Clean Power 2040

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2021 Integrated Resource Plan (IRP) Technical Advisory Committee (TAC) Meeting #9

April 8, 2021

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Welcome & meeting context

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Virtual meeting etiquette

These principles should make our meetings more effective

- As with in-person meetings, continue to have members participate and alternates observe
- Keep the conversation respectful by focusing on ideas, not the person
- Stay curious about new ideas
- Share the air time – to ensure everyone gets heard

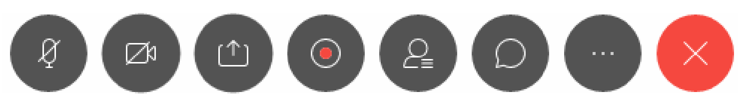
- To minimize distractions – keep yourself on mute
- We'll use the chat box to seek input and ask questions
- We'll not be recording these sessions, and ask for others not to record

Cisco Webex reminders

We'll be using a few basic tools, which you can find if you hover your mouse over the bottom of the screen

Mute/unmute your mic
& turn your video on/off

View the
participant list



Open the chat panel:
- to ask questions
- to provide feedback

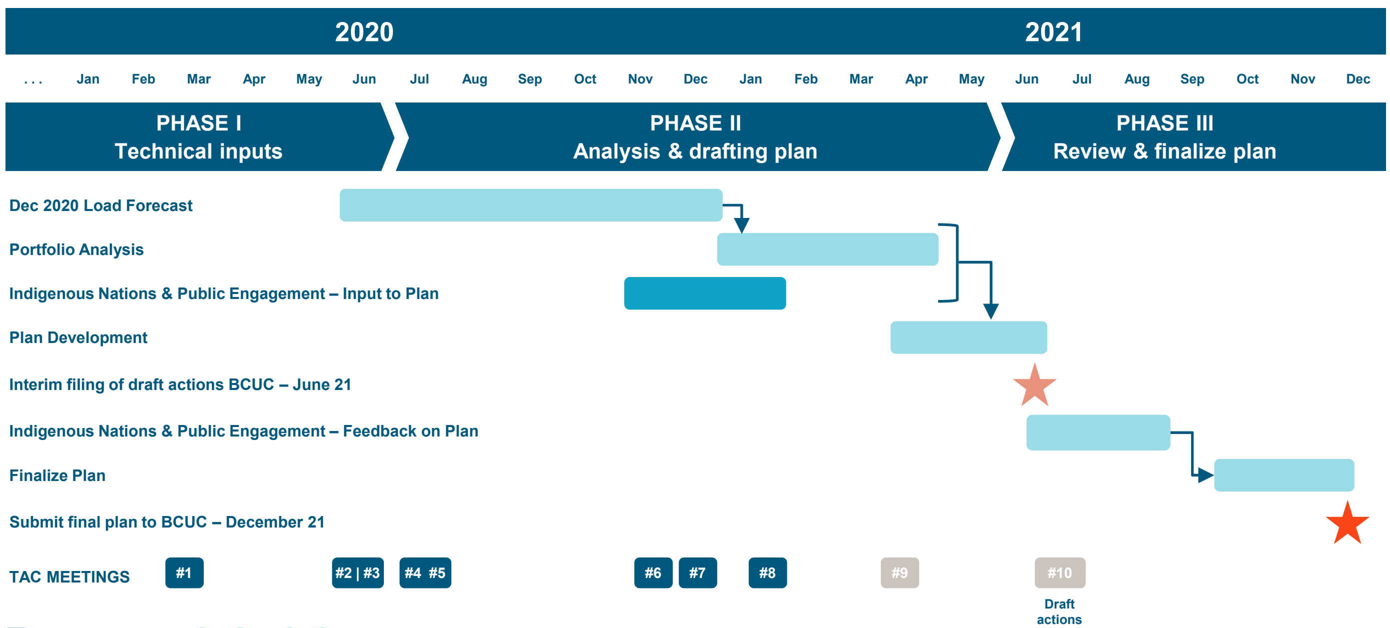
Audio connection trouble?
See the alternative options here

Agenda overview

9:00 START	TBD BREAK and LUNCH			3:00 END
Welcome & meeting context	Domestic non-firm / market allowance	Meeting future demand needs (South Coast)	Environmental attributes	Meeting close & next steps

Recap from last meeting – IRP 2021 schedule

We're resuming our fall consultation and presenting remaining inputs prior to analysis review



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Project updates

We’ve completed …

1. Updated Load Forecast and electrification scenarios for the IRP application
   - Which means we have our system outlooks and our regional outlooks
2. We’ve completed customer, public and Indigenous Nations Phase I consultation
   - TAC members invited to provide submissions based public survey (received four)
3. Portfolio analysis is underway
4. Engagement on electrification plan is next week
   - You should have received an invite (let us know if you haven’t)

Domestic non-firm / market allowance

Results and feedback

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SEE PRE-READ DOCUMENT

Recap: domestic non-firm / market allowance

In TAC meeting #7 we reviewed the concepts of a domestic non-firm / market allowance

- We're currently legislated to meet self-sufficiency requirement assuming heritage system average water conditions (Clean Energy Act S6(2))
- We've analyzed impacts under various planning positions if self-sufficiency requirement is removed
- The greater opportunity is to consider the energy allowance rather than capacity allowance for this IRP
- The analysis results presented today focuses on sourcing less / more of our long-term energy needs from a combination of domestic non-firm sources and the market

Domestic non-firm / market allowance in planning

We’ll review the analysis done to date

Analytical question

What is the volume of domestic non-firm / market allowance BC Hydro should rely on when developing the generation energy planning criterion in the absence of a self-sufficiency requirement?

Where…

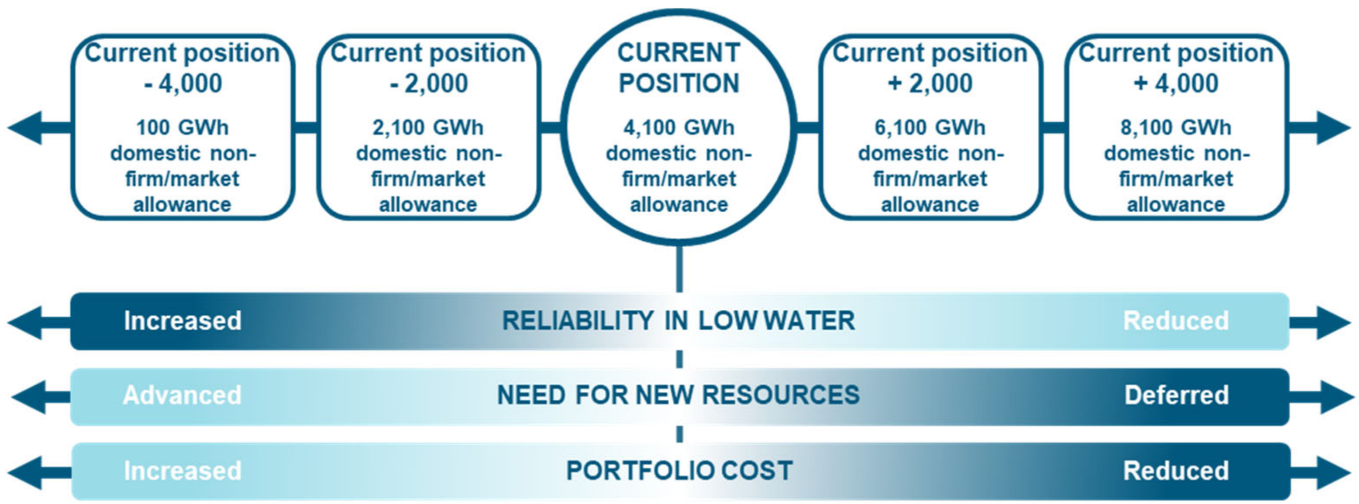
Domestic non-firm *is the portion of energy from renewable resources that cannot be accurately predicted on a year-to-year or seasonal basis*

Market imports *is energy sourced from outside the province*

Domestic non-firm / market allowance *is the combination of domestic non-firm energy and market energy that can be reliably counted upon to meet load*

Domestic non-firm / market allowances that were studied

A recap from TAC meeting #7 with the current allowance at 4,100 GWh under average water conditions



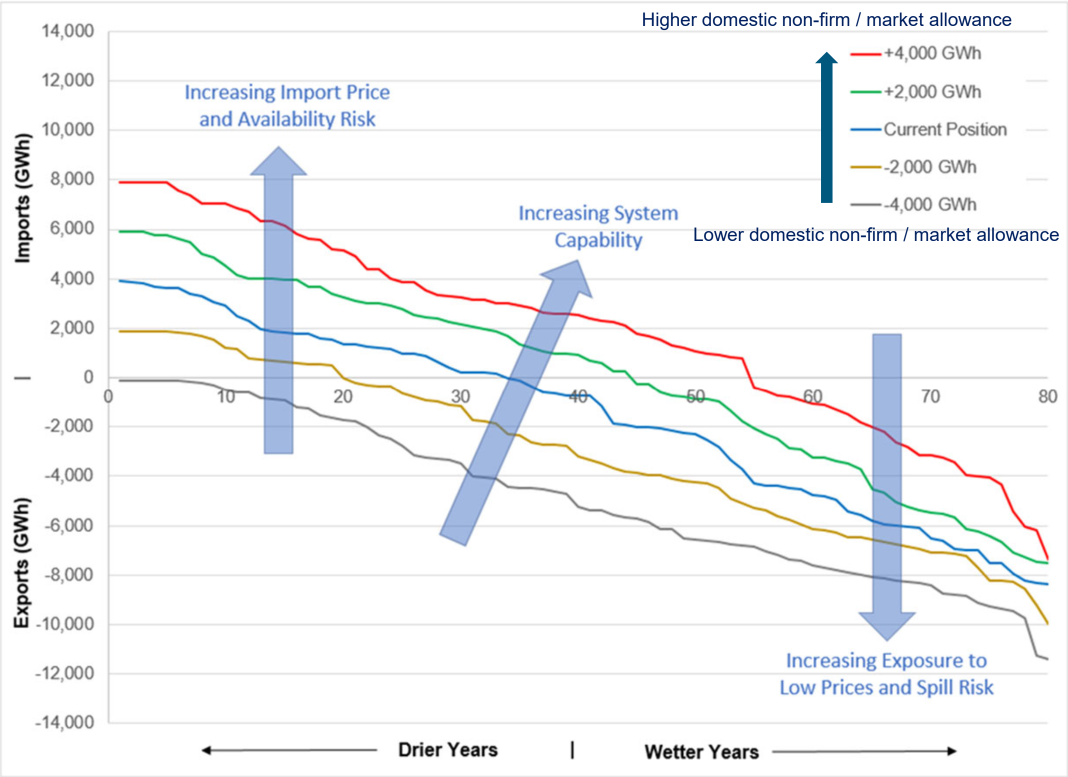
Factors guiding the use of domestic non-firm / market allowance

Multiple objectives are influenced by changes to the energy planning position, we'll walk through each in turn

- Reliability and operational flexibility
- Economics
- Indigenous Nations and economic development
- 100% clean electricity standard
- Any other?

Reliability and operational flexibility

Capability of the interties and market depth are considerations in the analysis



- The interties with external markets are about 2,500 MW considering the capability of both the US and Alberta interties.
- Market liquidity, desire to avoid lowest-priced periods for exports, highest priced periods for imports, and the ability of the BCH system to absorb imports place further practical limits on imports / exports.

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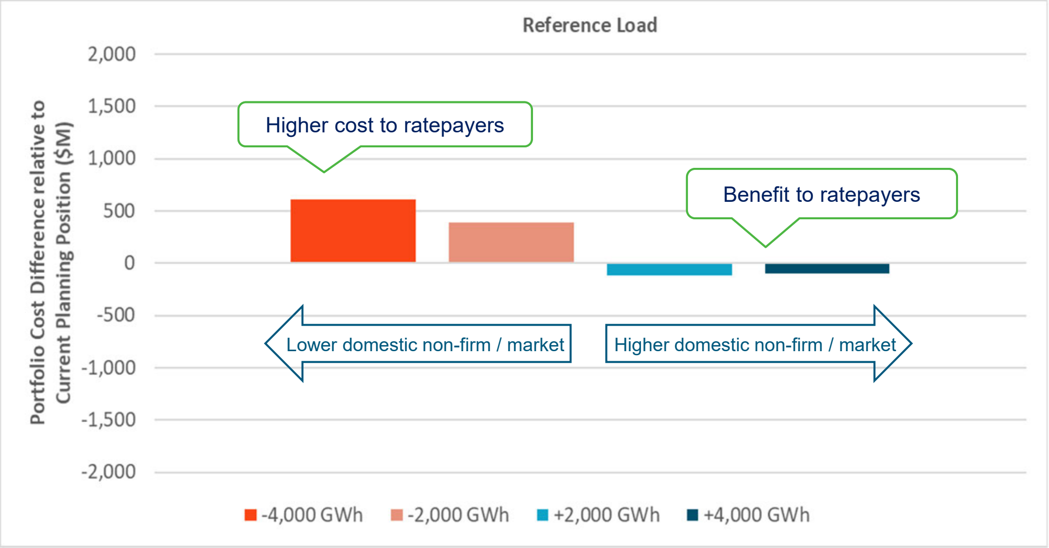
Economics

Opportunity cost of domestic non-firm and cost of market imports tend to be lower cost than acquiring new in-province energy resources



- The graph shows the net present value of the portfolio cost relative to the current position that could be expected over a 20-year period
- A higher market allowance (blue bars) that delays the need for new resources provides a financial benefit.
- The most recent system Load Resource Balances (LRBs) show a system-level surplus until the 2030s, which means we expect no immediate need for new resources. The future benefit of increasing domestic non-firm / market allowance shown here is masked by this period of energy surplus.

Indigenous Nations and economic development

An increase in the domestic non-firm / market allowance will defer the need for new energy resource developments within the province

- Higher levels of domestic non-firm / market allowance will reduce economic activity related to clean energy projects within the province
- Impact was assessed by looking at the jobs associated with the resource options making up the portfolios created for each domestic non-firm / market allowance position

100% clean electricity standard

Impact would depend on nature of future regulation

- Increasing the domestic non-firm / market allowance will result in higher volumes of imports in dry years
- This may require importing verified clean energy rather than unspecified energy in some years depending on the specifics of the standard

Summary of options

Comparing long-term market energy positions

Description of Alternative							
	Change in planning position (GWh/year)	**-4,000**	**-2,000**	**Current Position**	**+2,000**	**+4,000**
Reliability & Operational Flexibility	Months per year with imports >= 1,000 GWh (in a dry year)	0	2	3	3	5
	Months per year with imports >= 1,000 GWh (in an average year)	0.0	0.6	1.0	1.2	2.2
	Forced freshet exports (GWh/year in Q2)	1,300	1,200	700	700	200
	Years with system spill (%)	51%	46%	38%	33%	28%
	Average system spill (GWh/year)	1,500	1,200	800	500	500
Economic Benefits	Change in portfolio cost (NPV, $M)	$600	$400	-	($100)	($100)
Indigenous Nations & Economic Development	Change in clean energy sector jobs (person-years)	5,000	3,300	-	(1,700)	(2,500)

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Discussion & feedback

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Please share your feedback:

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Options to meet future demand needs

Lower Mainland | Vancouver Island (South Coast)

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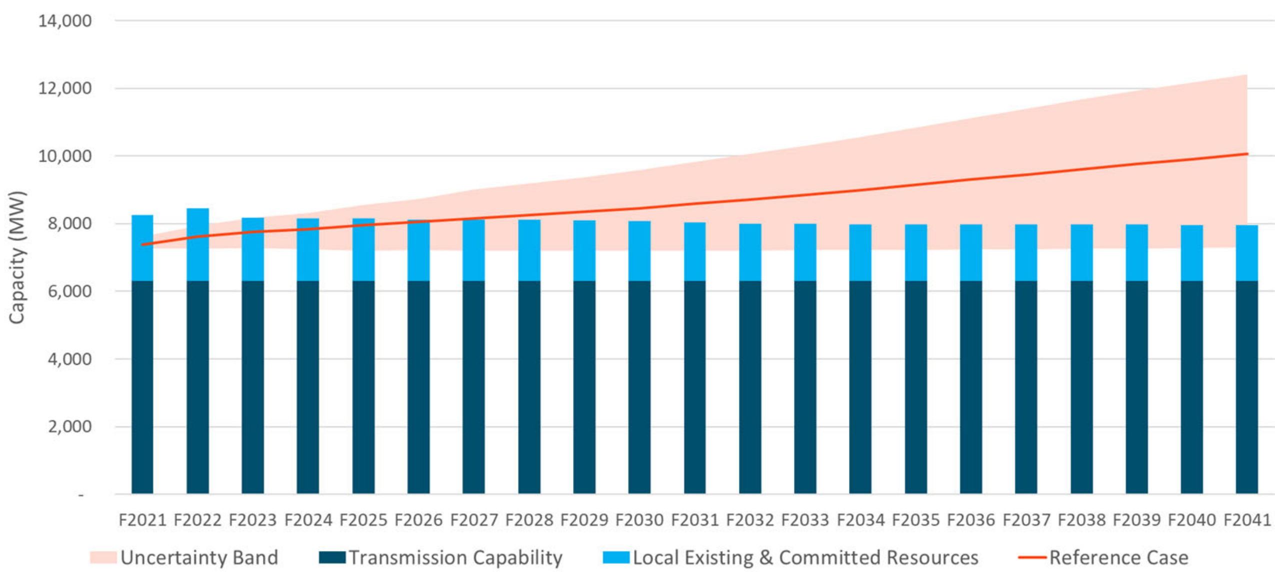
Lower Mainland / Vancouver Island (LMVI)

The regional load resource balance shows first year of need for capacity is F2027 under the reference load forecast, before future DSM and EPA renewals



A key driver of electricity demand growth in the region is due to electric vehicle charging under the Zero Emissions Vehicle (ZEV) mandate

SEE PRE-READ FOR DESCRIPTION OF OPTIONS

We start with demand-side options

We've expanded our demand side options available to provide (E)nergy and (C)apacity in LMVI which includes energy can capacity type options

Type	Resource Type	Examples in Lower Mainland / Vancouver Island
E/C	Demand-side – Energy efficiency	Base energy efficiency programs (incentives and education) Higher energy efficiency programs (more incentives and education) Higher plus energy efficiency programs (even more incentives) New construction programs
C	Demand-side – Time Varying Rates	Time of Use (Optional 'Opt in' and Default 'Opt out') Critical Peak Pricing
C	Demand-side – Demand response [paired to support rates options]	Direct load control programs Load curtailment Peak saver rebate programs
E/C	Other Distributed Energy Resources	Electric vehicle peak reduction programs Solar program

Electric vehicle (EV) peak reduction options

As electric vehicle charging drives customers' future increased electricity use in the Lower Mainland, options for shifting electric vehicle charging off of peak times have been created

Option name*	Options are combined with either 'opt-in' or 'opt-out/default' Residential Time of Use rate types	Features of the electric vehicle peak reduction program
35% target for EV load shifting	Opt-in	Simple marketing and education campaign to enhance EV-owner participation in responding to an optional residential ToU rate
50% target for EV load shifting	Opt-in	Advanced marketing and education, incentive and recruitment campaign coupled with an optional residential time of use rate
75% target for EV load shifting	Opt-out (default)	Education and customer smart charging technology incentives to support a default ToU rate

Reviewing DSM and rates options

The following slides provide the demand-side management options inputs

Inputs include:

- Potential energy savings (GWh/year)
- Potential capacity savings (MW)
- Costs of programs or initiative
    - Demand management costs are looked at in a couple of different ways

DSM options have two main cost definitions

Base analysis in the IRP is economic analysis using Net Total Resource Costs, but we also test other measures

Total Resource Cost (TRC) represents the total cost to BCH and customers:

- Includes costs incurred by customers; and
- BC Hydro program costs

Net total resource cost is the total resource cost minus non-electricity benefits to customers (e.g. reduced maintenance on their equipment) and benefits to BC Hydro (e.g. avoided costs of distribution and regional transmission costs).

Utility Cost (UC) represents the costs born by BC Hydro

Net utility cost is the utility cost minus benefits to BC Hydro from avoided distribution and regional transmission costs

DSM energy focused options – inputs

Net Total Resource Costs (NTRC) are used for base analysis

	MW in 2030 (province wide)	GWh in 2030 (province wide)	Total Resource Cost ($/MWh)	Net Total Resource Cost ($/MWh) *base assumption in analysis*	Utility Cost ($/MWh)	Net Utility Cost ($/MWh)
Base DSM	208	1224	71	12	45	34
Incremental Higher DSM	86	523	90	17	75	64
Incremental Higher DSM Plus	134	670	76	12	74	61
New Construction	7	33	175	157	132	117
Solar	0	29	168	168	138	138

DSM capacity focused options – inputs (before adjustments)

Capacity focused options include rate options paired with demand response, and new electric vehicle peak reduction (EVPR) options

Capacity focused option	MW in 2030 (province wide, before ELCC)	Total Resource Cost ($/kW-yr)	Net Total Resource Cost ($/kW-yr)	Utility Cost ($/kW-yr)	Net Utility Cost ($/kW-yr)
Suite 2 Rates with base demand response (opt in time of use)	288	61	16	75	30
Suite 3 Rates with higher demand response (opt out time of use)	536	43	6	39	3
Suite 4 Rates with higher demand response (opt out time of use)	1026	22	1	20	-1
Industrial load curtailment	89	34	-12	59	14
EV (35% target for EV load shifting)	64	14	-29	9	-34
EV (50% target for EV load shifting)	172	29	-8	11	-25
EV (75% target for EV load shifting)	332	23	7	28	11

DSM options capacity contribution assumptions

Capacity focused rates & demand response programs help reduce traditional system peak but would increase demand in other non-peak periods, potentially creating problems

Effective Load Carrying Capability (ELCC) of various options

- Rates Suite 2 with Base Demand Response & Peak Savers: 66%
- Rates Suite 3 with Higher Demand Response & Peak Savers: 54%
- EVPR (35% target): 63% (incremental to Suite 2)
- EVPR (50% target): 54% (incremental to Suite 2)
- EVPR (75% target): 24% (incremental to Suite 3)
- Industrial Load Curtailment: 100%

How to read the Effective Load Carrying Capability (ELCC) measure

Using Rates Suite 2 with Base DR as an example.

Its peak reduction saving is estimated at 288 MW (see the previous slide).

Its ELCC factor is 66%.

That means its contribution to capacity reliability is about 190 MW (= 288 x 66%).

This ELCC factor adjustment reflects the effect of this option on the load shape and its limited availability over the year.

Capacity options – additional cost adjustments

Two cost adjustments are made to the capacity inputs to understand the full cost to address Lower Mainland Vancouver Island need

				ADJUSTMENTS	
Example	MW in LMVI in 2030 (before ELCC)	Total Resource Cost ($/kW-yr)	Net Total Resource Cost ($/kW-yr)	LMVI adjusted Net Total Resource Cost ($/kW-yr)	ELCC LMVI adjusted Net Total Resource Cost ($/kW-yr)
Suite 2 Rates with base demand response (DR)	230	61	16	20	26

LMVI Adjustment Rates & Programs reduce (and must pay for) MW all over province, but only the fraction in LMVI (~75%) helps with the LMVI need

ELCC Adjustment Only 66% of “Suite 2 Rates with Base DR” MW contribute reliable capacity

Rate impact analysis to capture revenue losses

Demand-side management options all reduce BC Hydro revenue

- Energy efficiency options reduce overall customer consumption and energy sales
  - Estimates of reduced sales feed into rate impact analysis
- Capacity-focused rates and programs will shift customer consumption into off-peak periods where the tariff is lower
  - A high-level estimate of revenue loss associated with the Rate Suites and the EV Peak Reduction options will feed into rate impact analysis

Discussion & feedback

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Additional options to meet LMVI demand

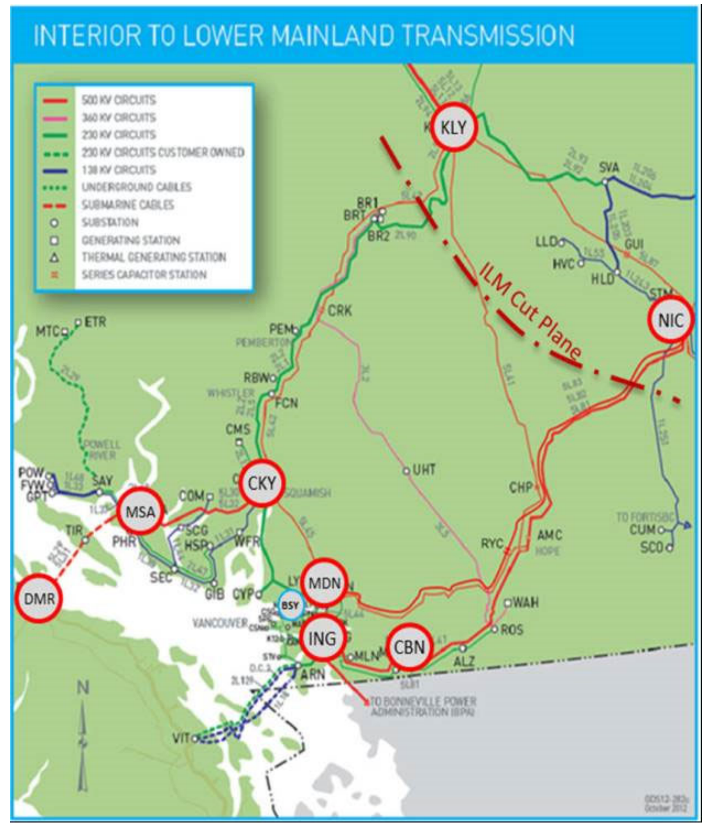
We'll now review generation and transmission supply side options to meet (E)nergy and (C)apacity needs in the Lower Mainland | Vancouver Island

Type	Resource Type	Examples in Lower Mainland / Vancouver Island
E/C	Demand-side – Energy efficiency	Power Smart programs, New Construction programs
C	Demand-side – Demand response	Direct load control programs, load curtailment, peak saver program
C	Demand-side – Rates	Time of Use, Critical Peak Pricing
C	Other Distributed Energy Resources	EV peak reduction programs
C	Transmission Expansion	Interior-to-Lower Mainland transmission reinforcements
E	Supply-side	Wind, Solar
C	Supply-side	Batteries, Pumped Storage
E/C	Supply-side	Small-storage hydro, biomass, geothermal
E/C	Heritage Expansion	Alouette, Wahleach
E/C	EPA Renewals	ICG, Biomass, RoR Hydro

Transmission reinforcements to South Coast

The results for transmission to the South Coast were grouped into three steps

- Given long lead times for transmission planning, the future options need to be considered now.
- The options have been prepared based on the initial IRP study portfolios and are draft results. A final analysis will be performed once the base plan is decided.
- The final BRP will inform both the bulk and regional transmission system requirements.



Transmission reinforcements to South Coast

Three stepped upgrades have been identified, with multiple projects in each step.

Grouping of upgrade options	MW	Lead time (approx)	Step description – what the upgrades are expected to include
Step #1	550	10 yrs	Series compensation, shunt capacitors, thermal upgrades
Step #2	700	10 yrs	Static VAR compensators
Step #3	500	10 yrs	New stations, transformers and more thermal upgrades

Note: final analysis may yield differences in selected projects and timing

Supply side options for LMVI – energy costs

Additional options have been assessed for costs and volume

Energy options		
Type	GWh	UEC By 2030 $/MWh
Wind	4,000	$68+
Solar	1,400	$70+

Capacity and Energy options			
Type	GWh	MW	UEC $/MWh
Storage hydro	2,900	550	$75+
Geothermal	1,600	250	$90+
EPA Renewal ICG	2,240	275	TBD
EPA Renewal other	749 by F2029	64 by F2029	TBD

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Supply side options for LMVI – capacity costs

Additional options have been assessed for costs and volume

Capacity supply options		
Type	MW	UCC By 2030 $/kW-yr
Utility Batteries	500+	115+ (over 200 if ELCC adjusted)
Pumped Storage	1000+	90+ (over 200 if ELCC adjusted)
Alouette	21	316
Trans. Reinforcement Step 1	550	101
Trans. Reinforcement Step 2	700	44
Trans. Reinforcement Step 3	500	93

Capacity and Energy options*		
Type	GWh	MW
Storage hydro	2,900	550
Geothermal	1,600	250
EPA Renewal ICG	2,240	275
EPA Renewal other	749 by F2029	64 by F2029

*Costs are expressed as $/MW on previous slide

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General reflections on analysis underway

Portfolio modelling is testing various levels of DSM and Rates options first

- Portfolios are developed for different levels of DSM and rates options, with a corresponding need for supply-side options including transmission to meet system and regional needs
- These portfolios allow us to systematically review each DSM elements (Energy Efficiency, Capacity focused Rates and programs, EV Peak Reduction)
- Today, we'll review the frame of SDM tables we're using to recommend the draft actions.
- A general observations on trade-offs allow a discussion with you about interests and gaps
- Modelled results are being reviewed internally, and so are not yet ready to be shared

Comparing options

Structured decision making tables highlight the key considerations to compare options

Cost	Present Value over 20 years, tested at mid and low market prices, and tested at higher and lower regional T&D avoided costs • Net Total Resource Cost (NTRC) • Net Utility Cost (NUC)
Cost Risk	• Under-delivery risk is captured here by a proxy measure of the MW difference between the mid and low savings estimates in F2030 • Schedule delivery risk for transmission by a proxy measure of ISD for ILM Expansion Step 2 – a project with an expected 10-year lead time. • PV of the amount of incentives provided under looser credit conditions for industrial customers
Rate Impact	• Cumulative incremental % increase
Environmental impact	• Scaled index of environmental footprint
Customer acceptance	• Captured by a binary measure as to whether residential default TOU rates are included or not

Preliminary observations – Energy Efficiency

Preliminary observations

Higher levels of Energy Efficiency DSM would be expected to:

- Improve financial metrics (across a variety of metrics)
- Delay the need for built solutions (T&D, energy, and capacity projects), and
- Delay or avoid environmental impacts of built solutions

But higher levels of Energy Efficiency DSM would also:

- Increase rate impacts
- Increase uncertainty around energy and capacity deliverability

DSM – Energy Efficiency (EE) option assessment

Structured decision making table framework

Objectives	Measures $Million Present Value (planning assumptions)	What is better? (Lower/Higher)	No EE programs	Base EE programs (current)	Higher EE programs	Higher Plus EE programs
Min Cost	$m PV (using net TRC, mid market)	Lower				
	$m PV (using net TRC, low market)	Lower				
	$m PV (using net UC, mid T/D benefit)	Lower				
	$m PV (using net UC, low T/D benefit)	Lower				
Min Cost Risk	Low scenario: MW below plan by 2030	Lower				
	In service date for Step 2 ILM Expansion	Higher				
Min Rate Impact	% increment over Base (F2030)	Lower				
	% increment over Base (F2041)	Lower				
Min Env Impact	Scaled Zonation Score	Lower				

UNDER CONSTRUCTION

Preliminary observations – rates and demand response

Preliminary observations

Higher levels of savings from rate design and supporting programs:

- Improve some financial metrics
- Helps defer the need for Transmission Upgrades
- Additional work is ongoing to better determine the level of program support needed for rate implementation

However, higher rates and supporting programs also:

- Increase uncertainty around savings delivery
- Increase rate impacts in the second half of the planning horizon
- Require default levels of rate design to achieve higher levels of savings (beyond Suite 2), which may not be acceptable to customers

Preliminary observations – EV peak reduction

Preliminary observations

Higher levels of savings from Electric Vehicle Peak Reduction:

- Improve financial metrics (across all ranges considered)
- Defer need for Transmission upgrades

However, increasing savings from Electric Vehicle Peak Reduction:

- Requires default-type rate designs for higher levels of savings, which risks customer acceptance
- Increases uncertainty around savings’ deliverability
- Increase rate impacts (but only in the latter half of the time horizon considered)

Discussion & feedback

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EPA renewals

EPA renewals also play a part in meeting future electricity needs

1. Modelling will not prescribe which EPAs to renew as actual renewals will depend on a number of factors (e.g. pricing, volumes, term)
2. Current information and preliminary modelling for Reference Load Forecast:
   - Retaining flexibility to re-evaluate options at a later time is expected to be cost-effective
   - Although a portion of the expiring EPAs are selected in portfolio modelling, not all EPAs are expected to be renewed
   - The number selected renewals increases under the Electrification load scenario
3. Actions on EPA renewals will include consideration of analysis results (technical, environmental, economic development) and consultation feedback

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Preparing for uncertainty

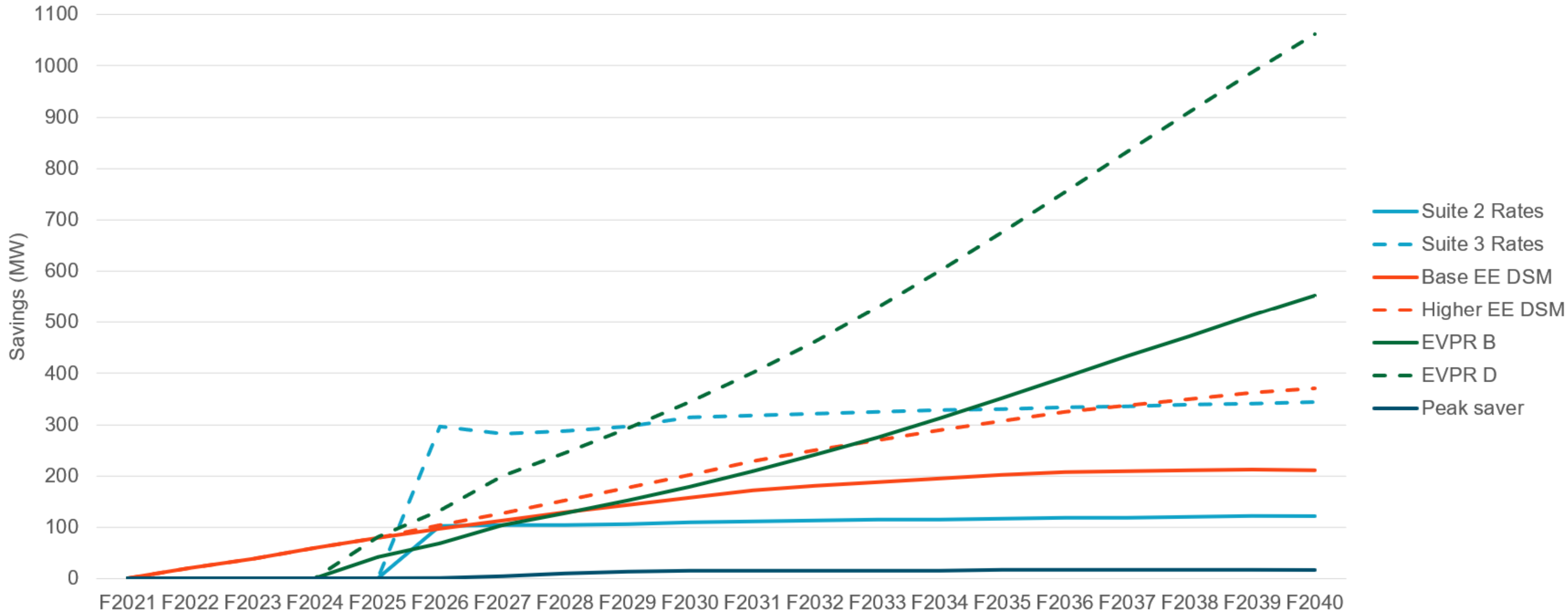
How do we prepare for higher, or lower, load growth (and other surprises)?

This section touches on:

- DSM delivery uncertainty
- Load uncertainty (electrification)
- Supply side uncertainty

DSM lead times and volumes

Savings beyond base energy efficiency likely won't materialize until F2026 or verified until F2028



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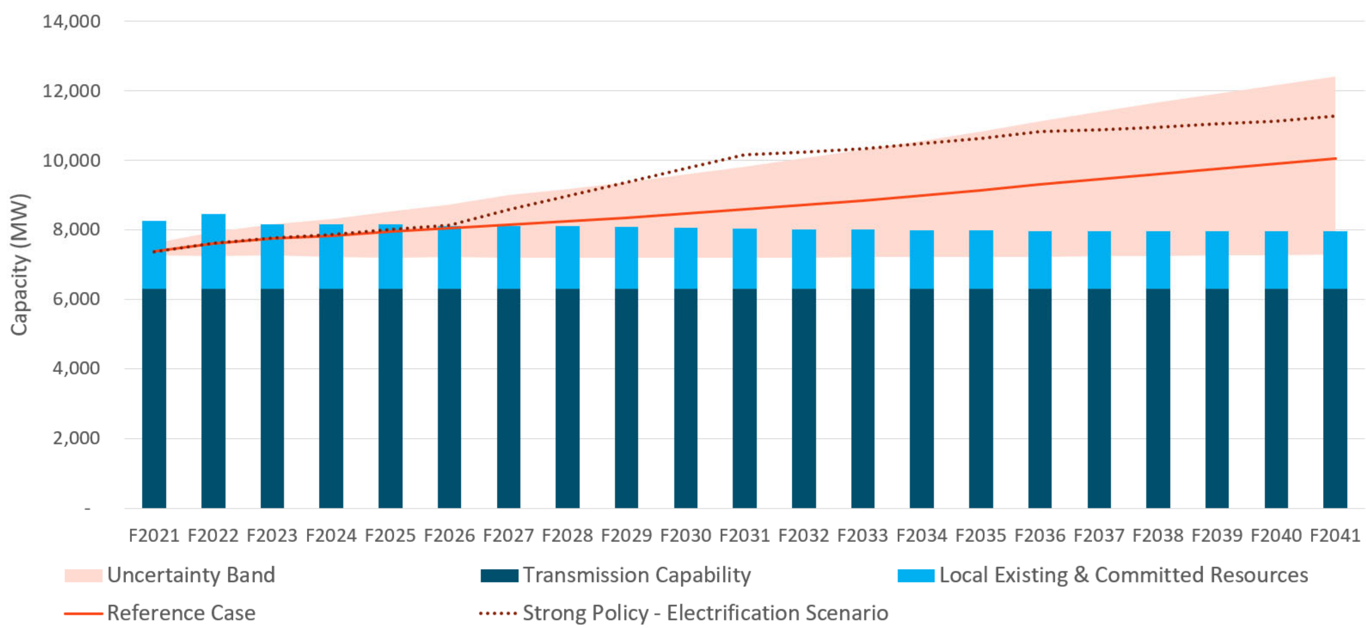
LMVI LRB uncertainty – load scenarios

Electrification may add about another 1,000 MW by F2030



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Any additional resource options to meet electrification?

Additional DSM/Rates options will depend on the type of end uses being electrified

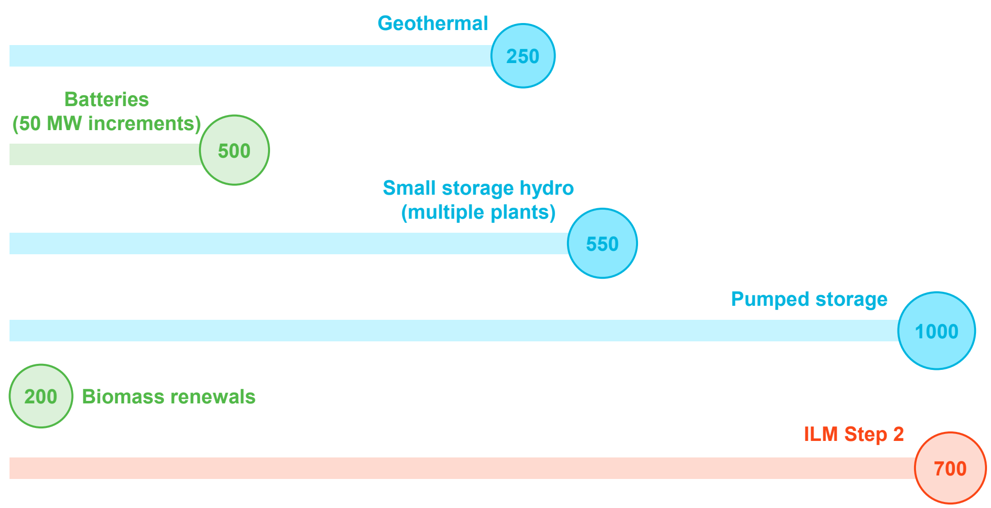
1. **Electric vehicle loads:** Higher or faster EV growth results in greater potential for EV peak load reduction. Higher EV peak reduction estimates based on accelerated EV uptake.
2. **Water heater | space heater | heat pump loads:** Increased potential for direct load control has not been assessed. This would be considered during implementation. Rate models are unable to estimate increased potential based on end-use, but residential load growth under electrification scenarios offers a slight increase in rate suite potential.
3. **Gas/LNG loads:** No opportunity – assume load growth is efficient already and load is 24/7.

Resources for uncertain higher load

Timelines and start times become important if load growth ramps up, assuming next IRP decision would be after Jan 1, 2028

Uncertainty and timelines

Balances the cost of starting some projects in advance of need versus the value of having resource in time to meet higher load.



Supply side option uncertainty

Supply options also have uncertainties, related to their costs, volume and timing

- EPA negotiation outcomes
- Capital cost uncertainties
- Lead times can be highly uncertain (e.g. ILM upgrade)
  - Land, environmental issue, Indigenous Nations consultation
  - Prudent to consider starting some built options in advance of load growth signals
  - Value of reducing lead time / uncertainty may be high

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Environmental analysis

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Discussion & feedback on pre-read material

Please share your feedback:

- Clarification needed on this material?
- Do you have feedback for BCH on this material?

Next steps

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Next steps

Analysis is underway, with a draft plan being submitted in June

- BCUC interim filing of draft IRP expected late June
- Will provide rationale and portfolio modelling results of actions
- Will engage with TAC on the draft IRP
- TAC members will be asked to provide written submissions on the draft plan