



Draft Assumptions for the 2026 eDSM Achievable Potential Study

April 22, 2026

Welcome and Introduction

- Today's session will be recorded and available for viewing online
- The recording and presentation for this engagement can be found on the [2026 Provincial eDSM Achievable Potential Study](#) engagement page

Shared Commitment to Respectful Participation

To support a focused and constructive discussion:

- We will take questions one at a time; please use the raise-hand feature to enter the speaking queue
- We encourage concise and focused comments to allow time for multiple perspectives
- Participants are encouraged to raise relevant points during the discussion and provide more detailed feedback through the written submission process
- We ask that all participants maintain a respectful and professional tone throughout the session
- Facilitators will guide the discussion and manage participation to stay aligned with today's focus and agenda
- Where necessary, we may disable a participant's microphone to manage participation

Territory Acknowledgement

The IESO acknowledges the land we are delivering today's webinar from is the traditional territory of many nations including the Mississaugas of the Credit, the Anishnawbe, the Chippewa, the Haudenosaunee and the Wendat peoples and is now home to many diverse First Nations, Inuit and Métis peoples. We also acknowledge that Toronto is covered by Treaty 13 with the Mississaugas of the Credit First Nation.

As we have attendees from across Ontario, the IESO would also like to acknowledge all of the traditional territories across the province, which includes those of the Algonquin, Anishnawbe, Cree, Oji-Cree, Huron-Wendat, Haudenosaunee and Métis peoples.

Agenda

1. IESO: Recap of the Feb 22 focused engagement session on Demand Response (DR), Solar/Storage, and Thermal Storage input assumptions and modelling
2. IESO: Planned "macro" input assumptions
3. Cadmus: Draft input assumptions for Energy Efficiency, DR, Solar/Storage, and Thermal Storage measures
4. IESO: Next steps

Recap: Focused DR and Behind-the-Meter DER engagement session

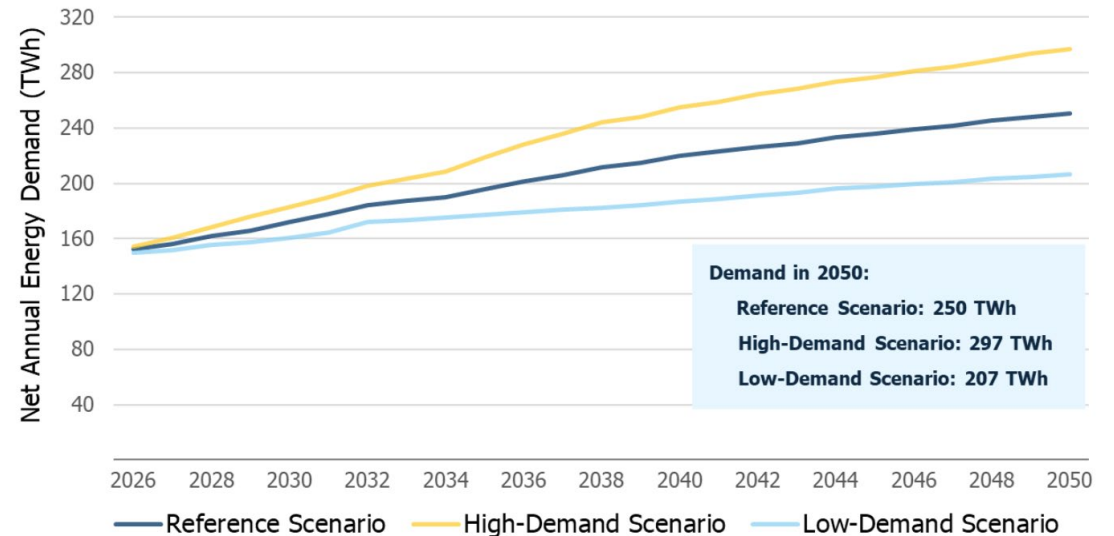
- Recognizing the IESO's less extensive program experience with demand response and behind-the-meter DER compared to traditional energy efficiency, the IESO and Cadmus hosted a focused engagement webinar on February 22
- The session shared and sought feedback on initial draft DR and DER input assumptions from stakeholders with direct DR / DER development and aggregation experience
- The feedback received has informed updated draft assumptions presented today
- A recording and materials are available on the IESO's APS engagement page

Macro inputs: demand forecast 1/2

- As discussed in previous webinars, Cadmus has built a new long-term demand forecasting tool for the IESO and is now building an integrated Achievable Potential Study module that will produce the 2026 eDSM APS
- Work is underway on development of the 2027 Annual Planning Outlook's (APO) three demand forecasts, the first to use the new long-term demand forecasting tool
- The forecasts, covering reference-, high-, and low-demand scenarios, will reflect differences in assumptions about the pace and scale of economic development and electrification (see example from the 2026 APO on the next slide), in alignment with the government's 2025 Integrated Energy Plan direction on scenario planning

Macro inputs: demand forecast 2/2

- The three demand forecasts will be used as direct inputs for the 2026 eDSM APS's three demand scenarios introduced at the September 11, 2025 webinar
- IESO has been soliciting stakeholder input on the development of the 2027 APO demand forecasts through the parallel [Annual Planning Outlook engagement](#)
- The demand forecasts, and their detailed stock assumptions, establish the technical potential available



Example 2026 APO reference, high, and low demand forecasts

Macro inputs: avoided system cost projections 1/2

- Avoided system cost projections are required to model measure cost-effectiveness at the economic potential stage
- Similar to past APS, the IESO will model annual eDSM energy and generation capacity avoided system cost projections based on the latest available (2026) APO's demand forecast and generation resource assumptions (see example at right)

Table 1: 2024 Avoided Costs (2024 Dollars)

Year	Avoided Energy Cost by Season and Time-of-Use Period (2024\$/MWh)									Avoided Capacity Costs (2024\$/kW-yr)		
	Winter Peak	Winter On Peak	Winter Mid-Peak	Winter Off-Peak	Summer On Peak	Summer Mid-Peak	Summer Off-Peak	Shoulder Mid-Peak	Shoulder Off Peak	Annual	Generation	
											Annual	System Need
2025	\$78	\$68	\$54	\$79	\$81	\$54	\$67	\$36	\$62	\$156	Summer Peak	
2026	\$89	\$77	\$69	\$85	\$81	\$65	\$67	\$57	\$71	\$156	Summer Peak	
2027	\$79	\$81	\$95	\$103	\$107	\$102	\$69	\$71	\$88	\$156	Summer Peak	
2028	\$86	\$81	\$72	\$89	\$96	\$79	\$78	\$66	\$79	\$418	Summer Peak	
2029	\$76	\$74	\$83	\$39	\$48	\$57	\$58	\$64	\$63	\$419	Summer Peak	
2030	\$50	\$54	\$69	\$48	\$48	\$63	\$51	\$70	\$59	\$419	Summer Peak	
2031	\$49	\$35	\$50	\$41	\$45	\$54	\$40	\$46	\$46	\$426	Summer Peak	
2032	\$46	\$37	\$44	\$39	\$44	\$50	\$39	\$44	\$43	\$425	Summer Peak	
2033	\$60	\$42	\$60	\$44	\$49	\$53	\$41	\$47	\$50	\$432	Summer Peak	
2034	\$50	\$36	\$47	\$37	\$39	\$42	\$28	\$31	\$38	\$452	Summer Peak	
2035	\$37	\$24	\$26	\$20	\$21	\$19	\$15	\$18	\$21	\$525	Summer Peak	
2036	\$19	\$11	\$13	\$16	\$19	\$14	\$12	\$13	\$14	\$482	Dual Peak	
2037	\$18	\$11	\$14	\$13	\$12	\$12	\$10	\$11	\$12	\$494	Dual Peak	
2038	\$16	\$9	\$12	\$11	\$12	\$11	\$10	\$10	\$11	\$482	Dual Peak	
2039	\$11	\$7	\$11	\$7	\$9	\$9	\$6	\$7	\$8	\$512	Dual Peak	
2040	\$9	\$6	\$9	\$2	\$3	\$3	\$3	\$4	\$5	\$538	Dual Peak	
2041	\$2	\$2	\$3	\$1	\$2	\$4	\$2	\$4	\$3	\$558	Dual Peak	
2042	\$3	\$1	\$3	\$2	\$4	\$7	\$2	\$6	\$4	\$573	Dual Peak	
2043	\$3	\$2	\$3	\$3	\$4	\$7	\$4	\$8	\$5	\$590	Dual Peak	
2044	\$3	\$2	\$4	\$3	\$5	\$8	\$5	\$9	\$5	\$609	Dual Peak	
2045	\$3	\$2	\$4	\$3	\$5	\$7	\$5	\$8	\$5	\$613	Dual Peak	
2046	\$3	\$2	\$4	\$4	\$6	\$8	\$7	\$9	\$6	\$612	Dual Peak	
2047	\$3	\$2	\$4	\$4	\$6	\$8	\$7	\$9	\$6	\$610	Dual Peak	
2048	\$3	\$2	\$4	\$3	\$4	\$7	\$5	\$9	\$5	\$607	Dual Peak	
2049	\$3	\$2	\$4	\$3	\$5	\$7	\$4	\$8	\$5	\$599	Dual Peak	
2050	\$3	\$2	\$4	\$3	\$5	\$7	\$4	\$8	\$5	\$610	Dual Peak	

Example 2024 APO avoided system cost projections

Macro inputs: avoided system cost projections 2/2

- Once finalized, the new set of energy and capacity benefits will be posted publicly with the 2026 APO materials
- While, the IESO does not presently have transmission deferral benefits estimates, the 2026 eDSM APS's fourth scenario explores the impact of layering on additional benefits streams (see next slide)

Macro inputs: new fourth scenario 1/2

- The IESO introduced the 2026 eDSM APS's three reference-, high-, and low-demand scenarios at the introductory engagement webinar in September 2025
- In feedback, stakeholders and the study's Advisory Group have expressed keen interest in exploring the impacts of:
 - 1.) "Stacking" additional benefits in the cost-effectiveness modelling, particularly transmission and distribution infrastructure deferral value
 - 2.) Potential trade and supply chain disruptions driving up costs for new supply resources (increasing value of new eDSM)

Macro inputs: new fourth scenario 2/2

- In response the study will include a fourth scenario featuring alternative higher capacity benefit assumptions and otherwise aligning with the reference demand scenario
- Historical and jurisdictional research has highlighted how variable and locationally contingent avoided transmission & distribution costs are based on load forecast, existing wires infrastructure, and physical constraints
- For the purposes of the study the IESO is proposing to apply a +50% adder to the "standard" generation capacity benefits that will be used for the other three scenarios

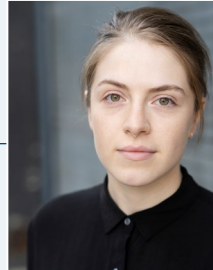
Macro inputs: customer electricity costs

- As part of the achievable potential stage, customer electricity cost inputs are required to model the customer economics of adopting eDSM measures
- Similar to past APS, these costs input assumptions will be produced based on the latest available (2026) APO.

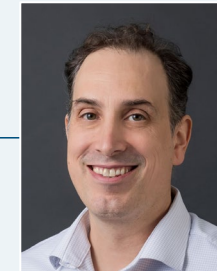
Cadmus Project Team



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Energy Efficiency and
Electrification Lead



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Danial McGhie
Behind-the-Meter Solar
and Storage Lead

Agenda: Inputs & Assumptions

Timeline and Stakeholder Engagement (2 minutes)

Energy Efficiency (15 minutes)

Demand Response (25 minutes)

Behind-the-Meter Solar and Storage (25 minutes)

Thermal Energy Storage (10 minutes)

Appendix A: Planning Study Priorities and Scope

Appendix B: Energy Efficiency Methodology &
Assumption Detail

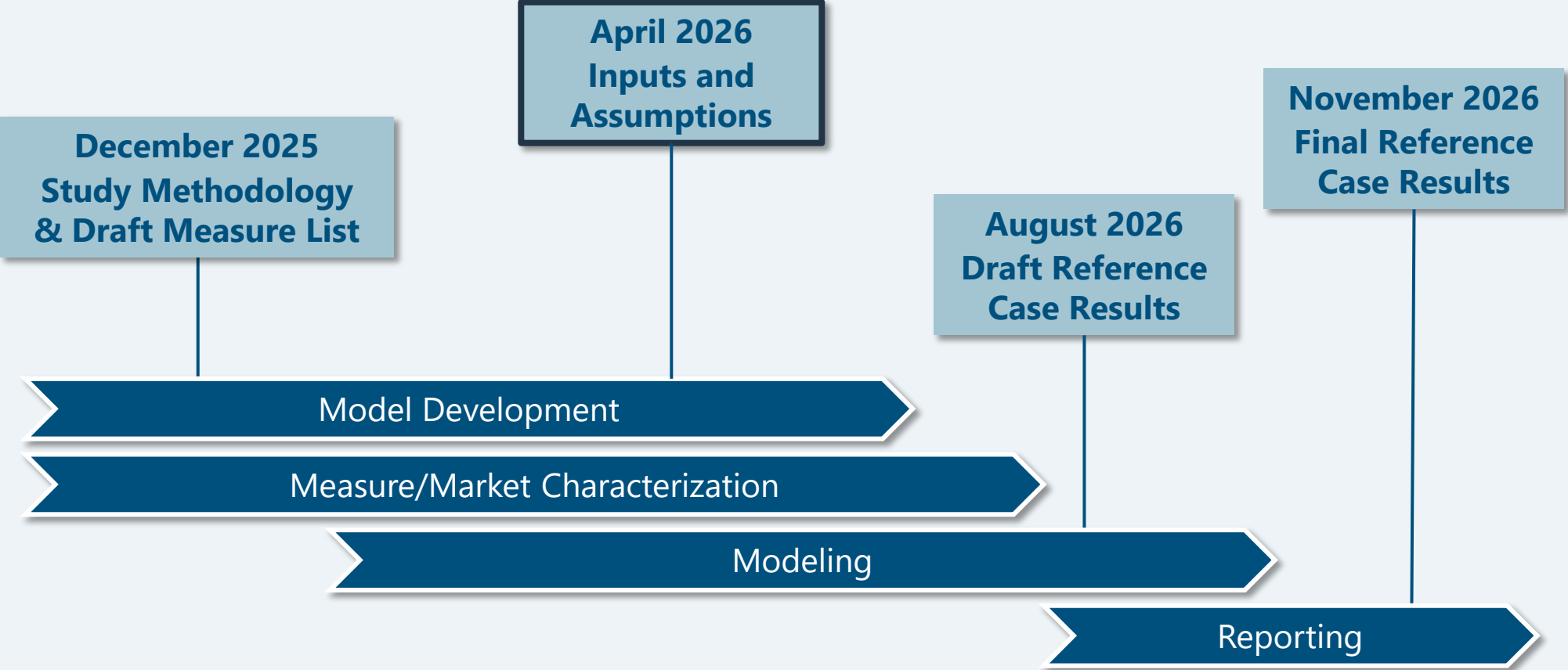
Appendix C: Demand Response Methodology Detail

Timeline and Stakeholder Engagement



Planning Study Timeline and Key Milestones

Stakeholder Presentation Schedule



Stakeholder Engagement Process

Stakeholder Meetings

Four public webinar meetings

- Study methodology
- Input assumptions
- Draft results
(reference scenario)
- Final results



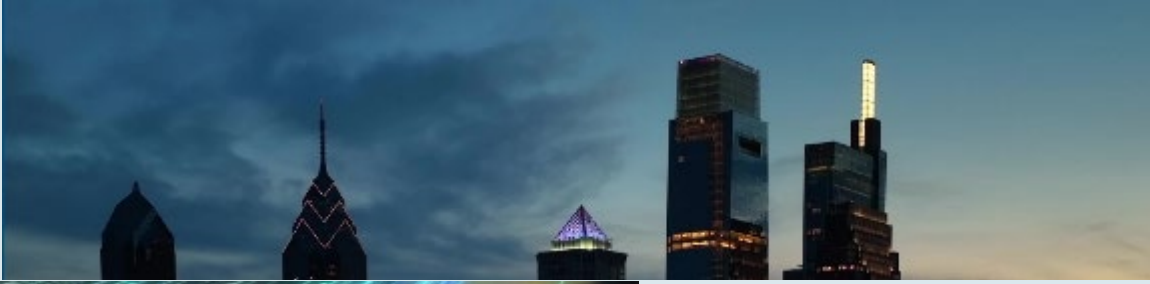
Stakeholder Feedback

- Feedback forms posted by the IESO for each meeting
- IESO will summarize feedback received
- Cadmus and the IESO will work together to address and incorporate feedback



Energy Efficiency and Electrification





Inputs and Data Sources: **Energy Efficiency**

Data Sources and Inputs

Data hierarchy

- IESO’s Measure Assumptions List (MAL)
- IESO and Ontario Energy Board Prior Achievable Potential Studies (APs)/ Technical Resource Manuals (TRMs)
- Utility data (if available)
- EIA data
- Secondary sources

Base Forecast Data Sources

Data	Primary Source	Secondary Source
Baseline/Forecasted Sales and Customers	<ul style="list-style-type: none"> • IESO’s Long Term Demand Forecast (LTDF) • Stokes Economics forecasts • IESO transmission-connected customer data • Q2 Reliability Outlook forecast of 2026 	
Percentage of Sales by Building Type	<ul style="list-style-type: none"> • 2025 Residential End-Use Survey • Stokes Economics forecasts • IESO industrial customer database 	<ul style="list-style-type: none"> • Natural Resources Canada’s Office of Energy Efficiency databases
End-Use Energy Consumption	<ul style="list-style-type: none"> • 2025 Residential End-Use Survey (REUS) • 2022 Commercial End-Use Survey (CEUS) • IESO’s Measure Assumptions List (MAL) • Ontario Energy Board TRMs • Survey of Commercial and Institutional Energy Use (SCIEU) • U.S. Energy Information Administration’s (EIA) Residential Energy Consumption Survey (RECS) • EIA’s Commercial Building Energy Consumption Survey (CBECS) • EIA’s Manufacturing Energy Consumption Survey (MECS) • EnerGuide associated with Canada’s energy-efficiency regulations 	<ul style="list-style-type: none"> • Canada Mortgage and Housing Corporation (CMHC) statistics • Natural Resources Canada’s Survey of Household Energy Use and SmartDriver and Fuel Management guide • ENERGY STAR unit shipment reports • U.S. DOE data and reports • Other TRMs from U.S. states
Saturations, Fuel, and Efficiency Shares	<ul style="list-style-type: none"> • REUS, CEUS, SCIEU, RECS, CBECS, MECS 	

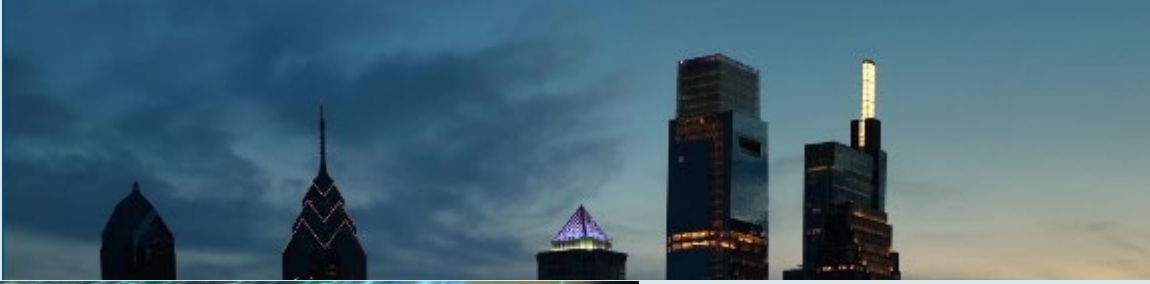
Data Sources and Inputs

Data hierarchy

- IESO's Measure Assumptions List (MAL)
- Utility data (if available)
- IESO and Ontario Energy Board Prior Achievable Potential Studies (APSS)/ Technical Resource Manuals (TRMs)
- Secondary sources

Measure Data Sources

Data	Primary Source	Secondary Source
Energy Savings	<ul style="list-style-type: none"> • IESO's MAL • Ontario Energy Board TRMs • Ontario evaluation reports • IESO's program data • ENERGY STAR Canada 	<ul style="list-style-type: none"> • Prior Ontario potential study • Incremental cost studies • ENERGY STAR shipments reports • U.S. DOE data and reports • Other TRMs from U.S. states
Equipment and Labor Costs	<ul style="list-style-type: none"> • IESO's MAL • Ontario Energy Board TRMs • ENERGY STAR Canada • RS Means cost database • Cadmus research 	
Measure Life	<ul style="list-style-type: none"> • IESO's MAL • Ontario Energy Board TRMs • ENERGY STAR Canada • Lifetime studies • Cadmus research 	
Measure Applicability (technical feasibility and percentage completed)	<ul style="list-style-type: none"> • REUS, CEUS, SCIEU, RECS, CBECS, MECS • Program evaluations / program data 	



Methodology and Assumptions: **Energy Efficiency**

Energy Efficiency and Electrification Methodology Overview

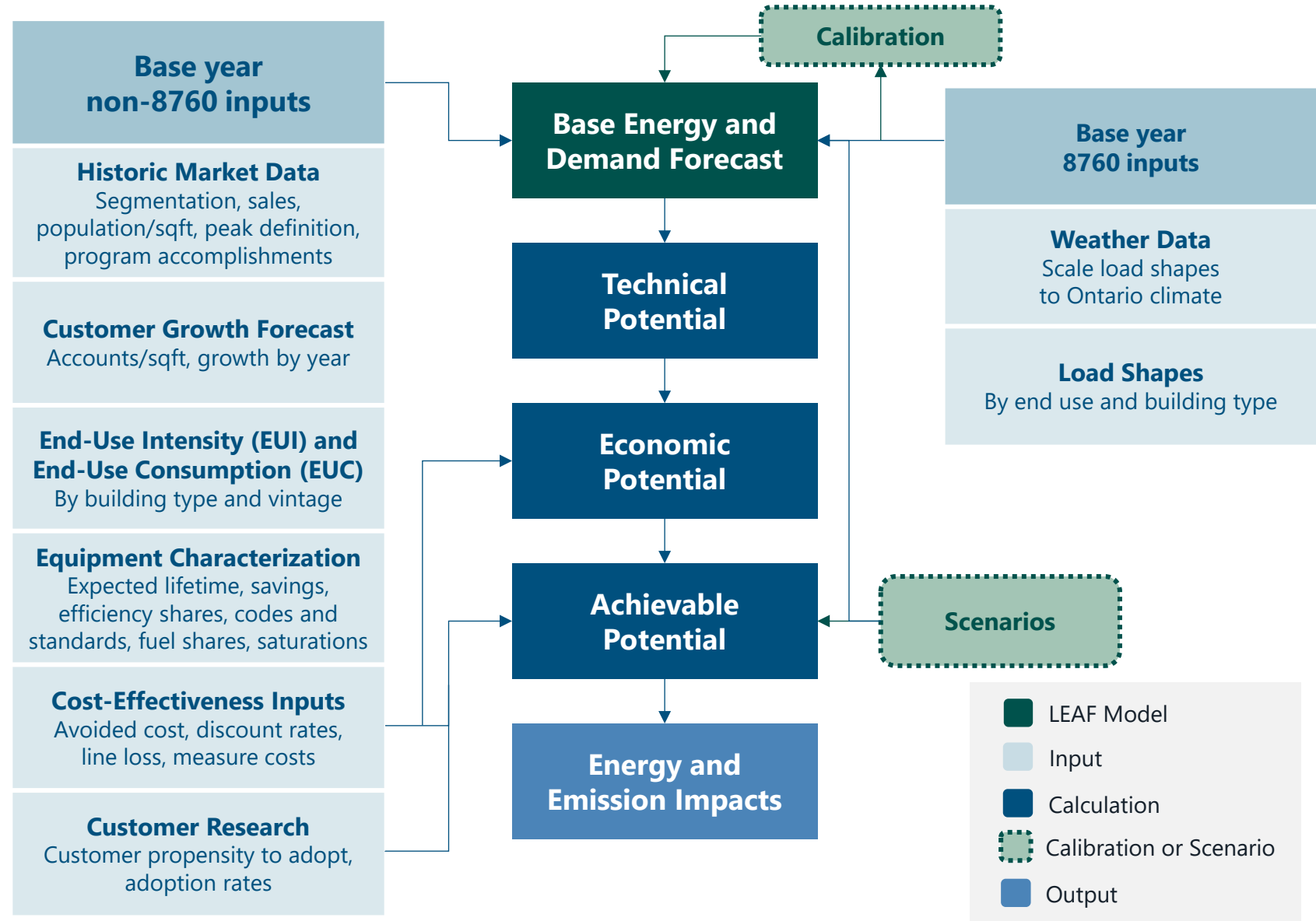
Purpose: Produce estimates of electric technical, economic, and achievable energy efficiency and fuel-switching potential

Sectors: Residential, commercial, and industrial

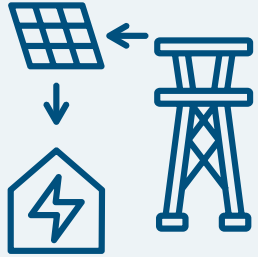
Period: 2026 base year with potential 2027 to 2050

Location: For each of the 10 IESO electrical zones as well as for the overall system

Load End-Use Adoption Forecast Model (LEAF)



Energy Efficiency and Electrification Assumptions



Electrification

Non-gas only; Commercial and residential only



Achievable Potential

Estimate based on customer decision model:

- Uses Bass diffusion-of-innovation and project payback period
- Accounts for customer payback acceptance (high acceptance of low payback, low acceptance of high payback)
- Incentives set to 100% of incremental measure cost (energy efficiency and electrification) to maximize adoption



Sectors

Commercial, Residential, Industrial, Agriculture, Water Treatment, Data Centers

Energy Efficiency and Electrification Permutations

Over 200 measures can quickly turn to thousands of inputs accounting for location, building type, vintage, equity status, and other dimensions.

End Use	Efficiency Description
Heat Central Electric Furnace	MSS Baseline ASHP - SEER2 14.3, HSPF2 6.0, EER 9.4



Sector	Zone	Segment	Vintage	Equity Status	End Use	Efficiency Description
Residential	Northeast	Single-Family Attached	Existing	Income Qualified	Heat Central Electric Furnace	MSS Baseline ASHP - SEER2 14.3, HSPF2 6.0, EER 9.4
Residential	Northeast	Single-Family Attached	New	Income Qualified	Heat Central Electric Furnace	MSS Baseline ASHP - SEER2 14.3, HSPF2 6.0, EER 9.4
Residential	Northeast	Single-Family Attached	Existing	Standard Income	Heat Central Electric Furnace	MSS Baseline ASHP - SEER2 14.3, HSPF2 6.0, EER 9.4
Residential	Northeast	Single-Family Attached	New	Standard Income	Heat Central Electric Furnace	MSS Baseline ASHP - SEER2 14.3, HSPF2 6.0, EER 9.4
Residential	Northeast	Single-Family Detached	Existing	Income Qualified	Heat Central Electric Furnace	MSS Baseline ASHP - SEER2 14.3, HSPF2 6.0, EER 9.4
Residential	Northeast	Single-Family Detached	New	Income Qualified	Heat Central Electric Furnace	MSS Baseline ASHP - SEER2 14.3, HSPF2 6.0, EER 9.4
Residential	Northeast	Single-Family Detached	Existing	Standard Income	Heat Central Electric Furnace	MSS Baseline ASHP - SEER2 14.3, HSPF2 6.0, EER 9.4
Residential	Northeast	Single-Family Detached	New	Standard Income	Heat Central Electric Furnace	MSS Baseline ASHP - SEER2 14.3, HSPF2 6.0, EER 9.4

Final Measure List

Energy Efficiency

Electrification

Equipment + Retrofit
Measures

Sources:

- IESO's Measure Assumptions List (MAL)
- IESO and Ontario Energy Board Prior Achievable Potential Studies (APSs)/ Technical Resource Manuals (TRMs)
- IESO model electrification measures
- Cadmus research

Measure List Details

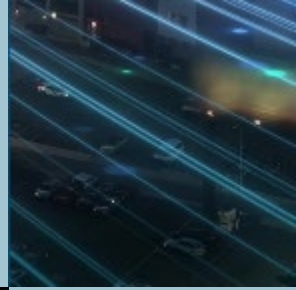
Updates based on feedback:

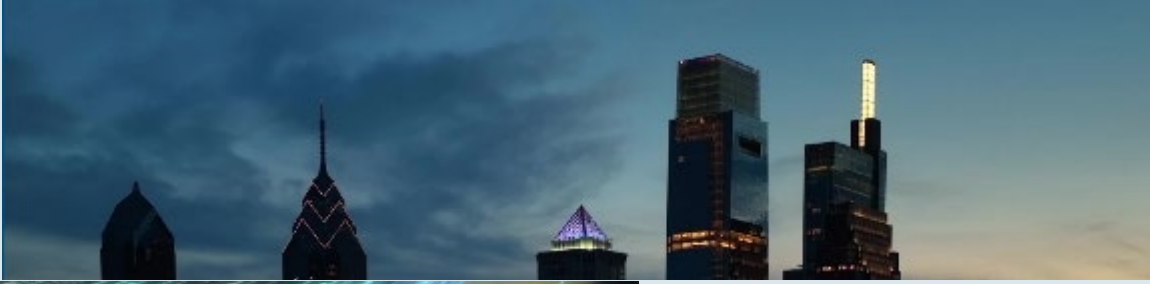
- Added 2029 water heating standard as baseline efficiency
- Better aligned several measure efficiencies with MAL (heat pumps, clothes washers, windows)
- Removed certain legacy APS measures now baseline or otherwise not applicable



Thank you for your feedback!

Demand Response





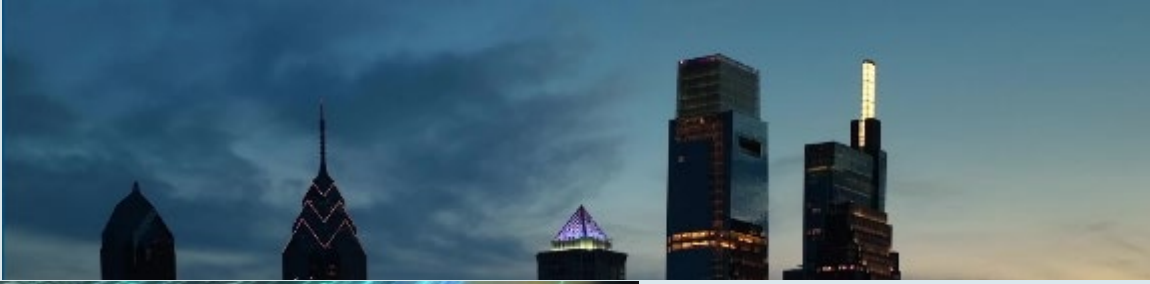
Inputs and Data Sources: **Demand Response**

Data Sources and Inputs

Data hierarchy

- IESO data (evaluations, program data, research, and other)
- Utility data (if available)
- Stakeholder input
- Cadmus evaluation and research
- Secondary sources

Data	Primary Source(s)	Secondary Source
Peak Definition (may vary by year)	<ul style="list-style-type: none"> • IESO Annual Demand Forecast (LEAF model output) 	<ul style="list-style-type: none"> • Benchmarking data from demand response programs in North America • Non-regional evaluations • Peak Load Management Alliance presentations and research
Demand Response Impact Characterization	<ul style="list-style-type: none"> • Base end-use load shapes from IESO forecasts • IESO/Ontario program data • Cadmus evaluations 	
Market Size	<ul style="list-style-type: none"> • IESO/Ontario program data • Cadmus' prior research 	
Demand Response Competition Factors	<ul style="list-style-type: none"> • Stakeholder input • Cadmus' prior research 	
Economic Inputs	<ul style="list-style-type: none"> • IESO data 	
Demand Response Program Costs / Incentives	<ul style="list-style-type: none"> • IESO/Ontario program data • Cadmus' prior research 	
Maximum Rate of Adoption	<ul style="list-style-type: none"> • IESO/Ontario program data • Stakeholder input • Cadmus' prior research 	
Annual Ramp Rate	<ul style="list-style-type: none"> • IESO/Ontario program data • Stakeholder input • Cadmus' prior research 	
Event Participation	<ul style="list-style-type: none"> • Program evaluations/program data • Stakeholder input • Cadmus' prior research 	



Methodology and Assumptions: **Demand Response**

Demand Response Methodology Overview

Purpose: Produce estimates of electric demand response technical, achievable, and economic potential

Sectors: Residential, commercial, industrial, and agriculture

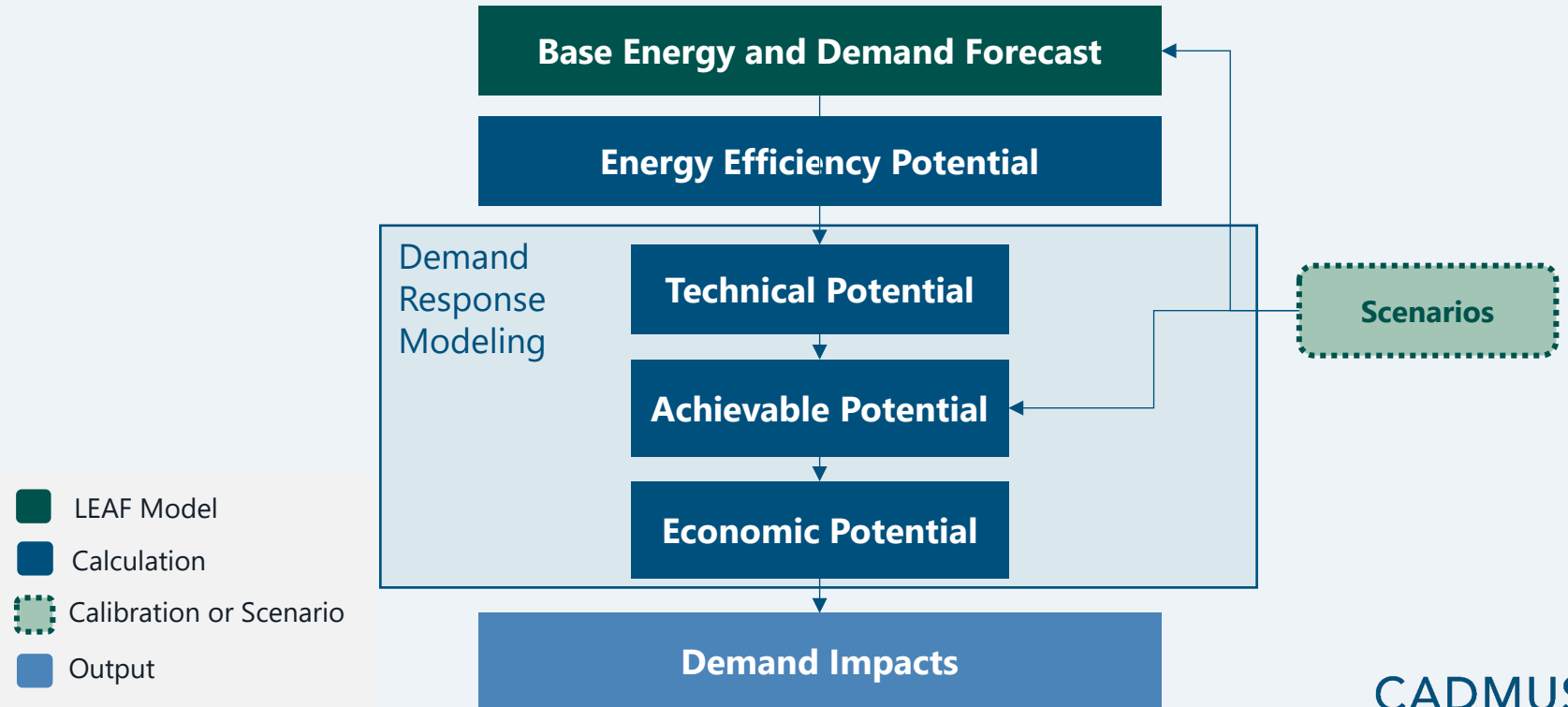
Period: 2026 base year with potential 2027 to 2050

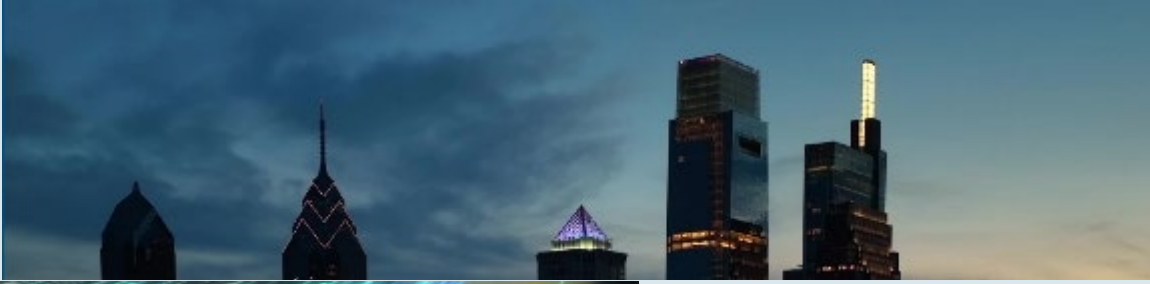
Location: For each of the 10 IESO electric zones as well as for the overall system

Reporting: Stand-alone report from energy efficiency

General Demand Response Product Categories by Sector

Sector	Product Demand Response Category
Residential, Commercial	Electric Vehicle DLC
Residential	Water Heat DLC
Residential	Pool Pump DLC
Residential, Commercial	Heating and Cooling DLC
Commercial, Industrial	Demand Curtailment
Agriculture	Irrigation Demand Response





Feedback Requests: Demand Response

Demand Response Product Inputs and Assumptions

We have provided a workbook with draft assumptions for each demand response product.

We are requesting feedback on the following inputs:

- Eligibility Criteria
- Admin Cost
- Marketing Cost
- Participation Incentives
- Product Impact
- Adoption Benchmarks and Maximum Rate of Adoption
- Attrition Rate
- Maturity (start year and adoption ramp)

Sector	Demand Response Product	Season Impact
Residential, Commercial	Electric Vehicle DLC	Summer / Winter
Residential	Water Heat DLC	Summer / Winter
Residential	Pool Pump DLC	Summer
Residential, Commercial	Heating and Cooling DLC	Summer / Winter
Commercial, Industrial	Demand Curtailment	Summer / Winter
Agriculture	Irrigation Demand Response	Summer

Feedback Workbook Example – Cost/Participation

Product:	Heating and Cooling DLC
Sector:	Residential
Description/Eligibility	Thermostat DLC (BYOT) for centrally controlled electric heating and cooling systems

Cost/Participation Assumptions

Parameter Group	Parameter	Unit Definition	Value	Source/Note	Stakeholder Feedback
Administrative Costs	Setup Cost	\$	\$500,000	Sunk cost. Program currently operational.	
Administrative Costs	O&M Cost	\$/year	\$1,750,000	Prior evaluation data indicates total annual administrative cost of \$4.8 million in 2023 and \$5.6 million in 2024. Assuming a meaningful portion is marketing, subtract ~\$2,000,000. Remaining value is \$3.5 mil. Shared 50:50 with commercial program.	
Administrative Costs	Equipment Cost	\$/new participant	\$0	None for BYOT model	
Administrative Costs	Marketing Cost	\$/new participant	\$25	Industry benchmark	
Administrative Costs	Incentive (recurring)	\$/participant-year	\$20	Current program offer	
Administrative Costs	Incentive (one-time)	\$/new participant	\$75	Current program offer	
Participation	Attrition	% of existing participants per year	8%	Assumption	
Participation	Expected Annual Incentive Level for 5% Participation	\$/participant-year	\$10	% reflects share of the eligible population, assuming 100% program awareness.	
Participation	Expected Annual Incentive Level for 50% Participation	\$/participant-year	\$150		
Participation	Event Participation	% (dispatch success rate)	85%	Prior evaluation indicates opt-out rates between 15-30%. Opt-outs typically occur partway through the event, so we are assuming an overall success rate at the higher end of this spectrum.	
Participation	Ramp Period (years to maturity)	Years	5	Assumption	

Source: https://www.ieso.ca/-/media/Files/IESO/Document-Library/conservation/EMV/2024/PY2024_2021-2024-CDM-Framework_Peak-Perks-Program_Evaluation-Report.pdf

This table is an example of draft values provided for review and feedback.



Feedback Workbook Example – Impacts

Product:	Heating and Cooling DLC
Sector:	Residential
Description/Eligibility	Thermostat DLC (BYOT) for centrally controlled electric heating and cooling systems

Event Impacts

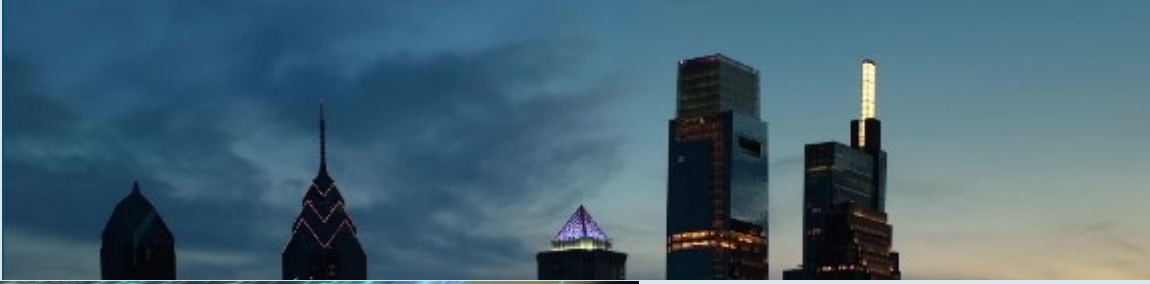
Event Hour	Impact (% of eligible end-use load)	Reference Benchmark Impact per participant (kW)	Reference Eligible End-use Load (kW)	Stakeholder Feedback
1	80%	0.8	1	
2	70%	0.7	1	
3	60%	0.6	1	

This table is an example of draft values provided for review and feedback.



Behind-the-Meter Solar and Storage





Inputs and Data Sources: **Solar and Storage**

Data Sources and Inputs: BTM Solar and Storage

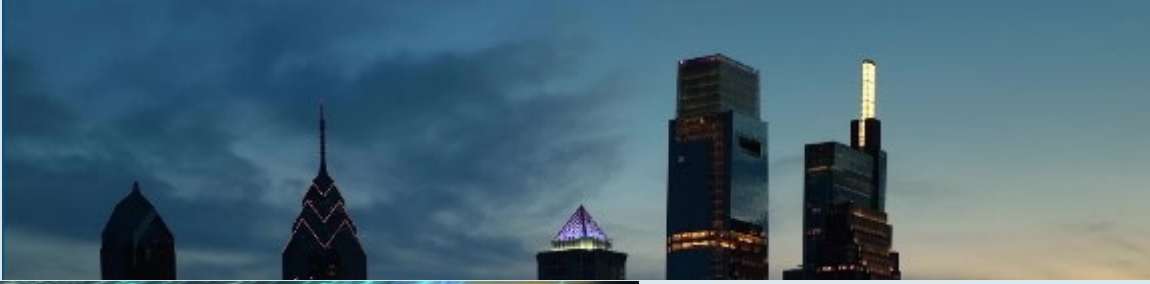
Data hierarchy

- IESO data (evaluations, program data, research, and other)
- Utility data (if available)
- Stakeholder input
- Cadmus evaluation and research
- Secondary sources

Solar Data	Primary Source	Secondary Source
Energy Savings	<ul style="list-style-type: none"> • Calculated 	<ul style="list-style-type: none"> • Benchmarking data from programs in North America • NLR • Lazard levelized cost analysis • IESO Pilot Data • NRCAN High Resolution Digital Elevation Model Mosaic (HRDEM Mosaic)
Equipment and Labor Costs	<ul style="list-style-type: none"> • National Lab of the Rockies (NLR) 	
Measure Life	<ul style="list-style-type: none"> • DSM MAL (20 years) 	
Measure Applicability	<ul style="list-style-type: none"> • DSM MAL; NLR; Cadmus targeted research of rooftop applicability 	

Battery Data	Primary Source	Secondary Source
Energy Savings	<ul style="list-style-type: none"> • Calculated 	<ul style="list-style-type: none"> • Benchmarking data from programs in North America • NLR • Lazard levelized cost analysis • IESO pilot programs analysis • IESO Pilot Data
Equipment and Labor Costs	<ul style="list-style-type: none"> • National Lab of the Rockies (NLR) • IESO Pilot Data 	
Measure Life	<ul style="list-style-type: none"> • Calculated based on Charge cycles 	
Measure Applicability	<ul style="list-style-type: none"> • DSM MAL; Ontario Electrical Safety Code; Cadmus Research 	

Load Shift Data	Primary Source	Secondary Source
Energy Savings	<ul style="list-style-type: none"> • DSM MAL; IESO Pilot Data; Cadmus Analysis 	<ul style="list-style-type: none"> • Utility studies and forecasts • NLR • IESO Pilot programs
Equipment and Labor Costs	<ul style="list-style-type: none"> • National Lab of the Rockies (NLR) • IESO Pilot Data 	
Measure Life	<ul style="list-style-type: none"> • DSM MAL; EE IESO data; Cadmus Research 	
Measure Applicability	<ul style="list-style-type: none"> • DSM MAL; IESO Annual Demand Forecast (LEAF model output); Cadmus Research 	



Methodology and Assumptions: **Solar and Storage**

Behind-the-Meter Solar and Storage Methodology Overview

Purpose: Produce hourly estimates of technical, economic, and achievable potential for behind-the-meter solar and storage, rooftop solar with battery, and battery without rooftop solar

Sectors: Residential, commercial, and industrial

Period: 2026 base year with potential 2027 to 2050

Location: For each of the 10 IESO electrical zone as well as for the overall system

Primary Tasks	Solar	Battery Storage
Segment building stock	✓	✓
Apply technical resource characteristics to calculate total available roof area and system capacities	✓	
Develop battery size bins by sector		✓
Determine adjustable load criteria (peak hours, 4-hour discharge capacity, charge period)		✓
Calculate cost-effectiveness	✓	✓
Forecast market adoption based on Bass diffusion and project economics (same as LEAF model)	✓	✓
Estimate technical, economic, and achievable potential	✓	✓
Develop hourly results and hourly load shifts	✓	✓
Reporting (this will be part of energy efficiency report)	✓	✓

Technical

Key Output: Total accounts possible under each measure

Key Assumptions: Prototypical systems are assigned to customers based on customer electricity consumption

Technical

Segment Accounts				
Consumption Buckets			Rate Structures	
Small	Medium	Large	TOU	ULO
			Tiered	Commercial

Assign System Sizes
Map system size ranges to each consumption bucket

Solar and Storage Optimization	
Optimal	Sub-Optimal
Sub-Optimal 2	Non-Optimal

Example of System Design Bucket Segmentation

- System design buckets are used to capture the range of rooftop characteristics
- We are using prototypical system sizes that are connected to each of the consumption buckets
- In sloped roofs the buckets indicate what share of the installed system is facing south, east, or north
- In flat roofs all systems are assumed to face south
- Buckets indicate reductions in total system size based on obstructions and the orientation of the building

Optimal

Sloped Roofs: 100% South

Flat Roofs: Building south/north orientation with little to no obstructions



Sub Optimal 1

Sloped Roofs: 50% South, 25% East, 25% West

Flat Roofs: Building south/north orientation with obstructions limiting system size



Sub Optimal 2

Sloped Roofs: 20% South, 40% East, 40% West

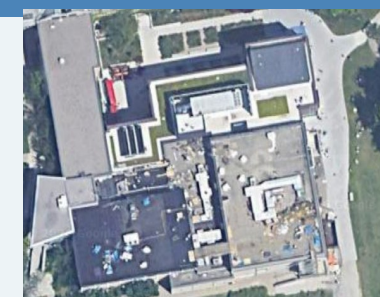
Flat Roofs: non-south/north orientation with little to no limiting system size



Non-Optimal

Sloped Roofs: No south facing space available

Flat Roofs: Non-south/north orientation with obstructions limiting system size



Simple Example of Technical Segmentation

Sector	Segment	Customer Electric Energy Usage Size Bucket	Rate Class	System Design Bucket	Efficiency Description	Solar Target System Size (kW)	Battery Target System Size (kW)	2025 (accounts)
Residential	Single Family	Small	TOU	Optimal	Solar (net metered)	4	0	244
Residential	Single Family	Small	TOU	Optimal	Solar (Non-net metered)	4	0	244
Residential	Single Family	Small	TOU	Optimal	Battery (net metered)	0	5	244
Residential	Single Family	Small	TOU	Optimal	Battery (Non-net metered)	4	5	244
Residential	Single Family	Small	TOU	Optimal	Battery with Solar (net metered)	4	5	244
Residential	Single Family	Small	TOU	Optimal	Battery with Solar (Non-net metered)	4	5	244

Simplified Fields,
more granularity exists

These measures
compete against
each other

Solar system sizes
remain the same for
all measures that
compete against
each other

Sample account
numbers to show
that the number
of accounts stays
the same



Economic and Achievable

Key Output: Adoption curves for technologies that pass the economic screen

Key Assumptions: Measures compete against each other (as outlined on the previous slide)

Economic and Achievable

Economic Screen

- Estimate potential for cost-effective measure adoption
- Use IESO existing economic screen

Adoption Screen

- Counterfactual: Assume no system installed
- Model adoption based on payback period, sentiment, technology maturity, and key barriers
- Calculate benefits from offset load and net metering

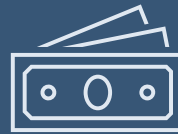
Compare System Types

Modeling Adoption

Net-meter vs Non-net-meter



Customer choice modeling valuing benefits (pay back) between net-meter vs non-net-meter applications

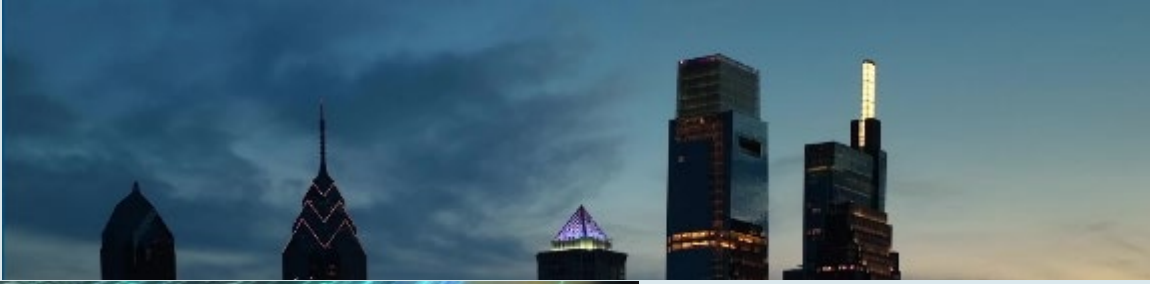


Non-net-meter customers receive upfront incentives (net-metered do not)



Modeling competition allows for assessing adoption impacts as incentives change





Feedback Requests: **Solar and Storage**

Assumptions:

- Battery systems are being used for peak shaving.
- Battery systems offset specific end-use loads (like HVAC and lighting loads in commercial buildings and communal HVAC and lighting), rather than individual unit consumption.

BTM - Feedback Requests



What end uses are battery systems typically offsetting in industrial and commercial applications?



Assumed discharge periods:

- 4-hours for all residential customers
- 2- or 4-hours for industrial and commercial customers

Solar Input Assumptions

Product:	Solar
Sector:	Residential, Commercial, Industrial
Description/Eligibility	Solar System

Cost/Participation Assumptions

Parameter Group	Parameter	Unit Definition	Value	Source/Note	Stakeholder Feedback
Residential and Small Business (<50kW peak demand) Measure Costs	CAPEX (Labor and Overnight Capital Costs)	\$/kW	\$2,484.62	Based IESO APO Resource Costs and Trends March 2024. Used 2024 values and projected to 2026 (shown here) based on APO forecasted data. Values are scaled linearly between base date 2024 and end forecast date 2050. APO Resource Costs and Trends March 2024: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Mar2024/Resource-Costs-and-Trends.pdf	
Residential and Small Business (<50kW peak demand) Measure Costs	Customer O&M	\$/kW	\$26.08		
Residential and Small Business (<50kW peak demand) Incentives	Non-net Metered Solar	\$/kW	\$1,000	Up to \$5,000. \$1,000/kW, up to 50% of total costs (current IESO program incentives). Incentive recipients cannot participate in net metering.	
Commercial & Industrial Measure Costs	CAPEX (Labor and Overnight Capital Costs)	\$/kW	\$1,714.71	Based IESO APO Resource Costs and Trends March 2024 and adjusted to represent nonresidential system cost. Used 2024 APO values and projected to 2026 (shown here) then scaled inline with NLR2024 Annual Technology Baseline to show the difference between Residential and commercial PV System Capex.	
Commercial & Industrial Measure Costs	Customer O&M	\$/kW per Year	\$10.27		
Commercial & Industrial Incentives	Incentive	\$/kWac	\$860		IESO and SaveOnEnergy Program. Up to \$860,000 or 50% of total Project Cost, minimum system size of 10kWac. Non-Net Metered
Commercial & Industrial Incentives	Incentive	Share of CAPEX	30%	Federal Investment Tax Credit (ITC) Stackable	
All	Effective Useful Life	Years	20	IESO Solar PV Workbook. Based on PV module manufacturers offering 25-year power production warranties.	
All	Degradation Rate	% per year	0.50%	IESO Solar PV Workbook. National Laboratory of the Rockies (NLR)	
All	DC to AC Ratio	DC_to_AC	1.2	IESO Solar PV Workbook. Industry standard	
All	Inverter Efficiency	%	96%	IESO Solar PV Workbook. Supported by a wide range of inverter technologies available in industry research (range 95% to 98%)	
All	Total System Losses	%	18.37%	IESO Solar PV Workbook. Derived from an analysis of multiple components (i.e. soiling, shading, etc)	
All	Hourly solar generation curves	Profiles	Varies by zone	Use NLR's PVWatts Module in SAM consistent with IESO Solar PV Workbook.	

Solar Input Assumptions - Measure Benefit

Product:	Solar
Sector:	Residential, Commercial, Industrial
Description/Eligibility	Solar System

Measure Benefit Assumptions

Measure	Rate	Net Metered vs Non-Net Metered	IESO Incentivized	Logic	Stakeholder Feedback
Solar	All	Non-Net Metered	Yes	Solar generation only offsets load. Generation above hourly consumption (when current hour consumption - current hour generation is negative) generates no benefit	
Solar	All	Net Metered	No	Solar generation only offsets load. Net meter credits are generated when generation exceeds consumption. Net meter credits are equivalent to current hour rate price	
Battery with Solar	All	Non-Net Metered	Yes	Solar generation offsets load. Generation above hourly consumption charges the linked battery system when battery can charge	
Battery with Solar	All	Net Metered	No	Solar generation only offsets load. Net meter credits are generated when generation exceeds consumption. Net meter credits are equivalent to current hour rate price	

Battery Input Assumptions

Product:	Battery
Sector:	Residential, Commercial, Industrial
Description/Eligibility	Battery System

Cost/Participation Assumptions

Parameter Group	Parameter	Unit Definition	Value	Source/Note	Stakeholder Feedback
Residential and Small Business (<50kW peak demand) Measure Costs	CAPEX (Labor and Overnight Capital Costs)	\$/kWh	\$1,200	Based on stakeholder inputs on CAPEX expenditure on existing system installations for 4-hour duration systems	
Residential and Small Business (<50kW peak demand) Measure Costs	Customer O&M	\$/kWh	\$0	Based on stakeholder feedback O&M is 0\$ for batteries given warrantee periods.	
Residential and Small Business (<50kW peak demand) Incentives	Incentive Non-net Metered Storage Paired with Solar	\$/kWh	\$300	Up to \$5,000. \$300/kWh, up to 50% of total costs (current IESO program incentives). Incentive recipients cannot participate in net metering.	
Commercial & Industrial Measure Costs	CAPEX (Labor and Overnight Capital Costs)	\$/kWh	\$525	Based on stakeholder inputs on CAPEX expenditure on existing system installations for 4-hour duration Lithium-Iron-Phosphate (LFP) battery 1-4 MW systems	
Commercial & Industrial Measure Costs	Customer O&M	\$/kWh per year	\$14	Based on stakeholder inputs on CAPEX expenditure on existing system installations for 4-hour duration Lithium-Iron-Phosphate (LFP) battery systems	
Commercial & Industrial Incentives	Incentive for Non-net Metered Storage Paired with Solar	\$/kWh	\$300	IESO and SaveOnEnergy Program. Up to \$860,000 or 50% of total Project Cost, minimum system size of 10kWac. Non-Net Metered. Systems must be designed to offset load, not export to the grid. IESO does not currently have a commercial battery incentive.	
Commercial & Industrial Incentives	Incentive	Share of CAPEX	30%	Federal Investment Tax Credit (ITC) Stackable	
All	Effective Useful Life	Years	15	NLR Annual Technology Baseline default assumption (https://atb.nrel.gov/electricity/2024b/utility-scale_battery_storage)	
Residential	Inverter ratio to capacity	Designed number of storage hours	4	The prototypical systems assume a discharge period of 4 hours. Inverters are sized to total kWh storage capacity to enable 4 hours of discharge at peak capacity	
Commercial & Industrial	Inverter ratio to capacity	Designed number of storage hours	2 or 4 Hours depending on energy intensity	The prototypical Commercial and Industrial systems assume a discharge period of 2 or 4 hours. Inverters are sized to total kWh storage capacity to enable 4 hours of discharge at peak capacity	
All	Inverter Efficiency	Inverter_Eff	96%	Inverter assumption within the IESO's Measure Specification Sheet (MSS)	
All	Roundtrip efficiency	Total_System_Loss	85%	NLR Annual Technology Baseline default assumption (https://atb.nrel.gov/electricity/2024b/utility-scale_battery_storage)	
All	Hourly battery charge and discharge curves	Profiles	Varies by application	Using the IESO rate definitions (TOU, ULO, Tiered) and application loads to determine charge and discharge cycles.	

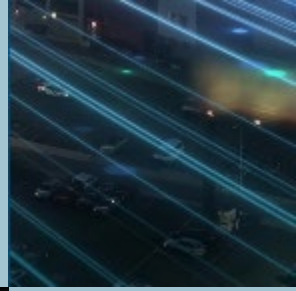
Battery Input Assumptions – Measure Benefit

Product:	Battery
Sector:	Residential, Commercial, Industrial
Description/Eligibility	Battery System

Measure Benefit Assumptions

Measure	Rate	Net Metered vs Non-Net Metered	IESO Incentivized	Logic	Stakeholder Feedback
Battery	All	Non-Net Metered	Yes	Battery charges during off peak hours, and discharges during on-peak hours. Depth of Discharge 20% Depth of Charge 100%	
Battery	All	Net Metered	No	Battery charges during off peak hours, and discharges during on-peak hours. Depth of Discharge 20% Depth of Charge 100%	
Battery with Solar	All	Non-Net Metered	Yes	Generation above hourly consumption charges the linked battery system when battery can charge. Battery supplements charge from solar system with grid electricity during off peak hours. Battery can discharge during On and Mid peak periods	
Battery with Solar	All	Net Metered	No	Battery charges during off peak hours, and discharges during on- and mid-peak hours. Depth of Discharge 20% Depth of Charge 100%	
Battery with Solar	Tiered	Non-Net Metered	Yes	Generation above hourly consumption charges the linked battery system when battery can charge. Battery does not supplement charge from solar system with grid electricity during off peak hours. Battery can discharge during any period.	

Thermal Energy Storage



Thermal Energy Storage (TES)

Primary Tasks	Thermal Storage
Segment building stock	✓
Apply non-adjustable load shifts to applicable existing building end-uses (consistent with LEAF model)	✓
Calculate cost-effectiveness	✓
Forecast market adoption based on Bass diffusion and project economics (same as LEAF model)	✓
Estimate technical, economic, and achievable potential	✓
Develop hourly results and hourly load shifts	✓
Reporting (this will be part of energy efficiency report)	✓

Sector	TES Type/Application	Load Shift Impact
Residential	Thermal Water Storage Heat Pump	Summer / Winter
Commercial	Thermal PCM Ice-water Storage HVAC Cooling	Summer
Commercial	Thermal PCM Saltwater-Ice Storage Refrigeration	Summer
Industrial	Thermal PCM Ice-water Storage HVAC Cooling	Summer
Industrial	Thermal Sensible Storage Process Heat	Summer / Winter

PCM = Phase Change Material

TES Considerations



TES systems are still emerging in the market. Our study approach is to use slow rates of adoption.



Most common and typically least cost TES systems are sensible heat (water, solid, salt, etc.) followed by latent heat or phase change materials (ice, salt hydrates, aqueous solutions, etc.).



Chemical reaction (thermochemical) shows promise in high temperature applications but is too expensive (more R&D needed; this study does not assess this type of TES).



Additional input assumptions may evolve as more information becomes available.



Feedback requests on input assumptions

* Three examples shown (see workbook for all measure details)

Residential TES HVAC Input Assumptions

Product:	Thermal Water Storage
Sector:	Residential
Description/Eligibility	Air-to-Water Heat Pump (Heating and Cooling) System

Application Assumptions

Application	End Use	Load Shift	Participation Assumption
Residential sector and segments	Air-to-water heat pump	Summer and winter season: remove load from peak periods. Shift space heating and cooling load to off-peak hours. Shifted load is redistributed to off peak hours of that day.	Program participation (a participant can opt at the time of equipment replacement) that has the eligible equipment. Considered as emerging technology adoption rate (slow). Adoption dependent on incentive costs to overcome high upfront costs. Benchmark utilities frequently pair rebates with participation in time of use programs.

Parameter Group	Parameter	Unit Definition	Value	Source/Note	Stakeholder Feedback
End Use Savings	Summer Demand Savings (Peak Load Shift)	% kW reduction	49%	Metered pilot project. Load shift 28% to 66% summer end-use load over 2- to 4- hour period. Based on Technical Evaluation of Air-to-Water Heat Pumps with Thermal Storage, CALNEXT report ET22SWE0050. Prepared by VEIC April 2025. Benchmarked saving of 25% total demand building load (~50% end-use load) "Role of Thermal Energy Storage in Reducing Peak Load from Building Electrification" Navius 2025 report for Natural Resources Canada.	
End Use Savings	Winter Demand Savings (Peak Load Shift)	% kW reduction	55%	Load shift 17% to 82% winter load over 2- to 4- hour period. Based on Technical Evaluation of Air-to-Water Heat Pumps with Thermal Storage, CALNEXT report ET22SWE0050. Prepared by VEIC April 2025.	
End Use Savings	Energy Savings	% kWh savings	0%	Assume no energy savings. Based on Technical Evaluation of Air-to-Water Heat Pumps with Thermal Storage, CALNEXT report ET22SWE0050. Prepared by VEIC April 2025.	
Measure Life	Measure Life	EUL	15	Based on Technical Evaluation of Air-to-Water Heat Pumps with Thermal Storage, CALNEXT report ET22SWE0050. Prepared by VEIC April 2025.	
Customer Incremental Cost	Equipment Cost (Full replacement cost)	\$/kW	\$2,775	Assume 5 kW system. Based on Technical Evaluation of Air-to-Water Heat Pumps with Thermal Storage, CALNEXT report ET22SWE0050. Prepared by VEIC April 2025. Assumes equipment and labor (80% equipment/20% labor).	
Customer Incremental Cost	Labor Cost (Full replacement cost)	\$/kW	\$694	Assume 5 kW system. Based on Technical Evaluation of Air-to-Water Heat Pumps with Thermal Storage, CALNEXT report ET22SWE0050. Prepared by VEIC April 2025. Assumes equipment and labor (80% equipment/20% labor).	
Customer Incentive	Incentive	\$/kW	\$3,468	Assume that significantly more incentive is needed to move the market, assume 100% of incremental cost consistent with the IESO energy efficiency program APO modeling.	
Program Administration Cost	Program Admin	% of incentive	20%	Estimated	

Commercial TES HVAC Input Assumptions

Product:	Thermal Storage (Ice-water phase change storage)
Sector:	Commercial
Description/Eligibility	Cooling

Application Assumptions

Application	End Use	Load Shift	Participation Assumption
Commercial sector and segments	Cooling	Summer seasons: Load-shifting measure; transferring cooling system energy use from afternoon peak hours to night-time operation using cooler outside air and store within ice/water system. Provides both energy and demand savings.	Program participation typically installed during equipment replace cycles. Considered as commercially available systems with a low adoption rate. Adoption dependent on incentive costs to overcome high upfront costs. Benchmark utilities frequently pair rebates with participation in time of use programs.

Parameter Group	Parameter	Unit Definition	Value	Source/Note	Stakeholder Feedback
End Use Savings	Demand Savings (Peak Load Shift)	% kW reduction	75%	Inferred from NLR building simulations and research. NLR, Space Conditioning Tech Team Webinar: Thermal Energy Storage, the lowest cost storage.	
End Use Savings	Energy Savings	% kWh savings	20%	Based on NLR building simulations and research. NLR, Space Conditioning Tech Team Webinar: Thermal Energy Storage, the lowest cost storage.	
Measure Life	Measure Life	EUL	20	Assume consistent EUL as baseline equipment (Chiller IESO Measure Specification Sheet)	
Customer Incremental Cost	Equipment Cost (Incremental cost)	\$/kW	\$1,184	Inferred from NLR building simulations and research. NLR, Space Conditioning Tech Team Webinar: Thermal Energy Storage, the lowest cost storage. Cost per \$1660/kW or \$275/kWh (full system). Assumes equipment and labor (80% equipment/20% labor). Base equipment (Chillers > 300 tons (centrifugal) ~\$180/kW (Northeast Energy Efficiency Partnerships. Incremental Cost Study Phase Two Final Report)	
Customer Incremental Cost	Labor Cost (Incremental cost)	\$/kW	\$296		
Customer Incentive	Incentive	\$/kW	\$1,480	Assume 100% of incremental cost consistent with the IESO energy efficiency program APO modeling. Other programs provide 10% of project total costs.	
Program Administration Cost	Program Admin	% of incentive	20%	Estimated	
End Use Savings	Demand Savings (Peak Load Shift)	% kW reduction	75%	Inferred from NLR building simulations and research. NLR, Space Conditioning Tech Team Webinar: Thermal Energy Storage, the lowest cost storage.	

Industrial TES Process Heat Input Assumptions

Product:	Thermal Sensible Storage (solid or liquid material)
Sector:	Industrial
Description/Eligibility	Sensible Heat Storage System for Industrial Electric Boilers and Other Process Heating Devices

Application Assumptions

Application	End Use	Load Shift	Participation Assumption
Industrial Sector	Current industrial heating processes using electricity	Summer and winter seasons: Shift process heating load to off-peak hours. Shifted load is redistributed to off peak hours of that day (pre-heating).	Barriers remain for high-temperature applications. Assume Sensible Heat Thermal Energy Storage for low to med temperature applications (least costly). Program participation (a participant can opt into a program at any time) that has the eligible equipment. Considered as emerging technology adoption rate (slow). Adoption dependent on incentive costs to overcome high upfront costs. Benchmark utilities frequently pair rebates with a minimum reduction during on peak hours, and provide a rebate incentive to customers.

Parameter Group	Parameter	Unit Definition	Value	Source/Note	Stakeholder Feedback
End Use Savings	Demand Savings (Peak Load Shift)	% kW reduction	40%	Industrial scale. 2022 Industrial Thermal Energy Storage report by European Energy Research Alliance (Energy Efficiency in Industrial Processes)	
End Use Savings	Energy Savings	% kWh savings	-50%	Requires energy for the storage process. Varies sources range from 60% to 40% in round-trip efficiency. Assume an efficiency value in the middle of this range.	
Measure Life	Measure Life	EUL	25	Assumed consistent with molten salt thermal energy storage system, deployed at scale.	
Customer Incremental Cost	Equipment Cost (Full replacement cost)	\$/kWh (delivered)	\$13	Average sensible TES costs - range from less than \$1.6 to \$35 per kWh delivered. 2022 Industrial Thermal Energy Storage report by European Energy Research Alliance (Energy Efficiency in Industrial Processes). Assumes equipment and labor (80% equipment/20% labor). Benchmarked with Development of Energy Storage: Cost models 2021 (Argonne National Laboratory)	
Customer Incremental Cost	Labor Cost (Full replacement cost)	\$/kWh (delivered)	\$3		
Customer Incentive	Incentive	\$/kWh (delivered)	\$16	Assume 100% of incremental cost consistent with maximum potential approach. (Not proposed program design)	
Program Administration Cost	Program Admin	% of incentive	20%	Estimated	

Q & A

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Next steps

- Interested stakeholders are invited to review the Demand Response, BTM Solar/Storage, and Thermal Energy Storage Input Assumption Excel workbooks and provide feedback in these files using the feedback columns
- Stakeholders are also invited to provide feedback on the other input assumptions presented or broader relevant trends/developments using the feedback form template
- The IESO requests written stakeholder feedback by May 7, 2026 to ensure consideration
- If you have any questions on the information shared today, please contact engagement@ieso.ca

For More Information

- The recording, presentation, and feedback form for this engagement can be found on the [2026 Provincial eDSM Achievable Potential Study](#) page
- If you have any questions on the information shared today, please contact engagement@ieso.ca



Thank You

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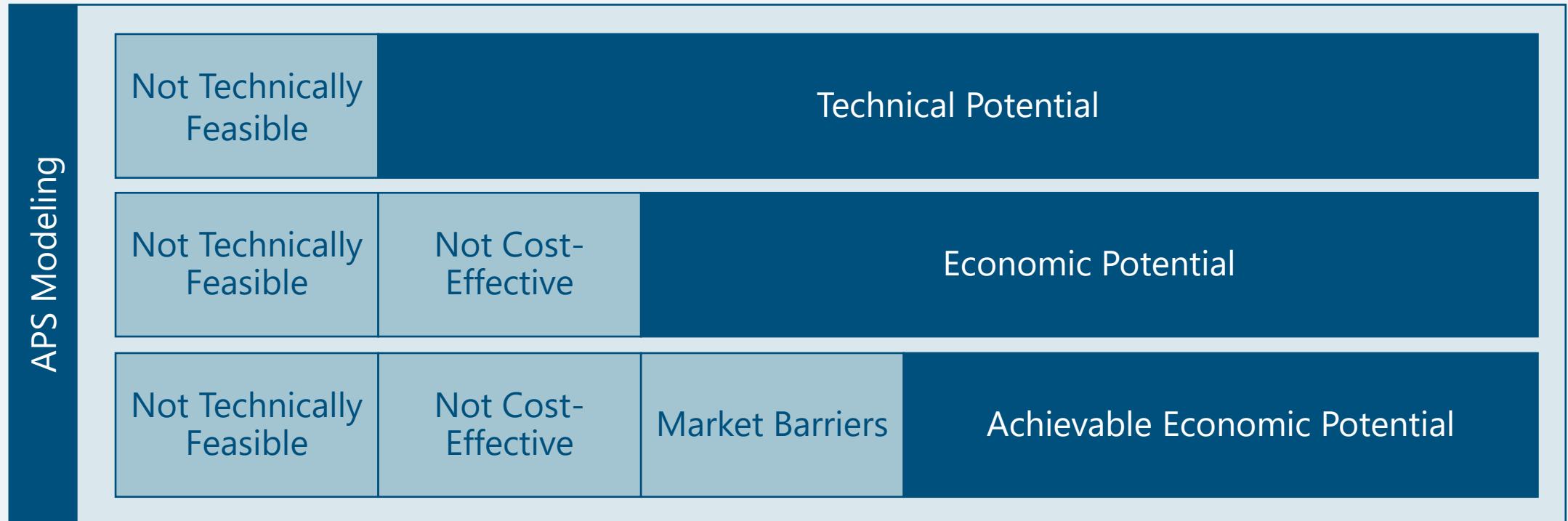



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Appendix A: Planning Study Priorities and Scope



Appendix A: Planning Study Priorities and Scope



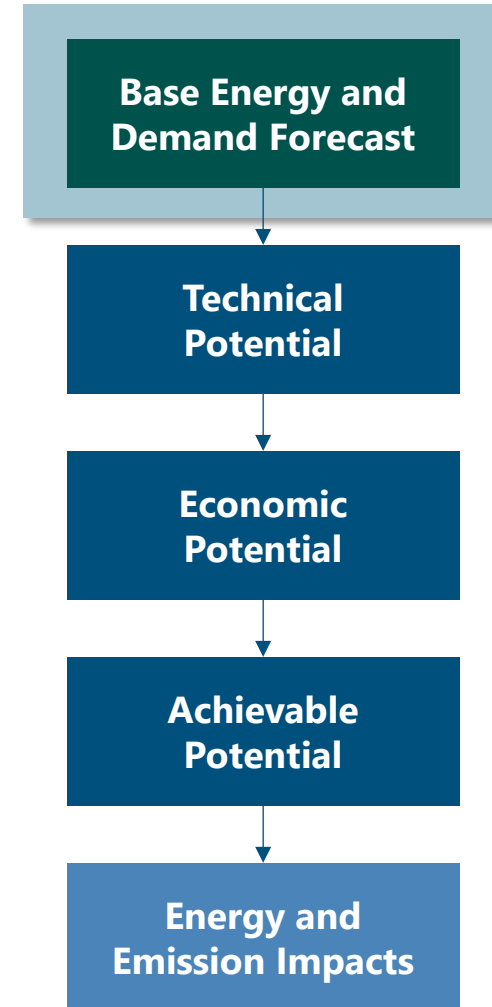


Appendix B: Energy Efficiency Methodology & Assumption Detail

Base Year Energy and Demand Forecast

Characteristics:

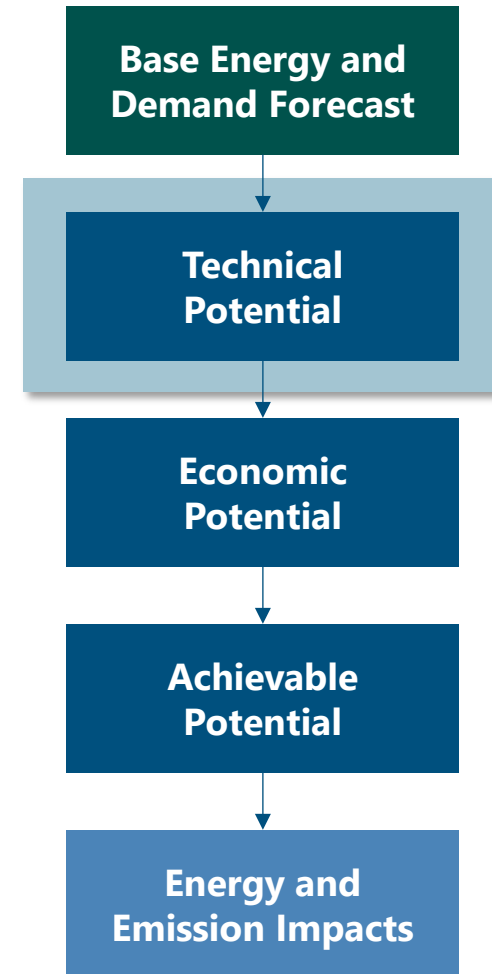
- Based on the IESO's Long Term Demand Forecast (LTDF) from LEAF
- Built up from customer accounts, end-use saturations, end-use fuel shares, end-use equipment efficiency shares, and end-use consumption
- Includes new construction and existing construction demolition/major renovation rates by building type
- Includes adjustments from climate forecast
- 8760 level results, built up from equipment load shapes



Technical Potential

Characteristics:

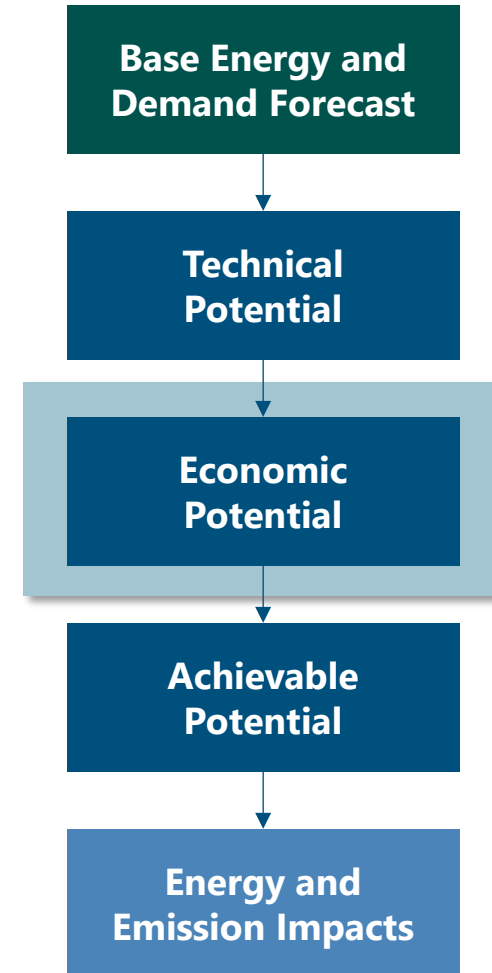
- Represents the maximum energy impact from study measures (technically feasible), regardless of economics or customer choice
- Built up from equipment load shape
- Estimates energy efficiency and electrification impacts separately due to downstream / interactive effects
- Develops database of measure-level impacts
- Incorporates equipment turnover assumptions, technical feasibility, and baseline code assumptions
- Accounts for interactions among measures—a treatment called measure stacking—to avoid overestimating total savings



Economic Potential

Characteristics:

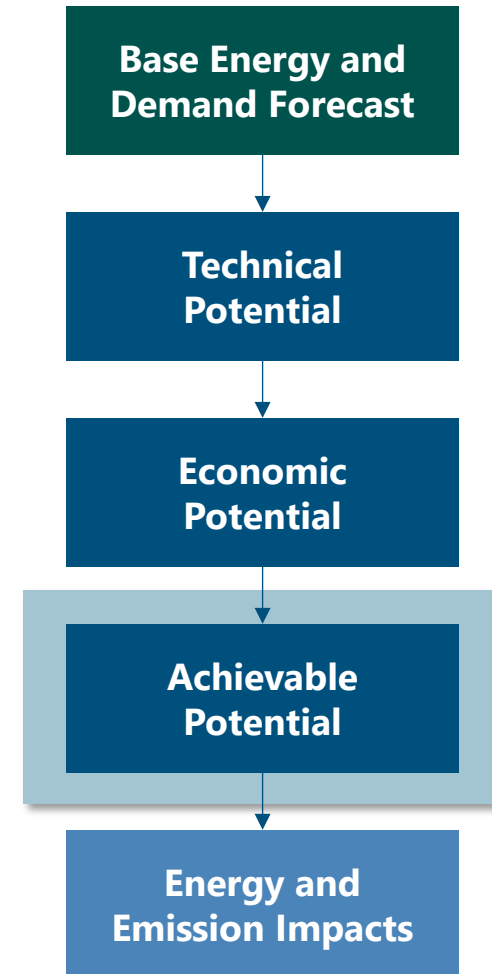
- Subset of technical potential, representing measures in technical potential that pass the IESO cost-effectiveness test
- Competing options weighed by customer decision-makers, the option with the highest energy impact that passed the cost-effectiveness screen is installed, regardless of other barriers
- The difference between technical and economic potential is the number and type of measure units assumed to be installed
- Data includes (but are not limited to) avoided energy, capacity, and transmission costs; discount rate; and forecasted electricity rates



Achievable Potential

Characteristics:

- Subset of economic potential that accounts for real-world market barriers to adoption of efficiency measures
 - Simulates customer decisions based on customer economics and adoption attributes (customer, technology, and market)
- Competing options weighed by the proportional measure market share
 - Allows for most mature and economically appealing options to claim the largest market shares without resorting to a simplistic winner-takes-all assumption
- Does not consider program / portfolio design or delivery mechanisms (this study does not estimate program potential)



Energy Consumer Segments, Modeling Considerations, and Impacts Measured

Customer Segmentation

Building Segments

Residential: Single-Family Attached, Single-Family Detached, Multifamily, Multifamily 5+ stories, Other

Commercial: Large Office, Office, Large Retail, Retail, Schools, Hospitals, etc.

Industrial: Primary Metals, Paper, Wood Products, etc.

Building Vintages

New, Existing

Residential Income Strata

Standard, Income Qualified

Residential Ownership Type

Owner, Renter

Geography

10 IESO Zones

Modeling Considerations



Building energy codes and appliance standards



Climate impacts on weather-sensitive measures



Non-energy impacts (applicable)



Underserved communities and equity



Customer choice adoption



Energy efficiency and electrification interactions

Reporting Metrics / Measures

Electric Energy Efficiency

MWh, MW Winter / Summer Peak, Economic Screen, Units

Electrification

MWh, MW Winter / Summer Peak (increase load), Economic Screen, Units

Energy Efficiency and Electrification Assumptions

Interactions can be measured over time or between measures within a single year.



Over Time

Measured by reducing end-use consumptions to account for all previously installed measures



Between measures within a single year

Stacking uses end-use percentage savings:

- First measure in stack saves full energy
- Subsequent measures save less energy due to previously installed measures

Not all measures are stacked: many water-saving measures are not (faucet aerator, showerhead)

Assume end-use equipment upgrades are installed first, then other measures in order of cost-effectiveness

Example

Three stacked measures each save 10% of an end use that consumes 1,000 kWh per year.

1st saves:

$$10\% * 1,000 = \mathbf{100 \text{ kWh}}$$

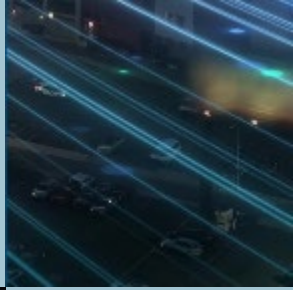
2nd saves:

$$10\% * (1,000 - 100) = \mathbf{90 \text{ kWh}}$$

3rd saves:

$$10\% * (1,000 - 190) = \mathbf{81 \text{ kWh}}$$

Appendix C: Demand Response Methodology Detail



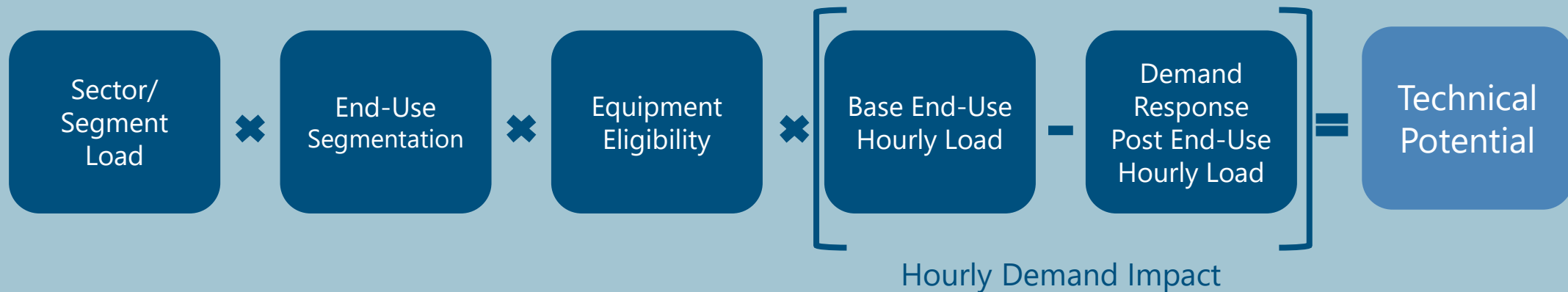
Demand Response Technical Potential

Technical potential assumes 100% participation and represents a theoretical limit for unconstrained potential

Methodology: Technical Potential

Each demand response opportunity will be characterized with the following steps:

- Reference load and peak coincidence
- Product design and impact
- Eligible market size
- Product competition



Demand Response Achievable Potential

Achievable potential is a subset of technical potential that accounts for real-world market barriers to the adoption of demand response opportunities

Methodology: Achievable Potential

The achievable potential will account for three assumptions:

- The maximum rate of adoption is the expected market maximum for a given price (incentive)
- The adoption ramp rate is the expected annual rate of incremental product enrollment to reach program maturity (also known as the maximum rate of adoption)
- Event participation represents the percentage of program customers who are expected to participate in an individual event



Adoption Approach

Assuming a customer is eligible and aware of a program offering, two main factors influence the decision to participate:

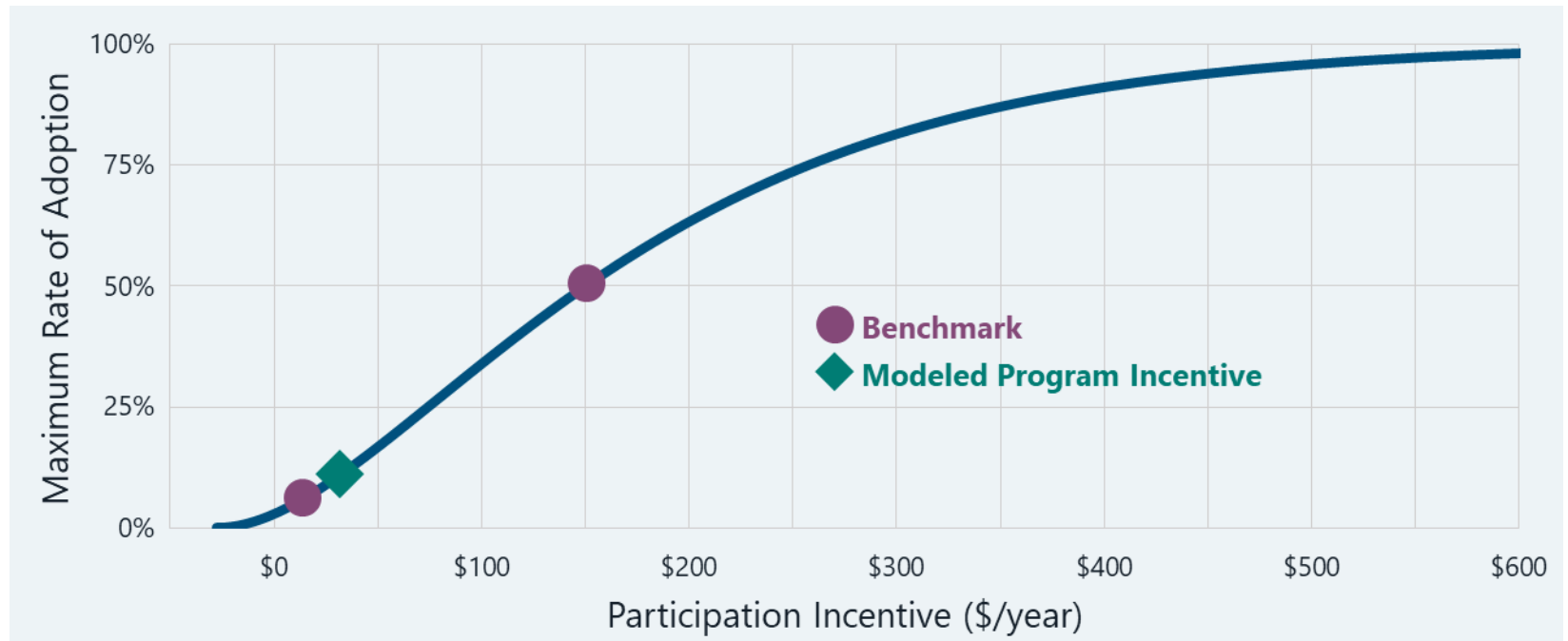
- Participation incentives
- Perceived cost of participation (including enrollment burden, discomfort, loss of privacy, loss of productivity, etc.)

The cost is subjective and varies across the population.

Using benchmarks, we can characterize the preference distribution and predict adoption at various incentive levels.



Methodology: Maximum Rate of Adoption



- For each program, using two benchmark points, we fit a curve using the CDF of a gamma distribution.
- This approach is flexible. We can take any incentive/adoption pair as benchmark points.
- This approach also allows us to calibrate to elasticity data. In this example the average elasticity is ~ 0.64 between benchmark points.

Point	Incentive Level	Max Adoption
Benchmark #1	\$10	5%
Benchmark #2	\$150	50%
Modeled Program Incentive	\$25	8.9%

Demand Response Economic Potential

Economic potential is a subset of achievable potential that represents potential from cost-effective measure applications

Methodology: Economic Potential

Four key factors affect the cost-effectiveness of demand response programs:

- The expected load reduction (in kW) provided by each participant
- The avoided capacity, transmission, and distribution costs
- Key financial assumptions such as discount rate, T&D line loss, and analysis period
- The fixed and variable costs of each program

The direct program costs of a demand response option can include setup costs, program operation and maintenance costs, equipment cost, marketing cost, and incentives