

Benefit-Cost Analysis of Demand Response Programs in Alberta

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List of Acronyms and Abbreviations

Acronym	Definition
AEEA	Alberta Energy Efficiency Alliance
AESO	Alberta Electric System Operator
AMI	Advanced metering infrastructure
AUC	Alberta Utilities Commission
BCA	Benefit-cost analysis
BCR	Benefit-cost ratio
BESS	Battery energy storage system
BYOD	Bring your own device
C&I	Commercial and industrial
CRF	Capital recovery factor
DER	Distributed energy resource
DERMS	Distributed energy resource management system
DFO	Distribution facility owner
DLC	Direct load control
DR	Demand response
DSM	Demand side management
EV	Electric vehicle
EVSE	Electric vehicle supply equipment
HVAC	Heating, ventilation and air conditioning
IESO	Independent Electricity System Operator (Ontario)
ISO-NE	ISO New England
kW / kWh	Kilowatt / kilowatt-hour
LCOCC	Levelized cost of conserved capacity
M&V	Measurement and verification
MTS	Municipal transformer station
MW / MWh	Megawatt / megawatt-hour
NPV	Net present value
NWA	Non-wires alternative
NWS	Non-wires solution
O&M	Operations and maintenance
OEB	Ontario Energy Board
OEM	Original equipment manufacturer
PV	Present value
REM	Restructured Energy Market
T&D	Transmission and distribution
TRC	Total Resource Cost (test)
UCT	Utility Cost Test
WACC	Weighted average cost of capital

1. Executive Summary

This report summarizes a benefit-cost analysis (BCA) completed for the Alberta Energy Efficiency Alliance (AEEA) to assess the potential value of demand response (DR) in Alberta at two scales: province-wide, screened as a system resource against Alberta-wide avoided costs, and two project-level non-wires solution (NWS) case studies that test whether targeted DR can cost-effectively defer specific wires investments on constrained circuits. By reducing peak demand, DR can help increase the ability of the existing grid infrastructure to accommodate growing demand during tight supply-demand conditions.

1.1. DR Resource Overview

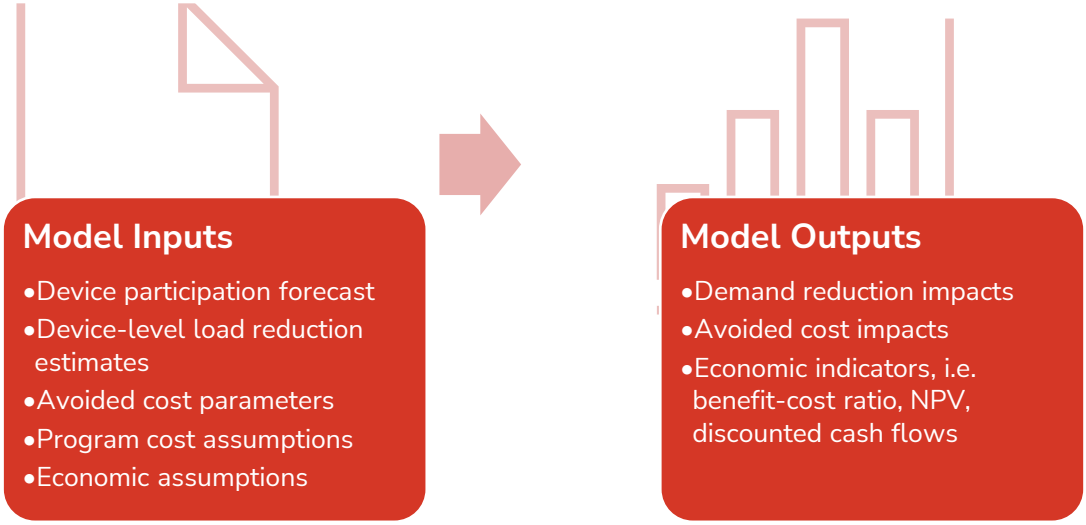
The analysis evaluates two complementary DR offerings: a residential bring-your-own-device (BYOD) program and an aggregator-led commercial and industrial (C&I) program. The residential program would enroll customers with eligible connected devices, including smart thermostats, electric vehicles, and battery energy storage systems. The C&I program would rely on third-party aggregators to recruit and manage non-residential sites such as commercial buildings, agricultural operations, warehouses, and industrial facilities. Together, these offerings create a diversified portfolio that combines broad residential participation with larger per-site reductions from non-residential customers. The project-level case studies draw on the same types of C&I and residential resources recruited within the footprint of a specific constrained circuit.

1.2. Methodology

CLEAResult applied an industry-standard BCA framework to compare the projected utility system benefits of the DR portfolio with the costs required to deliver it. The analysis translates forecast peak reductions into avoided generation, transmission, and distribution costs, then discounts annual costs and benefits to present value over the 2027–2036 study period.

The approach is consistent with standard demand side management (DSM) screening practice, which has been applied in DR plans and potential studies across North America. The analysis draws on recent publications from the Alberta Electric System Operator (AESO) and the Alberta Utilities Commission (AUC) for key inputs.

Figure 1: Overview of Modeling Approach



The benefits of demand response programs included in this analysis are the avoided or deferred utility system costs that would otherwise be incurred (or incurred sooner) without the DR portfolio. These benefits include avoided energy generation costs, avoided transmission and distribution capacity costs, and avoided marginal cost of energy during critical peak events. The costs of DR programs include all utility-incurred program delivery costs including participant incentives, program administration and delivery, distributed energy resource management system (DERMS) license fees, device integration costs, and measurement and verification.

While a set of programs and non-wires solution projects that could deliver benefits across all parts of the system (distribution, transmission and generation) requires the direct involvement of distribution utilities in the delivery of DR programs, the initial analysis presented is approached as a province-wide portfolio (rather than a single utility service territory). This is to provide an order-of-magnitude estimate of Alberta's DR opportunity and to reflect potential administrative efficiencies from standardized program delivery at scale. Results should therefore be interpreted as system-level screening results (i.e., "is DR cost-effective in Alberta?") rather than as a detailed implementation plan or a utility-specific business case for a particular service area. Capturing the full value of DR, particularly its local distribution value, requires programs to be embedded in distribution system planning and involve Distribution Facility Owners (DFOs), who can direct DR to local capacity needs while the same resources continue to provide bulk system support. The NWS case studies described below illustrate the localized approach to DR.

The report also includes two project-level NWS case studies (Section 5), which ask a narrower question: on a specific constrained circuit, can targeted DR defer a planned wires investment

and increase the capability of existing grid infrastructure at a cost lower than the value of the deferral to ratepayers? Rather than a program-level cost-effectiveness test, these case studies measure the non-wires solution benefit directly as the reduction in utility revenue requirement from deferring the capital project by five years, then add the bulk system value (avoided generation capacity, transmission capacity, and marginal energy) of the same resource.

1.3. Province-Wide DR Portfolio Results

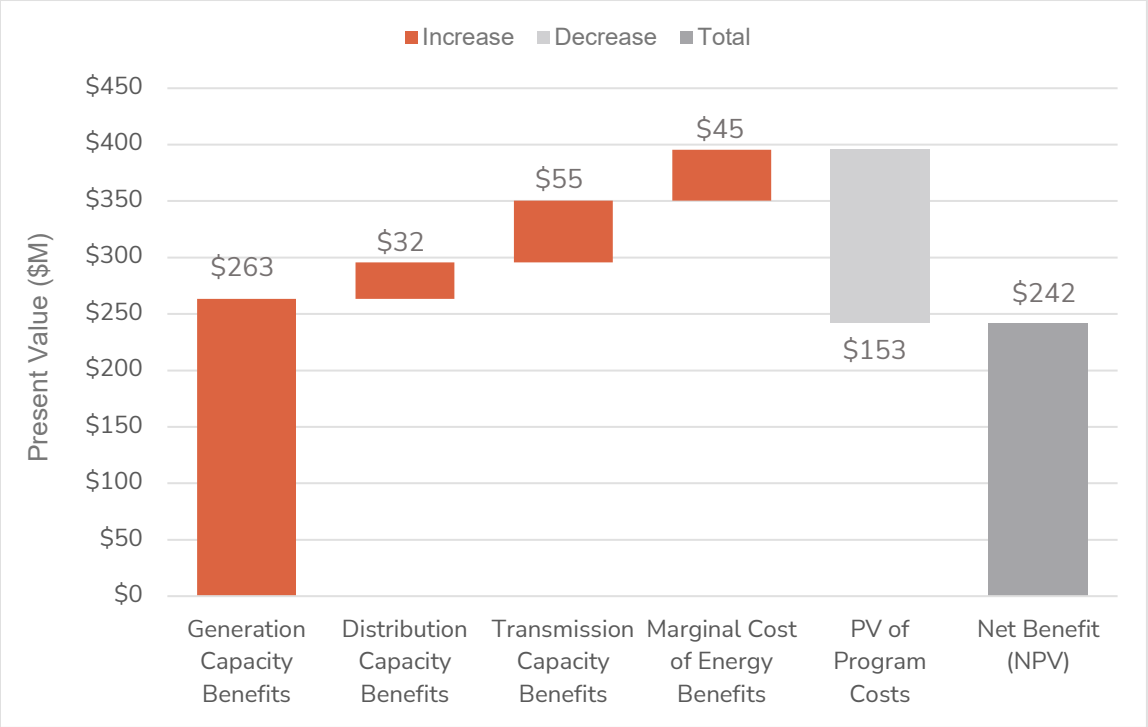
This analysis indicates that demand response can be a cost-effective, scalable, and strategically valuable resource for Alberta. Under a conservative 2027–2036 portfolio scenario, the combined residential and C&I programs deliver approximately 212 MW of peak reduction by 2036, produce a portfolio benefit-cost ratio of 2.58, and generate roughly $242 million in net present value.

Table 1: Cost-Effectiveness Summary of Province-Wide DR Portfolio (2027–2036)

	Avg Annual Program Cost ($M)	Peak Reduction by 2036 (MW)	Benefit-Cost Ratio	Net Present Value ($M)	Levelized Cost of Conserved Capacity ($/kW-yr)
Province-Wide DR Portfolio	$21.8	212.4	2.58	$242.2	$153.7

Avoided peak generation capacity is the largest single value stream for the province-wide program, accounting for roughly two-thirds of portfolio benefits, followed by avoided transmission capacity (about 14%), avoided marginal energy costs (about 11%), and avoided distribution capacity (about 8%). Since the DR programs are dispatched only during a limited number of critical peak hours (30 to 40 hours per year, or roughly 10 to 15 events), this value reflects deferring the need for new peaking capacity rather than displacing the energy that existing generators supply during the rest of the year. Because the province-wide portfolio is not necessarily dispatched against specific constrained circuits, distribution value is credited only at system-average avoided costs. Figure 2 below shows the present value of each benefit stream and of program costs, and the resulting net present value.

Figure 2: DR Portfolio-Level Net Benefits (2027–2036)



These results suggest that DR can provide meaningful system value, offering a flexible resource that can grow as customer-sited technologies become more common. While DR should not be viewed as a substitute for all generation, transmission, or distribution investment, it can help Alberta manage load growth more cost-effectively, improve system flexibility, and give customers a more active role in supporting grid reliability.

1.4. NWS Project-Level Results

As designed, both NWS project case studies screen as cost-effective. Project A, which uses about 1.5 MW of C&I DR to defer an approximately $3.3 million feeder upgrade by five years, produces a net benefit of approximately $1.8 million and a benefit-cost ratio of 3.9. Project B, which uses about 10.1 MW of DR (C&I and residential smart thermostats) to defer a $20 million substation expansion, produces a net benefit of approximately $11.4 million and a benefit-cost ratio of 3.7. Both projects clear the cost-effectiveness threshold on deferred distribution capacity benefits, with bulk system value providing further upside.

Table 2: Cost-Effectiveness Summary of NWS Projects (2030–2034)

	Total NWS Cost ($M)	Capital Deferred ($M)	Peak Reduction (MW)	Benefit-Cost Ratio	Net Present Value ($M)
Project A	$0.6	$3.3	1.5	3.9	$1.8
Project B	$4.3	$20.0	10.1	3.7	$11.4

Figure 3 illustrates the net benefits of the feeder upgrade project deferral (Project A). Avoided distribution capacity accounts for approximately $0.8 million of the total benefit, and $1.6 million comes from avoided bulk system value across avoided generation capacity, avoided transmission capacity, and avoided marginal energy costs. Together, these benefits total approximately $2.4 million while incurring about $0.6 million in project costs. Avoided distribution capacity alone, about one-third of total benefits, exceeds the cost of the DR resource, so the deferral is cost-effective on local distribution value alone, with bulk system value providing further upside.

Figure 3: Net Benefits of Feeder Expansion Deferral through NWS

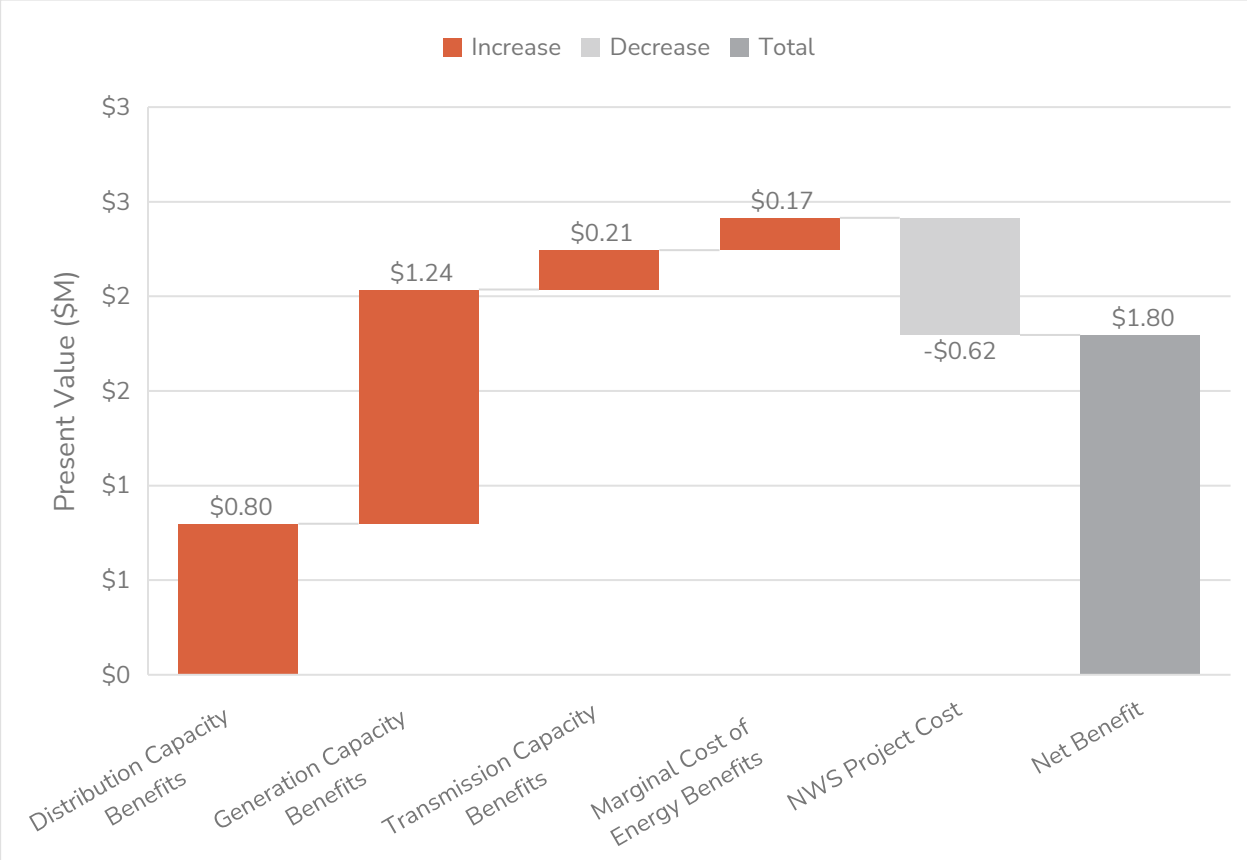
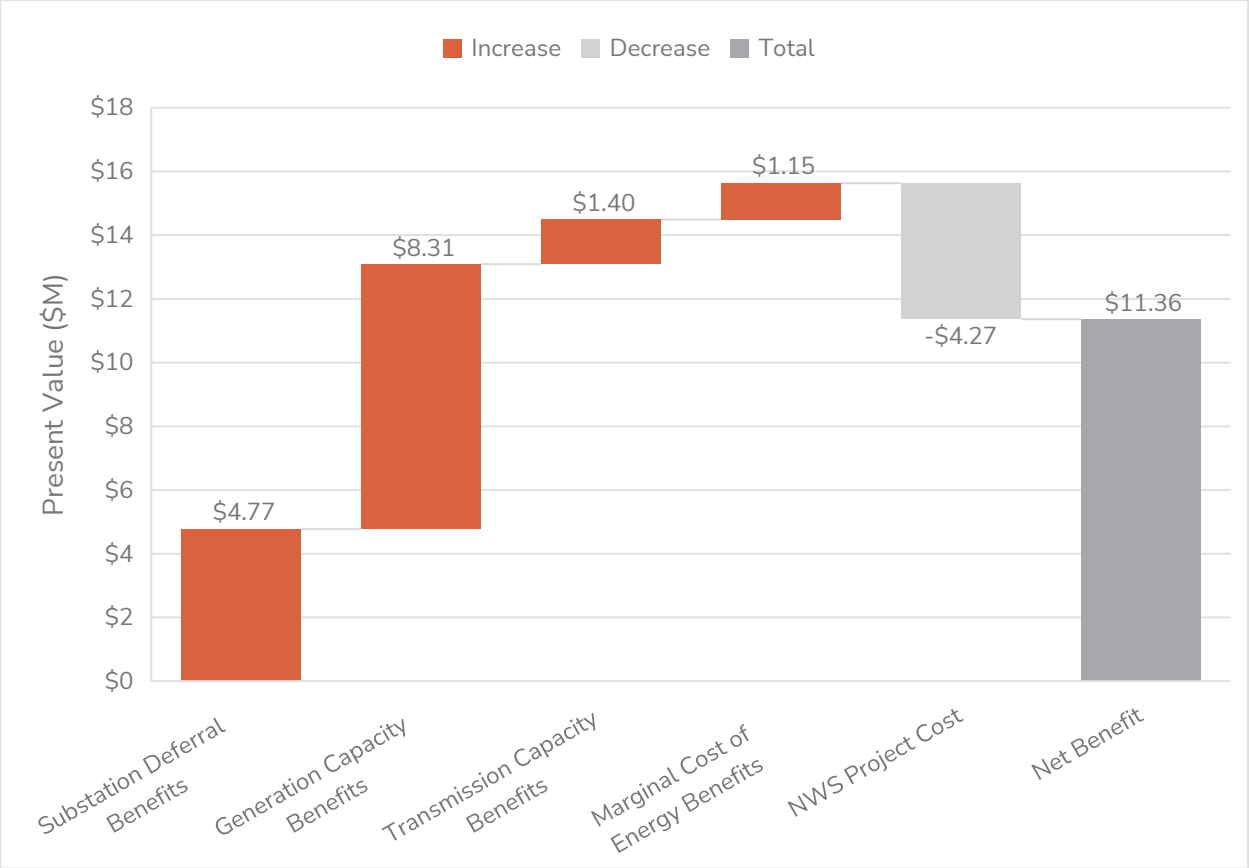


Figure 4 illustrates the net benefits of the substation expansion project deferral (Project B). Avoided distribution capacity accounts for approximately $4.8 million of the total benefit, and $10.9 million comes from avoided bulk system value across avoided generation capacity, avoided transmission capacity, and avoided marginal energy costs. Together, these benefits total approximately $15.6 million while incurring about $4.3 million in project costs. Avoided distribution capacity alone, about one-third of total benefits, exceeds the cost of the DR resource, so the deferral is cost-effective on local distribution value alone, with bulk system value providing further upside.

Figure 4: Net Benefits of Substation Expansion Deferral through NWS



1.5. Conclusions

This analysis demonstrates that demand response is a cost-effective resource for Alberta at both the system and the local level. Under a conservative 2027–2036 portfolio scenario, the combined residential and C&I programs deliver approximately 212 MW of peak reduction by 2036, a portfolio benefit-cost ratio of 2.6, and roughly $242 million in net present value. The NWS case studies provide an even greater benefit-cost ratio. Targeting about 1.5 MW of C&I DR at a constrained feeder (deferring a $3.3 million upgrade for 5 years) returns $3.91 in utility system benefits for every dollar spent (Project A). Targeting about 10 MW of DR at a constrained substation (deferring a $20 million upgrade for 5 years) returns $3.66 for every dollar spent and produces a net benefit of approximately $11.4 million from a single five-year deferral (Project B).

The value of DR is greatest when it is planned and dispatched with location in mind. In the NWS case studies, where DR is targeted at a known constraint and coordinated with the utility's capital plan, avoided distribution capacity accounts for roughly one-third of total benefits (about 33% in Project A and 31% in Project B), and would remain cost-effective on its distribution value alone. However, geotargeted opportunities are inherently limited: at any

given time, only a small share of Alberta's feeders and substations are approaching a capacity constraint that DR could defer, and those opportunities arise project by project rather than across the system.

A larger opportunity exists by pairing NWS projects with system-wide DR programming. This provides consistent participation opportunities for customers while delivering an estimated $242 million in net present value province-wide over the first 10 years of implementation. These savings are driven primarily by avoiding the need for new peak generation capacity during critical peaks (30 to 40 hours per year over 10 to 15 separate events), with additional benefits from passive deferral of transmission and distribution upgrades and avoided marginal energy costs. This system-wide resource is cost-effective on its own, even under the conservative assumptions used in this analysis, and should not be left on the table while targeted deferral opportunities are developed. The two are complementary: a province-wide DR resource delivers system-wide savings while building institutional capacity, an enrolled customer base and dispatch capability that utilities can then direct to local constraints as they emerge, capturing the additional locational value where and when it arises.

This value is technically available today, but it is not yet accessible. Capturing it requires distribution utilities to identify emerging constraints, procure DR as an alternative to wires investment, and dispatch it against local peaks, while allowing the same resource to earn its generation and transmission value. Alberta's current policy and regulatory framework does not yet provide a clear pathway for utilities to do this. Under current ratemaking, deferring a capital project also reduces the asset base on which a utility earns a return, so even a highly cost-effective deferral can work against the utility's financial interest. Without a framework that addresses these barriers, most of the stacked value demonstrated in this report will go unrealized, and load growth will continue to be met primarily by building new infrastructure, even where a lower-cost non-wires alternative exists.

The value of DR will continue to increase as load growth from data centres, electrification and EV adoption is expected to drive significant infrastructure investment over the coming decade. Each project built without a non-wires alternative being considered locks in capital costs for 40 years or more, while DR capability, once enrolled, can be redeployed as system needs change. Every year without an enabling framework is a year of deferral opportunities forgone.

To realize this value, Alberta should develop a policy and regulatory framework that: (1) guides utilities in how to evaluate DR and other non-wires alternatives alongside traditional solutions in distribution system planning and capital applications; (2) allows utilities to recover the cost of procuring DR as a non-wires solution and provides an incentive comparable to the

return earned on capital, so that deferral is not financially penalized; (3) establishes a consistent cost-effectiveness methodology that credits locational distribution value alongside generation and transmission value, consistent with the approach applied in this report and other jurisdictions; and (4) clarifies how utility-procured DR can also be used to provide value to the broader provincial electricity system.

DR will not replace the need for new generation, transmission, and distribution infrastructure, but it can help manage total system costs. This analysis shows that the value of DR is worth pursuing to help manage the affordability of Alberta's electricity system. A framework that enables utilities to capture both the locational and system-wide value of DR is the step needed to turn that value into lower costs for Alberta ratepayers and a more flexible, reliable grid.

2. Introduction

2.1. Purpose & Scope

This report focuses on a benefit-cost analysis (BCA) completed for the Alberta Energy Efficiency Alliance (AEEA) for a province-wide demand response (DR) portfolio covering both residential and commercial & industrial (C&I) customers. It evaluates cost-effectiveness from a utility system perspective using the industry-standard Utility Cost Test (UCT) over a 10-year period (2027–2036) and reports program impacts in terms of peak demand reduction (MW), energy shifted/curtailed during dispatched event hours (GWh), and utility system net benefits. Separate BCAs for two non-wires solution (NWS) example projects are included for comparison in Section 5.

2.2. Background & Context

The DR programs evaluated in this report are intended to reduce demand during the highest-stress hours on Alberta's electricity system (system peak) and, where DR can be targeted, to reduce loading on constrained portions of the distribution system (local peaks). By reducing peak demand, DR can help increase the ability of the existing grid infrastructure to accommodate growing demand during tight supply conditions.

While delivering cost-effective benefits across all parts of the system (distribution, transmission and generation) requires the direct involvement of distribution utilities in the delivery of DR programs[1], the initial analysis in this report is framed as a province-wide portfolio (rather than a single utility service territory) to provide an order-of-magnitude estimate of Alberta's DR opportunity and to reflect potential administrative efficiencies from standardized program delivery at scale. Results should therefore be interpreted as system-level screening results (i.e., "is DR cost-effective in Alberta?") rather than as a detailed implementation plan or a utility-specific business case for a particular service area. As mentioned, separate BCAs for two NWS example projects are included in Section 5 for comparison.

2.3. Program Design Description

The design of demand response programs is guided by the goals of the utility or jurisdiction implementing the program. DR programs often are utilized with the aim of achieving one or more of the following goals (among others):

[1] To maximize DR's distribution value, programs should be embedded in distribution system planning and involve the distribution operations of Distribution Facility Owners (DFOs), while remaining responsive to bulk system needs.

- Bulk system peak management: reducing or time-shifting the overall peak within the energy generation and transmission system, sometimes referred to as “peak shaving” or “peak shifting.” Utilizes DR assets during the hours that are projected to be the highest in the system.
- Distribution system peak management: reducing or time-shifting distribution system peaks. Often these take the form of Non-Wires Alternatives (NWA) programs that target specific constrained feeders or circuits to relieve congestion. The term “non-wires” refers to a portfolio of distributed energy resources (DERs) and operational measures used to defer or reduce the need for traditional poles-and-wires upgrades.
- Economic demand response: utilizing DR as a market participant in wholesale energy and/or capacity markets as a low-cost alternative to traditional peaking power plants (i.e., dispatching load reductions when market prices or system conditions indicate high value).
- Critical period demand response: utilizing DR to reduce grid consumption during periods of high grid need to help avoid power interruptions.

This report analyzes a province-wide demand response portfolio for Alberta that could contribute to all of the goals above. The portfolio is made up of two complementary program offerings: a residential bring-your-own-device (BYOD) program and an aggregator-led commercial and industrial (C&I) program. Both programs are designed to reduce electricity demand during a limited number of high-value hours each year, when the provincial system is under the greatest stress or when specific parts of the distribution grid are constrained.

The residential program enrolls customers who already have eligible connected devices in their homes, including smart thermostats for air conditioning or electric heating, managed electric vehicle charging, or residential battery storage. Participants receive incentives in exchange for allowing these devices to respond to dispatch signals during peak events. The C&I program relies on third-party aggregators to recruit and manage non-residential customer sites such as commercial buildings, agricultural operations, warehouses, and industrial facilities. These aggregators are responsible for assembling portfolios of flexible load, coordinating site performance, and delivering verified curtailment during events. Together, the two program types create a diversified demand response portfolio that can capture both broad participation from households and larger per-site reductions from non-residential customers.

For the purposes of this analysis, the programs are assumed to operate with 30 to 40 event hours per year (over 10 to 15 events) and to compensate participants for making load reductions available when called. This design reflects a practical, scalable approach to demand

response in Alberta: one that can support bulk system peak management, provide targeted value on constrained portions of the distribution system, and create a foundation for broader customer flexibility as electricity demand increases over time.

Below is a summary of some of the high-level program design characteristics that were selected for the analysis:

Table 3: Overview of Portfolio Characteristics

Program Characteristic	Residential Program	Non-Residential Program
Eligible Customer Type	Residential customers	Non-residential customers (e.g., commercial, industrial, agricultural, etc.)
Program Type	**Bring-your-own-device** (BYOD) program. Customer must have an eligible device to participate, including: • Smart thermostat connected to air conditioning and/or electric heating • Electric vehicle charged at home • Battery energy storage system	**Aggregator-led program** where third party companies "aggregate" non-residential customer sites to participate. Aggregator is responsible for managing customer performance and load curtailment strategies.
Event Strategy	• 40 event hours per year for electric vehicle charging and battery energy storage systems; 30 event hours per year for smart thermostats and C&I • Analysis is generally agnostic of whether events are called just in summer or winter (except for heating and cooling, which are seasonal)	
Customer Compensation	• One-time enrolment incentive • Ongoing performance-based incentive • Incentive rates dependent upon device type	• Ongoing performance incentive

2.4. Jurisdictional Scan

While DR is less common in Alberta's electricity system, it has been utilized in other jurisdictions across Canada and North America for decades. Recent studies show that these programs are broadly cost-effective, in addition to providing other non-energy benefits. According to a recent study done by Dunsky & Associates (Manitoba Demand Response Strategy, 2024), provinces across Canada have realized peak demand reductions through implementation of DR, outlined in Table 4 below.

Table 4: Jurisdictional Scan of Peak Demand Reduction in Canada

Jurisdiction	Peak Season	Capacity Reduction (%)	AMI	Programs
BC	Winter	1.6%	Yes	Res. Direct Load Control, C&I curtailment
Quebec	Winter	4.8%	Yes	Res. Direct Load Control, C&I curtailment, interruptible rate
Ontario	Summer	8.9%	Yes	Res. Direct Load Control, C&I curtailment, Capacity Auction
Newfoundland	Winter	7.0%	No	Res. Direct Load Control, C&I curtailment, EV smart charging
Nova Scotia	Winter	3.1% (2030 target)	Yes	Res. Direct Load Control, C&I curtailment, time-varying rates
Manitoba	Winter	4.7%	No	Res. Direct Load Control, C&I curtailment (upcoming)
Yukon	Winter	5.6%	No	Res. Direct Load Control, C&I curtailment (upcoming)

This table illustrates that different jurisdictions across Canada have achieved peak reductions through DR that have provided value to their grids. For reference, a 5% reduction in Alberta's 2025 peak demand equates to roughly 650 MW. As Alberta's electricity demand continues to grow, so will the potential for DR to provide peak demand reduction. This report is not a DR potential study and is not meant to offer a roadmap for realizing that potential, however, it is worth noting the scale of the opportunity that is being targeted and achieved across Canada. Table 5 below presents a range of recent cost-effectiveness results from DR programs in other jurisdictions.

Table 5: Jurisdictional Scan of DR Program Cost-Effectiveness Results

Source	Description	Benefit-Cost Test	Benefit-Cost Ratio
Efficiency Nova Scotia	DR Portfolio Plan	Utility Cost Test	1.7
Alectra/IESO York Region NWA Project	Non-wires solution	Modified Utility Cost Test	1.19–1.35
Essex Powerlines (ON)	Non-wires solution	Total Resource Cost Test	1.69–2.45
FortisBC	DR Portfolio Plan	Total Resource Cost Test	1.0
BC Hydro	DR Program Annual Report	Utility Cost Test	1.6–3.6
BC DER Potential Study	DR Portfolio	Utility Cost Test	3.15
AES Indiana	EV managed charging	Utility Cost Test	1.42

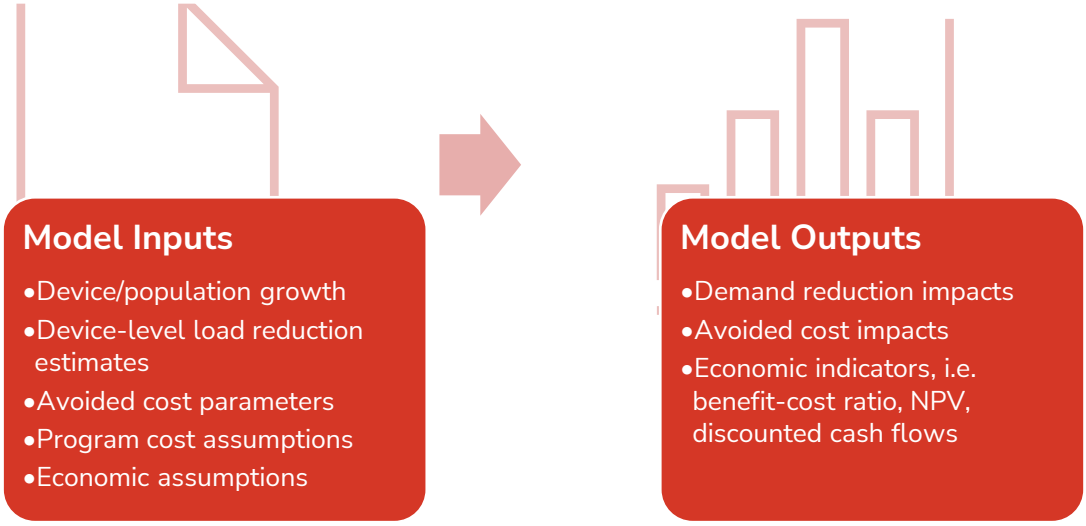
Programs in this jurisdictional scan had a range of program designs and applications, however, they aligned with the analysis done here in terms of customer segment, scale, and technology types. This demonstrates that DR is a widely used option to cost-effectively provide capacity to the grid by leveraging customer-sited devices targeted at peak hours.

3. Methodology for Province-Wide Program

CLEAResult used an industry-standard benefit-cost analysis (BCA) framework to estimate the system costs and benefits of an Alberta province-wide DR portfolio. The approach is consistent with common demand side management (DSM) screening practice and has been applied in DR plans and potential studies across North America.

Separate BCA models were developed for the residential and C&I programs to forecast participation, estimate per-participant load impacts, calculate incentive and administrative costs, and quantify avoided costs attributable to delivered DR capacity over time.

Figure 5: Overview of Modeling Approach



The models translate forecasted peak reductions into avoided generation, transmission, and distribution costs and discount annual cash flows to present value. The remainder of this section summarizes the benefit and cost components included in the UCT screening analysis.

3.1. Benefit-Cost Test Overview

This province-wide analysis used the Utility Cost Test (UCT), which is a standard cost-effectiveness screen used to assess whether a demand response (DR) program is a prudent investment from the utility system perspective. Because most DR programs primarily rely on customer compensation and program delivery costs (rather than utility-funded equipment installations), the UCT is commonly used to evaluate DR portfolios and individual DR offerings.

The UCT compares the present value (PV) of the utility's avoided costs attributable to the program (benefits) to the present value of the utility's incremental costs to deliver the program (costs). PV means future-year costs and benefits are discounted to a common base year (2027) using the discount rate in Appendix A. The UCT Benefit-Cost Ratio (BCR) is calculated as PV(Benefits) ÷ PV(Costs). A BCR greater than 1.0 indicates that benefits exceed costs on a PV basis. Net present value (NPV) is calculated as PV(Benefits) – PV(Costs); a positive NPV indicates net savings to the utility system over the analysis period. The following provides a brief overview of the components of the test; more detail on inputs and assumptions is provided in Appendix A.

3.2. Benefit Components

The benefits of demand response programs are the avoided or deferred utility system costs that would otherwise be incurred (or incurred sooner) without the DR portfolio. This analysis included avoided generation capacity costs, avoided energy costs during high-price/critical hours, and avoided transmission and distribution capacity costs, as outlined in Table 6 below.

Table 6: Modeled Benefits

Benefit	Description
Deferred transmission and distribution (T&D) capacity	Savings from postponing or avoiding investments in transmission lines and distribution system upgrades due to reduced peak loads.
Avoided generation costs	Savings from deferring or reducing the need for new peaking generation capacity by curtailing demand during system peak hours.
Avoided marginal cost of energy	Reduced need for procuring high-cost energy during critical peak events (assumes up to 40 hours of DR events per year for the residential program and up to 30 hours for the C&I program, at a high marginal energy cost).

The benefits included in this cost-effectiveness test are comparable to those chosen in tests across other jurisdictions in North America. Table 7 below summarizes the benefits included in benefit-cost analysis in other jurisdictions and compares them with the benefits proposed for use in this BCA.

Table 7: Jurisdictional Scan of Benefit-Cost Analysis Components

Benefit	Alberta (proposed)	Ontario	Nova Scotia	Texas	California	New York
Avoided generation costs	✓	✓	✓	✓	✓	✓
Deferred transmission and distribution (T&D) capacity	✓	✓	✓		✓	✓
Avoided marginal cost of energy	✓	✓	✓	✓	✓	✓
Avoided line losses	✓	✓	✓	✓	✓	✓
Avoided ancillary services					✓	✓
Avoided environmental compliance costs					✓	✓
Avoided credit and collection costs						✓
Increased resilience						✓

This table shows that an array of benefits beyond those chosen for this analysis are included across different jurisdictions, capturing the entire spectrum of benefits that DR can offer. The set that was chosen for this analysis reflects a basic set of benefit streams that can be readily quantified.

No additional "participant non-energy benefits" or societal environmental benefits were included in this analysis; the focus was on utility system economics. This may be an area for further research.

3.3. Program Cost Components

The costs of DR programs include all costs incurred by the utility in delivering the program. For this analysis these include participant incentives, program administration and delivery costs (marketing, customer support, aggregator payments/fees), technology/platform costs (e.g., DERMS fees, device integration, communications), measurement and verification (M&V) and evaluation costs, and utility overhead or one-time implementation costs.

Table 8: Modeled Program Costs

Cost	Description
Participant incentives	Upfront enrolment incentive and performance-based payments for each DR participant.
Technology costs	Includes DERMS platform fees and device integration costs (e.g., per-device vendor fees for connectivity/controls).
Program administration and delivery expenses	Program management, marketing, customer support, reporting and evaluation costs.
Utility overhead	Includes utility administrative costs and any other fixed startup costs (e.g., initial setup fees for systems).

Some costs that are not considered as part of this program are costs for equipment installation and O&M (as equipment is not directly incentivized, only program participation).

3.4. Time Horizon

Costs and benefits are forecast over the study horizon, adjusted for timing (e.g., seasonal/event-hour coincidence) and discounted to present value. An analysis period of 10 years (2027 through 2036) was used for this province-wide analysis.

3.5. Data Sources & Validation

This analysis draws on recent publications from the Alberta Electric System Operator (AESO) and the Alberta Utilities Commission (AUC) for avoided cost inputs and system planning context (see Appendix A.2). Population, customer counts, and technology adoption trajectories were developed using provincial statistics and benchmarks from similar programs. Where Alberta-specific primary data were limited (e.g., certain C&I end-use coincidence factors), assumptions were selected to be reasonable and generally conservative for screening purposes. A consolidated summary of major assumptions and their sources is provided in Appendix A.

4. Results for Province-Wide DR Portfolio

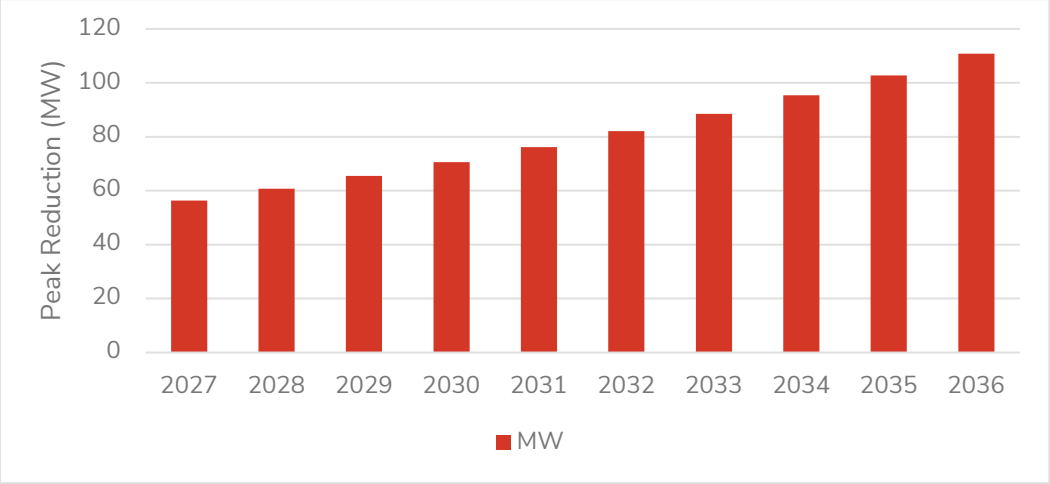
This section summarizes modeled impacts and cost-effectiveness results for (1) the Residential DR program, (2) the C&I DR program, and (3) the combined portfolio. Results are presented in terms of peak demand reduction (MW), event-hour energy impacts (GWh), and UCT cost-effectiveness.

4.1. Commercial & Industrial DR Program Results

Peak Demand Reduction

By 2036, the C&I program is projected to deliver roughly 111 MW of system peak reduction. This estimate is intended to be conservative; impacts could be significantly higher depending on policy, regulation, and program design. Figure 6 shows the modeled growth in C&I peak reductions over the analysis period.

Figure 6: C&I Program Peak Demand Reduction Forecast (MW)



Energy Savings

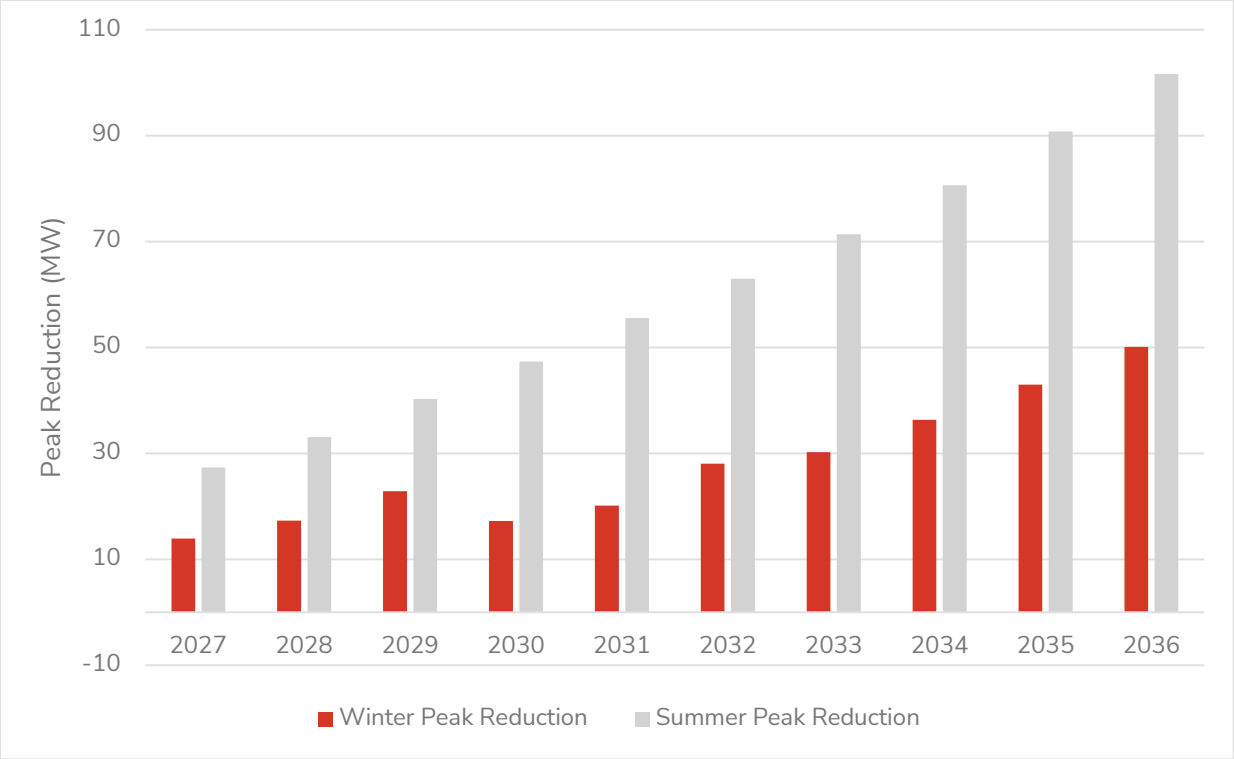
Because event hours are limited, C&I energy impacts are modest relative to capacity impacts, but still valuable during the highest-stress hours. As with residential DR, most impacts reflect load shifting/curtailment during events rather than permanent annual energy savings. By 2036, the C&I program is estimated to shift or curtail roughly 3 GWh during critical peak hours annually, contributing to reliability and reducing exposure to high marginal energy costs.

4.2. Residential DR Program Results

Peak Demand Reduction

By 2036, the residential DR program is projected to deliver approximately 50 MW of system peak reduction (weighted to system peak hours) and approximately 102 MW of summer distribution peak reduction. These estimates represent a conservative rate of device adoption and program participation; more aggressive programs or higher rates of adoption would yield substantially larger reductions. Figure 7 summarizes the modeled forecast of residential peak reductions over the study period.

Figure 7: Residential Program Peak Demand Reduction Forecast (MW)



Summer impacts are driven primarily by central A/C control, with additional contributions from managed EV charging and behind-the-meter batteries. Winter impacts are driven by electric heating control (where present), EV charging, and batteries, and are lower largely because electric heating penetration is lower than air conditioning penetration in Alberta. Because winter and summer peaks occur in different seasons, these values are not additive; together they indicate year-round capability to reduce peak demand when called. EV charging reductions are modeled as event-based DR that is dispatched to coincide with system peak hours. See Appendix A for more detail on the methodology.

Energy Savings

The energy impacts of the residential program occur primarily during dispatched event hours and are secondary to the program's peak demand reduction value. Because event hours are limited (up to 40 hours/year), the program does not materially reduce annual electricity consumption; instead, it shifts or curtails load during critical peaks (e.g., short-term heating, ventilation and air conditioning (HVAC) adjustments, pausing EV charging, and battery discharge). By 2036, the residential portfolio is estimated to shift or curtail roughly 3 GWh during critical peak hours annually, which can reduce critical period energy procurement and support reliability during tight system conditions.

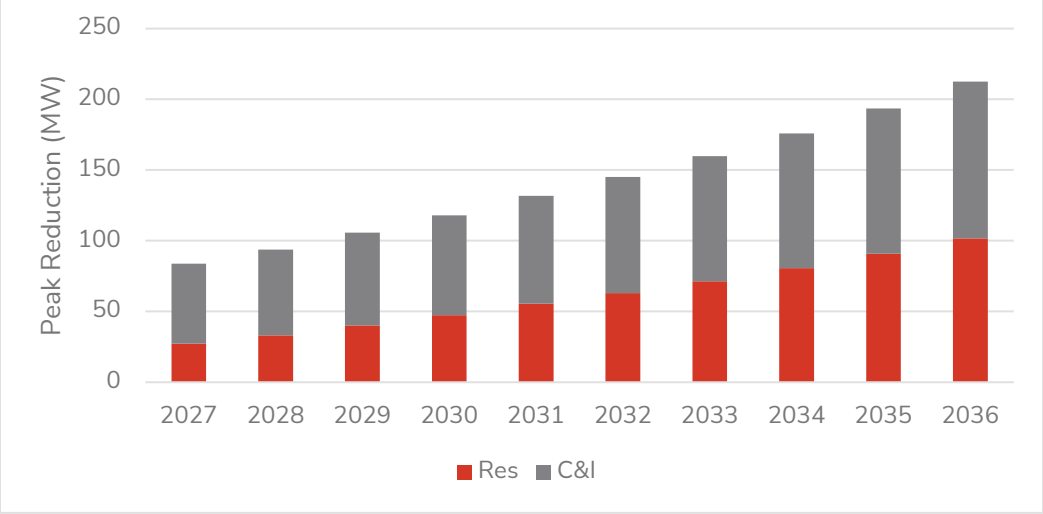
4.3. Portfolio Performance

Portfolio results combine residential and C&I impacts to reflect an overall DR resource offering. Portfolio screening is useful because early-year fixed costs or emerging segments (e.g., residential batteries) may be less cost-effective in isolation while still contributing to a cost-effective portfolio when combined with higher-performing measures.

Portfolio Impact

Together, the residential and C&I programs are projected to provide approximately 212 MW of system peak reduction capacity by 2036. Figure 8 below summarizes the end-of-period peak reduction targets used in the portfolio analysis.

Figure 8: Portfolio Total Peak Demand Reduction Forecast (MW)



Portfolio Cost-Effectiveness

The combined Alberta DR portfolio screens as cost-effective, with a BCR of 2.58 and a net present value of approximately $242M across 2027–2036. Figure 9 shows the modeled annual net benefits over the analysis period. The portfolio is projected to generate positive net benefits early and to increase total net benefits as enrolment and delivered peak reductions grow.

Figure 9: Portfolio-Level Annual Benefits and Costs

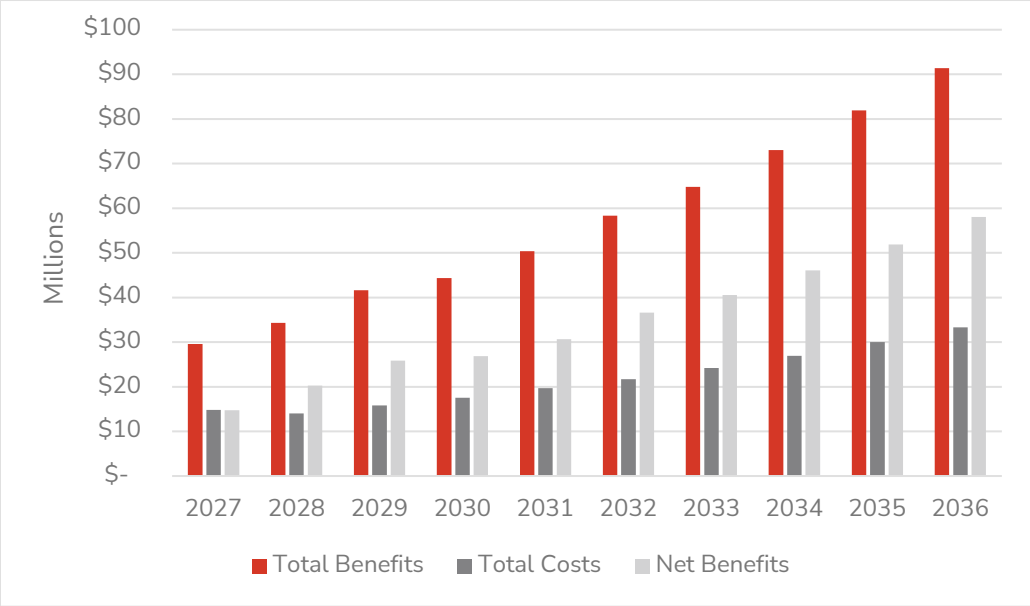


Table 9 summarizes capacity targets and cost-effectiveness metrics for each program and for the combined portfolio.

Table 9: Program- and Portfolio-Level Cost-Effectiveness Results

Program/Portfolio	Estimated Capacity by 2036 (MW, at generator)	Benefit-Cost Ratio (BCR)	Net Present Value (NPV)	Levelized Cost of Conserved Capacity ($/kW-yr)
Residential DR	101.6	1.47	$39.7	$209.0
C&I DR	110.8	3.93	$202.4	$125.1
Total Portfolio	**212.4**	**2.58**	**$242.2**	**$153.7**

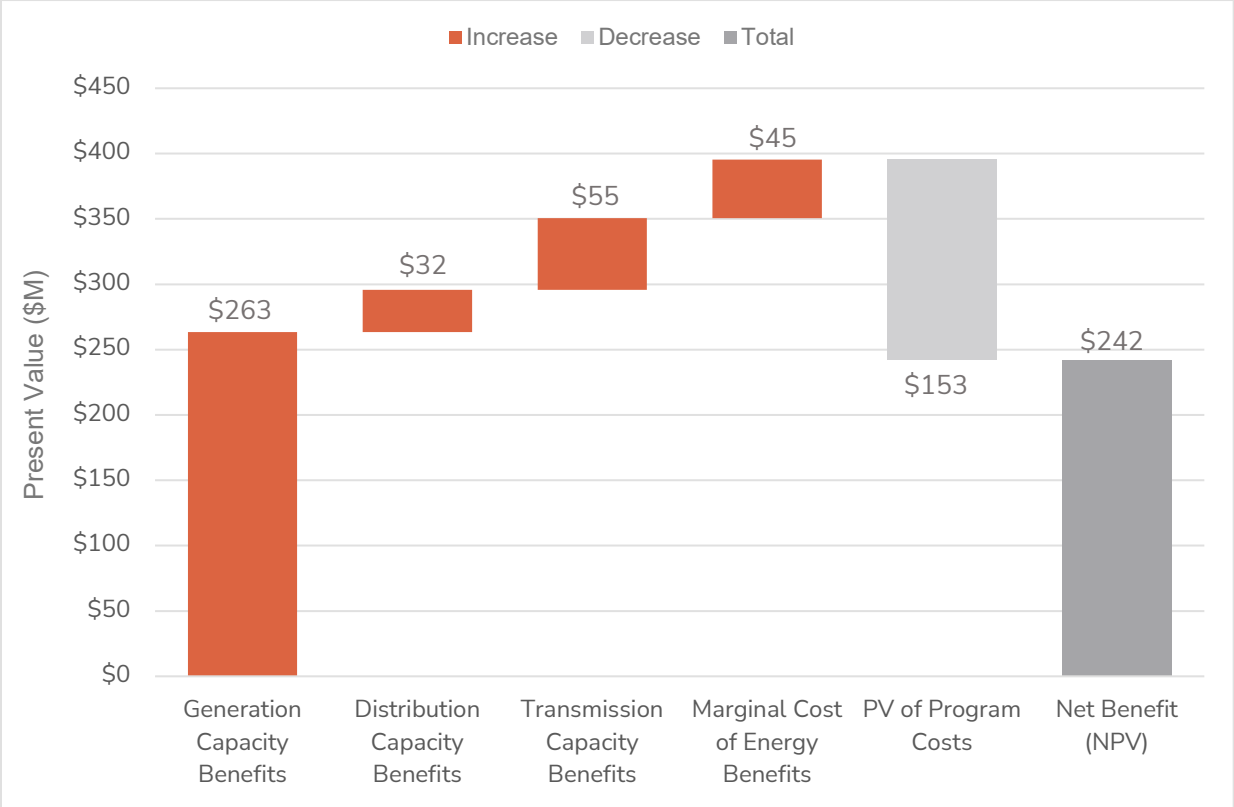
The residential program screens as cost-effective on its own, although with a lower BCR than the C&I program, because its per-device delivery costs (DERMS and OEM fees, enrolment incentives and marketing) are spread across smaller per-site load reductions. The province-wide screen also credits distribution capacity only at system-average costs, so it likely understates the value of residential devices, particularly managed EV charging, where they can be dispatched against local distribution constraints, as illustrated by the residential thermostat component of Project B in Section 5.

Utility Cost vs. Value

The portfolio's average levelized cost of conserved capacity (LCOCC) is approximately $154/kW-year. This is less than half of the assumed avoided generation capacity cost (~$314/kW-year in 2027), and well below the combined cost of meeting peak demand through generation plus network capacity (over $350/kW-year in 2027 when transmission and

distribution are included). Figure 10 below shows the present value of benefit and cost types underlying the portfolio's net present value.

Figure 10: Portfolio-Level Net Present Value by Avoided Cost Type (2027–2036)



Sensitivity and Uncertainty

The results are sensitive to participation growth, program delivery costs, per-unit demand savings (i.e., event performance), and avoided cost assumptions. Lower participation or lower per-participant performance reduces portfolio benefits; higher avoided costs (e.g., higher capacity value under tighter system conditions) increase portfolio benefits.

Sensitivity runs on the model indicate the portfolio BCR remains above 1.0 under each of the following single-variable changes: halving the avoided generation capacity cost to about $157/kW-year (BCR of 1.7 and NPV of about $110 million); reducing per-device and per-site load reductions by 25% (BCR of 2.1); halving first-year enrolment rates in both programs (BCR of 2.1); and increasing C&I incentives and program administration costs by 25% (BCR of 2.3). Combining a halved generation capacity cost, 25% lower load reductions, and 25% higher costs lowers the BCR to about 1.2 (NPV of about $39 million), so the portfolio remains cost-effective but with limited margin under that combined downside. Conversely, faster adoption or higher avoided costs would increase the BCR and NPV.

5. Results for NWS Project Case Studies

This section presents two project-level benefit-cost analyses prepared to illustrate how demand response can be evaluated as a non-wires solution (NWS) for a specific distribution system constraint. They are included as examples only.

5.1. Purpose & Case Study Description

The province-wide analysis in the body of this report screens demand response as a system resource, valued against Alberta-wide average avoided costs. A project-level analysis asks a narrower question: on a specific constrained circuit, can targeted demand response defer a planned wires investment, and is the cost of holding that resource across the deferral period outweighed by the value of the deferral to ratepayers? In this frame, demand response works alongside the utility's capital plan, optimizing when the investment is made rather than displacing it, and it is the frame distribution utilities use when evaluating a non-wires alternative.

Two hypothetical case studies are presented, chosen to show how the value of targeted demand response changes with the scale and cost of the asset being deferred. Project A defers an approximately $3.3 million feeder upgrade using about 1.5 MW of C&I demand response on a single constrained feeder. Project B defers a $20 million substation expansion using about 10 MW of demand response (C&I sites and residential smart thermostats) on a constrained circuit. Both case studies apply the same methodology, described in the following section, and are presented in turn below, followed by a comparison of their results.

Both projects are hypothetical and are not based on specific distribution circuits. They are intended to demonstrate the method and the order of magnitude of value available from targeted deployment, not to represent a committed or identified investment deferral.

5.2. Methodology

The project-level analysis does not use the Utility Cost Test applied in Section 3 and instead applies the Ontario Energy Board's (OEB) recently completed Phase Two BCA Framework for NWS[2]. Because a non-wires project is evaluated in relation to a single planned capital investment rather than against system-average avoided costs, the distribution capacity benefit is measured as the difference in the utility revenue requirement between building the asset on its original schedule and building it after deferral.

For each case, the installed capital cost is added to rate base and converted into an annual revenue requirement reflecting the return on and of capital (weighted average cost of capital

[2] https://engagewithus.oeb.ca/bcaframework

and straight-line depreciation over a 40-year asset life) plus ongoing operations and maintenance. The annual difference between the reference and deferred revenue requirements is the avoided distribution capacity benefit. The model then adds the bulk system value of the same resource (avoided generation capacity, avoided transmission capacity, and avoided marginal energy costs, calculated on the same basis as the province-wide analysis) to arrive at total utility system benefits. The cost side is the annual cost of procuring and dispatching the demand response resource across the deferral period. Both streams are expressed in constant 2027 dollars and discounted to present value, and the results are reported as present value of benefits, present value of costs, net benefit, and a benefit-cost ratio.

5.3. Project A: Feeder Upgrade Deferral

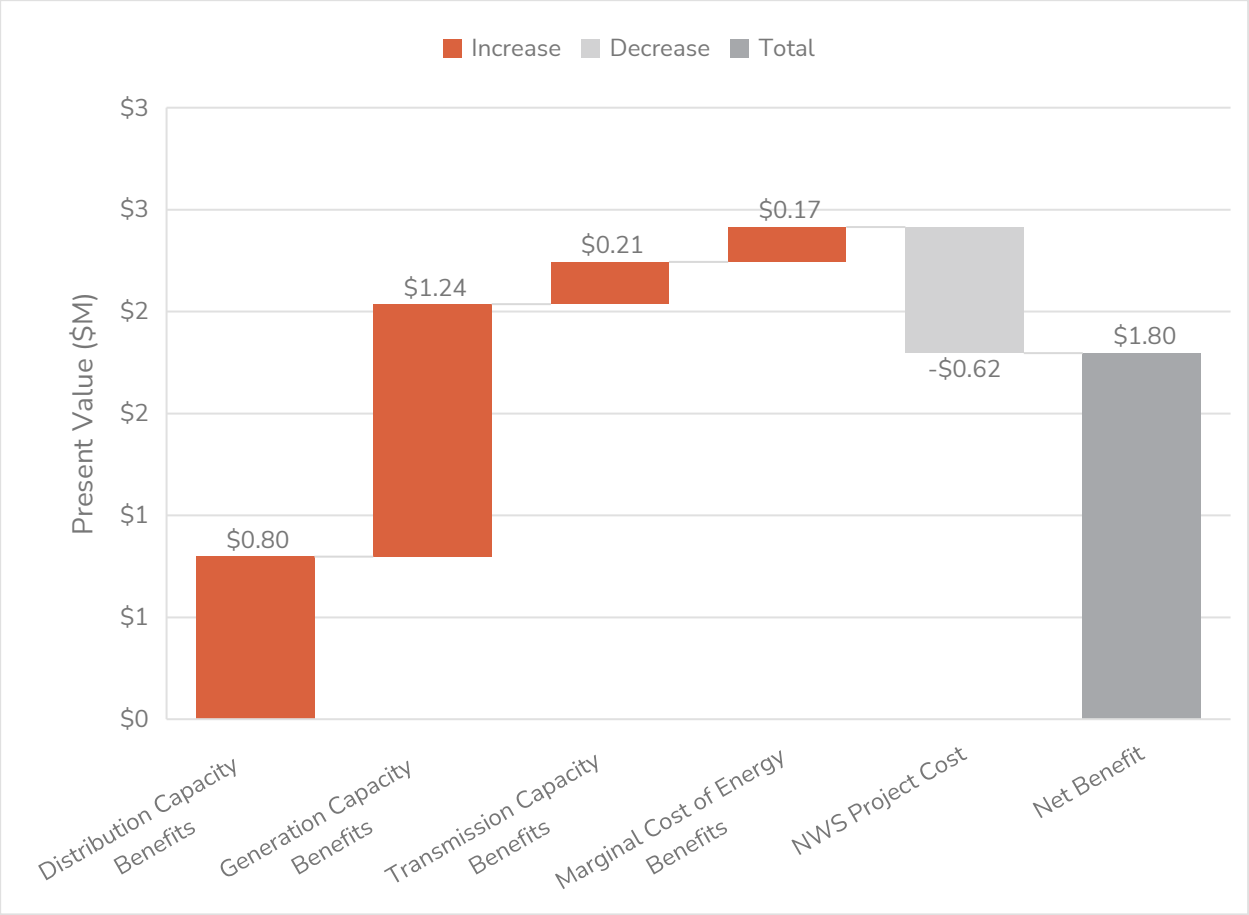
5.3.1. Project Description

Project A evaluates a hypothetical demand response deployment of approximately 1.5 MW of C&I demand response (three medium and three large sites) on a single constrained distribution feeder. In the reference case, load growth requires a distribution capacity upgrade (a new feeder, reconductoring, a regulator, and a recloser) to be placed in service in 2030, at an installed cost of approximately $3.3 million, built up from AUC/Guidehouse Net-Zero Analysis unit costs and incurred across 2027 to 2029. In the NWS case, targeted demand response holds feeder loading below the upgrade threshold for five years, deferring the same assets into service in 2035, with capital spend shifted to 2032 through 2034 and escalated at inflation. The analysis tests whether the cost of procuring and operating the demand response resource across the deferral period is less than the value to ratepayers of postponing the capital investment.

5.3.2. Results

Deferring the distribution capacity upgrade by five years produces a present value net benefit of approximately $1.8 million in constant 2027 dollars. The demand response resource costs approximately $0.6 million on a present value basis across the deferral period, while generating about $2.4 million in total utility system benefits, for a benefit-cost ratio of 3.91.

Figure 11: Net Benefits of Distribution Feeder Upgrade Deferral



As seen in Figure 11 above, avoided distribution capacity accounts for approximately $0.80 million of the total benefit, with a further $1.62 million from avoided bulk system value across avoided generation capacity, avoided transmission capacity, and avoided marginal energy costs. The bulk system contribution reflects the fact that a resource procured to relieve a local constraint also reduces some provincial peak demand during the hours it is dispatched, scaled by the coincidence factor (65%) to reflect that the feeder and system peaks do not align fully. On distribution capacity benefits alone, before any credit for bulk system value, the project would still clear the cost-effectiveness threshold, with a benefit-cost ratio of 1.3.

Table 10: Project A Cost-Effectiveness Summary

Metric	Value
Demand response capacity deployed	1.5 MW
Dispatched event hours per year	30
Deferral achieved	5 years (in service 2030 → 2035)
Traditional asset installed cost (reference case)	$3.3 million (2027 $)
PV of avoided distribution capacity benefits	$0.80 million
PV of avoided bulk system benefits	$1.62 million
PV of total utility system benefits	$2.42 million
PV of NWS project costs	$0.62 million
Net benefit (PV)	$1.80 million
Benefit-cost ratio	**3.91**

5.3.3. Assumptions & Inputs

The economic and financial parameters used in Project A are summarized below. The shared economic parameters (base year, discount rate, inflation, WACC, depreciation life, O&M share, line loss factor, and coincidence factor) also apply to Project B.

Table 11: Project A Key Assumptions

Parameter	Value
Analysis base year / dollar year	2027 (constant 2027 CAD)
Real discount rate	5.32% (7.26% nominal at 1.84% inflation)
Inflation rate	1.84%
Weighted average cost of capital	7.26%
Traditional asset depreciation life	40 years (2.5% straight-line)
O&M as share of capital expenditure	1.5% per year
Year of traditional asset need (reference case)	2030
Year of deferred installation (NWS case)	2035
Deferral period	5 years
Traditional asset installed cost	$3.3 million (2027 $), incurred 2027–2029
Deferred asset capital cost	$3.7 million nominal, incurred 2032–2034
NWS resource capacity	1.5 MW
Dispatched event hours per year	30
NWS operating period	2030–2034
Line loss factor	4.37%
C&I availability payment rate	C&I availability payment of $85/kW-year
Annual NWS project cost	$0.16 million per year
Coincidence factor (system peak vs. feeder peak)	0.65

Capital costs are built up from AUC / Guidehouse Net-Zero Analysis unit costs, escalated from their 2023 basis to constant 2027 dollars. Key economic inputs such as inflation, WACC, and

line loss, are identical to the province-wide analysis. The annual NWS project cost represents the all-in cost of holding approximately 1.5 MW of demand response available on the constrained feeder. It is incurred only during the 5-year deferral window, from the year the traditional asset would otherwise have entered service through the year before the deferred in-service date.

Because the NWS resource is dispatched against the feeder peak, which does not coincide with the provincial system peak, only part of its capability reduces load when generation and transmission capacity value is set. The avoided generation and transmission capacity benefits are therefore scaled by a coincidence factor of 0.65, crediting about 0.98 MW of the 1.5 MW feeder-peak capability.

5.4. Project B: Substation Expansion Deferral

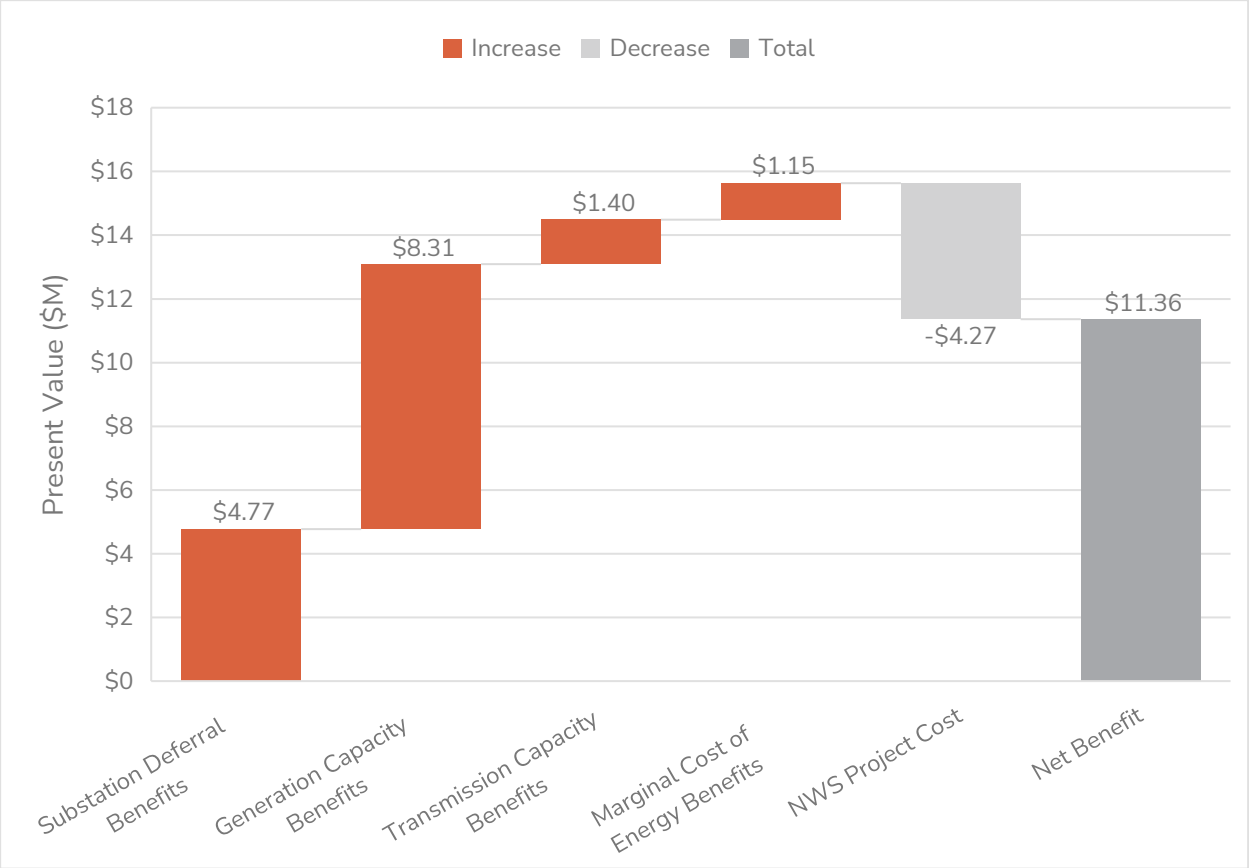
5.4.1. Project Description

Project B evaluates a hypothetical demand response deployment of approximately 10.1 MW on a constrained distribution circuit, comprising about 9.8 MW of C&I capacity (30 medium and 17 large sites) and about 0.3 MW from 500 residential smart thermostats. In the reference case, forecast load growth requires a substation expansion to be placed in service in 2030, at an installed capital cost of approximately $20 million in 2027 dollars ($20.3 million nominal) incurred across 2027 to 2029. In the NWS case, targeted demand response holds circuit loading below the expansion threshold for five years, deferring the same expansion into service in 2035, with capital spend shifted to 2032 through 2034 and escalated at inflation. The analysis tests whether the cost of procuring and operating the demand response resource across the deferral period is less than the value to ratepayers of postponing the capital investment.

5.4.2. Results

Deferring the substation expansion by five years produces a present value net benefit of approximately $11.4 million in constant 2027 dollars. The demand response resource costs approximately $4.3 million on a present value basis across the deferral period, while generating about $15.6 million in total utility system benefits, for a benefit-cost ratio of 3.7.

Figure 12: Net Benefits of Substation Expansion Deferral through NWS



As seen in Figure 12, avoided substation capacity increase accounts for approximately $4.8 million of the total benefit, and $10.9 million comes from avoided bulk system value across avoided generation capacity, avoided upstream transmission capacity, and avoided marginal energy costs. Measured against distribution capacity benefits alone, before any credit for bulk system value, the project screens as cost-effective, with a benefit-cost ratio of 1.1. The bulk system contribution reflects the fact that a resource procured to relieve a local constraint also reduces provincial peak demand during the hours it is dispatched, and it adds further upside on top of the substation deferral value alone.

Table 12: Project B Cost-Effectiveness Summary

Metric	Value
Demand response capacity deployed	10.1 MW
Deferral achieved	5 years (in service 2030 → 2035)
Traditional asset installed cost (reference case)	$20.0 million (2027 $)
PV of avoided distribution capacity benefits	$4.77 million
PV of avoided bulk system benefits	$10.86 million
PV of total utility system benefits	$15.63 million
PV of NWS project costs	$4.27 million
Net benefit (PV)	$11.36 million
Benefit-cost ratio	**3.66**

5.4.3. Assumptions & Inputs

Project B uses the same shared economic and financial parameters as Project A (Table 11). The project-specific parameters are summarized below.

Table 13: Project B Project-Specific Assumptions

Parameter	Value
Analysis base year / dollar year	2027 (constant 2027 CAD)
Real discount rate	5.32% (7.26% nominal at 1.84% inflation)
Inflation rate	1.84%
Weighted average cost of capital	7.26%
Traditional asset depreciation life	40 years (2.5% straight-line)
O&M as share of capital expenditure	1.5% per year
Year of traditional asset need (reference case)	2030
Year of deferred installation (NWS case)	2035
Deferral period	5 years
Traditional asset installed cost	$20.3 million nominal, incurred 2027–2029
Deferred asset capital cost	$22.2 million nominal, incurred 2032–2034
NWS resource capacity	10.1 MW (9.8 MW C&I; 0.3 MW residential)
Dispatched event hours per year	30
NWS operating period	2030–2034
Line loss factor	4.37%
C&I availability payment rate	C&I availability payment of $85/kW-year
Annual NWS project cost	$1.11 million per year
Coincidence factor (system peak vs. feeder peak)	0.65

The annual NWS project cost represents the all-in cost of holding approximately 10.1 MW of demand response available on the constrained circuit, including participant incentives, aggregator or delivery fees, and measurement and verification. As in Project A, it applies a C&I availability payment of $85 per kW-year, above the $75 per kW-year rate used in the

province-wide C&I program, reflecting the added cost of recruiting and holding capacity within a defined geographic footprint. It is incurred only during the 5-year deferral window, from the year the traditional asset would otherwise have entered service through the year before the deferred in-service date.

6. Conclusions

This analysis demonstrates that demand response is a cost-effective resource for Alberta at both the system and the local level. Under a conservative 2027–2036 portfolio scenario, the combined residential and C&I programs deliver approximately 212 MW of peak reduction by 2036, a portfolio benefit-cost ratio of 2.6, and roughly $242 million in net present value. The NWS case studies are more compelling still. Targeting about 1.5 MW of C&I DR at a constrained feeder (deferring a $3.3 million upgrade for 5 years) returns $3.91 in utility system benefits for every dollar spent (Project A). Targeting about 10 MW of DR at a constrained substation (deferring a $20 million upgrade for 5 years) returns $3.66 for every dollar spent and produces a net benefit of approximately $11.4 million from a single five-year deferral (Project B).

The value of DR is greatest when it is planned and dispatched with location in mind. In the NWS case studies, where DR is targeted at a known constraint and coordinated with the utility's capital plan, avoided wires capacity accounts for roughly one-third of total benefits and would remain cost-effective on its distribution value alone. However, geotargeted opportunities are inherently limited: at any given time, only a small share of Alberta's feeders and substations are approaching a capacity constraint that DR could defer, and those opportunities arise project by project rather than across the system.

A larger opportunity exists by pairing NWS projects with system-wide DR programming. This provides consistent participation opportunities for customers while delivering an estimated $242 million in net present value province-wide over the first 10 years of implementation. These savings are driven primarily by avoiding the need for new peak generation capacity during critical peaks (30 to 40 hours per year over 10 to 15 separate events), with additional benefits from passive deferral of transmission and distribution upgrades and avoided marginal energy costs. This system-wide resource is cost-effective on its own and should not be left on the table while targeted deferral opportunities are developed. The two are complementary: a province-wide DR resource delivers system-wide savings while building institutional capacity, an enrolled customer base and dispatch capability that utilities can then direct to local constraints as they emerge, capturing the additional locational value where and when it arises.

This value is technically available today, but it is not yet accessible. Capturing it requires distribution utilities to identify emerging constraints, procure DR as an alternative to wires investment, and dispatch it against local peaks, while allowing the same resource to earn its generation and transmission value. Alberta's current policy and regulatory framework does not yet provide a clear pathway for utilities to do this. Under current ratemaking, deferring a capital project also reduces the asset base on which a utility earns a return, so even a highly cost-effective deferral can work against the utility's financial interest. Without a framework that addresses these barriers, most of the stacked value demonstrated in this report will go unrealized, and load growth will continue to be met primarily by building new infrastructure, even where a lower-cost non-wires alternative exists.

The value of DR will continue to increase as load growth from data centres, electrification and EV adoption is expected to drive significant infrastructure investment over the coming decade. Each project built without a non-wires alternative being considered locks in capital costs for 40 years or more, while DR capability, once enrolled, can be redeployed as system needs change. Every year without an enabling framework is a year of deferral opportunities forgone.

To realize this value, Alberta should develop a policy and regulatory framework that: (1) guides utilities in how to evaluate DR and other non-wires alternatives alongside traditional solutions in distribution system planning and capital applications; (2) allows utilities to recover the cost of procuring DR as a non-wires solution and provides an incentive comparable to the return earned on capital, so that deferral is not financially penalized; (3) establishes a consistent cost-effectiveness methodology that credits locational distribution value alongside generation and transmission value, consistent with the approach applied in this report and other jurisdictions; and (4) clarifies how utility-procured DR can also be used to provide value to the broader provincial electricity system.

DR will not replace the need for new generation, transmission, and distribution infrastructure, but it can help manage total system costs. This analysis shows that the value of DR is worth pursuing to help manage the affordability of Alberta's electricity system. A framework that enables utilities to capture both the locational and system-wide value of DR is the step needed to turn that value into lower costs for Alberta ratepayers and a more flexible, reliable grid.

Appendix A: Model Inputs and Assumptions

This section outlines the major assumptions used in the province-wide BCA model, including common parameters applicable to both Residential and C&I programs, followed by specific assumptions for each of the programs.

A.1. Common Assumptions (All Province-Wide Programs)

A.1.1. Study Period

The model timeline was 2027 to 2036, covering a ten-year period for program implementation and impact evaluation. This duration was chosen to capture electric load growth anticipated to occur over that period, as well as to show the program impacts across the full effective useful life of the demand response devices. All monetary figures are presented in 2027 Canadian dollars, with cash flows adjusted annually by a 1.84% inflation rate to reflect projected cost increases over time.

A.1.2. Discount Rate

A 5.32% real discount rate is used to convert future costs and benefits to present value (this corresponds to a 7.26% nominal discount rate at 1.84% inflation). This rate reflects the utility-weighted average cost of capital (WACC) and is consistent with long-term financing assumptions for Alberta utility investments.

A.1.3. Line Losses

An electric line loss factor of 4.37% is applied to all energy and demand savings, meaning demand reductions at the customer level provide slightly higher upstream savings in generation and T&D due to avoided line losses. This analysis used the AESO system average loss factor, updated 2026.[3]

A.1.4. Event Frequency

The program is assumed to dispatch 40 hours of DR events per year for electric vehicle charging and battery energy storage systems, and 30 hours for smart thermostats and C&I DR (e.g., ten 3-hour events or fifteen 2-hour events during critical peak periods). These event design parameters are in line with utility DR program designs across North America. Note that the model does not make a distinction between the number of summer or winter events except for heating and cooling, which are seasonal.

[3] Alberta Electric System Operator. 2026. https://www.aeso.ca/grid/grid-related-initiatives/loss-factors/

A.1.5. Dispatch Strategy

The program is assumed to target system peak hours (likely hot summer afternoons and cold winter peak evenings) when the aggregated load reductions have highest value to the system[4]. Each participating customer receives a signal to reduce load or shift usage during these peak events through pre-enrolled curtailment strategies (e.g., HVAC cycling, delaying industrial processes, or using backup generators). A standard event opt-out rate of between 5% and 30% is factored in, depending on customer and device type. These opt-out values were derived from CLEAResult's recent DR program delivery experience.

A.2. Avoided Cost Parameters

Avoided capacity costs were drawn from recent Alberta-specific studies published by the AUC and AESO. The major avoided cost inputs in the model are enumerated below, along with sources and any associated calculations.

A.2.1. Avoided Generation Capacity Cost

The avoided generation capacity cost for this model was calculated as $314.33 per kW-year (CAD) in 2027, escalating with inflation to approximately $370 per kW-year by 2036, representing the annualized capital cost of a new combined-cycle gas generating plant. This value was derived using the capital cost of the Greenlight Electricity Centre project[5], which was cited by numerous stakeholders in AESO's 2026 Long-Term Outlook outreach[6] as a representative near-term estimate. The calculation accounts for an overnight capital cost of $4,290/kW (2026 CAD), inflation over the study period, a 25-year recovery period, and a capital recovery factor (CRF) of 0.0733 at the 5.32% real discount rate. Below is a comparison with other studies with calculated avoided generation capacity. The value used here is higher than the IESO and Manitoba Hydro estimates, which are based on simple-cycle gas turbines, and falls within the range of the BC Hydro long-run marginal cost of capacity.

[4] Distribution-level peaks do not always coincide with the provincial system peak. Where DR is used to address local constraints, event windows can be tailored to distribution peaks, although the province-wide analysis primarily values reductions at the system peak. The NWS case studies in Section 5 illustrate this approach: DR is dispatched against the local feeder or substation peak, and its bulk system value is credited using a coincidence factor of 0.65.
[5] https://www.aeso.ca/grid/grid-planning/forecasting/2024-long-term-outlook/ Pembina Corporation, Greenlight Electricity Centre project capital cost, as cited in AESO 2026 Long-Term Outlook stakeholder outreach. 2026. https://www.pembina.com/media-centre/news/details/3403fb77-2257-466b-a8e2-f043f4cd4650.
[6] AESO 2026 Long-Term Outlook Plan. https://aesoengage.aeso.ca/2026-long-term-outlook-plan.

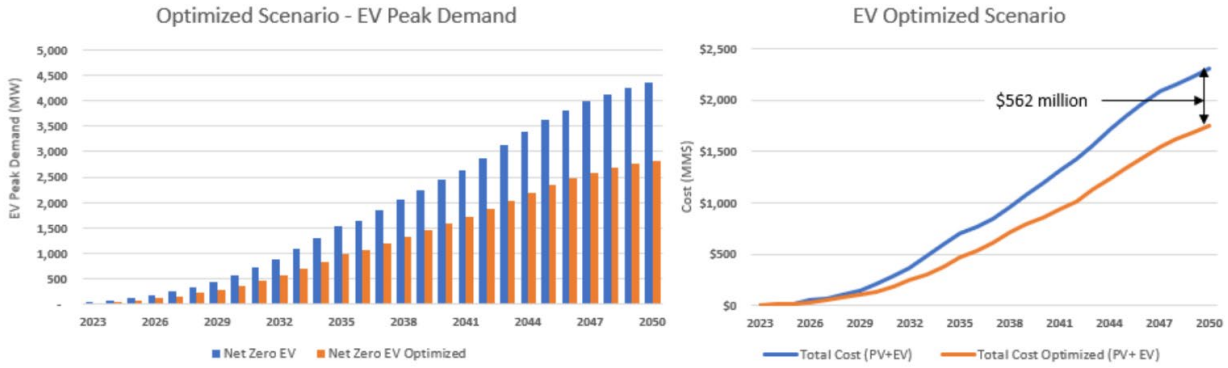
Table 14: Jurisdictional Scan of Avoided Generation Capacity Costs

Study/Source	Estimate	Resource/Type	Year
IESO: Guide to Assessing Non-Wires Alternatives[7]	$144/kW-year	Cost of the Marginal New Resource, simple cycle gas turbine	2023
Manitoba Hydro 2025 Integrated Resource Plan[8]	$121/kW-year	Levelized cost of winter capacity, natural gas simple cycle gas turbine	2026
BC Hydro 2025 Integrated Resource Plan[9]	$200–$400/kW-year	Long-run marginal cost of capacity	2025

A.2.2. Avoided Distribution System Capacity Cost

The avoided distribution system capacity cost is applied at the system level to all DR capacity in the model. The Guidehouse Net-Zero Analysis of Alberta's Electricity Distribution System commissioned by the AUC is used as the primary source for the system-level avoided capacity cost. Figure 13 below is contained within this report and shows the increasing cost of new distribution capacity as load growth expands on the distribution system.

Figure 13: Forecasted Peak Demand and Cost for Net-Zero and Optimized Scenarios



For this model, the avoided distribution capacity cost at the system level varies by year from $28 to $35 per kW-year as derived from the annualized avoided cost estimates in the Guidehouse report referenced above. For example, the report shows that optimized deployments of distribution systems could reduce incremental infrastructure costs by $230 million in 2036 or about $17 million/year on a revenue requirement basis. This investment

[7] IESO Guide to Assessing Non-Wires Alternatives. 2023. Page 25. https://www.ieso.ca/en/Sector-Participants/IESO-News/2023/06/Non-Wires-Alternatives-Guide-Posted-for-Regional-Planning
[8] Manitoba Hydro 2025 Integrated Resource Plan. 2026. Appendix 6 Resource Options. https://www.hydro.mb.ca/docs/corporate/irp/2025-irp-report-appendix-a6.pdf
[9] BC Hydro 2025 Integrated Resource Plan. 2025. Section 1.2.2 Capacity LRMC. https://docs.bcuc.com/documents/proceedings/2025/doc_84202_b-1-bch-2025-irp-application.pdf

would result in optimized savings of 510 MW of load, which is equivalent to an average value of $32/kW-yr (see Figure 13).

Below is a comparison with other recent studies with calculated costs of avoided distribution capacity.

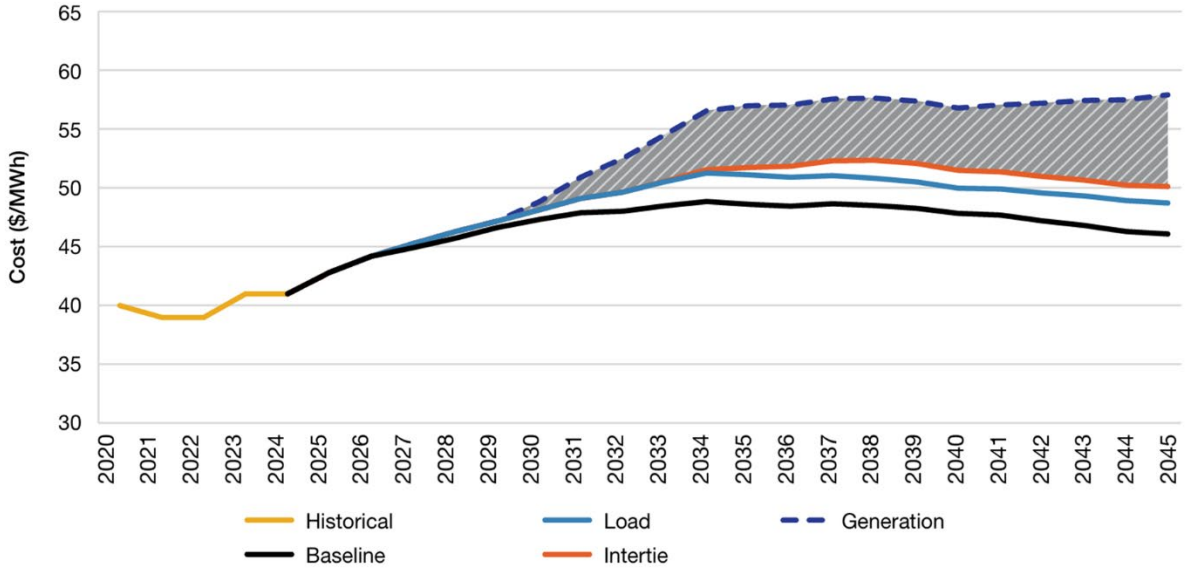
Table 15: Jurisdictional Scan of Avoided Distribution Capacity Costs

Study/Source	Estimate	Resource/Type	Year
IESO/ICF York Region Non-Wires Alternatives Demonstration Project (Table 15 – Rolling 5-year MTS Deferral Value)	$12/kW-year, $67/kW-year and $80/kW-year for slow, medium, and high growth cases.	Distribution deferral value	2023
BC Hydro 2025 Integrated Resource Plan (Section 1.3.3, Figure F-2)	Long Run Marginal Cost of distribution at $40/kW-year	Long run marginal cost of distribution	2025

A.2.3. Avoided Transmission Capacity Cost

For avoided transmission capacity costs, this analysis leveraged the load growth-driven transmission costs in the *2025 AESO Long Term Transmission Plan* (see the difference between the baseline and load curves in Figure 14 below). The avoided transmission capacity cost varies by year from $34 to $64 per kW-year.

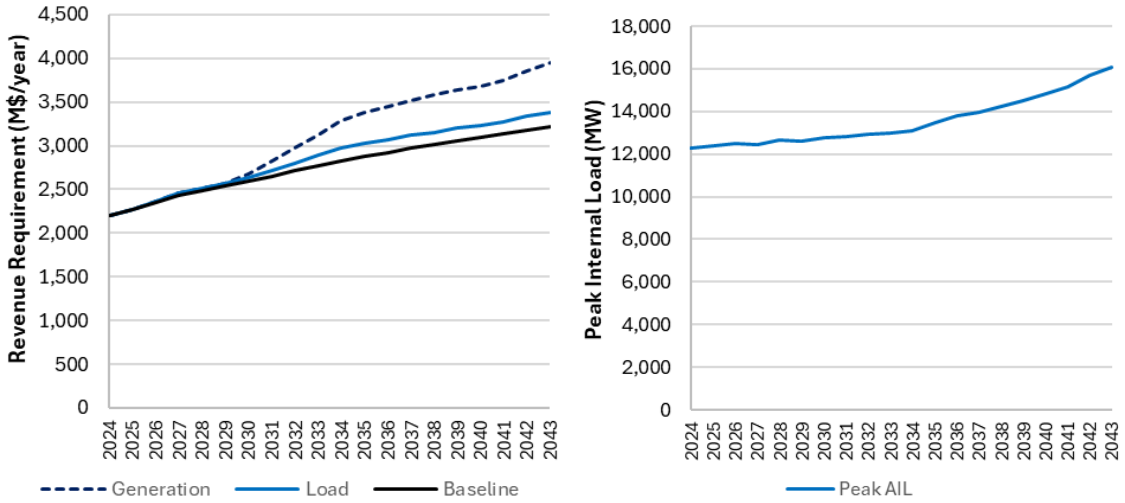
Figure 14: AESO Forecasted Transmission Costs ($/MWh)



The *AESO Long Term Transmission Plan* projects about $2.6/MWh transmission cost increase to meet load growth by 2036. This translates to approximately $150 million/year in 2036 on a revenue requirement basis for just the wires costs (see the left side of Figure 15 below). Since transmission assets must be constructed in advance, we make a further assumption that the

transmission is built to meet future load growth. For instance, a 5-year outlook would translate to about $64/kW-yr in 2036 for an incremental 2,430 MW of peak AESO internal load (AIL) expected by 2040 (see right side of Figure 15 below).

Figure 15: AESO Forecasted Revenue Requirement and Peak Internal Load



Below is a comparison with other studies with calculated costs of avoided transmission capacity.

Table 16: Jurisdictional Scan of Avoided Transmission Capacity Costs

Study/Source	Estimate	Resource/Type	Year
IESO Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives	$104/kW-year, $112/kW-year and $174/kW-year for slow, medium, and high growth cases	Transmission deferral value	2023
BC Hydro 2025 Integrated Resource Plan	$70/kW-year	Long run marginal cost of non-bulk transmission	2025
AESO 2026 Marginal Cost of Service Study	$64–79/kW-year	Long run marginal cost of transmission for coincident peak load	2026

A.2.4. Avoided Marginal Cost of Energy

Demand response dispatched during critical peak events avoids energy that would otherwise be procured at or near the wholesale market ceiling. Alberta's offer cap is currently $999.99/MWh. Under the Restructured Energy Market (REM), the offer cap will initially rise to $1,500/MWh (with an additional offer cap increase to $2,000/MWh in 2032) while the price cap rises to $3,000/MWh. For this analysis, avoided marginal energy costs were set at two-thirds of the initial $1,500/MWh REM offer cap, or $1,000/MWh for 2027–2028, increasing to $1,500 in 2029.

A.3. Residential DR Program Assumptions

The residential program focuses on controlling customer-sited devices to reduce peak demand in both summer and winter seasons. It targets widespread participation across Alberta's roughly 1.6 million households, emphasizing technologies that can deliver reliable demand reductions during peak periods.

A.3.1. Program Overview

The residential program has the following characteristics:

Table 17: Residential Program Characteristics

Characteristic	Details
Customer Class	Residential
Allowed Devices	• Smart thermostat-controlled electric heating (e.g., heat pump, baseboard heating) and/or air conditioning • Battery energy storage systems • Electric vehicle charging
Event Details	• Up to 40 event hours per year for electric vehicle charging and battery energy storage systems; up to 30 event hours per year for smart thermostats • Program is modeled to be operated year-round; however, electric heating would only be available in winter and Res A/C would only be available in summer.

A.3.2. Eligible Technologies

The program covers multiple device types in homes for both summer and winter DR. These technologies were chosen because of their suitability to demand response and increased grid impact due to their projected rate of adoption over the coming years.

- **Smart Thermostats – A/C Control**: Direct load control of central air conditioners and heat pumps (via thermostats or switches) to manage summer cooling demand.
- **Smart Thermostats – Heating Control**: Controlling electric heating systems (e.g., baseboard heaters, electric furnaces, and heat pumps) via smart thermostats.
- **Residential Electric Vehicle Service Equipment (EVSE)**: Level 2 home charging for electric vehicles. DR strategy is managed charging (no vehicle-to-grid), which pauses or shifts EV charging during peak hours. Enrolment and control can occur through the charging equipment or through direct vehicle telematics.
- **Residential Battery Energy Storage Systems (BESS):** Home battery installations that can be discharged to reduce grid load during peak events.

A.3.3. Participation & Growth

The participation rates in the residential DR program assume a first-year enrolment rate of 10–20% of eligible devices. Program enrolment then grows by 20% per year through 2029, by 15% per year in 2030 and 2031, and by 10% per year thereafter (i.e., the rate of growth slows as the program matures, but total enrolment continues to increase every year). A 2% annual attrition rate is applied to reflect natural withdrawals from the program each year. Initial program enrolment rates reflect the high likelihood that early adopters of DER technology are more likely to participate in energy management services than the general population.

For all device types except EVs, population growth rates are modeled to follow an S-curve with approximate growth rates specified by year including high growth in the first few years as more Albertans invest in DERs, increasing the addressable market and enrolment rates in the program, and growth tapering off in later years. EV adoption rates follow the adoption curve specified in the AUC-Guidehouse study, scaled to actual EV registration counts in 2025. Key participation assumptions are enumerated below:

Central A/C Thermostats

- **Starting participation (2027)**: The Central A/C smart-thermostat population is derived from Natural Resources Canada data on historical central cooling-system stock in Alberta, with an assumption that roughly 20% of the stock is managed by a smart thermostat. This produces an addressable population of approximately 200,000 devices in 2027. The model assumes a 20% program enrolment rate (of smart thermostat connected AC) in the first year.
- **Growth**: A/C thermostat growth projected forward on a saturation curve and multiplied by a smart-thermostat penetration curve rising from 20% of stock in 2027 to 49% in 2036.

Home Battery Energy Storage Systems (BESS)

- **Starting population (2027)**: The 2027 addressable population for home battery energy storage systems is estimated to be 100, based on information provided by distribution utilities. The model assumes a 10% program enrolment rate in the first year.
- **Growth**: Participation is modeled to follow the same S-curve adoption rate as smart thermostats, with the program population reaching 34 by 2036.

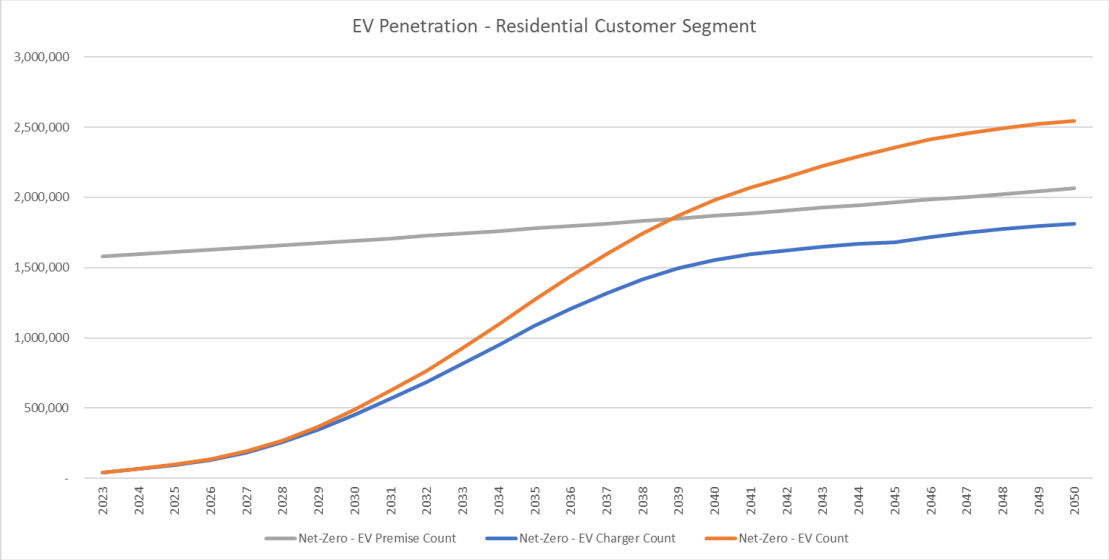
Residential EV Charging (EVSE)

- **Starting population (2027)**: There were 19,863 electric vehicles registered in Alberta as of 2025, according to the Alberta Government. This analysis estimates

approximately 39,700 vehicles to be registered as of 2027, of which 20% (approximately 7,900 EVs) are assumed to enroll in the first year.

- **Growth**: The model used the EV adoption curve developed for the AUC-Guidehouse Net-Zero Study to estimate annual growth in the program as shown in Figure 16 below. The annual participation numbers were scaled to the 2025 registration values, with an annual "catch-up" escalation factor of 5% applied to capture increasing rates of EV adoption. By 2036, the model forecasts approximately 88,000 enrolled EV chargers.

Figure 16: EV adoption curve, AUC-Guidehouse study



Electric Heating Thermostats

- **Starting participation (2027)**: The electric heating smart-thermostat population is derived from Natural Resources Canada data on the stock of electrically heated single-family homes in Alberta (roughly 160,000), with the same smart thermostat penetration assumed for central A/C (roughly 21% in 2027). This produces an addressable population of approximately 33,600 devices in 2027. The model assumes a 20% program enrolment rate in the first year.
- **Growth**: Thermostat growth projected forward on the same saturation curve as central A/C, and multiplied by a smart-thermostat penetration curve rising from 20% of stock in 2027 to 49% in 2036.

A.3.4. Load Reduction Capability

The estimated peak demand reduction per device is based on empirical results from similar DR programs and adjusted for Alberta's conditions. In the model, each enrolled device contributes a fraction of its capacity to peak load reduction, accounting for participant opt-out or under-performance:

Smart Thermostats (Heating/Cooling)

- **Load reduction per device**: 0.8 kW per central A/C thermostat and 0.7 kW per electric-heating thermostat, maximum reduction per home on average (per event)
- **Opt-out rate**: 30% opt-out rate on any given event.

Below is a comparison with load reduction values utilized for smart thermostats across other jurisdictions:

Table 18: Jurisdictional Scan of Thermostat Load Reductions

Jurisdiction	End-Use	Per-Device Load Reduction
British Columbia[10]	Electric Heating (Baseboard)	0.2–0.7 kW per thermostat
Ontario (IESO)[11]	Central A/C (Cooling)	0.8 kW per thermostat
Prince Edward Island[12]	Electric Heating (Baseboard and Air Source Heat Pump)	0.7–1.4 kW per thermostat

This table summarizes typical load reduction values found in demand response potential studies and utility pilot programs, showing that realized reductions depend on device type, climate, and program design.

EV Charging (Level 2)

The model assumes a maximum load reduction of 1.5 kW per enrolled Level 2 charger with a 30% in-service rate, reflecting the share of enrolled vehicles that are plugged in and charging when an event is called. This yields an effective average reduction of approximately 0.45 kW per enrolled EV, consistent with the AUC-Guidehouse Net Zero study estimate of 0.4 kW per EV.

Battery Energy Storage Systems (BESS)

For residential battery energy storage systems, the model assumes an average dispatchable load reduction of 4 kW per participating site during peak events. A 5% availability derate is applied to account for connectivity issues, operational constraints, or instances where the battery may not be sufficiently charged at the time of dispatch. The actual load reduction available from a home battery depends on the system's power rating, usable energy capacity, state of charge, and whether the battery is allowed to export or only serves household load during the event. The 4 kW assumption reflects a typical residential battery with a continuous power rating of about 5 kW and roughly 13.5 kWh of usable capacity; sustaining 4 kW over a

[10] BC Distributed Energy Resource Potential Study. 2022. https://cleanenergycanada.org/wp-content/uploads/2026/03/Dunsky_CEC_DER-Potential-Study_FINAL.pdf
[11] IESO 2025-2027 Electricity Demand Side Management Program Plan (with Beneficial Electrification). 2025.
[12] Dunsky & Associates EE & DR Achievable Potential Study Appendix E. 2021. https://irac.pe.ca/wp-content/uploads/Exhibit-E-1i-Appendix-F-Dunsky-Enegy-Consulting-PEI-Energy-Efficiency-Potential-Study-2021.12.20-Final.pdf

3-hour event uses about 12 kWh (roughly 90% of usable capacity), a discharge rate of about 0.3C.

A.3.5. Incentive Structure

The residential DR program uses a bring-your-own-device (BYOD) model, offering customers financial incentives to enroll their existing devices in DR events (rather than direct utility control of utility-owned devices). Incentives are designed to drive participation while remaining cost-effective. This model includes both a one-time enrolment incentive as well as an ongoing participation incentive to encourage continued participation in the program. Below is a breakdown of the different incentive levels specified for each device type.

Table 19: Incentive Levels by Device Type

Device Type	Enrolment Incentive	Participation Incentive
Smart Thermostat – Heating	$50	$25
Smart Thermostat – Cooling	$50	$25
Electric Vehicle	$50	$50
Battery Energy Storage	$200	$200

Below are some incentive rates from similar DR programs across similar jurisdictions for different device types.

Table 20: Jurisdictional Scan of Incentive Levels by Device Type

Program Name	Enrolment Incentive	Participation Incentive (per year/season)
Smart Thermostats		
IESO Peak Perks (summer)[13]	$75	$20
BC Hydro Peak Saver (winter)[14]	$100	$50
Hydro-Quebec Hilo (winter)[15]	$70–$110	$150
Efficiency Nova Scotia Eco Shift	$100	$30
MassSave Connected Solutions (summer) (MA, USA)[16]	$50–100 USD	$20 USD
Electric Vehicles		
BC Hydro Peak Saver (winter)	$250	$50
Efficiency Nova Scotia Eco Shift	$50	$50

[13] IESO Peak Perks. https://saveonenergy.ca/For-Your-Home/Peak-Perks
[14] BC Hydro Peak Saver. https://www.bchydro.com/powersmart/residential/rebates-programs/peak-saver/enroll-smart-home-devices.html
[15] Hydro-Quebec Hilo. https://www.hydroquebec.com/residential/energy-wise/offers-to-save/smart-thermostats-for-zero-dollar.html
[16] MassSave. https://www.masssave.com/residential/rebates-offers-services/connectedsolutions/connectedsolutions-thermostat

Portland General Electric Smart Charging Program (OR, USA)	$50 USD	$50 USD
Clark Public Utilities (WA, USA)	$25 USD	$25 USD
Battery Storage		
Efficiency Nova Scotia Eco Shift	$500	$300
BC Hydro Peak Saver (winter)	$500	$250
APS Storage Rewards Battery Pilot (AZ, USA)	$0	$110 per kW USD
National Grid ConnectedSolutions (MA, USA)	$0	$275 per kW USD

smart thermostat programs in North America generally offer in the range of $50–100 for a sign-up bonus and between $20–150 in annual ongoing incentives, depending on the program design. Electric vehicle programs in North America offer between $25–250 for an enrolment incentive and $25–50 per year for ongoing participation. Battery energy storage DR programs in North America offer a wide range of incentive amounts to program participants, owing to the wide range of applications for energy storage.

A.3.6. Program Costs

CLEAResult has extensive experience with implementing and managing demand management programs, and an understanding in general of how program budgets are allocated to different overhead costs. The following categories of program costs were included in the analysis:

- **DERMS Fees**:
  - Device Fees: Distributed Energy Resource Management System (DERMS) providers charge a per-device fee for device access. A DERMS system is a software platform that is used to enroll and coordinate devices/sites participating in DR/DER programs. There are often economies of scale for larger device counts.
  - Annual License Fee: Standard license fee charged for DERMS platform.
  - One-time Setup Fee: Standard fee charged by DERMS vendors associated with implementation, including integration, configuration, and testing.
  - OEM Fees: Original Equipment Manufacturers (OEMs, i.e., smart thermostat or EVSE vendors) generally charge a per-device fee on top of the DERMS device fee to access the device.
- **Program Admin & Management**: These costs include program design, customer enrolment, event management, DERMS management, customer support, and reporting.
- **Marketing/Recruitment**: Outreach to customers and recruitment of participants.
- **Measurement & Verification (M&V)**: Independent evaluation of the demand reductions achieved, consistent with regulatory expectations.

A.4. Commercial & Industrial (C&I) DR Program Assumptions

The C&I program targets demand response in commercial buildings and industrial facilities, leveraging load curtailment and behind-the-meter generation or storage to reduce peak demand. The program design is based on typical penetration rates and load reduction capabilities in various sectors.

A.4.1. Program Overview

Table 21: C&I Program Characteristics

Characteristic	Details
Customer Class	Non-Residential
Allowed Devices	No restrictions on devices; enrolment is run through aggregators
Event Details	Up to 30 event hours per year
Participation Model	Customers enroll through aggregators, who manage program participation and distribute incentive payments.

A.4.2. Target Facilities

The analysis encompasses a range of C&I customer segments in Alberta, including office buildings, retail stores, warehouses, and industrial plants. Different size categories within each segment are considered (e.g., small, medium, large offices; small vs. big-box retail; small vs. heavy industry) to estimate the number of sites and their available DR potential. All sectors are assumed to contribute to one unified C&I DR program.

A.4.3. Market Size & Enrolment

The total number of non-residential buildings in Alberta is approximately 30,700 spread across various building sizes and market segments. For this analysis, the program targets medium and large buildings (about 11,700 buildings; small offices, small retail, and small industrial and warehouse sites are not enrolled), and initial enrolment was estimated at roughly 5% of those buildings, for a total of 585 sites. Program enrolment grows by 10% each year (offset by a 2% annual attrition rate) as DR awareness and automated control capabilities expand in C&I sectors. By 2036, participation reaches approximately 1,200 sites (roughly doubling the first-year enrolment).

A.4.4. Per-Facility DR Potential

The load reduction per participating facility varies widely by type/size of customer, based on typical peak demands and curtailment strategies seen in other CLEAResult programs. The actual load reduction per site is highly variable, dependent upon available control technology, site energy use profile, and operational characteristics; however, round values were used to estimate average program-wide load reduction potential.

- **Small Commercial**: Peak demand of 20–50 kW per site; achievable curtailment of roughly **5 kW per site** (about 10–20% of peak load via HVAC and lighting adjustments).
- **Medium Commercial**: Peak demand of 150–300 kW; curtailment of roughly **30–40 kW per site** (shedding 10–20% through HVAC, lighting, refrigeration, etc.).
- **Large Commercial/Institutional**: Peak demand in the hundreds of kW to 1 MW+; curtailment **100–150 kW per site** (via advanced energy management systems, e.g., HVAC setpoint changes, dimming, and some standby generation).
- **Industrial Facilities**: Wide range; small industrial sites (100 kW peak) might curtail 10–30 kW, whereas large industrial plants (>5 MW peak) could curtail 500 kW or more via process adjustments or on-site generation. The model assumes peak reductions of 25 kW for small, 500 kW for medium, and 1,000 kW for large industrial and warehouse sites.

A.4.5. Incentive Structure

The C&I program is aggregator-led, and the incentive is designed to align with other aggregator-led programs that feature only a capacity payment for performance. This analysis assumed an annual payment of $75 per kW of verified demand reduction capability for each participant. For context, Table 22 below compares the modeled capacity payment with capacity-based compensation available to C&I demand response participants in other jurisdictions.

Table 22: Jurisdictional Scan of Aggregator-Led C&I Capacity Payments

Program (Jurisdiction)	Compensation Structure	Capacity Payment
IESO Peak Performance (Ontario)[17]	Performance payment on average kW curtailed	$75 per kW-season
BC Hydro DR for Business[18]	Performance payment on average kW curtailed	$50 per kW-season
Efficiency Nova Scotia Smart Synergy[19]	Performance payment on average kW curtailed	$100 per kW-season
NB Power Peak Rebate[20]	Performance payment on average kW curtailed	$60 per kW-season
C&I ConnectedSolutions – Targeted Dispatch (Massachusetts, USA)[21]	Performance payment on average kW curtailed	$35–$100 per kW-season (USD), depending on technology

[17] https://saveonenergy.ca/For-Business-and-Industry/Programs-and-incentives/Peak-Performance-Program
[18] https://www.bchydro.com/powersmart/business/programs/large-demand-response/behavioural.html
[19] https://www.efficiencyns.ca/programs-rebates/smart-synergy-program
[20] https://www.nbpower.com/en/save-energy/peak-rebate-program
[21] https://www.capelightcompact.org/program/commercial-connected-solutions/

The proposed $75 per kW-year is broadly consistent with the utility-funded C&I incentives above once currency and program design are accounted for, and it sits below gross wholesale capacity value. Market-cleared prices such as the IESO Capacity Auction represent revenue to the aggregator before margin, measurement and verification, and non-performance risk are deducted, so net payments reaching the end participant are materially lower than the clearing price implies. The Alberta assumption is therefore intended as a realistic net-to-customer capacity payment rather than a market price, while leaving room to escalate if Alberta system conditions tighten.