, provided that such acquisitions can be achieved at cost-effective pricing, expect such resources would be available prior to fiscal 2029. We anticipate that the acquisition of new clean energy from these existing facilities would be through a process of bilateral negotiations with individual independent power producers. Each executed Electricity Purchase Agreement would be filed under section 71 of the Utilities Commission Act.

Even with this additional new energy from existing independent power producer facilities, there is still a need for new energy from greenfield facilities as early as fiscal 2029. There are a number of other factors that may impact the required volume of energy to acquire from greenfield facilities including:

- Uncertainty associated with the volume of new energy that we may be able to acquire from existing facilities;
- Uncertainty associated with the volume of electricity purchase agreements that can be renewed cost-effectively; and
- Uncertainty that is generally associated with forecasts for existing, committed and planned supply resources.

In BC Hydro's view, acquiring approximately 3,000 GWh per year from greenfield facilities able to achieve commercial operation as early as fiscal 2029 is reasonable. At these planned volumes, BC Hydro would be:

- In an energy surplus position of greater than 1,000 GWh per year for two years under the April 2023 Reference Load Forecast before returning to a relatively balanced position, with an energy surplus of less than 1,000 GWh per year; and
- Positioned to meet the potential electrification load associated with the Government of B.C.'s greenhouse gas reduction targets, as represented by the Accelerated electrification load scenario, with a small surplus in fiscal 2029. The need for subsequent acquisitions of new clean energy from greenfield facilities would be informed through BC Hydro's "living" long-term resource planning cycle, starting with the 2025 Long-Term Resource Plan.

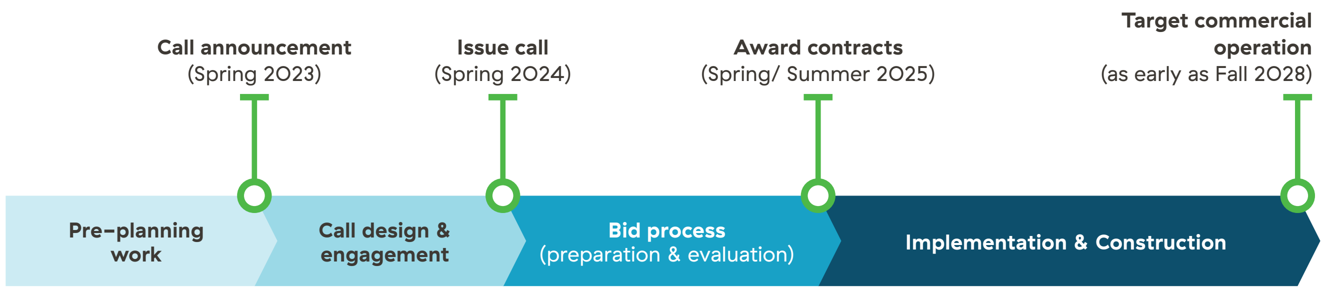
8.6 2023 UPDATE

In a scenario where there is under-delivery from planned DSM resources and load is higher, consistent with the 2023 Accelerated electrification load scenario with DSM Under-delivery scenario, BC Hydro could be in a deficit position; however, in such a scenario, BC Hydro could rely on the potential use of market imports as a temporary bridge until the next domestic resources become available.

Planning to acquire approximately 3,000 GWh per year from greenfield facilities able to achieve commercial operation as early as fiscal 2029 considers the lead time associated with the development of these resources. The forecast of the expected lead time for new wind projects remains within the range of five to seven years, consistent with the initial assumptions in the 2021 IRP. Although there is uncertainty regarding the number of projects that could be available at the lower end of that range, should an incremental need materialize, it could be met through the potential use of market imports as a temporary bridge until additional new clean energy resources are available to BC Hydro.

The figure below provides a high-level visual timeline showing the acquisition process for new energy from greenfield facilities, including pre-planning work initiated during the past year. This timeline also demonstrates how the estimated lead time for new greenfield resources aligns with having new projects on-line and operating as early as fiscal 2029 (i.e., Fall 2028 as shown below).

Figure 8.6-1 Visual timeline of acquisition of new clean clean or renewable from greenfield facilities



The Updated 2021 IRP element for utility-scale battery projects is to:

- Advance utility-scale batteries to enable BC Hydro to achieve approximately 50 MW of additional capacity as early as fiscal 2027 and up to 500 MW of additional capacity by fiscal 2030.

9

Near-term Actions

9.1 Introduction 2023 UPDATE

BC Hydro is taking steps to implement the elements of the Updated 2021 IRP. These steps are called Near-term Actions and are provided below.

Category	Updated 2021 IRP Element	Near-term Actions
Demand-side measures	Advance the ramp up from Base Energy Efficiency to Higher Energy Efficiency to achieve approximately 1,800 GWh/year of energy savings and 300 MW of capacity savings by fiscal 2030 while maintaining the option to ramp up to Higher Plus Energy Efficiency in future years to achieve approximately 1,950 GWh/year of energy savings and 350 MW of capacity savings by fiscal 2030. Retain the flexibility to ramp up or ramp down based on future need within an overall energy savings range of 1,250 GWh/year to 2,000 GWh/year by fiscal 2030 and an overall capacity savings range of 200 MW to 350 MW by fiscal 2030.	In August 2021, BC Hydro filed its fiscal 2023 to 2025 Demand-side Measures Expenditure Request with the BCUC to seek acceptance of the expenditures over that period to achieve the targeted savings. In April 2023, the Commission accepted this expenditure request pursuant to Order G-91-23. The advancement of activities will result in adjustments to the accepted DSM expenditures for fiscal 2024 and fiscal 2025, which will likely exceed the limits of the established DSM funding transfer rules. In fiscal 2024 BC Hydro will submit a proposal for changes to the transfer rules for the BCUC to consider, which may allow for the increase in fiscal 2024 expenditures. Revised DSM expenditures for fiscal 2025 will be filed for acceptance with the BCUC, along with expenditures for years beyond fiscal 2025, in our next DSM Expenditure Request.

Category	Updated 2021 IRP Element	Near-term Actions
Demand-side measures	Pursue voluntary time-varying rates supported by demand response programs to achieve up to approximately 220 MW of capacity savings at the system level by fiscal 2030. Advance the timing of the implementation of programs, technology and product offers for customers to facilitate an earlier understanding of the achievable capacity savings and to maintain the flexibility to ramp up in response to future needs. Advance industrial load curtailment to achieve up to approximately 100 MW of incremental capacity savings at the system level as early as fiscal 2025. Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers to support a voluntary residential time-of-use rate to shift home charging by 50 to 75 per cent of residential electric vehicle drivers to off-peak demand periods to achieve up to approximately 170 MW of capacity savings at the system level by fiscal 2030, with a planned amount of 100 MW by fiscal 2030.	In August 2021, BC Hydro filed its fiscal 2023 to 2025 Demand-side Measures Expenditure Request with the BCUC to seek acceptance of the expenditures over that period to achieve the targeted savings. In April 2023, the Commission accepted this expenditure request pursuant to Order G-91-23. The advancement of activities will result in adjustments to the accepted DSM expenditures for fiscal 2024 and fiscal 2025, which will likely exceed the limits of the established DSM funding transfer rules. In fiscal 2024 BC Hydro will submit a proposal for changes to the transfer rules for the BCUC to consider, which may allow for the increase in fiscal 2024 expenditures. Revised DSM expenditures for fiscal 2025 will be filed for acceptance with the BCUC, along with expenditures for years beyond fiscal 2025, in our next DSM Expenditure Request. In February 2023, BC Hydro filed a Residential Optional Time-of-Use Rates Application. The application seeks BCUC approval to offer an optional residential time of use rate to achieve approximately 45 MW to 300 MW of capacity savings at the system level by fiscal 2030, with an expected savings of 100 MW. BC Hydro will put forward additional optional rate applications in future years to achieve the fiscal 2030 capacity savings target. BC Hydro will initiate consultation on industrial load curtailment with customers in fiscal 2024. This will include considering whether industrial load curtailment should be a program or a rate.

Category	Updated 2021 IRP Element	Near-term Actions
Electricity Purchase Agreements	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. Renew existing clean or renewable independent power producers with electricity purchase agreements expiring after April 1, 2026 on a cost-effective basis, which may include continuing market-priced based renewal offers.	To-date, BC Hydro has executed six long term Electricity Purchase Agreements, representing approximately two-thirds of the total volume available from the 19 Electricity Purchase Agreements set to expire prior to April 1, 2026. The first two of these Electricity Purchase Agreements, for the Sechelt Creek Run-of-River Hydroelectric Project and the Brown Lake Hydroelectric Project, were filed with the Commission pursuant to section 71 of the *Utilities Commission Act* on May 1, 2023. BC Hydro will be filing an additional four Electricity Purchase Agreements later this summer. All electricity purchase agreements will be filed pursuant to section 71 of the *Utilities Commission Act* as they are renewed.
Energy Acquisitions	Acquire approximately 3,000 GWh of new clean or renewable energy from greenfield facilities in the province able to achieve commercial operation as early as fiscal 2029 and approximately 700 GWh of new clean or renewable energy from existing facilities prior to fiscal 2029. The timing, and volume, and the period across which projects are required to be in service will be adjusted, as required, based on future need.	BC Hydro has commenced pre-design activities, which will include consultation with Indigenous Nations, stakeholders and the public to be prepared to launch an acquisition process for new clean energy resources in Spring 2024. Electricity purchase agreements will be filed pursuant to section 71 of the *Utilities Commission Act*.

Category	Updated 2021 IRP Element	Near-term Actions
Transmission	Advance the first step of sequential upgrades to transmission infrastructure into the South Coast region, including series compensation, shunt capacitors, and thermal upgrades to achieve approximately 750 MW of additional transmission capacity for the South Coast region by fiscal 2033; prepare to initiate a second step of upgrades to achieve approximately an additional 550 MW of capacity for the South Coast region by fiscal 2040.	The project to deliver the first step of sequential upgrades will be included in the fiscal 2025 to 2034 capital plan and relevant expenditures will be detailed in the next Revenue Requirements Application, for a test period starting on April 1, 2025. As appropriate, we will engage early with Indigenous Nations and the public that may be potentially affected. BC Hydro will further work towards filing a future Certificate of Public Convenience and Necessity Application for this project.
	Continue to advance the Prince George to Terrace Capacitor Project to maintain its earliest in-service date of fiscal 2028.	Expenditures for the project will be detailed in the next Revenue Requirements Application for a test period starting on April 1, 2025.
	Reserve transmission capacity to allow BC Hydro to designate contingency resources to serve higher load if the contingency scenarios materialize.	Within the 2021 IRP Application, we are seeking BCUC approval to use the Contingency Resource Plans within future Network Integration Transmission Service submissions. This action will commence once BCUC approvals to use the Contingency Resource Plans are received.

<table>
<tr><th>Category</th><th>Updated 2021 IRP Element</th><th>Near-term Actions</th></tr>
<tr><td>Existing BC Hydro generating facilities</td><td>Undertake a structured decision making approach to evaluate small BC Hydro plants requiring end-of-life investment decisions on a facility-by-facility basis to determine whether to decommission or refurbish these facilities. These facilities would be evaluated on the following schedule:
<table>
<tr><th>Facility</th><th>Evaluation Timing</th></tr>
<tr><td>Shuswap</td><td>Analysis in progress</td></tr>
<tr><td>Elko</td><td>2025</td></tr>
<tr><td>Spillimacheen</td><td>2029</td></tr>
<tr><td>Alouette</td><td>2030</td></tr>
<tr><td>Falls River</td><td>In operation—date not set</td></tr>
<tr><td>Walter Hardman</td><td>In operation—date not set</td></tr>
</table></td><td>BC Hydro will make filings with the BCUC that align with the decision for each facility, as applicable.

As appropriate, we will engage early with Indigenous Nations and the public that may be potentially affected.</td></tr>
<tr><td>Utility-scale batteries</td><td>Advance utility-scale batteries to enable BC Hydro to achieve approximately 50 MW of additional capacity as early as fiscal 2027 and up to 500 MW of additional capacity by fiscal 2030.</td><td>BC Hydro is operationalizing and integrating small-scale battery energy storage systems of varying capacities to evaluate their performance.

We will consult with Indigenous Nations and the public that may be potentially affected and to identify suitable locations for utility-scale batteries in the South Coast.

BC Hydro will detail the expenditures for small scale battery installations in the next Revenue Requirements Application for a test period starting on April 1, 2025.</td></tr>
</table>

Clean Power 2040
Powering the future

BC Hydro
Power smart

Attachments

Load Resource Balances – 2023 Update
Glossary of terms

CS-3311

A1

2023 UPDATE

Attachment 1: Load Resource Balances

Table of Contents

List of Figures

List of Tables

1 Introduction

The following Load Resource Balances graphs and tables reflect the information shared in the IRP Signposts Update and use the 2023 Load scenarios.

In this Attachment, we present the Load Resource Balances before planned resources (i.e., based on existing and committed resources) that show when we expect to need new resources, and Load Resource Balances after planned resources that show how we will meet future electricitiy demand under the reference load forecast (Base Resource Plan) and a number of other scenarios (Contigency Resource Plans).

The Load Resource Balances are shown at the integrated system level for both energy and capacity. In addition, we consider capacity Load Resource Balances for three regions of the province – South Coast, Vancouver Island and North Coast. The regional peak loads are served by power generated from the regional supply resources as well as transmitted from other regions through the bulk transmission system. Regional Load Resource Balances are used to illustrate potential regional supply constraints.

2 Existing and committed resources

Existing and committed resources include both supply- and demand-side resources. In Load Resource Balance graphs, existing and committed demand-side resources are included as a reduction in the load.

Existing resources are resources that are currently operating and expected to continue to operate into, if not to the end of, the planning horizon. They include the following:

- Existing BC Hydro generation facilities (except for Alouette, Elko, Spillimacheen and one unit at Shuswap, which are currently out of service);[1]
- Independent power producer projects currently in commercial operation (until their electricity purchase agreements expire); and
- Forecasted savings from current codes and standards, and current rate structures (including net metering service).

Committed resources are those that have received necessary internal authorizations to proceed to implementation as well as any required regulatory approvals and are expected to begin operating during the planning horizon. They include the following:

- Site C;

[1] Major outages, defined as 100 MW or larger and lasting longer than one year, are included in load resource balances for the first 10 years of the planning horizon.

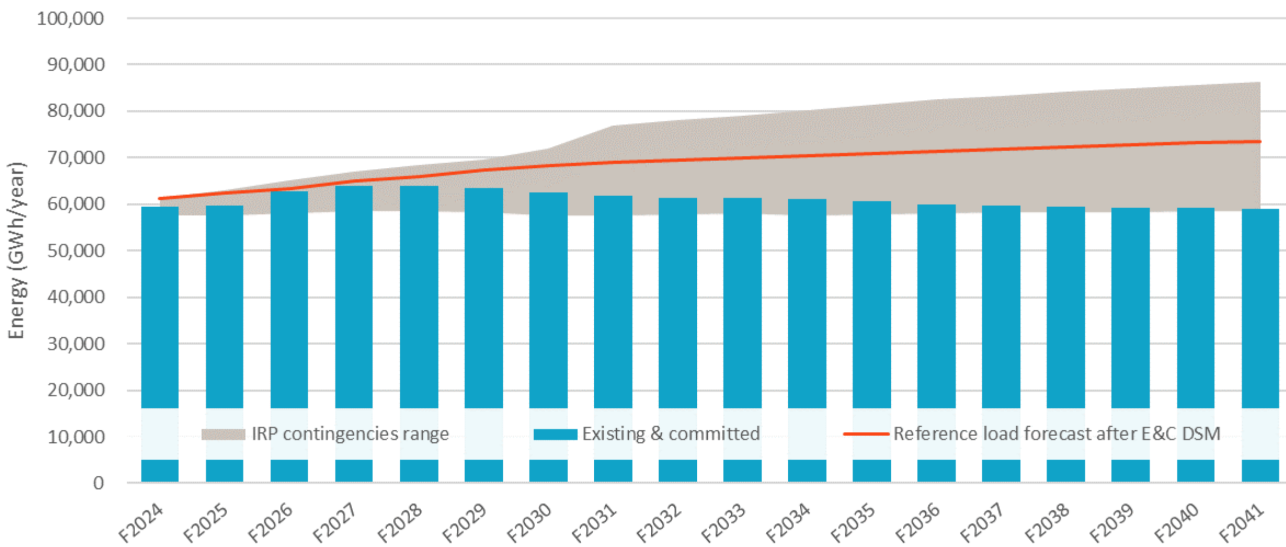
- Future forecast codes and standards savings;
- One electricity purchase agreements with project currently under construction (expected in-service date fiscal 2024);
- Two Standing Offer Program run-of-river projects with Indigenous Nations ownership/involvement excepted from the indefinite suspension of the Standing Offer Program; and
- Three electricity purchase agreements that include a seller’s option to extend.

3 Load Resource Balances before planned resources

3.1 System energy and capacity Load Resource Balances before planned resources

Figure 1-1, Table 1-1, Figure 1-2, and Table 1-2 show the system-wide energy and capacity Load Resource Balances before planned resources.

Figure 1-1 System energy Load Resource Balance before planned resources

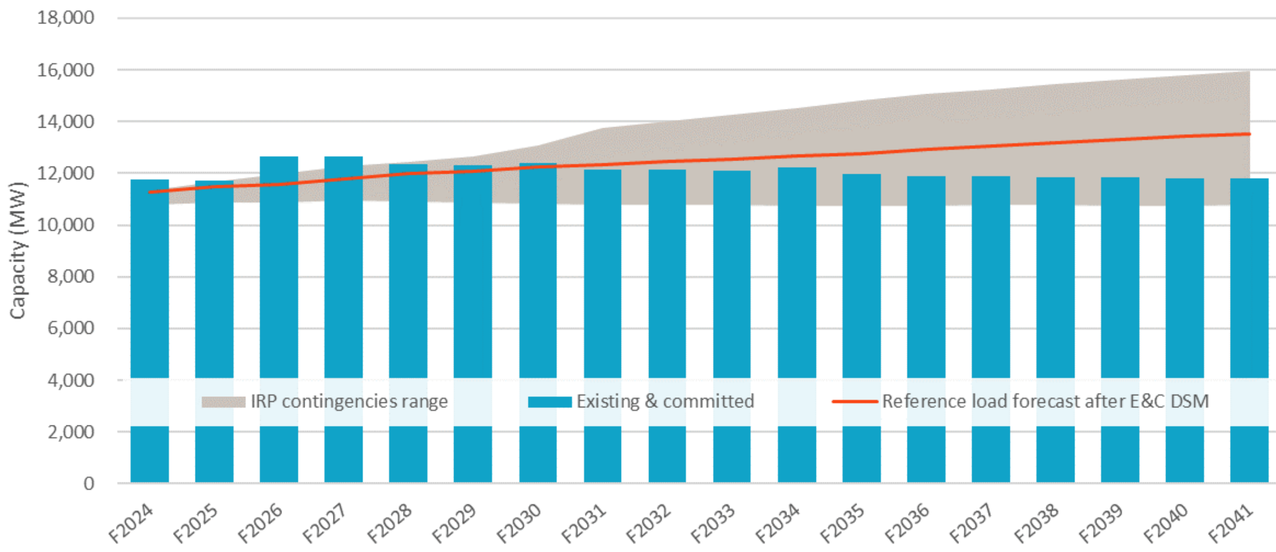


Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-1 System energy Load Resource Balance before planned resources

(GWh/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
Existing and Committed Electricity Purchase Agreements	(b)	12,649	12,404	11,991	11,783	11,734	11,294	10,318	9,611	9,272	9,212	9,024	8,507	7,810	7,455	7,311	7,051	7,021	6,834
System Capability (before planned resources)	(c) = a+b	59,547	59,668	62,781	63,967	63,918	63,478	62,502	61,795	61,456	61,396	61,208	60,691	59,994	59,639	59,495	59,235	59,205	59,018
Demand - Integrated System Total Gross Requirements																			
Reference Load Forecast	(d)	(61,828)	(63,323)	(64,531)	(66,407)	(67,630)	(69,235)	(70,386)	(71,319)	(71,980)	(72,584)	(73,251)	(73,936)	(74,669)	(75,347)	(76,062)	(76,752)	(77,464)	(78,064)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards plus Voltage and VAR Optimization		454	709	953	1,192	1,406	1,603	1,782	1,952	2,115	2,271	2,427	2,584	2,741	2,897	3,053	3,210	3,366	3,526
Energy Conservation Rate Structures		150	193	161	110	99	94	94	94	93	76	45	14	-	-	-	-	-	-
Sub-total	(e)	605	902	1,114	1,302	1,505	1,697	1,875	2,045	2,209	2,347	2,473	2,598	2,741	2,897	3,053	3,210	3,366	3,526
Net Metering	(f)	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**(1,614)**	**(2,676)**	**(541)**	**(1,021)**	**(2,064)**	**(3,886)**	**(5,797)**	**(7,220)**	**(8,004)**	**(8,470)**	**(9,133)**	**(10,136)**	**(11,346)**	**(12,144)**	**(12,765)**	**(13,476)**	**(13,978)**	**(14,522)**

Figure 1-2 System capacity Load Resource Balance before planned resources



Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-2 System capacity Load Resource Balance before planned resources

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources [1]	(a)	11,818	11,818	12,963	12,963	12,616	12,616	12,963	12,789	12,789	12,789	12,963	12,963	12,963	12,963	12,963	12,963	12,963	12,963
Existing and Committed Electricity Purchase Agreements	(b)	1,472	1,458	1,379	1,379	1,370	1,342	1,048	954	943	920	886	582	482	482	446	446	438	437
12% Reserves [2]	(c)	(1,538)	(1,538)	(1,672)	(1,672)	(1,631)	(1,627)	(1,634)	(1,601)	(1,600)	(1,598)	(1,617)	(1,584)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
System Peak Load Carrying Capability (before Planned Resourc	(d) = a+b+c	11,752	11,738	12,670	12,670	12,356	12,331	12,377	12,142	12,132	12,111	12,232	11,961	11,868	11,868	11,833	11,833	11,825	11,824
Demand - Integrated System Total Gross Requirements																			
Reference Load Forecast	(e)	(11,381)	(11,631)	(11,780)	(12,023)	(12,266)	(12,398)	(12,610)	(12,716)	(12,854)	(12,983)	(13,131)	(13,279)	(13,437)	(13,596)	(13,756)	(13,914)	(14,070)	(14,205)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards		80	129	177	219	263	302	338	371	403	435	467	498	528	558	587	616	646	677
Energy Conservation Rate Structures		13	18	17	13	12	11	11	11	11	9	5	2	-	-	-	-	-	-
Sub-total	(f)	92	147	194	232	274	313	349	382	414	444	472	500	528	558	587	616	646	677
Surplus / (Deficit) before planned resources	(g) = d+e+f	**464**	**254**	**1,084**	**879**	**363**	**246**	**117**	**(193)**	**(309)**	**(428)**	**(427)**	**(819)**	**(1,040)**	**(1,170)**	**(1,337)**	**(1,465)**	**(1,600)**	**(1,704)**

Notes:

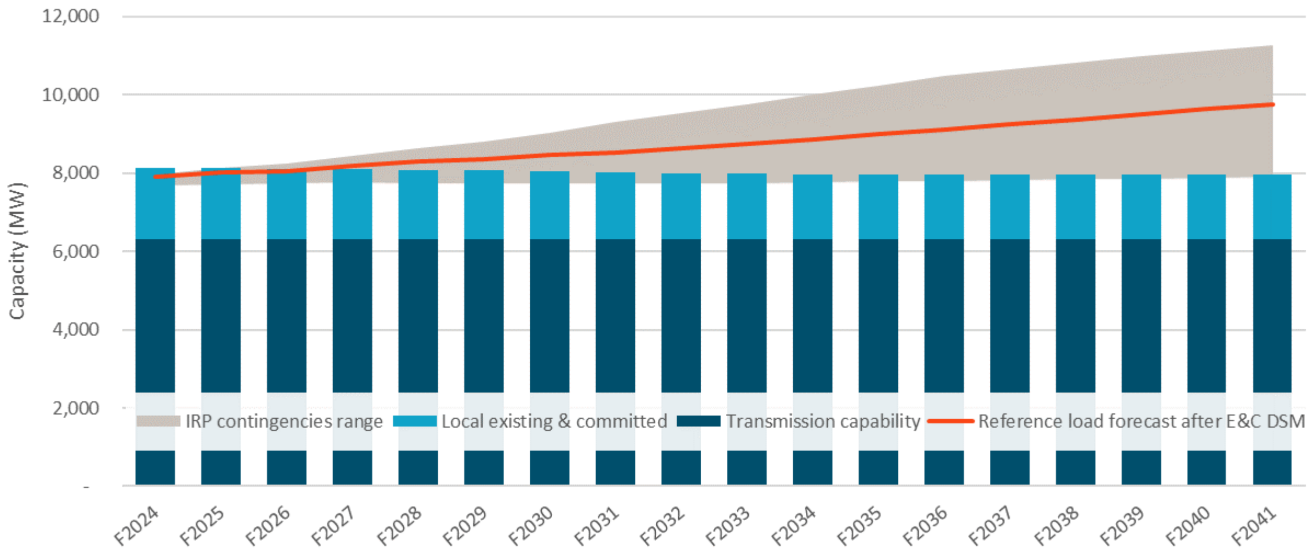
[1] Includes outages for Mica and Seven Mile

[2] The 12% reserve margin is applied to dependable capacity resources only

3.2 Regional capacity Load Resource Balances before planned resources

Figure 1-3, Table 1-3, Figure 1-4, and Table 1-4 show the capacity Load Resource Balances before planned resources for the South Coast, Vancouver Island and the North Coast.

Figure 1-3 South Coast capacity Load Resource Balance before planned resources

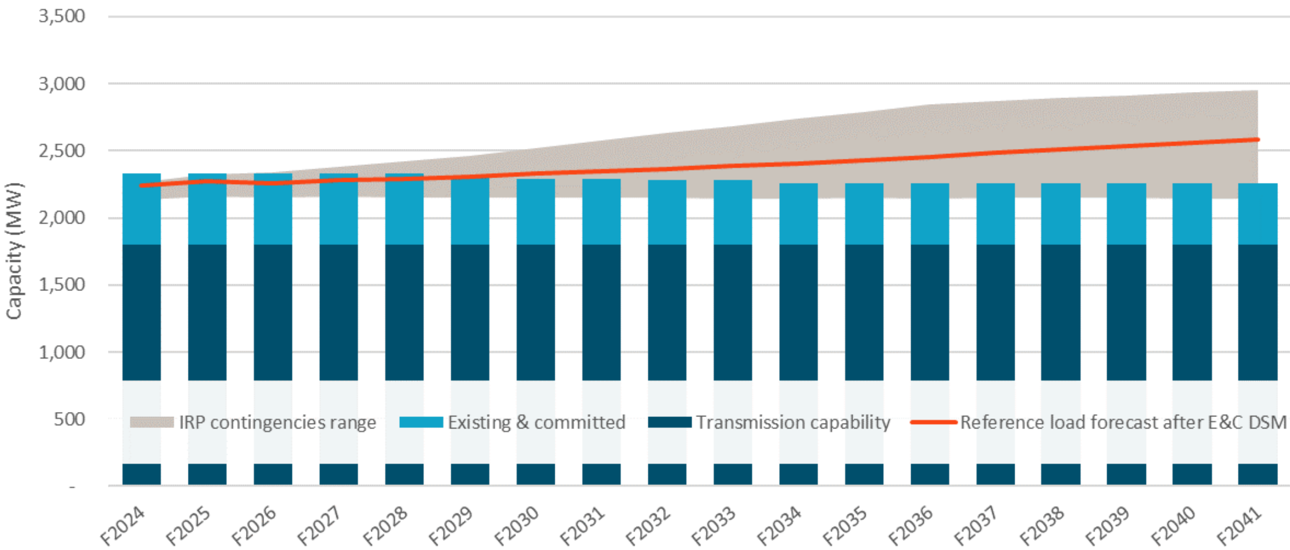


Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-3 South Coast capacity Load Resource Balance before planned resources

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Existing and Committed Electricity Purchase Agreements	(b)	322	311	282	282	274	251	233	192	186	185	160	160	149	149	149	149	141	141
Regional Supply Capacity (before planned resources)	(c) = a+b	1,839	1,828	1,799	1,799	1,791	1,768	1,750	1,709	1,703	1,702	1,677	1,677	1,666	1,666	1,666	1,666	1,658	1,658
Transmission Capability	(d)	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300
Demand - Regional Gross Requirements																			
Reference Load Forecast	(e)	(7,975)	(8,124)	(8,184)	(8,337)	(8,493)	(8,578)	(8,710)	(8,799)	(8,931)	(9,056)	(9,196)	(9,338)	(9,487)	(9,638)	(9,790)	(9,941)	(10,090)	(10,222)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	59	95	128	157	187	214	240	263	285	307	329	350	371	392	412	433	453	476
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**223**	**99**	**43**	**(81)**	**(215)**	**(296)**	**(419)**	**(528)**	**(643)**	**(746)**	**(890)**	**(1,011)**	**(1,150)**	**(1,280)**	**(1,412)**	**(1,542)**	**(1,679)**	**(1,788)**

Figure 1-4 Vancouver Island capacity Load Resource Balance before planned resources

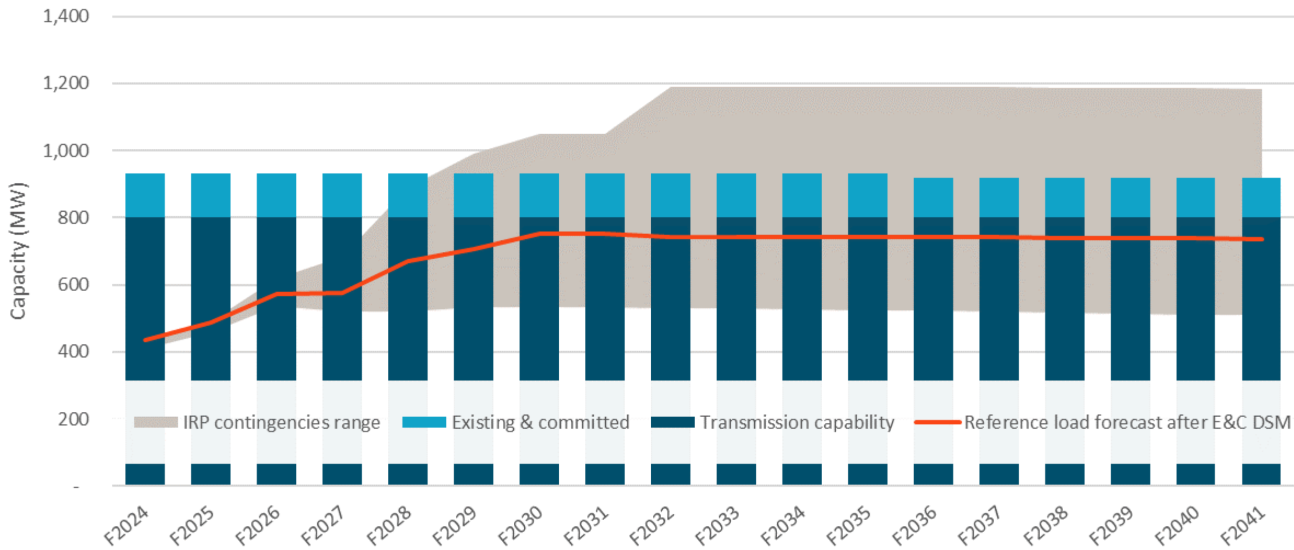


Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-4 Vancouver Island capacity Load Resource Balance before planned resources

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
Existing and Committed Electricity Purchase Agreements	(b)	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
Regional Supply Capacity (before planned resources)	(c) = a+b	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
Transmission Capability	(d)	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
Demand - Regional Gross Requirements																			
Reference Load Forecast	(e)	(2,258)	(2,302)	(2,297)	(2,323)	(2,346)	(2,364)	(2,397)	(2,417)	(2,444)	(2,469)	(2,498)	(2,526)	(2,557)	(2,588)	(2,619)	(2,650)	(2,679)	(2,705)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	17	27	36	44	52	60	66	72	78	84	89	94	99	104	109	114	119	124
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**91**	**56**	**69**	**51**	**36**	**2**	**(41)**	**(55)**	**(83)**	**(103)**	**(150)**	**(173)**	**(199)**	**(225)**	**(251)**	**(277)**	**(302)**	**(322)**

Figure 1-5 North Coast capacity Load Resource Balance before planned resources



Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-5 North Coast capacity Load Resource Balance before planned resources

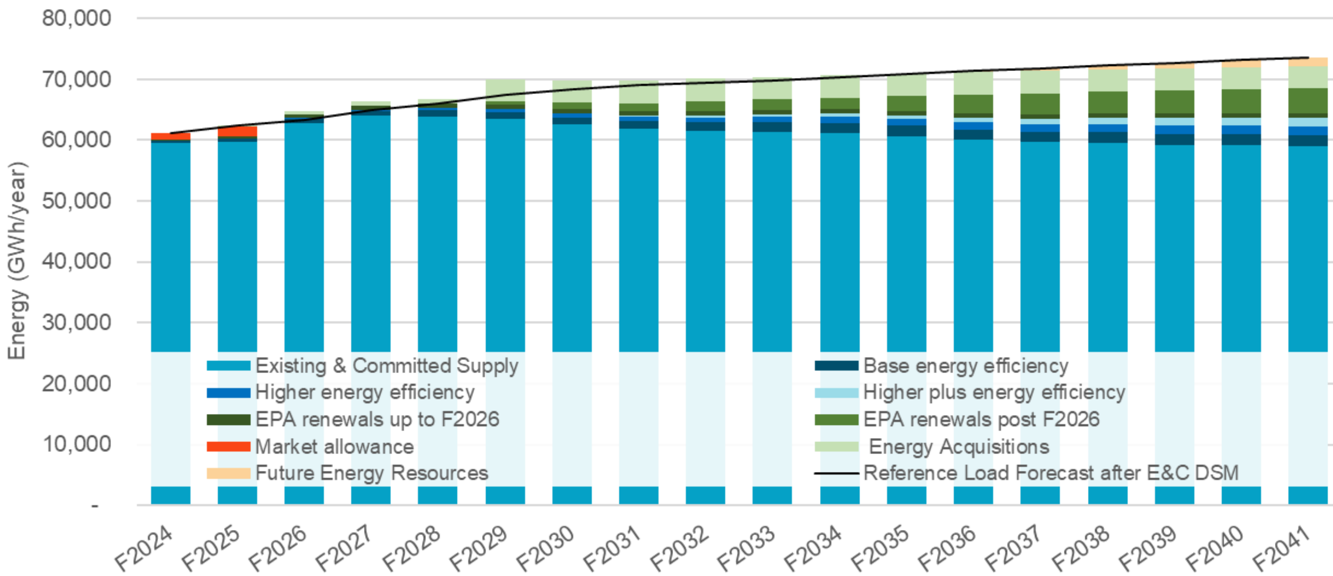
(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Existing and Committed Electricity Purchase Agreements	(b)	124	124	124	124	124	124	124	124	124	124	124	124	112	112	112	112	112	112
Regional Supply Capacity (before planned resources)	(c) = a+b	131	131	131	131	131	131	131	131	131	131	131	131	119	119	119	119	119	119
Transmission Capability	(d)	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Demand - Regional Gross Requirements																			
Reference Load Forecast	(e)	(440)	(494)	(582)	(585)	(682)	(719)	(765)	(766)	(760)	(760)	(760)	(760)	(761)	(761)	(761)	(761)	(761)	(761)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	4	6	9	10	12	13	14	15	16	17	18	18	19	20	21	22	23	24
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**495**	**444**	**357**	**355**	**260**	**225**	**180**	**180**	**187**	**188**	**188**	**189**	**177**	**178**	**179**	**180**	**181**	**182**

4 Load Resource Balances – Base Resource Plan

4.1 System Load Resource Balances with Base Resource Plan

Figure 1-6, Table 1-6, Figure 1-7 and Table 1-7 present the system-wide energy and capacity Load Resource Balances with selected resources in place to fill the energy and capacity gaps based on the reference load forecast. The figures and tables illustrate the timing of the resources and their energy/capacity contributions. In this section, the savings from Higher Plus Energy Efficiency are shown as incremental to the savings from Higher Energy Efficiency. This is to highlight the transition from Higher Energy Efficiency to Higher Plus Energy Efficiency.

Figure 1-6 System energy Load Resource Balance with Base Resource Plan resources

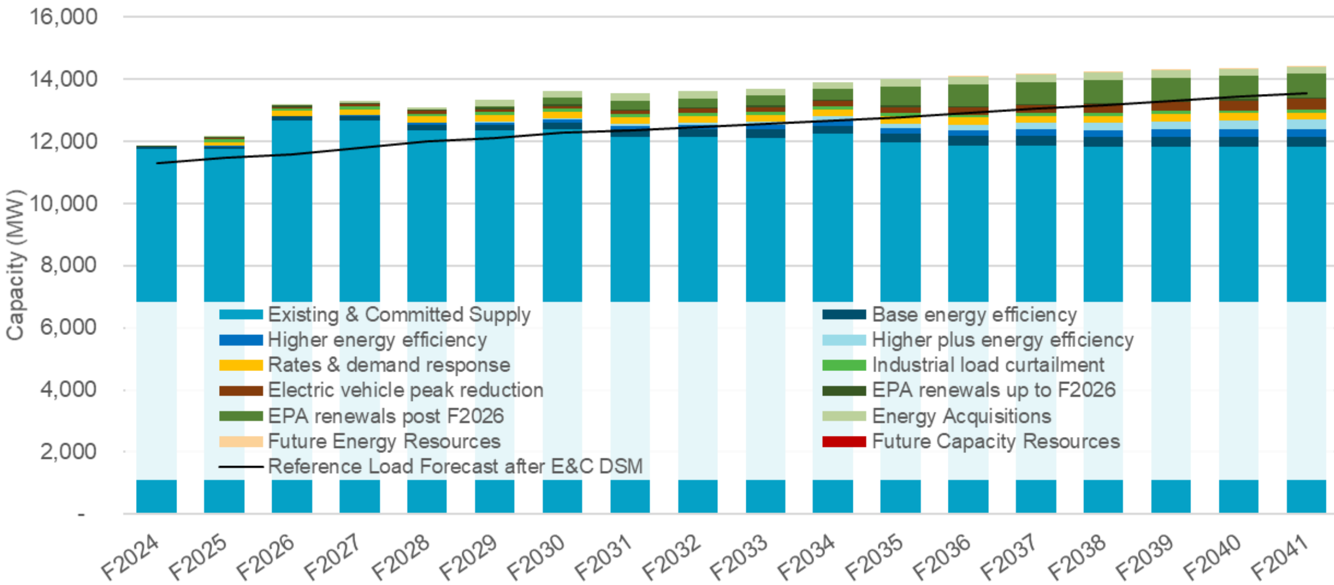


Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-6 System energy Load Resource Balance with Base Resource Plan resources

(GWh/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
Existing and Committed Electricity Purchase Agreements	(b)	12,649	12,404	11,991	11,783	11,734	11,294	10,318	9,611	9,272	9,212	9,024	8,507	7,810	7,455	7,311	7,051	7,021	6,834
System Capability (before planned resources)	(c) = a+b	59,547	59,668	62,781	63,967	63,918	63,478	62,502	61,795	61,456	61,396	61,208	60,691	59,994	59,639	59,495	59,235	59,205	59,018
Demand - Integrated System Total Gross Requirements																			
Reference Load Forecast	(d)	(61,828)	(63,323)	(64,531)	(66,407)	(67,630)	(69,235)	(70,386)	(71,319)	(71,980)	(72,584)	(73,251)	(73,936)	(74,669)	(75,347)	(76,062)	(76,752)	(77,464)	(78,064)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards plus Voltage and VAR Optimization		454	709	953	1,192	1,406	1,603	1,782	1,952	2,115	2,271	2,427	2,584	2,741	2,897	3,053	3,210	3,366	3,526
Energy Conservation Rate Structures		150	193	161	110	99	94	94	94	93	76	45	14	-	-	-	-	-	-
Sub-total	(e)	605	902	1,114	1,302	1,505	1,697	1,875	2,045	2,209	2,347	2,473	2,598	2,741	2,897	3,053	3,210	3,366	3,526
Net Metering	(f)	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**(1,614)**	**(2,676)**	**(541)**	**(1,021)**	**(2,064)**	**(3,886)**	**(5,797)**	**(7,220)**	**(8,004)**	**(8,470)**	**(9,133)**	**(10,136)**	**(11,346)**	**(12,144)**	**(12,765)**	**(13,476)**	**(13,978)**	**(14,522)**
Base Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		324	508	679	825	977	1,112	1,237	1,375	1,456	1,528	1,584	1,629	1,694	1,719	1,753	1,765	1,774	1,781
Higher Energy Efficiency		-	35	118	222	327	448	576	709	813	926	1,025	1,108	1,192	1,255	1,320	1,387	1,410	1,438
Higher Plus Energy Efficiency		-	-	-	-	21	72	140	203	288	392	513	635	777	919	1,071	1,225	1,359	1,485
Sub-total	(h)	324	543	796	1,047	1,325	1,632	1,953	2,287	2,557	2,845	3,123	3,372	3,663	3,894	4,143	4,377	4,543	4,704
Surplus / (Deficit) after planned DSM	(i) = g+h	**(1,290)**	**(2,133)**	**256**	**26**	**(739)**	**(2,254)**	**(3,844)**	**(4,934)**	**(5,447)**	**(5,624)**	**(6,010)**	**(6,764)**	**(7,683)**	**(8,250)**	**(8,622)**	**(9,100)**	**(9,435)**	**(9,818)**
Electricity Purchase Agreement Renewals prior to F2026	(j)	160	356	634	707	707	707	707	707	707	707	707	707	707	707	707	707	707	707
Electricity Purchase Agreement Renewals post F2026	(k)	-	-	-	-	90	498	964	1,299	1,637	1,698	1,885	2,402	3,090	3,420	3,564	3,824	3,854	4,041
Market Allowance	(l)	1,130	1,577	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Acquisitions	(m)	-	200	500	700	700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Future Energy Resources	(n)	-	-	-	-	-	-	-	-	-	-	-	-	186	423	651	869	1,174	1,370
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**0**	**0**	**1,389**	**1,433**	**758**	**2,651**	**1,527**	**772**	**597**	**480**	**282**	**45**	**0**	**0**	**0**	**0**	**0**	**0**

Figure 1-7 System capacity Load Resource Balance with Base Resource Plan resources



Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-7 System capacity Load Resource Balance with Base Resource Plan resources

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources [1]	(a)	11,818	11,818	12,963	12,963	12,616	12,616	12,963	12,789	12,789	12,789	12,963	12,963	12,963	12,963	12,963	12,963	12,963	12,963
Existing and Committed Electricity Purchase Agreements	(b)	1,472	1,458	1,379	1,379	1,370	1,342	1,048	954	943	920	886	582	482	482	446	446	438	437
12% Reserves [2]	(c)	(1,538)	(1,538)	(1,672)	(1,672)	(1,631)	(1,627)	(1,634)	(1,601)	(1,600)	(1,598)	(1,617)	(1,584)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
System Peak Load Carrying Capability (before Planned Resourc	(d) = a+b+c	11,752	11,738	12,670	12,670	12,356	12,331	12,377	12,142	12,132	12,111	12,232	11,961	11,868	11,868	11,833	11,833	11,825	11,824
Demand - Integrated System Total Gross Requirements																			
Reference Load Forecast	(e)	(11,381)	(11,631)	(11,780)	(12,023)	(12,266)	(12,398)	(12,610)	(12,716)	(12,854)	(12,983)	(13,131)	(13,279)	(13,437)	(13,596)	(13,756)	(13,914)	(14,070)	(14,205)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards		80	129	177	219	263	302	338	371	403	435	467	498	528	558	587	616	646	677
Energy Conservation Rate Structures		13	18	17	13	12	11	11	11	11	9	5	2	-	-	-	-	-	-
Sub-total	(f)	92	147	194	232	274	313	349	382	414	444	472	500	528	558	587	616	646	677
Surplus / (Deficit) before planned resources	(g) = d+e+f	**464**	**254**	**1,084**	**879**	**363**	**246**	**117**	**(193)**	**(309)**	**(428)**	**(427)**	**(819)**	**(1,040)**	**(1,170)**	**(1,337)**	**(1,465)**	**(1,600)**	**(1,704)**
Base Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		59	89	118	142	166	188	209	229	244	257	266	276	285	291	295	297	298	301
Higher Energy Efficiency		-	10	23	39	57	75	94	115	132	151	168	184	199	212	226	240	247	252
Higher Plus Energy Efficiency		-	-	-	-	10	22	37	53	72	95	120	146	175	204	234	261	287	312
Time-Varying Rates & Demand Response		-	132	149	175	202	215	218	220	221	223	224	225	227	228	230	231	233	233
Industrial Load Curtailment		-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Electric Vehicle Peak Reduction		-	24	40	60	73	87	102	119	138	157	178	201	224	247	270	293	315	339
Sub-total	(h)	59	354	428	514	604	685	758	833	905	980	1,054	1,130	1,207	1,280	1,353	1,420	1,478	1,536
Surplus / (Deficit) after planned DSM	(i) = g+h	**522**	**608**	**1,512**	**1,393**	**968**	**931**	**875**	**641**	**596**	**552**	**628**	**311**	**167**	**110**	**16**	**(45)**	**(121)**	**(168)**
Electricity Purchase Agreement Renewals prior to F2026 [3]	(j)	12	26	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Electricity Purchase Agreement Renewals post F2026 [3]	(k)	-	-	-	-	9	35	198	281	291	311	344	615	700	700	736	736	744	745
Energy Acquisitions (Capacity Contribution) [3]	(l)	-	7	39	60	60	223	223	223	223	223	223	223	223	223	223	223	223	223
Future Energy Resources (Capacity Contribution)	(m)	-	-	-	-	-	-	-	-	-	-	-	-	8	15	21	27	36	42
Future Capacity Resources	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**535**	**641**	**1,603**	**1,505**	**1,089**	**1,241**	**1,348**	**1,196**	**1,162**	**1,138**	**1,247**	**1,201**	**1,150**	**1,101**	**1,048**	**993**	**934**	**893**

Notes:

[1] Includes outages for Mica and Seven Mile

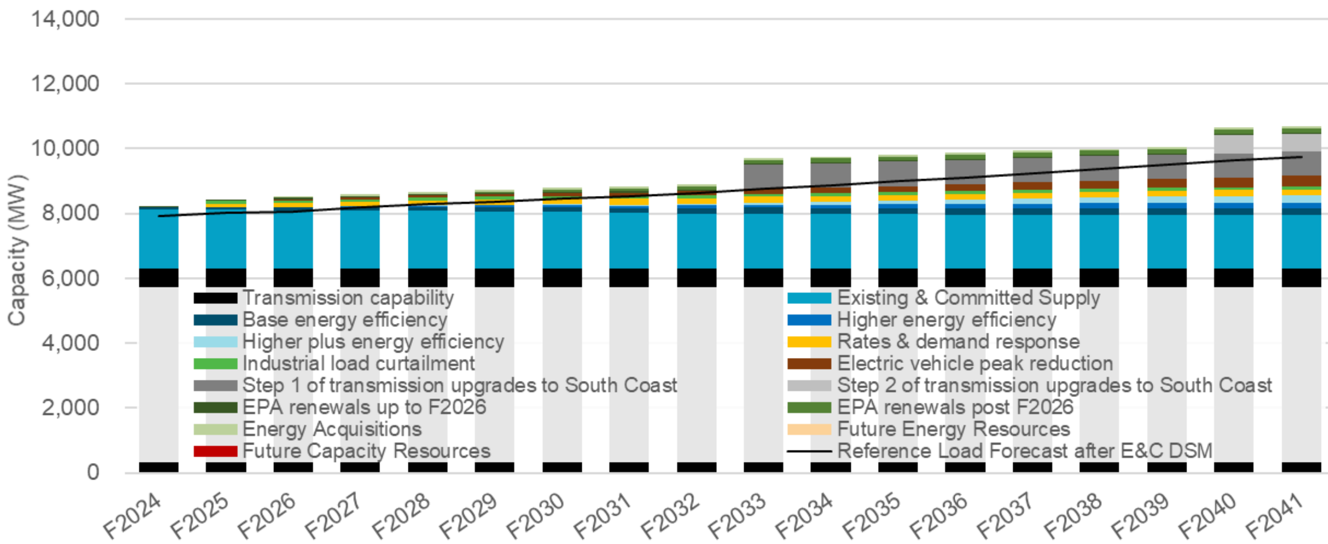
[2] The 12% reserve margin is applied to dependable capacity resources only

[3] The numbers shown include the 12% reserve margin

4.2 Regional capacity Load Resource Balances with Base Resource Plan

Figure 1-8, Table 1-8, Figure 1-9, and Table 1-9 present the capacity Load Resource Balances for the South Coast and Vancouver Island with selected resources in place to fill the capacity gaps based on the reference load forecast.[2] The figures and tables illustrate the timing of the resources and their capacity contributions. In this section, the savings from Higher Plus Energy Efficiency are shown as incremental to the savings from Higher Energy Efficiency. This is to highlight the transition from Higher Energy Efficiency to Higher Plus Energy Efficiency.

Figure 1-8 South Coast capacity Load Resource Balance with Base Resource Plan resources



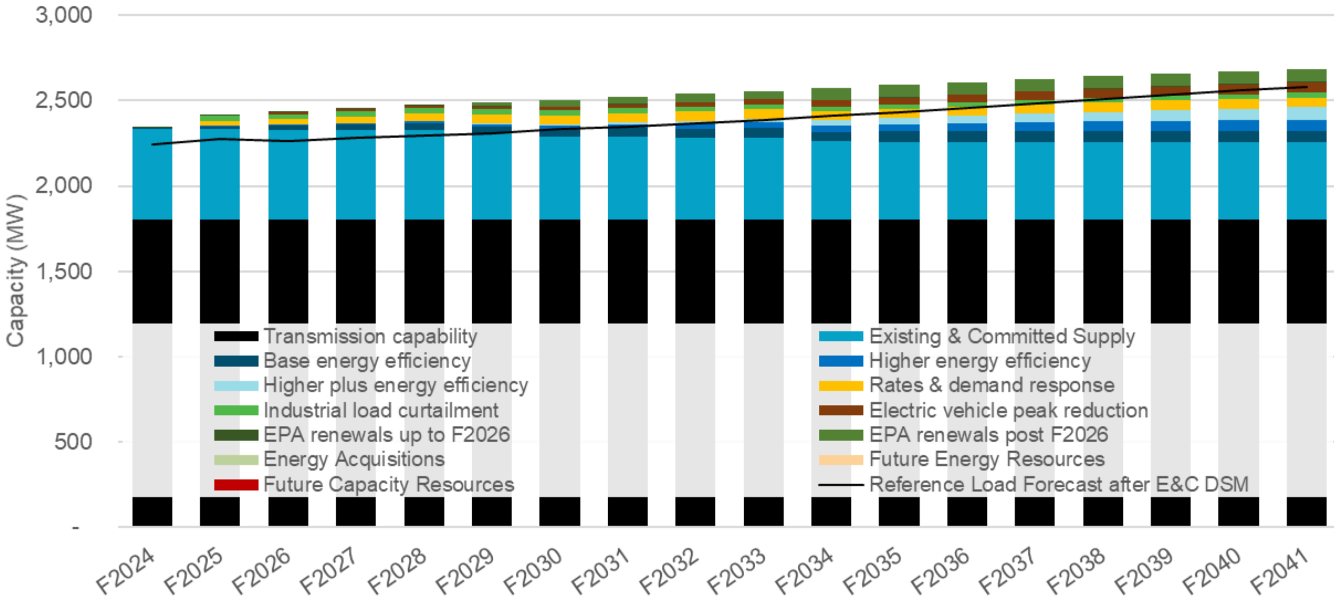
Note: E&C DSM denotes existing and committed demand-side measures.

2 A Load Resource Balance is not presented for the North Coast region as there is no gap based on the Reference Load Forecast.

Table 1-8 South Coast Capacity Load Resource Balance with Base Resource Plan Resources

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Existing and Committed Electricity Purchase Agreements	(b)	322	311	282	282	274	251	233	192	186	185	160	160	149	149	149	149	141	141
Regional Supply Capacity (before planned resources)	(c) = a+b	1,839	1,828	1,799	1,799	1,791	1,768	1,750	1,709	1,703	1,702	1,677	1,677	1,666	1,666	1,666	1,666	1,658	1,658
Transmission Capability	(d)	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300
Demand - Regional Gross Requirements																			
Reference Load Forecast	(e)	(7,975)	(8,124)	(8,184)	(8,337)	(8,493)	(8,578)	(8,710)	(8,799)	(8,931)	(9,056)	(9,196)	(9,338)	(9,487)	(9,638)	(9,790)	(9,941)	(10,090)	(10,222)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	59	95	128	157	187	214	240	263	285	307	329	350	371	392	412	433	453	476
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**223**	**99**	**43**	**(81)**	**(215)**	**(296)**	**(419)**	**(528)**	**(643)**	**(746)**	**(890)**	**(1,011)**	**(1,150)**	**(1,280)**	**(1,412)**	**(1,542)**	**(1,679)**	**(1,788)**
Base Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		42	63	82	99	115	130	145	159	169	178	185	191	198	202	205	207	207	209
Higher Energy Efficiency		-	7	15	24	35	46	57	69	81	93	106	117	128	139	150	161	167	172
Higher Plus Energy Efficiency		-	-	-	-	7	16	26	38	52	68	85	105	125	146	168	188	207	225
Time-Varying Rates & Demand Response		-	100	114	135	157	168	171	172	173	174	176	177	178	179	180	182	183	183
Industrial Load Curtailment		-	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86
Electric Vehicle Peak Reduction		-	23	37	57	69	82	97	113	130	149	169	190	212	234	256	277	298	321
Sub-total	(h)	42	278	334	401	469	528	581	636	691	748	806	865	927	986	1,045	1,100	1,148	1,196
Surplus / (Deficit) after planned DSM	(i) = g+h	**265**	**377**	**377**	**320**	**253**	**232**	**162**	**109**	**48**	**2**	**(84)**	**(145)**	**(223)**	**(294)**	**(367)**	**(442)**	**(531)**	**(592)**
Transmission Upgrades																			
Step 1 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	750	750	750	750	750	750	750	750	750
Step 2 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	550	550
Sub-total	(j)	-	-	-	-	-	-	-	-	-	750	750	750	750	750	750	750	1,300	1,300
Electricity Purchase Agreement Renewals prior to F2026	(k)	5	16	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Electricity Purchase Agreement Renewals post F2026	(l)	-	-	-	-	9	31	49	91	97	97	122	122	126	126	126	126	133	133
Energy Acquisitions (Capacity Contribution)	(m)	-	-	36	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Future Energy Resources (Capacity Contribution)	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Capacity Resources	(o)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus / (Deficit) after planned resources	(p) = i+j+k+l+m+n+o	**270**	**393**	**458**	**425**	**367**	**368**	**316**	**305**	**250**	**954**	**893**	**832**	**758**	**687**	**614**	**539**	**1,007**	**946**

Figure 1-9 Vancouver Island capacity Load Resource Balance with Base Resource Plan resources



Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-9 Vancouver Island capacity Load Resource Balance with Base Resource Plan resources

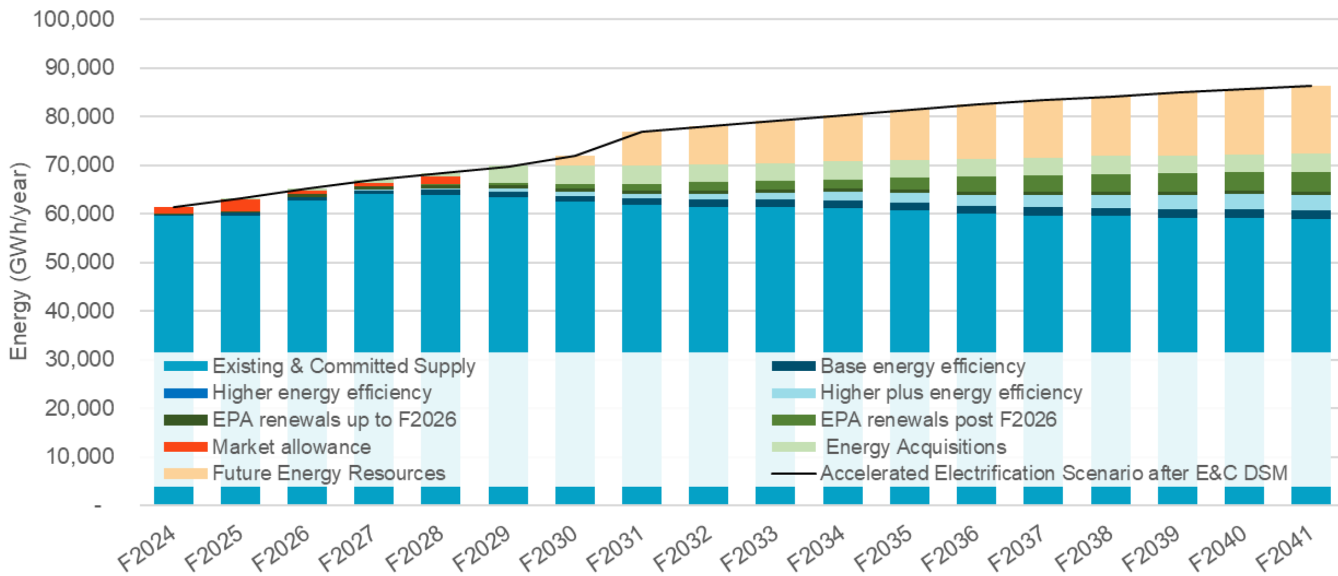
(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
Existing and Committed Electricity Purchase Agreements	(b)	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
Regional Supply Capacity (before planned resources)	(c) = a+b	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
Transmission Capability	(d)	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
Demand - Regional Gross Requirements																			
Reference Load Forecast	(e)	(2,258)	(2,302)	(2,297)	(2,323)	(2,346)	(2,364)	(2,397)	(2,417)	(2,444)	(2,469)	(2,498)	(2,526)	(2,557)	(2,588)	(2,619)	(2,650)	(2,679)	(2,705)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	17	27	36	44	52	60	66	72	78	84	89	94	99	104	109	114	119	124
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**91**	**56**	**69**	**51**	**36**	**2**	**(41)**	**(55)**	**(83)**	**(103)**	**(150)**	**(173)**	**(199)**	**(225)**	**(251)**	**(277)**	**(302)**	**(322)**
Base Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		13	20	25	30	36	40	45	50	53	56	58	60	62	63	64	64	64	65
Higher Energy Efficiency		-	3	6	9	13	17	21	25	29	34	38	43	47	51	55	59	61	63
Higher Plus Energy Efficiency		-	-	-	-	2	5	9	13	18	23	29	36	42	49	56	63	68	74
Time-Varying Rates & Demand Response		-	28	33	40	48	51	51	52	52	52	53	53	53	54	54	54	55	55
Industrial Load Curtailment		-	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29
Electric Vehicle Peak Reduction		-	4	7	11	13	16	19	22	25	29	33	37	41	46	50	54	58	63
Sub-total	(h)	13	84	101	120	141	159	175	191	207	224	241	258	275	292	309	324	336	349
Surplus / (Deficit) after planned DSM	(i) = g+h	**104**	**140**	**170**	**171**	**178**	**161**	**134**	**136**	**124**	**122**	**91**	**85**	**77**	**67**	**58**	**47**	**34**	**27**
Electricity Purchase Agreement Renewals prior to F2026	(j)	1	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Electricity Purchase Agreement Renewals post F2026	(k)	-	-	-	-	-	23	40	40	46	47	70	71	71	71	71	71	71	71
Energy Acquisitions (Capacity Contribution)	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Energy Resources (Capacity Contribution)	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Capacity Resources	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**105**	**141**	**173**	**174**	**181**	**187**	**177**	**179**	**173**	**172**	**164**	**159**	**151**	**141**	**132**	**121**	**108**	**101**

5 Load Resource Balances – Contingency Resource Plans

5.1 System Load Resource Balances with Contingency Resource Plan for Accelerated electrification scenario

Figure 1-10, Table 1-10, Figure 1-11 and Table 1-11 present the system-wide energy and capacity Load Resource Balances with selected resources in place to fill the energy and capacity gaps under the Contingency Resource Plan for the Accelerated electrification scenario. The figures and tables illustrate the timing of the resources and their energy/capacity contributions. In this section, the savings from Higher Plus Energy Efficiency include the savings from Higher Energy Efficiency.

Figure 1-10 System energy Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario

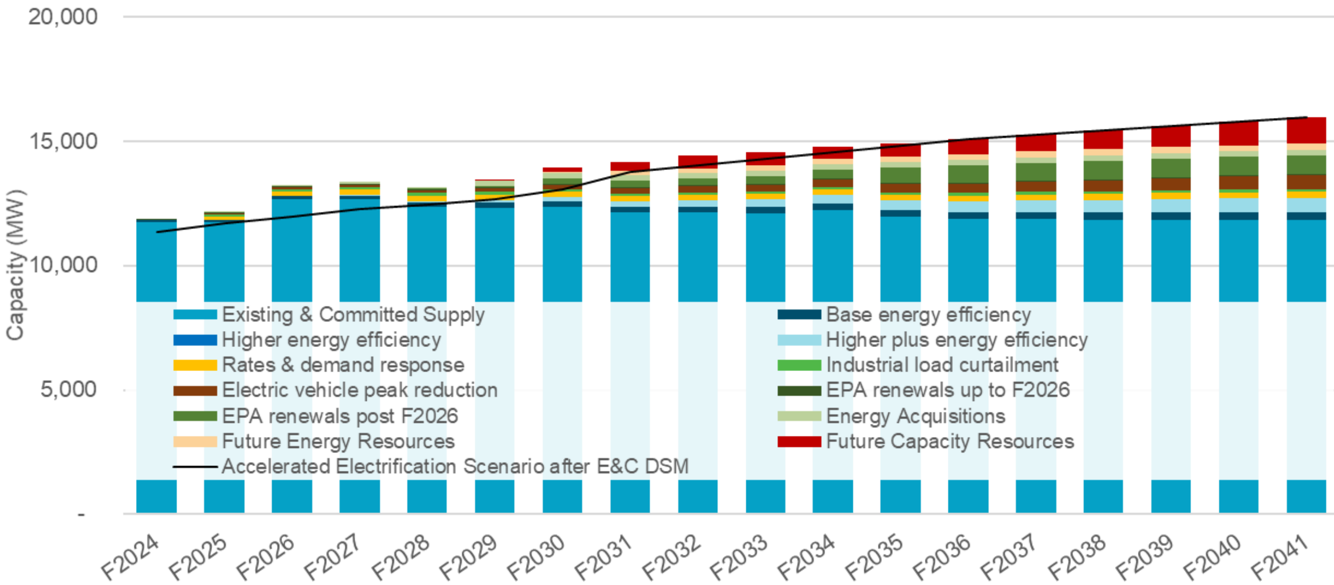


Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-10 System energy Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario

(GWh/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
Existing and Committed Electricity Purchase Agreements	(b)	12,649	12,404	11,991	11,783	11,734	11,294	10,318	9,611	9,272	9,212	9,024	8,507	7,810	7,455	7,311	7,051	7,021	6,834
System Capability (before planned resources)	(c) = a+b	59,547	59,668	62,781	63,967	63,918	63,478	62,502	61,795	61,456	61,396	61,208	60,691	59,994	59,639	59,495	59,235	59,205	59,018
Demand - Integrated System Total Gross Requirements																			
Accelerated Electrification Scenario	(d)	(62,032)	(64,079)	(66,433)	(68,463)	(70,015)	(71,555)	(74,106)	(79,251)	(80,562)	(81,864)	(83,201)	(84,542)	(85,945)	(86,937)	(87,951)	(88,928)	(89,928)	(90,782)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards plus Voltage and VAR Optimization		454	709	953	1,192	1,406	1,603	1,782	1,952	2,115	2,271	2,427	2,584	2,741	2,897	3,053	3,210	3,366	3,526
Energy Conservation Rate Structures		150	193	161	110	99	94	94	94	93	76	45	14	-	-	-	-	-	-
Sub-total	(e)	605	902	1,114	1,302	1,505	1,697	1,875	2,045	2,209	2,347	2,473	2,598	2,741	2,897	3,053	3,210	3,366	3,526
Net Metering	(f)	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**(1,818)**	**(3,432)**	**(2,443)**	**(3,077)**	**(4,449)**	**(6,206)**	**(9,516)**	**(15,153)**	**(16,586)**	**(17,750)**	**(19,083)**	**(20,742)**	**(22,622)**	**(23,734)**	**(24,655)**	**(25,652)**	**(26,442)**	**(27,239)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		324	508	679	825	977	1,112	1,237	1,375	1,456	1,528	1,584	1,629	1,694	1,719	1,753	1,765	1,774	1,781
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	56	190	362	530	737	967	1,222	1,448	1,703	1,945	2,179	2,417	2,614	2,804	2,987	3,092
Sub-total	(h)	324	508	735	1,014	1,339	1,642	1,974	2,343	2,678	2,976	3,287	3,574	3,872	4,136	4,367	4,570	4,761	4,873
Surplus / (Deficit) after planned DSM	(i) = g+h	**(1,494)**	**(2,924)**	**(1,709)**	**(2,063)**	**(3,110)**	**(4,564)**	**(7,542)**	**(12,811)**	**(13,908)**	**(14,774)**	**(15,795)**	**(17,168)**	**(18,749)**	**(19,598)**	**(20,288)**	**(21,082)**	**(21,681)**	**(22,365)**
Electricity Purchase Agreement Renewals prior to F2026	(j)	160	356	634	707	707	707	707	707	707	707	707	707	707	707	707	707	707	707
Electricity Purchase Agreement Renewals post F2026	(k)	-	-	-	-	90	498	964	1,299	1,637	1,698	1,885	2,402	3,090	3,420	3,564	3,824	3,854	4,041
Market Allowance	(l)	1,334	2,368	575	656	1,613	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Acquisitions	(m)	-	200	500	700	700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Future Energy Resources	(n)	-	-	-	-	-	-	2,172	7,105	7,864	8,670	9,504	10,359	11,252	11,771	12,317	12,851	13,420	13,918
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**0**	**0**	**0**	**0**	**0**	**341**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Figure 1-11 System capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario



Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-11 System capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources [1]	(a)	11,818	11,818	12,963	12,963	12,616	12,616	12,963	12,789	12,789	12,789	12,963	12,963	12,963	12,963	12,963	12,963	12,963	12,963
Existing and Committed Electricity Purchase Agreements	(b)	1,472	1,458	1,379	1,379	1,370	1,342	1,048	954	943	920	886	582	482	482	446	446	438	437
12% Reserves [2]	(c)	(1,538)	(1,538)	(1,672)	(1,672)	(1,631)	(1,627)	(1,634)	(1,601)	(1,600)	(1,598)	(1,617)	(1,584)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
System Peak Load Carrying Capability (before Planned Resourc	(d) = a+b+c	11,752	11,738	12,670	12,670	12,356	12,331	12,377	12,142	12,132	12,111	12,232	11,961	11,868	11,868	11,833	11,833	11,825	11,824
Demand - Integrated System Total Gross Requirements																			
Accelerated Electrification Scenario	(e)	(11,446)	(11,835)	(12,162)	(12,494)	(12,727)	(12,974)	(13,408)	(14,157)	(14,439)	(14,714)	(15,008)	(15,303)	(15,607)	(15,816)	(16,027)	(16,234)	(16,440)	(16,624)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards		80	129	177	219	263	302	338	371	403	435	467	498	528	558	587	616	646	677
Energy Conservation Rate Structures		13	18	17	13	12	11	11	11	11	9	5	2	-	-	-	-	-	-
Sub-total	(f)	92	147	194	232	274	313	349	382	414	444	472	500	528	558	587	616	646	677
Surplus / (Deficit) before planned resources	(g) = d+e+f	**398**	**50**	**702**	**409**	**(97)**	**(331)**	**(682)**	**(1,633)**	**(1,893)**	**(2,159)**	**(2,304)**	**(2,843)**	**(3,211)**	**(3,390)**	**(3,607)**	**(3,785)**	**(3,969)**	**(4,123)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		59	89	118	142	166	188	209	229	244	257	266	276	285	291	295	297	298	301
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	20	45	76	110	148	189	235	279	326	372	418	460	500	538	574	599
Time-Varying Rates & Demand Response		-	140	158	185	211	225	229	230	232	234	235	237	239	240	242	244	246	247
Industrial Load Curtailment		-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Electric Vehicle Peak Reduction		-	40	66	100	121	146	171	199	230	263	299	336	375	414	453	491	528	568
Sub-total	(h)	59	367	459	569	672	766	854	945	1,039	1,130	1,223	1,318	1,414	1,503	1,587	1,667	1,744	1,812
Surplus / (Deficit) after planned DSM	(i) = g+h	**457**	**418**	**1,161**	**978**	**575**	**435**	**172**	**(688)**	**(855)**	**(1,029)**	**(1,081)**	**(1,525)**	**(1,797)**	**(1,887)**	**(2,020)**	**(2,118)**	**(2,225)**	**(2,311)**
Electricity Purchase Agreement Renewals prior to F2026 [3]	(j)	12	26	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Electricity Purchase Agreement Renewals post F2026 [3]	(k)	-	-	-	-	9	35	198	281	291	311	344	615	700	700	736	736	744	745
Energy Acquisitions (Capacity Contribution) [3]	(l)	-	7	39	60	60	223	223	223	223	223	223	223	223	223	223	223	223	223
Future Energy Resources (Capacity Contribution)	(m)	-	-	-	-	-	-	70	163	174	187	198	211	223	229	235	241	248	254
Future Capacity Resources	(n)	-	-	-	-	-	10	171	360	521	521	521	521	599	683	774	865	958	1,037
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**469**	**451**	**1,252**	**1,090**	**696**	**755**	**887**	**391**	**407**	**266**	**257**	**97**	**0**	**0**	**0**	**0**	**0**	**0**

Notes:

[1] Includes outages for Mica and Seven Mile

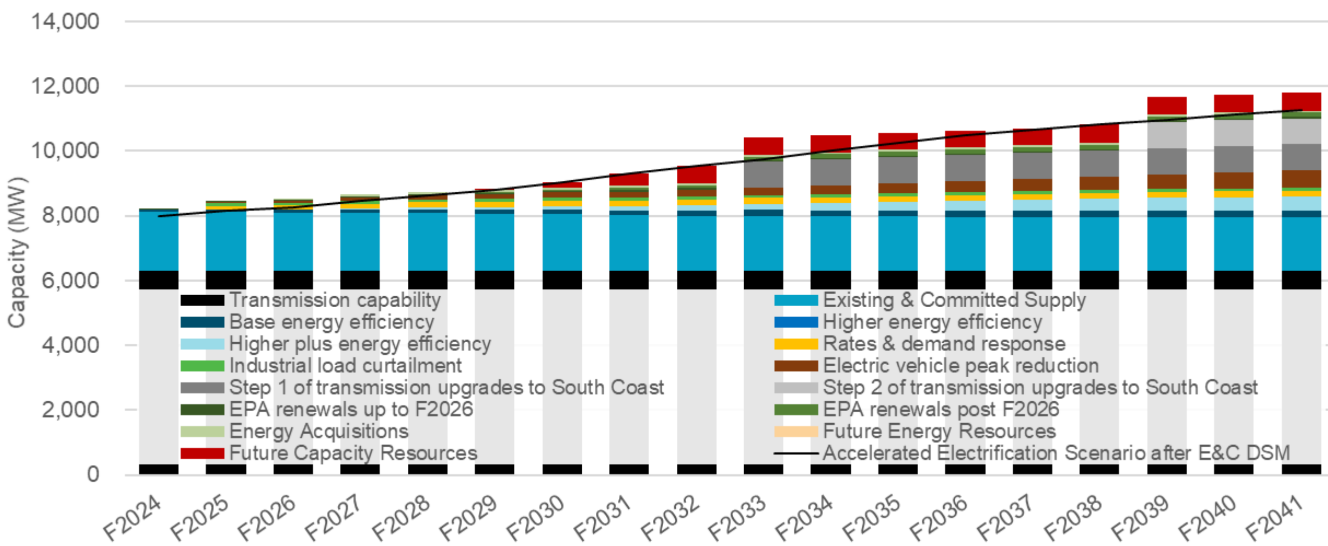
[2] The 12% reserve margin is applied to dependable capacity resources only

[3] The numbers shown include the 12% reserve margin

5.2 Regional capacity Load Resource Balances with Contingency Resource Plan for Accelerated electrification scenario

Figure 1-12, Table 1-12, Figure 1-13 and Table 1-13 present the capacity Load Resource Balances for the South Coast and Vancouver Island with selected resources in place to fill the capacity gaps under the Contingency Resource Plan for the Accelerated electrification scenario.[3] The figures and tables illustrate the timing of the resources and their capacity contributions. In this section, the savings from Higher Plus Energy Efficiency include the savings from Higher Energy Efficiency.

Figure 1-12 South Coast capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario



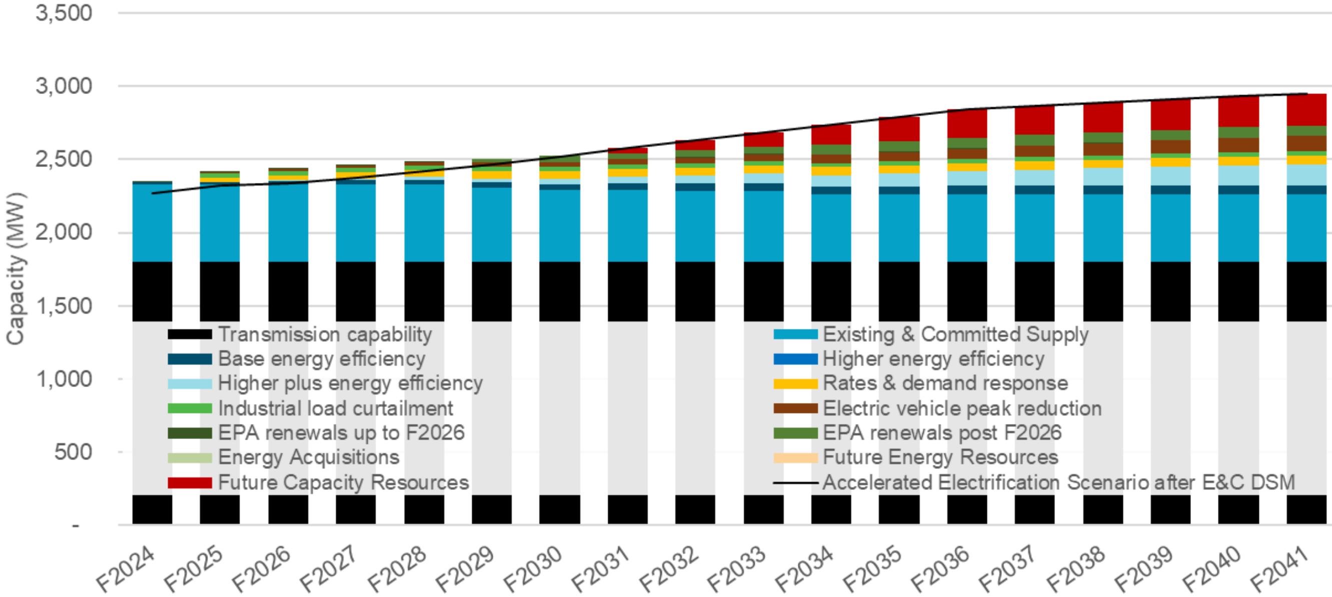
Note: E&C DSM denotes existing and committed demand-side measures.

[3] A Load Resource Balance is not presented for the North Coast region as the load growth associated with the accelerated electrification scenario primarily occurs in the South Coast.

Table 1-12 South Coast capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Existing and Committed Electricity Purchase Agreements	(b)	322	311	282	282	274	251	233	192	186	185	160	160	149	149	149	149	141	141
Regional Supply Capacity (before planned resources)	(c) = a+b	1,839	1,828	1,799	1,799	1,791	1,768	1,750	1,709	1,703	1,702	1,677	1,677	1,666	1,666	1,666	1,666	1,658	1,658
Transmission Capability	(d)	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300
Demand - Regional Gross Requirements																			
Accelerated Electrification Scenario	(e)	(8,031)	(8,238)	(8,379)	(8,604)	(8,828)	(9,028)	(9,281)	(9,563)	(9,817)	(10,064)	(10,326)	(10,590)	(10,862)	(11,044)	(11,227)	(11,409)	(11,589)	(11,752)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	59	95	128	157	187	214	240	263	285	307	329	350	371	392	412	433	453	476
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**167**	**(15)**	**(151)**	**(347)**	**(550)**	**(746)**	**(991)**	**(1,291)**	**(1,529)**	**(1,755)**	**(2,020)**	**(2,263)**	**(2,525)**	**(2,686)**	**(2,849)**	**(3,010)**	**(3,178)**	**(3,318)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		42	63	82	99	115	130	145	159	169	178	185	191	198	202	205	207	207	209
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	14	30	50	73	98	125	154	185	218	252	285	316	346	375	402	421
Time-Varying Rates & Demand Response		-	104	118	140	162	173	176	178	179	180	181	183	184	186	187	189	190	191
Industrial Load Curtailment		-	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86
Electric Vehicle Peak Reduction		-	38	62	94	115	138	162	189	218	249	282	318	355	391	428	464	499	537
Sub-total	(h)	42	291	362	450	529	600	667	736	806	878	953	1,029	1,107	1,181	1,252	1,320	1,385	1,445
Surplus / (Deficit) after planned DSM	(i) = g+h	**209**	**276**	**211**	**102**	**(21)**	**(146)**	**(325)**	**(556)**	**(723)**	**(876)**	**(1,067)**	**(1,234)**	**(1,418)**	**(1,505)**	**(1,597)**	**(1,690)**	**(1,793)**	**(1,873)**
Transmission Upgrades																			
Step 1 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	800	800	800	800	800	800	800	800	800
Step 2 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	800	800	800
Sub-total	(j)	-	-	-	-	-	-	-	-	-	800	800	800	800	800	800	1,600	1,600	1,600
Electricity Purchase Agreement Renewals prior to F2026	(k)	5	16	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Electricity Purchase Agreement Renewals post F2026	(l)	-	-	-	-	9	31	49	91	97	97	122	122	126	126	126	126	133	133
Energy Acquisitions (Capacity Contribution)	(m)	-	-	36	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Future Energy Resources (Capacity Contribution)	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Capacity Resources	(o)	-	-	-	-	-	10	171	360	521	521	521	521	521	521	566	566	566	566
Surplus / (Deficit) after planned resources	(p) = i+j+k+l+m+n+o	**214**	**292**	**292**	**207**	**93**	**0**	**0**	**0**	**0**	**647**	**481**	**314**	**135**	**47**	**0**	**707**	**611**	**531**

Figure 1-13 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario



Note: E&C DSM denotes existing and committed demand-side measures.

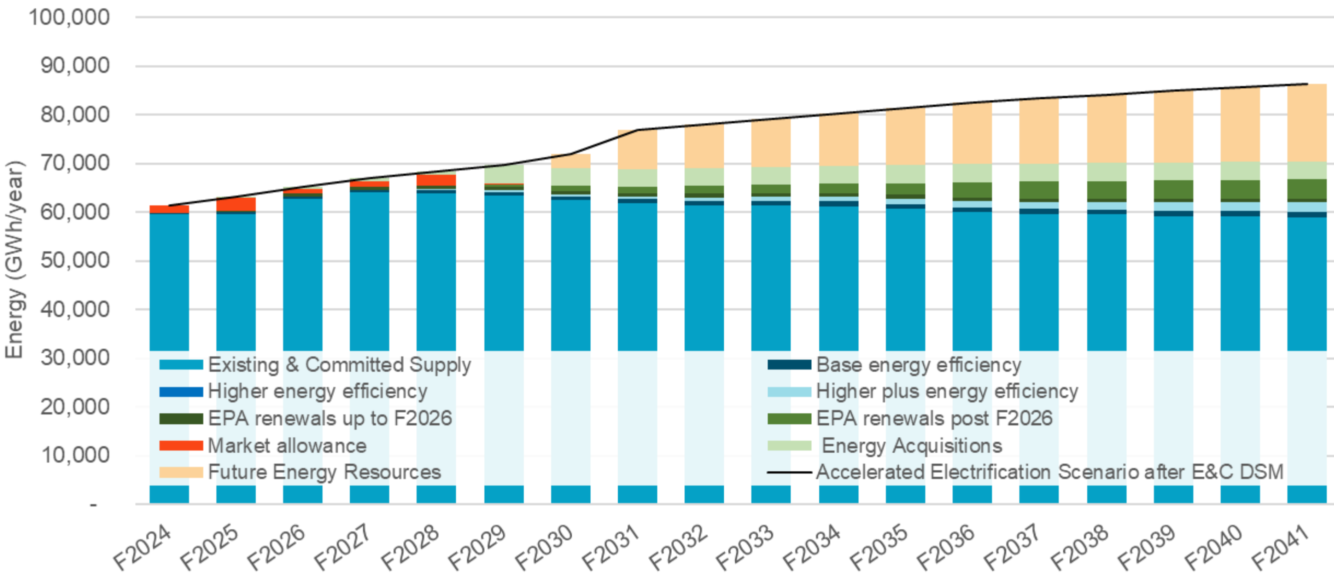
Table 1-13 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
Existing and Committed Electricity Purchase Agreements	(b)	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
Regional Supply Capacity (before planned resources)	(c) = a+b	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
Transmission Capability	(d)	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
Demand - Regional Gross Requirements																			
Accelerated Electrification Scenario	(e)	(2,285)	(2,347)	(2,374)	(2,422)	(2,472)	(2,523)	(2,586)	(2,652)	(2,710)	(2,766)	(2,825)	(2,885)	(2,946)	(2,974)	(3,001)	(3,028)	(3,054)	(3,076)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	17	27	36	44	52	60	66	72	78	84	89	94	99	104	109	114	119	124
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**64**	**12**	**(8)**	**(48)**	**(90)**	**(156)**	**(231)**	**(290)**	**(349)**	**(399)**	**(477)**	**(532)**	**(588)**	**(610)**	**(633)**	**(655)**	**(677)**	**(693)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		13	20	25	30	36	40	45	50	53	56	58	60	62	63	64	64	64	65
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	5	11	18	26	35	44	54	65	76	88	99	109	119	129	138	145
Time-Varying Rates & Demand Response		-	29	34	42	49	53	53	54	54	54	55	55	56	56	56	57	57	57
Industrial Load Curtailment		-	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29
Electric Vehicle Peak Reduction		-	7	12	18	22	27	32	37	43	49	55	62	69	77	84	91	98	105
Sub-total	(h)	13	86	106	131	155	175	194	214	233	253	274	294	315	334	352	370	387	401
Surplus / (Deficit) after planned DSM	(i) = g+h	**78**	**97**	**99**	**83**	**65**	**19**	**(36)**	**(76)**	**(116)**	**(146)**	**(203)**	**(237)**	**(273)**	**(276)**	**(281)**	**(285)**	**(290)**	**(292)**
Electricity Purchase Agreement Renewals prior to F2026	(j)	1	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Electricity Purchase Agreement Renewals post F2026	(k)	-	-	-	-	-	23	40	40	46	47	70	71	71	71	71	71	71	71
Energy Acquisitions (Capacity Contribution)	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Energy Resources (Capacity Contribution)	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Capacity Resources	(n)	-	-	-	-	-	-	-	33	67	96	130	163	199	202	207	211	216	218
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**79**	**98**	**102**	**86**	**68**	**45**	**7**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

5.3 System Load Resource Balances with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

Figure 1-14, Table 1-14 Figure 1-15 and Table 1-15 present the system-wide energy and capacity Load Resource Balances with selected resources in place to fill the energy and capacity gaps under the Contingency Resource Plan for the Accelerated electrification with demand-side measures under-delivery scenario. The figures and tables illustrate the timing of the resources and their energy/capacity contributions. In this section, the savings from Higher Plus Energy Efficiency include the savings from Higher Energy Efficiency.

Figure 1-14 System energy Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

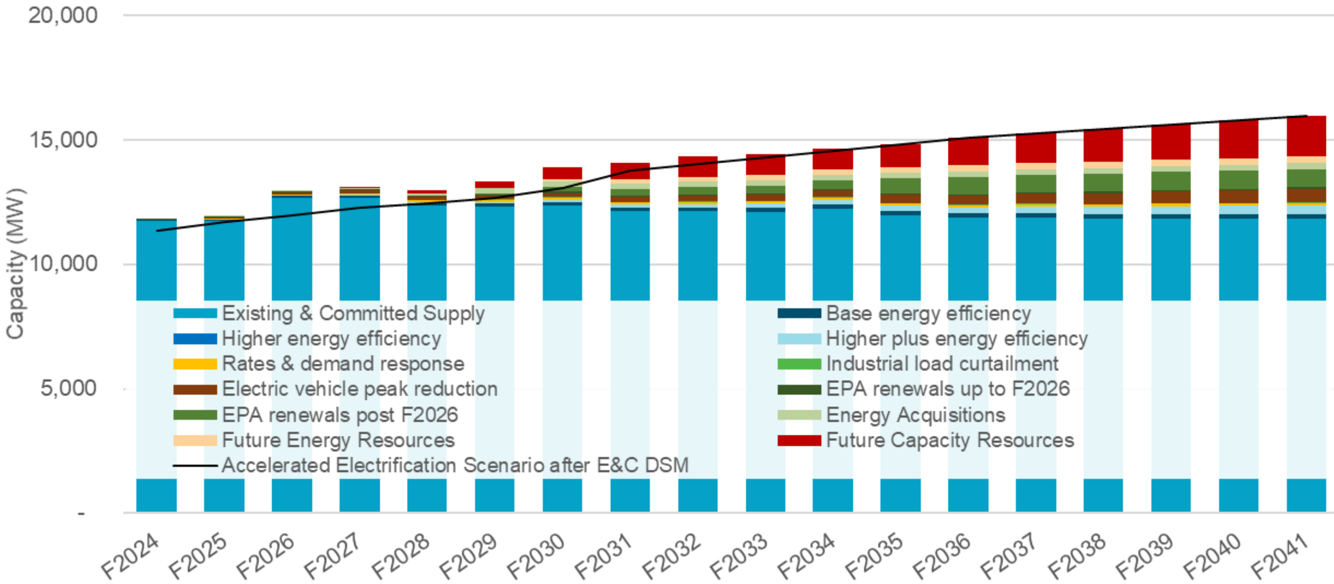


Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-14 System energy Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

(GWh/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
Existing and Committed Electricity Purchase Agreements	(b)	12,649	12,404	11,991	11,783	11,734	11,294	10,318	9,611	9,272	9,212	9,024	8,507	7,810	7,455	7,311	7,051	7,021	6,834
System Capability (before planned resources)	(c) = a+b	59,547	59,668	62,781	63,967	63,918	63,478	62,502	61,795	61,456	61,396	61,208	60,691	59,994	59,639	59,495	59,235	59,205	59,018
Demand - Integrated System Total Gross Requirements																			
Accelerated Electrification Scenario	(d)	(62,032)	(64,079)	(66,433)	(68,463)	(70,015)	(71,555)	(74,106)	(79,251)	(80,562)	(81,864)	(83,201)	(84,542)	(85,945)	(86,937)	(87,951)	(88,928)	(89,928)	(90,782)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards plus Voltage and VAR Optimization		454	709	953	1,192	1,406	1,603	1,782	1,952	2,115	2,271	2,427	2,584	2,741	2,897	3,053	3,210	3,366	3,526
Energy Conservation Rate Structures		150	193	161	110	99	94	94	94	93	76	45	14	-	-	-	-	-	-
Sub-total	(e)	605	902	1,114	1,302	1,505	1,697	1,875	2,045	2,209	2,347	2,473	2,598	2,741	2,897	3,053	3,210	3,366	3,526
Net Metering	(f)	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**(1,818)**	**(3,432)**	**(2,443)**	**(3,077)**	**(4,449)**	**(6,206)**	**(9,516)**	**(15,153)**	**(16,586)**	**(17,750)**	**(19,083)**	**(20,742)**	**(22,622)**	**(23,734)**	**(24,655)**	**(25,652)**	**(26,442)**	**(27,239)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		150	268	378	474	574	659	739	827	880	930	968	998	1,040	1,061	1,091	1,102	1,110	1,117
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	33	112	213	313	435	571	721	854	1,005	1,147	1,285	1,426	1,542	1,655	1,762	1,824
Sub-total	(h)	150	268	411	586	787	972	1,174	1,398	1,601	1,784	1,973	2,145	2,325	2,487	2,633	2,757	2,872	2,941
Surplus / (Deficit) after planned DSM	(i) = g+h	**(1,669)**	**(3,164)**	**(2,033)**	**(2,491)**	**(3,662)**	**(5,234)**	**(8,342)**	**(13,756)**	**(14,985)**	**(15,966)**	**(17,110)**	**(18,597)**	**(20,297)**	**(21,247)**	**(22,022)**	**(22,895)**	**(23,571)**	**(24,298)**
Electricity Purchase Agreement Renewals prior to F2026	(j)	160	356	634	707	707	707	707	707	707	707	707	707	707	707	707	707	707	707
Electricity Purchase Agreement Renewals post F2026	(k)	-	-	-	-	90	498	964	1,299	1,637	1,698	1,885	2,402	3,090	3,420	3,564	3,824	3,854	4,041
Market Allowance	(l)	1,509	2,609	899	1,084	2,165	329	-	-	-	-	-	-	-	-	-	-	-	-
Energy Acquisitions	(m)	-	200	500	700	700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Future Energy Resources	(n)	-	-	-	-	-	-	2,971	8,050	8,941	9,861	10,818	11,788	12,800	13,420	14,051	14,665	15,310	15,850
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Figure 1-15 System capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario



Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-15 System capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources [1]	(a)	11,818	11,818	12,963	12,963	12,616	12,616	12,963	12,789	12,789	12,789	12,963	12,963	12,963	12,963	12,963	12,963	12,963	12,963
Existing and Committed Electricity Purchase Agreements	(b)	1,472	1,458	1,379	1,379	1,370	1,342	1,048	954	943	920	886	582	482	482	446	446	438	437
12% Reserves [2]	(c)	(1,538)	(1,538)	(1,672)	(1,672)	(1,631)	(1,627)	(1,634)	(1,601)	(1,600)	(1,598)	(1,617)	(1,584)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
System Peak Load Carrying Capability (before Planned Resourc	(d) = a+b+c	11,752	11,738	12,670	12,670	12,356	12,331	12,377	12,142	12,132	12,111	12,232	11,961	11,868	11,868	11,833	11,833	11,825	11,824
Demand - Integrated System Total Gross Requirements																			
Accelerated Electrification Scenario	(e)	(11,446)	(11,835)	(12,162)	(12,494)	(12,727)	(12,974)	(13,408)	(14,157)	(14,439)	(14,714)	(15,008)	(15,303)	(15,607)	(15,816)	(16,027)	(16,234)	(16,440)	(16,624)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards		80	129	177	219	263	302	338	371	403	435	467	498	528	558	587	616	646	677
Energy Conservation Rate Structures		13	18	17	13	12	11	11	11	11	9	5	2	-	-	-	-	-	-
Sub-total	(f)	92	147	194	232	274	313	349	382	414	444	472	500	528	558	587	616	646	677
Surplus / (Deficit) before planned resources	(g) = d+e+f	**398**	**50**	**702**	**409**	**(97)**	**(331)**	**(682)**	**(1,633)**	**(1,893)**	**(2,159)**	**(2,304)**	**(2,843)**	**(3,211)**	**(3,390)**	**(3,607)**	**(3,785)**	**(3,969)**	**(4,123)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		27	47	65	81	97	111	124	137	147	156	162	168	174	179	183	184	186	189
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	12	27	45	65	87	112	139	165	192	219	247	271	295	317	339	353
Time-Varying Rates & Demand Response		-	34	44	59	75	82	84	85	85	86	86	87	87	88	89	89	90	90
Industrial Load Curtailment		-	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Electric Vehicle Peak Reduction		-	40	65	98	119	143	168	195	226	258	293	330	368	406	443	481	517	557
Sub-total	(h)	27	138	203	282	352	418	480	546	613	681	750	821	893	962	1,027	1,089	1,149	1,206
Surplus / (Deficit) after planned DSM	(i) = g+h	**425**	**188**	**905**	**691**	**256**	**87**	**(201)**	**(1,088)**	**(1,280)**	**(1,478)**	**(1,554)**	**(2,022)**	**(2,318)**	**(2,429)**	**(2,580)**	**(2,696)**	**(2,820)**	**(2,917)**
Electricity Purchase Agreement Renewals prior to F2026 [3]	(j)	12	26	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Electricity Purchase Agreement Renewals post F2026 [3]	(k)	-	-	-	-	9	35	198	281	291	311	344	615	700	700	736	736	744	745
Energy Acquisitions (Capacity Contribution) [3]	(l)	-	7	39	60	60	223	223	223	223	223	223	223	223	223	223	223	223	223
Future Energy Resources (Capacity Contribution)	(m)	-	-	-	-	-	-	94	177	191	203	217	229	241	248	255	262	267	279
Future Capacity Resources	(n)	-	-	-	14	152	274	452	659	837	837	837	903	1,102	1,205	1,313	1,424	1,534	1,618
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**438**	**221**	**996**	**816**	**528**	**671**	**818**	**304**	**314**	**149**	**119**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes:

[1] Includes outages for Mica and Seven Mile

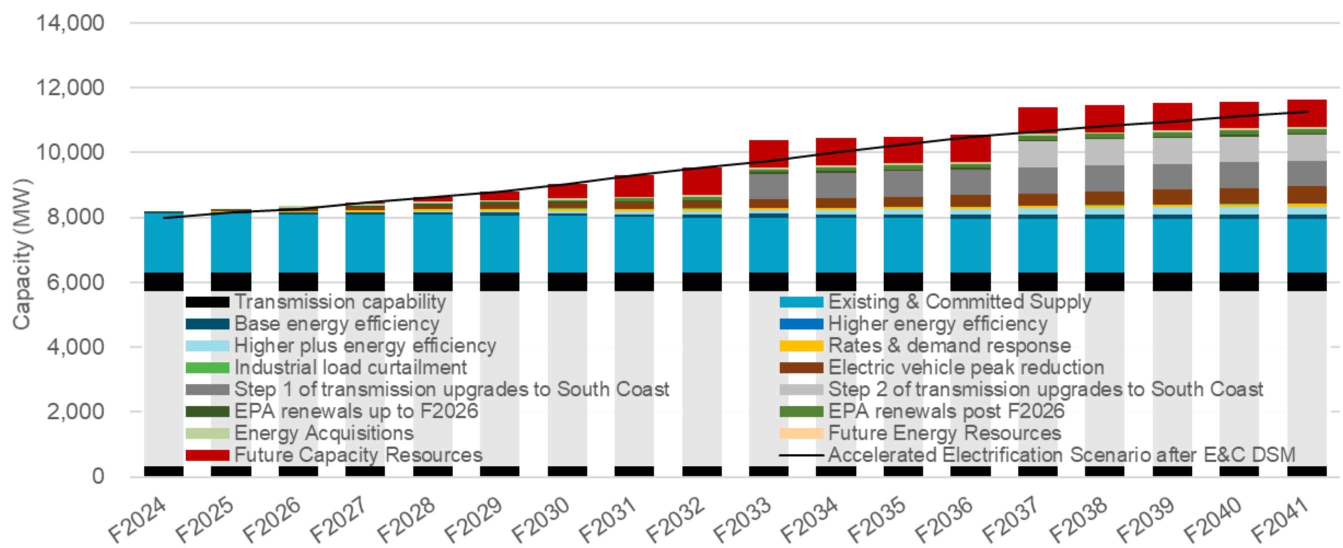
[2] The 12% reserve margin is applied to dependable capacity resources only

[3] The numbers shown include the 12% reserve margin

5.4 Regional capacity Load Resource Balances with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

Figure 1-16, Table 1-16, Figure 1-17 and Table 1-17 present the capacity Load Resource Balances for the South Coast and Vancouver Island with selected resources in place to fill the capacity gaps under the Contingency Resource Plan for the Accelerated electrification with demand-side measures under-delivery scenario.[4] The figures and tables illustrate the timing of the resources and their capacity contributions. In this section, the savings from Higher Plus Energy Efficiency include the savings from Higher Energy Efficiency.

Figure 1-16 South Coast capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario



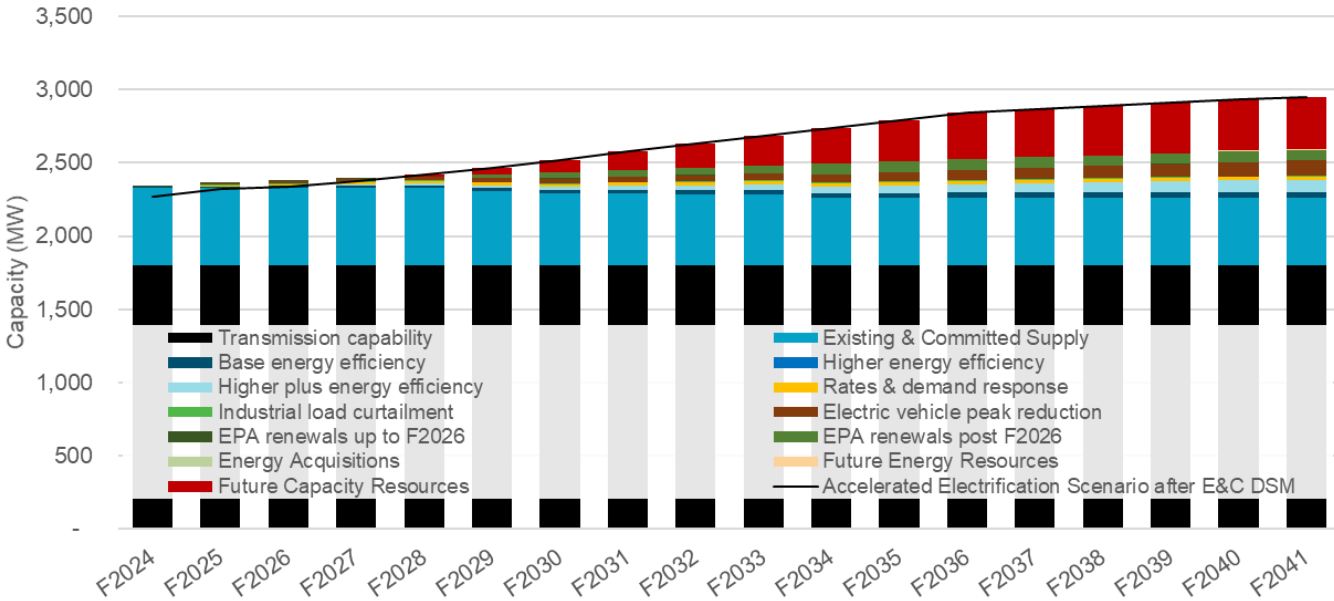
Note: E&C DSM denotes existing and committed demand-side measures.

[4] A Load Resource Balance is not presented for the North Coast region as the load growth associated with the Accelerated electrification scenario primarily occurs in the South Coast.

Table 1-16 South Coast capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Existing and Committed Electricity Purchase Agreements	(b)	322	311	282	282	274	251	233	192	186	185	160	160	149	149	149	149	141	141
Regional Supply Capacity (before planned resources)	(c) = a+b	1,839	1,828	1,799	1,799	1,791	1,768	1,750	1,709	1,703	1,702	1,677	1,677	1,666	1,666	1,666	1,666	1,658	1,658
Transmission Capability	(d)	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300
Demand - Regional Gross Requirements																			
Accelerated Electrification Scenario	(e)	(8,031)	(8,238)	(8,379)	(8,604)	(8,828)	(9,028)	(9,281)	(9,563)	(9,817)	(10,064)	(10,326)	(10,590)	(10,862)	(11,044)	(11,227)	(11,409)	(11,589)	(11,752)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	59	95	128	157	187	214	240	263	285	307	329	350	371	392	412	433	453	476
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**167**	**(15)**	**(151)**	**(347)**	**(550)**	**(746)**	**(991)**	**(1,291)**	**(1,529)**	**(1,755)**	**(2,020)**	**(2,263)**	**(2,525)**	**(2,686)**	**(2,849)**	**(3,010)**	**(3,178)**	**(3,318)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		20	33	46	57	68	77	86	95	102	108	113	117	121	124	127	128	129	131
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	8	18	30	43	58	74	91	109	129	148	168	186	204	221	237	249
Time-Varying Rates & Demand Response		-	26	34	46	59	66	67	67	68	68	69	69	70	70	71	71	72	72
Industrial Load Curtailment		-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Electric Vehicle Peak Reduction		-	38	61	92	113	135	159	185	213	244	277	312	348	384	419	454	489	526
Sub-total	(h)	20	112	164	229	284	336	385	436	489	545	602	661	721	780	836	890	943	994
Surplus / (Deficit) after planned DSM	(i) = g+h	**187**	**97**	**13**	**(119)**	**(266)**	**(410)**	**(606)**	**(855)**	**(1,039)**	**(1,210)**	**(1,418)**	**(1,602)**	**(1,804)**	**(1,907)**	**(2,012)**	**(2,120)**	**(2,235)**	**(2,324)**
Transmission Upgrades																			
Step 1 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	800	800	800	800	800	800	800	800	800
Step 2 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	-	-	800	800	800	800	800
Sub-total	(j)	-	-	-	-	-	-	-	-	-	800	800	800	800	1,600	1,600	1,600	1,600	1,600
Electricity Purchase Agreement Renewals prior to F2026	(k)	5	16	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Electricity Purchase Agreement Renewals post F2026	(l)	-	-	-	-	9	31	49	91	97	97	122	122	126	126	126	126	133	133
Energy Acquisitions (Capacity Contribution)	(m)	-	-	36	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Future Energy Resources (Capacity Contribution)	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
Future Capacity Resources	(o)	-	-	-	14	152	274	452	659	837	837	837	837	837	837	837	837	837	837
Surplus / (Deficit) after planned resources	(p) = i+j+k+l+m+n+o	**192**	**113**	**94**	**0**	**0**	**0**	**0**	**0**	**0**	**630**	**446**	**262**	**65**	**762**	**656**	**549**	**446**	**357**

Figure 1-17 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario



Note: E&C DSM denotes existing and committed demand-side measures.

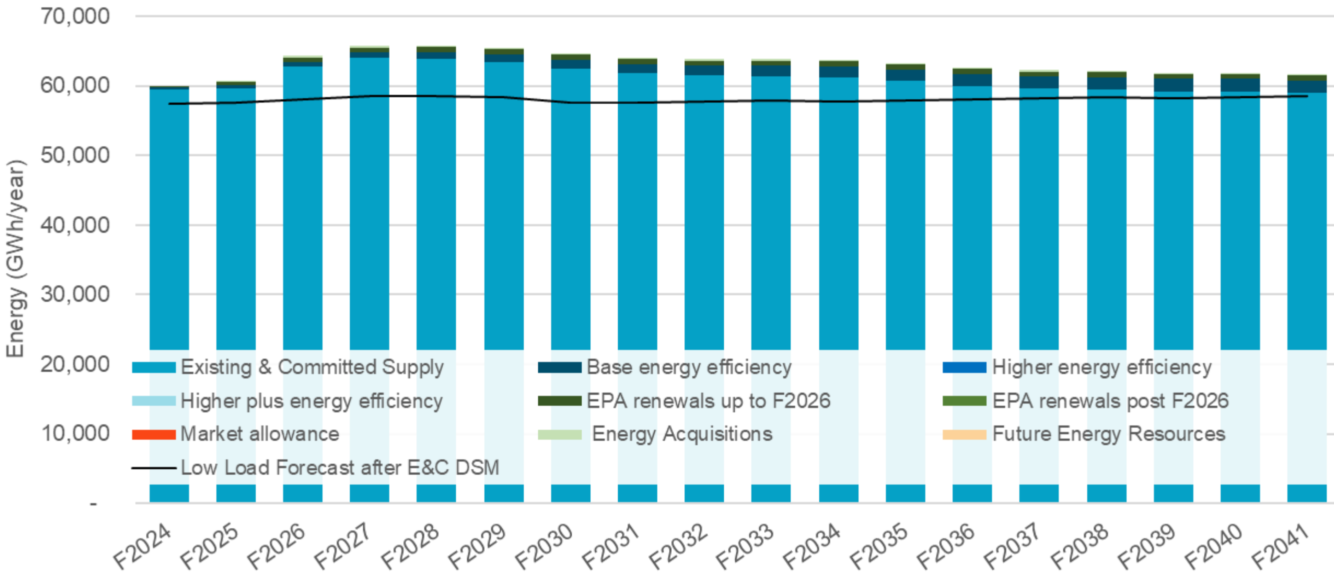
Table 1-17 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
Existing and Committed Electricity Purchase Agreements	(b)	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
Regional Supply Capacity (before planned resources)	(c) = a+b	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
Transmission Capability	(d)	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
Demand - Regional Gross Requirements																			
Accelerated Electrification Scenario	(e)	(2,285)	(2,347)	(2,374)	(2,422)	(2,472)	(2,523)	(2,586)	(2,652)	(2,710)	(2,766)	(2,825)	(2,885)	(2,946)	(2,974)	(3,001)	(3,028)	(3,054)	(3,076)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	17	27	36	44	52	60	66	72	78	84	89	94	99	104	109	114	119	124
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**64**	**12**	**(8)**	**(48)**	**(90)**	**(156)**	**(231)**	**(290)**	**(349)**	**(399)**	**(477)**	**(532)**	**(588)**	**(610)**	**(633)**	**(655)**	**(677)**	**(693)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		7	11	14	18	21	24	27	30	32	34	36	37	38	39	40	40	40	41
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	3	7	11	15	21	26	32	38	45	52	58	64	70	76	82	85
Time-Varying Rates & Demand Response		-	7	10	15	19	21	21	21	21	21	22	22	22	22	22	22	22	23
Industrial Load Curtailment		-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Electric Vehicle Peak Reduction		-	7	12	18	22	26	31	36	42	48	54	61	68	75	82	89	96	103
Sub-total	(h)	7	31	45	62	78	92	105	119	133	147	162	176	191	206	219	232	245	256
Surplus / (Deficit) after planned DSM	(i) = g+h	**71**	**42**	**37**	**14**	**(12)**	**(64)**	**(126)**	**(171)**	**(216)**	**(252)**	**(315)**	**(355)**	**(397)**	**(405)**	**(414)**	**(423)**	**(432)**	**(437)**
Electricity Purchase Agreement Renewals prior to F2026	(j)	1	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Electricity Purchase Agreement Renewals post F2026	(k)	-	-	-	-	-	23	40	40	46	47	70	71	71	71	71	71	71	71
Energy Acquisitions (Capacity Contribution)	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Energy Resources (Capacity Contribution)	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
Future Capacity Resources	(n)	-	-	-	-	9	38	83	128	167	202	242	281	323	331	340	349	352	357
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**72**	**43**	**40**	**17**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

5.5 System Load Resource Balances with Contingency Resource Plan for Low load scenario

Figure 1-18, Table 1-18 Figure 1-19 and Table 1-19 present the system-wide energy and capacity Load Resource Balances under the Contingency Resource Plan for the Low load scenario.

Figure 1-18 System energy Load Resource Balance with Contingency Resource Plan for Low load scenario

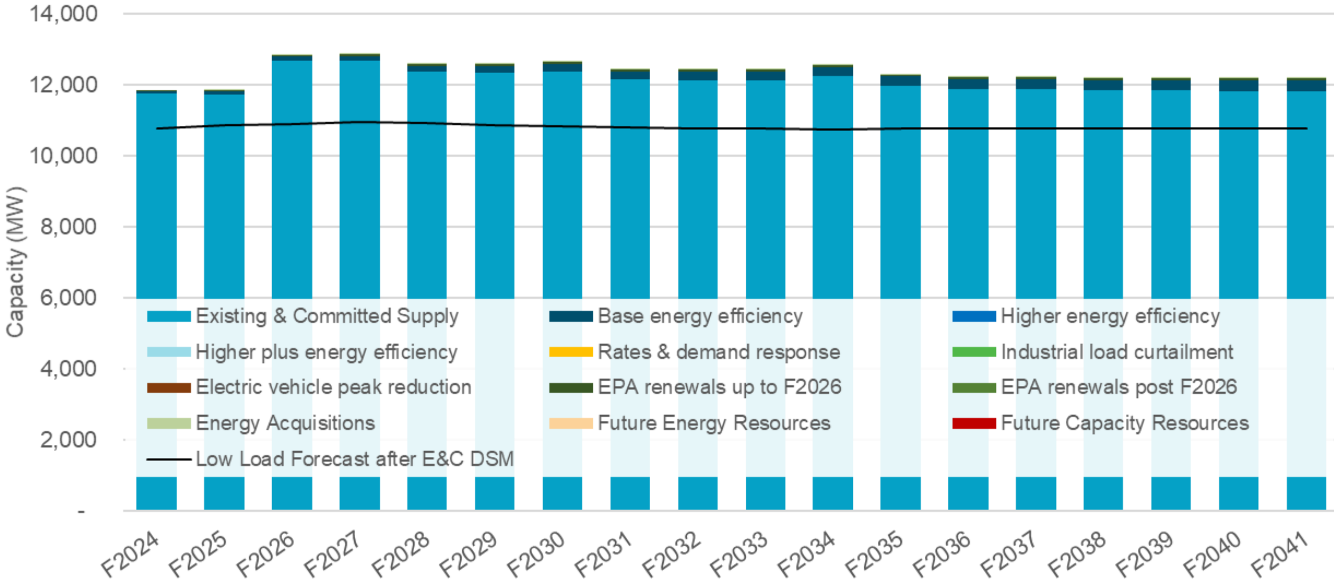


Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-18 System energy Load Resource Balance with Contingency Resource Plan for Low load scenario

(GWh/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
Existing and Committed Electricity Purchase Agreements	(b)	12,649	12,404	11,991	11,783	11,734	11,294	10,318	9,611	9,272	9,212	9,024	8,507	7,810	7,455	7,311	7,051	7,021	6,834
System Capability (before planned resources)	(c) = a+b	59,547	59,668	62,781	63,967	63,918	63,478	62,502	61,795	61,456	61,396	61,208	60,691	59,994	59,639	59,495	59,235	59,205	59,018
Demand - Integrated System Total Gross Requirements																			
Low Load Forecast	(d)	(58,041)	(58,415)	(59,025)	(59,677)	(59,855)	(59,810)	(59,218)	(59,454)	(59,765)	(60,077)	(59,957)	(60,293)	(60,644)	(61,014)	(61,387)	(61,458)	(61,824)	(62,151)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards plus Voltage and VAR Optimization		369	571	760	942	1,096	1,234	1,361	1,478	1,590	1,696	1,803	1,910	2,022	2,135	2,248	2,363	2,479	2,597
Energy Conservation Rate Structures		121	154	128	87	77	72	71	71	70	57	34	10	-	-	-	-	-	-
Sub-total	(e)	489	726	888	1,028	1,173	1,306	1,432	1,549	1,660	1,752	1,836	1,921	2,022	2,135	2,248	2,363	2,479	2,597
Net Metering	(f)	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**2,057**	**2,056**	**4,739**	**5,436**	**5,379**	**5,149**	**4,928**	**4,147**	**3,663**	**3,442**	**3,525**	**2,829**	**1,960**	**1,427**	**1,105**	**972**	**775**	**463**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		324	508	679	825	977	1,112	1,237	1,375	1,456	1,528	1,584	1,629	1,694	1,719	1,753	1,765	1,774	1,781
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total	(h)	324	508	679	825	977	1,112	1,237	1,375	1,456	1,528	1,584	1,629	1,694	1,719	1,753	1,765	1,774	1,781
Surplus / (Deficit) after planned DSM	(i) = g+h	**2,381**	**2,564**	**5,418**	**6,260**	**6,356**	**6,260**	**6,165**	**5,523**	**5,119**	**4,970**	**5,109**	**4,458**	**3,654**	**3,146**	**2,858**	**2,737**	**2,548**	**2,244**
Electricity Purchase Agreement Renewals prior to F2026	(j)	160	356	634	707	707	707	707	707	707	707	707	707	707	707	707	707	707	707
Electricity Purchase Agreement Renewals post F2026	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Market Allowance	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Acquisitions	(m)	-	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Future Energy Resources	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**2,541**	**3,120**	**6,252**	**7,167**	**7,263**	**7,167**	**7,072**	**6,430**	**6,026**	**5,877**	**6,016**	**5,365**	**4,561**	**4,053**	**3,764**	**3,644**	**3,455**	**3,151**

Figure 1-19 System capacity Load Resource Balance with Contingency Resource Plan for Low load scenario



Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-19 System capacity Load Resource Balance with Contingency Resource Plan for Low load scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources [1]	(a)	11,818	11,818	12,963	12,963	12,616	12,616	12,963	12,789	12,789	12,789	12,963	12,963	12,963	12,963	12,963	12,963	12,963	12,963
Existing and Committed Electricity Purchase Agreements	(b)	1,472	1,458	1,379	1,379	1,370	1,342	1,048	954	943	920	886	582	482	482	446	446	438	437
12% Reserves [2]	(c)	(1,538)	(1,538)	(1,672)	(1,672)	(1,631)	(1,627)	(1,634)	(1,601)	(1,600)	(1,598)	(1,617)	(1,584)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
System Peak Load Carrying Capability (before Planned Resourc	(d) = a+b+c	11,752	11,738	12,670	12,670	12,356	12,331	12,377	12,142	12,132	12,111	12,232	11,961	11,868	11,868	11,833	11,833	11,825	11,824
Demand - Integrated System Total Gross Requirements																			
Low Load Forecast	(e)	(10,849)	(10,962)	(11,023)	(11,098)	(11,082)	(11,057)	(11,021)	(11,016)	(11,025)	(11,034)	(11,009)	(11,029)	(11,042)	(11,063)	(11,083)	(11,075)	(11,091)	(11,114)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards		58	90	122	130	153	175	196	219	235	247	258	268	279	290	302	313	327	343
Energy Conservation Rate Structures		9	12	12	8	7	6	6	7	6	5	3	1	-	-	-	-	-	-
Sub-total	(f)	67	102	133	138	160	182	202	226	241	252	261	269	279	290	302	313	327	343
Surplus / (Deficit) before planned resources	(g) = d+e+f	**970**	**879**	**1,780**	**1,710**	**1,433**	**1,455**	**1,559**	**1,351**	**1,348**	**1,329**	**1,483**	**1,201**	**1,105**	**1,095**	**1,051**	**1,071**	**1,061**	**1,053**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		59	89	118	142	166	188	209	229	244	257	266	276	285	291	295	297	298	301
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Time-Varying Rates & Demand Response		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total	(h)	59	89	118	142	166	188	209	229	244	257	266	276	285	291	295	297	298	301
Surplus / (Deficit) after planned DSM	(i) = g+h	**1,028**	**968**	**1,898**	**1,852**	**1,599**	**1,643**	**1,768**	**1,580**	**1,591**	**1,586**	**1,749**	**1,477**	**1,390**	**1,386**	**1,346**	**1,368**	**1,359**	**1,353**
Electricity Purchase Agreement Renewals prior to F2026 [3]	(j)	12	26	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Electricity Purchase Agreement Renewals post F2026 [3]	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Acquisitions (Capacity Contribution) [3]	(l)	-	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Future Energy Resources (Capacity Contribution)	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Capacity Resources	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**1,041**	**1,001**	**1,957**	**1,911**	**1,658**	**1,702**	**1,827**	**1,639**	**1,650**	**1,645**	**1,808**	**1,536**	**1,449**	**1,445**	**1,405**	**1,427**	**1,418**	**1,412**

Notes:

[1] Includes outages for Mica and Seven Mile

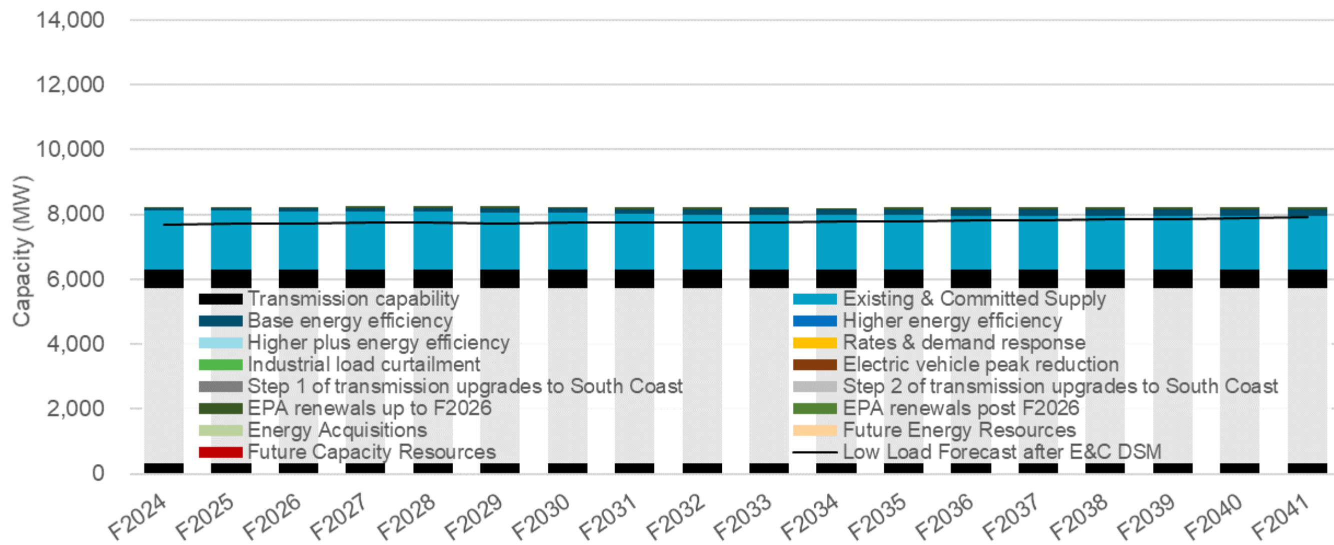
[2] The 12% reserve margin is applied to dependable capacity resources only

[3] The numbers shown include the 12% reserve margin

5.6 Regional capacity Load Resource Balances with Contingency Resource Plan for Low load scenario

Figure 1-20, Table 1-20, Figure 1-21 and Table 1-21 present the South Coast and Vancouver Island capacity Load Resource Balances under the Contingency Resource Plan for the Low load scenario.

Figure 1-20 South Coast capacity Load Resource Balance with Contingency Resource Plan for Low load scenario

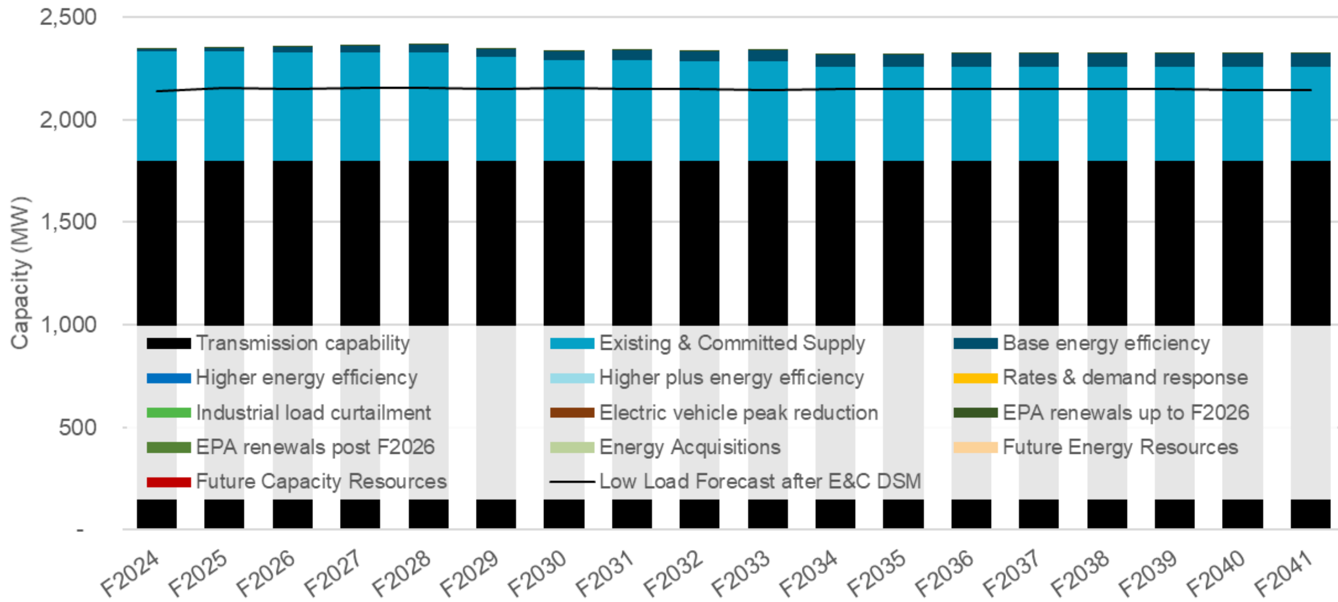


Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-20 South Coast capacity Load Resource Balance with Contingency Resource Plan for Low load scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Existing and Committed Electricity Purchase Agreements	(b)	322	311	282	282	274	251	233	192	186	185	160	160	149	149	149	149	141	141
Regional Supply Capacity (before planned resources)	(c) = a+b	1,839	1,828	1,799	1,799	1,791	1,768	1,750	1,709	1,703	1,702	1,677	1,677	1,666	1,666	1,666	1,666	1,658	1,658
Transmission Capability	(d)	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300
Demand - Regional Gross Requirements																			
Low Load Forecast	(e)	(7,720)	(7,790)	(7,821)	(7,850)	(7,850)	(7,854)	(7,890)	(7,897)	(7,910)	(7,926)	(7,951)	(7,977)	(7,999)	(8,028)	(8,056)	(8,086)	(8,114)	(8,147)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	43	66	88	93	109	125	139	155	166	174	182	189	196	204	212	220	229	241
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**462**	**404**	**367**	**343**	**349**	**339**	**299**	**267**	**259**	**250**	**208**	**189**	**163**	**142**	**121**	**100**	**74**	**52**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		42	63	82	99	115	130	145	159	169	178	185	191	198	202	205	207	207	209
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Time-Varying Rates & Demand Response		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total	(h)	42	63	82	99	115	130	145	159	169	178	185	191	198	202	205	207	207	209
Surplus / (Deficit) after planned DSM	(i) = g+h	**504**	**466**	**449**	**441**	**464**	**468**	**444**	**426**	**428**	**428**	**393**	**380**	**361**	**344**	**327**	**306**	**281**	**261**
Transmission Upgrades																			
Step 1 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Step 2 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total	(j)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electricity Purchase Agreement Renewals prior to F2026	(k)	5	16	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Electricity Purchase Agreement Renewals post F2026	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Acquisitions (Capacity Contribution)	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Energy Resources (Capacity Contribution)	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Capacity Resources	(o)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus / (Deficit) after planned resources	(p) = i+j+k+l+m+n+o	**509**	**482**	**494**	**486**	**509**	**513**	**489**	**471**	**473**	**473**	**438**	**425**	**406**	**389**	**372**	**351**	**326**	**306**

Figure 1-21 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Low load scenario



Note: E&C DSM denotes existing and committed demand-side measures.

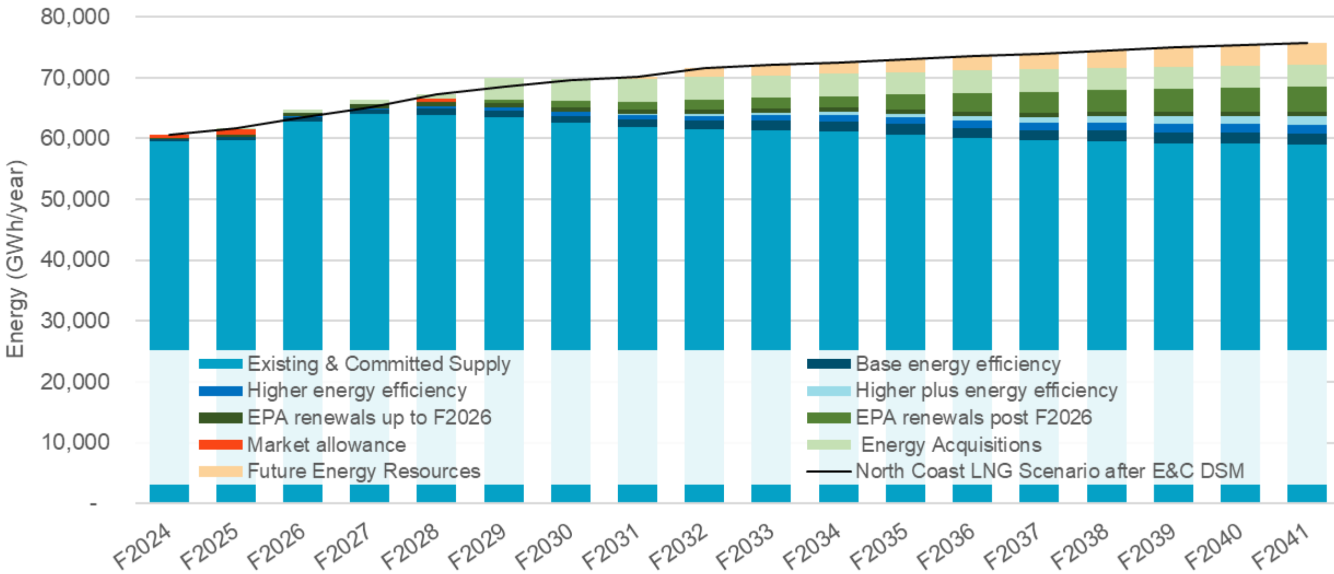
Table 1-21 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Low load scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
Existing and Committed Electricity Purchase Agreements	(b)	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
Regional Supply Capacity (before planned resources)	(c) = a+b	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
Transmission Capability	(d)	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
Demand - Regional Gross Requirements																			
Low Load Forecast	(e)	(2,151)	(2,175)	(2,173)	(2,182)	(2,184)	(2,183)	(2,193)	(2,193)	(2,194)	(2,194)	(2,196)	(2,199)	(2,200)	(2,202)	(2,204)	(2,206)	(2,206)	(2,208)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	12	19	25	26	30	35	38	43	45	47	49	51	52	54	56	58	60	63
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**193**	**175**	**182**	**174**	**176**	**158**	**134**	**139**	**135**	**136**	**112**	**111**	**112**	**111**	**111**	**111**	**112**	**113**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		13	20	25	30	36	40	45	50	53	56	58	60	62	63	64	64	64	65
Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Higher Plus Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Time-Varying Rates & Demand Response		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total	(h)	13	20	25	30	36	40	45	50	53	56	58	60	62	63	64	64	64	65
Surplus / (Deficit) after planned DSM	(i) = g+h	**206**	**195**	**207**	**204**	**211**	**198**	**179**	**188**	**188**	**192**	**170**	**171**	**174**	**174**	**175**	**175**	**176**	**177**
Electricity Purchase Agreement Renewals prior to F2026	(j)	1	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Electricity Purchase Agreement Renewals post F2026	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Acquisitions (Capacity Contribution)	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Energy Resources (Capacity Contribution)	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Capacity Resources	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**207**	**196**	**210**	**207**	**214**	**201**	**182**	**191**	**191**	**195**	**173**	**174**	**177**	**177**	**178**	**178**	**179**	**180**

5.7 System Load Resource Balances with Contingency Resource Plan for North Coast scenario

Figure 1-22, Table 1-22, Figure 1-23 and Table 1-23 present the system-wide energy and capacity Load Resource Balances with selected resources in place to fill the energy and capacity gaps under the Contingency Resource Plan for the North Coast liquified natural gas and mining scenario (North Coast scenario). The figures and tables illustrate the timing of the resources and their energy/capacity contributions.

Figure 1-22 System energy Load Resource Balance with Contingency Resource Plan for North Coast scenario

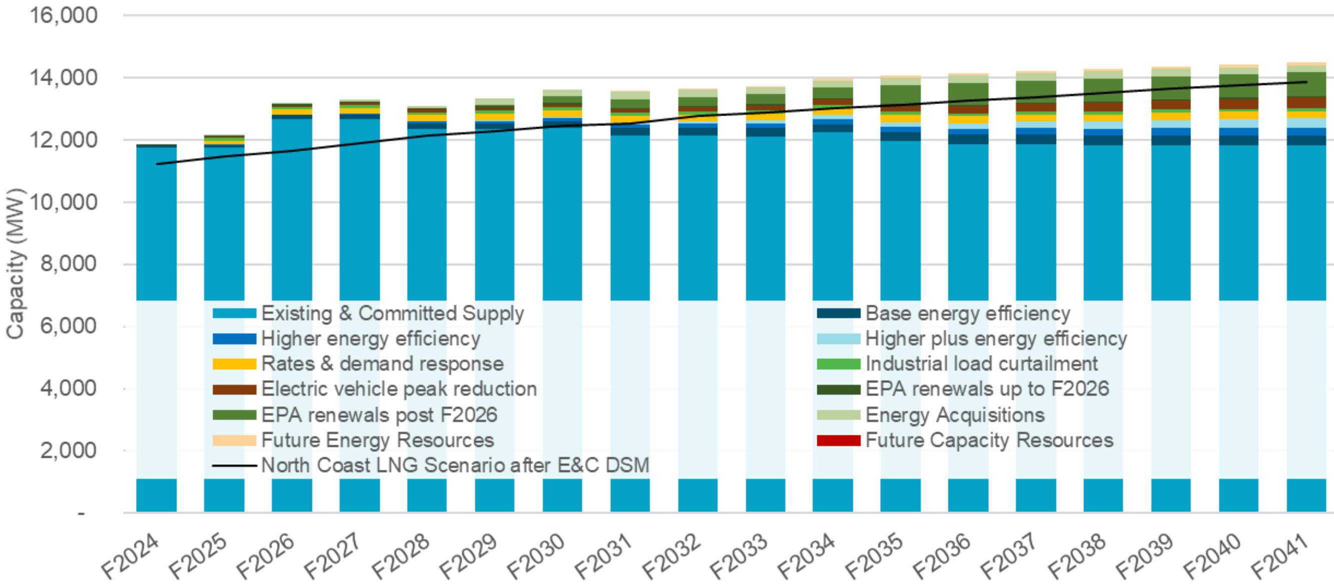


Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-22 System energy Load Resource Balance with Contingency Resource Plan for North Coast scenario

(GWh/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
Existing and Committed Electricity Purchase Agreements	(b)	12,649	12,404	11,991	11,783	11,734	11,294	10,318	9,611	9,272	9,212	9,024	8,507	7,810	7,455	7,311	7,051	7,021	6,834
System Capability (before planned resources)	(c) = a+b	59,547	59,668	62,781	63,967	63,918	63,478	62,502	61,795	61,456	61,396	61,208	60,691	59,994	59,639	59,495	59,235	59,205	59,018
Demand - Integrated System Total Gross Requirements																			
North Coast LNG Scenario	(d)	(61,311)	(62,700)	(64,613)	(66,442)	(68,824)	(70,365)	(71,607)	(72,366)	(74,175)	(74,805)	(75,470)	(76,139)	(76,870)	(77,562)	(78,276)	(78,953)	(79,653)	(80,206)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards plus Voltage and VAR Optimization		454	709	953	1,192	1,406	1,603	1,782	1,952	2,115	2,271	2,427	2,584	2,741	2,897	3,053	3,210	3,366	3,526
Energy Conservation Rate Structures		150	193	161	110	99	94	94	94	93	76	45	14	-	-	-	-	-	-
Sub-total	(e)	605	902	1,114	1,302	1,505	1,697	1,875	2,045	2,209	2,347	2,473	2,598	2,741	2,897	3,053	3,210	3,366	3,526
Net Metering	(f)	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**(1,097)**	**(2,053)**	**(623)**	**(1,056)**	**(3,258)**	**(5,016)**	**(7,018)**	**(8,268)**	**(10,199)**	**(10,691)**	**(11,352)**	**(12,339)**	**(13,547)**	**(14,359)**	**(14,979)**	**(15,677)**	**(16,167)**	**(16,663)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		324	508	679	825	977	1,112	1,237	1,375	1,456	1,528	1,584	1,629	1,694	1,719	1,753	1,765	1,774	1,781
Higher Energy Efficiency		-	35	118	222	327	448	576	709	813	926	1,025	1,108	1,192	1,255	1,320	1,387	1,410	1,438
Higher Plus Energy Efficiency		-	-	-	-	21	72	140	203	288	392	513	635	777	919	1,071	1,225	1,359	1,485
Sub-total	(h)	324	543	796	1,047	1,325	1,632	1,953	2,287	2,557	2,845	3,123	3,372	3,663	3,894	4,143	4,377	4,543	4,704
Surplus / (Deficit) after planned DSM	(i) = g+h	**(773)**	**(1,510)**	**173**	**(9)**	**(1,933)**	**(3,384)**	**(5,065)**	**(5,981)**	**(7,642)**	**(7,846)**	**(8,229)**	**(8,967)**	**(9,884)**	**(10,465)**	**(10,836)**	**(11,300)**	**(11,624)**	**(11,959)**
Electricity Purchase Agreement Renewals prior to F2026	(j)	160	356	634	707	707	707	707	707	707	707	707	707	707	707	707	707	707	707
Electricity Purchase Agreement Renewals post F2026	(k)	-	-	-	-	90	498	964	1,299	1,637	1,698	1,885	2,402	3,090	3,420	3,564	3,824	3,854	4,041
Market Allowance	(l)	613	955	-	-	436	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Acquisitions	(m)	-	200	500	700	700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Future Energy Resources	(n)	-	-	-	-	-	-	-	275	1,598	1,741	1,937	2,158	2,387	2,638	2,865	3,069	3,363	3,511
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**0**	**0**	**1,307**	**1,398**	**0**	**1,521**	**306**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Figure 1-23 System capacity Load Resource Balance with Contingency Resource Plan for North Coast scenario



Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-23 System capacity Load Resource Balance with Contingency Resource Plan for North Coast scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources [1]	(a)	11,818	11,818	12,963	12,963	12,616	12,616	12,963	12,789	12,789	12,789	12,963	12,963	12,963	12,963	12,963	12,963	12,963	12,963
Existing and Committed Electricity Purchase Agreements	(b)	1,472	1,458	1,379	1,379	1,370	1,342	1,048	954	943	920	886	582	482	482	446	446	438	437
12% Reserves [2]	(c)	(1,538)	(1,538)	(1,672)	(1,672)	(1,631)	(1,627)	(1,634)	(1,601)	(1,600)	(1,598)	(1,617)	(1,584)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
System Peak Load Carrying Capability (before Planned Resourc	(d) = a+b+c	11,752	11,738	12,670	12,670	12,356	12,331	12,377	12,142	12,132	12,111	12,232	11,961	11,868	11,868	11,833	11,833	11,825	11,824
Demand - Integrated System Total Gross Requirements																			
North Coast LNG Scenario	(e)	(11,325)	(11,601)	(11,842)	(12,116)	(12,403)	(12,590)	(12,803)	(12,909)	(13,192)	(13,321)	(13,468)	(13,617)	(13,774)	(13,934)	(14,094)	(14,252)	(14,408)	(14,543)
Existing and Committed Demand-side Measures																			
Energy Conservation Programs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Codes & Standards		80	129	177	219	263	302	338	371	403	435	467	498	528	558	587	616	646	677
Energy Conservation Rate Structures		13	18	17	13	12	11	11	11	11	9	5	2	-	-	-	-	-	-
Sub-total	(f)	92	147	194	232	274	313	349	382	414	444	472	500	528	558	587	616	646	677
Surplus / (Deficit) before planned resources	(g) = d+e+f	**519**	**285**	**1,022**	**786**	**227**	**53**	**(77)**	**(385)**	**(647)**	**(766)**	**(764)**	**(1,156)**	**(1,378)**	**(1,508)**	**(1,674)**	**(1,803)**	**(1,937)**	**(2,041)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		59	89	118	142	166	188	209	229	244	257	266	276	285	291	295	297	298	301
Higher Energy Efficiency		-	10	23	39	57	75	94	115	132	151	168	184	199	212	226	240	247	252
Higher Plus Energy Efficiency		-	-	-	-	10	22	37	53	72	95	120	146	175	204	234	261	287	312
Time-Varying Rates & Demand Response		-	132	149	175	202	215	218	220	221	223	224	225	227	228	230	231	233	233
Industrial Load Curtailment		-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Electric Vehicle Peak Reduction		-	24	40	60	73	87	102	119	138	157	178	201	224	247	270	293	315	339
Sub-total	(h)	59	354	428	514	604	685	758	833	905	980	1,054	1,130	1,207	1,280	1,353	1,420	1,478	1,536
Surplus / (Deficit) after planned DSM	(i) = g+h	**578**	**639**	**1,450**	**1,301**	**831**	**738**	**681**	**448**	**258**	**214**	**290**	**(27)**	**(171)**	**(227)**	**(321)**	**(382)**	**(459)**	**(506)**
Electricity Purchase Agreement Renewals prior to F2026 [3]	(j)	12	26	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Electricity Purchase Agreement Renewals post F2026 [3]	(k)	-	-	-	-	9	35	198	281	291	311	344	615	700	700	736	736	744	745
Energy Acquisitions (Capacity Contribution) [3]	(l)	-	7	39	60	60	223	223	223	223	223	223	223	223	223	223	223	223	223
Future Energy Resources (Capacity Contribution)	(m)	-	-	-	-	-	-	-	10	50	55	62	70	78	86	91	96	102	105
Future Capacity Resources	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n	**590**	**672**	**1,541**	**1,413**	**952**	**1,048**	**1,154**	**1,014**	**874**	**855**	**971**	**933**	**883**	**834**	**781**	**724**	**662**	**618**

Notes:

[1] Includes outages for Mica and Seven Mile

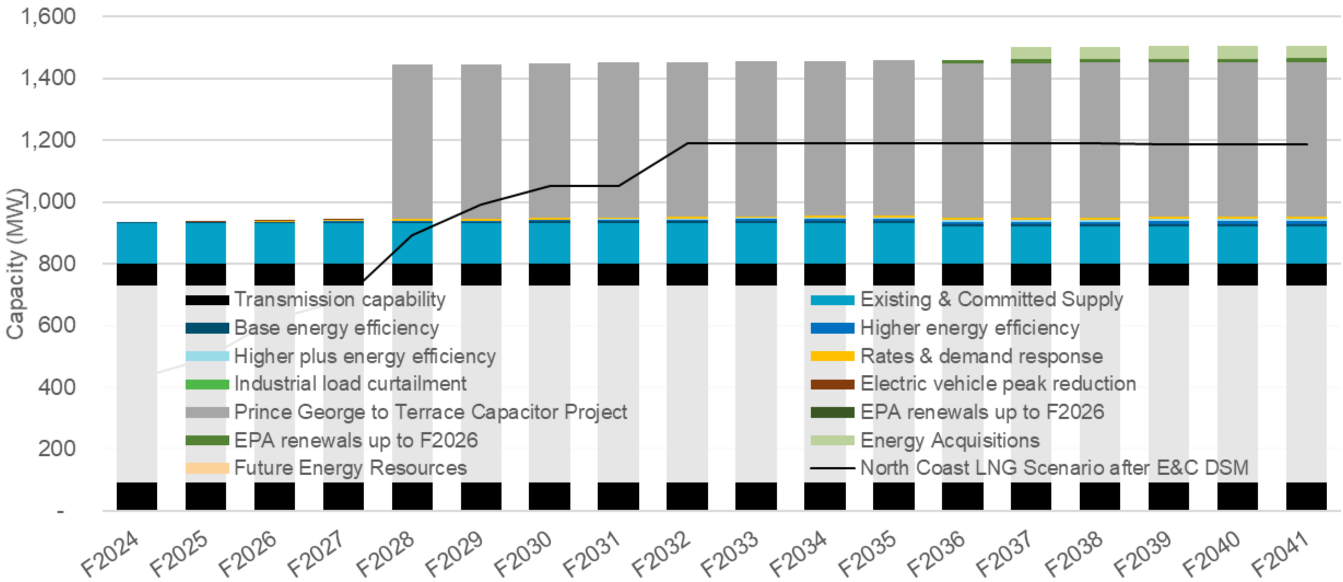
[2] The 12% reserve margin is applied to dependable capacity resources only

[3] The numbers shown include the 12% reserve margin

5.8 Regional capacity Load Resource Balance with Contingency Resource Plan for North Coast scenario

Figure 1-24 and show the North Coast capacity Load Resource Balance with selected resources in place to fill the capacity gap under the Contingency Resource Plan scenario for North Coast liquified natural gas and mining. The figure and table illustrate the timing of the resources and their energy/capacity contributions. Regional Load Resource Balances for the South Coast and Vancouver Island are not shown as they are not impacted by this scenario. In this section, the savings from Higher Plus Energy Efficiency are shown as incremental to the savings from Higher Energy Efficiency to highlight the transition from Higher Energy Efficiency to Higher Plus Energy Efficiency.

Figure 1-24 North Coast capacity Load Resource Balance with Contingency Resource Plan for North Coast scenario



Note: E&C DSM denotes existing and committed demand-side measures.

Table 1-24 North Coast capacity Load Resource Balance with Contingency Resource Plan for North Coast scenario

(MW/year)		F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																			
Existing and Committed Heritage Resources	(a)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Existing and Committed Electricity Purchase Agreements	(b)	124	124	124	124	124	124	124	124	124	124	124	124	112	112	112	112	112	112
Regional Supply Capacity (before planned resources)	(c) = a+b	131	131	131	131	131	131	131	131	131	131	131	131	119	119	119	119	119	119
Transmission Capability	(d)	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Demand - Regional Gross Requirements																			
North Coast LNG Scenario	(e)	(431)	(497)	(628)	(693)	(902)	(1,005)	(1,065)	(1,065)	(1,208)	(1,208)	(1,208)	(1,208)	(1,208)	(1,209)	(1,209)	(1,209)	(1,209)	(1,209)
Existing and Committed Demand-side Measures																			
Program Savings, Codes & Standards, Rates	(f)	4	6	9	10	12	13	14	15	16	17	18	18	19	20	21	22	23	24
Surplus / (Deficit) before planned resources	(g) = c+d+e+f	**504**	**440**	**312**	**248**	**40**	**(61)**	**(120)**	**(119)**	**(261)**	**(260)**	**(259)**	**(259)**	**(270)**	**(270)**	**(269)**	**(268)**	**(267)**	**(265)**
Contingency Resource Plan																			
Future Demand-side Measures																			
Base Energy Efficiency		2	3	4	4	5	6	6	7	7	8	8	9	9	9	9	9	9	9
Higher Energy Efficiency		-	0	1	1	2	3	4	4	5	6	6	7	7	7	8	8	8	8
Higher Plus Energy Efficiency		-	-	-	-	0	1	1	2	2	3	4	4	5	6	7	8	8	9
Time-Varying Rates & Demand Response		-	-	4	5	5	6	6	7	7	7	7	7	7	7	7	7	7	7
Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Vehicle Peak Reduction		-	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1
Sub-total	(h)	2	3	8	10	13	15	18	20	21	23	25	27	28	30	31	32	33	34
Surplus / (Deficit) after planned DSM	(i) = g+h	**505**	**444**	**320**	**258**	**53**	**(46)**	**(102)**	**(99)**	**(239)**	**(236)**	**(234)**	**(232)**	**(242)**	**(240)**	**(238)**	**(236)**	**(234)**	**(232)**
Transmission Upgrades																			
Prince George to Terrace Capacitors Project (PGTC)	(j)	-	-	-	-	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Electricity Purchase Agreement Renewals prior to F2026	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electricity Purchase Agreement Renewals post F2026	(l)	-	-	-	-	-	-	-	-	-	-	-	-	12	12	12	12	12	12
Energy Acquisitions (Capacity Contribution)	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Energy Resources (Capacity Contribution)	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	40	40	40
Future Capacity Resources	(o)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus / (Deficit) after planned resources	(o) = i+j+k+l+m+n+o	**505**	**444**	**320**	**258**	**553**	**454**	**398**	**401**	**261**	**264**	**266**	**268**	**270**	**312**	**314**	**316**	**318**	**320**

A2

Attachment 2: glossary and abbreviations

Words and abbreviations used in the 2021 IRP	Definitions
attribute	A characteristic that describes a resource option or portfolio, used to assess its performance in meeting the planning objectives.
B.C.	British Columbia
Base Resource Plan (BRP)	BC Hydro's plan for meeting its current and future customers' expected electricity needs on a reliable and cost-effective basis.
BC Hydro	British Columbia Hydro and Power Authority
British Columbia Utilities Commission (Commission or BCUC)	An independent regulatory agency of the provincial government operating under and administering the Utilities Commission Act. The BCUC regulates BC Hydro's domestic supply and rates, as well as the safety and reliability of the services BC Hydro provides. The BCUC also assesses concerns from ratepayers regarding BC Hydro's service.
Bulk Transmission System	The major lines or "backbone" of the high voltage transmission system that transfers large amounts of power between regions.
capability	In relation to the integrated electricity system, capability refers to facilities that can be used under specified conditions for a given purpose. Energy capability is the amount of energy that can be generated under specified conditions by a generating unit or by the electric system over a period of time, typically expressed in GWh/year. Transmission capability is the amount of electric power that can be moved or transferred reliably from one area to another on the transmission systems via transmission lines between those areas under specified system conditions.
capacity	The power output of a generator at a given point in time under specified conditions, normally measured in kilowatts (kW) or megawatts (MW). A transmission line's ability to transmit electricity at a given point in time under specified conditions.

capacity factor	The ratio of the average annual power output to the maximum possible output of generating plants.
capacitor station	A capacitor station is a facility where electricity from a high-voltage transmission line is carried through a series of devices call capacitors. This helps to maintain the voltage levels in a transmission line, allowing more electricity to pass through a line over long distances.
carbon dioxide (CO_2) equivalent emissions	Carbon dioxide equivalent" or CO_2e is a term for describing different greenhouse gases in a common unit. For any quantity and type of greenhouse gas, CO2e signifies the amount of CO2 which would have the equivalent climate change impact.
Clean Energy Act (CEA)	The Provincial legislation that sets the foundation for electricity self-sufficiency, energy efficiency, and reduced greenhouse gas emissions for the utility sector. The Act also sets out the consideration of investments in electricity generation from clean or renewable resources across the province.
clean or renewable resource	Defined by the Clean Energy Act as biomass, biogas, geothermal heat, hydro, solar, ocean, wind or other prescribed resources. The Clean or Renewable Resource Regulation prescribes biogenic waste, waste heat and waste hydrogen as additional clean or renewable resources.
Climate Action Plan	A policy document produced by the B.C. Government that describes actions that will be undertaken as government moves to its target of reducing greenhouse gas emissions by 33 per cent below 2007 levels by 2020 and 80 per cent by 2050.
climate change	A change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods.
committed resources	Committed resources are those resources that have received necessary internal authorizations to proceed to implementation, as well as any required regulatory approvals, and are expected to begin operating during the planning horizon of the 2021 IRP.
consequence table	Consequence tables are tools that support decision-making by comparing decision alternatives in relation to specific objectives where trade-offs must be made.
Contingency Resource Plan (CRP)	A plan that identifies sources of supply including demand-side measures, storage and transmission components that could be required should the Base Resource Plan not materialize as expected.
December 2020 Load Forecast	BC Hydro's 20-year load forecast finalized in December 2020. It includes reference, high, and low cases for both energy and peak, before and after various adjustments.

demand	Customers' requirements for electric power.
demand response	The shifting of electricity usage out of peak times into periods when supply is more available. Demand Response programs provide utilities the ability to shift electricity usage by directly controlling customers' devices (e.g. water heaters) through voluntary programs.
demand-side measures (DSM)	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. 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.
dependable capacity	The maximum generator output that can be reliably supplied coincident with the system peak load, taking into account the physical state and availability of the equipment, and on water or fuel constraints. Same as dependable generating capacity.
Discount rate	A rate used to determine the present value of cash flows (expenses and revenues) that will occur over a period of time, reflecting the cost of capital.
dispatchable	A resource whose output can be adjusted to meet various conditions including fluctuating demand, weather changes, outages, market price changes and non-power considerations.
electricity grid	An interconnected network for electricity delivery from generators to consumers. Electrical grids vary in size and can cover whole countries or continents. B.C.'s electrical grid is connected to a much larger grid covering B.C., Alberta, portions of 14 western U.S. states, and a small part of Mexico.
electricity purchase agreement (EPA)	A contract that defines the terms and conditions by which BC Hydro purchases electric energy from an independent power producer.
Electricity Self-Sufficiency Regulation	A regulation issued by the Provincial government which prescribes that average water conditions and mid-load forecasts are to be used for the purposes of the "electricity supply obligation" in the Clean Energy Act.
electric vehicle peak reduction	A demand-side measure combining time-varying rates with supporting programs to encourage customers to shift electric vehicle charging outside of system peak periods.

Electrification Plan	BC Hydro’s Electrification Plan is a five-year plan to make it easier and more affordable for people to use B.C.’s clean electricity in place of fossil fuels to power their homes, buildings, businesses, and vehicles. The plan proposes new programs and incentives to promote this switch from fossil fuels to clean electricity and attract new industries to B.C. that are looking for clean power.
emissions	Any direct or indirect discharge of solid, liquid or gaseous pollutants into the air.
energy	The amount of electricity produced or used over a period of time, usually measured in kilowatt hours (kWh), megawatt hours (MWh) and gigawatt hours (GWh).
energy efficiency (EE)	A reduction in energy usage while providing the same nature and quality of energy service, such as lighting, cooling or motor torque.
firm energy	Firm energy refers to electricity that is available at all times.
fiscal year (F)	BC Hydro’s fiscal year beginning April 1 and ending March 31. Dates marked with an F refer to the year ending March 31 in the year given.
fossil fuel	A fossil fuel is a hydrocarbon-containing material formed underground from the remains of plants and animals that humans extract and burn to release energy for use. The main fossil fuels are coal, petroleum and natural gas, which humans extract through mining and drilling.
FTE	Full-time equivalent
generation	The production of electricity.
gigawatt hour (GWh)	A unit of electrical energy used to describe the total amount of electricity used over time. One GWh is equivalent to one billion watts of energy consumed in one hour.
greenfield site	Land on which no development has previously taken place.
greenhouse gas emissions (GHG emissions)	Any of the atmospheric gases that contribute to climate change such as water vapour, methane, and carbon dioxide.
Greenhouse Gas Reduction Targets Act (GGRTA)	The Greenhouse Gas Reduction Targets Act is Provincial legislation that sets into law B.C.’s greenhouse gas emissions target of at least 33 per cent below 2007 levels by 2020, and at least 80 per cent below 2007 levels by 2050.

GWh/year	Gigawatt hours per year.
independent power producer (IPP)	A non-utility-owned electricity generating facility that produces electricity for sale to utilities or other customers.
Integrated Resource Plan (IRP)	The document describing BC Hydro's long-term plan to meet customers' needs using existing, committed, and new demand-side and supply-side resources.
Intergovernmental Panel on Climate Change (IPCC)	The United Nations body for assessing the science related to climate change.
intermittent resource	A source of energy that has varying output due to natural changes and is not dispatchable. Can also refer to electricity supply that fluctuates or is not available at all times.
liquefied natural gas (LNG)	Natural gas in a liquid form. When natural gas is cooled to minus 259 degrees Fahrenheit (minus 161 degrees Celsius) through liquefaction, it becomes a clear, colorless, odourless liquid.
load	The amount of electricity required by a customer or group of customers.
load centre	An area with a significant number of electricity customers.
load curtailment	A measure that reduces electrical use for a period of time. Load curtailment programs provide customers with an incentive in exchange for agreeing to curtail energy use during specific periods requested by the utility.
Load Forecast	The load requirements that an electricity system will have to meet in future years.
Load-Resource Balance (LRB)	A comparison of the load forecast and existing and committed resources available to meet the load. In this IRP, the Load Resource Balance is such a comparison over a 20-year planning horizon.
megawatt (MW)	A unit of electrical power equal to one million watts.
Near-term Action	The actions that BC Hydro is taking to implement the Base Resource Plan and prepare for contingency scenarios, during the period between the submission of the 2021 IRP and the submission of the next IRP.

net present value (NPV)	The difference between the present value of benefits and the present value of costs (including capital, operating, maintenance and administration costs) for a given discount rate.
net total resource cost	Measures the total costs and benefits of a resource to both the utility and the participants.
net utility cost	Measures the total costs and benefits of a resource to the utility.
North Coast (NC)	Region of the BC Hydro transmission system that is west of Prince George.
off-peak	The time when there is less demand on BC Hydro's system.
peak demand/load	The highest electrical power demand on a power system in a specified period of time.
planned resource	Resources that BC Hydro is planning to pursue and is taking actions to acquire or develop. Planned resources have not necessarily received regulatory or Board of Director approval.
planning period / planning horizon	Period over which the operation of the various elements of the power system are modelled. For the 2021 Integrated Resource Plan, the planning/period horizon is twenty years.
resource portfolio	A group of individual resource options to be acquired in a sequence over time to meet customers' future electricity needs.
portfolio analysis	A process of developing and evaluating resource portfolios, each consisting of a combination of supply side, transmission and demand-side resources, which meet customers' future electricity needs.
present value (PV)	Today's discounted value of future receipts or expenditures. Refer also to discount rate and net present value.
rate	A utility's unit price for electricity service provided.
rate impact	The effect on electricity rates.

Reference Load Forecast	The reference forecasts for both energy and peak of the 2020 December Load Forecast, after rate impacts, and without any demand-side measures savings. For the purposes of the 2021 IRP and the time period that it addresses, the Reference Load Forecast reflects further adjustments to the reference forecast of the December 2020 Load Forecast in relation to energy and peak savings attributed to demand-side measures actions and expenditures during fiscal 2021, subsequent to the date of the forecast.
reliability (electric system)	A measure of the adequacy and operating reliability of electric service. Adequacy refers to the existence of sufficient facilities in the system to satisfy the demand and system operational constraints. Operating reliability refers to the system's ability to withstand sudden disturbances in the system.
resource option	A source of electricity or electricity savings that is available to help meet electricity demand, including generation, demand-side measures and transmission facilities.
Resource Options Database (RODAT)	BC Hydro's database of information on a broad range of resources and their attributes that could potentially be used to meet future electricity demand.
Revenue Requirements Application	BC Hydro's application before the British Columbia Utilities Commission expected to determine the revenues BC Hydro will need for its operations, to ensure a safe and reliable supply of electricity to its customers.
Roadmap	The CleanBC: Roadmap to 2030
sequence	The order in which resources should be scheduled or acquired to meet the demand growth.
series compensation	The installation of a series capacitor station in a transmission line to reduce the line's impedance (opposition to electrical flow), permitting higher power transfer.
shunt capacitor	A device that produces reactive power to support the system voltage.
smart-charging technology	Technology that facilitates shifting of residential electric vehicle charging to off-peak times to take advantage of lower time-of-use rates.
South Coast (SC)	The South Coast encompasses the Lower Mainland and Vancouver Island regions of B.C.
Standing Offer Program	A program developed to streamline the process for developers of small and clean energy projects to sell electricity to BC Hydro. The Program applied to proposals for generating projects rated less than 15 MW. The Program has been indefinitely suspended.

static VAR compensator (SVC)	A set of electrical devices that can quickly and reliably control line voltages by providing fast-acting reactive power.
Structured Decision Making	Structured Decision Making is an organized approach to identifying and evaluating creative options and making choices in complex decision situations.
substation	An electrical switching station for terminating transmission lines. It can also be a station at which the system voltage is transformed from a high level to a level suitable for sub-transmission or distribution systems.
supply-side resources	Refers to BC Hydro generation and transmission resources or electricity purchased from independent power producers.
system optimizer (SO)	A computer model used for portfolio modelling in integrated resource planning. For the 2021 IRP, SO was used to select available resources to fill the gap between the forecast load and the available supply in the lowest cost way that meets the planning objectives.
thermal upgrades	A transmission line thermal upgrade involves increasing the current-carrying capability of a transmission line by replacing the conductor with a conductor of a larger size or increasing the ground clearance to allow the line to operate at a higher temperature.
time-of-Use (TOU)	An example of a time-varying rate which generally includes two or more predetermined daily price periods to encourage customers to shift their use of electricity from the system peak period to off-peak periods.
trade-off Analysis	A trade-off analysis is used to inform decisions and to be transparent about the reasons for those decisions by showing explicitly what is gained and what is given up in terms of impacts on decision-objectives when choosing one option over another.
transmission system	Electrical facilities used to transmit electricity over long distances, usually at voltages greater than 69 kV.
unit cost of capacity (UCC)	Present value of the total annual cost of a capacity resource divided by the resource's dependable capacity. It is measured in dollars per kilowatt per year.
unit energy cost (UEC)	Present value of the total annual cost of an energy resource divided by the present value of its annual average energy benefit. It is calculated using either a discounted cash flow method or annualized cost method and is measured in dollars per MWh.

United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP)	A resolution passed by the United Nations in 2007 defining the rights of Indigenous peoples. In 2020, Canada committed to implement UNDRIP into Canadian law.
Utilities Commission Act (UCA)	Provincial legislation setting out the mandate and powers of the British Columbia Utilities Commission, which regulates BC Hydro and other utilities in the province.
volt (V)	The basic unit of measurement of electromotive force, the force required to change the random motion of electrons into an electric current. Refer also to voltage.
voltage	The strength of electromotive force
watt (W)	The basic unit of measurement of electric power, indicating the rate at which electric energy is generated or consumed (1 watt = 1 joule per second).
wholesale electricity trade	The buying and selling for resale of large amounts of electricity at the trading hubs in interconnected electric systems.