BC Hydro and Power Authority

DRAFT 2021 Integrated Resource Plan

NOTE TO READER OF DRAFT 2021 IRP:

BC Hydro's 2021 IRP is expected to be finalized in December 2021, in time to be filed with the BC Utilities Commission before December 31, 2021, in accord with Commission Order No. G-28-21

BC Hydro
Power smart

Table of contents

(Continued)

Appendices

NOTE TO READER OF DRAFT 2021 IRP

BC Hydro anticipates including additional appendices in the final 2021 IRP

1. Executive summary

NOTE TO READER OF DRAFT 2021 IRP

This DRAFT 2021 IRP was developed for consultation purposes and will differ from the final 2021 IRP. These differences may be large or small. As a draft document that is still under development, it can be expected that the executive summary also reflects preliminary considerations and will differ from the executive summary in the final 2021 IRP.

An integrated resource plan is a guidebook for what, when, why 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 how to meet future customer needs for electricity until our next integrated resource plan.

The 2021 IRP is aligned with government policy objectives, such as CleanBC and the requirements of the *Utilities Commission Act* and the British Columbia Utilities Commission. Its development was also informed by our planning objectives and our commitment to reconciliation with Indigenous communities.

NOTE TO READER OF DRAFT 2021 IRP

BC Hydro's planning objectives were the subject of consultation in late 2020 and into 2021. Currently they include 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. However, further information on an additional objective considered can be found in the Note to Reader in Section 2.3.

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. At a system-wide level, 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 South Coast of the province means we expect to need additional regional capacity resources in fiscal 2027.

The 2021 IRP consists of a Base Resource Plan and several Contingency Resource Plans. The Base Resource Plan contains the activities that BC Hydro intends to pursue to meet future electricity demands. In developing the Base Resource Plan, we considered resource options including demand side-measures, rates, and acquiring power via renewing electricity purchase agreements, enhancing our own facilities and from new clean and renewable sources.

The legal framework of 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, customers and stakeholders during early consultation was consistent with this preference. So, our first step was to decide the levels of demand-side measures we ought to pursue, which we did using a structured decision-making process. These demand-side measures 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 GWh/year of energy savings and 290 MW of capacity savings at the system level by fiscal 2030;
- Pursue voluntary time-varying rates supported by demand response programs to achieve 220 MW of capacity savings at the system level by fiscal 2030, and advance the Industrial Load Curtailment Program to achieve 100 MW of incremental capacity savings at the system level by no later than the fiscal 2027 to fiscal 2030 period;
- Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers to support a new or existing (as applicable) 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:

- Offer a market-price based renewal option to existing clean or renewable independent power producers with electricity purchase agreements expiring in the next five years. There are approximately 20 existing clean or renewable projects, that produce a total of roughly 900 GWh, with electricity purchase agreements set to expire before April 1, 2026;
- Advance the first sequential step of upgrades to existing transmission infrastructure into the South Coast region to achieve 550 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 700 MW of capacity for the South Coast region by fiscal 2039;
- Beyond the elements identified above and after demand-side measures, plan to acquire new energy and capacity resources starting with 580 GWh in fiscal 2031, then shifting to primarily capacity resources starting with 110 MW in fiscal 2038. These future resources would be selected from amongst:
    - Expiring electricity purchase agreements with independent power producers;
    - New clean and renewable energy resources; and
    - Upgrades to BC Hydro facilities.
- Undertake a structured decision-making approach to evaluate small BC Hydro plants that are at end-of-life, or in operation and nearing end-of-life, on a facility by facility basis to determine whether to decommission, divest or refurbish these facilities.

Finally, Contingency Resource Plans were developed to ensure sufficient resources would be available to address scenarios where our customers' electricity needs were higher or lower that expected and/or our resources did not deliver as we anticipated.

The scenarios included in the DRAFT 2021 IRP are:

- electricity demand stagnates,
- electrification accelerates more quickly, **and**
- electrification accelerates and rates and support programs don't perform as expected.

The analysis showed that BC Hydro could respond to those contingencies from the foundation laid by the Base Resource Plan without additional activities, with one exception. One of the Contingency Resource Plans signalled that it would be prudent for BC Hydro to explore integration of utility-scale battery technology now as a hedge against future uncertainty.

2. Introduction

2.1 About BC Hydro

BC Hydro is a provincial Crown corporation, owned by the people of British Columbia. We safely provide reliable, affordable and clean electricity to our customers throughout the province.

As one of the largest energy suppliers in Canada, we generate and deliver electricity to 95 per cent of the population of British Columbia, helping to power our economy and quality of life.

We operate an integrated system backed by 30 hydroelectric plants and a thermal generating station, as well as approximately 18,400 kilometres of transmission and 59,000 kilometres of distribution lines. We also have 127 agreements with Independent Power Producer facilities that largely use clean sources for electricity generation, including biomass, hydro, wind and solar. In aggregate, our system electricity generation is 96 per cent clean.

NOTE TO READER OF DRAFT 2021 IRP

96 per cent is based on BC Hydro's fiscal 2021 Annual Report. This number will be updated to be consistent with the fiscal 2022 Annual Report once released.

As a Crown corporation, BC Hydro reports to the Government of B.C. through the Minister of Energy, Mines and Low Carbon Innovation.

BC Hydro is a public utility regulated by the British Columbia Utilities Commission (**Commission**) under the *Utilities Commission Act.*

2.2 What is the 2021 Integrated Resource Plan?

An integrated resource plan is a guidebook for decisions on the what, when and why of our actions to meet customers' evolving electricity needs and is updated periodically.

This 2021 Integrated Resource Plan (**2021 IRP**) looks at a 20-year time frame and will guide decisions on how to meet future customer needs for electricity until our next integrated resource plan.

The 2021 IRP is aligned with government policy objectives, such as CleanBC and the requirements of the *Utilities Commission Act* and the Commission. Appendix A provides a summary of the legal and regulatory requirements and policy considerations that apply to the 2021 IRP.

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 the future turns out as we currently expect;
- Several **Contingency Resource Plans**, which are the strategies BC Hydro will pursue if future needs deviate significantly from what we expect under the Base Resource Plan; and
- Several **Near-Term Actions**, which are the steps BC Hydro expects to take to implement elements of the Base Resource Plan and Contingency Resource Plans before our next integrated resource plan is filed. Many of the Near-Term Actions in the 2021 IRP will require separate applications to the Commission to be implemented.[1] The 2021 IRP will inform the Commission's consideration of those applications.

The 2021 IRP informs our other efforts that contribute to BC Hydro's mission and objectives. It is also informed by these efforts.

For example, over the past several years, we've been supporting electrification and greenhouse gas emission reductions through low carbon electrification programs, electric vehicle charging infrastructure, support for customer connections, expansions of the transmission system and new rate designs. On a go-forward basis, we have included those efforts in an **Electrification Plan** in our Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, filed with the Commission in August 2021. The 2021 IRP considers strategies to meet future customer needs under a range of electrification scenarios, including those that encompass BC Hydro's near-term electrification target in the Electrification Plan.

NOTE TO READER OF DRAFT 2021 IRP

BC Hydro currently expects to file the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application with the Commission in August in 2021, about four months before the 2021 IRP is finalized.

1 The need for future Commission approvals is one reason the 2021 IRP is not considered to be binding on BC Hydro.

2.3 Our planning objectives in developing the 2021 IRP

NOTE TO READER OF DRAFT 2021 IRP

BC Hydro's planning objectives were the subject of consultation in late 2020 and into 2021. Currently we would say that they include 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. An additional objective, supporting reconciliation with Indigenous peoples, was the subject of input by Indigenous communities. Although reconciliation had strong support, many participants viewed it as being inappropriately expressed as a trade-off objective to be ranked among other objectives. Based on this perspective and out of respect, supporting reconciliation with Indigenous Peoples was not included as a stand-alone objective. Notwithstanding the removal of the objective, input from the first phase of consultation identified Indigenous interests within each of the remaining objectives. BC Hydro has a shared interest with Indigenous communities to seek ways to advance reconciliation and has a mandate to incorporate the UN Declaration on the Rights of Indigenous Peoples (UNDRIP) into its business within our specific mandate and context. We will continue to consider how to reflect this in the final 2021 IRP.

2.4 Our next integrated resource plan

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

For these reasons, we plan to complete our next 20-year integrated resource plan in late 2026 or early 2027, about five years after this 2021 IRP. During these five years, the 2021 IRP will be subject to a review by the Commission, many of the specific elements of the 2021 IRP will be subject to further Commission approvals, and the planning context will continue to evolve.

We'll be continually assessing the 2021 IRP against planning developments and may advance the timing of the next integrated resource plan, as needed.

3. Where does BC Hydro find itself today?

Climate action, changes in electricity consumption, and the evolution of energy markets are changing the way electrical utilities do business. Utilities are evolving their business models to respond to customer needs. No longer is the traditional operating model to be taken for granted: in some cases, utilities are supplementing and changing their current offerings while customers are looking for more choice in how they manage their energy use and more opportunities to take advantage of clean and renewable solutions.

NOTE TO READER OF DRAFT 2021 IRP

The following sections identify preliminary context for the DRAFT 2021 IRP. In the final 2021 IRP these sections will be distilled and revised, as necessary, so we can show the links between them and the final Base Resource Plan or one or more of the final Contingency Resource Plans.

3.1 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, before the addition of any new clean resources. Our integrated system is currently in surplus, which we expect to continue for several years.

This means we're ready to support growth in British Columbia's population and economy, while playing our part in achieving the Government of BC's climate action initiatives as laid out in CleanBC. 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.

3.2 Our customers are using electricity differently

Customer demand for electricity is also changing. For example, in traditional resource-based industries, many economic factors are combining to cause decreases in demand. These factors result in the need for our existing system costs to be recovered from remaining customers, which has rate impacts.

An example of a growing area of demand is transportation. 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. British Columbia currently leads North America in the sale of electric vehicles (**EVs**), with EVs 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.

New demand presents an opportunity for us to mitigate the risk of declines in traditional demand, but it also may require new infrastructure.

3.3 British Columbia is part of an evolving, regional energy landscape

British Columbia's electricity grid is embedded in a much larger grid that covers B.C. and Alberta plus 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 cost of energy in the wholesale market has been relatively inexpensive, but capacity and flexibility are increasingly valuable as jurisdictions add more intermittent renewables to their supply mix. Capacity is produced by firm, dependable sources of power, like hydroelectric with storage, that can be relied upon whenever needed without the intermittent nature of renewable sources such as wind and solar. Non-intermittent resources that provide dependable capacity at peak times and flexibility associated with storage are key to integrating intermittent renewables.

Hydroelectricity, with storage, is a clean way of providing this capacity. Hydroelectric storage also enables water to be stored during periods of high supply/low demand and to be used for generation in periods of low supply/high demand. With much of BC Hydro's power generated through hydroelectricity, with storage, BC Hydro is well-positioned to maximize the value of its generation and transmission assets.

3.4 The technology to produce and deliver electricity is changing

New technology is 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 shifting of 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 even further while capabilities increase.

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

3.5 Customer expectations are changing

Customer expectations from energy providers are broadening beyond reliable service to include utilization of technology and data on energy use. The advancement of new energy choices such as small-scale battery storage, self-generation and new ways to manage energy use provide new opportunities to engage customers in meeting our future electricity needs. 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. Optional rates can provide customers with more choice and programs can provide customers with new ways to manage their energy use and take advantage of those choices.

Affordability for all customers will always be a key priority for BC Hydro. BC Hydro can support affordability by advancing cost-effective customer-based solutions to help meet our future electricity needs and to help customers save money on their bills through conservation. Implementation of these solutions can support affordability by considering the ability of customers to participate and ways to support those customers who are less able to change their consumption in response to new programs or rates.

Customers are also increasingly concerned about how their energy choices impact the environment and sustainability. By encouraging customers to use clean and reliable electricity instead of higher emitting fuels to power their homes, vehicles and businesses, BC Hydro can help to reduce greenhouse gas emissions and contribute to meeting the government's climate goals.

4. Load Resource Balances

A load resource balance compares future expected electricity demand and resources already in place to show when we expect to need new resources (**Load Resource Balance**). By including planned future resources, a Load Resource Balance also shows how we will meet future electricity demand.

We develop two types of Load Resource Balance. An **energy** Load Resource Balance ensures we can meet customers' electrical energy needs for each year of our planning horizon (expressed as gigawatt-hours per year, GWh/year). A **capacity** Load Resource Balance ensures we can meet our customers' peak electricity use at any point in time in the planning horizon (expressed as megawatts, MW).

4.1 Load forecast

In December 2020 we finalized a 20-year load forecast (**December 2020 Load Forecast**) which is used for the 2021 IRP. The December 2020 Load Forecast includes a mid-range or reference forecast before accounting for demand-side measures (**Reference Load Forecast**).[2] The Base Resource Plan is based on the Reference Load Forecast. The Reference Load Forecast projects moderate growth averaging about 1.5 per cent per year over the planning horizon (again, before accounting for demand-side measures). Growth is primarily due to electric vehicles and oil & gas load growth (including liquefied natural gas), 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 a 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 risks associated with different future outcomes. The Contingency Resource Plans are based on some of these scenarios.

4.2 Existing and committed resources

Resources already in place — one of the key inputs into our Load Resource Balances — include both existing and committed resources. **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** generally 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. Existing and committed resources include BC Hydro generation resources and bulk transmission resources, as well as electricity purchase agreements until the date of their expiry.[3,4]

2 The December 2020 Load Forecast also includes a high load forecast and a low load forecast (**High Load Forecast** and **Low Load Forecast**, respectively).

3 Facilities under electricty purchase agreements, and certain potential EPAs under the Standing Offer Program excepted from the indefinite suspension, that have yet to achieve commercial operation date, but are expected to within the planning horizon of the 2021 IRP are considered committed resources

4 Existing and committed DSM includes savings from codes and from the energy conservation rate structure for our transmission voltage customers; as well the savings and the persistence of the savings from the F2021 program expenditures which was approved in the F20-F21 RRA.

4.3 **Planning criteria**

Planning criteria are used to ensure we have a reliable electrical system, including adequate generating capability (energy and capacity), and adequate transmission capability. They provide, in effect, planning limits on the capability of the existing and committed generation resources, and transmission resources, used to develop the Load Resource Balances. These criteria are periodically reviewed, and if necessary, updated, to reflect best practices and information about the performance of our electrical system. Three of our primary criteria are:

- An **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 criteria, consistent with the requirements of the *Clean Energy Act* and the *Electricity Self-Sufficiency Regulation*.
- A **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*.
- Our **transmission planning criteria** are a set of rules drawn, in part, from standards developed through the North American Electric Reliability Corporation and the Western Electricity Coordinating Council. Many of these rules are part of the Mandatory Reliability Standards enacted by the Commission. The rules include BC Hydro's Generation Dispatch in Transmission Planning Guideline, which lays out the methods and assumptions for calculating the capability of our current bulk transmission system and inform us when additional transmission resources are required.

4.4 **How much electricity will BC Hydro 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 in the December 2020 Load Forecast, we establish when we anticipate we will need additional energy and capacity resources. The resulting Load Resource Balances are illustrated in Figures 1 and 2.

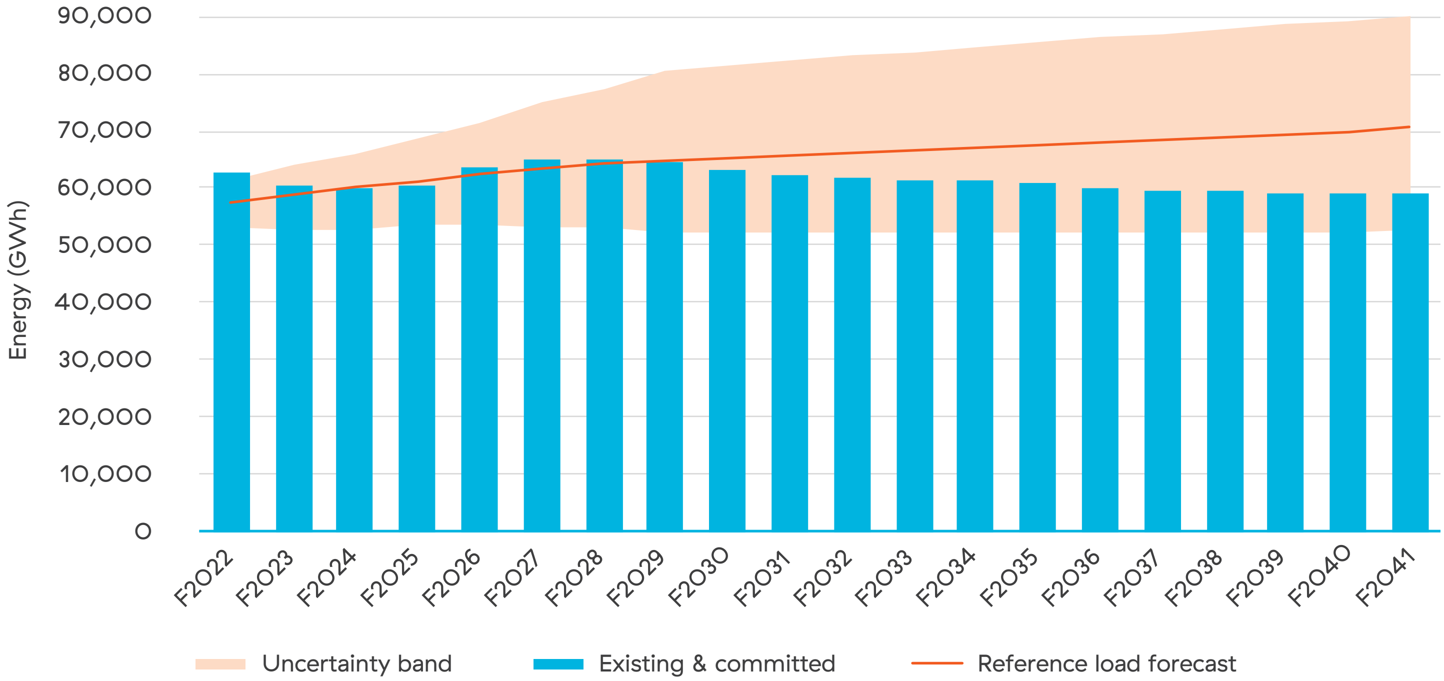


Figure 1. System energy Load Resource Balance – December 2020 Load Forecast vs. existing & committed resources — before planned resources

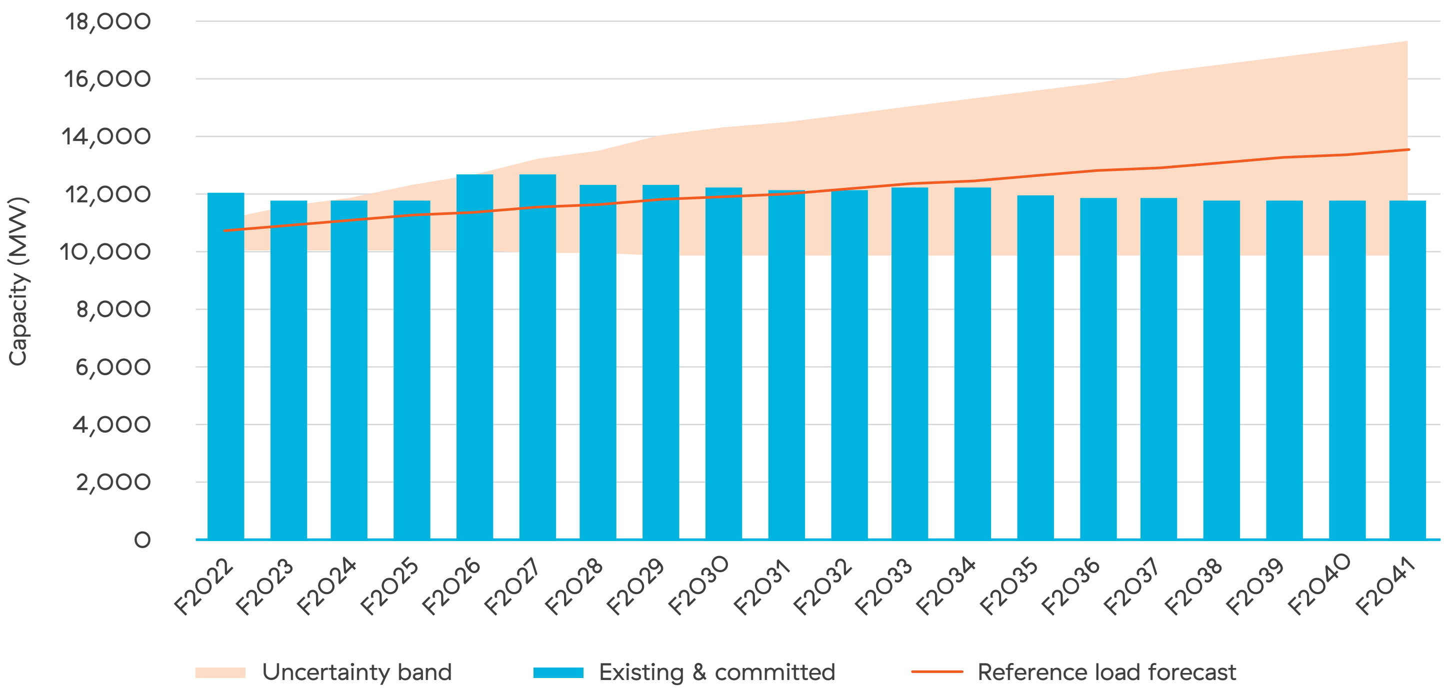


Figure 2. System capacity Load Resource Balance – December 2020 Load Forecast vs. existing & committed resources — before planned resources

Each blue bar represents the capability of our existing and committed resources according to our planning criteria. The orange line represents the Reference Load Forecast – what we expect customer electricity demand to be 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 new energy needs are expected to occur in fiscal 2029 while capacity needs are expected to occur in fiscal 2032, in both cases before any planned resources.

In assessing the amount of electricity BC Hydro will require, we have also considered the potential effects of climate change and determined the effects to be within existing bounds of uncertainties based on preliminary results. Additionally, we studied how our system generation capability might change under a range of climate change scenarios from the Intergovernmental Panel on Climate Change. The preliminary study results showed that these scenarios could result in a range of +/- five per cent change in our system generation capability by the end of the century.

BC Hydro has previously conducted an analysis of the impact of various climate change scenarios on load. Those study results show about a two per cent reduction in electricity demand for both energy and capacity on average for the mid to late century. In partnership with the Pacific Climate Impacts Consortium (PCIC), new climate scenarios have been developed since then. However, these scenarios have not yet been analyzed for potential impacts to future load. Based on a preliminary review of the updated climate projections from the PCIC, the trends identified in the previous climate change scenario analysis completed in 2013 appear to be continuing. The PCIC's results are consistent with the recently published *Canada's Changing Climate Report* produced by Environment and Climate Change Canada.

In terms of BC Hydro's load forecasting processes, the direct input in our residential and commercial models that can account for climate trends is the temperature element which is measured in heating and cooling degree days. The model forecasts are based on a normal temperature, which is defined as a ten year rolling average of monthly heating and cooling degree days that are region specific to BC Hydro's service area. Using a ten year rolling average reflects current trends relative to longer term averaging periods.

Turning to a specific driver of electricity demand, British Columbia is a leader in electric vehicle adoption within Canada. This is partially what's behind higher load growth in the South Coast region compared to the rest of the province.[5] The South Coast capacity Load Resource Balance shows the need for additional capacity resources in that region (before any new demand-side measures) occurs in fiscal 2027, earlier than for the province as a whole. This is illustrated in the Load Resource Balance shown in Figure 3.

5 Encompasses the Lower Mainland and Vancouver Island regions of British Columbia.

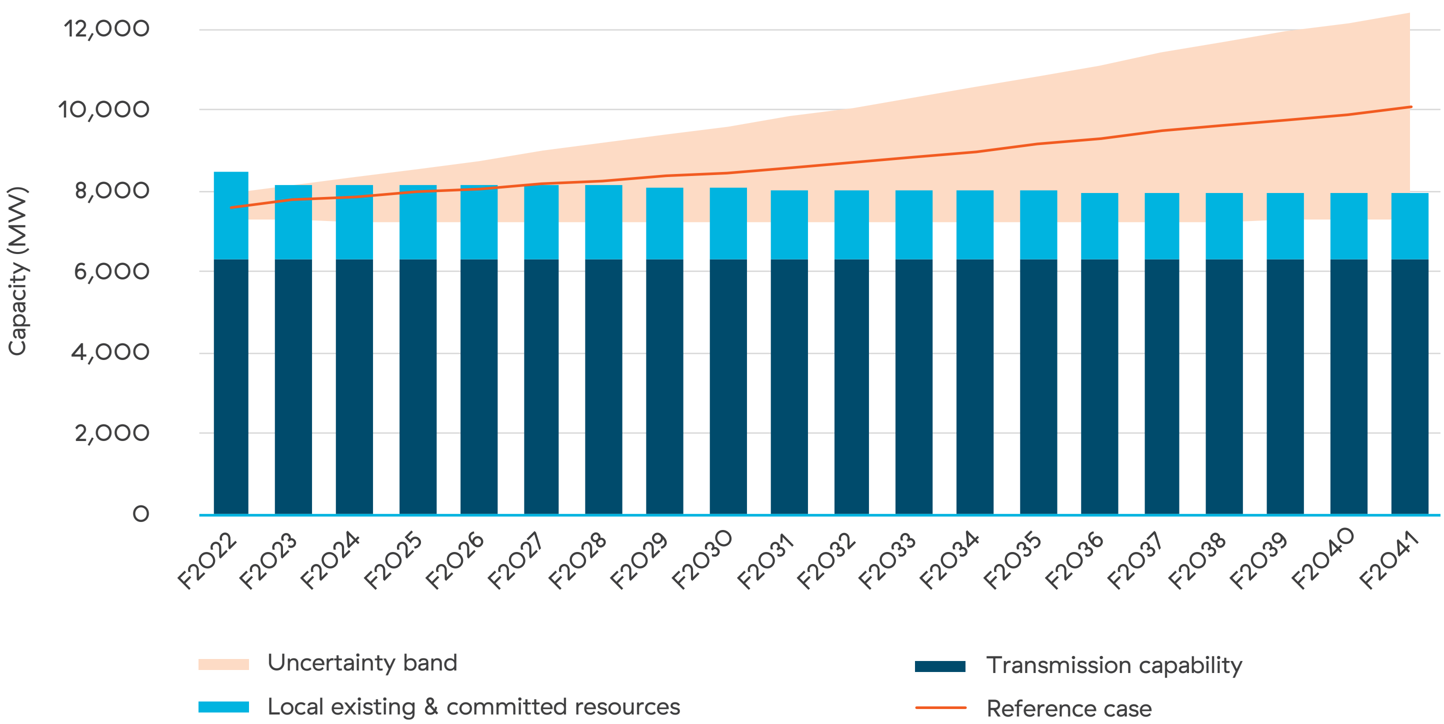


Figure 3. South Coast capacity Load Resource Balance: December 2020 Load Forecast vs. existing & committed resources (w/ transmission) – before planned resources

The system capacity Load Resource Balances shown in Figures 1 and 2 focus on planning generation resources from a province-wide integrated system perspective. For Figure 3, the transmission capability is reflected in the regional Load Resource Balances where the future electricity needs could be met by both the local generation resources and resources transmitted from the other regions of British Columbia.

The 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 uncertainty band represents a range of possible electricity demand outcomes.

Relative to the Reference Load Forecast, the lower part of the uncertainty band generally includes lower levels of electrification; no growth in residential and commercial demand; and some closures of industrial operations. The upper part of the uncertainty band is generally driven by higher levels of electrification, higher growth in the residential and commercial sectors to reflect greater economic and population growth; additional expansions of industrial operations; and new customers proceeding with projects and/or electrifying those projects.

5. The resource options available

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

BC Hydro maintains a database of a broad range of resources to meet future electricity needs, including associated technical, financial, social and environmental attributes (**Resource Options Database**). The most recent update to the Resource Options Database was completed in 2021. The resources available are not restricted to upgrades to BC Hydro-owned physical generation. The database includes demand-side measures, electricity purchase agreement renewals, upgrades to BC Hydro bulk transmission facilities, and new clean 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 on-line; 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. As resource options are different, we need to think about how different options contribute to and provide value to meet annual electricity (energy) needs as well as peak electricity (capacity) needs. For example, some resources are more dependable than others. A dependable resource may cost more but will also be worth more compared to a resource that isn't as dependable, if it can help meet our peak electricity demand. Resources that are not dependable can still contribute to meeting our energy and capacity needs, and we undertake studies to understand what percentage of their power we can count on during peak demand periods.

The **social** attributes are an estimate of the new jobs created from resource development, and the **environmental** attributes are an estimate of the greenhouse gas and terrestrial impacts from resource development. These attributes are currently only ascribed to new supply-side resources.

For generation resource options, we calculate a **Unit Cost of Energy** and a **Unit Cost of Capacity** to provide a simplified comparison between options. These measures describe the cost to deliver energy or capacity to the grid over the life of the resource.

For demand-side measures, the approach is different because both customer and utility costs must be considered. The unit cost is described in terms of **Net Utility Cost** and **Net Total Resource Cost.** The Net Utility Cost measures the costs and benefits from the perspective of the utility. The Net Total Resource Cost measures the costs and benefits of both the utility and the participants to capture the full value of the resource.

5.2 Demand–side measures

Demand–side measures include energy efficiency programs, as well as time–varying rates and demand response programs. Each is described below.

5.2.1 Energy efficiency resource options

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

Several different portfolios of energy efficiency resource options have been defined which reflect 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 the Resource Options Database are as follows:

- **No energy efficiency:** halt our current programs except for those mandated in the *Demand–Side Measures Regulation*.
- **Base energy efficiency:** maintain a base level of demand–side measures 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 Higher energy efficiency, to cover 100 per cent of incremental customer costs.
- **New construction:** new incentives to build new buildings to higher efficiency than current building code.
- **Customer solar:** capital incentives to support customer adoption of small solar rooftop systems.
- **Customer batteries supported by 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 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 overall system electrical demand to periods of lower system 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, as determined by the Commission.

Individual rate options were arranged into four **Rate suites** which combined different voluntary and default rate options across the various customer classes. Each of the rate suites is described in the Resource Options Database.

Demand response programs refers to programs that enable customers to shift their load away from BC Hydro's peak period through voluntary programs that manage and control customers' electricity demand. Demand response programs include programs to provide support to customers to respond appropriately to time-varying rates. Without program support, time-varying rates may not achieve their expected peak demand reduction potential. Demand response programs include **direct load control**, where the customer can choose to participate in a program where the utility has control of a customer's device (e.g., devices for space heating or water heating) and can turn the device off during a peak event, in exchange for an incentive; **load curtailment**, where customers provide a firm load reduction during a peak event, in exchange for an incentive; and **peak saver incentives**, where residential customers are given 24-hours notice of an upcoming peak event and receive an incentive if they successfully reduce load during that event. The demand response programs we developed are also described in the Resource Options Database.

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. The groupings compared in the analysis are shown in the table below.

Grouping Rate Suites with supporting Demand Response program options	
No time-varying rates Do nothing.	**No demand response programs** Do nothing.
Rates suite 2 Voluntary time-of-use rates (for residential, large commercial and industrial customers) and voluntary critical peak pricing (for residential and 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.

Table 1. Summary of rate suite and demand response options

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 contracts, enabling more customers to participate in the program and providing BC Hydro with more flexibility to meet various needs. Industrial load curtailment targets similar savings as voluntary critical peak pricing but allows for more flexibility for both BC Hydro and the customer. Many large industrial customers have been strong advocates 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 other demand response programs.

Electric vehicle peak reduction is focused on electric vehicles. The electric vehicle market is rapidly increasing in size. From a utility perspective, the ability to supply electric vehicles can be a challenge if most electric vehicles are charged during peak demand periods such as in the early evening or at the end of the workday.

Electric Vehicle Peak Reduction options combine time-varying rates with supporting programs or incentives to shift electric vehicle charging outside of system peak periods. The Electric Vehicle Peak Reduction options in the Resource Options database are:

- **No EV Option:** the no-action case;
- **35 per cent EV 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 EV 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 EV 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.

These electric vehicle peak reduction options are described in the Resource Options Database.

5.3 Electricity purchase agreement renewals

As of February 2020, BC Hydro had a total of 127 electricity purchase agreements with independent power producers. About 70 of these agreements are expiring over the next 20 years, representing approximately 9,100 GWh of firm energy and 1,300 MW of dependable capacity. The expiring agreements are primarily small run-of-river facilities as well as some are larger run-of-river, storage hydro, biomass, municipal solid waste, wind, solar, waste heat, biogas, and gas-fired generation facilities. These agreements are all considered as existing resources until the year they expire.

As BC Hydro does not own these facilities, for the purposes of evaluation we must make assumptions 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. These assumptions are set out in the Resource Options Database.

5.4 BC Hydro resources (exclusive of demand-side measures)

BC Hydro resources, exclusive of demand-side measures, include upgrades to BC Hydro bulk transmission facilities and to generating facilities. Each is described below.

5.4.1 Upgrades to BC Hydro transmission facilities

Upgrades to BC Hydro's bulk transmission facilities 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. Transmission upgrades in the Resource Options Database include improvements to existing infrastructure as well as options to add additional transmission lines.

Most of BC Hydro's customer load is located in the South Coast region of the province. While some generation resources are located within the South Coast region, most of the electricity required to serve this customer load is transmitted into the region from the Interior of the province through five transmission lines. In addition, two transmission lines are available to transmit electricity to the South Coast from external markets in the United States.

Table 2 outlines the incremental upgrades to transmission lines serving the South Coast that are identified in the Resource Options Database that are the focus of discussion in the DRAFT 2021 IRP.

Transmission resource options (sequential)	Capacity	Lead time
Step 1 Upgrades (series compensation, shunt capacitors, thermal upgrades)	550 MW (-200 / +200)	10 Years
Step 2 Upgrades (static VAR compensators))	700 MW (-200 / +100)	10 Years
Step 3 Upgrades (new stations, transformers and more thermal upgrades)	500 MW (-200 / +100)	10 Years

Table 2. South Coast transmission upgrade resource options

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 are 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 re-develop. Those facilities that are currently in service are considered existing resources for the entire time horizon of the 2021 IRP, while those that are not in service are not considered as either existing or committed resources. The Resource Options Database includes all previously identified potential upgrades to BC Hydro generating facilities except those with very high costs of incremental energy or capacity.

5.5 New resources

Many different types of new sources of electricity are available across British Columbia. BC Hydro monitors the potential and characteristics of these resources. Table 2 illustrates the range of options currently included 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	Battery storage – customer-scale
Municipal solid waste	Natural gas – simple cycle gas turbine
Natural gas	Pumped storage
Offshore wind	
Onshore wind	
Renewable natural gas	
Run-of-river hydro	
Small storage hydro	
Solar – utility-scale	
Solar – distribution-scale	
Solar – customer-scale	
Solar and batteries combined – customer-scale	

Table 3. New clean resource options in the Resource Options Database

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, over the long-term, large-scale solar resources are expected to become more competitive.

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

6. The process used to build the 2021 IRP

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 use to evaluate whether we are meeting these objectives. The approach helps clarify the choices and trade-offs we make between potential options.

6.1 What process did we use to generate portfolios and make decisions?

There are different ways to assemble portfolios of resources that meet our future load-serving obligations and our planning objectives. Figure 4 illustrates the general process of developing and evaluating portfolios using portfolio modelling and structured decision-making.

Inputs and assumptions

Inputs can be 'fixed' for the model

KEY INPUTS

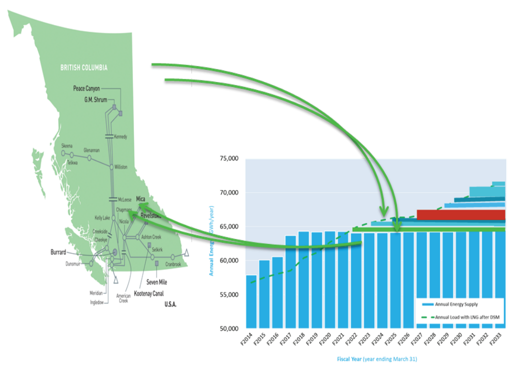
Demand forecast
Existing resource characteristics
Demand side measure options
Generation resource options
Transmission options
Market price parameters

PLANNING ASSUMPTIONS

Timeframe
Planning criteria
Financial assumptions

Use computer modelling

System Optimizer model picks resources to fill the supply demand gap in the lowest cost way



Structure decisions

Portfolios of resources selected based on least cost

PORTFOLIO

Least cost (present value)
Resources selected
Resource timing over horizon

These portfolios can be assessed for planning objectives in addition to cost

	Portfolio 1	Portfolio 2	Portfolio 3
Keeping costs down			
Reducing greenhouse gases			
Limiting land / water impacts			
Supporting BC's economy			

Once resources are evaluated, resources that are winners across multiple portfolios can be 'fixed' as part of the plan. Model runs are done again to determine what next resources are best fit.

Figure 4. Process of developing and evaluating portfolios

The general process steps are as follows:

1 We gather our technical inputs and assumptions. These include all our potential resource options in the Resource Options Database, as well as other inputs like our load forecast, our planning criteria; and other technical inputs.

2 We use a computer model (**System Optimizer**) to select amongst 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 initial resource. We then generate least cost portfolios around each of those assumptions to compile a complete set of resources, the timing of those resources, and an overall portfolio cost.

3 Additional impacts are then considered beyond the portfolio cost to see how other objectives are impacted by a particular resource selection. We then conduct a structured 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 initial resource option in the chosen portfolio is then "fixed" for the purpose of the analysis, and the process is repeated using the next resource and assumptions about the size or volume of that next resource.

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 demand-side measures. Accordingly, our process to develop and evaluate portfolios started with demand-side measures (energy efficiency, and time-varying rates & demand response programs). This was also consistent with the consultation feedback we received as we developed the 2021 IRP.

NOTE TO READER OF DRAFT 2021 IRP

The consultation feedback referred to was received during the first phase of consultation.

Once the demand-side measures resource options were fixed, we then determined the other resource options required to fill the remaining gap.

6.2 How did we make trade-offs using our objectives?

NOTE TO READER OF DRAFT 2021 IRP

As discussed in section 2.3, currently BC Hydro's planning objectives include 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. These objectives are preliminary, and the measures presented in Table 4 below are equally preliminary.

Table 4 expands on this 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. The measures are used in the consequence tables that evaluate the trade-offs between different portfolios.[6]

6 Not all of the objectives and sub-objectives in Table 3 will be relevant for each portfolio being considered.

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).[7] Net Total Resource Cost measures the total costs to the utility and program participants, less any non-energy benefits to both the utility and participants.
Minimize Net Utility Cost	$M PV	Lower	Millions of dollars in present value (PV). Net utility cost measures the costs of resource in terms of the utility expenditures (program administration costs and incentive payments) less any non-energy benefits to the utility.
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. Larger divergences 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	Later	The earliest in-service date for the particular transmission upgrade is not met. 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	Percent	Lower	Rate increases incremental to the portfolio of existing and committed resources.
Maximize ability for all to benefit from a rate	Default rate (Yes/No)	No	Default (opt-out) rates increase the chance that those unable to take advantage of rate structure will have higher electricity bills.

Table 4. Planning Objectives

7 A Present Value (PV) calculation considers the fact that financial impacts (costs or benefits) that occur years from now have less weight from today's perspective. They are related by the interest rate, such that a present value calculation will take a stream of annual financial impacts (costs or benefits) and translate them using the interest rate into today's values, and them sum them up into one value.

Limit land and water impacts			
Minimize land and water impacts	Index	Lower	An indexed summation of land and water impacts. A Scaled Zonation impacts index was developed and used for this measure.[8]
Reduce greenhouse gas emissions			
Minimize greenhouse gas emissions	t CO_2e	Lower	Tonnes of carbon dioxide equivalent emissions from system generation.
Support growth of B.C.'s economy			
Maximize economic development of communities	New Generation jobs (full-time equivalents)	Higher	Estimated number of jobs that would be created through development of greenfield generation projects or upgrades to existing facilities. This includes both construction and operation jobs and is converted into 20-year job equivalents.

Table 4. Planning Objectives (continued)

6.3 How consultation helped build the 2021 IRP

Building the 2021 IRP was a collaborative process which involved Indigenous Nations, customers, stakeholders, and the broader public.

Our consultation process included three streams: customers and the public; Indigenous Nations; and a technical stream. Figure 5 illustrates the interactions we have had since the start of this process.

NOTE TO READER OF DRAFT 2021 IRP

Figure 5 below shows consultation efforts to the date of this DRAFT 2021 IRP, and currently planned consultation to the date of the final 2021 IRP.

8 A Scaled Zonation score is a summary index, aggregating several dimensions of impacts to land and water attributes. A more detailed description of the method and results regarding environmental impacts will be included in the final IRP.

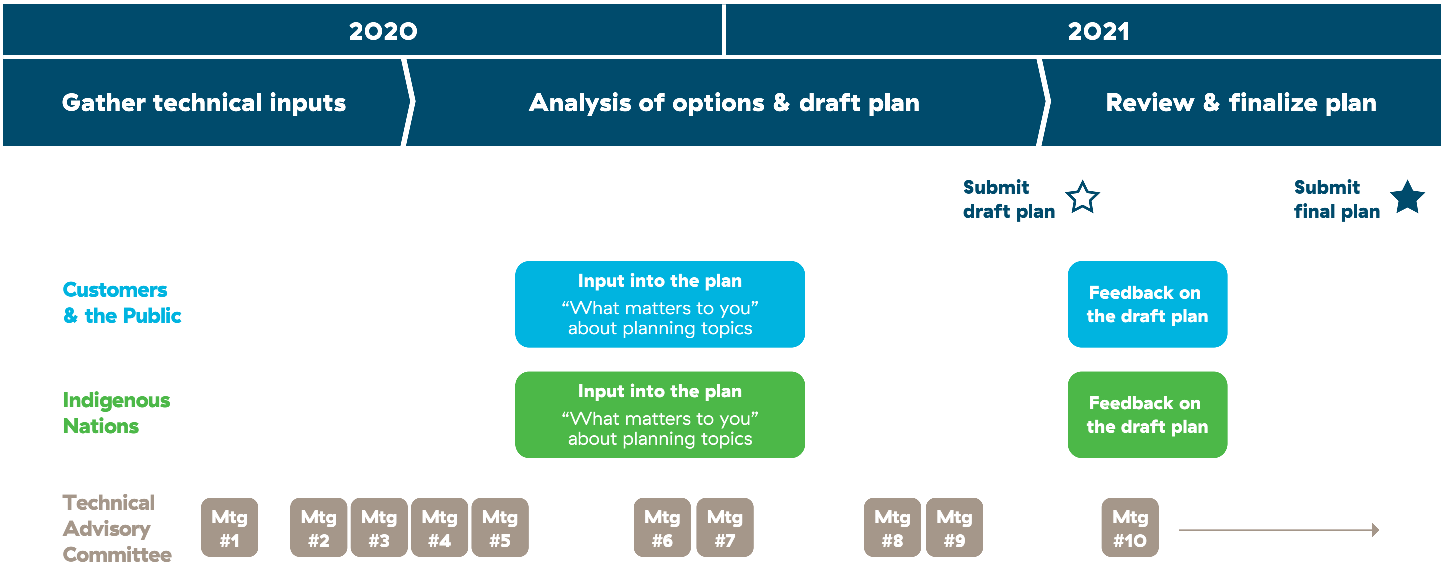


Figure 5. Summary of Consultation Plan

While the technical stream was ongoing throughout the plan development process, consultation with our customers and the public, and Indigenous Nations, was undertaken in two phases.

The first phase, which occurred in fall 2020, was designed to gather input on interests and values by finding out 'what matters' to people about various planning topics. Sixty-four Indigenous Nations and over 5000 customer and public stream participants provided input into the plan. Input from the first phase of consultation was considered, along with technical, financial, and other environmental and economic development analysis, to develop the DRAFT 2021 IRP.

NOTE TO READER OF DRAFT 2021 IRP

The balance of this section will be completed as part of the final 2021 IRP. The final 2021 IRP will also summarize how it was informed by the consultation throughout the development process. A full consultation record will be included with BC Hydro's IRP application to the Commission (to which the 2021 IRP will be appended).

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

The Base Resource Plan is BC Hydro's strategy to meet the future needs of our customers if the future turns out as we currently expect. In the 2021 IRP, the Base Resource Plan will be developed through the process set out above and will consider input received during both phases of consultation. Most of the elements of the Base Resource Plan will require further approvals from the Commission and so cannot be considered binding commitments for future action.

NOTE TO READER OF DRAFT 2021 IRP

The Base Resource Plan below reflects BC Hydro's preliminary thinking and was developed for the purpose of continued consultation.

7.1 What are the elements of the Base Resource Plan?

The Base Resource Plan consists of seven elements, as follows:[9]

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 1,700 GWh/year of energy savings and 290 MW of capacity savings at the system level by fiscal 2030;

2 Pursue voluntary time-varying rates supported by demand response programs to achieve 220 MW of capacity savings at the system level by fiscal 2030 (Rate suite 2 and Demand Response Program A), and advance the Industrial Load Curtailment Program to achieve 100 MW of incremental capacity savings at the system level by no later than the fiscal 2027 to fiscal 2030 period;

3 Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers to support a new or existing (as applicable) 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 EV driver participation) to achieve 100 MW of capacity savings at the system level by fiscal 2030;

9 The GWh/yr and MW numbers quoted in the Base Resource Plan are consistent with the volumes shown in the Load Resource Balances with Base Resource Plan Actions shown in section 7.2.

4 Offer a market-price based renewal option to existing clean or renewable independent power producers with electricity purchase agreements expiring in the next five years. There are approximately 20 existing clean or renewable projects, that produce a total of roughly 900 GWh, with electricity purchase agreements set to expire before April 1, 2026;

5 Advance the first sequential step of upgrades to transmission infrastructure into the South Coast region including series compensation, shunt capacitors and thermal upgrades to achieve 550 MW of capacity for the South Coast region by fiscal 2033; prepare to initiate a second step of upgrades to achieve an additional 700 MW of capacity for the South Coast region by fiscal 2039;

6 Beyond the elements identified above and after demand-side measures, plan to acquire new energy and capacity resources starting with 580 GWh in fiscal 2031, then shifting to primarily capacity resources starting with 110 MW in fiscal 2038. These future resources would be selected from amongst:

- Expiring electricity purchase agreements with independent power producers;
- New clean and renewable energy resources; and
- Upgrades to BC Hydro facilities.

7 Undertake a structured decision-making approach to evaluate small BC Hydro plants that are at end-of-life, or in operation and nearing end-of-life, on a facility by facility basis to determine whether to decommission, divest or refurbish these facilities, on the following schedule:

Facility	Timing to review end-of-life investment decision
Shuswap	Analysis in progress
Elko	2025
Spillimacheen	2029
Alouette	2030
Falls River	In operation – date not set
Walter Hardman	In operation – date not set

Table 5. BC Hydro small plants at or reaching end-of-life

NOTE TO READER OF DRAFT 2021 IRP

The Base Resource Plan above reflects BC Hydro's preliminary thinking and was developed for the purpose of continued consultation. The rationale for the entire Base Resource Plan and its individual components is also preliminary and developed for the purpose of consultation.

One important caveat on the Base Resource Plan is that the structured decision-making process described in sections 6.1 and 6.2 was applied-in-full only to the demand-side measure resources. This reflects in part the time available to complete the analysis for the DRAFT 2021 IRP in time for a June filing. It also reflects that after planned demand-side measures, the date of system energy and capacity shortfalls moves 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 fiscal, and these dates are quite late in the planning horizon. The consequence is that specific resource acquisition decisions after planned demand-side measures are particularly uncertain. BC Hydro will be addressing that uncertainty and the analytical support for the future resources beyond planned demand-side measures in the final 2021 IRP

7.2 The Load Resource Balances with Base Resource Plan: how does the plan meet the future electricity needs of our customers over time?

The Base Resource Plan described in words in section 7.1 is shown here in Figures 6 through 11. Figures 6 and 7 show how "Planned DSM" (i.e. only the DSM elements as described in the Base Resource Plan – elements number 1 through 3) would contribute to serving the anticipated future needs of our customers for energy and capacity respectively. Figure 8 provides a similar view for capacity on the South Coast.

Figures 9 and 10 present the same view but with the full suite of Base Resource Plan elements. Similarly, Figure 11 provides that view for capacity on the South Coast.

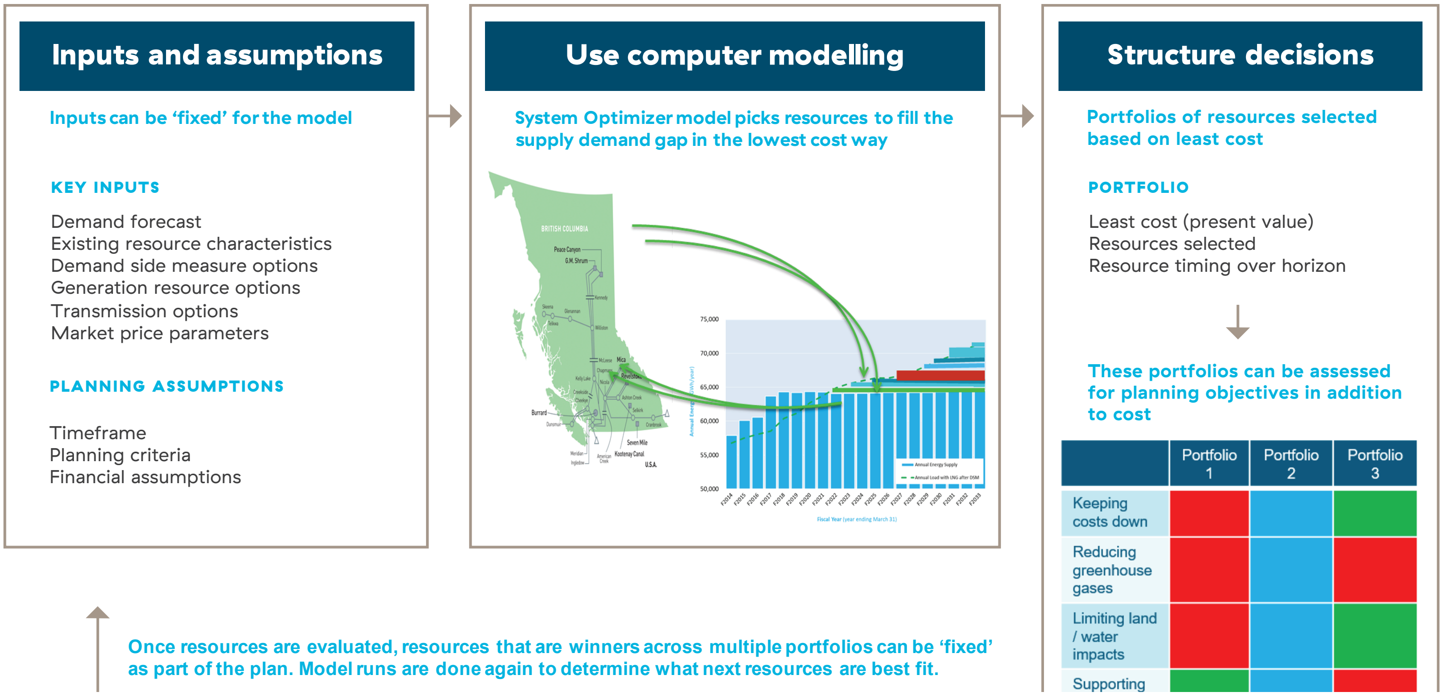


Figure 6. System energy Load Resource Balance (with Planned DSM only)

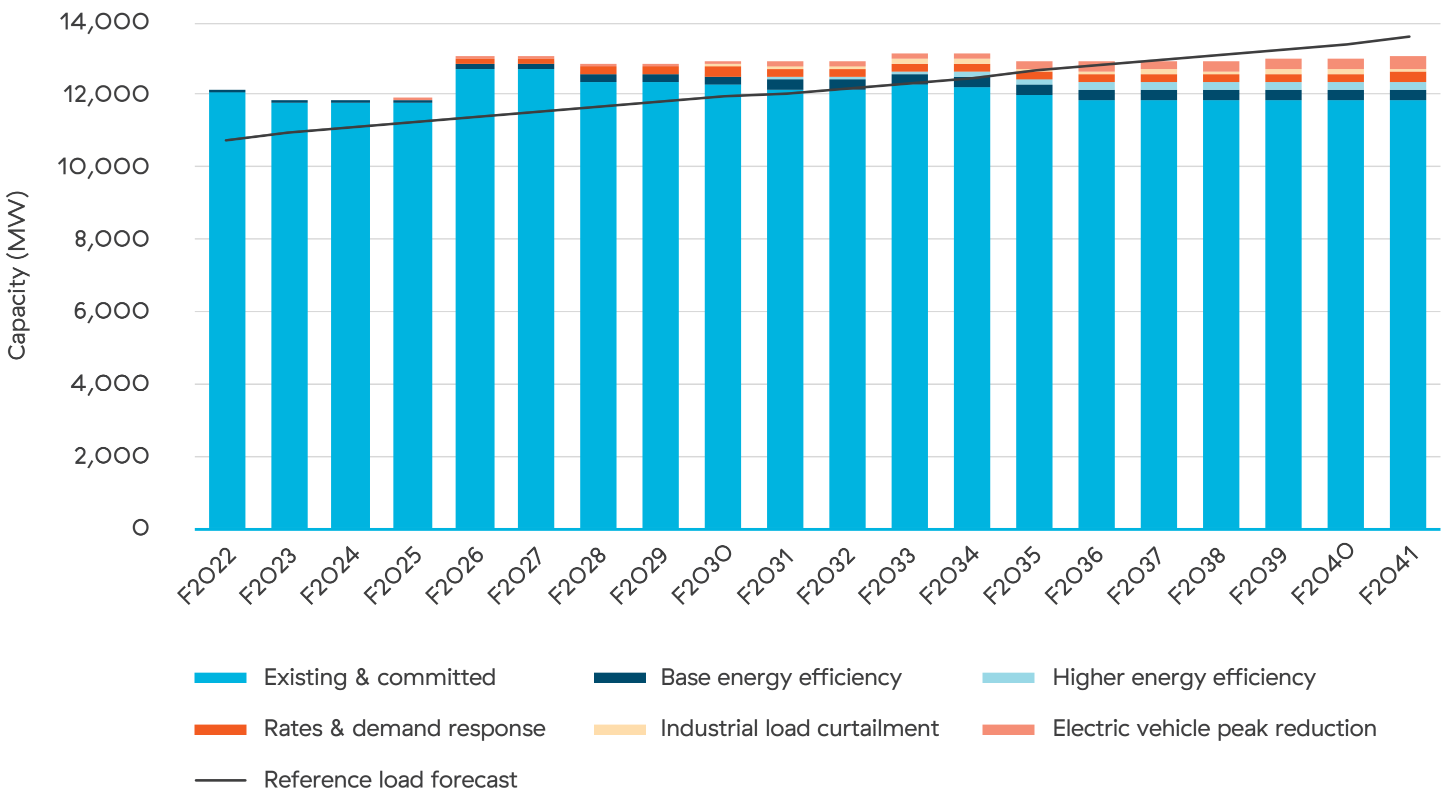


Figure 7. System capacity Load Resource Balance (with Planned DSM only)

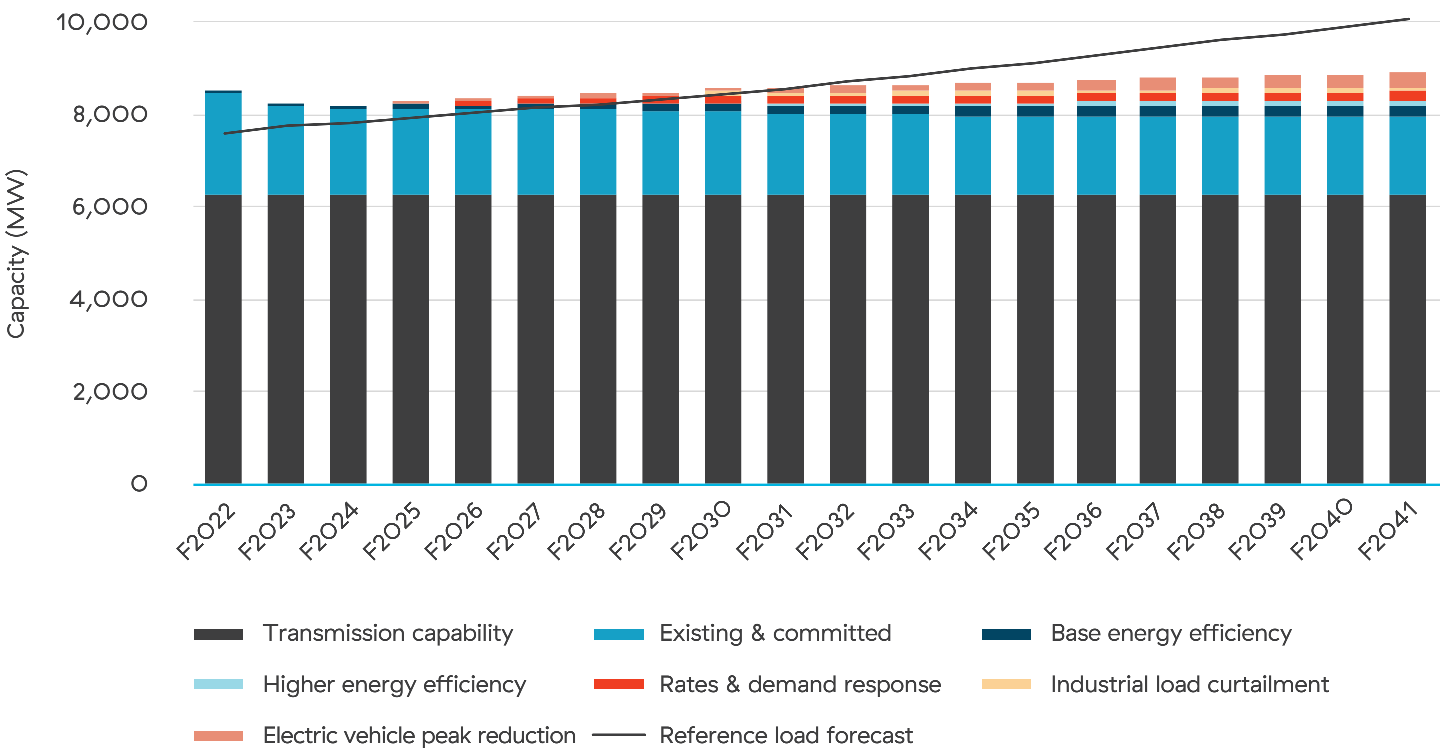


Figure 8. South Coast capacity Load Resource Balance (with Planned DSM only)

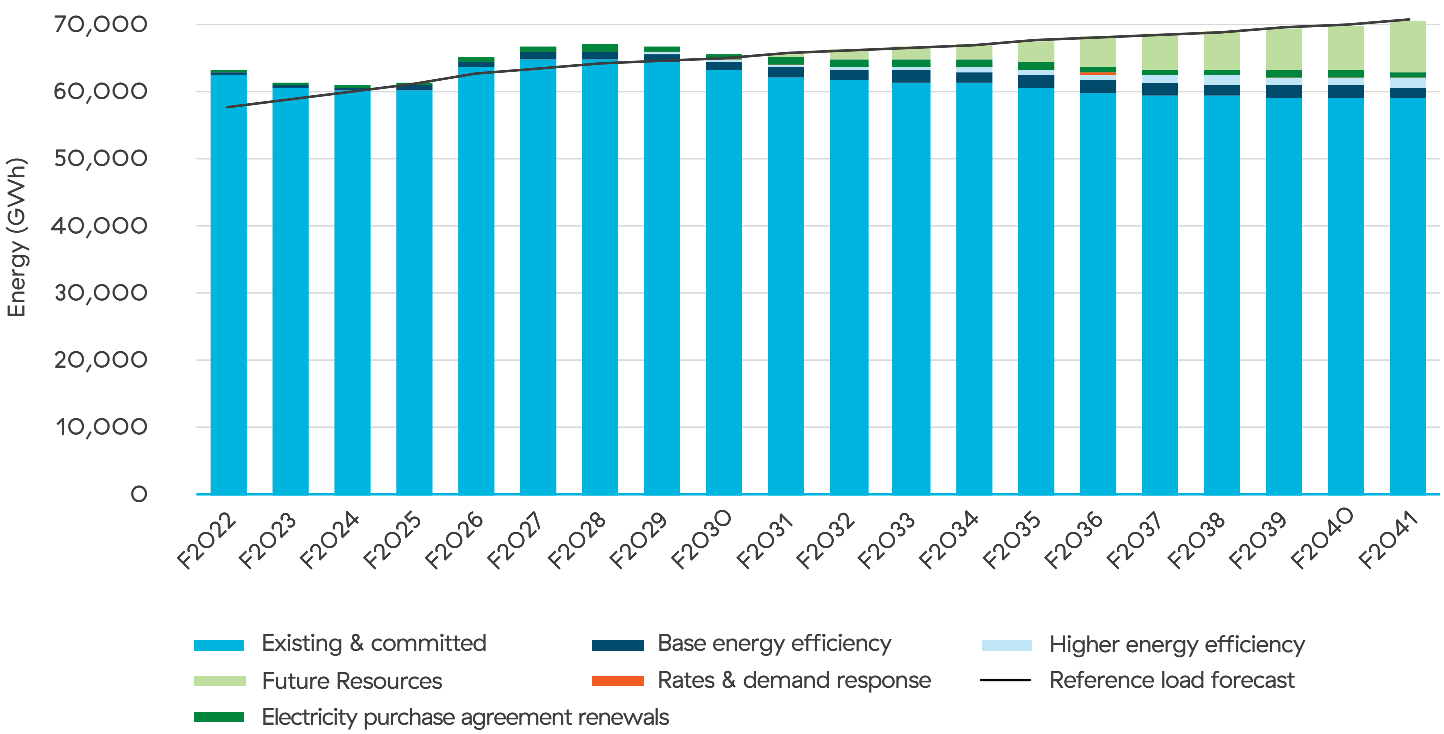


Figure 9. System energy Load Resource Balance (with all Base Resource Plan elements)

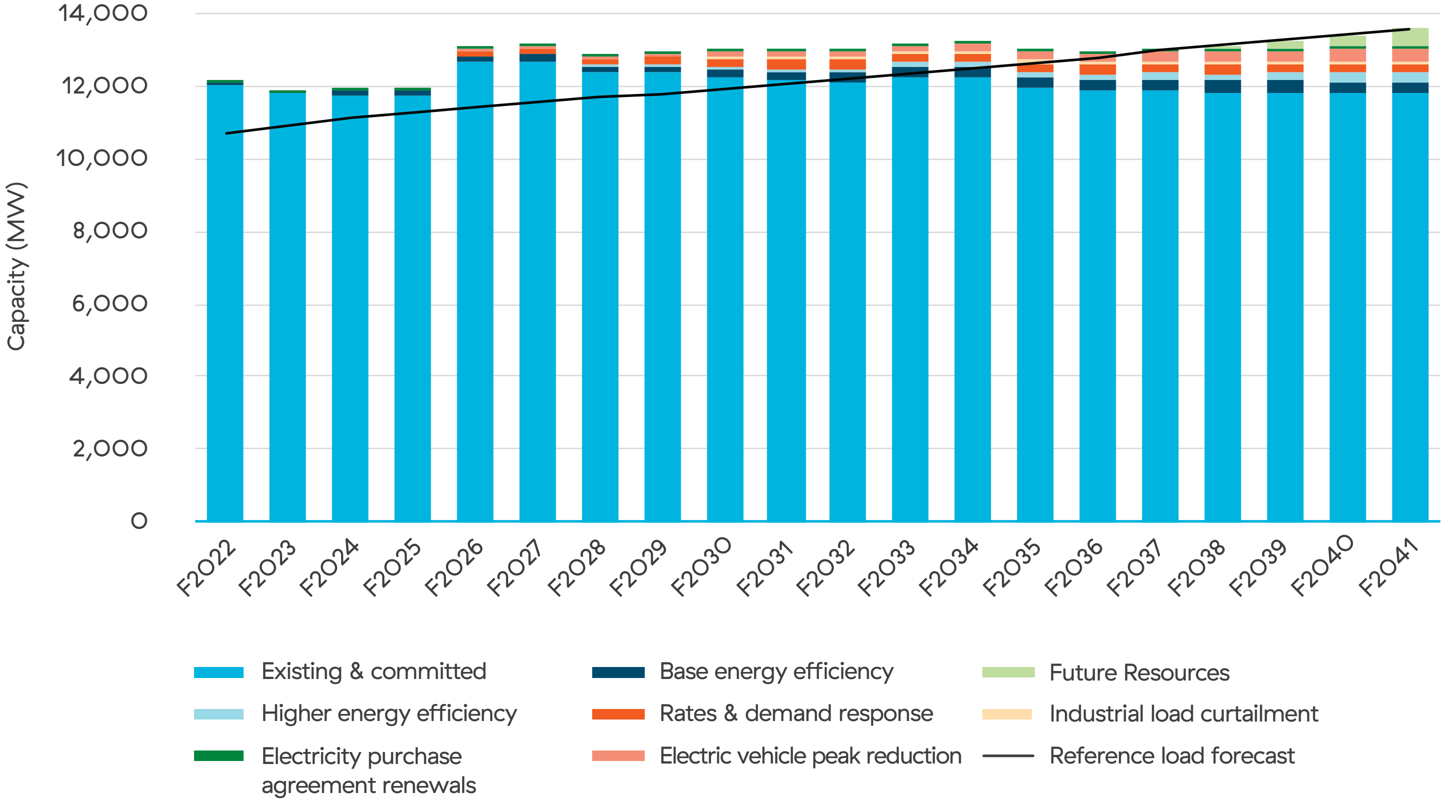


Figure 10. System capacity Load Resource Balance (with Planned DSM only)

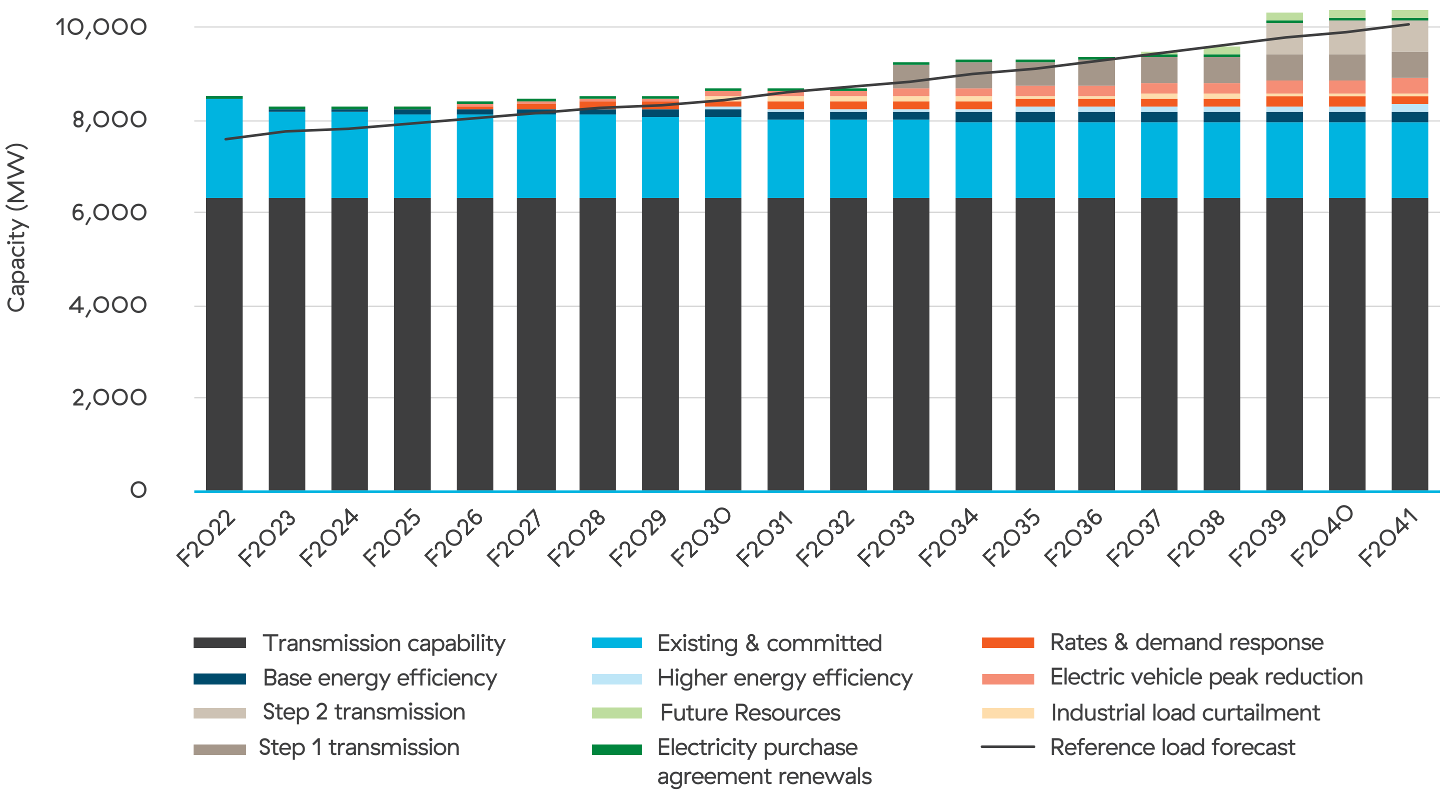


Figure 11. South Coast capacity Load Resource Balance (with all Base Resource Plan elements)

These figures are the same Load Resource Balances shown in section 4 (Figures 1, 2 and 3) but with the resources described in the Base Resource Plan filling-in the energy and capacity shortfalls. The figures illustrate which resources come on-line, when they come on-line, and how much of that resource is used.

7.3 What analysis lead to the Base Resource Plan?

Using the process outlined in section 6, we developed and evaluated portfolios for the Base Resource Plan starting with demand-side measures (energy efficiency and rates & demand response programs). Once the demand-side measures resource options were fixed, we then determined the other resource options required to fill the remaining gap. The following sections describe each step of this process.

7.3.1 How was the level of energy efficiency programs selected?

NOTE TO READER OF DRAFT 2021 IRP

The Base Resource Plan above reflects BC Hydro's preliminary thinking and was developed for the purpose of continued consultation. The rationale for the entire Base Resource Plan and its individual components is also preliminary and developed for the purpose of consultation.

Energy efficiency programs provide both energy and capacity savings and are flexible and scalable. We analyzed the four levels of energy efficiency savings outlined in section 5.2.1. Figure 12 provides a consequence table, outlining the trade-offs between portfolios where each of the energy efficiency levels is a fixed input, and the remaining non-demand-side measure resources are filled in, through portfolio optimization, to complete a set of least-cost portfolios that meet our load-serving obligations.

HOW TO READ THIS TABLE

Each column corresponds to a portfolio formed by selecting the level of **Energy Efficiency** and then letting the portfolio optimization fill in the rest of the resource choices

Other portfolio resources chosen by the optimization model

The highest level of new renewables and the largest and fastest transmission build out

The lowest level of new renewables and the least and latest transmission build out

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	$2,470	$1,090	$480	–$150
Net Utility Cost ($M PV)	Lower	$2,470	$1,440	$1,210	$960
Cost risk from DSM under-delivery (MW below plan in 2030)	Lower	0	80	110	130
Cost risk from transmission schedule uncertainty (year in service Step 2)	Later	2034	2034	2034	2035
(year in service Step 3)	Later	2042	–	–	–

Figure 12. Consequence table of portfolios with fixed energy efficiency options

- the portfolio used as the basis of comparison
- the alternative is **worse** than the base portfolio
- the alternative is **better** than the base portfolio

HOW TO READ THIS TABLE

Each column corresponds to a portfolio formed by selecting the level of **Energy Efficiency** and then letting the portfolio optimization fill in the rest of the resource choices

The highest level of new renewables and the largest and fastest transmission build out

The lowest level of new renewables and the least and latest transmission build out

Objective (measure)	What is better?	No Energy Efficiency	Base Energy Efficiency	Higher Energy Efficiency	Higher Plus Energy Efficiency
Rate impact (% change in F2030)	Lower	NA	0.0%	0.6%	1.2%
(% change in F2041)	Lower	NA	0.0%	1.5%	3.7%
Land and water impacts (index)	Lower	10.0	6.3	4.4	NA
New generation jobs (full-time equivalents)	Higher	730	570	370	260

Figure 12. Consequence table of portfolios with fixed energy efficiency options (continued)

- the portfolio used as the basis of comparison
- the alternative is **worse** than the base portfolio
- the alternative is **better** than the base portfolio

7.3.1.1 **Trade-offs in the consequence table**

Pursuing different levels of energy efficiency impacts multiple objectives. BC Hydro views the major trade-offs here to be balancing portfolio cost, rate increases, and land and water impacts. The magnitude to which the other objectives (i.e., under-delivery risk and new generation jobs) are impacted is relatively small in comparison.

> **NOTE TO READER OF DRAFT 2021 IRP**
>
> The discussion below is focused on the major trade-offs identified above, reflecting the preliminary nature of BC Hydro's thinking at this time.

Across the full range of options, Figure 12 shows that pursuing higher levels of energy efficiency results in substantially lower portfolio costs. In fact, the level of energy efficiency to be pursued is the largest single action we can take to impact portfolio costs within the IRP. In addition, higher levels of energy efficiency postpone or remove the need for transmission upgrades, alleviating multiple issues that could lead to costly project delays.

However, pursuing higher levels of energy efficiency can also result in higher rates. This is because, 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.

For example, moving from Base energy efficiency to Higher energy efficiency, and then from Higher energy efficiency to Higher plus energy efficiency results in $600 million of 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 long-term rate increases. Similarly, moving from Base energy efficiency to Higher plus energy efficiency means 3.7 per cent higher long-term rate increases.

Figure 12 also shows that doing any energy efficiency, as opposed to no energy efficiency, avoids significant land and water impacts.

7.3.1.2 **What level of energy efficiency was chosen for the Base Resource Plan?**

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 7.1 and shown in section 7.2.

Our preliminary assessment is that:

- The assumed rate impact benefits Note to reader of DRAFT 2021 IRP: To be estimated for the final IRP of the No energy efficiency option are outweighed by the cost and environmental footprint trade-offs;
- The cost and environmental footprint benefits associated with the Higher plus energy efficiency option are outweighed by the additional incremental rate increases trade-off;
- Some level of energy efficiency programs is needed to support rates and demand response programs, as well as to provide the flexibility to ramp up energy efficiency efforts as needed;
- A staged approach – moving from Base energy efficiency to Higher energy efficiency, takes advantage of the flexibility of energy efficiency and allows us to minimize incremental rate impacts while in surplus and ramp up to the Higher energy efficiency as need re-emerges; and
- Results from our consultation show strong support for our energy efficiency programs and for increasing those programs when needed. 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.

7.3.1.3 What Near-Term Actions are associated with the chosen energy efficiency level?

NOTE TO READER OF DRAFT 2021 IRP

This section will include Near-Term Actions related to this element of the Base Resource Plan.

7.3.2 How were the time-varying rate suite and supporting demand response programs selected?

NOTE TO READER OF DRAFT 2021 IRP

The Base Resource Plan above reflects BC Hydro's preliminary thinking and was developed for the purpose of continued consultation. The rationale for the entire Base Resource Plan and its individual components is also preliminary and developed for the purpose of consultation.

Time-varying rates and demand response programs are two methods to encourage customers to shift their consumption out of peak periods. We analyzed rates suites and supporting demand response programs as well as an industrial load curtailment program, all of which are outlined in section 5.2.2.

Figure 13 provides a consequence table outlining the trade-offs between portfolios where each suite of time-varying rates and supporting demand response programs is a fixed input, and the remaining non-demand-side measure resources are filled in, through portfolio optimization, to complete a set of least-cost portfolios that meet our load-serving obligations.

HOW TO READ THIS TABLE

Each column corresponds to a portfolio formed by selecting the level of **rates suite** and then letting the portfolio optimization fill in the rest of the resource choices

Other portfolio resources chosen by the optimization model

Base and then higher energy efficiency in first 10 years
No new renewables in first 10 years

More batteries in later years ⟷ Less batteries in later years

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	$480	$420	$360
Net Utility Cost ($M PV)	Lower	$1,210	$1,210	$1,060
Cost risk from DSM under-delivery (MW below plan in 2030)	Lower	80	410	220
Cost risk from transmission schedule uncertainty (year in service Step 2)	Later	2034	2035	2036
Rate impact (% change in F2030)	Lower	0.6%	0.6%	0.6%
(% change in F2041)	Lower	1.5%	1.9%	1.7%
Default rate (Y/N)	No	No	No	Yes
New generation jobs (full-time equivalents)	Higher	370	380	350

Figure 13. Voluntary time-varying rates and demand response programs portfolio selection consequence table

- (blue) the portfolio used as the basis of comparison
- (orange) the alternative is **worse** than the base portfolio
- (green) the alternative is **better** than the base portfolio

7.3.2.1 **Trade-offs in the consequence table**

Figure 13 shows that pursuing more savings via time-varying rates and demand response programs provides modest financial benefits. More savings from rates and programs also pushes out the required in-service date of the Step 2 transmission upgrade. As noted in the comparison of energy efficiency levels, giving more time to deliver long lead-time transmission projects can alleviate issues that may lead to costly project delays. However, both the Step 1 and Step 2 transmission upgrades are still needed by around the mid-2030s, regardless of which portfolio of rates and is chosen.

We view the major trade-offs here to be balancing the financial benefits of increased savings from time-varying rates and supporting demand response programs compared to the types of rate structures that could be needed to achieve these benefits (for example, opt-in versus opt-out rate structures). For example, moving from Rate suite 2 (with Demand Response Program A) to Rate suite 3 (with Demand Response Program B) lowers portfolio costs by $60 million but is expected to require the implementation of default time-of-use rates. Customers able to adjust their consumption in response to time-of-use rates may benefit but customers less able to respond may face higher costs.

We also chose the Industrial Load Curtailment Program as part of the least cost portfolio across all three options of rate suites and associated demand response programs albeit with varied timing.

7.3.2.2 **What time-varying rate and supporting Demand Response Programs were chosen?**

We have chosen Rate Suite 2 with Demand Response Program A, and the Industrial Load Curtailment Program, as described in section 7.1 and shown in section 7.2.

Our preliminary assessment is that:

- Rate suite 2 has portfolio cost benefits compared to the No rates suite and provides a potential platform for the various electric vehicle peak reduction options.
- The financial benefits associated with Rate suite 3 and Demand Response Program B are outweighed by the expected challenges of implementing default (opt-out) time-of-use rates.
- Opt-in rates can provide greater product and service differentiation compared to the default (opt-out) rates of Rate suite 3 and avoid the potential customer bill impacts associated with a default (opt-out) rate with Rate suite 3.
- Consultation results from customers and the public as well as Indigenous Nations showed an overall openness and support for time-varying rates; however some participants did not support time-varying rates, raising concerns about equity and the potential that customers who cannot take advantage of time-varying rates to lower their bills may be penalized. Rates suite 2 emphasizes customer choice and mitigates the potential for negative bill impacts for customers who could be defaulted into a rate that is not well suited for them.

- While BC Hydro has years of experience and success implementing energy efficiency programs and conservation rates, our experience with demand response programs and time-varying rates is limited. Rate suite 2 with Demand Response Program A will allow BC Hydro, and our customers, to gain more experience in this area over time, which will improve our ability to successfully implement more challenging options, as required, in response to future needs if needed.
- Consultation results showed an overall openness and support for demand response technologies; however, many participants were not familiar with these technologies and some participants raised concerns about data privacy. Rate Suite 2 with Demand Response Program A allows marketing and incentive activities to be deployed at a pace and scale that reflects customer readiness for these programs.
- The Industrial Load Curtailment Program is a low-cost option to meet capacity needs compared to new supply capacity resources. It can 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.

7.3.2.3 What Near-Term Actions are associated with the chosen time-varying rates suite and supporting demand response programs?

NOTE TO READER OF DRAFT 2021 IRP

This section will include near term actions related to this element of the Base Resource Plan.

7.3.3 How was the electric vehicle peak reduction selected?

NOTE TO READER OF DRAFT 2021 IRP

The Base Resource Plan above reflects BC Hydro's preliminary thinking and was developed for the purpose of continued consultation. The rationale for the entire Base Resource Plan and its individual components is also preliminary and developed for the purpose of consultation.

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 6.2. Figure 14 provides a consequence table, outlining the trade-offs between portfolios where each of the electric vehicle peak reduction options is a fixed input, and the remaining non-demand-side measure resources are filled in, through portfolio optimization, to complete a set of least-cost portfolios that meet our load-serving obligations.

HOW TO READ THIS TABLE

Each column corresponds to a portfolio formed by selecting the level of **Electric Vehicle (EV) driver participation** and then letting the portfolio optimization fill in the rest of the resource choices

Other portfolio resources chosen by the optimization model

Base and then higher energy efficiency and Rates Suite 2
No major differences in new renewables

More batteries in later years ← → Less batteries in later years

Objective (measure)	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	$420	$300	$260	$170
Net Utility Cost ($M PV)	Lower	$1,210	$1,090	$980	$1,000
Cost risk from DSM under-delivery (MW below plan in 2030)	Lower	410	460	540	650
Cost risk from transmission schedule uncertainty (year in service Step 2)	Later	2035	2036	2037	–
Rate impact (% change in F2030)	Lower	0.6%	0.6%	0.6%	NA
(% change in F2041)	Lower	1.9%	1.5%	1.3%	NA
Land and water impacts (index)	Lower	NA	NA	NA	NA
New generation jobs (full-time equivalents)	Higher	380	340	260	320

Figure 14. Electric vehicle peak reduction portfolio selection consequence table

- the portfolio used as the basis of comparison
- the alternative is **worse** than the base portfolio
- the alternative is **better** than the base portfolio

7.3.3.1 **Trade-offs in the consequence table**

Figure 14 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, but benefits from a Net Utility Cost perspective reach their peak at the 50 per cent participation level. Increased participation also pushes out the required in-service date of the Step 2 transmission upgrade.

> **NOTE TO READER OF DRAFT 2021 IRP**
>
> The rate impact metric is counterintuitive. It was expected that more savings from rate design would lead to incremental rate increases. We are currently looking into this finding and will address it in the final 2021 IRP.

We view the major trade-offs here to be portfolio cost benefits compared to the required increased reliance on an energy planning tool that is relatively new to us. As Figure 14 shows, the highest level of savings from electric vehicle peak reduction contributes to a potential overall downside from missing planned demand-side measures savings targets of approximately 650 MW in fiscal 2030.

7.3.3.2 **What electric vehicle peak reduction option was chosen for the Base Resource Plan?**

We have chosen the 50 per cent EV driver participation option, as described in section 7.1 and shown in section 7.2.

Our preliminary assessment is that:

- Higher participation levels for electric vehicle peak reduction result in lower portfolio costs;
- The greatest risk of under delivery is associated with the 75 per cent EV driver participation option. Electric vehicle peak reduction options are new in general and relatively unfamiliar to BC Hydro specifically;
- The 50 per cent EV driver participation option has portfolio cost benefits over the no participation option and the 35 per cent EV driver participation option without a noticeable increase in the relative risk of under-performance; and
- Demand-side measures, such as electric vehicle peak reduction, are consistent with customer and Indigenous Nations' consultation feedback because they keep costs down and limit land and water impacts by mitigating the need for new infrastructure.

7.3.3.3 What Near-Term Actions are associated with the chosen electric vehicle peak reduction option ?

NOTE TO READER OF DRAFT 2021 IRP

This section will include Near-Term Actions related to this element of the Base Resource Plan.

7.3.4 What is our approach to electricity purchase agreement renewals?

NOTE TO READER OF DRAFT 2021 IRP

The Base Resource Plan above reflects BC Hydro's preliminary thinking and was developed for the purpose of continued consultation. The rationale for the entire Base Resource Plan and its individual components is also preliminary and developed for the purpose of consultation. In addition, and as noted above, we have not completed the structured decision-making process for any of the resources after demand-side measures. Our approach to electricity purchase agreement renewals is focused on 1: the approximately 20 clean or renewable electricity purchase agreements that are set to expire before April 1, 2026; and 2: electricity purchase agreements associated with two natural gas-fired facilities. We have addressed requirements for future resources (e.g., new clean resources, electricity purchase agreement renewals beyond April 1, 2026, BC Hydro upgrade options) that occur later in the planning period in section 7.3.7

Clean/renewable electricity purchase agreements expiring before April 1, 2026

There are approximately 20 existing clean or renewable projects, totaling approximately 900 GWh of annual energy, with electricity purchase agreements set to expire before April 1, 2026.

With the demand-side measures outlined in the previous sections, the integrated system is expected to have sufficient energy and capacity until the early 2030s.

This means that 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 independent power producers may be willing to accept market-based prices in contracts to provide operational certainty.

Preliminary 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 when compared to meeting future load with new clean resources. Further, provided the electricity purchase agreement renewals are structured properly and are based on market prices, the cost risk to BC Hydro's customers should be limited.

In addition, 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.

Finally, consultation input from the customer and public stream 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.

For all these reasons we propose to offer to renew these electricity purchase agreements as described in sections 7.3.4.1 and 7.1.

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.

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 biggest source of greenhouse gas emissions on the system at about 340,000 tonnes of CO_2e per year. The electricity purchase agreement with McMahon expires in fiscal 2030.

The 275 MW Island Generation facility (located 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 in favour of other lower cost resources, which means that its greenhouse gas emissions are typically lower than a project like McMahon, about 10,000 tonnes of CO_2e per year. The electricity purchase agreement with Island Generation expires in fiscal 2023.

While we have had discussions with the Island Generation counterparty to understand potential terms of a renewal, 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 in operation in the applicable Load Resource Balances after fiscal 2023, and its renewal is not contemplated in the Base Resource Plan.

We also do not expect to renew the electricity purchase agreement for McMahon. This may have some impact to the regional transmission system which is currently being studied. For now, McMahon is not assumed to be in operation in the applicable Load Resource Balances after fiscal 2030, and its renewal is not contemplated in the Base Resource Plan.

Looking for opportunities to reduce commitments with greenhouse gas emitting facilities also incorporates consultation results which placed a high priority on reducing greenhouse gas emissions through clean electricity. Not renewing the McMahon and Island Generation electricity purchase agreements could reduce annual system emissions by roughly 340,000 tonnes of CO_2e and 10,000 tonnes of CO_2e, respectively.

7.3.4.1 What Near-Term Actions are associated with the approach to electricity purchase agreement renewals?

NOTE TO READER OF DRAFT 2021 IRP

This section will include Near-Term Actions related to this element of the Base Resource Plan.

7.3.5 How were the upgrades to the transmission system selected?

NOTE TO READER OF DRAFT 2021 IRP

The Base Resource Plan above reflects BC Hydro's preliminary thinking and was developed for the purpose of continued consultation. The rationale for the entire Base Resource Plan and its individual components is also preliminary and developed for the purpose of consultation. In addition, and as noted above, we have not completed the structured decision-making process for any of the resources after demand-side measures. Further, we have at this time given explicit consideration only to the transmission upgrades described in section 5.4.1 and not other transmission upgrades described in the Resource Options Database. Finally, once the non-wires elements of the Base Resource Plan and Contingency Resource Plans are finalized, additional studies will confirm specific transmissions requirements for the final 2021 IRP.

In section 5.4.1, we describe the three sequential steps of transmission upgrades which were developed and analyzed as options to serve the South Coast region.

Through the preliminary portfolio analysis outlined in section 6.1, these transmission upgrade options competed with other non-wires solutions to meet South Coast regional capacity needs (for example, pumped storage, small storage hydro, and utility-scale batteries). In all cases the Step 1 transmission upgrade was selected for meeting these capacity needs.

When given the option, the System Optimizer software also always selected the Step 2 transmission upgrade as part of the lowest cost portfolio to meet capacity needs on the South Coast.

The Step 3 transmission upgrade was chosen when energy efficiency demand-side measures was set to its lowest level. However, this was a very high-cost solution. In addition, feedback from customers and public and Indigenous Nations emphasized the importance of avoiding land and water impacts as well as keeping costs low. Accordingly, further analysis of strategies that included Step 3 as a way of meeting the Reference Load Forecast were not undertaken.

Considering the selected level of demand-side measures, the Step 1 and Step 2 transmission upgrades provide a large amount of capacity relative to other resources.

Customer and public input indicated a priority for keeping costs down and limiting land and water impacts. 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. As part of our plan, we'll be engaging early with Indigenous Nations that may be potentially affected by these upgrades.

For all these reasons we have chosen to advance the Step 1 and Step 2 transmission upgrades as described in section 7.1.

7.3.5.1 What Near-Term Actions are associated with the selected transmission system upgrades for the Base Resource Plan?

NOTE TO READER OF DRAFT 2021 IRP

This section will include Near-Term Actions related to this element of the Base Resource Plan.

7.3.6 What is the role for existing BC Hydro generating facilities?

NOTE TO READER OF DRAFT 2021 IRP

The Base Resource Plan above reflects BC Hydro's preliminary thinking and was developed for the purpose of continued consultation. The rationale for the entire Base Resource Plan and its individual components is also preliminary and developed for the purpose of consultation. In addition, and as noted above, we have not completed the structured decision-making process for any of the resources after demand-side measures.

We considered upgrades to existing BC Hydro facilities, as described in section 5.4.2, in conjunction with other sources of generation, when building preliminary least cost portfolios to meet future customer needs. Of the potential major 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 the most prominent. 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. Three of the small plants that are currently in-service are considered existing resources and are included in the applicable Load Resource Balances, while two small plants and one unit at another small plant that are not in-service are not considered existing resources and are not included in the Load Resource Balances. The options for the facilities are to decommission or refurbish, with subsequent choices in the refurbish scenario on whether BC Hydro refurbishes the facility or whether the facility is divested and refurbished by another entity.

BC Hydro's preliminary 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.

Further, a staged approach provides an opportunity to align re-development with evolving load requirements and the extent to which BC Hydro's planned demand and supply side resources are acquired and perform as expected. This is particularly important for planned capacity resources in the South Coast region.

Customer and public input showed an interest in de-commissioning and habitat restoration and keeping costs low, as well as looking for viable alternatives, if possible. Input through the engagement process 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.

For all these reasons, we have chosen the small plant strategy described in section 7.1.

7.3.6.1 What Near-Term Actions are associated with the approach to existing BC Hydro facilities for the Base Resource Plan?

NOTE TO READER OF DRAFT 2021 IRP

This section will include Near-Term Actions related to this element of the Base Resource Plan.

7.3.7 How are new resources considered?

NOTE TO READER OF DRAFT 2021 IRP

The Base Resource Plan above reflects BC Hydro's preliminary thinking and was developed for the purpose of continued consultation. The rationale for the entire Base Resource Plan and its individual components is similarly preliminary and developed for the purpose of consultation. In addition, and as noted above, we have not completed the structured decision-making process for any of the resources after demand-side measures. In the final 2021 IRP we expect to continue to address the requirements for future resources (e.g., new clean resources, electricity purchase agreement renewals beyond April 1, 2016, BC Hydro upgrade options) that occur later in the planning period in an aggregated manner.

Once the demand-side measures options were set, the System Optimizer model selected the lowest cost combination of resources, including new generation supply, to meet the remaining system energy and capacity needs.

The selected demand-side measures and BC Hydro's approach to electricity purchase agreement renewals before April 1, 2026 push out the need for new clean resources to the second half of the planning horizon.

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 amongst a variety of types of supply options (developing new clean resources, renewing expiring EPAs, 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.

For these reasons the Base Resource Plan shows that we will plan to acquire new clean resources as described in section 7.1.

7.3.7.1 What Near-Term Actions are associated with the approach to new clean resources?

NOTE TO READER OF DRAFT 2021 IRP

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.

7.3.8 Why don't we pursue enough demand-side measures to meet all of our future needs?

Sections 7.3.1 to 7.3.3 show that much of our future needs can be met 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 level of energy and capacity savings. On balance, our preliminary assessment is that the selected portfolios of demand-side measures represent a cost-effective way to meet future customer needs. Our preliminary assessment is that pursuing more demand-side measures to meet our Reference Load Forecast could:

- Increase bills for those not able to take advantage of energy efficiency programs;
- Default customers into rate options that are not well-suited to their consumption; and/or,
- 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.

7.3.9 How does our Base Resource Plan meet our planning objectives?

NOTE TO READER OF DRAFT 2021 IRP

The planning objectives in section 2.3 are, subject to the final 2021 IRP, to keep costs down for customers; reduce greenhouse gas emissions; limit land and water impacts; and support the growth of BC's economy. These preliminary objectives are the basis for the trade-off discussion and the rationale for the preliminary Base Resource Plan and its elements in the previous sections. In this section, in the final 2021 IRP, we will summarize how the Base Resource Plan serves the final planning objectives.

8. The Contingency Resource Plans: preparing for the unexpected

The Contingency Resource Plans are our plans to ensure sufficient resources are available to meet load scenarios other than the Reference Load Forecast and/or resource performance scenarios over a 20-year time horizon. The analyses underpinning the Contingency Resource Plans are not as extensive as those underpinning the Base Resource Plan but are sufficient to identify any necessary Near-Term Actions required to prepare for each scenario.

NOTE TO READER OF DRAFT 2021 IRP

The final 2021 IRP will include triggers, or signposts, associated with the scenarios that will let us know when we need to initiate a Contingency Resource Plan or accelerate the timing of the next integrated resource plan.

8.1 What contingency scenarios are we preparing for?

The Table 6 summarizes the scenarios we identified and which ones have an associated Contingency Resource Plan in this DRAFT 2021 IRP.

IRP Contingency scenarios	Draft	Final
Low Load Forecast (Low Load Scenario)	X	X
Accelerated North Coast liquified natural gas (LNG) & mining load scenario (North Coast Scenario)		X
Accelerated electrification load scenario (Accelerated Scenario)	X	X
○ variation: **with delays to BRP's transmission upgrades to the South Coast** (Accelerated – delayed transmission Scenario)		X
○ variation: **with undelivery of BRP's transmission upgrades to the South Coast** (Accelerated – DSM undelivery Scenario)	X	X

Table 6. 2021 IRP contingency scenarios

NOTE TO READER OF DRAFT 2021 IRP

The table above is included to show the contingency scenarios BC Hydro currently expects to address in the final 2021 IRP. BC Hydro is still examining whether the December 2020 high load forecast is an appropriate basis for a final IRP Contingency Resource Plan scenario.

Figures 15 and 16 show the contingency scenarios in Table 6 at the system level. Figure 17 shows the contingency scenarios in Table 6 for the South Coast region.

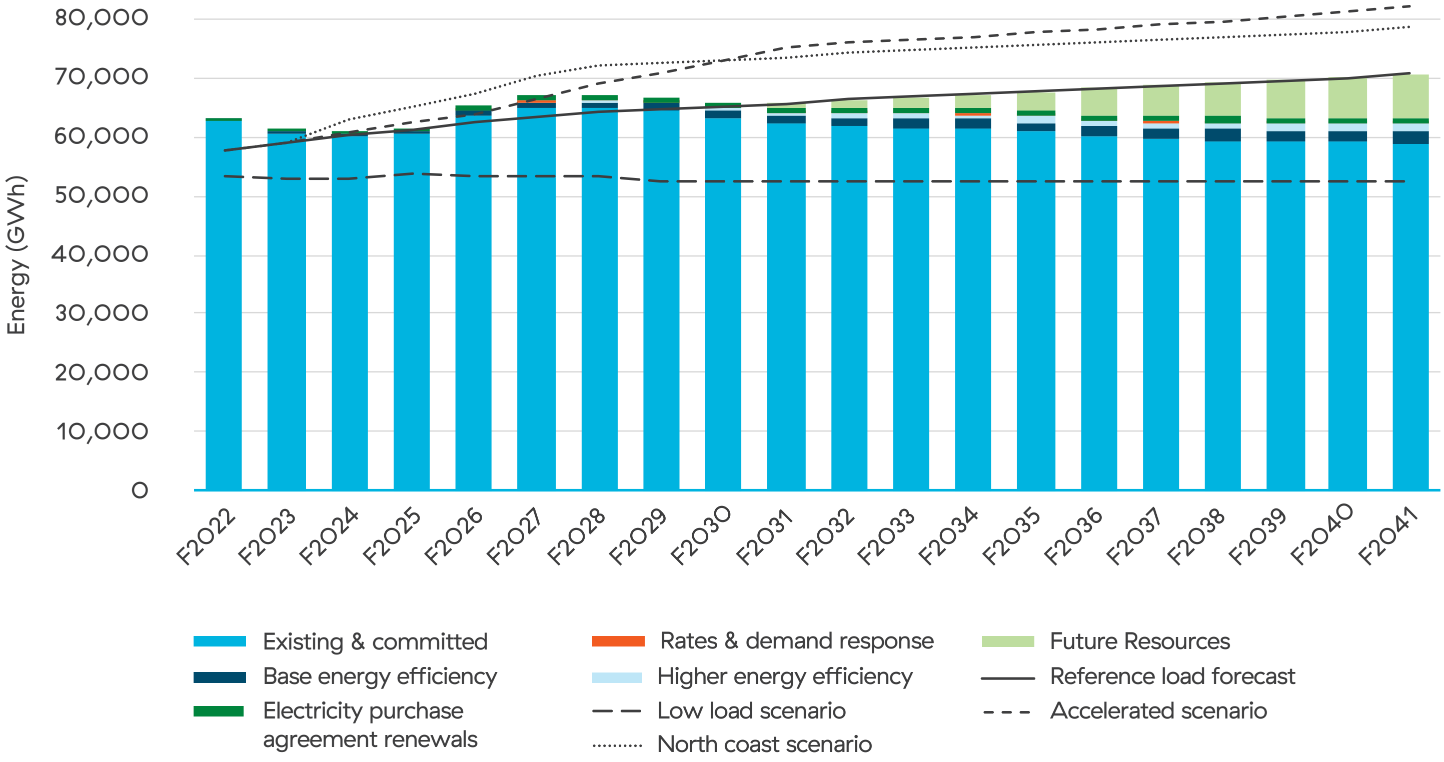


Figure 15. System energy Load Resource Balance with Base Resource Plan and contingency scenarios

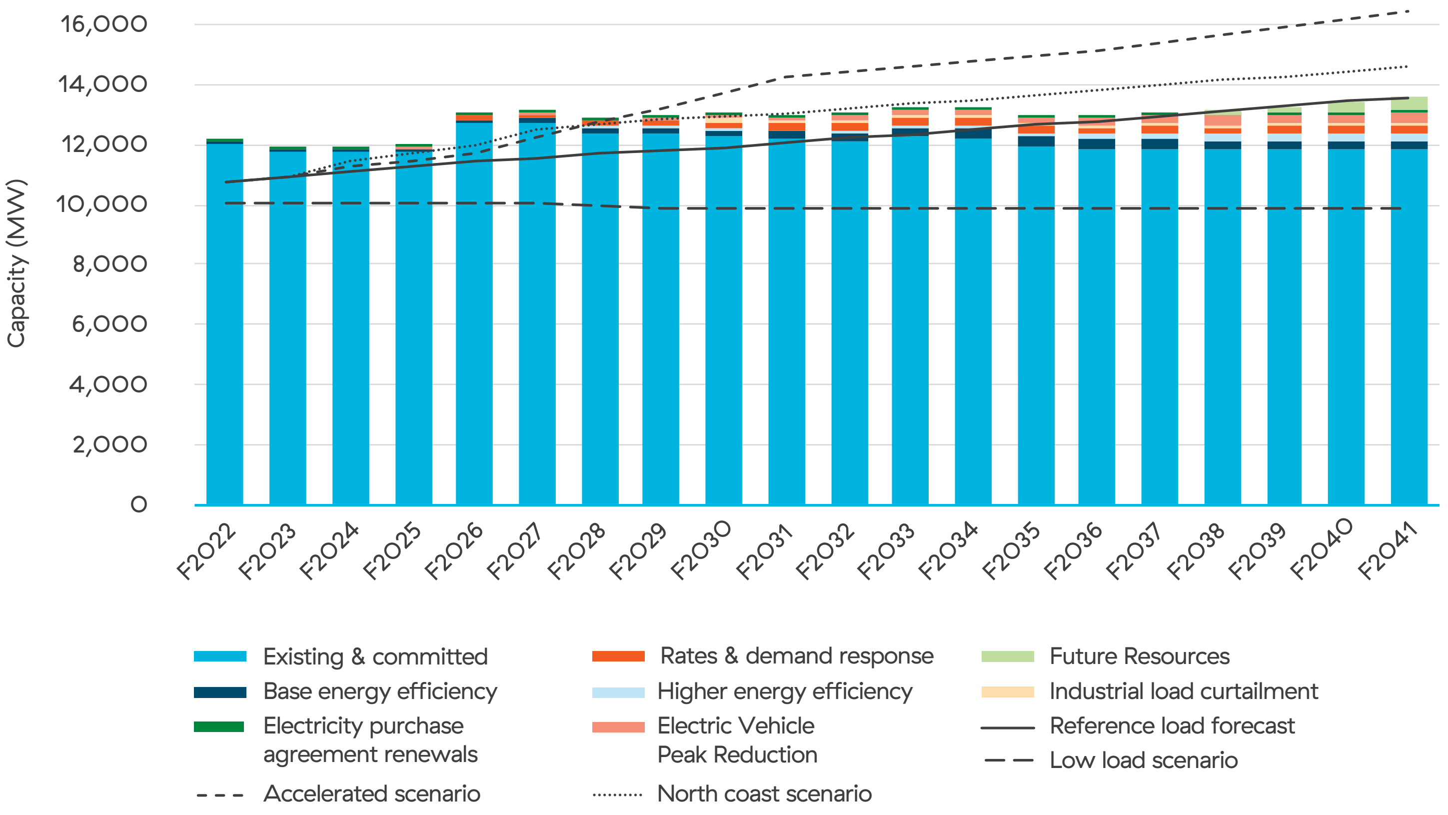


Figure 16. System capacity Load Resource Balance with Base Resource Plan and contingency scenarios

Figure 17. South Coast region capacity Load Resource Balance with Base Resource Plan and contingency scenarios

8.2 Accelerated Scenario

The Accelerated Scenario assumes that provincial greenhouse gas reduction targets are met over the milestone years of 2025, 2030 and 2040. This scenario has impacts across the province, both in the Lower Mainland where our main load centre is, and elsewhere in the province where the natural gas sector would need to electrify. Under this scenario, and after existing and committed resources, we would be in a system capacity deficit in fiscal 2028 and a system energy deficit in fiscal 2024. The South Coast region would move into a capacity deficit starting in fiscal 2026. The strategy for meeting demand under this scenario calls mostly upon short lead-time resources that have a focus on the South Coast region. The highlights of the plan are built on the assumption that changes to the Load Resource Balance could occur as early as fiscal 2025.

The Contingency Resource Plan for this scenario (**Accelerated Scenario CRP**) is as follows:[10]

NOTE TO READER OF DRAFT 2021 IRP

The contingency resources set out below reflect BC Hydro's preliminary thinking for the Accelerated Scenario and were developed for the purpose of continued consultation.

- Temporarily bridging load with market supply including up to 300 MW of capacity for four years and up to 2,000 GWh/year of energy for four years;
- Implement EV peak reduction initiatives to achieve 75 per cent EV driver participation and up to 480 MW of capacity savings by fiscal 2030;
- Ramp-up from base to higher levels of energy efficiency programs to achieve up to 2,300 GWh/year of energy savings and up to 420 MW of capacity savings at the system level by fiscal 2030;
- Implement voluntary time-varying rates and supporting programs to achieve up to 300 MW of capacity savings at the system level by fiscal 2030;[11]
- Initiate processes to renew electricity purchase agreements to provide 2,100 GWh of energy supply and 260 MW of capacity supply by fiscal 2030;
- Initiate processes to acquire new clean resources to achieve up to 3,400 GWh/year of energy supply and up to 310 MW of capacity at the system level by fiscal 2030; and
- Implement BC Hydro facility upgrades at Revelstoke, GM Shrum and Wahleach in the later years of the IRP period to achieve 600 MW of capacity at the system level by 2040.

When combined, these resources and others later in the planning horizon are needed to meet our load serving obligations. As none of these supply plans require funding or work within the next five years in order to be available as contingency resource options based on the timing of demand in this scenario, no additional Near-Term Actions are driven by this scenario.

10 Energy and capacity additions are here described as incremental to existing and committed resources.

11 Supporting programs include demand response and load curtailment initiatives.

8.2.1 Accelerated – DSM Underdelivery Scenario

This scenario is based on the Accelerated Scenario, but also assumes that the Base Resource Plan itself does not perform as expected.

To develop this scenario, demand-side measures savings forecasts were split into an “mid level”, a “low level; and a “high level”. Demand-side measures underperformance is when all demand-side measures perform at the “low level”. In that case, the Accelerated Scenario CRP would be insufficient to meet customers’ electricity requirements. In the South Coast region, demand-side measures underperformance would remove approximately 280 MW of capacity from the Contigency Resource Plan by fiscal 2030. On a system-wide basis, demand-side measures underperformance would remove approximately 900 GWh of energy and 380 MW of capacity from the Contigency Resource Plan by fiscal 2030.

NOTE TO READER OF DRAFT 2021 IRP

The final 2021 IRP will include additional information on BC Hydro’s approach to assessing the uncertainty of the delivery of demand-side measures.

The Contingency Resource Plan for this scenario (**Accelerated – DSM Underdelivery Scenario CRP**) is as follows:[12]

NOTE TO READER OF DRAFT 2021 IRP

The contingency resources set out below reflect BC Hydro’s preliminary thinking for the Accelerated – DSM Underdelivery Scenario and were developed as a placeholder for the purpose of continued consultation.

- Temporarily bridging load with market supply including up to 300 MW of additional capacity for four years and up to 2,000 GWh/year of additional energy for four years (same as Accelerated Scenario CRP);
- Advance utility-scale batteries, with the first units installed in fiscal 2029, ramping up to 500 MW of additional capacity by fiscal 2031;

12 Energy and Capacity additions are here described as incremental to existing and committed resources.

- Implement EV Peak Reduction initiatives to achieve 75 per cent EV driver participation and up to 470 MW of capacity savings by fiscal 2030;
- Ramp-up from base to higher levels of energy efficiency programs to achieve up to 1,400 GWh/year of energy savings and up to 260 MW of capacity savings by fiscal 2030;
- Implement voluntary time-varying rates and supporting programs to achieve up to 90 MW of capacity savings at the system level by fiscal 2030;[13]
- Initiate processes to renew electricity purchase agreements to provide 2,100 GWh of energy supply and 260 MW of capacity supply by fiscal 2030;
- Initiate processes to acquire new clean resources to achieve up to 4,200 GWh/year of energy supply and up to 340 MW of capacity supply at the system level by fiscal 2030; and
- Implement BC Hydro facility upgrades at Revelstoke, GM Shrum and Wahleach in the later years of the IRP period to achieve 600 MW of capacity at the system level by 2040.

These resources would allow us to meet our load serving obligations under the Accelerated – DSM Underdelivery Scenario.

NOTE TO READER OF DRAFT 2021 IRP

Only one element of the Accelerated Scenario CRP— utility-scale batteries — is expected to require a Near-Term Action within the next five years. While the earliest in-service date for utility-scale batteries in this scenario is fiscal 2029, BC Hydro's initial assessment is that preparing to deploy utility-scale batteries in advance of need would be an effective way to:

- Confirm the expected lead-time of utility-scale batteries in the B.C. market, and develop capabilities to rapidly deploy battery systems if required.
- Gain experience integrating the operations of this new technology into our grid; and,
- Respond to consultation input that indicated support for local supply solutions if they are cost effective and help avoid new transmission lines. Participants expressed an openness to explore battery technology, with some environmental concerns raised about their production and disposal.

13 Supporting programs include demand response and load curtailment initiatives.

8.3 Low Load Scenario

The Low Load Forecast (Low Load Scenario) assumes lower economic growth and resource sector development relative to the Reference Load Forecast, combined with lower rates of light duty electric vehicle penetration and lower industrial electrification uptake. This scenario also assumes long-term structural changes occur in the B.C. economy, due to the COVID-19 pandemic, that adversely impact electricity consumption.

The response to lower than expected load does not call for contingency resources in the traditional sense. However, the Base Resource Plan allows for significant flexibility in response to this type of scenario because of the priority it puts on demand-side measures. Those resources can be ramped down or delayed if load growth turns out to be closer to the Low Load Scenario. **The Low Load Scenario CRP** is described below in terms of adjustments to the Base Resource Plan.

NOTE TO READER OF DRAFT 2021 IRP

The CRP below reflects BC Hydro's preliminary thinking on potential steps in response to this scenario and were developed for the purpose of continued consultation.

- Delay ramping up from Base energy efficiency to Higher energy efficiency, to reduce energy savings by up to 330 GWh/year and capacity savings by up to 60 MW by fiscal 2030, relative to the Base Resource Plan; Defer offers to renew electricity purchase agreements to reduce generation supply by Note to reader of DRAFT 2021 IRP: Savings would depend on when this change was initiated – preliminary decision not made in time for June 2021 filing of DRAFT 2021 IRP.
- Delay the initiation of Step 2 transmission upgrades to reduce transmission capacity to the South Coast region by up to 700 MW by fiscal 2038, relative to the Base Resource Plan;
- Defer implementation of voluntary time-varying rates and supporting programs to reduce system capacity by up to 200 MW by fiscal 2030, relative to the Base Resource Plan;
- Defer implementation of the Industrial Load Curtailment Program to reduce system capacity by up to 100 MW by fiscal 2030, relative to the Base Resource Plan; and
- Defer implementation of 50 per cent EV driver participation to reduce system capacity by up to 100 MW by fiscal 2030, relative to the Base Resource Plan.

NOTE TO READER OF DRAFT 2021 IRP

We don't anticipate that there will be any Near-Term Actions in the Low Load Scenario CRP.

9. Near–Term Actions

NOTE TO READER OF DRAFT 2021 IRP

This section is intentionally left blank. It will include components of the Base Resource Plan and Contingency Resource Plans that are Near–Term Actions upon the submission of the final IRP in December.

A Legal and regulatory requirements

BC Hydro is a public utility regulated by the British Columbia Utilities Commission under the *Utilities Commission Act* and related laws, including the *Clean Energy Act* (the **Legal Framework**). Under the Legal Framework, public utilities must submit "long-term resource plans" to the Commission in the form and on the timeline required by the Commission. The Commission may establish a process to review "long-term resource plans", and after the review process must decide whether the "long-term resource plan" is "in the public interest".

In considering whether a long-term resource plan is in the public interest the Commission considers:

- Whether the long-term resource plan will allow the public utility to cost-effectively meet its customers' electricity needs over time horizon of the plan;
- Whether the long-term resource plan satisfies all the requirements of the Legal Framework; and
- Whether the long-term resource plan meets the Commission's more granular requirements for long-term resource plans.

Customers' electricity needs

The fundamental purpose of a long-term resource plan is to ensure that the public utility will be able to "cost-effectively" meet its customers future electricity needs. It follows that this is the most important consideration for the Commission when it reviews a long-term resource plan to determine whether it is in the public interest. In particular, the Commission must assess whether the plan properly:

- accounts for current circumstances, including customer electricity requirements and the utility's generation resources; and
- accounts for reasonable forecasts of future circumstances, including future customer electricity needs and potential generation resources.

"Cost-effectiveness" is a flexible concept that is focused on economic factors, but not to the exclusion of social, environmental and Indigenous interests.

Requirements of the Legal Framework

A long-term resource plan submitted to the Commission under the *Utilities Commission Act* must expressly address a number of issues including:

- A forecast of the customers' electricity needs over the time horizon of the plan;
- A plan to reduce those electricity needs through demand-side measures;
- A description of the facilities the public utility intends to construct to meet customer needs;
- Information regarding purchases of electricity from third parties to meet customer needs; and
- An explanation of why demand-side measures cannot fully substitute for planned construction and third-party purchases.

In addition, the Legal Framework expressly requires the Commission to consider a number of factors in making its public interest determination, including "British Columbia's energy objectives', as set out in the *Clean Energy Act*, and the interests of the public utility's customers.

Under section 44.1(2)(g) of the *Utilities Commission Act* the Commission may require a long-term resource plan to include additional information not otherwise specified in that statute.

The Commission's requirements

Over the years, the Commission has provided significant guidance to public utilities regarding the form and contents of a long-term resource plan, and the processes by which long-term resource plans should be developed. This guidance is reflected in part in the Commission's 2003 Resource Planning Guidelines, as well as decisions of the Commission in relation to the long-term resource plans that have been previously submitted to it. For example, the Commission has required that long-term resource plans should:

- be developed through a meaningful stakeholder consultation process;
- be consistent with the public utility's corporate strategy; and
- address commitments the public utility has made in previous Commission proceedings regarding the form and content of its next long-term resource plan.

Following its review of a long-term resource plan, the Commission may decide whether it is in the public interest, or not, in whole or part. However, the legal responsibility for developing a long-term resource plan belongs to public utilities. It follows that if a long-term resource plan is found by the Commission to have deficiencies, it falls to the public utility to remedy those deficiencies. That is, the Commission does not develop the long-term resource plans of the public utilities it regulates.

The 2021 IRP

BC Hydro's 2021 IRP is a long-term resource plan under the *Utilities Commission Act* and conforms to the Legal Framework described above. BC Hydro was ordered by the Commission to file the 2021 IRP no later than December 31, 2021, by Order G-28-21.

Because BC Hydro is a Crown corporation it has additional obligations, including the following:

- BC Hydro must satisfy its legal obligations to act honourably with respect to Indigenous peoples in the development of the 2021 IRP;
- The 2021 IRP must be consistent with government policy direction; and
- The 2021 IRP must be consistent, or satisfy, as applicable, legal requirements that are applicable specifically to BC Hydro. For example, BC Hydro is required to develop its 2021 IRP on the basis that it be self-sufficient in energy, as defined in the *Clean Energy Act* and the *Electricity Self-Sufficiency Regulation*, which is not a requirement for other public utilities.

The Commission has issued only two directions to BC Hydro with regard to other information to be included in the 2021 IRP.

- In Order E-12-21 regarding the Walden North Forbearance Agreement, dated May 7, 2021, the Commission directed BC Hydro to, "perform an analysis of alternative means of meeting its obligations to the Department of Fisheries and Oceans in the absence of the Diversion Agreement and to submit this analysis to the Commission for review as part of BC Hydro's next long-term resource plan".
- In Order Order G-246-20 regarding BC Hydro's Fiscal 2020-Fiscal 2021 Revenue Requirements Application, the Commission directed BC Hydro, "to present options for the level of DSM in future years for BCUC review as part of BC Hydro's next IRP, using the results of the latest Conservation Potential Review and any other relevant analysis".

In addition, in the reasons accompanying Order G-28-21 the Commission declined to direct BC Hydro to include in the 2021 IRP any long-term plans and targets for low-carbon electrification, concluding that, "there is no obligation for BC Hydro to include such plans outside of how they affect the key components of the IRP".

NOTE TO READER OF DRAFT 2021 IRP

In the IRP Application, to which the final 2021 IRP will be appended, BC Hydro will explain how it has satisfied all the various legal and regulatory requirements applicable to it.

B Load resource balances

Existing and committed resources

SYSTEM-WIDE ENERGY AND CAPACITY LOAD RESOURCE BALANCES

By comparing the existing and committed resources to the future electricity needs of our customers, as outlined in the December 2020 Reference Load Forecast, we establish when we anticipate we will need additional energy and capacity resources.

Figure 1. System energy Load Resource Balance - December 2020 Load Forecast vs. existing & committed resources – before planned resources

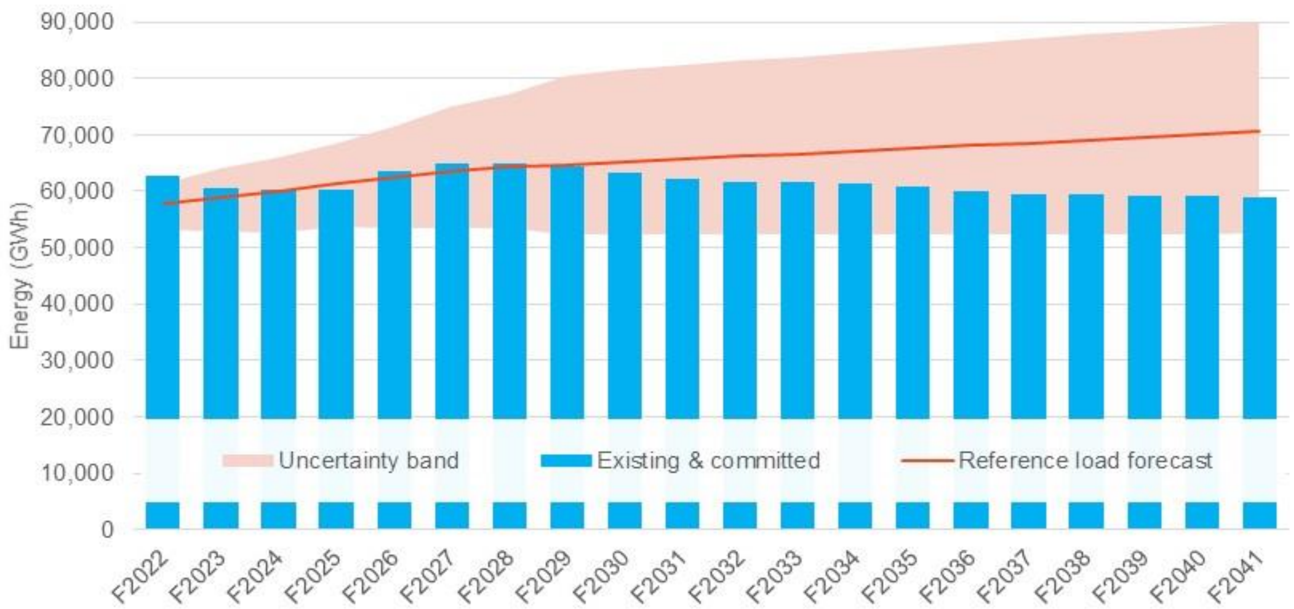


Table 1. System energy Load Resource Balance-
December 2020 Load Forecast vs. existing & committed resources – before planned resources

	(GWh)		F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																							
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	46,898	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
2	***Existing and Committed IPP Resources***	(b)	15,451	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a + b	62,349	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																						
4	Dec 2020 Reference Load Forecast before DSM	(d)	(56,513)	(58,526)	(60,140)	(61,545)	(63,029)	(64,573)	(65,696)	(66,789)	(67,435)	(68,127)	(68,811)	(69,594)	(70,214)	(70,903)	(71,612)	(72,371)	(73,002)	(73,698)	(74,379)	(75,121)	(75,829)
	Existing and Committed Demand Side Management																						
5	F21 Energy Conservations Programs Savings		72	105	117	117	118	112	112	112	109	104	71	60	47	47	43	17	12	12	12	11	10
6	Codes & Standards		233	563	824	1,077	1,316	1,543	1,750	1,938	2,118	2,288	2,451	2,607	2,756	2,905	3,056	3,206	3,357	3,507	3,657	3,807	3,870
7	Energy Conservation Rate Structures		63	138	177	210	239	268	296	325	354	383	396	396	396	396	396	396	396	396	396	396	333
8	Sub-total	(e)	368	806	1,118	1,404	1,673	1,922	2,159	2,375	2,582	2,775	2,917	3,063	3,200	3,349	3,495	3,619	3,764	3,915	4,065	4,215	4,213
9	***Net Metering***	(f)	32	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c + d + e + f	**6,237**	**4,937**	**1,643**	**97**	**(957)**	**1,042**	**1,492**	**552**	**(286)**	**(1,958)**	**(3,454)**	**(4,535)**	**(5,136)**	**(5,877)**	**(6,881)**	**(8,264)**	**(9,037)**	**(9,639)**	**(10,346)**	**(10,886)**	**(11,698)**

Figure 2. System capacity Load Resource Balance -
December 2020 Load Forecast vs. existing & committed resources – before planned resources

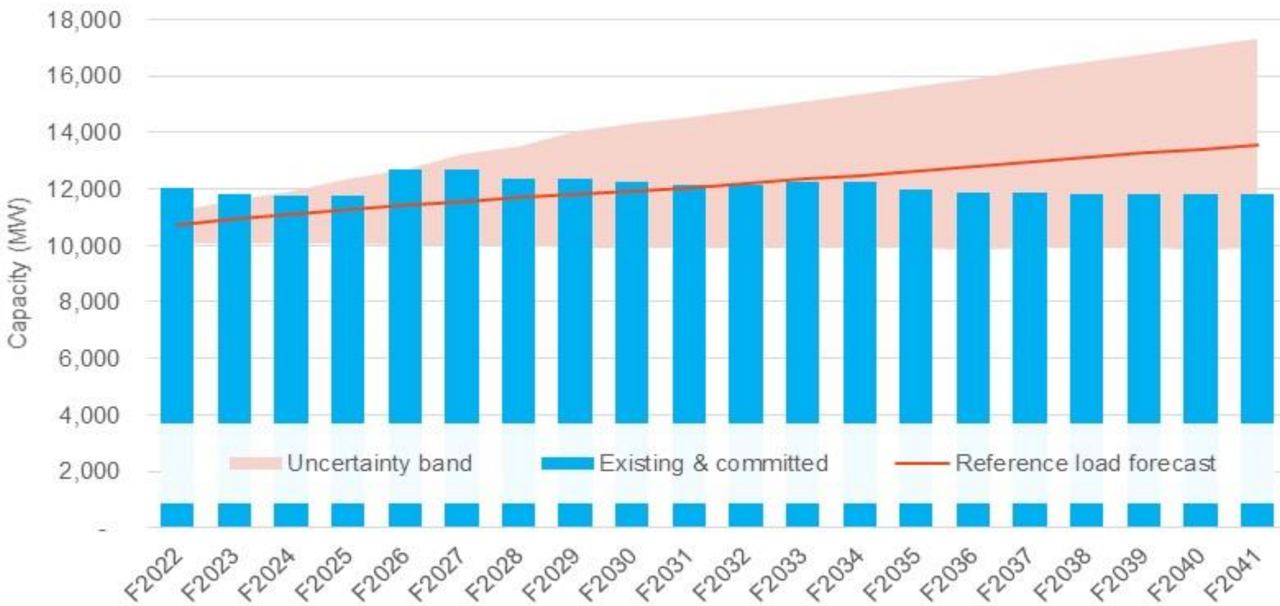


Table 2. System capacity Load Resource Balance -
December 2020 Load Forecast vs. existing & committed resources – before planned resources

	(MW)		F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																							
1	***Existing and Committed Heritage Resources*** [1]	(a)	11,628	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed IPP Resources***	(b)	1,663	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves*** [2]	(c)	(1,537)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,615)	(1,604)	(1,600)	(1,618)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a + b + c	11,754	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,244	12,162	12,131	12,264	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																						
5	Dec 2020 Reference Load Forecast before DSM	(e)	(10,478)	(10,862)	(11,140)	(11,363)	(11,560)	(11,753)	(11,936)	(12,100)	(12,247)	(12,399)	(12,550)	(12,718)	(12,882)	(13,052)	(13,230)	(13,420)	(13,605)	(13,788)	(13,970)	(14,149)	(14,318)
	Existing and Committed Demand Side Management																						
6	F21 Energy Conservations Programs Savings		21	21	21	21	20	18	18	17	17	16	12	10	8	8	8	4	3	3	3	3	3
7	Codes & Standards		49	118	166	212	254	293	329	361	391	419	445	470	493	520	548	576	604	632	659	687	700
8	Energy Conservation Rate Structures		5	11	16	19	23	26	29	31	34	37	38	38	37	37	37	37	37	37	37	37	33
9	Sub-total	(f)	75	150	203	252	297	337	375	410	442	472	495	517	538	566	593	617	644	672	700	728	736
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d + e + f + g	**1,351**	**1,327**	**853**	**662**	**496**	**1,274**	**1,130**	**686**	**545**	**317**	**107**	**(70)**	**(80)**	**(254)**	**(675)**	**(933)**	**(1,091)**	**(1,283)**	**(1,437)**	**(1,596)**	**(1,756)**

Notes:

[1] Includes outages for Mica and Seven Mile for the period F2029 to F2032

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

REGIONAL CAPACITY LOAD RESOURCE BALANCES

Figure 3. South Coast capacity Load Resource Balance - December 2020 Load Forecast vs. existing & committed resources (w/ transmission) – before planned resources

Table 3. South Coast capacity Load Resource Balance-
December 2020 Load Forecast vs. existing & committed resources (w/ transmission) – before planned resources

	(MW)		F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																						
1	***Existing and Committed Heritage Resources***	(a)	1,327	1,517	1,517	1,517	1,517	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519
2	***Existing and Committed IPP Resources***	(b)	627	635	357	347	336	305	305	296	273	256	214	185	185	161	161	150	150	150	150	142	142
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	1,954	2,152	1,874	1,864	1,853	1,824	1,824	1,815	1,792	1,775	1,733	1,704	1,704	1,680	1,680	1,669	1,669	1,669	1,669	1,661	1,661
4	***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	6,300	6,300	6,300
	Demand - Local Gross Requirements																						
5	Dec 2020 Reference Load Forecast before DSM	(e)	(7,433)	(7,726)	(7,911)	(8,019)	(8,174)	(8,313)	(8,433)	(8,558)	(8,687)	(8,822)	(8,963)	(9,112)	(9,268)	(9,430)	(9,601)	(9,781)	(9,959)	(10,136)	(10,310)	(10,481)	(10,646)
	Existing and Committed Demand Side Management																						
6	F21 Programs Savings, Codes & Standards, Rates	(f)	55	113	153	190	225	256	285	312	336	360	379	398	416	439	461	481	504	527	550	572	581
7	**Regional Surplus / (Deficit) before planned resources**	(g) = c + d + e + f	**877**	**838**	**416**	**335**	**203**	**66**	**(23)**	**(131)**	**(258)**	**(387)**	**(551)**	**(710)**	**(848)**	**(1,011)**	**(1,160)**	**(1,331)**	**(1,487)**	**(1,640)**	**(1,792)**	**(1,948)**	**(2,104)**

Figure 4. Vancouver Island capacity Load Resource Balance - December 2020 Load Forecast vs. existing & committed resources (w/ transmission) – before planned resources

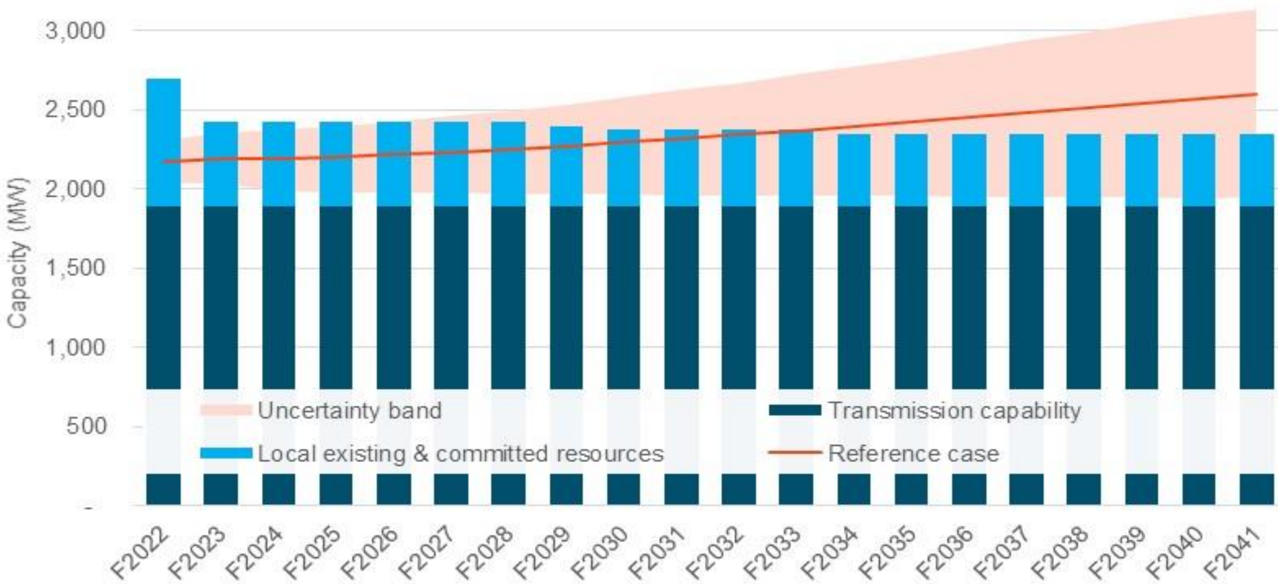


Table 4. Vancouver Island capacity Load Resource Balance -
December 2020 Load Forecast vs. existing & committed resources (w/ transmission) – before planned resources

	(MW)		F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																							
1	***Existing and Committed Heritage Resources***	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
2	***Existing and Committed IPP Resources***	(b)	361	361	86	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	809	809	534	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
4	***Transmission Capability***	(d)	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Demand - Local Gross Requirements																						
5	Dec 2020 Reference Load Forecast before DSM	(e)	(2,145)	(2,200)	(2,231)	(2,243)	(2,259)	(2,285)	(2,309)	(2,335)	(2,361)	(2,389)	(2,417)	(2,447)	(2,477)	(2,510)	(2,543)	(2,580)	(2,614)	(2,650)	(2,684)	(2,719)	(2,751)
	Existing and Committed Demand Side Management																						
6	F21 Programs Savings, Codes & Standards, Rates	(f)	15	31	41	51	60	68	75	82	88	94	99	104	108	114	119	124	130	135	141	147	149
7	**Regional Surplus / (Deficit) before planned resources**	(g) = c + d + e + f	**569**	**530**	**234**	**229**	**222**	**203**	**186**	**167**	**124**	**85**	**61**	**30**	**4**	**(47)**	**(75)**	**(106)**	**(136)**	**(165)**	**(194)**	**(224)**	**(254)**

Base Resource Plan

SYSTEM-WIDE ENERGY AND CAPACITY LOAD RESOURCE BALANCE

Presented with planned DSM only and then presented with all Base Resource Plan elements

Figure 5. System energy Load Resource Balance (with Planned DSM only)

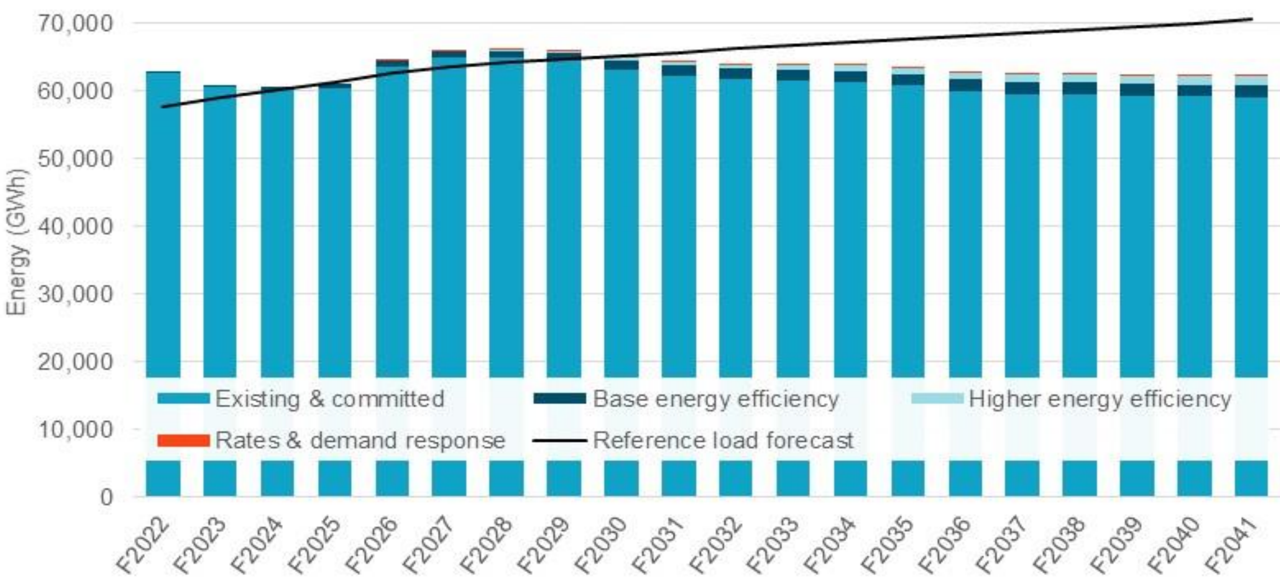


Figure 6. System capacity Load Resource Balance (with Planned DSM only)

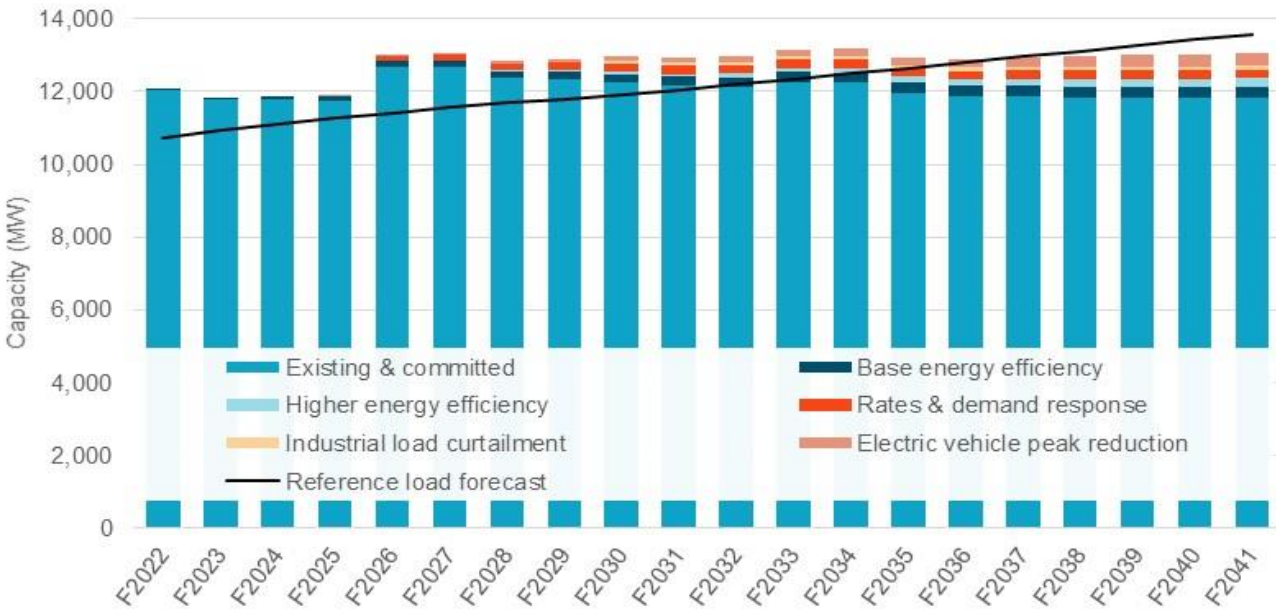


Figure 7. System energy Load Resource Balance (with all Base Resource Plan elements)

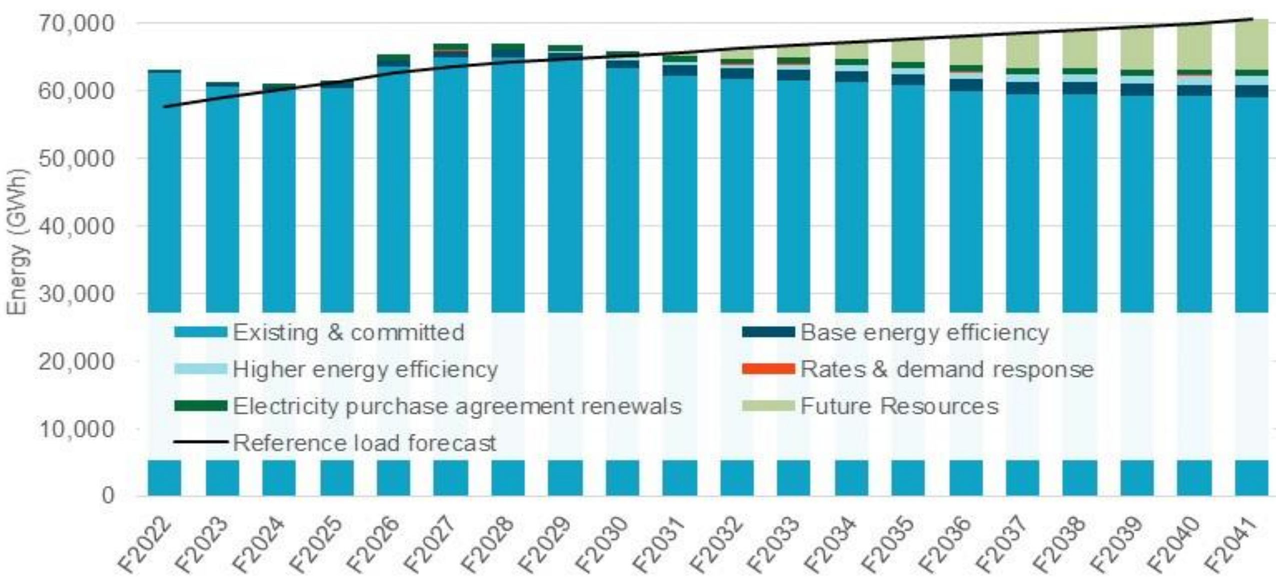


Figure 8. System capacity Load Resource Balance (with all Base Resource Plan elements)

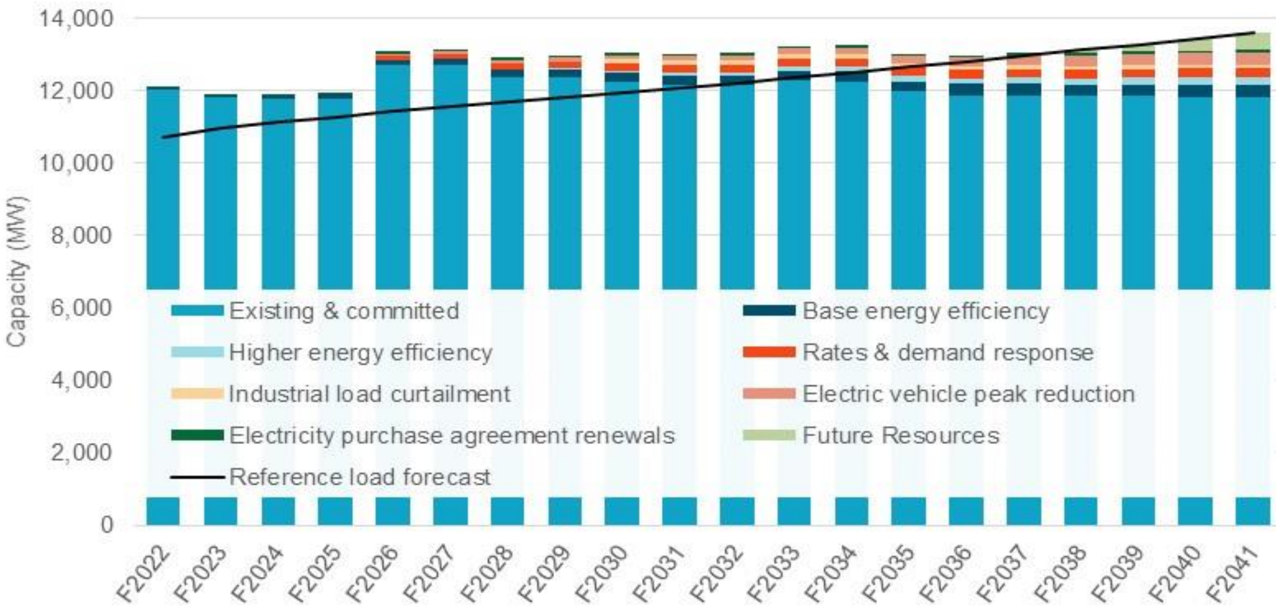


Table 5. System energy Load Resource Balance (with both planned DSM only and all Base Resource Plan elements)

	(GWh)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	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
2	***Existing and Committed IPP Resources***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a + b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	Dec 2020 Reference Load Forecast before DSM	(d)	(58,526)	(60,140)	(61,545)	(63,029)	(64,573)	(65,696)	(66,789)	(67,435)	(68,127)	(68,811)	(69,594)	(70,214)	(70,903)	(71,612)	(72,371)	(73,002)	(73,698)	(74,379)	(75,121)	(75,829)
	Existing and Committed Demand Side Management																					
5	F21 Energy Conservations Programs Savings		105	117	117	118	112	112	112	109	104	71	60	47	47	43	17	12	12	12	11	10
6	Codes & Standards		563	824	1,077	1,316	1,543	1,750	1,938	2,118	2,288	2,451	2,607	2,756	2,905	3,056	3,206	3,357	3,507	3,657	3,807	3,870
7	Energy Conservation Rate Structures		138	177	210	239	268	296	325	354	383	396	396	396	396	396	396	396	396	396	396	333
8	Sub-total	(e)	806	1,118	1,404	1,673	1,922	2,159	2,375	2,582	2,775	2,917	3,063	3,200	3,349	3,495	3,619	3,764	3,915	4,065	4,215	4,213
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c + d + e + f	**4,937**	**1,643**	**97**	**(957)**	**1,042**	**1,492**	**552**	**(286)**	**(1,958)**	**(3,454)**	**(4,535)**	**(5,136)**	**(5,877)**	**(6,881)**	**(8,264)**	**(9,037)**	**(9,639)**	**(10,346)**	**(10,886)**	**(11,698)**
	Base Resource Plan																					
	Future Demand Side Management																					
11	Base Energy Efficiency		161	296	472	649	814	948	1,090	1,224	1,347	1,483	1,558	1,616	1,666	1,706	1,768	1,779	1,788	1,794	1,795	1,795
12	Higher Energy Efficiency		-	-	-	-	-	35	118	222	327	448	576	709	813	926	1,025	1,108	1,192	1,255	1,320	1,387
13	Time-Varying Rates & Demand Response		-	-	-	-	46	46	47	47	47	47	48	48	48	48	48	49	49	49	49	49
14	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Sub-total	(h)	161	296	472	649	860	1,029	1,255	1,493	1,721	1,979	2,181	2,372	2,527	2,680	2,842	2,935	3,029	3,098	3,164	3,231
17	**Surplus / (Deficit) after planned DSM**	**(i) = g + h**	**5,099**	**1,939**	**570**	**(307)**	**1,902**	**2,521**	**1,806**	**1,206**	**(237)**	**(1,475)**	**(2,354)**	**(2,764)**	**(3,350)**	**(4,201)**	**(5,423)**	**(6,101)**	**(6,610)**	**(7,249)**	**(7,722)**	**(8,467)**
18	***Electricity Purchase Agreement Renewals***	(j)	0	59	312	535	816	895	895	895	895	895	895	895	895	895	895	895	895	895	895	895
19	***Future Resources***	(k)	-	-	-	-	-	-	-	-	-	580	1,458	1,869	2,454	3,306	4,527	5,206	5,714	6,353	6,826	7,572
20	**Surplus / (Deficit) after planned resources**	(l) = i + j + k	**5,099**	**1,998**	**882**	**227**	**2,718**	**3,417**	**2,701**	**2,102**	**659**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(0)**	**(0)**	**0**	**0**

Table 6. System capacity Load Resource Balance (with both planned DSM only and all Base Resource Plan elements)

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***[1]	(a)	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed IPP Resources***	(b)	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves***[2]	(c)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,615)	(1,604)	(1,600)	(1,618)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a + b + c	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,244	12,162	12,131	12,264	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																					
5	Dec 2020 Reference Load Forecast before DSM	(e)	(10,862)	(11,140)	(11,363)	(11,560)	(11,753)	(11,936)	(12,100)	(12,247)	(12,399)	(12,550)	(12,718)	(12,882)	(13,052)	(13,230)	(13,420)	(13,605)	(13,788)	(13,970)	(14,149)	(14,318)
	Existing and Committed Demand Side Management																					
6	F21 Energy Conservations Programs Savings		21	21	21	20	18	18	17	17	16	12	10	8	8	8	4	3	3	3	3	3
7	Codes & Standards		118	166	212	254	293	329	361	391	419	445	470	493	520	548	576	604	632	659	687	700
8	Energy Conservation Rate Structures		11	16	19	23	26	29	31	34	37	38	38	37	37	37	37	37	37	37	37	33
9	Sub-total	(f)	150	203	252	297	337	375	410	442	472	495	517	538	566	593	617	644	672	700	728	736
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d + e + f + g	**1,327**	**853**	**662**	**496**	**1,274**	**1,130**	**686**	**545**	**317**	**107**	**(70)**	**(80)**	**(254)**	**(675)**	**(933)**	**(1,091)**	**(1,283)**	**(1,437)**	**(1,596)**	**(1,756)**
	Base Resource Plan																					
	Future Demand Side Management																					
12	Base Energy Efficiency		30	56	85	115	142	164	187	209	229	248	261	272	281	290	299	302	303	304	302	302
13	Higher Energy Efficiency		-	-	-	-	-	10	23	39	57	75	94	115	132	151	168	184	199	212	226	240
14	Time-Varying Rates & Demand Response		-	-	-	-	136	145	173	201	221	225	227	229	231	232	234	236	237	239	240	242
15	Industrial Load Curtailment		-	-	-	-	-	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98
16	Electric Vehicle Peak Reduction		-	-	-	24	40	60	73	87	102	119	138	157	178	201	224	247	270	293	315	339
17	Sub-total	(i)	30	56	85	139	318	380	456	536	707	765	818	871	920	972	1,023	1,066	1,107	1,146	1,182	1,222
18	**Surplus / (Deficit) after planned DSM**	(j) = h + i	**1,357**	**909**	**747**	**635**	**1,593**	**1,510**	**1,142**	**1,081**	**1,023**	**872**	**748**	**791**	**667**	**296**	**90**	**(25)**	**(176)**	**(291)**	**(414)**	**(534)**
19	***Electricity Purchase Agreement Renewals***[3]	(k)	0	8	24	38	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
20	***Future Resources***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	225	348	467
22	**Surplus / (Deficit) after planned resources**	(n) = j + k + l + m	**1,357**	**916**	**771**	**673**	**1,659**	**1,576**	**1,208**	**1,147**	**1,090**	**938**	**814**	**857**	**733**	**363**	**156**	**41**	**(0)**	**(0)**	**0**	**(1)**

Notes:

[1] Includes outages for Mica and Seven Mile for the period F2029 to F2032

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

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

REGIONAL CAPACITY LOAD RESOURCE BALANCES

Presented with planned DSM only and with all Base Resource Plan elements

Figure 9. South Coast capacity Load Resource Balance (with planned DSM only)

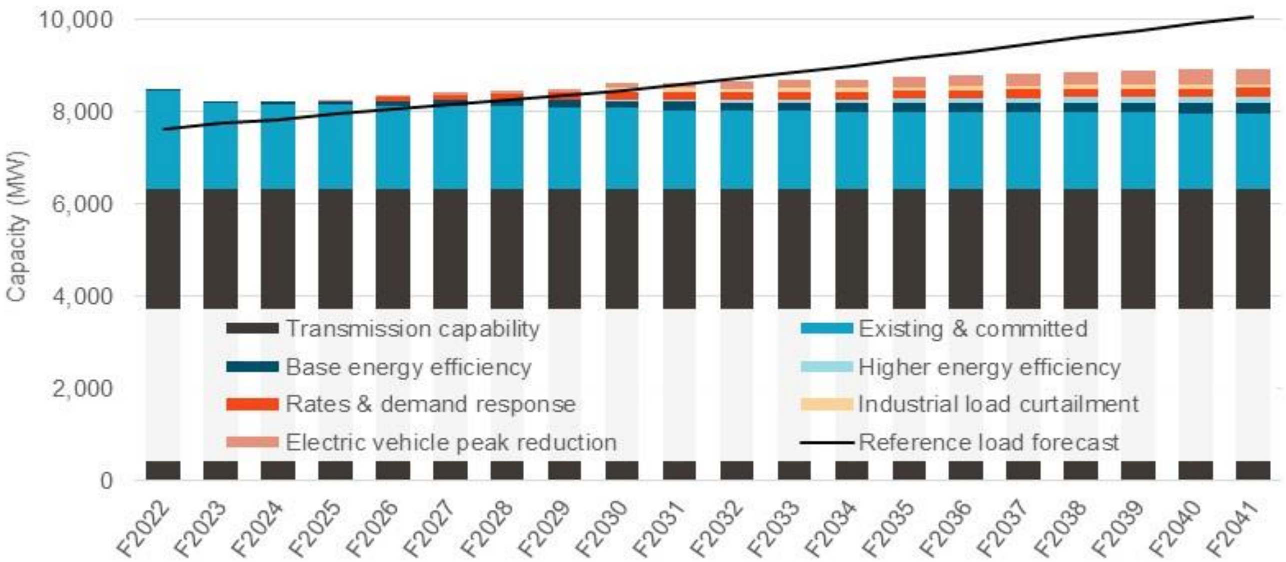


Figure 10. Vancouver Island capacity Load Resource Balance (with planned DSM only)

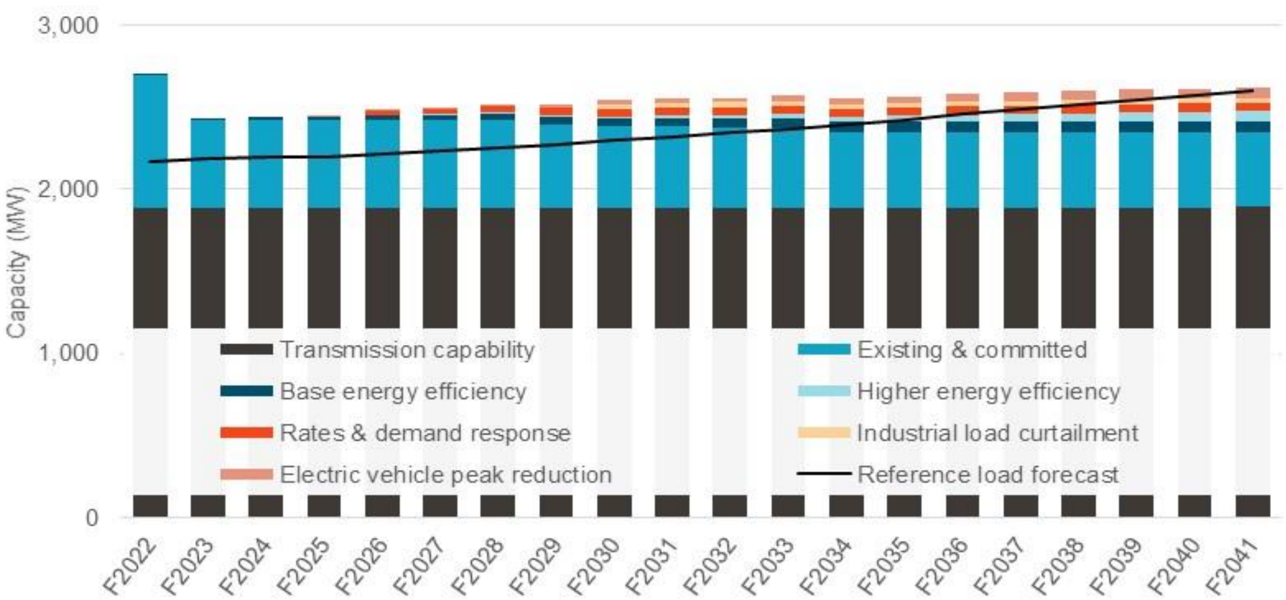


Figure 11. South Coast capacity Load Resource Balance (with all Base Resource Plan elements)

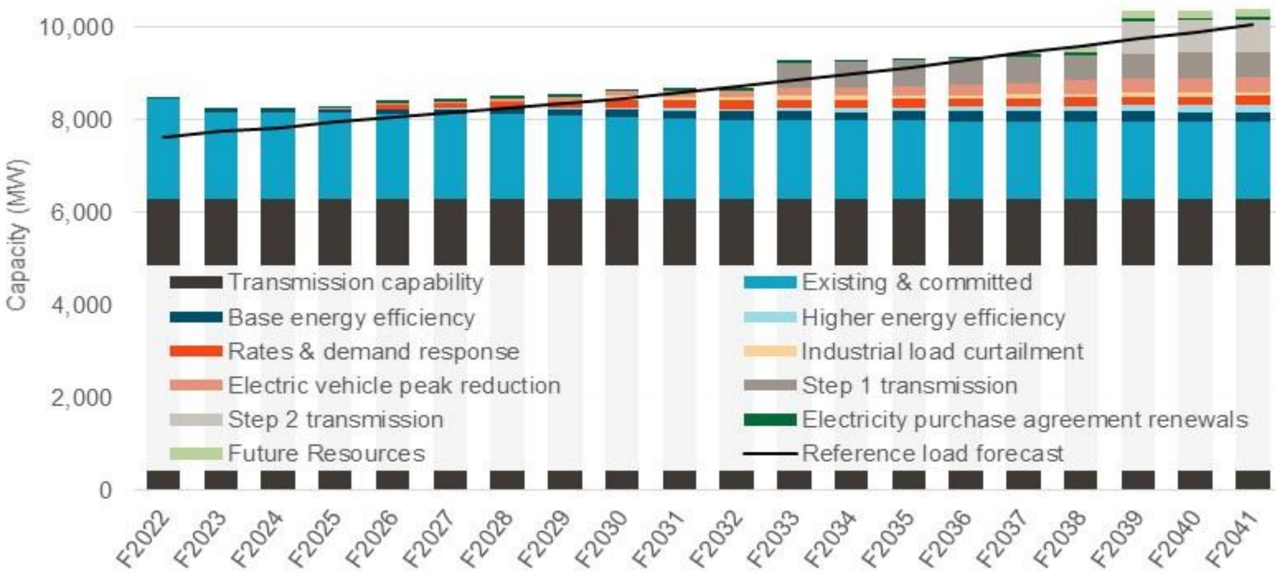


Figure 12. Vancouver Island capacity Load Resource Balance (with all Base Resource Plan elements)

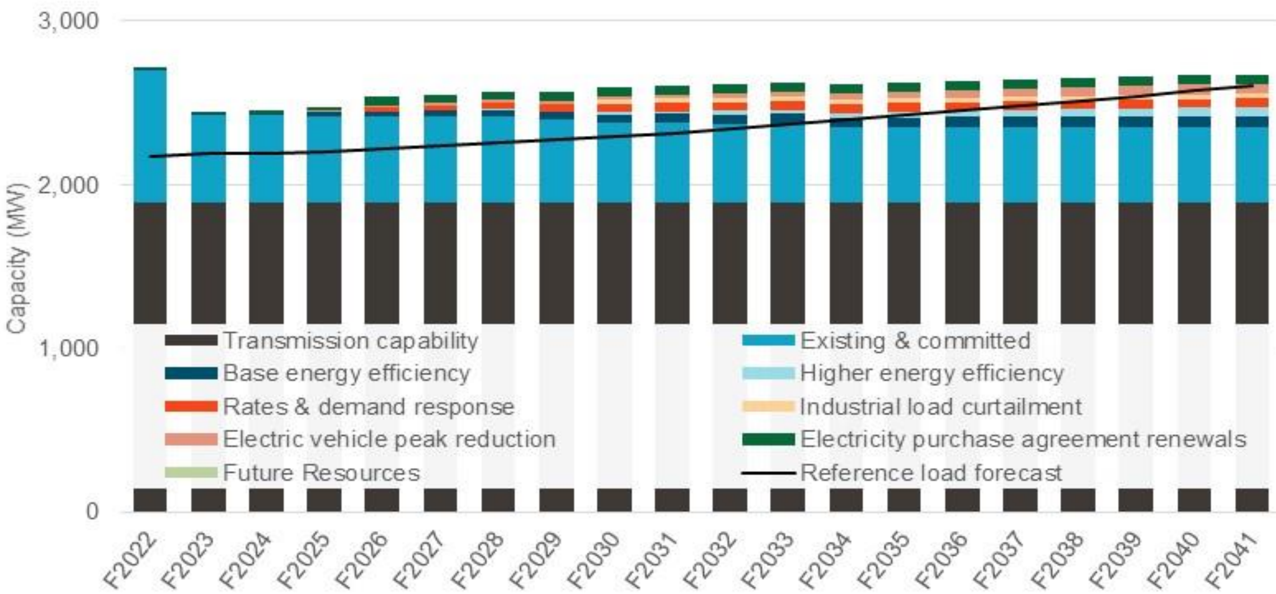


Table 7. South Coast capacity Load Resource Balance (with both planned DSM only and all Base Resource Plan elements)

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	1,517	1,517	1,517	1,517	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519
2	***Existing and Committed IPP Resources***	(b)	635	357	347	336	305	305	296	273	256	214	185	185	161	161	150	150	150	150	142	142
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	2,152	1,874	1,864	1,853	1,824	1,824	1,815	1,792	1,775	1,733	1,704	1,704	1,680	1,680	1,669	1,669	1,669	1,669	1,661	1,661
4	***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	6,300	6,300
	Demand - Regional Gross Requirements																					
5	Dec 2020 Reference Load Forecast before DSM	(e)	(7,726)	(7,911)	(8,019)	(8,174)	(8,313)	(8,433)	(8,558)	(8,687)	(8,822)	(8,963)	(9,112)	(9,268)	(9,430)	(9,601)	(9,781)	(9,959)	(10,136)	(10,310)	(10,481)	(10,646)
	Existing and Committed Demand Side Management																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	113	153	190	225	256	285	312	336	360	379	398	416	439	461	481	504	527	550	572	581
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c + d + e + f + g	**838**	**416**	**335**	**203**	**66**	**(23)**	**(131)**	**(258)**	**(387)**	**(551)**	**(710)**	**(848)**	**(1,011)**	**(1,160)**	**(1,331)**	**(1,487)**	**(1,640)**	**(1,792)**	**(1,948)**	**(2,104)**
	Base Resource Plan																					
	Future Demand Side Management																					
9	Base Energy Efficiency		21	39	59	79	98	113	129	143	157	171	181	189	195	202	208	210	211	212	211	211
10	Higher Energy Efficiency		-	-	-	-	-	7	15	24	35	46	57	69	81	93	106	117	128	139	150	161
11	Time-Varying Rates & Demand Response		-	-	-	-	95	103	126	149	164	167	169	170	171	173	174	175	176	178	179	180
12	Industrial Load Curtailment		-	-	-	-	-	-	-	-	86	86	86	86	86	86	86	86	86	86	86	86
13	Electric Vehicle Peak Reduction		-	-	-	23	37	57	69	82	97	113	130	149	169	190	212	234	256	277	298	321
14	Sub-total	(i)	21	39	59	102	230	279	337	398	539	583	622	662	702	744	785	822	857	892	923	958
15	**Surplus / (Deficit) after planned DSM**	(j) = h + i	**859**	**455**	**394**	**306**	**296**	**256**	**206**	**140**	**152**	**32**	**(87)**	**(186)**	**(309)**	**(416)**	**(546)**	**(665)**	**(783)**	**(900)**	**(1,025)**	**(1,145)**
	Transmission Upgrades																					
16	Step 1		-	-	-	-	-	-	-	-	-	-	-	550	550	550	550	550	550	550	550	550
17	Step 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	700	700	700
18	Sub-total	(k)	-	-	-	-	-	-	-	-	-	-	-	550	550	550	550	550	550	1,250	1,250	1,250
19	***Electricity Purchase Agreement Renewals***	(l)	0	3	13	24	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
20	***Future Resources***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	178	178	178	178
21	**Regional Surplus / (Deficit) after planned resources**	(n) = j + k + l + m	**859**	**457**	**407**	**330**	**351**	**311**	**262**	**195**	**207**	**87**	**(32)**	**419**	**296**	**189**	**59**	**0**	**0**	**583**	**459**	**338**

Table 8. Vancouver Island capacity Load Resource Balance (with both planned DSM only and all Base Resource Plan elements)

	(MW)		F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																						
1	***Existing and Committed Heritage Resources***	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
2	***Existing and Committed IPP Resources***	(b)	361	361	86	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	809	809	534	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
4	***Transmission Capability***	(d)	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Demand - Regional Gross Requirements																						
5	Dec 2020 Reference Load Forecast before DSM	(e)	(2,145)	(2,200)	(2,231)	(2,243)	(2,259)	(2,285)	(2,309)	(2,335)	(2,361)	(2,389)	(2,417)	(2,447)	(2,477)	(2,510)	(2,543)	(2,580)	(2,614)	(2,650)	(2,684)	(2,719)	(2,751)
	Existing and Committed Demand Side Management																						
6	F21 Programs Savings, Codes & Standards, Rates	(f)	15	31	41	51	60	68	75	82	88	94	99	104	108	114	119	124	130	135	141	147	149
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c + d + e + f + g	**569**	**530**	**234**	**229**	**222**	**203**	**186**	**167**	**124**	**85**	**61**	**30**	**4**	**(47)**	**(75)**	**(106)**	**(136)**	**(165)**	**(194)**	**(224)**	**(254)**
	Base Resource Plan																						
	Future Demand Side Management																						
9	Base Energy Efficiency		-	6	12	18	24	29	34	39	44	48	53	56	59	61	63	65	65	65	65	65	65
10	Higher Energy Efficiency		-	-	-	-	-	-	3	6	9	13	17	21	25	29	34	38	43	47	51	55	59
11	Time-Varying Rates & Demand Response		-	-	-	-	-	26	30	37	45	49	50	50	51	51	51	52	52	52	53	53	53
12	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	29	29	29	29	29	29	29	29	29	29	29	29
13	Electric Vehicle Peak Reduction		-	-	-	-	4	7	11	13	16	19	22	25	29	33	37	41	46	50	54	58	63
14	Sub-total	(i)	-	6	12	18	28	63	77	95	114	159	171	182	193	204	215	226	235	244	253	261	270
15	**Surplus / (Deficit) after planned DSM**	**(j) = h + i**	**569**	**536**	**246**	**247**	**250**	**266**	**264**	**262**	**238**	**244**	**232**	**212**	**197**	**157**	**140**	**119**	**99**	**78**	**58**	**37**	**16**
16	***Electricity Purchase Agreement Renewals***	(k)	0	0	0	2	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
17	***Future Resources***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	**Regional Surplus / (Deficit) after planned resources**	(m) = j + k + l	**569**	**536**	**246**	**249**	**252**	**270**	**268**	**266**	**242**	**248**	**237**	**216**	**201**	**161**	**144**	**123**	**103**	**83**	**63**	**41**	**20**

Contingency Resource Plans

ACCELERATED SCENARIO

System-wide energy and capacity load resource balances

Figure 13. System energy Load Resource Balance for the Accelerated Scenario Contingency Resource Plan

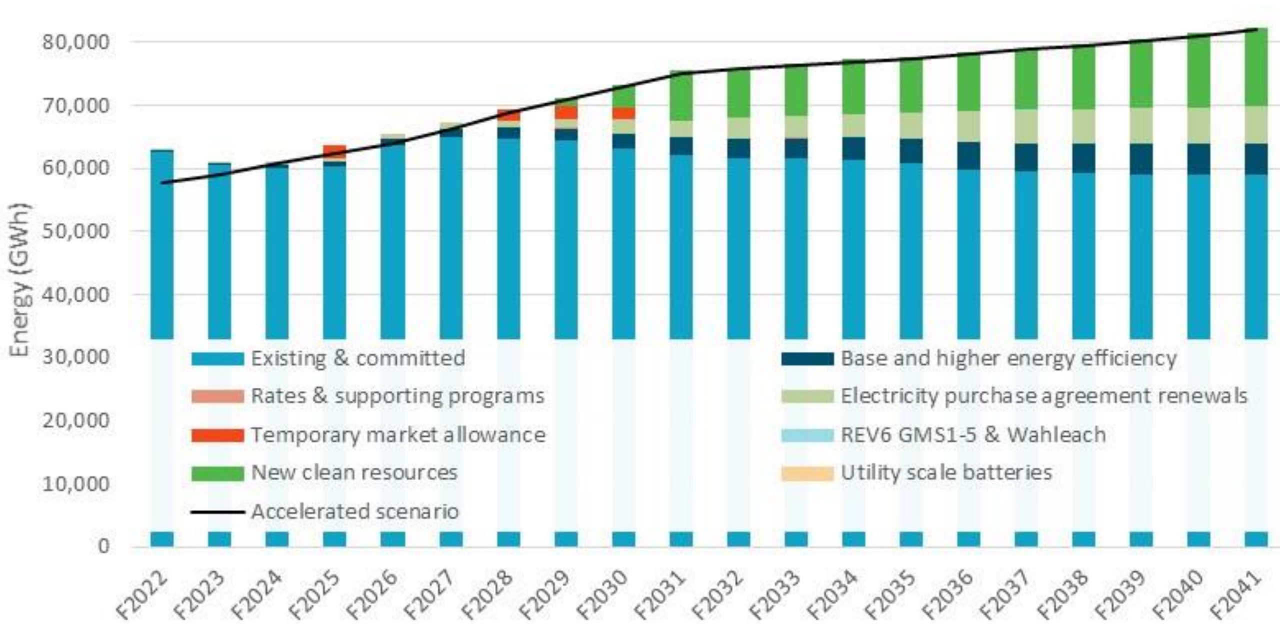


Table 9. System energy Load Resource Balance for the Accelerated Scenario Contingency Resource Plan

	(GWh)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	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
2	***Existing and Committed IPP Resources***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a + b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	Accelerated Scenario	(d)	(58,526)	(60,140)	(62,313)	(64,057)	(65,861)	(68,628)	(71,366)	(73,656)	(75,993)	(78,321)	(79,197)	(79,909)	(80,691)	(81,492)	(82,344)	(83,251)	(84,224)	(85,181)	(86,200)	(87,184)
	Existing and Committed Demand Side Management																					
5	F21 Energy Conservations Programs Savings		105	117	117	118	112	112	112	109	104	71	60	47	47	43	17	12	12	12	11	10
6	Codes & Standards		563	824	1,077	1,316	1,543	1,750	1,938	2,118	2,288	2,451	2,607	2,756	2,905	3,056	3,206	3,357	3,507	3,657	3,807	3,870
7	Energy Conservation Rate Structures		138	177	210	239	268	296	325	354	383	396	396	396	396	396	396	396	396	396	396	333
8	Sub-total	(e)	806	1,118	1,404	1,673	1,922	2,159	2,375	2,582	2,775	2,917	3,063	3,200	3,349	3,495	3,619	3,764	3,915	4,065	4,215	4,213
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c + d + e + f	**4,937**	**1,643**	**(671)**	**(1,985)**	**(246)**	**(1,440)**	**(4,025)**	**(6,507)**	**(9,824)**	**(12,964)**	**(14,138)**	**(14,831)**	**(15,665)**	**(16,761)**	**(18,237)**	**(19,286)**	**(20,165)**	**(21,148)**	**(21,965)**	**(23,053)**
	Contingency Resource Plan																					
	Future Demand Side Management																					
11	Base & Higher Energy Efficiency		161	296	472	705	1,004	1,309	1,620	1,960	2,314	2,705	3,006	3,319	3,611	3,885	4,185	4,393	4,593	4,781	4,887	4,988
12	Rates & Supporting Programs		-	-	-	49	50	51	52	53	53	53	54	54	54	54	55	55	55	55	56	56
13	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sub-total	(h)	161	296	472	754	1,054	1,361	1,672	2,013	2,367	2,758	3,060	3,372	3,665	3,939	4,240	4,448	4,648	4,836	4,943	5,044
15	***Electricity Purchase Agreement Renewals***	(i)	0	59	312	535	816	895	985	1,370	2,140	2,710	3,204	3,356	3,610	4,125	4,853	5,219	5,357	5,617	5,647	5,833
16	***Market Allowance***	(j)	-	-	-	2,000	-	-	2,000	2,000	2,000	-	-	-	-	-	-	-	-	-	-	-
17	***REV6 GMS1-5 & Wahleach***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26	26	26	26	26
18	***New Clean Resources***	(l)	-	-	-	-	-	-	-	1,323	3,442	7,945	7,945	8,261	8,783	8,783	9,298	9,656	10,220	10,902	11,805	12,341
19	***Utility Scale Batteries***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Surplus / (Deficit) after planned resources**	(n) = g + h + i + j + k + l + m	**5,099**	**1,998**	**114**	**1,304**	**1,624**	**816**	**632**	**199**	**125**	**449**	**71**	**157**	**394**	**86**	**179**	**64**	**86**	**232**	**456**	**191**

Figure 14. System capacity Load Resource Balance for the Accelerated Scenario Contingency Resource Plan

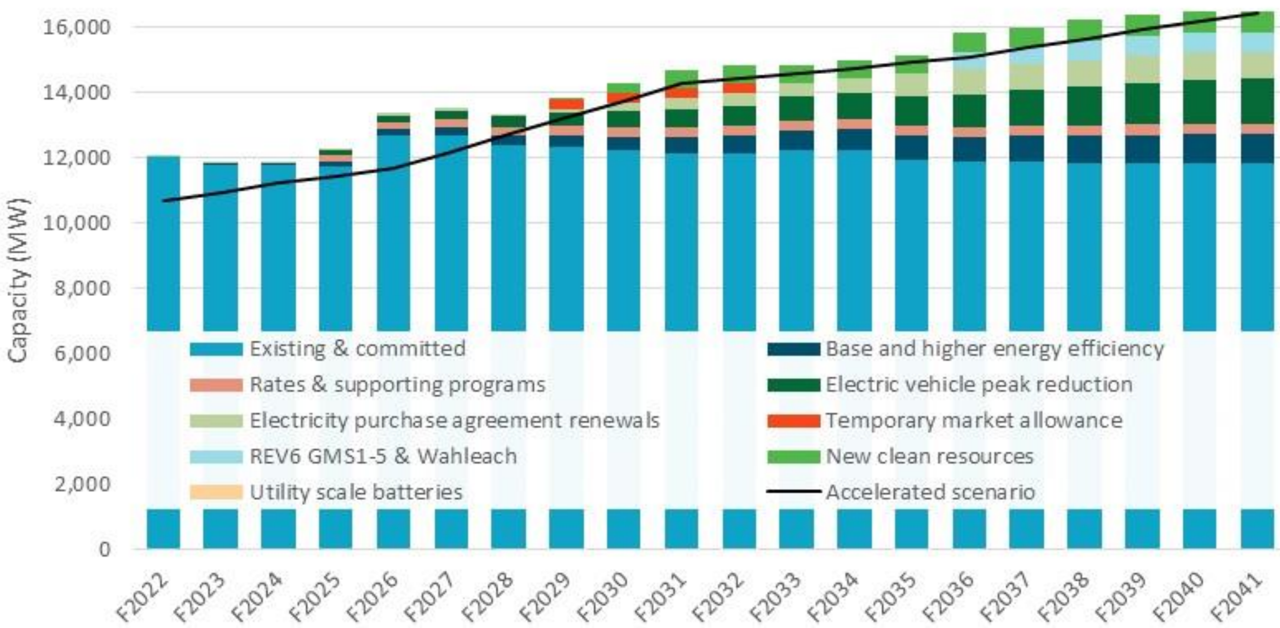


Table 10. System capacity Load Resource Balance for the Accelerated Scenario Contingency Resource Plan

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***[1]	(a)	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed IPP Resources***	(b)	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves***[2]	(c)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,615)	(1,604)	(1,600)	(1,618)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources**	(d) = a + b + c	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,244	12,162	12,131	12,264	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																					
5	Accelerated Scenario	(e)	(10,862)	(11,140)	(11,514)	(11,763)	(12,006)	(12,583)	(13,140)	(13,680)	(14,226)	(14,770)	(14,956)	(15,138)	(15,327)	(15,522)	(15,730)	(16,031)	(16,329)	(16,627)	(16,920)	(17,205)
	Existing and Committed Demand Side Management																					
6	F21 Energy Conservations Programs Savings		21	21	21	20	18	18	17	17	16	12	10	8	8	8	4	3	3	3	3	3
7	Codes & Standards		118	166	212	254	293	329	361	391	419	445	470	493	520	548	576	604	632	659	687	700
8	Energy Conservation Rate Structures		11	16	19	23	26	29	31	34	37	38	38	37	37	37	37	37	37	37	37	33
9	Sub-total	(f)	150	203	252	297	337	375	410	442	472	495	517	538	566	593	617	644	672	700	728	736
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d + e + f + g	**1,327**	**853**	**511**	**293**	**1,021**	**483**	**(354)**	**(888)**	**(1,510)**	**(2,113)**	**(2,308)**	**(2,336)**	**(2,529)**	**(2,967)**	**(3,243)**	**(3,517)**	**(3,824)**	**(4,094)**	**(4,367)**	**(4,643)**
	Contingency Resource Plan																					
	Future Demand Side Management																					
12	Base & Higher Energy Efficiency		30	56	85	135	187	240	297	356	418	483	540	598	653	708	759	801	841	878	901	919
13	Rates & Supporting Programs		-	-	-	217	230	255	279	291	295	297	300	302	303	305	307	308	310	311	312	313
14	Electric Vehicle Peak Reduction		-	-	-	141	199	270	333	402	477	557	642	732	825	923	1,021	1,116	1,205	1,290	1,369	1,369
15	Sub-total	(i)	30	56	85	492	616	765	909	1,050	1,190	1,337	1,482	1,631	1,782	1,936	2,087	2,225	2,356	2,479	2,582	2,601
16	***Electricity Purchase Agreement Renewals***[3]	(j)	0	8	24	38	66	66	75	101	264	347	377	397	429	700	792	792	828	828	836	837
17	***Temporary Market Allowance***	(k)	-	-	-	-	-	-	-	300	300	300	300	-	-	-	-	-	-	-	-	-
18	***REV6 GMS1-5 & Wahleach***[3]	(l)	-	-	-	-	-	-	-	-	-	-	-	-	14	14	502	502	602	602	602	602
19	***New Clean Resources***	(m)	-	-	-	-	-	-	-	46	307	532	532	532	557	557	583	601	634	658	704	721
20	***Utility Scale Batteries***	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	**Surplus / (Deficit) after planned resources**	(o) = h + i + j + k + l + m + n	**1,357**	**916**	**620**	**823**	**1,703**	**1,315**	**630**	**608**	**551**	**404**	**384**	**226**	**253**	**239**	**722**	**603**	**597**	**473**	**357**	**118**

ACCELERATED SCENARIO

Regional capacity load resource balances

Figure 15. South Coast region capacity Load Resource Balance for the Accelerated Scenario Contingency Resource Plan

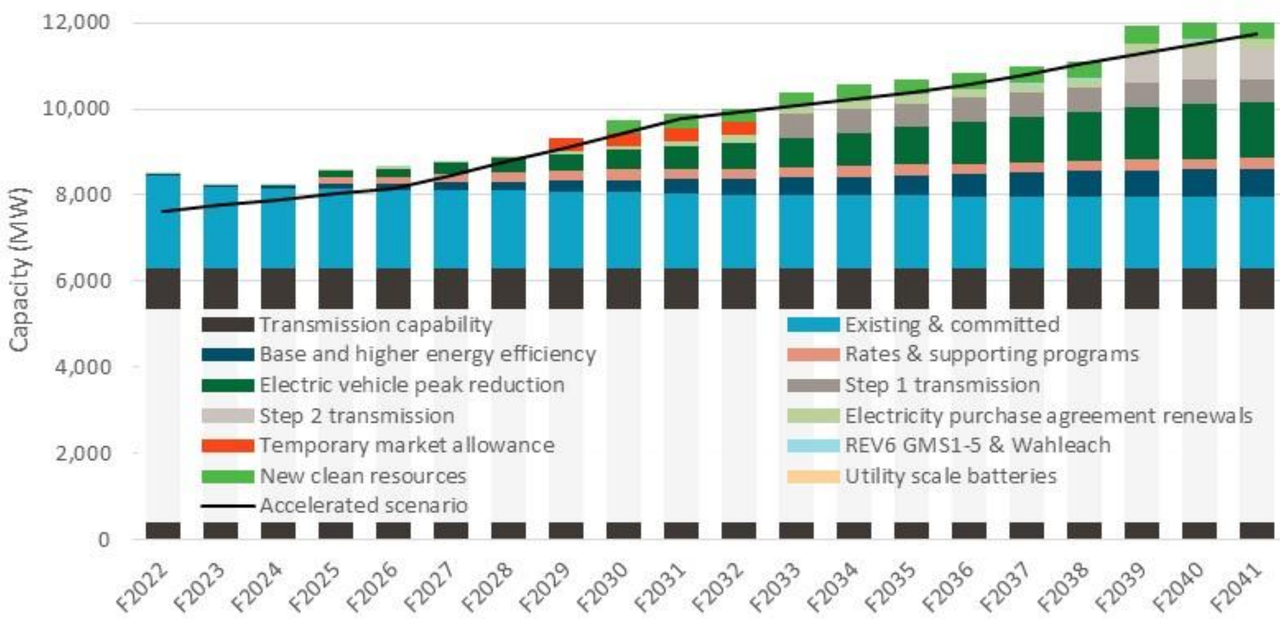


Table 11. South Coast region capacity Load Resource Balance for the Accelerated Scenario Contingency Resource Plan

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	1,517	1,517	1,517	1,517	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519
2	***Existing and Committed IPP Resources***	(b)	635	357	347	336	305	305	296	273	256	214	185	185	161	161	150	150	150	150	142	142
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	2,152	1,874	1,864	1,853	1,824	1,824	1,815	1,792	1,775	1,733	1,704	1,704	1,680	1,680	1,669	1,669	1,669	1,669	1,661	1,661
4	***Firm 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	6,300	6,300
	Demand - Regional Gross Requirements																					
5	Accelerated Scenario	(e)	(7,726)	(7,911)	(8,072)	(8,245)	(8,401)	(8,742)	(9,087)	(9,437)	(9,793)	(10,154)	(10,317)	(10,487)	(10,664)	(10,849)	(11,043)	(11,308)	(11,572)	(11,833)	(12,091)	(12,343)
	Existing and Committed Demand Side Management																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	113	153	190	225	256	285	312	336	360	379	398	416	439	461	481	504	527	550	572	581
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c + d + e + f + g	**838**	**416**	**282**	**132**	**(22)**	**(332)**	**(660)**	**(1,008)**	**(1,358)**	**(1,742)**	**(1,915)**	**(2,067)**	**(2,245)**	**(2,408)**	**(2,593)**	**(2,836)**	**(3,076)**	**(3,315)**	**(3,558)**	**(3,801)**
	Contingency Resource Plan																					
	Future Demand Side Management																					
	Base & Higher Energy Efficiency		21	39	59	93	128	164	201	241	282	326	366	407	447	487	524	556	586	614	632	648
19	Rates & Supporting Programs		-	-	-	168	179	200	219	229	232	234	236	237	238	239	241	242	243	244	245	245
20	Electric Vehicle Peak Reduction		-	-	-	133	188	256	315	380	451	527	607	692	780	872	966	1,055	1,139	1,219	1,294	1,294
21	Sub-total	(i)	21	39	59	394	496	619	736	851	965	1,086	1,209	1,336	1,466	1,598	1,730	1,852	1,968	2,077	2,171	2,187
	Transmission Upgrades																					
	Step 1		-	-	-	-	-	-	-	-	-	-	-	550	550	550	550	550	550	550	550	550
	Step 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	700	700	700
	Sub-total	(k)	-	-	-	-	-	-	-	-	-	-	-	550	550	550	550	550	550	1,250	1,250	1,250
	Electricity Purchase Agreement Renewals	(j)	0	3	13	24	55	55	64	87	104	146	175	175	199	199	210	210	210	210	218	218
	Temporary Market Allowance	(l)	-	-	-	-	-	-	-	300	300	300	300	-	-	-	-	-	-	-	-	-
	REV6 GMS1-5 & Wahleach	(m)	-	-	-	-	-	-	-	-	-	-	-	-	14	14	14	14	14	14	14	14
	New Clean Resources	(o)	-	-	-	-	-	-	-	-	280	328	328	328	352	352	379	396	396	396	396	396
	Utility Scale Batteries	(p)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	**Regional Surplus / (Deficit) after planned resources**	(q) = h + i + j + k + l + m + n + o + p	**859**	**457**	**354**	**551**	**529**	**342**	**140**	**229**	**291**	**118**	**96**	**321**	**335**	**306**	**290**	**187**	**62**	**632**	**490**	**264**

Figure 16. Vancouver Island region capacity Load Resource Balance for the Accelerated Scenario Contingency Resource Plan

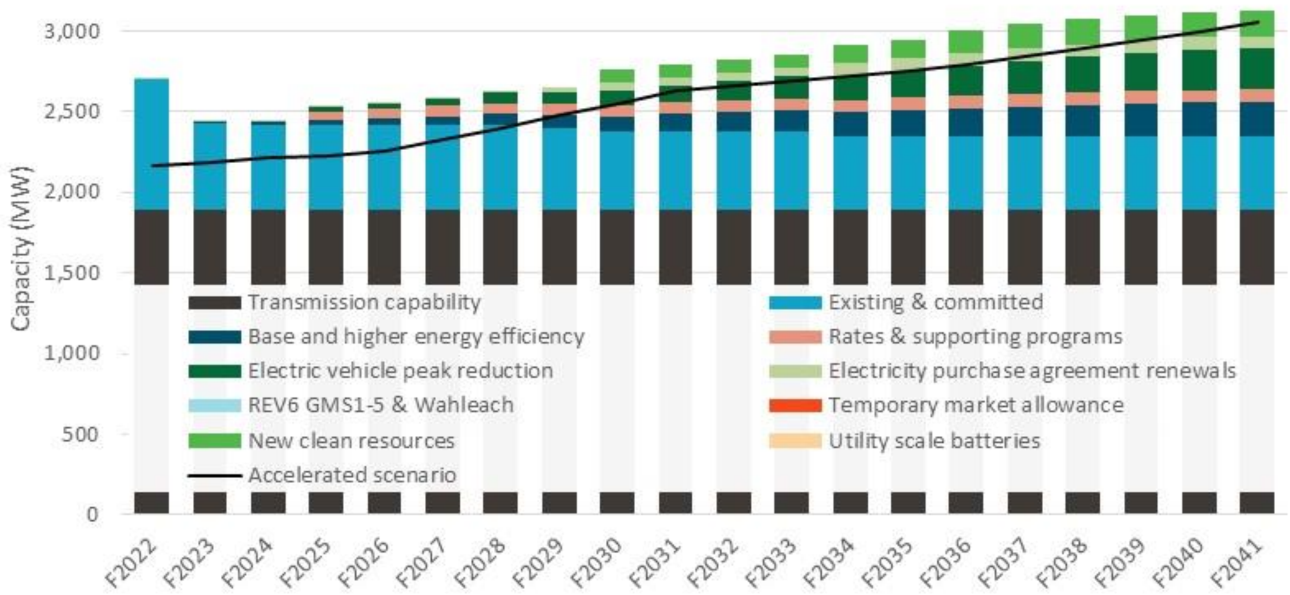


Table 12. Vancouver Island region capacity Load Resource Balance for the Accelerated Scenario Contingency Resource Plan

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
2	***Existing and Committed IPP Resources***	(b)	361	86	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	809	534	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
4	***Firm Transmission Capability***	(d)	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Demand - Regional Gross Requirements																					
5	Accelerated Scenario	(e)	(2,200)	(2,231)	(2,264)	(2,287)	(2,320)	(2,400)	(2,482)	(2,564)	(2,648)	(2,732)	(2,766)	(2,800)	(2,837)	(2,874)	(2,915)	(2,972)	(3,031)	(3,088)	(3,146)	(3,201)
	Existing and Committed Demand Side Management																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	31	41	51	60	68	75	82	88	94	99	104	108	114	119	124	130	135	141	147	149
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c + d + e + f + g	**530**	**234**	**208**	**194**	**168**	**95**	**20**	**(79)**	**(174)**	**(254)**	**(289)**	**(319)**	**(374)**	**(406)**	**(441)**	**(494)**	**(546)**	**(598)**	**(651)**	**(704)**
	Contingency Resource Plan																					
	Future Demand Side Management																					
	Base & Higher Energy Efficiency		6	12	18	29	40	52	65	78	92	107	121	135	149	162	174	185	194	204	209	214
9	Rates & Supporting Programs		-	-	-	52	56	63	69	72	73	73	74	74	75	75	75	75	76	76	76	76
10	Electric Vehicle Peak Reduction		-	-	-	26	37	50	62	74	88	103	119	135	153	171	189	206	223	239	253	253
11	Sub-total	(i)	6	12	18	107	133	165	196	225	253	283	313	344	376	407	438	466	493	518	539	544
12	***Electricity Purchase Agreement Renewals***	(j)	0	0	2	3	4	4	4	27	44	44	51	51	75	75	75	75	75	75	75	75
13	***Temporary Market Allowance***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	***REV6 GMS1-5 & Wahleach***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	***New Clean Resources***	(n)	-	-	-	-	-	-	-	-	80	88	88	88	112	112	139	156	156	156	156	156
17	***Utility Scale Batteries***	(o)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	**Surplus / (Deficit) after planned resources**	(p) = h + i + j + k + l + m + n + o	**536**	**246**	**228**	**303**	**305**	**265**	**220**	**173**	**204**	**162**	**162**	**163**	**189**	**188**	**210**	**203**	**177**	**150**	**119**	**71**

ACCELERATED – DSM UNDERDELIVERY SCENARIO

System-wide energy and capacity load resource balances

Figure 17. System energy Load Resource Balance for the Accelerated – DSM Underdelivery Scenario Contingency Resource Plan

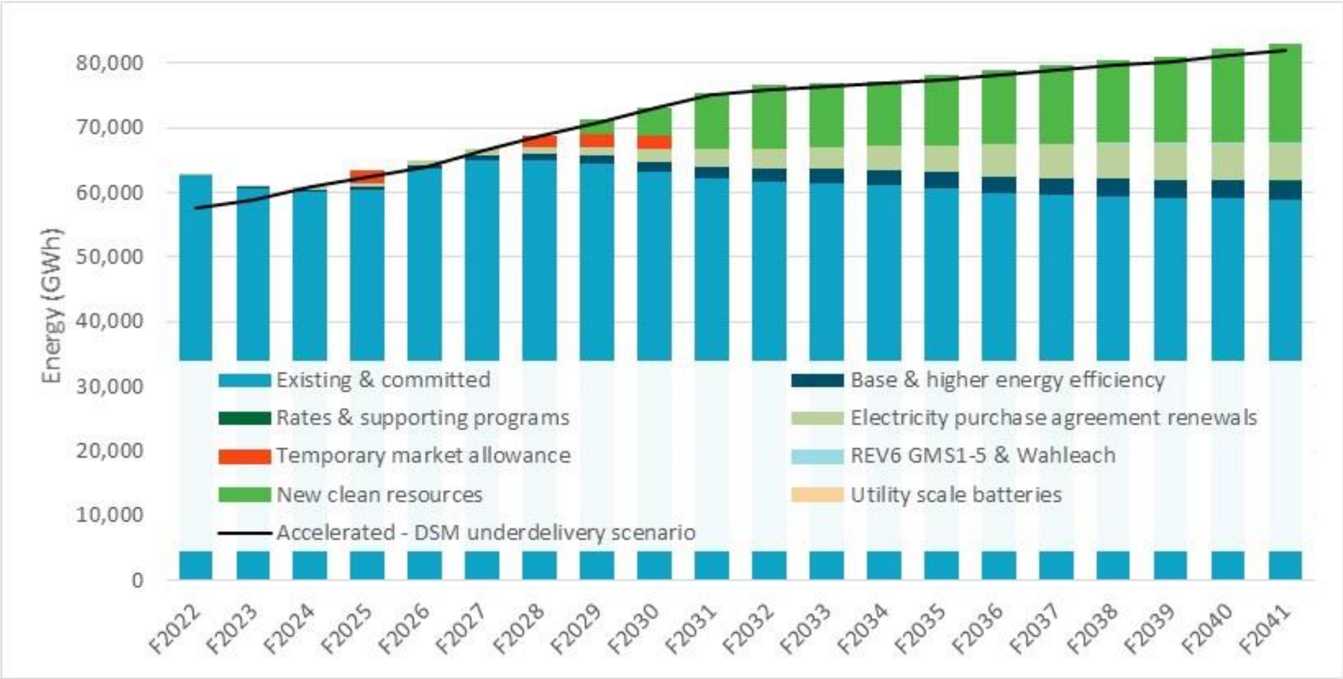


Table 13. System energy Load Resource Balance for the Accelerated – DSM Underdelivery Scenario Contingency Resource Plan

	(GWh)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	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
2	***Existing and Committed IPP Resources***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a + b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	Accelerated Electrification Scenario	(d)	(58,526)	(60,140)	(62,313)	(64,057)	(65,861)	(68,628)	(71,366)	(73,656)	(75,993)	(78,321)	(79,197)	(79,909)	(80,691)	(81,492)	(82,344)	(83,251)	(84,224)	(85,181)	(86,200)	(87,184)
	Existing and Committed Demand Side Management																					
5	F21 Energy Conservations Programs Savings		105	117	117	118	112	112	112	109	104	71	60	47	47	43	17	12	12	12	11	10
6	Codes & Standards		563	824	1,077	1,316	1,543	1,750	1,938	2,118	2,288	2,451	2,607	2,756	2,905	3,056	3,206	3,357	3,507	3,657	3,807	3,870
7	Energy Conservation Rate Structures		138	177	210	239	268	296	325	354	383	396	396	396	396	396	396	396	396	396	396	333
8	Sub-total	(e)	806	1,118	1,404	1,673	1,922	2,159	2,375	2,582	2,775	2,917	3,063	3,200	3,349	3,495	3,619	3,764	3,915	4,065	4,215	4,213
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c + d + e + f	**4,937**	**1,643**	**(671)**	**(1,985)**	**(246)**	**(1,440)**	**(4,025)**	**(6,507)**	**(9,824)**	**(12,964)**	**(14,138)**	**(14,831)**	**(15,665)**	**(16,761)**	**(18,237)**	**(19,286)**	**(20,165)**	**(21,148)**	**(21,965)**	**(23,053)**
	Contingency Resource Plan																					
	Future Demand Side Management																					
11	Base & Higher Energy Efficiency		102	187	297	431	608	817	1,008	1,218	1,439	1,690	1,878	2,074	2,262	2,415	2,581	2,695	2,809	2,812	2,813	2,813
12	Rates & Supporting Programs		-	-	-	29	30	30	31	31	31	32	32	32	32	32	32	32	33	33	33	33
13	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sub-total	(h)	102	187	297	460	637	847	1,039	1,249	1,470	1,722	1,910	2,106	2,294	2,447	2,613	2,727	2,841	2,845	2,846	2,846
15	***Electricity Purchase Agreement Renewals***	(i)	0	59	312	535	816	895	985	1,370	2,140	2,710	3,204	3,356	3,610	4,125	4,853	5,219	5,357	5,617	5,647	5,833
16	***Market Allowance***	(j)	-	-	-	2,000	-	-	2,000	2,000	2,000	-	-	-	-	-	-	-	-	-	-	-
17	***REV6 GMS1-5 & Wahleach***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26	26	26	26	26
18	***New Clean Resources***	(l)	-	-	-	-	-	-	-	2,385	4,207	8,783	9,855	9,855	9,855	10,926	11,440	12,132	12,695	13,352	14,545	15,240
19	***Utility Scale Batteries***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Surplus / (Deficit) after planned resources**	(n) = g + h + i + j + k + l + m	**5,039**	**1,888**	**(61)**	**1,010**	**1,207**	**303**	**(2)**	**498**	**(7)**	**251**	**831**	**485**	**94**	**736**	**695**	**818**	**754**	**691**	**1,099**	**892**

Figure 18. System capacity Load Resource Balance for the Accelerated – DSM Underdelivery Scenario Contingency Resource Plan

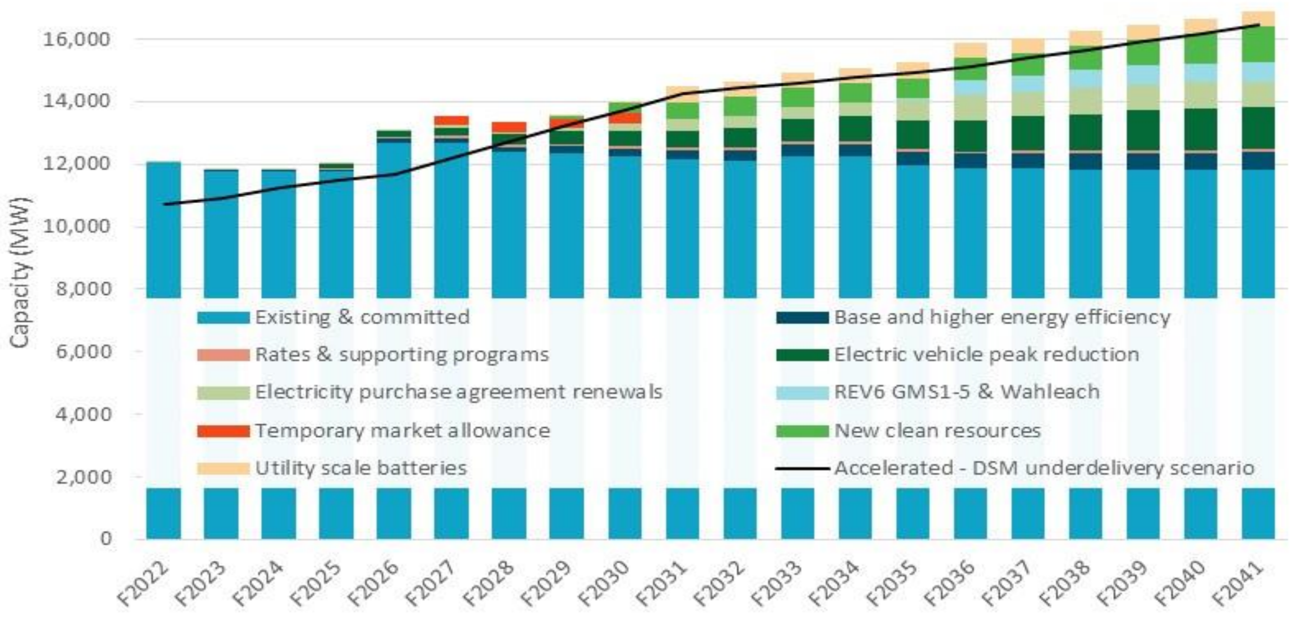


Table 14. System capacity Load Resource Balance for the Accelerated – DSM Underdelivery Scenario Contingency Resource Plan

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***[1]	(a)	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed IPP Resources***	(b)	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves***[2]	(c)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,615)	(1,604)	(1,600)	(1,618)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a + b + c	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,244	12,162	12,131	12,264	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																					
5	Accelerated Electrification Scenario	(e)	(10,862)	(11,140)	(11,514)	(11,763)	(12,006)	(12,583)	(13,140)	(13,680)	(14,226)	(14,770)	(14,956)	(15,138)	(15,327)	(15,522)	(15,730)	(16,031)	(16,329)	(16,627)	(16,920)	(17,205)
	Existing and Committed Demand Side Management																					
6	F21 Energy Conservations Programs Savings		21	21	21	20	18	18	17	17	16	12	10	8	8	8	4	3	3	3	3	3
7	Codes & Standards		118	166	212	254	293	329	361	391	419	445	470	493	520	548	576	604	632	659	687	700
8	Energy Conservation Rate Structures		11	16	19	23	26	29	31	34	37	38	38	37	37	37	37	37	37	37	37	33
9	Sub-total	(f)	150	203	252	297	337	375	410	442	472	495	517	538	566	593	617	644	672	700	728	736
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d + e + f + g	**1,327**	**853**	**511**	**293**	**1,021**	**483**	**(354)**	**(888)**	**(1,510)**	**(2,113)**	**(2,308)**	**(2,336)**	**(2,529)**	**(2,967)**	**(3,243)**	**(3,517)**	**(3,824)**	**(4,094)**	**(4,367)**	**(4,643)**
	Contingency Resource Plan																					
	Future Demand Side Management																					
12	Base & Higher Energy Efficiency		19	35	54	84	116	148	182	218	256	295	329	364	397	429	460	485	508	530	544	554
13	Rates & Supporting Programs		-	-	-	45	53	65	78	84	86	87	87	88	89	89	90	90	91	91	92	93
14	Electric Vehicle Peak Reduction		-	-	-	138	194	264	326	393	466	545	628	715	807	902	999	1,091	1,179	1,261	1,339	1,339
15	Sub-total	(i)	19	35	54	267	363	478	586	696	808	926	1,045	1,167	1,292	1,421	1,548	1,666	1,778	1,883	1,974	1,986
16	***Electricity Purchase Agreement Renewals***[3]	(j)	0	8	24	38	66	66	75	101	264	347	377	397	429	700	792	792	828	828	836	837
17	***Temporary Market Allowance***	(k)	-	-	-	-	-	300	300	300	300	-	-	-	-	-	-	-	-	-	-	-
18	***REV6 GMS1-5 & Wahleach***[3]	(l)	-	-	-	-	-	-	-	-	-	-	-	-	14	14	502	502	602	602	602	602
19	***New Clean Resources***[3]	(m)	-	-	-	-	-	-	-	83	337	557	611	611	611	657	683	718	751	830	925	1,139
20	***Utility Scale Batteries***	(n)	-	-	-	-	-	-	-	35	35	490	490	490	490	490	490	490	490	490	490	490
21	**Surplus / (Deficit) after planned resources**	(o) = h + i + j + k + l + m + n	**1,346**	**896**	**589**	**598**	**1,451**	**1,327**	**607**	**327**	**234**	**207**	**215**	**330**	**308**	**314**	**773**	**651**	**625**	**539**	**461**	**410**

[1] Includes outages for Mica and Seven Mile for the period F2029 to F2032.
[2] The 12% reserve margin is applied to dependable capacity resources only.
[3] The numbers shown include the 12% reserve margin.

ACCELERATED – DSM UNDERDELIVERY SCENARIO

Regional capacity load resource balances

Figure 19. South Coast region capacity Load Resource Balance for the Accelerated – DSM Underdelivery Scenario Contingency Resource Plan

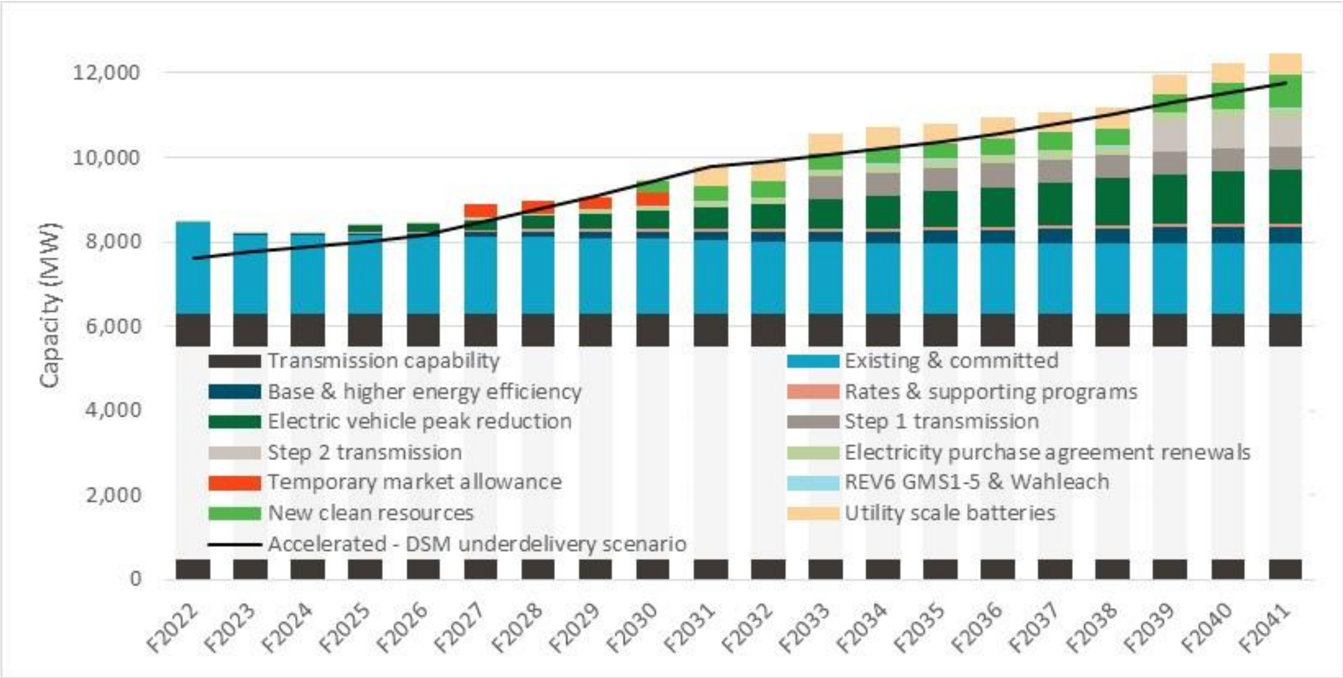


Table 15. South Coast region capacity Load Resource Balance for the Accelerated – DSM Underdelivery Scenario Contingency Resource Plan

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	1,517	1,517	1,517	1,517	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519
2	***Existing and Committed IPP Resources***	(b)	635	357	347	336	305	305	296	273	256	214	185	185	161	161	150	150	150	150	142	142
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	2,152	1,874	1,864	1,853	1,824	1,824	1,815	1,792	1,775	1,733	1,704	1,704	1,680	1,680	1,669	1,669	1,669	1,669	1,661	1,661
4	***Firm 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	6,300	6,300
	Demand - Regional Gross Requirements																					
5	Accelerated Electrification Scenario	(e)	(7,726)	(7,911)	(8,072)	(8,245)	(8,401)	(8,742)	(9,087)	(9,437)	(9,793)	(10,154)	(10,317)	(10,487)	(10,664)	(10,849)	(11,043)	(11,308)	(11,572)	(11,833)	(12,091)	(12,343)
	Existing and Committed Demand Side Management																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	113	153	190	225	256	285	312	336	360	379	398	416	439	461	481	504	527	550	572	581
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c + d + e + f + g	**838**	**416**	**282**	**132**	**(22)**	**(332)**	**(660)**	**(1,008)**	**(1,358)**	**(1,742)**	**(1,915)**	**(2,067)**	**(2,245)**	**(2,408)**	**(2,593)**	**(2,836)**	**(3,076)**	**(3,315)**	**(3,558)**	**(3,801)**
	Contingency Resource Plan																					
	Future Demand Side Management																					
9	Base & Higher Energy Efficiency		13	25	37	58	80	101	124	148	173	199	223	248	272	295	317	336	354	371	381	390
10	Rates & Supporting Programs		-	-	-	35	41	52	62	67	69	69	70	70	71	71	72	72	72	73	73	74
11	Electric Vehicle Peak Reduction		-	-	-	130	184	250	308	372	441	515	594	676	763	853	944	1,032	1,114	1,192	1,266	1,266
12	Sub-total	(i)	13	25	37	223	305	403	494	587	682	783	887	994	1,105	1,219	1,333	1,440	1,541	1,636	1,720	1,730
	Transmission Upgrades																					
13	Step 1		-	-	-	-	-	-	-	-	-	-	-	550	550	550	550	550	550	550	550	550
14	Step 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	700	700	700
15	Sub-total	(j)	-	-	-	-	-	-	-	-	-	-	-	550	550	550	550	550	550	1,250	1,250	1,250
16	***Electricity Purchase Agreement Renewals***	(k)	0	3	13	24	55	55	64	87	104	146	175	175	199	199	210	210	210	210	218	218
17	***Temporary Market Allowance***	(l)	-	-	-	-	-	300	300	300	300	-	-	-	-	-	-	-	-	-	-	-
18	***REV6 GMS1-5 & Wahleach***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	14	14	14	14	14	14	14	14
19	***New Clean Resources***	(n)	-	-	-	-	-	-	-	-	288	352	361	361	361	361	387	404	404	404	582	784
20	***Utility Scale Batteries***	(o)	-	-	-	-	-	-	-	35	35	490	490	490	490	490	490	490	490	490	490	490
21	**Regional Surplus / (Deficit) after planned resources**	(p) = h + i + j + k + l + m + n + o	**851**	**443**	**332**	**380**	**338**	**426**	**198**	**0**	**51**	**29**	**(3)**	**503**	**473**	**425**	**391**	**272**	**133**	**689**	**716**	**686**

Figure 20. Vancouver Island region capacity Load Resource Balance for the Accelerated – DSM Underdelivery Scenario Contingency Resource Plan

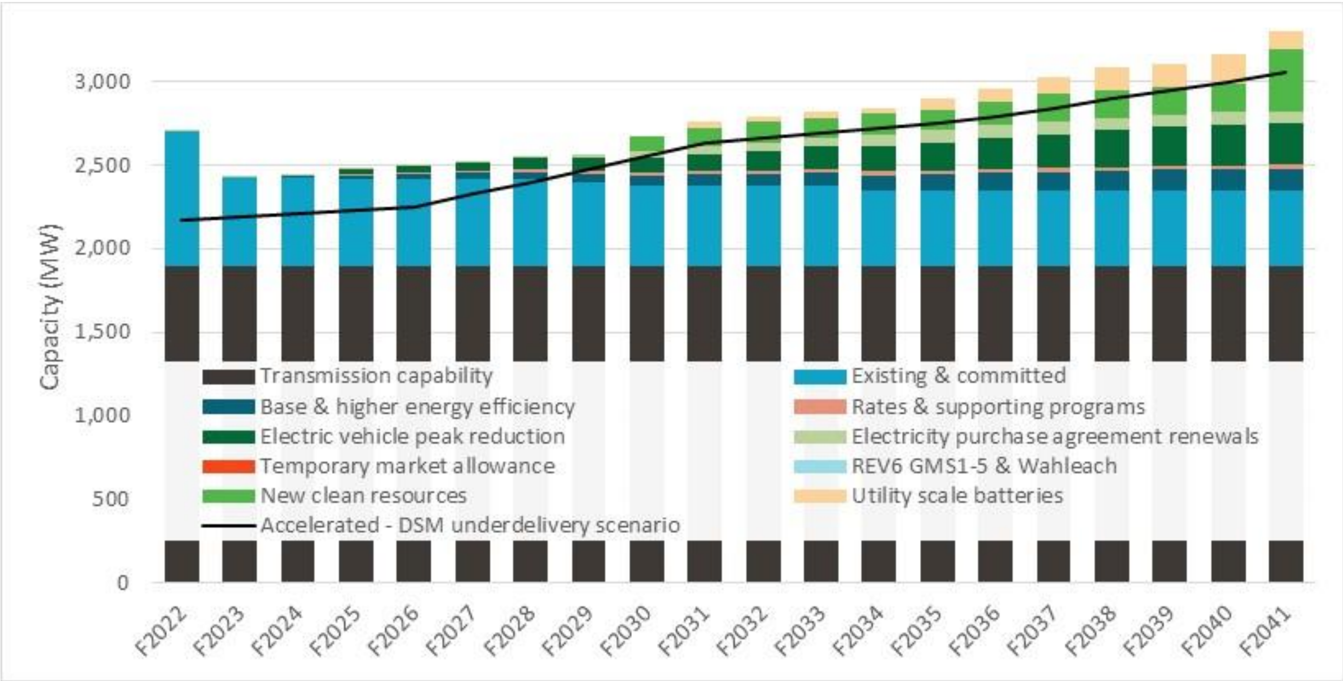


Table 16. Vancouver Island region capacity Load Resource Balance for the Accelerated – DSM Underdelivery Scenario Contingency Resource Plan

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
2	***Existing and Committed IPP Resources***	(b)	361	86	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	809	534	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
4	***Firm Transmission Capability***	(d)	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Demand - Regional Gross Requirements																					
5	Accelerated Electrification Scenario	(e)	(2,200)	(2,231)	(2,264)	(2,287)	(2,320)	(2,400)	(2,482)	(2,564)	(2,648)	(2,732)	(2,766)	(2,800)	(2,837)	(2,874)	(2,915)	(2,972)	(3,031)	(3,088)	(3,146)	(3,201)
	Existing and Committed Demand Side Management																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	31	41	51	60	68	75	82	88	94	99	104	108	114	119	124	130	135	141	147	149
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c + d + e + f + g	**530**	**234**	**208**	**194**	**168**	**95**	**20**	**(79)**	**(174)**	**(254)**	**(289)**	**(319)**	**(374)**	**(406)**	**(441)**	**(494)**	**(546)**	**(598)**	**(651)**	**(704)**
	Contingency Resource Plan																					
	Future Demand Side Management																					
9	Base & Higher Energy Efficiency		4	7	11	18	25	32	40	48	56	65	74	82	90	98	105	111	117	123	126	129
10	Rates & Supporting Programs		-	-	-	11	13	17	20	22	22	22	22	23	23	23	23	23	23	23	23	23
11	Electric Vehicle Peak Reduction		-	-	-	25	36	49	60	73	86	101	116	132	149	167	185	202	218	233	248	248
12	Sub-total	(i)	4	7	11	54	74	98	121	143	165	188	212	237	262	288	313	336	358	379	397	400
13	***Electricity Purchase Agreement Renewals***	(j)	0	0	2	3	4	4	4	27	44	44	51	51	75	75	75	75	75	75	75	75
14	***Temporary Market Allowance***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	***REV6 GMS1-5 & Wahleach***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	***New Clean Resources***	(n)	-	-	-	-	-	-	-	-	88	112	121	121	121	121	147	164	164	164	164	366
17	***Utility Scale Batteries***	(o)	-	-	-	-	-	-	-	-	-	35	35	35	35	70	70	105	140	140	175	175
18	**Surplus / (Deficit) after planned resources**	(p) = h + i + j + k + l + m + n + o	**534**	**241**	**221**	**250**	**246**	**197**	**145**	**91**	**122**	**126**	**129**	**124**	**118**	**147**	**163**	**186**	**191**	**160**	**161**	**312**

LOW LOAD SCENARIO

System-wide energy and capacity load resource balances

Figure 21. System energy Load Resource Balance for the Low Load Scenario Contingency Resource Plan

Table 17. System energy Load Resource Balance for the Low Load Scenario Contingency Resource Plan

	(GWh)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	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
2	***Existing and Committed IPP Resources***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a + b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	Dec 2020 Low Load Forecast before DSM	(d)	(53,881)	(53,982)	(54,051)	(55,172)	(55,224)	(55,446)	(55,643)	(54,901)	(55,093)	(55,284)	(55,466)	(55,647)	(55,856)	(56,066)	(56,267)	(56,422)	(56,626)	(56,826)	(57,075)	(57,351)
	Existing and Committed Demand Side Management																					
5	F21 Energy Conservations Programs Savings		95	105	106	106	101	101	101	98	93	64	54	43	43	39	15	11	11	11	10	9
6	Codes & Standards		507	743	970	1,186	1,390	1,577	1,746	1,909	2,062	2,208	2,349	2,484	2,618	2,754	2,889	3,025	3,160	3,295	3,431	3,487
7	Energy Conservation Rate Structures		124	159	189	215	241	267	293	319	345	357	357	357	357	357	357	357	357	357	357	300
8	Sub-total	(e)	727	1,007	1,265	1,507	1,732	1,946	2,140	2,326	2,500	2,629	2,760	2,883	3,018	3,150	3,261	3,392	3,527	3,663	3,798	3,796
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c + d + e + f	**9,503**	**7,690**	**7,452**	**6,735**	**10,201**	**11,528**	**11,463**	**11,993**	**10,801**	**9,785**	**9,290**	**9,114**	**8,839**	**8,318**	**7,481**	**7,171**	**7,046**	**6,804**	**6,744**	**6,363**
	Base Resource Plan																					
	Future Demand Side Management																					
11	Base Energy Efficiency		161	296	472	649	814	948	1,090	1,224	1,347	1,483	1,558	1,616	1,666	1,706	1,768	1,779	1,788	1,794	1,795	1,795
12	Higher Energy Efficiency		-	-	-	-	-	35	118	222	327	448	576	709	813	926	1,025	1,108	1,192	1,255	1,320	1,387
13	Time-Varying Rates & Demand Response		-	-	-	-	39	39	40	40	40	40	41	41	41	41	41	41	41	42	42	42
14	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Sub-total	(h)	161	296	472	649	853	1,022	1,247	1,486	1,714	1,972	2,174	2,365	2,520	2,673	2,835	2,928	3,022	3,090	3,156	3,223
17	***Energy Purchase Agreement Renewals***	(i)	0	59	312	535	816	895	895	895	895	895	895	895	895	895	895	895	895	895	895	895
18	***New Supply***	(j)	-	-	-	-	-	-	-	-	-	580	1,458	1,869	2,454	3,306	4,527	5,206	5,714	6,353	6,826	7,572
19	**Surplus / (Deficit) after planned resources**	(k) = g + h + i + j	**9,664**	**8,046**	**8,237**	**7,920**	**11,870**	**13,446**	**13,606**	**14,374**	**13,411**	**13,231**	**13,818**	**14,243**	**14,708**	**15,192**	**15,739**	**16,200**	**16,678**	**17,143**	**17,622**	**18,053**
	Contingency Resource Plan																					
	BRP Off-Ramp																					
20	Higher Energy Efficiency		-	-	-	-	-	(35)	(118)	(222)	(327)	(448)	(576)	(709)	(813)	(926)	(1,025)	(1,108)	(1,192)	(1,255)	(1,320)	(1,387)
21	Time-Varying Rates & Demand Response		-	-	-	-	(39)	(39)	(40)	(40)	(40)	(40)	(41)	(41)	(41)	(41)	(41)	(41)	(41)	(42)	(42)	(42)
22	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Electricity Purchase Agreement Renewals & Future Resources		-	-	-	-	-	(80)	(80)	(80)	(80)	(659)	(1,538)	(1,948)	(2,534)	(3,385)	(4,607)	(5,286)	(5,794)	(6,433)	(6,906)	(7,652)
25	Sub-total	(l)	-	-	-	-	(39)	(154)	(237)	(341)	(447)	(1,148)	(2,154)	(2,698)	(3,387)	(4,352)	(5,673)	(6,434)	(7,028)	(7,730)	(8,267)	(9,080)
26	**Surplus / (Deficit) after planned resources**	(m) = k + l	**9,664**	**8,046**	**8,237**	**7,920**	**11,831**	**13,292**	**13,369**	**14,032**	**12,964**	**12,083**	**11,664**	**11,545**	**11,321**	**10,840**	**10,065**	**9,766**	**9,650**	**9,413**	**9,355**	**8,973**

Figure 22. System capacity Load Resource Balance for the Low Load Scenario Contingency Resource Plan

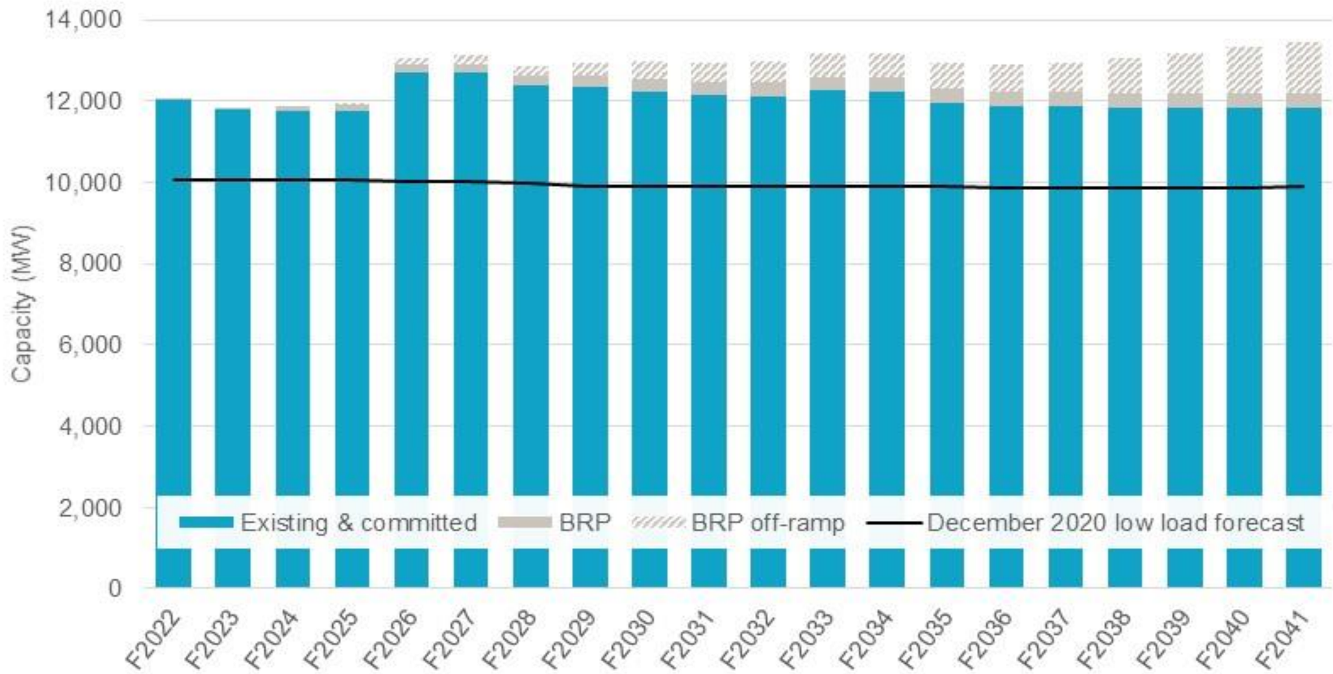


Table 18. System capacity Load Resource Balance for the Low Load Scenario Contingency Resource Plan

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																						
1	***Existing and Committed Heritage Resources***[1]	(a)	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed IPP Resources***	(b)	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves***[2]	(c)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,615)	(1,604)	(1,600)	(1,618)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a + b + c	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,244	12,162	12,131	12,264	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																					
5	Dec 2020 Low Load Forecast before DSM	(e)	(10,205)	(10,246)	(10,296)	(10,325)	(10,340)	(10,348)	(10,364)	(10,304)	(10,323)	(10,341)	(10,354)	(10,378)	(10,398)	(10,419)	(10,435)	(10,462)	(10,485)	(10,510)	(10,529)	(10,551)
	Existing and Committed Demand Side Management																					
6	F21 Energy Conservations Programs Savings		18	18	18	18	16	16	15	15	14	10	9	7	7	7	4	3	3	3	3	3
7	Codes & Standards		104	147	187	225	260	292	321	348	374	398	421	442	467	492	517	542	567	592	617	629
8	Energy Conservation Rate Structures		10	14	17	20	23	25	28	30	33	34	34	33	33	33	33	33	33	33	33	29
9	Sub-total	(f)	132	179	222	262	298	333	365	394	421	443	464	483	508	533	555	579	604	629	654	662
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d + e + f + g	**1,965**	**1,723**	**1,699**	**1,697**	**2,649**	**2,676**	**2,378**	**2,440**	**2,342**	**2,263**	**2,241**	**2,369**	**2,343**	**2,076**	**1,989**	**1,986**	**1,952**	**1,952**	**1,951**	**1,937**
Base Resource Plan																						
	Future Demand Side Management																					
12	Base Energy Efficiency		30	56	85	115	142	164	187	209	229	248	261	272	281	290	299	302	303	304	302	302
13	Higher Energy Efficiency		-	-	-	-	-	10	23	39	57	75	94	115	132	151	168	184	199	212	226	240
14	Time-Varying Rates & Demand Response		-	-	-	-	124	132	158	185	203	205	205	206	206	206	206	207	207	207	208	208
15	Industrial Load Curtailment		-	-	-	-	-	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98
16	Electric Vehicle Peak Reduction		-	-	-	24	38	57	68	81	95	108	124	140	157	175	194	211	229	246	262	262
17	Sub-total	(i)	30	56	85	138	304	364	436	513	680	734	783	831	875	920	965	1,001	1,035	1,067	1,096	1,111
18	***Electricity Purchase Agreement Renewals***[3]	(j)	0	8	24	38	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
19	***Future Resources***[3]	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	225	348	467
20	**Surplus / (Deficit) after planned resources**	(l) = h + i + j + k	**1,995**	**1,787**	**1,809**	**1,873**	**3,019**	**3,106**	**2,880**	**3,019**	**3,089**	**3,064**	**3,090**	**3,266**	**3,284**	**3,062**	**3,020**	**3,053**	**3,163**	**3,311**	**3,461**	**3,581**
Contingency Resource Plan																						
	BRP Off-Ramp																					
21	Higher Energy Efficiency		-	-	-	-	-	(10)	(23)	(39)	(57)	(75)	(94)	(115)	(132)	(151)	(168)	(184)	(199)	(212)	(226)	(240)
22	Time-Varying Rates & Demand Response		-	-	-	-	(124)	(132)	(158)	(185)	(203)	(205)	(205)	(206)	(206)	(206)	(206)	(207)	(207)	(207)	(208)	(208)
23	Industrial Load Curtailment		-	-	-	-	-	-	-	-	(98)	(98)	(98)	(98)	(98)	(98)	(98)	(98)	(98)	(98)	(98)	(98)
24	Electric Vehicle Peak Reduction		-	-	-	(24)	(38)	(57)	(68)	(81)	(95)	(108)	(124)	(140)	(157)	(175)	(194)	(211)	(229)	(246)	(262)	(262)
25	Electricity Purchase Agreement Renewals & Future Resources[3]		-	-	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(110)	(225)	(348)	(467)
26	Sub-total	(m)	-	-	-	(24)	(162)	(200)	(249)	(304)	(452)	(486)	(521)	(559)	(594)	(630)	(666)	(700)	(842)	(988)	(1,142)	(1,276)
27	**Surplus / (Deficit) after planned resources**	(n) = l + m	**1,995**	**1,787**	**1,809**	**1,849**	**2,857**	**2,906**	**2,631**	**2,715**	**2,637**	**2,578**	**2,568**	**2,707**	**2,690**	**2,432**	**2,354**	**2,353**	**2,321**	**2,323**	**2,319**	**2,305**

Notes:

[1] Includes outages for Mica and Seven Mile for the period F2029 to F2032.

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

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

LOW LOAD SCENARIO

Regional capacity load resource balances

Figure 23. South Coast region capacity Load Resource Balance for the Low Load Scenario Contingency Resource Plan

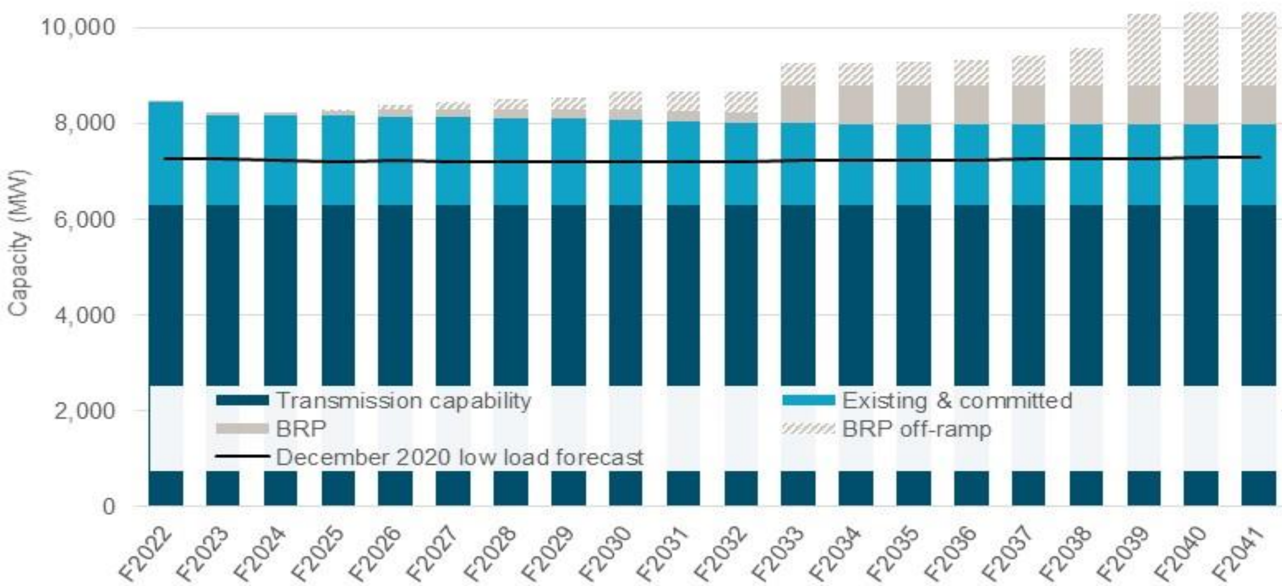


Table 19. South Coast region capacity Load Resource Balance for the Low Load Scenario Contingency Resource Plan

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	1,517	1,517	1,517	1,517	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519
2	***Existing and Committed IPP Resources***	(b)	635	357	347	336	305	305	296	273	256	214	185	185	161	161	150	150	150	150	142	142
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	2,152	1,874	1,864	1,853	1,824	1,824	1,815	1,792	1,775	1,733	1,704	1,704	1,680	1,680	1,669	1,669	1,669	1,669	1,661	1,661
4	***Firm 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	6,300	6,300
	Demand - Regional Gross Requirements																					
5	Dec 2020 Low Load Forecast before DSM	(e)	(7,358)	(7,407)	(7,400)	(7,408)	(7,443)	(7,461)	(7,479)	(7,504)	(7,525)	(7,546)	(7,564)	(7,592)	(7,618)	(7,644)	(7,668)	(7,701)	(7,731)	(7,763)	(7,790)	(7,821)
	Existing and Committed Demand Side Management																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	99	135	168	199	227	254	278	300	322	340	357	374	394	415	433	453	473	494	514	522
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c + d + e + f + g	**1,193**	**902**	**932**	**944**	**908**	**916**	**914**	**889**	**872**	**827**	**797**	**785**	**757**	**750**	**734**	**721**	**711**	**700**	**685**	**662**
	Base Resource Plan																					
	Future Demand Side Management																					
9	Base Energy Efficiency		21	39	59	79	98	113	129	143	157	171	181	189	195	202	208	210	211	212	211	211
10	Higher Energy Efficiency		-	-	-	-	-	7	15	24	35	46	57	69	81	93	106	117	128	139	150	161
11	Time-Varying Rates & Demand Response		-	-	-	-	81	91	113	136	150	153	154	156	157	158	159	160	161	162	164	165
12	Industrial Load Curtailment		-	-	-	-	-	-	-	-	86	86	86	86	86	86	86	86	86	86	86	86
13	Electric Vehicle Peak Reduction		-	-	-	22	36	54	64	76	89	102	117	133	149	166	183	200	216	232	248	248
14	Sub-total	(i)	21	39	59	102	215	264	320	379	517	559	595	632	668	705	742	773	803	832	858	870
15	***Energy Purchase Agreement Renewals***	(j)	0	3	13	24	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
16	***New Supply***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	178	178	178	178
	Transmission Upgrades																					
17	Step 1	(l)	-	-	-	-	-	-	-	-	-	-	-	550	550	550	550	550	550	550	550	550
18	Step 2	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	700	700	700
19	**Regional Surplus / (Deficit) after planned resources**	(n) = h + i + j + k + l + m	**1,214**	**943**	**1,005**	**1,070**	**1,179**	**1,236**	**1,290**	**1,323**	**1,444**	**1,441**	**1,448**	**2,022**	**2,030**	**2,060**	**2,081**	**2,159**	**2,297**	**3,015**	**3,027**	**3,015**
	Contingency Resource Plan																					
	BRP Off-Ramp																					
20	Higher Energy Efficiency		-	-	-	-	-	(7)	(15)	(24)	(35)	(46)	(57)	(69)	(81)	(93)	(106)	(117)	(128)	(139)	(150)	(161)
21	Time-Varying Rates & Demand Response		-	-	-	-	(81)	(91)	(113)	(136)	(150)	(153)	(154)	(156)	(157)	(158)	(159)	(160)	(161)	(162)	(164)	(165)
22	Industrial Load Curtailment		-	-	-	-	-	-	-	-	(86)	(86)	(86)	(86)	(86)	(86)	(86)	(86)	(86)	(86)	(86)	(86)
23	Electric Vehicle Peak Reduction		-	-	-	(22)	(36)	(54)	(64)	(76)	(89)	(102)	(117)	(133)	(149)	(166)	(183)	(200)	(216)	(232)	(248)	(248)
24	Step 2 transmission upgrade		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(700)	(700)	(700)
25	Electricity Purchase Agreement Renewals & Future Resources		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(60)	(178)	(178)	(178)	(178)
26	Sub-total	(o)	-	-	-	(22)	(118)	(151)	(192)	(236)	(360)	(387)	(414)	(443)	(472)	(503)	(533)	(623)	(770)	(1,498)	(1,526)	(1,538)
27	**Surplus / (Deficit) after planned resources**	(p) = n + o	**1,214**	**943**	**1,005**	**1,047**	**1,061**	**1,085**	**1,098**	**1,087**	**1,084**	**1,053**	**1,033**	**1,579**	**1,557**	**1,557**	**1,547**	**1,536**	**1,527**	**1,517**	**1,501**	**1,478**

Figure 24. Vancouver Island region capacity Load Resource Balance for the Low Load Scenario Contingency Resource Plan

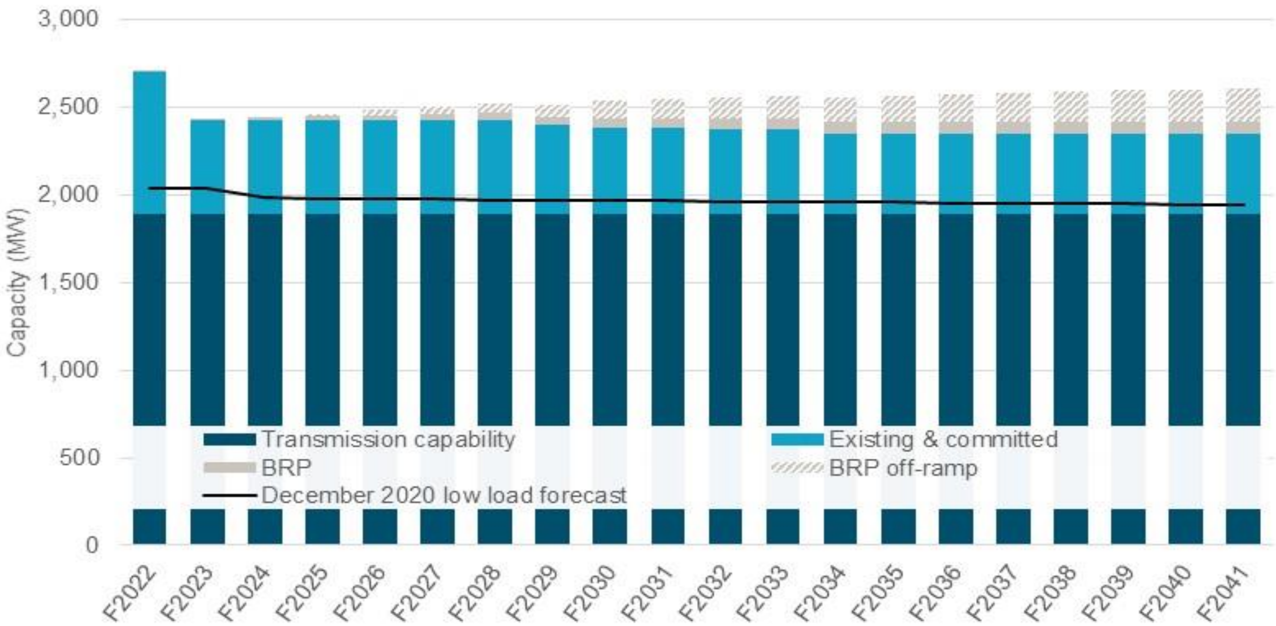


Table 20. Vancouver Island region capacity Load Resource Balance for the Low Load Scenario Contingency Resource Plan

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
LRB with Existing and Committed Supply																						
1	***Existing and Committed Heritage Resources***	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
2	***Existing and Committed IPP Resources***	(b)	361	86	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	809	534	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
4	***Firm Transmission Capability***	(d)	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Demand - Regional Gross Requirements																					
5	Dec 2020 Low Load Forecast before DSM	(e)	(2,062)	(2,070)	(2,033)	(2,033)	(2,040)	(2,043)	(2,044)	(2,048)	(2,051)	(2,053)	(2,054)	(2,058)	(2,060)	(2,063)	(2,064)	(2,069)	(2,071)	(2,075)	(2,076)	(2,079)
	Existing and Committed Demand Side Management																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	28	37	46	54	61	68	74	80	86	90	94	98	104	109	113	118	123	128	133	135
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c + d + e + f + g	**664**	**390**	**435**	**442**	**441**	**445**	**450**	**429**	**415**	**417**	**414**	**414**	**392**	**395**	**398**	**398**	**401**	**402**	**406**	**405**
Base Resource Plan																						
	Future Demand Side Management																					
9	Base Energy Efficiency		6	12	18	24	29	34	39	44	48	53	56	59	61	63	65	65	65	65	65	65
10	Higher Energy Efficiency		-	-	-	-	-	3	6	9	13	17	21	25	29	34	38	43	47	51	55	59
11	Time-Varying Rates & Demand Response		-	-	-	-	23	26	34	41	46	46	46	47	47	47	48	48	48	49	49	49
12	Industrial Load Curtailment		-	-	-	-	-	-	-	-	29	29	29	29	29	29	29	29	29	29	29	29
13	Electric Vehicle Peak Reduction		-	-	-	4	7	11	13	15	17	20	23	26	29	32	36	39	42	45	48	48
14	Sub-total	(i)	6	12	18	28	59	74	91	109	154	165	176	186	196	206	216	224	232	240	247	251
15	***Energy Purchase Agreement Renewals***	(j)	0	0	2	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
16	***New Supply***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Regional Surplus / (Deficit) after planned resources**	(l) = h + i + j + k	**670**	**402**	**454**	**473**	**504**	**523**	**545**	**543**	**572**	**586**	**594**	**604**	**593**	**605**	**618**	**627**	**637**	**646**	**657**	**660**
Contingency Resource Plan																						
	BRP Off-Ramp																					
18	Higher Energy Efficiency		-	-	-	-	-	(3)	(6)	(9)	(13)	(17)	(21)	(25)	(29)	(34)	(38)	(43)	(47)	(51)	(55)	(59)
19	Time-Varying Rates & Demand Response		-	-	-	-	(23)	(26)	(34)	(41)	(46)	(46)	(46)	(47)	(47)	(47)	(48)	(48)	(48)	(49)	(49)	(49)
20	Industrial Load Curtailment		-	-	-	-	-	-	-	-	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
21	Electric Vehicle Peak Reduction		-	-	-	(4)	(7)	(11)	(13)	(15)	(17)	(20)	(23)	(26)	(29)	(32)	(36)	(39)	(42)	(45)	(48)	(48)
22	Electricity Purchase Agreement Renewals & Future Resources		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Sub-total	(m)	-	-	-	(4)	(30)	(39)	(52)	(66)	(105)	(112)	(120)	(127)	(135)	(143)	(151)	(159)	(167)	(174)	(182)	(186)
24	**Surplus / (Deficit) after planned resources**	(n) = l + m	**670**	**402**	**454**	**468**	**474**	**483**	**493**	**477**	**467**	**474**	**474**	**477**	**458**	**462**	**467**	**468**	**470**	**472**	**475**	**474**