BC Distributed Energy Resource Potential Study

Final Report

CLEAN ENERGY CANADA

dunsky Energy + Climate

February 2026

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ACCELERATING THE CLEAN ENERGY TRANSITION

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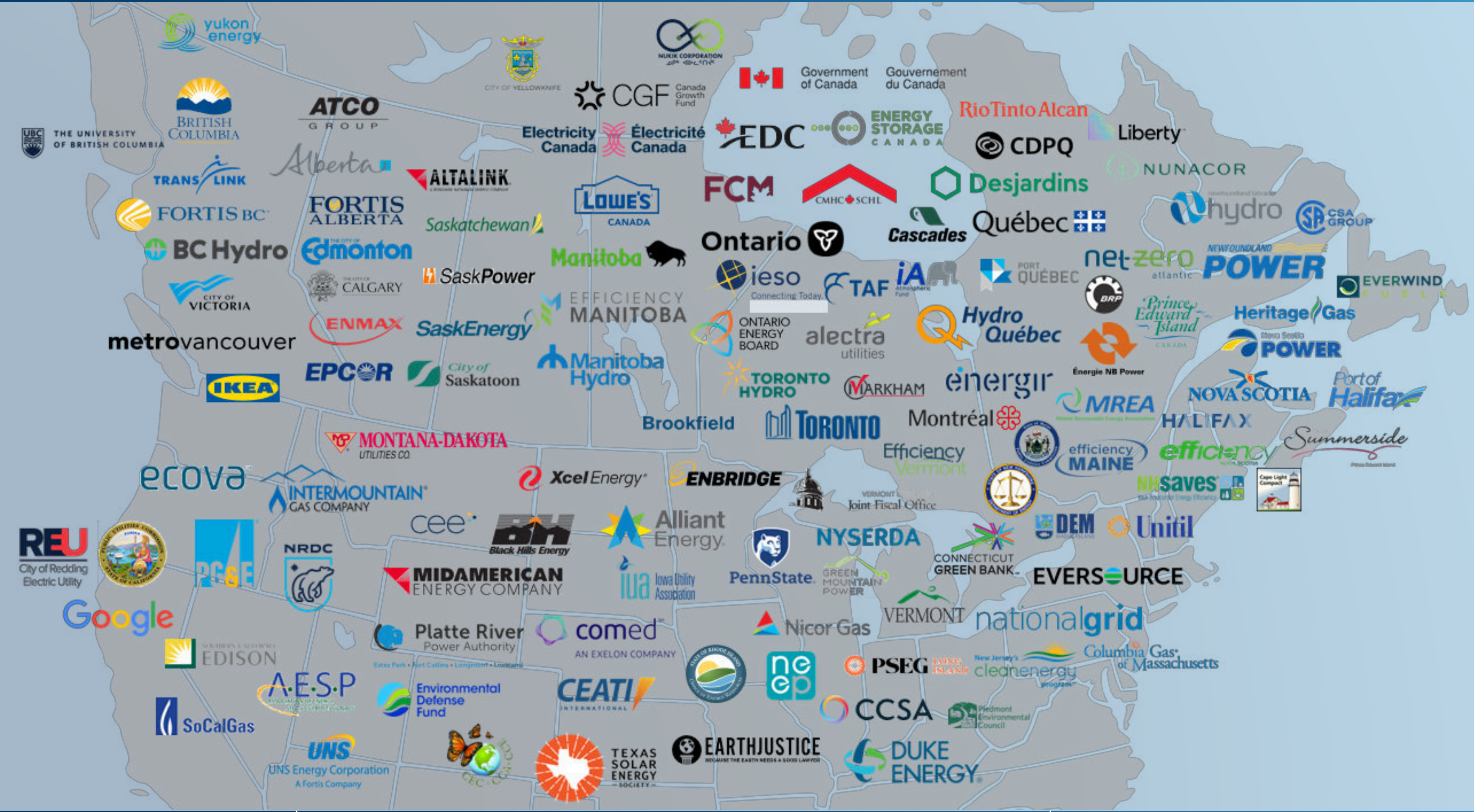

GOVERNMENTS

UTILITIES

CORPORATE + NON-PROFIT

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Background

What are DERs and why they matter

- Distributed Energy Resources (DERs) are technologies that are connected to the electricity distribution system behind a customer's meter that generate energy, store energy, or control load.
- Common DERs include distributed energy storage, flexible space and water heating loads, electric vehicle (EV) load management, and dispatchable load curtailment.
- DERs can provide multiple system benefits, including:
  - Peak capacity reduction
  - Improved system flexibility and reliability
  - Potential cost deferral of transmission and distribution system investments
- DERs can help meet BC's increasing electricity needs, which are driven by market growth and the electrification of key energy end uses (i.e. mining, EV adoption, space/water heating), with BC Hydro projecting an average of annual load growth of 1.4% over the 2025-2050 horizon.[1]

Current state of load flexibility in BC

- Demand Response (DR) programs in BC currently deliver **<1%** of capacity savings relative to the electric peak load of BC Hydro and FortisBC.[1]
- Current programs focus on residential direct-load control (smart thermostats, water heater, EVSE, storage) as well as C&I curtailment and storage.

Comparison with other jurisdictions

- Other analogous jurisdictions show that more may be possible.[2]
  - Hydro-Quebec: 5.5% [2024-2025]
  - Niagara Mohawk Power Corp. (National Grid): 3.9% [2023]
- BC Hydro's 2025 Integrated Resource Plan (IRP) projected 270 MW (**1.9%** of peak) of demand response and time-varying rate capacity savings **by 2030**.

1. BC Hydro 2025 IRP - 70MW as of the end of FY 2025, with a system peak of over 11,000 MW.
2. Percent of peak demand. Benchmarking of other jurisdictions available on Slide 31.

Objectives

Study Objectives

- **Identify** technically feasible, cost-effective DERs that are appropriate to meet the needs of BC's electricity grid.
- **Quantify** the technical, economic and achievable potentials for DERs over the 2025-2040 period.
- **Assess** the impact of electric demand growth and policy support on DER potential through scenario analysis

Scope and Limitations

- This study is focused on the **demand side impact** of DERs, as represented by the potential capacity benefits they offer.
- The analysis **focuses on DERs' ability to reduce peak demand**, but does not fully account for supply side limitations such as prolonged electricity generation shortfalls, or additional DER benefits such as ancillary services or energy arbitrage.
- **Further work** – including deeper engagement with BC Hydro and integrated portfolio modeling – would be required to determine more **granular locational and distribution level benefits**, and how to best align DER deployment with **supply-side needs**.

Study Scope

Customer archetypes

Residential

Single Family

Multi-unit

C&I

Small Commercial

Large Commercial

Industrial

Study horizon: 2026-2040

This timeframe broadly aligns with BC Hydro's long-term planning horizon (20 years), while remaining close enough to support near- and mid-term policy, program, and investment decisions without relying on highly uncertain long-term assumptions.

Measure List

Residential

- BTM battery storage
- Smart thermostat (electric furnace)
- Smart thermostat (HP)
- Smart thermostat (electric resistance)
- Water heater controls (resistive)
- Water heater controls (HP)
- EV managed charging
- Vehicle-to-grid (V2G)

C&I

- C&I thermal storage
- Commercial curtailment
- Industrial curtailment
- BTM battery storage
- Buses load control (Smart charging and V2G)
- C&I Baseboard Smart Thermostat

Measures selected represent a high-level yet comprehensive set of commercially available technologies, consistent with those considered in comparable DER studies. New and emerging DER technologies that could be deployed over the study period were not extensively considered due to their inherent uncertainty.

Scenarios

This study assesses the potential for DERs in BC under three different scenarios:

1

Reference

What will be the potential for DERs under business-as-usual policies and market conditions?

2

Accelerated

How much more could DERs contribute in a high electrification future?

3

DER-Centric

How much could DERs contribute if they were prioritized as a primary solution to meet increasing electricity demand in BC?

Scenario Design

	1 Reference	2 Accelerated	3 DER-Centric
Load Growth / Electrification	Reference load scenario [1]	Accelerated electrification load scenario [2]	
Programs and Policies	Business-as-usual incentives and market conditions [3]		Strong policy support

1. Reference load scenario based on BC Hydro 2025 IRP Reference Load Scenario.
2. Accelerated electrification scenario builds on BC Hydro's 2025 IRP Reference Load Scenario, but assumes higher load growth driven by more ambitious EV adoption (drawing on Dunsky's Powering Up study from August 2025) and by deeper electrification of space and water heating required to meet legislated 80% decarbonization target. For more detail, see Section 2.
3. Business-as-usual policies reflect current programs, with the addition of two new programs. For more detail, see Section 2.

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Methodology

DER **potential** can be expressed in several ways:

Potential	Definition	Constraints
Technical	The total capacity of all controllable load devices	Reflects the quantity of controllable loads on the system, but does not consider system needs
Economic	The portion of controllable loads that offers cost-effective load reduction opportunities	
Achievable	The portion of controllable loads that can realistically be enrolled in initiatives.	Reflects both enrolled capacity and projected potential considering opt-outs, overrides, connectivity issues, and other factors that may reduce performance during peak events
Effective	The resulting system-wide peak load reduction, accounting for utility load shape constraints	Reflects the actual peak load reduction experienced by the utility, considering all hours of a typical peak day

Understanding Potential – Illustrative Example

Enrolled Capacity

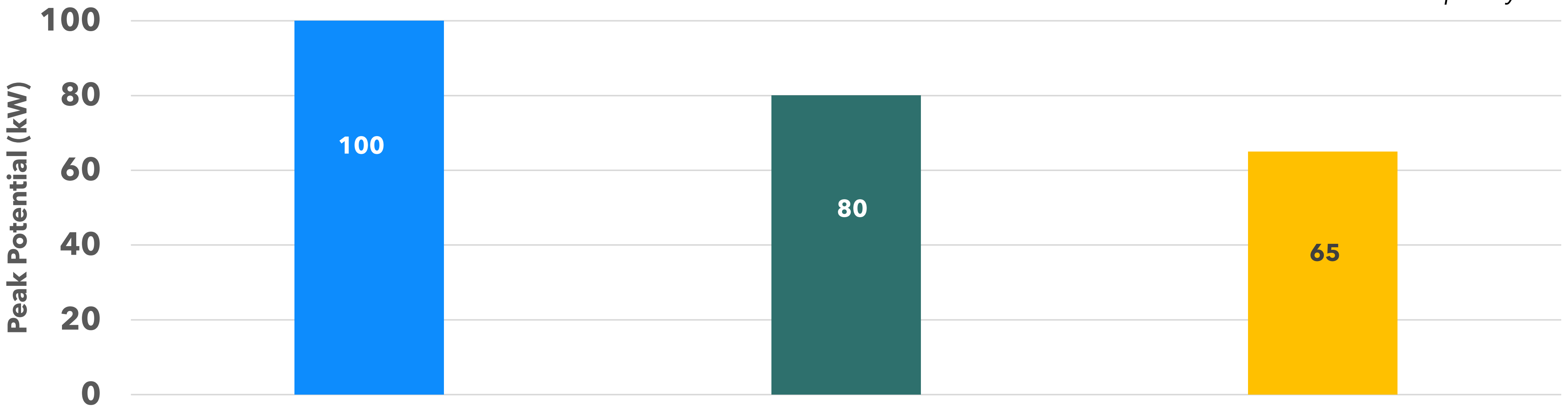
100 devices enrolled and able to curtail 1 kW on average (accounting for the peak load diversity factor)

Achievable Capacity

Of the 100 enrolled devices, some may opt out of a given event, or may have telemetry issues, so the actual achievable capacity is lower than the enrolled

Effective Peak Load Reduction

However, when load curve interactions are considered (i.e. new peak timing) the resulting effective peak reduction will typically be lower than the theoretical achievable capacity



Methodology

- **The standard peak day was derived by scaling BC Hydro's historical load data – based on the top 10 peak days in each year – to the peak demand forecast from the IRP.**
  - Net new load was added (EV, Solar, Heat Pumps)
  - The analysis is then completed on that peak day.
- **Measures were classified into two distinct types:**
  - **Type 1:** Constrained. Measures that exhibit notable pre-charging/rebound within the same day as the DR event.
    - E.g., Water heater control
  - **Type 2:** Unconstrained. Measures that do not demand bounce-back and therefore are not constrained by the addressable peak.
    - E.g., Battery energy storage
- **Type 1 measures are applied to the peak window, while Type 2 measures are optimized to lower the peak at any time.**

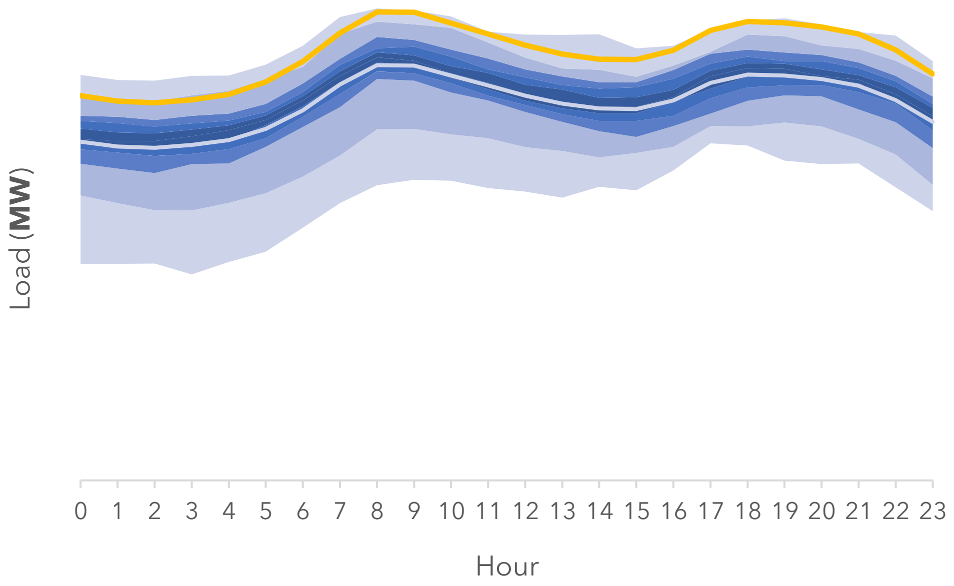
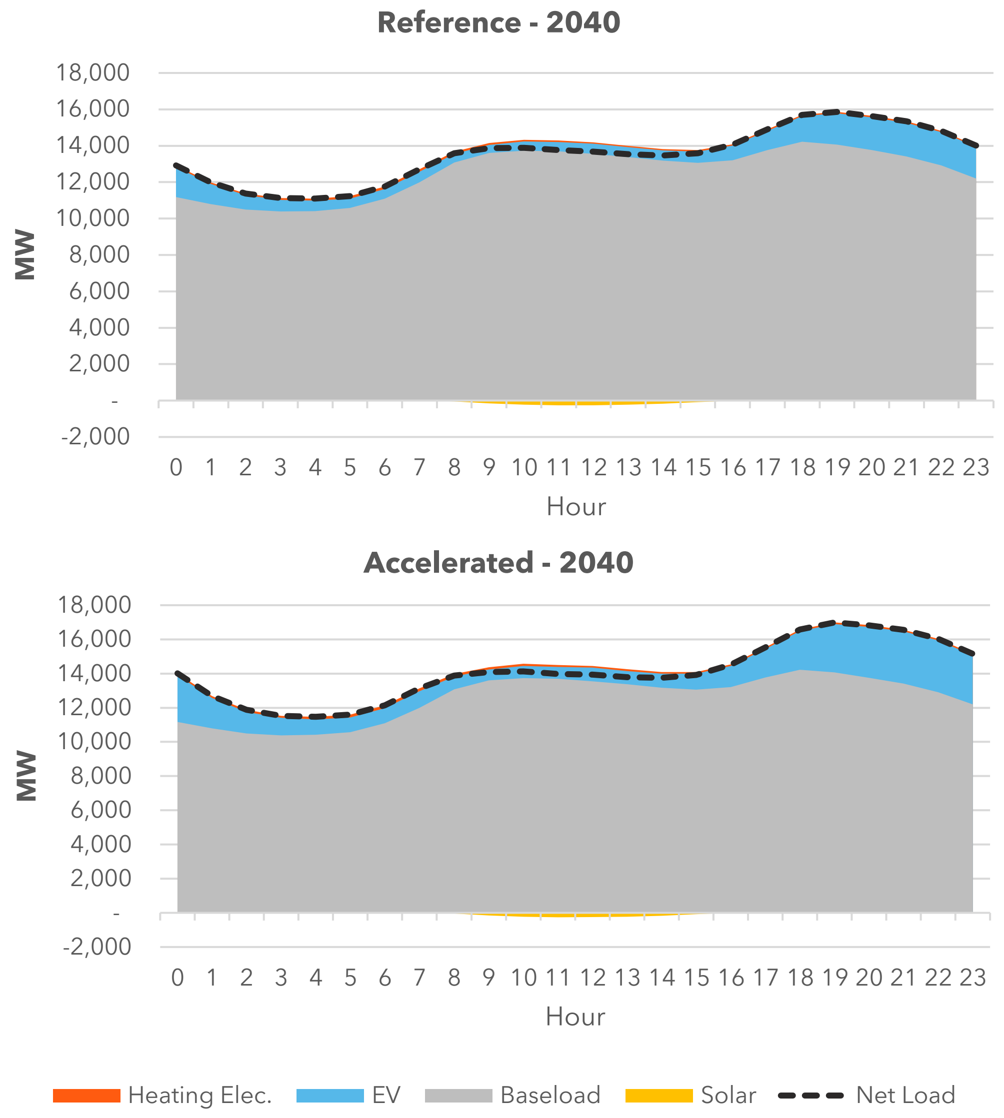


Figure: Illustrative Example of a standard peak curve analysis. Each blue shading area represents a 10-percentile gradient.

Load Growth Inputs & Assumptions

Further electrification added to the baseline for the Accelerated & DER-Centric scenarios, to illustrate the potential for DERs in a high electrification future.

		1 Reference	2 Accelerated	3 DER-Centric
Electric Space and Water Heating	**Assumption**	Aligned with BC Hydro's 2025 IRP	Adoption is aligned with BC's Economy-wide 80% GHG reduction target by 2050 (from 2007 level)	
	Impact relative to Reference	N/A	2040 morning peak increase: ~0.3% 2040 evening peak increase: ~0.1%	
Solar PV *From BC Hydro's Solar Potential Study*	**Assumption**	Aligned with Incentive Program Scenario (Medium)	Aligned with Policy Support Scenario (Max)	
	Impact relative to Reference	N/A	2040 noon peak decrease: ~0.8%	
Electric Vehicles	**Assumption**	Aligned with BC Hydro's 2025 IRP	Powering Up [Dunsky] (High Growth scenario)	
	Impact relative to Reference	N/A	2040 morning peak increase: ~3% 2040 evening peak increase: ~7%	



Measure Inputs & Assumptions

Market-sizing and adoption assumptions tailored to each technology and DER measure.

- **Solar + Storage:** Solar PV has a low coincidence factor with BC Hydro's peak demand hours. However, the study accounted for the impact of BTM Solar PV adoption on BC Hydro's hourly utility load curve and assessed the opportunity that solar paired with battery storage offers to shift solar power to meet BC Hydro's peak needs.
- **EV Managed Charging:** EV adoption is expected to contribute significantly to peak load growth in BC. This study accounts for EV's emerging peak load contribution, applying inputs and assumptions that are informed by BC Hydro's Public EV Charging Evaluation Report, including:
  - Share of residential EVs charging at home
  - Share of network-connected chargers
  - Share of Level 1 & Level 2 chargers[1]
- **Vehicle-to-Everything (V2X):** V2X (bi-direction charging) technology readiness is scaled over time, with most vehicles assumed to be V2G-ready by 2035.[2]
  - All other technologies covered in this study are assumed to have already reached market maturity.

For all measures, DER program participation rates reflect realistic levels (ranging from 2% to 35%), informed by real-world data. Full details are provided in the Appendix.

1. Level 1 chargers are leveraging a standard 120V circuit. Level 2 chargers are using a 240V outlet.
2. For the purposes of this study, V2X technology includes vehicle-to-grid (V2G) and vehicle-to-building/home (V2H/V2B).

Program Inputs & Assumptions

In the **Reference** and **Accelerated** scenarios, we used BC Hydro's existing incentives and programs as the baseline, with two additional programs:

- **Vehicle-to-Everything (V2X):** V2X incentives are assumed to gradually become available for buses and residential light-duty vehicles (LDV). While no program currently exists, BC Hydro has committed to developing programs as V2X-capable vehicle adoption increases.
- **Commercial baseboard:** Eligibility for BC Hydro's electric-resistance heating load-control incentives was expanded to include commercial customers. This adjustment was tested to determine whether a simple eligibility expansion of an existing program would generate additional DER potential; however, the resulting impact is negligible.

For the **DER-Centric** scenario, two new programs were added:

- **BES direct install:** Utility-funded direct installation of battery energy storage (BES) systems for net-metering (NEM) solar customers.
- **Control-ready water heaters:** Starting in 2030, building code requires new water heaters to be compatible with load-control technologies.*

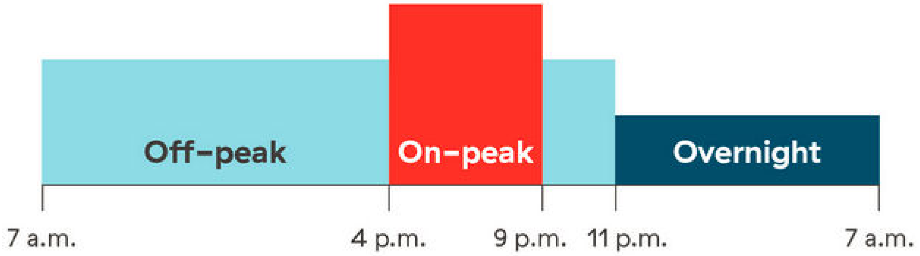
These additional programs are not an exhaustive list of possible options, but were selected based on demonstrated cost-effectiveness, high impact, and technical feasibility.

	1 Reference	2 Accelerated	3 DER-Centric
Existing Programs	Residential Peak Saver program: $50/year ($250/year for batteries) incentive, plus an enrollment bonus ($100 to $500, based on the device) Commercial DR program: 50$/kW Commercial Energy Storage: 80% of installation costs		Incentives were increased to maximize potential, while maintaining program cost-effectiveness. See Appendix B for details.
New Programs	V2X for buses and residential LDV Commercial baseboards load control		All **Reference** & **Accelerated** programs BES direct install for Solar NEM customers Control-Ready Water Heater Code Standards

* Program participation was fixed at 35% of the control-ready water heaters.

BC Hydro's Residential Time-of-Use Rate

- This study modeled BC Hydro's existing time-of-use (TOU) rate (+/- 5¢/kWh - flat rate 12.6 ¢/kWh)



- The current TOU rate structure is designed to primarily target EV owners, with limited benefits for other participants.*
- The TOU reduces the incremental benefits of active EV load management, as the rate design already captures a portion of this value by encouraging off-peak charging through price signals. Cost-motivated customers participating in active EV load management are often also on the TOU rate and may already be charging outside the peak window.
- About **62% of EV owners charge at home**. 32% have a networked Level 2 charger and 30% have a non-networked Level 2 charger, leaving 38% with a Level 1 charger.

*More details on rate design considerations for DERs on slide 28.

Assessing DER Cost-Effectiveness

About the Utility Cost Test

- DER Measures were selected based on their cost-effectiveness to BC's energy system, using the **Utility Cost Test (UCT)**.[1]
- **The UTC evaluates cost-effectiveness from the utility's perspective** by comparing program costs to avoided supply-side resource costs.
- In this study, the test compares the cost of DERs (including program administration and incentives) to the avoided cost of both generating capacity and transmission and distribution (T&D) capacity.
- This cost-effectiveness test was selected as it is aligned with the test used by BC Hydro, as required by the British Columbia Utilities Commission (BCUC).
- UCT is one of several tests that utilities and program administrators can use to assess cost-effectiveness across North America.

Measure Cost-Effectiveness

- Avoided cost benefits were quantified **based on each measure's contribution to peak capacity reduction**. We then assessed the collective cost-effectiveness of the DER portfolio for each scenario, accounting for the effective load reduction delivered by the measures.
- An individual measure is considered cost-effective if, from the utility's perspective, **its cost is lower than the avoided cost of the counterfactual resource**. In this case, the counterfactual is the cost of generating and delivering new capacity, including transmission and distribution (T&D) infrastructure. This assessment does not evaluate customer-level economics or bill impacts.
- Customer bill savings and incentives were assessed separately, as these inform assumptions about DER technology adoption and program participation. However, these factors are not included in the UCT assessment itself.

Understanding Avoided Cost

What is an avoided cost?

- Avoided cost represents the estimated value to a utility (e.g., BC Hydro) of reducing system peak demand or deferring system investments. It reflects **the cost the utility would otherwise incur** to add equivalent capacity.
- Avoided cost values are utility-specific, and are typically updated through formal planning processes (e.g., Integrated Resource Plans or resource adequacy assessments). These costs vary over time based on system conditions, demand forecasts, reserve margins, and the cost of new supply options.
- Across North America, avoided capacity costs have **in many cases increased in recent years,** reflecting rising demand and increasing conventional generation equipment costs.
- **Avoided capacity cost provide a measure of DERs' value to the system, but do not capture the full range of DER benefits** (see Slide 20 for more detail).

What are BC Hydro's avoided costs?

- BC Hydro's 2025 IRP reports a **capacity avoided cost of $410/kW-yr**, which includes both the avoided generation ($300/kW-yr) and the transmission and distribution costs ($110/kW-yr).
- This represents a **significant increase** over the previous value of $202/kW, as reported in BC Hydro's 2021 IRP.
- BC Hydro's current capacity avoided costs are at the upper end of the range observed among Canadian utilities. However, even if these values were revised downward in the future, this may not impact DER cost-effectiveness, as there are several unquantified value streams that DERs can provide (See Slide 20). Additionally, many of the DERs evaluated in this study exhibit levelized costs per kW that are materially below the current avoided capacity costs.

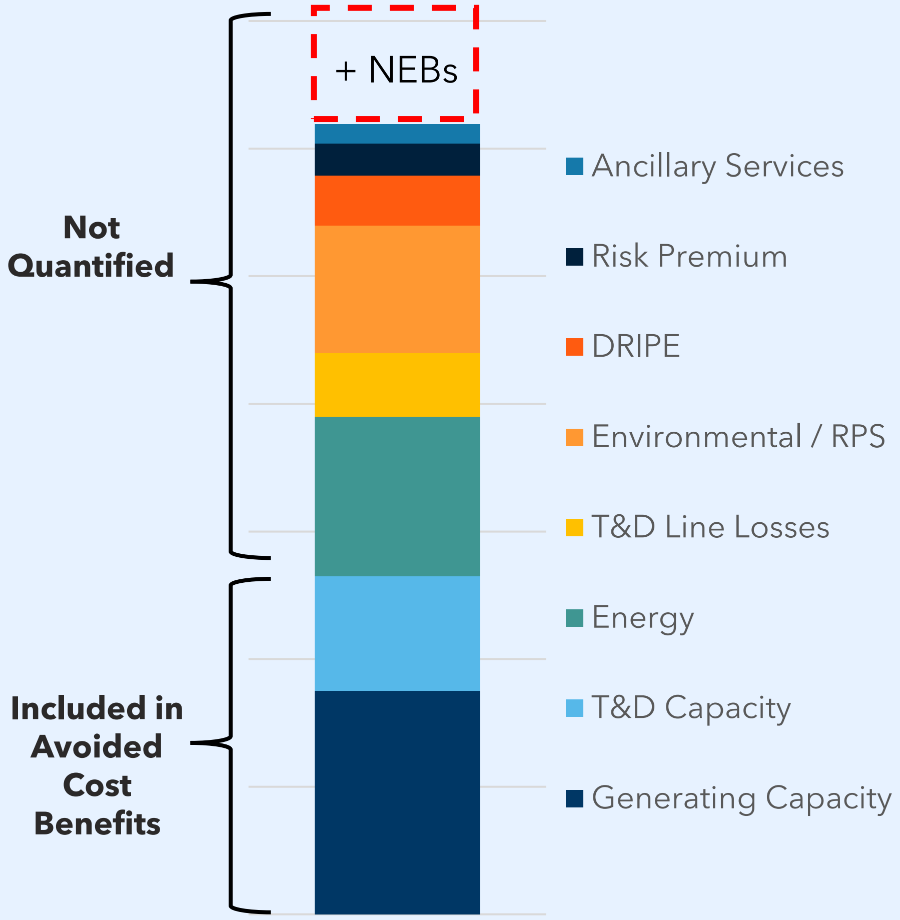
DER Value Stack – Other Benefits

Some DER value streams were not accounted for in this study, as they are not included in BC Hydro's capacity avoided cost. These include:

- **Energy**: Avoided marginal cost of generating or procuring electricity (kWh) that a DER offsets through on-site production or load reduction.
- **T&D Line Losses:** Avoided cost of T&D system losses that occur as electricity is delivered from centralized generation to end users, which DERs reduce by serving load locally.
- **Environmental / Renewable Portfolio Standard (RPS):** Monetized value of avoided emissions and contributions RPS compliance obligations attributable to DER generation.
- **DRIPE (Demand Reduction Induced Price Effect):** The wholesale market price suppression effect resulting from DER-driven reductions in system demand, which lower clearing prices for all customers.
- **Risk Premium:** Avoided cost of hedging against fuel price volatility and other market uncertainties, reflecting the risk mitigation value of fixed-price or zero-fuel-cost DERs.
- **Ancillary Services:** Grid support services—such as frequency regulation, voltage control, spinning reserve, and ramping—that some DERs can provide to maintain system reliability and power quality.
- **Non-Energy Benefits (NEBs):** Quantifiable and non-quantifiable societal and participant-level benefits beyond direct energy savings, such as improved health outcomes, comfort, resilience, and economic development.

These additional value streams, if quantified, would strengthen the case for DER deployment.

Typical DER Value Stack



This figure is illustrative only. The relative sizes of value components are an approximation and do not represent actual or modeled values.

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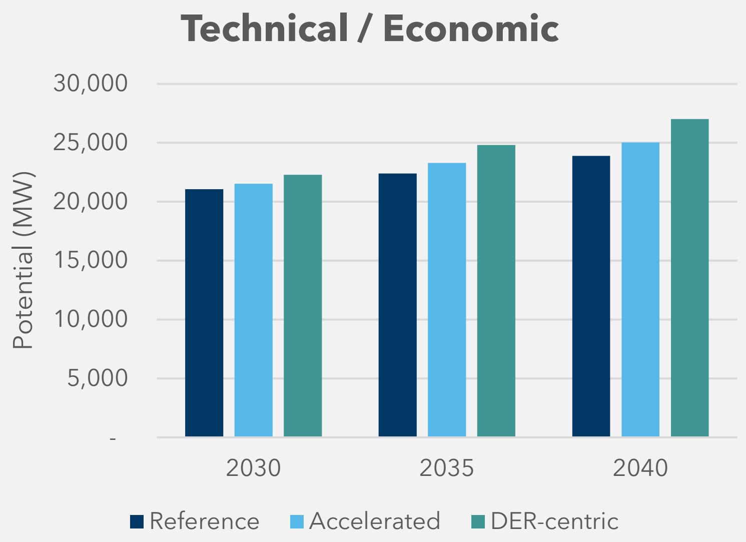
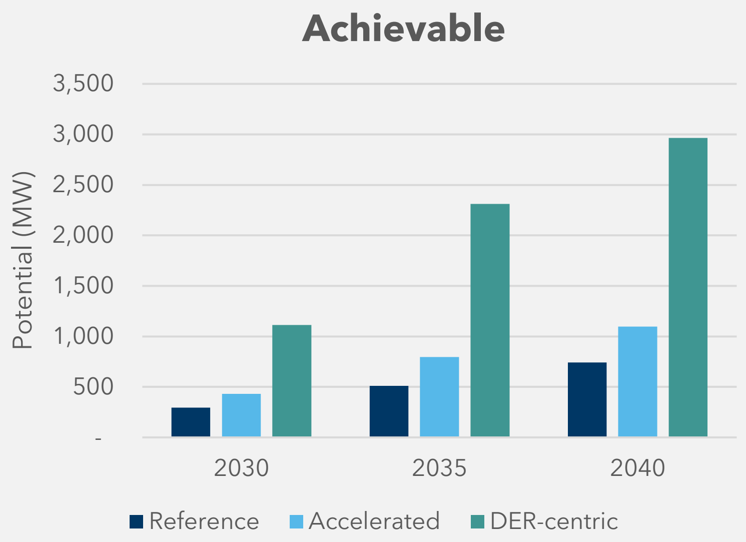
Scenarios Comparison – Potential

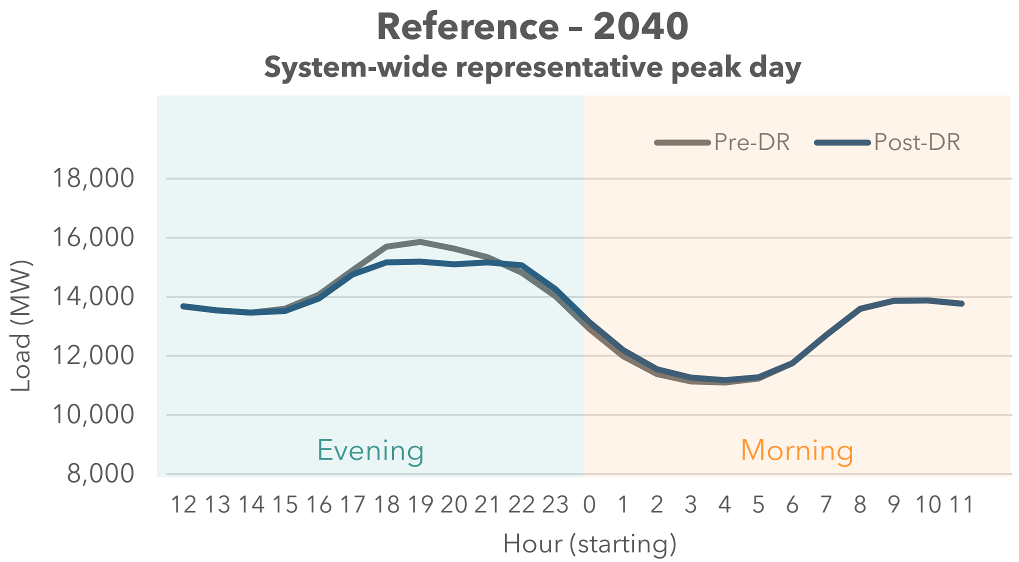




Scenario	Achievable Potential in 2040 (MW)	Effective Peak Load Reduction in 2040 (MW)	Effective Load Reduction Capacity
Reference	740	669	90%
Accelerated	1,097	926	84%
DER-Centric	2,966	1,758	59%

- BC Hydro's avoided capacity costs are sufficient that each individual measure, in isolation, proves to be cost-effective in this study. As a result, technical potential and economic potential are equivalent across all three scenarios.
- Effective peak load reduction in 2040 ranges from 669 MW in the **Reference** scenario (4.2% of peak) to 1,758 MW (10.4% of peak) in the **DER-Centric** scenario.
- As demand response potential increases, longer DR event durations reduce the share of achievable DER capacity that can effectively target peak demand (effective load reduction capacity). In the **Reference** scenario, 90% of the 740 MW achievable potential is available to reduce peak demand, while in the **DER-Centric** scenario, only 59% of the achievable 2,966 MW can effectively reduce annual peak demand, resulting in 1,758 MW effective peak load reduction.

Reference Scenario



- By 2040, about **670 MW (4.2% of peak)** of effective peak reduction can be achieved
- Most of the **potential is attributed to EV** load control by 2040

Measure Group	Achievable Potential (MW - 2040)
Residential EV Load Management	402
C&I Curtailment	152
Residential Storage	74.1
Residential Space Heating	53.6
Residential Water Heating	26.0
C&I Storage	20.9
Residential TOU, Others	7.1
Commercial EV Load Management	4.0
Commercial Space Heating	0.2

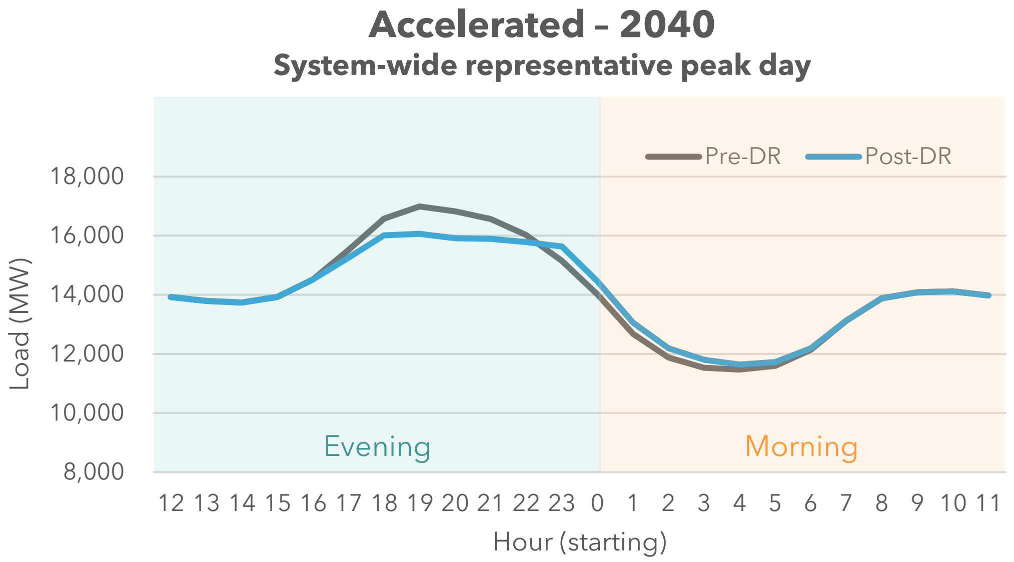
This scenario largely aligns with BC Hydro 2025 IRP DER projections

~160 MW potential from Residential control

~400 MW potential from EV load control measures

~170 MW potential from C&I control

Accelerated Scenario

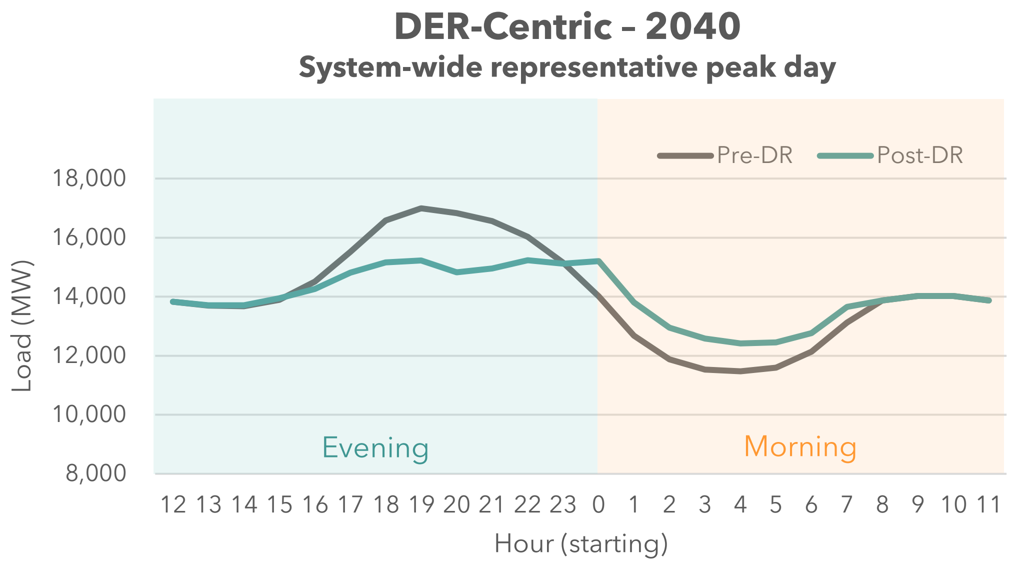


- Aggressive **electrification adds 1,100 MW** to the peak compared to reference scenario
- By 2040, about **930 MW (5.5% of peak)** of effective peak reduction
- **EV** load control potential **increases from about 400MW** (reference) **to 680 MW**
  - V2G represents 2/3 of the EV load control potential [1]

Measure Group	Achievable Potential (MW - 2040)
Residential EV Load Management	679
C&I Curtailment	181
Residential Storage	77.5
Residential Space Heating	63.4
Residential Water Heating	52.0
C&I Storage	28.7
Residential TOU, Others	12.0
Commercial EV Load Management	4.0
Commercial Space Heating	0.3

1. As noted on Slide 15, V2G is the only technology included in this study that has not yet reached full commercial maturity, resulting in greater uncertainty regarding its future potential relative to other measures. This uncertainty reflects assumptions about the timing and scale of V2G adoption. However, V2G and unidirectional EV load management (smart charging) target overlapping peak-demand MWs; if V2G adoption is delayed, a share of this potential would be expected to be captured through conventional active EV charging.

DER-Centric Scenario



- By 2040, about **1,760 MW (10.4% of peak)** of effective peak reduction
- Widening peak window reduces marginal DR value
- **The two new programs** (NEM customer battery and Control-Ready Water Heater Code) **yield a 1.5 GW potential increase**

- **Increased incentives improve** the adoption of load control for **EV, C&I curtailment, and energy storage.**
  - ~**2.0 GW** achievable potential from **Residential** sector
  - ~**1.0 GW** achievable potential from **C&I** sector

Measure Group	Achievable Potential (MW - 2040)
Residential Storage	793
Residential EV Load Management	718
C&I Storage	638
C&I Curtailment	351
Residential Water Heating	308
Residential Space Heating	142
Residential TOU, Others	12.0
Commercial EV Load Management	4.0

Scenarios Comparison – Program Costs

- Achieving the DER potential outlined across the modeled scenarios requires increased program spending.
  - Program costs primarily consist of incentive costs (>75% of total cost), but also include non-incentive costs, such as the cost of direct-install equipment and cost to run programs.
  - Upfront equipment and enrollment incentives range from 35% (**Reference**) to 63% (**DER-Centric**) of the total incentive costs. The remaining share is annual participation incentives.

- Table below shows the estimated program cost per kW, for both achievable potential and effective peak load reduction in 2040.

Scenario	Achievable Potential in 2040	Effective Peak Load Reduction in 2040
Reference	117 $/kW	130 $/kW
Accelerated	107 $/kW	127 $/kW
DER-Centric	243 $/kW	404 $/kW

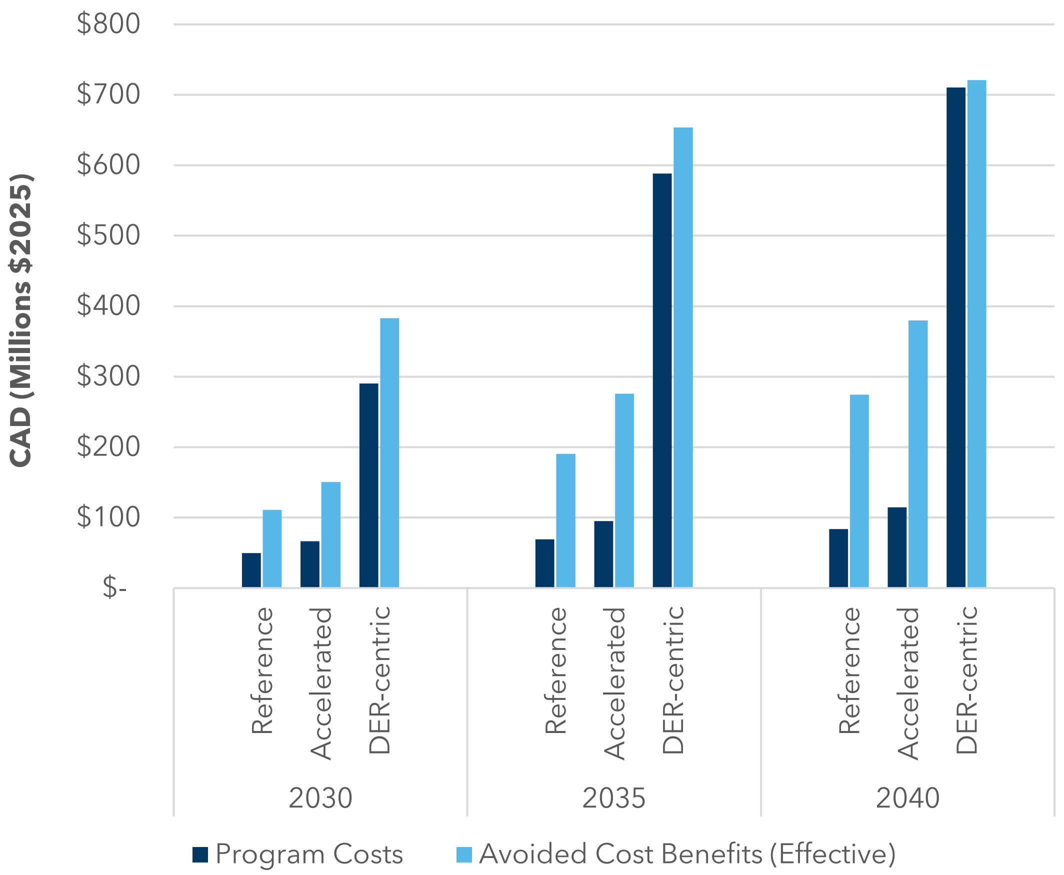


Figure: Total program costs and assessed avoided cost benefits, across each scenario.

Note: All program and avoided costs are expressed in 2025 dollars. Costs considered include incentive costs; fixed costs, such as full-time equivalent (FTE) staffing and software required to administer and operate the programs; and variable costs, such as Distributed Energy Resource Management Systems (DERMS), manual customer outreach (e.g., phone calls and emails), and other program-related operational expenses.

Scenarios Comparison – Program vs. Avoided Costs

- Across all scenarios, avoided cost benefits exceed program spending (See chart on Slide 26)
  - In the **Reference** and **Accelerated** scenarios, avoided cost benefits substantially exceed program costs, with the benefits more than double the costs across all modeled years.
  - In the **DER-Centric** scenario, benefits and costs are more closely aligned, reflecting the deliberate increase in program incentives toward the upper bound of cost-effectiveness.
- In all scenarios, programs costs (whether for achievable potential or effective peak load reduction) were lower than BC Hydro's avoided cost value of $410/kW.
- The high avoided costs raises the ceiling on what is considered cost-effective, enabling more DER measures and more ambitious program design.
- Ancillary services benefits were not quantified, but could further support the cost-effectiveness of some measures, particularly the extensive Battery Energy Storage and Controllable Water Heaters measures in the **DER-Centric** scenario.

Scenario	Effective Peak Load Reduction in 2040	*BC Hydro Avoided Cost*
Reference	$130/kW	*$410/kW*
Accelerated	$127/kW	
DER-Centric	$404/kW	

Note: All program and avoided costs are expressed in 2025 dollars

Comparison with BC Hydro's 2025 IRP

- BC Hydro has achieved **70 MW of demand response capacity savings** by the end of FY2025. It now projects that demand response supported by voluntary time-varying rates will reach **270 MW by FY2030**, including 100MW from EV load control.
- The **Reference** scenario is **generally aligned with BC Hydro's projections.** However, Dunsky is expecting EV load control to reach 65MW by FY2030 and exceed 100MW in FY2032, two years after BC Hydro's target.
  - The current TOU participation level data were not available to calibrate the model for this study. The DR model participation is therefore based on meta-studies of TOU penetration rates across multiple jurisdictions. BC customers could behave differently from the average TOU customer, and/or BC Hydro may be tapping into more enthusiastic customers, exceeding participation expectations in the first few years of deployment.

	Capacity Load Resource Balance (MW) *2025 IRP's Table B-2*	**Achievable Potential (MW)** **Reference** *Scenario*
Demand Response + Residential TOU - FY2029	270	289
Industrial Load Curtailment - FY2029	70	74
Total	**340**	**363**

Behind-the-Meter (BTM) Solar PV

dunsky

Treatment of Solar in DER Potential Study

- Solar is accounted for in the load shape (see slide 15), based on the solar adoption analysis done by Dunsky.
- Solar adoption was not modelled in this study, but the impact of BC Hydro's projected solar adoption was applied to the utility load curve, recognizing that it is not a dispatchable resource and cannot be called during peak events.
- For winter peak conditions, solar provides limited direct peak reduction, as generation declines rapidly after ~16:00 with sunset.
- Solar PV adoption increases BC Hydro's overall generation capacity, and can offer pre-charge/recharge opportunities for other DERs (such as battery storage), particularly during the afternoon, following the morning peak events, and prior to evening peak events.

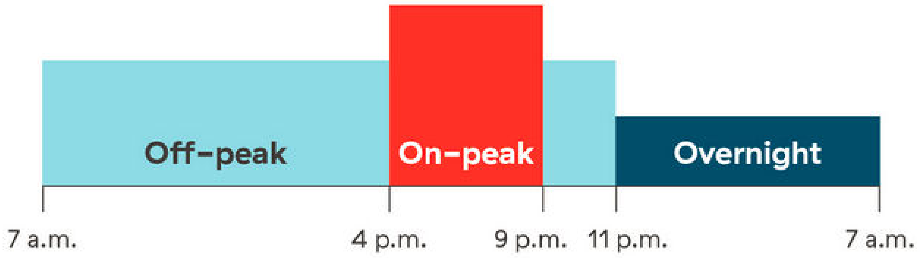
Considerations for Solar in BC

- BC Hydro's energy-constrained, hydro-dominant system context increases the potential value of solar paired with storage, even if standalone solar provides limited winter peak contribution.
- Cold, high-pressure winter peak events, which can lower wind generation on BC Hydro's system, are typically associated with clear skies. Thus, net-metered solar paired with storage can offer a valuable load replacement option.
- Under the **DER-Centric** scenario, solar-plus-storage shows notable potential to enable energy shifting into critical evening hours, reinforcing its role as a complementary resource rather than a standalone peak solution.

Hour	Solar Production (Winter Peak – 2040 – DER-centric)
0:00 to 6:00	0
7:00	2
8:00	61
9:00	207
10:00	320
11:00	370
12:00	364
13:00	323
14:00	250
15:00	119
16:00	9
17:00	2
18:00 to 23:00	0

Rate Design Considerations for DER Potential

- **Current TOU rate structure in BC is primarily oriented toward EVs and provides limited incentives for other DERs.**
  - With a delta of +/- 5¢/kWh (10¢ difference between the on-peak and overnight rates), battery systems are not likely to discharge for arbitrage benefits, as the spread does not sufficiently cover battery costs.
  - DER solutions, other than EVs, can benefit from the current rate structure:
    - Thermal energy storage
    - Dual-fuel heating (natural gas, wood, etc. to reduce on-peak demand)



- **TOU Rate design adjustments that could increase DER participation include:**
  - Introducing the lowest off-peak rates immediately prior to, or following peak rate window can allow time-constrained DERs (such as electric space and water heating load flexibility) to participate more effectively.
  - Battery storage would require an increase in the peak-to-overnight price ratio to offset the roundtrip efficiency losses and the cycling degradation.

Rate design is one mechanism that enables DERs, and can be complementary to other load control solutions (such as BC Hydro Peak Saver)

Benchmarking

- This study's results are broadly consistent with DER peak contribution estimates reported by other North American utilities and system operators, as shown in the table below. The **Reference** and **Accelerated** scenario results (4.2% and 5.5% of peak load, respectively) fall within the range observed across jurisdictions, reflecting differences in system characteristics, DER scope, and whether results represent realized impacts or forward-looking potential.
- The 10.4% peak load reduction in the **DER-Centric** scenario is at the upper end of observed ranges but is comparable to high-potential scenarios in peer studies, including the IESO potential study (9% in 2032) and the Northwest Power & Conservation Council assessment (9.6% in 2041). This result reflects the strong policy and programmatic support assumed under the **DER-Centric** scenario.
- Hydro-Québec provides a particularly relevant comparator for this study, as it operates a predominantly hydroelectric system with seasonal and operational constraints similar to those faced by BC Hydro. Hydro-Québec's demand response portfolio is dominated by commercial and industrial load control (~77% of its peak contribution), while residential programs also provide a meaningful share of peak reduction through direct load control (~9%) flexible rates (~14%).

	British Columbia DER Potential Study	Hydro-Quebec	NB Power	Niagara Mohawk Power Corp. (National Grid)	IESO (Winter Peak)	Northwest Power & Cons. Council	Duke Energy (DEC & DEP)
Portion of Peak Load	**4.2% - 10.4%**	5.5%	3.9% - 6.5%	3.9%	4 – 9%	9.6%	4.0%-4.4%
Type	**Potential (2040)**	Actual (2024-2025)	Potential (2040)	Actual (2023)	Potential (2032)	Potential (2041)	Potential (2041)
Release Year	**2026**	2025	2025	2024	2022	2021	2020

All comparisons are for winter peaks

Summer Peak Impacts

Much of the potential evaluated in this study can also be leveraged in summer, however, the potential of key measures changes seasonally:

- **Electric Vehicles:**
  - Summer energy usage is expected to decrease (no heating, relatively mild AC, etc.). This leads to less charging, and therefore less DR potential.
  - Note that V2G is the exception, leaving more energy in the battery when a car is back home to be used by the utility.
- **Heating:**
  - Space heating does not contribute to summer peaks, however, controllable heat pumps that are used for cooling can contribute to summer peak reduction.
  - Water heating needs are similar across the year, but a higher water input temperature in summer lowers the peak reduction benefits.
- **Battery:**
  - Battery energy storage is not expected to be affected by seasonality.
- **Non-Residential Curtailment:**
  - AC loads are expected to replace a good part of the heating loads. Curtailment can vary widely by segment and end-use, and its effects could depend on the composition of the pool of participants.

Key Measures	Summer Potential
V2G	↗
EV Managed Charging	↘
EV TOU	↘
Space Heating	↓
Water Heating	↘
Non-Res Curtailment	→
Battery Storage	→

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Key Takeaways

1. **BC Hydro is on solid footing for expanding DER contributions.** The **Reference** scenario forecasts roughly 670 MW of effective peak reduction by 2040 (4.2% of peak). This scenario aligns closely with the DER contributions projected in BC Hydro's 2025 IRP through 2030 and reflects meaningful progress supported by the utility's current programs and planning. However, these results also rely on the assumption that BC Hydro follows through on its commitment to introduce V2X participation opportunities as V2X-capable vehicles become more common.

2. **Avoided cost for capacity have risen substantially – rendering *all* individual DERs cost-effective.**[1] Given BC Hydro's updated avoided costs of capacity ($410/kW-year, up from $202/kW-year in the previous IRP) every DER measure included in this study is cost-effective, meaning that economic DER potential is equivalent to technical potential. This also supports much higher incentive levels for DERs, as assessed under the **DER-Centric** scenario.

3. **With stronger incentives, the role of DER's in meeting BC's emerging grid needs could be transformative.** The **DER-Centric** scenario yields a *~90% increase* in potential compared to the **Accelerated** scenario, demonstrating that there is room to unlock significantly more DER capacity. This would entail ambitious policies such as code requirements for controllable water heaters, and fully paid batteries for all solar NEM customers, ultimately moving DERs from a supplemental resource to become a central load growth solution that can be rolled out instep with BC's decarbonization efforts.

1. It is important to note that this does not imply that all DER measures are cost-effective at all times or under all conditions (e.g., when multiple measures are called in combination). In practice, only a subset of measures may be cost-effective at a given time, depending on system needs and other variables.

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Results by scenario

An Excel file was provided with this report, which contains a table of potential, for each year, for each measure.

Load Forecast

Year	Reference Load Forecast (MW)	Accelerated & DER-Centric Load Forecast (MW)
2026	11,832	11,945
2027	12,119	12,314
2028	12,221	12,506
2029	12,528	12,898
2030	12,810	13,290
2031	13,048	13,637
2032	13,332	14,028
2033	13,652	14,432
2034	13,950	14,805
2035	14,330	15,225
2036	14,724	15,624
2037	15,031	15,986
2038	15,311	16,322
2039	15,594	16,664
2040	15,861	16,992

Cumulative EV Forecast

Year	Residential LDV (Reference)	Residential LDV (Accelerated & DER-Centric)	Commerical LDV	MDV	HDV	Buses
2026	86,777	253,192	15,314	341	114	788
2027	97,087	383,562	17,133	546	182	1,038
2028	113,441	533,714	20,019	751	250	1,337
2029	155,037	696,040	27,359	1,024	341	1,587
2030	212,631	869,981	37,523	1,228	409	1,889
2031	286,579	1,055,592	50,573	1,501	500	2,035
2032	375,458	1,250,608	66,257	1,774	591	2,181
2033	510,200	1,454,532	90,035	2,047	682	2,194
2034	667,694	1,664,818	117,828	2,252	751	2,207
2035	848,298	1,878,778	149,700	2,525	842	2,220
2036	1,052,721	2,086,851	185,774	2,798	933	2,239
2037	1,204,883	2,299,449	212,626	3,002	1,001	2,259
2038	1,349,934	2,506,088	238,224	3,275	1,092	2,278
2039	1,487,520	2,708,229	262,503	3,411	1,137	2,297
2040	1,616,573	2,905,144	285,278	3,548	1,183	2,316

EV Load Control Inputs

Year	Share of V2G ready EVs	Smart Charging Incremental Cost Decrease	V2G Incremental Cost Decrease
2026	15%	100%	95%
2027	25%	100%	91%
2028	35%	100%	84%
2029	45%	100%	75%
2030	55%	97%	68%
2031	65%	93%	59%
2032	75%	90%	48%
2033	85%	87%	39%
2034	95%	83%	29%
2035	100%	80%	21%
2036	100%	77%	21%
2037	100%	73%	20%
2038	100%	70%	19%
2039	100%	67%	19%
2040	100%	63%	18%

WH Code Standard Deployment - DER-Centric Only

Year	Share of Smart Water Heater (Code Standard)
2026	0%
2027	0%
2028	0%
2029	0%
2030	10%
2031	20%
2032	30%
2033	40%
2034	50%
2035	60%
2036	70%
2037	80%
2038	90%
2039	100%
2040	100%

Program Inputs

Program	Included Measures	Fixed Costs	Variable Costs
Commercial Curtailment - Auto	Commercial Curtailment – Auto-DR	$180,000	$50 / participant $ 60 / participant (DER-centric)
Commercial Curtailment - Manual	Commercial Curtailment - Manual	$420,000	$5 / participant
Industrial Curtailment	Industrial Curtailment	$180,000	$10 / participant
Commercial DLC – Energy Storage	BTM Battery Storage; Thermal Storage	$120,000	$65 / participant $ 70 / participant (DER-centric)
Commercial DLC – Heating	Smart Thermostat Baseboard Control	$180,000	$40 / participant $ 45 / participant (DER-centric)
Commercial DLC – EV Smart Charging	Buses Smart Charging; Buses V2G	$240,000	$45 / participant $ 55 / participant (DER-centric)
Residential DLC – Energy Storage	BTM Battery Storage	$120,000	$70 / participant $ 80 / participant (DER-centric)
Residential DLC – Heating & EV	Smart Thermostat; Water Heater Control; EV Managed Charging; V2G	$300,000	$ 45 / participant $ 55 / participant (DER-centric)

All costs are expressed in 2025 CAD. Fixed costs include full-time equivalent (FTE) staffing and software required to administer and operate the programs. Variable costs include Distributed Energy Resource Management Systems (DERMS), manual customer outreach (e.g., phone calls and emails), and other program-related operational expenses. Incentive costs are separate from fixed and variable costs (see Slide 42).

Residential Measures – Reference & Accelerated Scenarios

Measures	Average Saving Per Unit (kW)	Incremental Cost (2025 CAD)	Incentive Level per Unit	Participation Level
TOU	0.53	N/A	N/A	12%
EV Managed Charging, BYOD	0.53	-	$50 annual	19%
V2X, Direct Install	8.35	$8670	100% of installation costs $50 annual	33%
Smart Thermostat, Baseboard	0.55	SF: $612 MF: $459	100% of installation costs (0% for BYOD) $50 annual	BYOD: 12% DI: 9%
Smart Thermostat, Electric Furnace	0.70	$102	100% of installation costs (0% for BYOD) $50 annual	BYOD: 12% DI: 9%
Smart Thermostat, Heat Pump	0.20	SF: $245 MF: $122	100% of installation costs (0% for BYOD) $50 annual	BYOD: 12% DI: 9%
Resistive Water Heater, Control	0.53	SF: $357 MF: $261	100% of installation costs (0% for BYOD) $50 annual	BYOD: 12% DI: 9%
Heat Pump Water Heater, Control	0.53	SF: $357 MF: $261	100% of installation costs (0% for BYOD) $50 annual	BYOD: 12% DI: 9%
Battery Energy Storage	5.3	$21,751	DI: 100% of installation costs SI: 25% of installation costs (0% for BYOD) $250 annual	BYOD: 11% SI: 14% DI*: 1%

*Battery Direct Install is only for key constrained areas and is limited to 1%

Appendix B

Residential Measures – DER-Centric Scenario

Measures	Average Saving Per Unit (kW)	Incremental Cost (2025 CAD)	Incentive Level per Unit	Participation Level
TOU	0.53	N/A	N/A	12%
EV Managed Charging, BYOD	0.53	-	$90 annual	22%
V2X, Direct Install	8.35	$8670	100% of installation costs $90 annual	35%
Smart Thermostat, Baseboard	0.55	SF: $612 MF: $459	100% of installation costs (0% for BYOD) $90 annual	BYOD: 26% DI: 22%
Smart Thermostat, Electric Furnace	0.70	$102	100% of installation costs (0% for BYOD) $90 annual	BYOD: 26% DI: 22%
Smart Thermostat, Heat Pump	0.20	SF: $245 MF: $122	100% of installation costs (0% for BYOD) $90 annual	BYOD: 26% DI: 22%
Resistive Water Heater, Control	0.53	SF: $357 MF: $261	100% of installation costs (0% for BYOD) $90 annual	BYOD: 26% DI: 22% Code: 35%
Heat Pump Water Heater, Control	0.53	SF: $357 MF: $261	100% of installation costs (0% for BYOD) $90 annual	BYOD: 26% DI: 22% Code: 35%
Battery Energy Storage	5.3	$21,751	DI: 100% of installation costs SI: 25% of installation costs (0% for BYOD) $250 annual	BYOD: 24% SI: 20% DI: 77%

*DI is for NEM customers with solar PV only.

Appendix B

Commercial Measures – Reference & Accelerated Scenarios

Measures	Average Saving Per Unit (kW)	Incremental Cost (2025 CAD)	Incentive Level per Unit	Participation Level
Automatic Curtailment	42.2	$4,000	100% of installation costs $50/kW	7%
Manual Curtailment	49.2	-	$50/kW	7%
Interruptible Rate	3,000	-	$50/kW	7%
Central Thermal Energy	2.0 / 34 / 5.6*	$15k / 275k / 45k	DI: 100% of installation costs (0% for BYOD) $0/kW	BYOD: 4% DI: 2%
Battery Energy Storage	10 / 81 / 70*	$39k / 348k / 343k	SI: 80% of installation costs (0% for BYOD) $0/kW	BYOD: 4% SI: 2%
EV Smart Charging, Buses, BYOD	8.13	-	$60/kW	16%
V2X Buses, Direct Install	29.18	$8,670	100% of installation costs $60/kW	20%
Smart Thermostat, Baseboard, BYOD	0.82	-	$60/kW	6%

*For small commercial, medium & large commercial, and industrial (all sizes), respectively.

Appendix B

Commercial Measures – DER-Centric Scenario

Measures	Average Saving Per Unit (kW)	Incremental Cost (2025 CAD)	Incentive Level per Unit	Participation Level
Automatic Curtailment	42.2	$4,000	100% of installation costs $125/kW	14%
Manual Curtailment	49.2	-	$125/kW	14%
Interruptible Rate	3,000	-	$125/kW	17%
Central Thermal Energy	2.0 / 34 / 5.6*	$15k / 275k / 45k	DI: 100% of installation costs (0% for BYOD) $65/kW	BYOD: 10% SI: 5 %
Battery Energy Storage	10 / 81 / 70*	$39k / 348k / 343k	DI: 100% of installation costs SI: 80% of installation costs (0% for BYOD) $65/kW	BYOD: 9% SI: 5 % DI: 77%**
EV Smart Charging, Buses, BYOD	8.13	-	$80/kW	17%
V2X Buses, Direct Install	29.18	$8,670	100% of installation costs $80/kW	21%
Smart Thermostat, Baseboard, BYOD	0.82	-	$65/kW	10%

*For small commercial, medium & large commercial, and industrial (all sizes), respectively.
** DI is for NEM customers with solar PV only.

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